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Ranking of Air Force Heating Plants Relative to the Economic Benefit of Coal Utilization

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OPERATED BY
MARTIN MARIETTA ENERGY SYSTEMS, INC.
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Engineering Technology Division

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LIST OF SYMBOLS, ABBREVIATIONS, AND ACRONYMS

AAC	Alaskan Air Command
AEO	Annual Energy Outlook
AFB	Air Force base
AFESC	Air Force Engineering and Services Center
AFLC	Air Force Logistics Command
AFS	Air Force station
AFSC	Air Force Systems Command
ATC	Air Training Command
AU	Air University
Btu	British thermal unit
BBtu	billion Btu
CY	calendar year
DEIS	Defense Energy Information System
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ESP	electrostatic precipitator
FBC	fluidized-bed combustor
FY	fiscal year
gal	gallon
HHV	higher heating value
h	hour
HTHW	high-temperature hot water
kWh	kilowatt hour
$K	thousand dollars
lb	pound
LCC	life-cycle cost
MAC	Military Airlift Command
MAJCOM	major command
MBtu	million Btu
MCP	Military Construction Program
MFBI	Major Fuel Burning Installation
ORNL	Oak Ridge National Laboratory

O&M	operating and maintenance
ROM	run-of-mine
ROR	rate of return
SAC	Strategic Air Command
SOYD	sum-of-the-years digits
UPW	uniform present worth
USAFA	United States Air Force Academy

RANKING OF AIR FORCE HEATING PLANTS RELATIVE TO THE ECONOMIC BENEFIT OF COAL UTILIZATION

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ABSTRACT

The Defense Appropriations Act of 1986 requires the Department of Defense to use an additional 1.6 million tons of coal per year at their U.S. facilities by 1995. It also states that the most economical fuel should be used at each facility. To comply with this act, the United States Air Force requested Oak Ridge National Laboratory to evaluate the feasibility and economics of using coal at Air Force heating plants that currently burn natural gas and/or oil. A life-cycle cost analysis of 16 heating plants was performed, and the results were used to rank the facilities from best to worst according to their potential for economical utilization of coal. As many as 12 different coal combustion technologies were analyzed at each Air Force site. Also, two types of financing and three levels of fuel escalation were examined in the analysis for a total of six economic scenarios. The heating plants at Arnold, Kelly, Grand Forks, Minot, Robins, Plattsburgh, and McGuire Air Force bases were consistently identified as the top seven facilities for coal conversion, but the actual amount of cost savings will be strongly dependent on future fuel escalation rates.

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1. EXECUTIVE SUMMARY

1.1 BACKGROUND

The Defense Appropriations Act of 1986 (PL 99-190 Section 8110) requires the U.S. Department of Defense (DOD) to use an additional 1,600,000 short tons per year of coal at their U.S. facilities by 1995. It also states that the most economical fuel should be used at each facility. To comply with this act, the United States Air Force requested Oak Ridge National Laboratory (ORNL) to evaluate the feasibility and economics of replacing gas- and/or oil-firing at Air Force heating plants with coal-firing.

In a previous study by ORNL,[1] commercial and near-commercial coal-burning technologies applicable to conversion of Air Force facilities were reviewed. The capital, operating, and maintenance costs for these coal technologies were estimated generically for typical heating plant installations, from which cost equations were formulated and put into a cost-estimating computer model for use in subsequent tasks. For comparison, the computer model also included cost estimates for gas- and oil-fired boilers.

In a second study by ORNL,[2] Air Force installations that currently burn significant quantities of gas and/or oil were reviewed to determine a list of 15 to 20 candidate sites for conversion to coal. Experience has shown that small heating plants (annual average fuel usage <30 MBtu/h) will be unable to burn coal economically in the near future. Using this fuel-use criteria as a cutoff point, in conjunction with a simple economic analysis based on the use of uniform present worth factors, a list was developed consisting of 16 Air Force sites that could potentially use coal with a cost savings.

1.2 DESCRIPTION

In this report, the 16 Air Force sites mentioned above were evaluated further to determine their relative potential for cost savings through coal utilization. The types of projects examined were ones that incorporate coal-firing to meet only the base load of a given heating plant; it was assumed that gas and/or oil would continue to be used for peaking and backup requirements. Commercial and near-commercial coal combustion technologies were evaluated, including technologies for both refitting and replacing existing boilers. As many as 12 coal technology options were considered for each Air Force site.

An economic analysis was performed using the cost-estimating computer model that was developed during an earlier task of the project, together with a newly developed life-cycle cost (LCC) computer model. The economic results were evaluated by calculating a benefit/cost ratio for each coal-conversion option at each site. In this study, the term "benefit" is used to refer to cost avoidance (i.e., the cost of continued operation of an existing system) rather than cost savings (i.e., the difference between the cost of an existing system and the cost of a new system). The benefit/cost ratio is therefore defined as the LCC of the portion of the existing gas- or oil-fired system that would be displaced by coal, divided by the LCC of the new coal-fired system. The 16 Air Force sites were then ranked from best to worst according to the benefit/cost ratios for the most cost-effective coal technology at each site.

The LCC results were found to be very sensitive to the assumed fuel escalation rates; therefore three separate escalation scenarios were examined. These three escalation assumptions represent high, medium, and low cases for escalation of gas and oil prices relative to coal prices. The high fuel escalation case was developed from DOD guidelines for energy-dependent economic analyses.[3] These DOD escalators are based directly on the *Annual Energy Outlook 1986* report, published by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE).[4] The DOD fuel escalation scenario just described will be referred to as the "nominal" case.

The second fuel escalation scenario was developed from the recently published *Annual Energy Outlook 1987* report.[5] The 1987 projections for fuel escalation are somewhat lower than the 1986 projections, and they represent a medium fuel escalation scenario. This second set of escalators is referred to as the "AEO 1987" fuel escalators. A third escalation scenario was also examined; simply assuming zero escalation of fuel prices.

In addition to the three assumptions for fuel escalation, two types of financing were examined: Air Force-owned and -financed projects and privately owned and financed projects. The combinations of fuel escalation and type of financing produce six economic scenarios that have been examined. Tables 1.1 and 1.2 summarize the ranking results for the most cost-effective coal-conversion project (highest benefit/cost ratio) at each site.

1.3 RESULTS AND RECOMMENDATIONS

Tables 1.1 and 1.2 show that the three fuel escalation scenarios have a very significant effect on the calculated benefit/cost ratios for

Table 1.1. Summary of Air Force-financed project results for the most cost-effective technology

Base	"Nominal" fuel escalation		"AEO 87" fuel escalation		Zero fuel escalation		Projected coal use (tons/year)
	Benefit/cost ratio	Rank	Benefit/cost ratio	Rank	Benefit/cost ratio	Rank	
Arnold	2.141	1	1.616	1	1.191	1	23,650
Kelly	1.798	2	1.369	2	1.022	3	16,010
Minot	1.743	3	1.348	3	1.018	4	12,180
Robins	1.737	4	1.330	5	1.003	6	17,270
McGuire	1.643	5	1.264	7	0.950	7	13,220
Grand Forks	1.632	6	1.345	4	1.057	2	13,500
Plattsburgh	1.562	7	1.281	6	1.011	5	16,340
Pease[a]	1.540	8	1.196	8	0.917	10	13,060
Tinker	1.532	9	1.151	11	0.840	14	45,680
Elmendorf[b]	1.527	10	1.146	12	0.851	12	154,370
Hill	1.486	11	1.141	14	0.848	13	23,560
Scott	1.473	12	1.141	13	0.854	11	13,730
Dover	1.434	13	1.188	9	0.947	8	12,470
Andrews	1.431	14	1.185	10	0.945	9	12,940
USAF Academy	1.339	15	1.038	15	0.790	16	24,990
Hanscom	1.267	16	1.035	16	0.828	15	20,140
						Total	433,110

[a]LCC results for Pease may be optimistic because of questionable access to inexpensive rail delivery for coal.

[b]LCC results for Elmendorf may be optimistic because of questionable availability of inexpensive coal.

Table 1.2. Summary of privately financed project results for the most cost-effective technology

Base	"Nominal" fuel escalation		"AEO 87" fuel escalation		Zero fuel escalation	
	Benefit/cost ratio	Rank	Benefit/cost ratio	Rank	Benefit/cost ratio	Rank
Arnold	1.946	1	1.468	1	1.077	1
Kelly	1.608	2	1.223	2	0.909	6
Robins	1.586	3	1.213	4	0.911	5
Minot	1.567	4	1.211	5	0.912	4
McGuire	1.482	5	1.140	7	0.854	7
Grand Forks	1.474	6	1.213	3	0.951	2
Plattsburgh	1.425	7	1.168	6	0.918	3
Elmendorf[a]	1.386	8	1.039	11	0.767	11
Pease[b]	1.384	9	1.075	8	0.820	10
Tinker	1.304	10	0.979	12	0.711	14
Dover	1.295	11	1.073	9	0.851	8
Andrews	1.287	12	1.066	10	0.846	9
Scott	1.263	13	0.978	13	0.72[illegible]	13
Hill	1.252	14	0.961	14	0.710	15
Hanscom	1.168	15	0.954	15	0.760	12
USAF Academy	1.152	16	0.894	16	0.678	16

[a]LCC results for Elmendorf may be optimistic because of questionable availability of inexpensive coal.

[b]LCC results for Pease may be optimistic because of questionable access to inexpensive rail delivery for coal.

coal-conversion projects. There is much uncertainty associated with future fuel prices, and caution should be used when interpreting the results. A large number of projects appear to be economically viable when the DOD fuel escalators ("nominal" case) are used, and only a small number appear economical if zero fuel escalation is assumed. There are no profound differences observed between the Air Force- and private-financing cases; the benefit/cost ratios are only slightly higher for Air Force financing.

Although the fuel escalation assumptions can greatly affect the benefit/cost ratios, some consistency is observed regarding the ranking of the Air Force sites. Arnold is consistently ranked first for all six economic scenarios in Tables 1.1 and 1.2. The sites ranked 2 through 7 include Kelly, Grand Forks, Minot, Robins, Plattsburgh, and McGuire, although their respective order changes. These seven sites are recommended as the leading candidates for project implementation.

The potential coal usage listed in Table 1.1 shows that, with the possible exception of Elmendorf, a relatively small amount of coal would be used by any individual project when compared to the DOD target of 1,600,000 tons/year. Projects at the top seven Air Force bases would consume only about 112,000 tons/year. Other types of projects that would use greater amounts of coal, such as cogeneration or increasing heating loads through distribution system extensions, should be examined.

Noneconomic factors such as Air Force energy security, aesthetics, and possible effects on base missions have not been considered up to this point. Obviously, these types of considerations must be factored into future decision-making processes.

2. INTRODUCTION

ORNL is supporting the Air Force Coal Utilization/Conversion Program by providing the Air Force Engineering and Services Center (AFESC) with a defensible plan to meet the provisions of the Defense Appropriations Act of 1986 (PL 99-190 Section 8110). This Act directs the Air Force to implement the rehabilitation and conversion of Air Force central heating plants [either steam or high-temperature hot water (HTHW)] from natural gas- and/or oil-firing to coal-firing, if a cost savings can be realized. This directive applies to Air Force installations in the contiguous 48 states and Alaska.

2.1 RELATED WORK

ORNL has been involved in the Air Force Coal Utilization/Conversion Program since 1986. In a previous report by ORNL for AFESC,[1] the full range of commercial and near-commercial coal-burning technologies applicable to the conversion of Air Force central heating plants was reviewed. General descriptions and characterization of each technology are presented including the degree of commercialization or development, combustion efficiency, environmental performance, applications, and limitations. The capital and operating costs for these technologies have been estimated for generic or typical heating plant installations. These cost estimates were formulated into algorithms and put into a spreadsheet computer program for use in subsequent studies.

In another report by ORNL,[2] Air Force installations currently burning significant quantities of gas and/or oil were reviewed. This previous report was a screening study to find the installations most suitable for coal use. Heating plants at 16 installations were identified as having enough potential for coal utilization with an economic benefit to warrant further analysis. The 16 Air Force bases previously identified are considered further in this report. More details of the previous screening study are explained in Chap. 3.

A complementary study for AFESC was completed recently by ORI Inc. and C. H. Guernsey and Co.[6] That study examined central heating plants at 34 selected Air Force bases. Leading candidate heating plants were identified for a few specific coal-conversion scenarios. Those scenarios fit into two categories: (1) complete conversion of the existing steam/HTHW systems to stoker coal-firing by boiler conversion or replacement, and (2) building coal-fired cogeneration systems sized to meet peak electric loads. Stoker-firing was the only coal technology considered in the ORI Inc./C. H. Guernsey and Co. report.

2.2 PURPOSE

The primary objective of this study is to establish a priority list of Air Force sites with the best potential for cost-effective coal utilization. A small number of installations are identified as leading sites for coal-utilization project implementation.

The analysis work provides a quantitative ranking of the heating plants at each site according to the economic benefit of coal utilization. In order to accomplish this ranking, a wide variety of coal-burning technologies have been evaluated in this study. Heating plant conversion may include alteration of existing boilers with the addition of certain equipment to allow coal-firing, or adding a new coal-fired boiler system to the heating plant. Cogeneration of heat and electricity will be considered in a separate report.

2.3 METHOD

Available information about Air Force central heating plants has been collected and organized to examine conversion to coal-firing. Emphasis was put on determining steam/HTHW loads, electric loads, existing boiler design and condition, current fuel costs, local environmental regulations, and site-specific factors that will affect conversion project costs and technology selection. The 16 candidate heating plants identified in the previous screening study[2] were examined more closely, and LCC economic analyses were performed for each heating plant. The plants were then ranked according to the results of the economic analyses.

A variety of coal technology options were examined for each site. These technology options are described in a previous ORNL report[1] and discussed very briefly later in this report. A computer model was developed to generate itemized costs for each coal-burning technology based on project size, capacity factor, fuel costs, coal specifications, SO_2 removal requirements, electricity costs, and other variables. Cost estimates can be generated for as many as seven boiler refit technologies and six types of replacement boilers. For comparison, the cost of continued operation of the existing gas-/oil-fired system that would be replaced by coal-firing is also calculated. The cost of the gas/oil system represents the expenditures that can be avoided by switching to coal.

For each Air Force site, conversion project specifications, such as steam/HTHW output capacity and type of coal technology, were selected on the basis of economics and site-specific limitations. Because high capacity factors are generally required for coal systems to be economical, the typical result is that only a portion of the maximum steam/HTHW load should be met with coal-firing, while the remaining steam/HTHW load should be met with gas/oil peaking units. This is a notable contrast to the ORI Inc./C. H. Guernsey and Co. report, which used the assumptions of 100% coal-firing capability for all heating plant conversions and stoker-firing as the only technology option.

Two types of project financing are analyzed in this report. One scenario represents an Air Force-owned project using Military Construction Program (MCP) funds, and the other scenario assumes that a private company builds, owns, and operates the heating plant. The economic assumptions and their effects on the results are discussed in Chaps. 5 and 6.

2.4 LIMITATIONS

This study has certain limitations relating to site and fuel cost data. Some of the site-specific information is either unknown or incomplete, and therefore some of the project options and possible problems are unknown. Detailed architectural, engineering, and environmental studies will be required before implementing an actual project.

Another condition that cannot be predicted accurately is future changes in fuel prices. This is an especially important consideration in this study because it is likely that coal, gas, and oil prices will all escalate at different rates. Fuel prices greatly affect the LCCs of the existing gas/oil systems as well as all of the potential coal-conversion projects. The LCC estimates must be updated as fuel price conditions change.

Despite some limitations, the cost-estimation and economic analyses described in this report have provided an effective way to identify and rank Air Force central heating plants that have the best potential for coal utilization. The information presented in this report can be used for future studies leading to actual project implementation at selected heating plants.

3. PREVIOUS HEATING PLANT SCREENING STUDY

A previous report[2] was aimed at narrowing the number of gas- and/or oil-burning Air Force facilities to be considered as viable coal-utilization candidates. ORNL reviewed and analyzed data pertaining to gas- and/or oil-fired central heating plants and documented the results in that report. The objective of the screening study was to develop a list of the 15 to 20 Air Force sites with the best potential for conversion to coal.

3.1 SOURCES OF INFORMATION

Reliable information characterizing the Air Force heating plants was necessary to accomplish the objectives of the previous screening study. The information needed for each Air Force base included current fuel use, heating load profile, fuel prices, possible coal delivery methods, boiler design and condition, status and condition of peripheral equipment, and electric power consumption and price.

ORI Inc. and C. H. Guernsey and Co. report. A major source of information was the report entitled *Air Force Coal Conversion Phase III Discovery and Fact Finding Study* by ORI Inc. and C. H. Guernsey and Co.[6] In that report, 34 Air Force bases were examined by using questionnaires, telephone contacts, and personal visits to gather information needed to assess coal use at the central heating plants. Other sources of information, such as previous Air Force assessments, were also used to supplement those efforts to obtain information. This study was particularly helpful because current gas, oil, and electricity prices were obtained, as well as load information, heating plant capacity-rating data, and other up-to-date information.

MFBI survey. Useful information concerning many important Air Force heating plants was found in the results of a 1980 inventory of Air Force boilers larger than 10 MBtu/h output capacity. This inventory was part of the Federal Facilities Power Plant and Major Fuel Burning Installation Survey (MFBI Survey) requested by DOE by authority of the Power Plant and Industrial Fuel Use Act of 1978.

Much information that is useful for analysis of the central heating plants was included in this MFBI Survey. The major drawbacks were that some Air Force base surveys were incomplete or contained conflicting information. The MFBI Survey information is dated, and a few heating plants have been upgraded or the heating loads have changed somewhat in the interim.

Other sources. Several other sources of information were also utilized for the previous screening study, including contacts with knowledgeable individuals, applicable Defense Energy Information System (DEIS) data, several internal studies of Air Force heating plants, and a boiler data base developed by the U.S. Army's Construction Engineering Research Laboratory from Hartford Steam Boiler Co. data. This data base was helpful in cross-checking the existence and capacity ratings of individual boilers. The internal Air Force studies provided 1985 and 1986 load information (steam/HTHW and electric) for selected Air Force bases.

3.2 SELECTION OF CANDIDATE AIR FORCE SITES

3.2.1 Fuel-Use Criteria

In the previous screening study, a list was made of Air Force gas- and/or oil-burning heating plants identified as significant fuel users. Information pertaining to these heating plants was then examined more closely. Large plants were sought because coal utilization is much more competitive at large sizes. Favorable economics for coal use depends on displacing large amounts of gas and/or oil with coal. Furthermore, capital, operating, and maintenance costs for coal-fired boiler equipment have less impact on total costs as the size of the boiler increases (see discussion of economy of scale in Sect. 5.2.1).

A list was developed identifying 26 heating plants at 24 Air Force facilities that have a reported annual fuel use >260 BBtu (annual average fuel consumption >30 MBtu/h). Based on experience, it was judged that facilities using less energy than this cutoff point could not be viable candidates for coal use in the near term. All heating plants for which at least one source of data indicated a fuel use >260

BBtu/year are included in Table 3.1. Note that two heating plants are treated as a single system at Andrews Air Force Base (AFB) because they feed into a common distribution system.

3.2.2 Uniform Present Worth Economic Analysis

In the previous screening study, a relatively simple economic analysis was used to identify where coal would be economically competitive with the current fuel being used. This process allowed the elimination of ten additional heating plants from further consideration by verifying that they were very poor candidates for coal use. In this way, the study identified 16 gas- and/or oil-fired heating plants at 16 Air Force bases that should be investigated further to determine their potential for coal utilization.

The previous economic analysis was not as sophisticated or detailed as the one presented later in this report. In the previous analysis, the annual fuel, operating, and maintenance costs were multiplied by a uniform present worth (UPW) factor to determine their present values. The assumption was made that these series of annual costs would remain uniform over the life of the project. Projects were chosen for each heating plant based on conversion of only a portion of the plant to coal-firing; one or two boilers at each heating plant were assumed to be refitted for coal-firing or replaced with new coal-fired boilers. Each project was optimized to be near the most cost-effective size. The cost-estimation and economic assumptions used in the UPW analysis are listed in Table 3.2. The economic assumptions resulted in a UPW factor of 9.427.

The capital investment requirements, operating and maintenance (O&M) costs, and fuel costs for each simulated project were estimated in the previous screening study with the aid of a cost-estimation computer model. This model has been reused in this ranking study, but different values are used for the input parameters to reflect new information about the Air Force bases. The cost-estimation model is described in Sect. 5.1 of this report.

Each heating plant was evaluated according to the economic benefit of conversion to coal. Those plants that showed the least promise for

Table 3.1. Heating plants meeting fuel-use criteria

Base	Major command	Building No.	Number of units	Type of fuel[a] Pri	Type of fuel[a] Sec	Plant output capacity (MBtu/h)	1978 Fuel use (BBtu)	1978 Lim[b]	1979 Fuel use (BBtu)	1979 Lim[b]	1985 Fuel use (BBtu)	ORI/ Guernsey survey (BBtu)
Elmendorf	AAC	22-004	6	G	2	900	2673		2694			2616
Hill	AFLC	260	8	G	2	258	1331		1087		1074	
Hill	AFLC	825	3	G	2	150					300	
Kelly	AFLC	376	5	G	2	259	597		570		540	504
McClellan	AFLC	367	2	G	5	100	129	G	170	G	340	
Robins	AFLC	177	5	G	2	358	948		903		865	872
Tinker	AFLC	3001	3	G	2	291	1262		1411			
Tinker	AFLC	208	4	G	2	164	671		647			
Arnold	AFSC	1411	4	G	2	240	599		589			642
Hanscom	AFSC	1201	4	6	G	203	739		751			856
Keesler	ATC	409	5	G	2	84						300
Lowry	ATC	361	4	G	2	232	222		269			199
Maxwell	AU	1410	5	G	5	110	358		308			411
Andrews	MAC	1515/1732	8	6	N	295	527		546			557
Charleston	MAC	431	4	6	N	201	276		229		175	160
Dover	MAC	617	4	6	N	200	511		444		407	407
McChord	MAC	734	3	G	2	86	326		361		344	325
McGuire	MAC	2101	6	G	2	262	811		801		488	809
Scott	MAC	45	4	G	6	252	493		495		347	436
Grand Forks	SAC	423	5	6	P	159	548		611		555[c]	480[c]
Minot	SAC	413	6	G	6	167	584		644			463
Pease	SAC	124	2	G	6	220	433	6	337	6		370
Plattsburgh	SAC	2658	6	6	N	300	848		801			825
Whiteman	SAC	140	3	G	6	106	216		311			312
Wurtsmith	SAC	305	4	6	N	112	319		329			319
USAF Academy	USAFA	2560	4	G	5	380	800	?	800	?		562

[a]Fuels: Pri – primary, Sec – secondary, G – natural gas, 6 – No. 6 (residual) oil, 5 – No. 5 oil, 2 – No. 2 (distillate) oil, P – propane, N – none.

[b]Limitations on fuel-use data: G – gas use only; 6 – No. 6 oil use only, ? – data is missing or suspect.

[c]An electric boiler system was in use. An estimate of fossil fuel that would otherwise be consumed was calculated assuming a 75% boiler efficiency.

Table 3.2. Cost and economic parameters used in the UPW analysis

Cost-estimating assumptions	
Price of stoker coal	\$1.75/MBtu
Price of run-of-mine coal	\$1.50/MBtu
Price of coal/water slurry	\$3.00/MBtu
Price of coal/oil slurry	\$3.50/MBtu
Price of natural gas	Local price
Price of No. 2 distillate oil	\$4.71/MBtu (\$0.65/gal)
Price of No. 6 residual oil	\$3.67/MBtu (\$0.55/gal)
Labor rate	\$35,000/man-year
Ash disposal price	\$10/ton
Electric price, \$/kWh	Local price
No active SO_2 removal required	
Economic assumptions	
Air Force-owned and -operated project	
Economic life is 30 years	
Real discount rate is 10%	
UPW factor applied to fuel and O&M costs is 9.427	
All capital is invested at the beginning of the project	
No salvage value after 30 years	
No local property taxes and insurance	
No real escalation of fuel and O&M costs	
General inflation effects are negligible	

being candidates from an economic standpoint were reviewed further by considering annual fuel use, annual electric use, and electric price (cogeneration possibilities). For McClellan, the strict California environmental regulations were also considered. Using this information to make judgements, the heating plants at McClellan, Keesler, Lowry, Maxwell, Charleston, McChord, Whiteman, and Wurtsmith were eliminated along with plant No. 825 at Hill and plant No. 208 at Tinker. Hill and Tinker have larger heating plants remaining in the list.

The results of the screening study produced a list of 16 heating plants at 16 Air Force bases to be given further consideration. Each of the remaining sites has a single heating plant that may be a viable candidate for a conversion project, with the exception of the two plants at Andrews that are treated as a single system because they are connected to a common distribution system. The relative potential for coal utilization at these 16 Air Force installations is the subject of the remainder of this report.

4. NEW INFORMATION FOR 16 CANDIDATE AIR FORCE SITES

This chapter describes the efforts since the heating plant screening study was completed. It was deemed necessary to produce a more in-depth analysis of the remaining 16 Air Force sites to accurately rank them according to the economic benefit of coal utilization. Many of the differences between the previous screening study and this current ranking effort are highlighted in this chapter.

4.1 LOCAL COAL PRICES AND PROPERTIES

It is important to understand the prices and characteristics of the coals available at each prospective site. To obtain such information, a large number of coal suppliers and transportation companies were contacted. Information was requested for both stoker-grade and run-of-mine (ROM) coals.

Each request to coal suppliers asked for the mine mouth price (more precisely, the price of coal brought to a specific rail or truck loading point) and the following characteristics for each coal: higher heating value; content of ash, sulfur, nitrogen, and fines; top and bottom size; ash-softening temperature; swelling index; and grindability index. The transportation costs were estimated by the coal supplier and/or the railroad companies that would be involved. Generally, rail delivery is cheaper when the delivery distance is significant (>200 miles). When rail shipment was not possible or inappropriate, truck delivery rates were estimated.

The use of locally available coal properties and prices in this study represents a significant improvement over the previous screening study, which assumed uniform coal prices of $1.50/MBtu for ROM coal and $1.75/MBtu for stoker coal. The coal properties and prices that were used for each Air Force site are summarized in the Appendix.

4.2 LOCAL ENVIRONMENTAL REGULATIONS

To understand the environmental control requirements for each Air Force site under consideration, the appropriate state agencies were contacted. Most of the 15 states contacted sent copies of the latest regulations and other helpful material. Another highly utilized source was the *Environmental Reporter*,[7] which publishes state environmental regulations.

Federal environmental regulations applicable to fossil-fuel-burning installations were also reviewed. Generally, the federal regulations only apply to coal-burning systems with fuel input capacities >100 MBtu/h. However, if the site is located in, or near, a zone ruled to be in noncompliance with ambient SO_2, NO_x, or particulate standards, special federal regulations can apply regardless of size. Information to determine if a given Air Force base is within a noncompliance zone was available from other ORNL studies.

In the previous screening study, the costs of SO_2 or NO_x reduction were not included in the analysis, although particulate removal costs were included in all cases (baghouses were assumed necessary). The appropriate environmental regulations have been taken into consideration in this ranking study. For most sites it was found that when the fuel input capacity is below 100 MBtu/h, there are either no SO_2 emission regulations or low-sulfur coal will be sufficient to meet the SO_2 regulations. Furthermore, current coal combustion technology will achieve sufficient NO_x control in most cases. The effect that environmental regulations have in each specific case is discussed in the Appendix.

4.3 OTHER SITE-SPECIFIC INFORMATION

Other site-specific information not considered in the previous screening study has been included in this study. This is the result of more information being obtained and also implementation of a more detailed analysis. The availability of FY 1986 fuel-use data led to the revision of the expected capacity factors for some heating plants. The expected capacity factor is a key parameter when calculating the LCC of a coal-utilization project. Another source of information was from a separate effort at ORNL concerning energy security at Air Force installations.[8] Also, a draft copy of the information in the Appendix of this report has been sent to the appropriate major command (MAJCOM) headquarters for their review and comments. Their written and verbal responses contained new and updated information for some of the bases.

Some Air Force sites currently have no room for a coal pile on the base or perhaps only have sufficient space at a site remote from the central heating facility. This affects the type of coal technologies that can be used at the site. Another space problem that can occur is when there is very little room near the existing boilers because of the presence of other equipment and other buildings. If a space shortage is severe enough, the refit technologies that require large pieces of equipment to be located near the existing boiler will be penalized or eliminated. Such space shortages were not accounted for in the previous report but are considered in this study.

The site-specific considerations that affect the economic analysis of each heating plant are described in the information summaries provided in the Appendix for each of the 16 Air Force sites.

5. DESCRIPTION OF COST-ESTIMATION AND ECONOMIC ANALYSES

5.1 COMPUTER MODEL FOR HEATING PLANT COST ESTIMATION

5.1.1 Description and Purpose

In a previous study by ORNL for the Air Force,[1] coal combustion technologies found to be applicable to Air Force central heating plants were reviewed and evaluated. As a part of that previous work, O&M and capital cost equations were developed for the many coal technology options that could be employed at a heating plant. O&M cost equations for firing gas or oil at a central heating plant were also developed for comparison. A computer model, based on these cost equations, was developed to estimate heating plant costs for each of 13 different coal technology options and for gas- and oil-firing. The costs generated for the coal technology options can be compared with each other and with the costs of continued firing of gas or oil. A much more detailed discussion of the development of the heating plant cost-estimating equations can be found in the previous report prepared for the Air Force Engineering and Services Center.[1]

The 13 coal-utilizing technologies included in the cost-estimating model are divided into the following two categories:

Refit technologies	Replacement boilers
Micronized coal-firing	Packaged shell stoker
Slagging pulverized coal burner	Packaged shell FBC*
Modular FBC add-on unit	Field-erected stoker
Return to stoker-firing	Field-erected FBC
Coal/water slurry	Pulverized coal boiler
Coal/oil slurry	Circulating FBC
Low-Btu gasifier	

The refit technologies reuse as much of the existing boiler equipment as possible. In a micronized coal system, the coal is pulverized

*FBC — fluidized-bed combustor.

to a size much smaller than ordinary pulverized coal, and it is burned directly in the existing boiler. In a slagging system, pulverized coal is burned in a small, high-temperature, cyclone burner that is connected to the existing boiler. In a modular FBC system, part of the steam/HTHW is generated in an add-on bubbling FBC unit, and the existing boiler is used as a waste heat recovery unit. The return to stoker-firing option can only be considered if the existing boiler was originally designed for stoker coal. In slurry systems, the coal/water and coal/oil mixtures are burned directly in the existing boiler. In a gasifier system, stoker coal is gasified with air in an add-on unit and the hot, low-Btu gas is burned in the existing boiler.

The replacement boilers reuse only the existing water treatment system and the steam/HTHW distribution system. For the stoker and bubbling FBC systems, both packaged and field-erected units have been examined. The packaged units are factory-built, shell (fire-tube) boilers that are small enough to be shipped by rail. The field-erected units are larger, water-tube boilers. For the pulverized coal and circulating FBC systems, only field-erected, water-tube boilers have been examined.

The costs of emission control systems for particulates, NO_x, and SO_2 are included in the cost-estimating model. All 13 coal technologies are assumed to require baghouses to meet the particulate emission regulations. Particulate control beyond cyclone-type devices is required virtually everywhere in the United States, and baghouses are judged to be the most cost-effective and appropriate technology. NO_x emissions are assumed to be controlled with conventional combustion control systems for all coal technologies. The need for active SO_2 removal systems varies from location to location, and the type of SO_2 control system required depends on the coal technology. Costs associated with SO_2 control can be included or excluded in the cost-estimating model on a case-by-case basis. The assumptions about SO_2 control systems are discussed later in Sect. 5.1.3.

The computer model consists of two corresponding spreadsheets for each of the 13 coal technologies, one for estimating the capital investment and another for estimating O&M costs. Each spreadsheet calculates an itemized cost table, such as the examples shown in Tables 5.1 and 5.2. The purpose of using this itemized cost table format is to generate very consistent and comparable cost estimates for each technology considered. Any calculated project costs can easily be examined in detail. The personal computer software package used to develop the costing program is Framework II, by Ashton-Tate Corp.

5.1.2 Basis of Costs

The cost-estimating algorithms are based on recent cost studies, vendor and user information, and applicable reported costs of coal-based projects. The cost equations for commercialized technologies were developed from a literature review and extensive previous work at ORNL.

Table 5.1. Example capital investment cost spreadsheet for micronized coal

Technology: MICRONIZED COAL BURNER - REFIT TO EXISTING BOILER 20-200 MBTU/HR

Size (MBtu/hr)
Output steam = 72.00
No. of units = 1
Output/unit = 72
Multiple unit multiplier = 1

ITEM	SCALING FACTOR	COSTS IN k$
Site work & foundations	.50	24.
Boiler modifications	.50	12.
Soot blowers	.60	0.
TAS micronized comb. system	.52	176.
Boiler house modification	.50	24.
Fuel handling & storage	.40	781.
No bottom ash system		0.
Ash handling	.40	298.
Electrical	.80	100.
Baghouse	.80	520.
Subtotal		1935.
Indirects (30%)		581.
Contingency (20%)		503.
Total for each unit		3019.
Grand total		3019.

Table 5.2. Example operating and maintenance cost spreadsheet for micronized coal

Technology: MICRONIZED COAL BURNER REFIT TO EXISTING BOILER
SIZE 10-200 MBTU/HR

Total output (MBtu/hr)	= 72.00	COAL, LIMESTONE, ASH	
Number of units converted	= 1	Ash fraction	= .10
Unit output (MBtu/hr)	= 72.00	S fraction	= .015
Fuel to steam efficiency	= .80	HHV (Btu/lb)	= 12000.00
Capacity factor	= .72	Ton coal/yr	= 23652.00
Ash disposal price($/ton)	= 10.00	Ca/S ratio	= .00
Electric price(cents/kWh)	= 4.50	Inert fraction	= .05
Labor rate (k$/yr)	= 35.00	Ton sorbent/yr	= .0
Limestone price ($/ton)	= 20.00	Waste/sorbent	= .858
		Ton ash/yr	= 2365.2

CATEGORY	SCALING FACTOR	COST IN k$
Direct manpower (f)	.18	557.9
Repair labor & materials (f)	.36	374.3
Electricity (f)	1.00	36.2
Electricity inc. baghse (v)	1.00	74.1
Baghouse (f)	.36	29.8
Limestone (v)	1.00	.0
Ash disposal (v)	1.00	23.7
Nonfuel O&M total		1095.92

A large amount of information concerning coal-, gas-, and oil-fired systems can be found in a report published by the U.S. Army Corps of Engineers, Construction Engineering Research Laboratory,[9] which includes background information and cost equations developed by ORNL for a variety of coal-based systems and other energy technologies.

Cost data for technologies that are "emerging" or not yet commercialized are either unreliable or unavailable. Therefore, costs of such systems were developed by reviewing each emerging technology and comparing with conventional coal technologies. When comparing these technologies, several cost items (equipment, maintenance, manpower) will often be identical or very similar. The differences between technologies have been explored to develop cost estimates that are consistent and comparable. Costs for certain items were developed through contact with and visits to vendors and users. Actual prices and costs were obtained (rather than budgetary estimates) whenever possible. More information concerning the development of the cost equations can be found in Refs. 1 and 9.

5.1.3 Options and Input Parameters

A list of input parameters for the cost-estimating model is given in Table 5.3. Numerical values are given for those parameters that are

Table 5.3. Input parameters for calculation of project costs

Project definition parameters	
1. Total project heat output capacity, MBtu/h	Variable
2. New boiler system expected capacity factor, %	Variable
3. Number of existing units to be refit, integer number	Variable
4. SO_2 control option, on/off switch	Variable
5. Soot blower option, on/off switch	Variable
6. Tube-bank modification option, on/off switch	Variable
7. Bottom ash pit option, on/off switch	Variable
O&M cost parameters	
8. Hydrated lime price, \$/ton	41.60
9. Ash disposal price, \$/ton	10.40
10. Electric price, ¢/kWh	Variable
11. Labor rate, \$K/(man-year)	36.40
12. Limestone price, \$/ton	20.80
Fuel prices	
13. Natural gas, \$/MBtu	Variable
14. No. 2 oil, \$/MBtu	4.71 (\$0.65/gal)
15. No. 6 oil, \$/MBtu	3.67 (\$0.55/gal)
16. ROM coal, \$/MBtu	Variable
17. Stoker coal, \$/MBtu	Variable
18. Coal/water mixture, \$/MBtu	3.00
Coal properties	
19. Ash fraction	Variable
20. Sulfur fraction	Variable
21. HHV, Btu/lb	Variable
Limestone/lime properties	
22. Inert fraction	0.050

assumed to have fixed values. The numerical values of the other parameters vary from site to site as is discussed later in Sect. 6.1.1. These input parameters and variables are defined in this section.

Project size. Three important input variables are used to define the project size. The project thermal output capacity (size) must be specified, and the expected capacity factor for the new coal-fired system is associated with a given output capacity. The way that output capacity and expected capacity factor were determined in this study is explained in Sect. 5.2.1. Inherent to choosing the capacity of any project involving refit technologies is the number of existing boilers to be converted to coal-firing. These three variables (numbered 1–3 in Table 5.3) are project specific and must be uniquely determined for each case.

SO_2 control. Based on the applicable regulations at each site, for each project it must be determined if the available coals can be burned without using special SO_2 control methods. SO_2 emissions will be controlled passively if an inexpensive low-sulfur coal is available. However, when active SO_2 removal is needed, an "on/off switch" input variable can be turned on to add costs for SO_2 control to all coal combustion technologies. This includes added costs for capital equipment, lime or limestone, labor, electricity, etc. The active SO_2 removal techniques assumed in the computer model are limestone injection for micronized coal-firing, slagging combustors, and the two slurry technologies; limestone addition for all fluidized-bed combustion technologies; lime spray-dry flue gas scrubber systems for all stoker and pulverized coal technologies; and chemical H_2S stripping from coal gasification product gas.

Existing boiler modifications. Some refit technologies require up to three types of modifications to the existing boilers: addition of soot blowers, adding a bottom ash pit (ash removal) system, and boiler heat transfer tube-bank modifications. The decision of when to include these modifications is a function of the design of the existing boilers and the type of coal-utilization technology employed. The procedure used for adding the costs of the three boiler modifications is illustrated in Tables 5.4 and 5.5 and described below. Also, background information for this decision-making process can be found in Ref. 1.

Table 5.4. Usual positions of boiler modification switches

Existing boiler design	Soot blower option	Tube-bank modification option	Bottom ash pit option
Coal	Off	Off	On
Residual oil	Off	On	On
Distillate oil	On	On	On

Table 5.5. Coal refit technologies affected when boiler modification switches are turned on

Coal refit technology	Soot blowers added	Tube-bank modification included	Bottom ash pit system added
Micronized coal-firing	Yes	No	No
Slagging pulverized coal combustor	Yes	No	Yes
Modular fluidized-bed unit	Yes	No	Yes
Return to stoker-firing	No	No	Yes
Coal/water slurry-firing	Yes	Yes	Yes
Coal/oil slurry-firing	Yes	Yes	Yes
Coal gasification	No	No	No

The computer model has three on/off switch variables (numbered 5–7 in Table 5.3) that control whether or not the costs of a particular boiler modification are included in the total costs. Table 5.4 shows how the switch positions are usually selected as a function of the boiler design. For example, if an existing boiler was designed for residual oil, it is normally assumed that the boiler already has soot blowers, but requires tube-bank modifications and the addition of an ash pit. Deviations from these usual switch positions are sometimes necessary based on more detailed information pertaining to a given boiler.

When the boiler modification switches are turned on, the appropriate costs are automatically added by the computer model to some, but not all, of the refit technologies. Table 5.5 illustrates which coal refit technologies are affected by the three boiler modification switches. For example, when a bottom ash pit must be added, costs are added to all of the refit technologies except micronized coal-firing and coal gasification.

O&M cost parameters. A number of parameters that affect nonfuel O&M costs are inputs to the cost-estimating computer model. Table 5.3 gives the values used for limestone price, lime price, ash disposal price, and labor rate. The values of these four parameters were fixed throughout this study and include a 4% adjustment from 1987 to 1988 dollars. The assumption of a uniform labor rate in the United States may be somewhat simplified, but more detailed information was not available. Locally reported values were used for price of electricity at each Air Force base.

Fuel prices. The values for fuel prices (numbered 13–18 in Table 5.3) must be specified in current dollars. These current prices may escalate with time; different escalation scenarios can be modeled by the LCC computer program. The current prices used for No. 2 and No. 6 oils were assumed to be uniform in all regions of the country and equal to the DOD stock fund prices. It is assumed that the higher heating value (HHV) of No. 2 oil is 138,000 Btu/gal and the HHV of No. 6 oil is 150,000 Btu/gal. For lack of better information, a uniform price was also used for coal/water slurry. The cost of coal/water slurry would no doubt have regional variations, but such variations cannot really be known at this time. Any price used for slurry fuels is questionable.

Local prices that vary from region to region were used for natural gas, ROM coal, and stoker coal. Gas prices reflect recent reported costs from the Air Force bases under consideration. Coal prices were determined from the study described in Sect. 4.1. The prices used were for the lowest-cost ROM and stoker coals with acceptable properties.

Coal and limestone properties. Coal properties were taken from the coal selection study described in Sect. 4.1. The properties used were for the lowest-cost ROM and stoker coals with acceptable characteristics. The inert fraction of limestone and lime (caused by impurities) was specified as a single value equal to 5% by weight. It was also assumed that lime would be hydrated with one water molecule per calcium atom.

5.2 COAL-UTILIZATION PROJECT ASSUMPTIONS

A number of choices must be made to define the scope of a coal-utilization project at a given heating plant. Section 5.1.3 already has touched on some of these choices by defining the computer input parameters and variables for the cost-estimation model. The assumptions involved in selecting actual values for some of these input variables are discussed further in this section. The procedure for choosing the size of a coal project is explained in Sect. 5.2.1, and the method for selecting applicable coal technologies at each site is explained in Sect. 5.2.2.

5.2.1 Steam/HTHW Output Capacity

When examining coal-utilization projects at a particular heating plant, it is desirable to find the optimum (most economical) size for the coal-firing equipment. The size of a coal project is defined here as the design steam/HTHW output capacity in MBtu/h. To understand how the steam/HTHW output capacity was selected for the coal-fired systems at each Air Force base, it is helpful to examine the trade-offs involved.

When compared to gas-/oil-fired boilers, coal systems require much higher capital investments and are more costly to operate and maintain. A coal system can realize an overall cost savings only if coal is sufficiently less expensive than gas or oil. A basic trade-off exists between gas/oil systems with high fuel prices and coal systems with low fuel prices but high capital and O&M costs. The optimum size of a coal-conversion project is influenced by this trade-off, which is discussed below along with some other important considerations.

Economy of scale. The costs of coal-fired boilers are affected by what is sometimes termed the "economy of scale." This means that as the design capacity of a boiler or boiler plant is increased (without major design changes), the accompanying capital investment required and annual

O&M costs also increase, but at a slower rate. The following values illustrate this principle:

	Capital investment ($)	Nonfuel O&M annual cost ($)
25,000-lb/h stoker boiler	3,250,000	761,000
50,000-lb/h stoker boiler	4,900,000	934,000

These example cost estimates are for single-boiler heating plants operating at 60% annual capacity factor and are for illustration only. It is seen that doubling the boiler system size increases the costs but does not double them. This economy of scale effect causes coal systems to be less competitive for small applications and more competitive for large applications, when compared to gas/oil systems.

Capacity factor vs size. The capacity factor is defined in this report as the total amount of heat that a boiler produces in 1 year divided by the total amount of heat that the boiler could produce if it operated at its design output capacity (maximum continuous rating) for the entire year. The Air Force heating plants examined in this report have capacity factors that range from ~25% to 40%. These low capacity factors are a result of redundancy built into most of the central heating plants. Apparently this excess capacity ensures very high heating source reliability, even at peak load conditions.

An important question that must be answered is how much plant capacity should be converted to coal-firing to achieve the best economic results. The answer depends largely on the heating load profile of a particular heating plant, but the general rule is that only a small portion of the plant should be converted. Any newly installed coal-fired equipment should be used as much as is practical to minimize the effect of capital and O&M costs. All heating load that is not provided by coal-firing should be supplied by the remaining gas- or oil-fired equipment.

The principle of "diminishing returns" is at work here. As the size of a proposed coal system is increased, the expected capacity factor for that system will decrease. For each incremental increase in the output capacity of a coal system, the incremental savings of fuel costs will decrease. Even with the economy of scale effect, a point is reached where the additional capital and O&M costs of a larger coal system are not offset by the potential fuel cost savings.

Accurate information about the load profile of an existing heating plant is needed to determine the optimum size for a coal-conversion project. The type of information available for Air Force heating plants is shown in Fig. 5.1, which illustrates an example of monthly average heating load. From this monthly average load data, "ideal" capacity factors were calculated as a function of boiler output capacity, as is shown in Fig. 5.2. These ideal capacity factors must be adjusted to account for daily and hourly load fluctuations and equipment repair time. For this study, the ideal capacity factors calculated from monthly data were multiplied by a factor of 0.9. A small table that

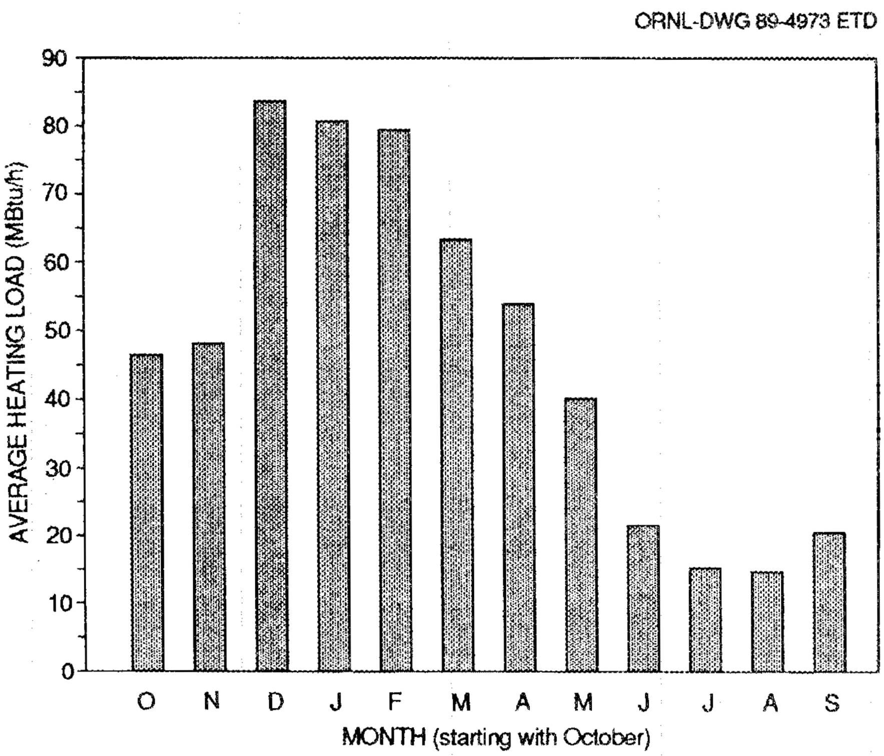

Fig. 5.1. Illustration of monthly average heating load.

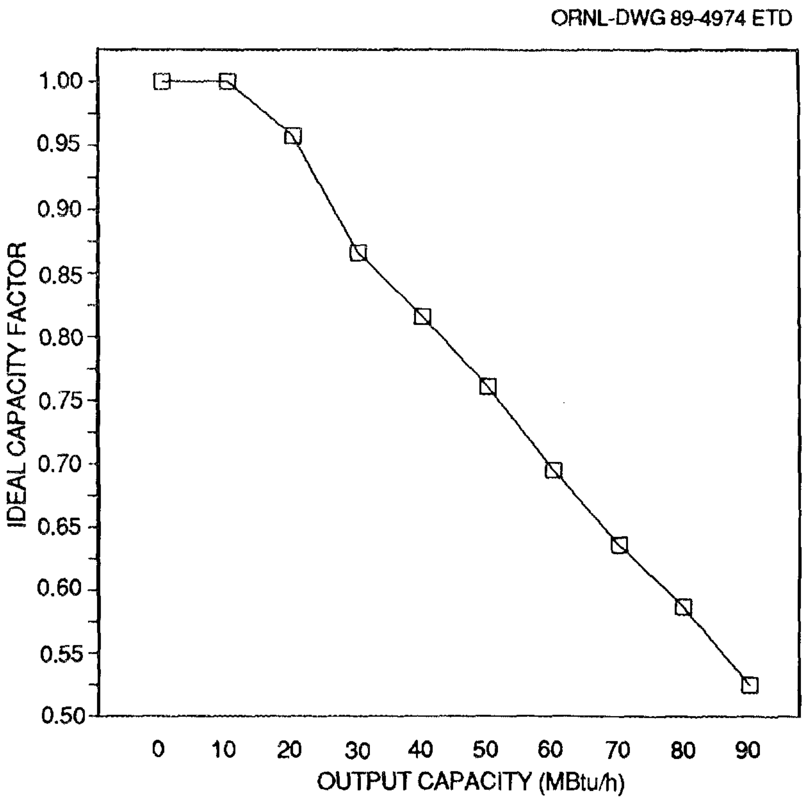

Fig. 5.2. Illustration of ideal capacity factor as a function of boiler output capacity.

lists expected capacity factor vs coal project size is included in each Air Force base information summary in the Appendix.

Size and design of existing boilers. One of the conclusions of the previous heating plant screening study[2] was that the coal refit technologies tend to be more economical than the boiler replacement technologies. Because of that trend, the analysis in this ranking study concentrated more on the refit technologies. The capacities of the existing boilers at a heating plant therefore had a strong influence on the selection of output capacity. Only one or two of the existing boilers would generally be chosen for conversion to coal-firing. This obviously limited the selection of possible output capacities to discrete steps.

The design of the existing boilers also influenced the selection of output capacity. If the existing boilers were originally designed for either coal or residual (No. 6) oil, it was assumed that the boilers have enough volume in the furnace to operate at their full design capacity with any of the coal refit technologies, if the boilers are modified as discussed in Sect. 5.1.3. However, boilers that were originally designed for distillate (No. 2) oil tend to have smaller furnace volumes with tightly spaced tubes. In addition to the boiler modifications discussed in Sect. 5.1.3, it was assumed that No. 2 oil-fired boilers would require a capacity derating of 20% to accommodate the coal combustion equipment. The boilers that were actually selected for coal refit and their capacity before and after conversion are explained in the Air Force base information summaries in the Appendix.

Emission regulations. At a few Air Force sites, the applicable SO_2 emission regulations affected the choice of project size. The federal New Source Performance Standards regulate SO_2 emissions from coal-burning equipment only if fuel input ratings are 100 MBtu/h or greater (assuming the location is in compliance with federal ambient air quality standards). When the state regulations allow coal to be burned without SO_2 removal, there is an economic incentive to keep a coal system smaller than 100 MBtu/h of fuel input (equivalent to about 75 or 80 MBtu/h of steam/HTHW output). If the design capacities of the existing boilers in a heating plant are larger than this cutoff value, then it was sometimes advantageous to derate the boilers to eliminate the need for active SO_2 removal systems. The effects of the applicable environmental regulations on each simulated project are discussed in the Air Force base information summaries in the Appendix.

5.2.2 Combustion Technologies

The 13 coal-utilizing technologies included in the cost-estimating model are discussed in Sect. 5.1.1. Only a subset of those technologies was evaluated for each particular heating plant site, and the technologies that were included or excluded were determined on a case-by-case basis. Technologies were only eliminated if a valid reason for removal was determined. The general reasoning behind the elimination of certain technologies is described here. Information pertaining to the selection of appropriate technology options for each Air Force base is found in the information summaries in the Appendix.

Coal/oil slurry. Coal/oil mixture technology was eliminated entirely from this study for a number of reasons. The cost estimates for the slurry technologies (both coal/oil and coal/water) were based on the assumption that near-term commercialization would make large quantities of slurry fuels available regionally or locally at competitive prices. However, there is currently very little interest (or research and development work) in coal/oil slurries for either industrial or utility applications. This is in direct contrast to coal/water slurry-firing, which is currently receiving much more attention. It seems that coal/oil slurries have a much smaller chance of becoming commercialized than coal/water slurries.

Coal/oil slurry-firing was judged to be much less attractive than coal/water slurry-firing if oil prices are assumed to escalate significantly faster than coal prices. Because ~50% of the coal/oil slurry heating value comes from oil, the benefit of coal/oil slurry-firing decreases rapidly as oil prices rise relative to coal prices.

There have been some technical problems specifically associated with coal/oil slurries, one of which is NO_x control. Flame temperatures have been reported to be high, causing excessive amounts of thermally produced NO_x. This type of problem is not seen with coal/water slurry-firing. Also it may not be possible to use a baghouse for particulate control with coal/oil slurries because of the possibility of blinding the bag material. An electrostatic precipitator (ESP) may be required instead of a baghouse. The disadvantage is that an ESP is a more costly technology for the size of the systems under consideration.

It is acknowledged that coal slurries containing both oil and water are being developed and marketed at this time. This type of slurry was not examined directly in this study. However, coal/water/oil mixtures are judged to be similar to coal/water slurries because only a small amount of the total heating value (<30%) comes from the oil.

Return to stoker-firing. One of the coal refit options is to reuse stoker-firing in a boiler that was originally designed for stoker-firing. If none of the existing boilers at a heating plant were designed for stoker-firing, then this refit technology must obviously be eliminated from consideration.

Space limitations. At some Air Force bases, some of the technologies could not be considered as viable alternatives because of site-specific space limitations. The two types of space considerations examined in this study were (1) space for the coal combustion and coal-handling equipment and (2) space for a coal pile. Space must be available inside a boiler house for any new boilers, boiler modifications, add-on combustion equipment, coal feeding equipment, and any coal preparation equipment such as pulverizers. The boiler house can be expanded if necessary. Space is required outside a boiler house for the day storage silos and coal conveyors. The coal pile should be located no more than a few hundred meters from the boiler house, and there must be ample room for the rail or truck unloading station as well as a 90-d supply of coal.

The refit technologies are affected when space is limited in and around the existing boiler house. The slagging combustor, modular FBC, return to stoker, and gasifier technologies were dropped from the analysis first because they require the greatest amount of equipment space in the boiler house. The micronized coal equipment occupies somewhat less room, and this technology could be retained in a few special situations when the other dry coal technologies were eliminated. All of the above dry coal technologies were eliminated when there is no room for a coal pile near the existing boiler house. The coal/water slurry technology was analyzed at all of the Air Force bases because it was assumed to require no more room than an oil-fired boiler.

The replacement technologies are affected by space limitations at both the existing boiler house and other locations on the base. All six replacement technologies could be considered at almost all of the Air Force bases. If the replacement boilers had to be located at a new heating plant, then it was assumed that the costs of connecting the new boilers to the existing distribution system would be negligible.

5.3 COMPUTER MODEL FOR LCC ANALYSIS

In addition to the cost-estimation model, a computer model devoted to LCC analysis was also developed. The LCC model has two main parts: a discounted cash flow spreadsheet and an LCC summary spreadsheet. In the cash flow spreadsheet, the capital and O&M costs (including fuel) are distributed over time, while the value of money is assumed to be time-dependent (i.e., the cash flows are discounted). The calculated LCC of a project is the summation of these discounted cash flows over the economic life of the project. In the LCC summary spreadsheet, the LCCs of the proposed coal-fired boilers are compared to the LCC of the existing gas/oil system.

Two major financing scenarios were included in the economic analysis: one for Air Force ownership and operation of the coal equipment and one for private ownership and operation. The economic assumptions used in the LCC analysis are listed in Table 5.6 for both the Air Force- and private-financing scenarios. The primary differences between the Air Force- and private-financing scenarios are in the way that capital costs and taxes are treated. Four of the parameters in Table 5.6 (general inflation, fuel escalation, discount rate, and return on investment) are labelled as variables. The values used in the LCC analysis for these four variables are discussed later in Sect. 6.1.2.

Table 5.6. Economic assumptions used in the LCC analysis

Parameter	Air Force financing	Private financing
Project start year, start of construction	1990	1990
Construction period, year	1	1
Economic life of project, years	30	30
Salvage value at end of economic life	0	0
Time-dependent curve for maintenance costs	U-shaped	U-shaped
Inflation and discounting base year	1988	1988
General inflation rate	Variable	Variable
Fuel real escalation rates	Variable	Variable
Real discount rate	Variable	Variable
Equity, percent of capital investment	Not applicable	100%
Before-tax real return on investment	Not applicable	Variable
Amount of working capital, months	Not applicable	2
SOYD depreciation life, years	Not applicable	15
Local property tax and insurance rate, %	0	2
Federal income tax rate, %	Not applicable	34
Investment tax credits	Not applicable	None

5.3.1 Air Force Financing

The Air Force-financing assumptions in Table 5.6 can be explained most easily with the aid of the example discounted cash flow spreadsheet shown in Table 5.7. Coal-fired boiler projects are assumed to start at the beginning of 1990 with a 1-year construction period. Coal-firing begins in 1991 and continues for 30 years through the end of 2020. All dollar amounts in the cash flow spreadsheet are in as-spent thousands of dollars (k$) that are inflated from a base year of 1988. However, in the example in Table 5.7, as-spent thousands of dollars are actually equal to constant 1988 thousands of dollars because the spreadsheet was calculated for zero general inflation, as is seen in the "GENERAL INFLATION INDEX" line.

The cash flow spreadsheet can accommodate fuel prices with escalation rates that differ from the general inflation rate as is seen in the "FUEL INFLATION INDEX" line of Table 5.7. Fuel inflation is calculated from the same 1988 base year as general inflation. The fuel costs shown in the "FUEL" line are determined by estimating the annual fuel cost in the 1988 base year and then multiplying by the fuel inflation index for each year.

The maintenance costs in the "MAINTENANCE" line of the cash flow spreadsheet are treated in a special way. The annual maintenance costs generated by the cost-estimation model are adjusted by the time-dependent multiplier shown in Fig. 5.3 when they are entered into the cash flow spreadsheet. The U-shaped curve accounts for extra costs that occur because of infant failures during the first 3 years of heating plant operation and old-age failures during the last 8 years.

The "TOTAL COST TO AIR FORCE" line of Table 5.7 is the sum of the annual capital and O&M costs. The present value of these total costs are calculated in the "DISCOUNTED AF TOTAL" line by discounting back to the 1988 base year. The LCC of the project appears in the lower right-hand corner of the cash flow spreadsheet.

Table 5.7. Example discounted cash flow spreadsheet for Air Force financing (17 middle years are hidden)

CASH FLOWS - AS SPENT k$

COST ELEMENT	1990	1991	1992	1993	1994		2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
GENERAL INFLATION INDEX (BASE = 1988)	1.000	1.000	1.000	1.000	1.000	- -	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	
FUEL INFLATION INDEX (BASE = 1988)	1.023	1.047	1.071	1.096	1.121	- -	1.403	1.419	1.436	1.453	1.471	1.488	1.506	1.524	1.542	
CAPITAL INVESTMENT	3,140															3,140
CAPITAL COST	3,140	0	0	0	0	- -	0	0	0	0	0	0	0	0	0	3,140
OPERATING & MAINTENANCE	0	2,600	2,288	2,245	2,254	- -	2,533	2,588	2,646	2,707	2,774	2,844	2,920	3,001	3,089	75,195
FUEL	0	1,040	1,064	1,089	1,114	- -	1,393	1,410	1,427	1,444	1,461	1,478	1,496	1,514	1,532	38,791
MAINTENANCE	0	841	504	437	420	- -	420	458	499	544	593	647	705	768	837	14,820
OTHER O&M	0	719	719	719	719	- -	719	719	719	719	719	719	719	719	719	21,584
RETURN ON WORK CAP	0	0	0	0	0	- -	0	0	0	0	0	0	0	0	0	0
BEFORE TAX INCOME	0	0	0	0	0	- -	0	0	0	0	0	0	0	0	0	0
LOCAL PROP TAX (& INSUR)	0	0	0	0	0	- -	0	0	0	0	0	0	0	0	0	0
FEDERAL INCOME TAX	0	0	0	0	0	- -	0	0	0	0	0	0	0	0	0	0
TOTAL COST TO AIR FORCE	3,140	2,600	2,288	2,245	2,254	- -	2,533	2,588	2,646	2,707	2,774	2,844	2,920	3,001	3,089	78,335
TOTAL COST TO GOVERNMENT	Not used															
DISCOUNT FACTOR (BASE = 1988)	.826	.751	.683	.621	.564	- -	.102	.092	.084	.076	.069	.063	.057	.052	.047	
DISCOUNTED AF TOTAL	2,595	1,954	1,563	1,394	1,272	- -	257	239	222	207	192	179	167	156	146	21,239
DISCOUNTED GOVT TOTAL	Not used															

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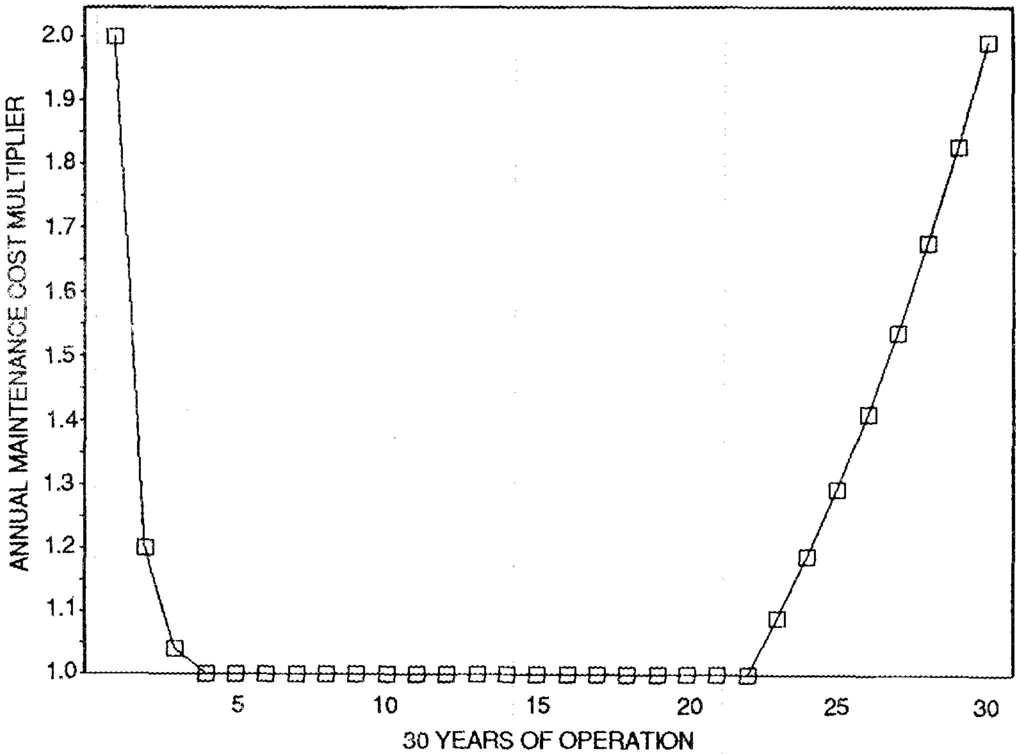

Fig. 5.3. Time-dependent multiplier applied to annual maintenance costs.

5.3.2 Private Financing

For the private-financing scenario, it was assumed that the Air Force will enter into a 31-year contract with a private company to purchase, construct, operate, and maintain the coal-fired boiler equipment. The Air Force will reimburse the contractor directly for their O&M costs and will pay the contractor an annual fee for recovery of their capital investment and profit. Many of the costs associated with private financing are identical to those for Air Force financing. The differences between private and Air Force financing are explained here with the aid of the example discounted cash flow spreadsheet for private financing shown in Table 5.8.

The annual fee in the "CAPITAL COST" line of Table 5.8 is calculated using the standard capital recovery equation over the 30-year economic life of the project with a rate of return on investment that

Table 5.8. Example discounted cash flow spreadsheet for private financing (17 middle years are hidden)

CASH FLOWS - AS SPENT k$

COST ELEMENT	1990	1991	1992	1993	1994	- -	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
GENERAL INFLATION INDEX (BASE = 1988)	1.000	1.000	1.000	1.000	1.000	- -	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	
FUEL INFLATION INDEX (BASE = 1988)	1.023	1.047	1.071	1.096	1.121	- -	1.403	1.419	1.436	1.453	1.471	1.488	1.506	1.524	1.542	
CAPITAL INVESTMENT	3,140															3,140
CAPITAL COST	0	539	539	539	539	- -	539	539	539	539	539	539	539	539	539	16,158
OPERATING & MAINTENANCE	0	2,674	2,353	2,309	2,317	- -	2,605	2,661	2,720	2,784	2,852	2,925	3,003	3,086	3,176	77,326
FUEL	0	1,040	1,064	1,089	1,114	- -	1,393	1,410	1,427	1,444	1,461	1,478	1,496	1,514	1,532	38,791
MAINTENANCE	0	841	504	437	420	- -	420	458	499	544	593	647	705	768	837	14,820
OTHER O&M	0	719	719	719	719	- -	719	719	719	719	719	719	719	719	719	21,584
RETURN ON WORK CAP	0	74	65	64	64	- -	72	73	75	77	79	81	83	85	88	2,131
BEFORE TAX INCOME	-392	246	263	288	315	- -	610	612	614	615	617	619	621	624	626	15,149
LOCAL PROP TAX (& INSUR)	63	63	63	63	63	- -	63	63	63	63	63	63	63	63	63	1,947
FEDERAL INCOME TAX	-155	62	68	77	86	- -	186	187	187	188	188	189	190	191	192	4,489
TOTAL COST TO AIR FORCE	0	3,212	2,891	2,847	2,856	- -	3,143	3,199	3,259	3,323	3,391	3,464	3,542	3,625	3,715	93,483
TOTAL COST TO GOVERNMENT	Not used															
DISCOUNT FACTOR (BASE = 1988)	.826	.751	.683	.621	.564	- -	.102	.092	.084	.076	.069	.063	.057	.052	.047	
DISCOUNTED AF TOTAL	0	2,414	1,975	1,768	1,612	- -	319	295	273	253	235	218	203	189	176	23,368
DISCOUNTED GOVT TOTAL	Not used															

will be defined in Sect. 6.1.2. It was also assumed that the contractor incurs O&M costs (including fuel costs) an average of 2 months before it is reimbursed for them. The contractor is payed the same rate of return for these 2 months of working capital. The working capital costs are itemized in the "RETURN ON WORK CAP" line of the cash flow spreadsheet.

A private contractor must pay local taxes, insurance, and federal taxes. These costs are calculated in the cash flow spreadsheet, but they do not affect the "TOTAL COST TO AIR FORCE" line of Table 5.8 because it was assumed that the contractor pays these costs out of their own pocket using their return on investment. Local property taxes and insurance are lumped together, and their annual cost was assumed to be 2% of the capital investment. The federal income tax calculations are based on the following assumptions: (1) capital equipment is depreciated over 15 years using the sum-of-the-years digits (SOYD) method with no salvage value, (2) the tax rate is 34%, and (3) the private contractor is a large company with other sources of income to balance any negative income from this project.

5.3.3 Definitions of Figures-of-Merit

The LCC summary spreadsheet lists the economic results for the existing gas-/oil-fired system plus all 13 coal technologies with either Air Force or private financing. An example LCC summary spreadsheet is shown in Table 5.9. Three different figures-of-merit are presented in the LCC summary spreadsheet: (1) LCC, (2) benefit/cost ratio, and (3) discounted payback period. These figures-of-merit are defined and discussed in this section.

Some of the coal combustion technologies that are examined in this report (such as micronized coal) are not fully commercialized. A word of caution when interpreting the economic results is that the risks and uncertainties of these newer coal technologies have not been penalized in the economic analysis relative to the more established coal technologies (such as stoker coal-firing).

LCC. The LCC of a project is the summation of the discounted annual expenditures over the 30-year economic life of the project. The LCCs shown in Table 5.9 come from the lower right-hand corner of the

Table 5.9. Example LCC summary spreadsheet for Arnold Air Force Station

ARNOLD AFS: 1 X 72 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output (MBtu/hr) = 72.0
Boiler capacity factor = .720
Number of units for refit = 1

Primary fuel = NATURAL GAS
Primary fuel price (constant 1988 $/MBtu) = 3.97

			AIR FORCE PROJECT			PRIVATE PROJECT	
TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	45,468	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	46,608	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	23,652	21,239	2.141	3.9	23,368	1.946
Slagging burner refit	1	23,652	23,168	1.963	5.7	26,489	1.717
Modular FBC refit	1	23,951	23,600	1.927	6.2	27,334	1.663
Stoker firing refit	Not applicable because existing boiler was designed for pulverized coal						
Coal/water slurry	1	25,229	27,624	1.646	5.8	29,789	1.526
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	25,348	28,215	1.612	8.3	32,101	1.416
Packaged shell stoker	2	22,633	25,101	1.811	6.4	28,476	1.597
Packaged shell FBC	2	24,897	25,226	1.802	7.1	29,303	1.552
Field erected stoker	1	21,502	25,887	1.756	7.9	30,572	1.487
Field erected FBC	1	23,652	26,247	1.732	8.4	31,346	1.451
Pulverized coal boiler	1	23,075	26,716	1.702	8.9	32,080	1.417
Circulating FBC	1	23,360	27,578	1.649	9.7	33,610	1.353

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discounted cash flow spreadsheets. The cash flow spreadsheets are executed numerous times in order to fill Table 5.9. The LCC parameter is calculated for all of the proposed coal-fired systems, as well as the existing gas-/oil-fired system that they would replace. LCCs that have been inflated and discounted over a 30-year period can result in dollar amounts that are difficult to comprehend in absolute terms. It is best if LCCs are used only for relative comparisons between projects.

Benefit/cost ratio. The term "benefit" is used in this report to refer to cost avoidance (i.e., the cost of continued operation of an existing system) rather than cost savings (i.e., the difference between the cost of an existing system and the cost of a new system). The benefit/cost ratio is therefore defined as the LCC of the portion of the existing gas/oil system that would be displaced by coal, divided by the LCC of the proposed new coal system. In the example LCC summary spreadsheet in Table 5.9, the numerators of the benefit/cost ratios are all equal to the LCC of the natural gas boiler, and the denominators depend on the coal technology and financing scenario.

The benefit/cost ratio is the primary figure-of-merit used in this report to interpret the economic results. In general, the use of benefit/cost ratios is not recommended when budget constraints are an important consideration. However, the results in this report are not intended to be used for allocating a fixed budget between competing projects; the purpose instead is to provide guidance for planning Air Force budget requests and/or planning privatized projects. The use of benefit/cost ratios ensures that cost-effective projects are not overlooked just because they are capital intensive.

Three questions can be answered by examining the benefit/cost ratios:

1. What is the best (most economical) coal technology and financing scenario at a particular Air Force base?
2. Which air base has the greatest potential for economical utilization of coal?
3. Will coal be more economical than the existing gas or oil fuels?

The first and second questions involve relative comparisons between two or more benefit/cost ratios, while the third question depends only on the absolute magnitude of the benefit/cost ratios. In the example in Table 5.9, micronized coal with Air Force financing is the best technology because it has the largest benefit/cost ratio, and it will be more economical than the existing gas system because the ratio is greater than 1.0.

Discounted payback period. This parameter is defined as the time period (measured from the beginning of construction) required for the cumulative savings from a project to pay back the initial investment and other cumulative costs of the project, taking into account the time value of money. During the first few years of a coal-fired boiler project, the cumulative discounted costs of the coal system are generally greater than the cumulative discounted costs of the existing gas/oil system because of the capital costs of the coal equipment. However, coal prices are usually less than gas/oil prices, and the cumulative costs of the coal system tend to increase with time more slowly than the cumulative costs of the gas/oil system. The discounted payback period is defined as the point in time where the cumulative discounted costs of the coal system fall below the cumulative discounted costs of the existing gas/oil system.

The discounted payback period is used in this report only as a secondary figure-of-merit for the following reasons: (1) the discounted payback period has no meaning in the private-financing scenarios where the Air Force does not invest any of their own capital, (2) the discounted payback period will sometimes be undefined because it can be greater than the economic life of the project, and (3) an economic evaluation using discounted payback periods will sometimes be misleading because it completely ignores the economic consequences beyond the payback period.

6. RESULTS OF RANKING STUDY

The cost-estimation and LCC analysis models described in Chap. 5 have been used to examine the economics of coal utilization at 16 Air Force facilities. After some further description concerning input variables and how the results were obtained, the results are presented and a method of ranking the 16 sites is discussed. Some sensitivity analyses to key parameters have been included to help understand the results more thoroughly.

6.1 VALUES OF INPUT VARIABLES

The input parameters for the cost-estimation model and LCC model are defined and described in Chap. 5. The numerical values used in this study for the parameters that vary from site to site are summarized here.

6.1.1 Cost-Estimation Variables

A list of input parameters for the cost model is provided in Table 5.3. Numerical values are given in the table for eight of the parameters. The remaining parameters that are labeled as variables are discussed further in this section.

Important assumptions that define the coal-conversion projects examined in this study are summarized for each Air Force site in Table 6.1. The number of boilers for refit and total output capacity chosen for each project were found through optimization as discussed in Sect. 5.2.1. The expected capacity factor is dependent on this chosen output capacity and the heating load of each boiler plant. Also listed is the need for active SO_2 removal, which has been determined from the sulfur content of available coals (Sect. 4.1) and applicable local environmental regulations (Sect. 4.2). Active SO_2 removal was found to be required at 6 of the 16 sites.

The existing boiler design is also listed in Table 6.1 and was used to determine what boiler modifications are needed for refit technologies and whether derating of a refitted boiler is necessary. Boiler modifications were determined as explained in Sect. 5.1.3, using Tables 5.4 and

Table 6.1. Coal-conversion project definition parameters

Base	Major command	Existing boiler design fuel	Number of boilers for refit	Total output capacity (MBtu/h)	Expected overall capacity factor (%)	Active SO_2 removal	Refit boilers derated	Number of technologies considered
Elmendorf	AAC	Stoker coal	2	300.0	71.9	Yes	No	12
Hill	AFLC	No. 2 oil	3	75.0	63.5	Yes	Yes	7
Kelly	AFLC	No. 2 oil	1	43.5	82.4	No	Yes	7
Robins	AFLC	Stoker coal	1	54.0	80.6	No	No	8
Tinker	AFLC	No. 2 oil	2	150.0	71.2	Yes	Yes	7
Arnold	AFSC	Pulverized coal	1	72.0	72.0	No	No	11
Hanscom	AFSC	No. 6 oil	1	50.0	88.3	Yes	No	1
Andrews	MAC	Stoker coal	1	60.0	50.4	No	No	12
Dover	MAC	Stoker coal	1	50.0	58.3	No	No	12
McGuire	MAC	Stoker coal	1	50.0	61.8	Yes	No	12
Scott	MAC	Stoker coal	1	40.0	62.6	Yes	No	7
Grand Forks	SAC	Stoker coal	1	42.0	71.6	No	No	12
Minot	SAC	Stoker coal	1	42.0	64.6	No	No	12
Pease	SAC	No. 6 oil	1	75.0	40.7	No	Yes	11
Plattsburgh	SAC	No. 6 oil	1	50.0	76.4	No	No	11
USAF Academy	USAFA	No. 5 oil	1	80.0	58.0	No	No	7

5.5 as a guide. Boiler derating was assumed to be necessary at four sites; three were derated simply because they were No. 2 oil-designed units, and the boiler at Pease AFB was assumed to be derated to avoid SO_2 emission regulations (discussed in Sect. 5.2.1). Many details about each individual site are summarized in the Appendix.

The current prices for fuels used in the study are listed in the main tables that summarize the results (Tables 6.3 and 6.5 of Sect. 6.2). Oil and coal/water slurry prices do not vary from site to site, as discussed in Sect. 5.1.3, while natural gas, ROM coal, and stoker coal prices do vary from site to site. One note about coal prices is that the prices used in the analysis for Elmendorf AFB and Pease AFB are optimistic. The coal prices quoted for Elmendorf are from a new company that is not yet in operation. If this new coal is not available in the future, then coal would have to be purchased at a much higher price from the only coal supplier near Elmendorf that is currently in operation. The coal prices quoted for Pease are based on inexpensive rail delivery; however, higher-cost truck delivery may be necessary because the rail connection to Pease is scheduled for removal.

The remaining input variables that have not been defined are the price of electricity and the coal properties (higher heating value, ash content, and sulfur content). Values were determined for these parameters for each of the 16 Air Force sites and can be found in the information summaries in the Appendix.

6.1.2 Economic Variables

Many of the economic assumptions made for the LCC analysis are discussed in Sect. 5.3, and the input parameters to the LCC model are listed in Table 5.6. Four key economic variables are discussed further here because of their potential importance to the study.

General inflation. General inflation, which is a loss in the buying power of money, is an input variable to the LCC model. General inflation is often thought of as being very important in an economic analysis. However, general inflation has no effect on the LCC results for Air Force-financed projects, if the actual discount rate is also inflated to maintain a constant real discount rate. Although inflation does have a minor effect on the LCC results for privately financed projects, the general inflation rate was assumed to be zero in this study. The effect of this assumption is that all future values in the cash flow spreadsheets will be in constant dollars, as is required by federal guidelines.[10]

Discount rate. Federal guidelines specify that a real discount rate of 10% should be used for the evaluation of projects that are not primarily for energy conservation.[10] For most of this study, an actual discount rate of 10% was used, which is equivalent to a real discount rate of 10% because of the assumption of zero general inflation. A 7% discount rate is also examined in Sect. 6.3.2 to determine the sensitivity of the results to the discount rate.

Rate of return on investment. A representative rate of return (ROR) on investment is needed for evaluation of privately financed projects. A before-tax ROR of 17% was selected. Based on the local and federal tax assumptions shown in Table 5.6, this translates to an after-tax ROR of about 12%.

Fuel escalation. Because the results of the LCC analysis were found to be very sensitive to the assumed fuel escalation rates, and because fuel escalation projections are so highly subject to question, three separate fuel escalation scenarios have been examined.

One set of fuel escalators was derived from a DOD memo that gives guidelines for energy-dependent economic analyses.[3] The DOD escalators are based directly on the report *Annual Energy Outlook 1986*, published by the Energy Information Administration (EIA) of DOE.[4] Fuel escalation projections are tabulated in the DOD memo and the 1986 EIA report for distillate oil, residual oil, natural gas, and coal, for both commercial and industrial sectors, in ten different regions of the United States. For the LCC analysis in this report, it was assumed that the industrial fuel escalation rates, averaged over all ten regions of the United States, are applicable. Also, distillate and residual oils were assumed to escalate at the same rate (equal to an average of the escalation rates for distillate and residual oils).

The 1986 study by the EIA includes projections only to the year 2000. The DOD escalation tables were extended to the year 2017 by assuming that the 1986 EIA escalation projections for the years 1996–2000 (escalation rates for each fuel are constant during this 5-year period) would remain constant through the year 2017. For the LCC analysis in this report, the 30-year economic life ends in the year 2020; therefore, the same escalation rates were assumed to apply all the way to the year 2020. The DOD escalation scenario just described is referred to as the "nominal values" case for fuel escalation. These escalation rates are shown in Table 6.2. For this "nominal values" case, gas and oil prices escalate at rather high rates relative to the price of coal, which will enhance the economic outlook of coal projects.

Table 6.2. Fuel escalation scenarios

Fuel	Real escalation rate (%/year)			
	1988–1990	1990–1995	1995–2000	2000 and beyond
		"Nominal values" case		
Gas	3.89	8.87	5.77	5.77
Oil	4.86	7.87	4.16	4.16
Coal	1.16	2.31	1.19	1.19
		"AEO 1987" case		
Gas	2.28	4.70	5.49	2.75
Oil	0.17	4.16	5.55	2.77
Coal	1.46	1.76	1.61	0.81
		Zero case		
Gas	0	0	0	0
Oil	0	0	0	0
Coal	0	0	0	0

A second fuel escalation scenario was developed from the updated *Annual Energy Outlook 1987* report.[5] Because the updated 1987 report also does not include any escalation projections beyond the year 2000, an author of the report was contacted and asked to recommend the best assumptions during that time period. The opinion received was that the forces causing high oil and gas price escalation during the 1995–2000 period will weaken significantly in years beyond 2000. To simulate reduced pressure on fuel prices for years beyond 2000, it was assumed that each fuel escalates at one-half the projected rate for the 1995–2000 period. This set of escalators will be referred to as the "AEO 1987" fuel escalators. The precise values used for fuel escalation are given in Table 6.2. The "AEO 1987" escalators lie approximately midway between the "nominal values" escalators and the third escalation scenario of zero fuel escalation.

6.2 RANKING BY BENEFIT/COST RATIO

The 16 Air Force base heating plants have been ranked according to the benefit/cost ratio (see Sect. 5.3.3 for definition). Six economic scenarios were examined: three separate sets of assumptions for fuel escalation were considered, and both Air Force ownership and private ownership were examined. The economic ranking results for the six scenarios are summarized in Tables 6.3 through 6.7. These rankings are discussed in the following sections.

6.2.1 Air Force Financing and Ownership

A summary of the coal-conversion projects examined assuming Air Force ownership is given in Table 6.3. All of the coal combustion technologies that were evaluated at each of the 16 sites are included in the table. The 149 potential coal projects are ranked according to the first column of benefit/cost ratios that were calculated for the "nominal values" of the economic parameters. The list of coal projects for each Air Force site is ordered so that the highest benefit (most attractive) option appears first and the lowest benefit option appears last. The Air Force sites are ordered in Table 6.3 according to the benefit/cost ratios of the best coal technology at each base.

Table 6.4 summarizes the most attractive coal technology at each base for the three fuel escalation scenarios. Micronized coal refit is

Table 6.3. Air Force-financing results with ranking according to "nominal values"

Base (Major command)	Current fuel and price	Rank	Coal Technology	Technology type: Refit	Technology type: New	Coal price ($/MBtu)	Benefit/cost ratio: Parameters = nominal values	Benefit/cost ratio: Fuel real escalation = AEO 1987	Benefit/cost ratio: Fuel real escalation = zero
Arnold	Natural gas	1	Micronized	X		1.75	2.141	1.616	1.191
(AFSC)	$3.97/MBtu	2	Slagging	X		1.75	1.963	1.480	1.085
		3	FBC refit	X		1.75	1.927	1.453	1.064
		4	Pkg. stoker		X	1.97	1.811	1.367	1.008
Potential coal use =		5	Pkg. FBC		X	1.75	1.802	1.359	0.994
23,652 tons/year		8	Field stoker		X	1.97	1.756	1.325	0.971
		11	Field FBC		X	1.75	1.732	1.306	0.949
		12	Pulverized		X	1.75	1.702	1.282	0.930
		13	Circ. FBC		X	1.75	1.649	1.242	0.900
		14	Coal/water	X		3.00	1.646	1.246	0.946
		18	Gasifier	X		1.97	1.612	1.216	0.896
Kelly	Natural gas	6	Pkg. stoker		X	1.98	1.798	1.369	1.022
(AFLC)	$4.00/MBtu	7	Pkg. FBC		X	1.87	1.760	1.339	0.995
		16	Field stoker		X	1.98	1.643	1.249	0.925
		19	Field FBC		X	1.87	1.585	1.205	0.887
Potential coal use =		24	Pulverized		X	1.87	1.553	1.181	0.867
16,014 tons/year		25	Coal/water	X		3.00	1.545	1.179	0.900
		32	Circ. FBC		X	1.87	1.522	1.157	0.849
Minot	Natural gas	9	Micronized	X		1.48	1.743	1.348	1.018
(SAC)	$3.60/MBtu	20	Slagging	X		1.48	1.577	1.219	0.917
		21	Pkg. FBC		X	1.48	1.570	1.214	0.915
		22	Stoker refit	X		1.87	1.564	1.210	0.923
Potential coal use =		27	FBC refit	X		1.48	1.539	1.189	0.894
12,176 tons/year		30	Pkg. stoker		X	1.87	1.525	1.180	0.899
		51	Gasifier	X		1.87	1.421	1.100	0.840
		60	Field FBC		X	1.48	1.369	1.058	0.791
		63	Field stoker		X	1.87	1.362	1.053	0.795
		67	Coal/water	X		3.00	1.357	1.053	0.823
		74	Pulverized		X	1.48	1.329	1.026	0.766
		82	Circ. FBC		X	1.48	1.314	1.015	0.757
Robins	Natural gas	10	Micronized	X		1.77	1.737	1.330	1.003
(AFLC)	$3.19/MBtu	40	Pkg. FBC		X	1.77	1.470	1.124	0.842
		42	Pkg. stoker		X	1.99	1.463	1.119	0.844
		50	Field stoker		X	1.99	1.426	1.091	0.818
Potential coal use =		54	Field FBC		X	1.77	1.410	1.077	0.802
17,268 tons/year		58	Pulverized		X	1.77	1.383	1.057	0.785
		68	Coal/water	X		3.00	1.357	1.041	0.808
		69	Circ. FBC		X	1.77	1.349	1.031	0.765
McGuire	Natural gas	15	Micronized	X		1.89	1.643	1.264	0.950
(MAC)	$4.00/MBtu	33	Pkg. FBC		X	1.89	1.513	1.163	0.873
		34	Slagging	X		1.89	1.510	1.161	0.869
		35	FBC refit	X		1.89	1.496	1.150	0.861
Potential coal use =		55	Coal/water	X		3.00	1.407	1.085	0.836
13,217 tons/year		62	Field FBC		X	1.89	1.364	1.048	0.781
		76	Stoker refit	X		2.25	1.324	1.019	0.767
		81	Circ. FBC		X	1.89	1.314	1.009	0.750
		87	Pkg. stoker		X	2.25	1.299	0.999	0.752
		112	Gasifier	X		2.25	1.236	0.951	0.719
		119	Field stoker		X	2.25	1.199	0.921	0.689
		128	Pulverized		X	1.89	1.173	0.901	0.667
Grand Forks	No. 6 oil	17	Micronized	X		1.48	1.632	1.345	1.057
(SAC)	$3.67/MBtu	37	Slagging	X		1.48	1.485	1.223	0.957
		38	Pkg. FBC		X	1.48	1.483	1.221	0.958
		41	Stoker refit	X		1.87	1.469	1.211	0.962
Potential coal use =		43	FBC refit	X		1.48	1.456	1.199	0.938
13,495 tons/year		46	Pkg. stoker		X	1.87	1.434	1.183	0.938
		85	Field FBC		X	1.48	1.303	1.072	0.834
		86	Gasifier	X		1.87	1.300	1.072	0.851
		94	Field stoker		X	1.87	1.292	1.064	0.837
		98	Pulverized		X	1.48	1.269	1.044	0.811
		104	Coal/water	X		3.00	1.258	1.040	0.846
		108	Circ. FBC		X	1.48	1.247	1.026	0.797

Table 6.3 (continued)

Base (Major command)	Current fuel and price	Rank	Coal technology	Technology type: Refit	Technology type: New	Coal price ($/MBtu)	Benefit/cost ratio: Parameters = nominal values	Benefit/cost ratio: Fuel real escalation = AEO 1987	Benefit/cost ratio: Fuel real escalation = zero
Plattsburgh	No. 6 oil	23	Micronized	X		1.97	1.562	1.281	1.011
(SAC)	$3.67/MBtu	45	Slagging	X		1.97	1.440	1.180	0.926
		48	Pkg. FBC		X	1.97	1.431	1.172	0.923
		52	FBC refit	X		1.97	1.418	1.162	0.912
Potential coal use =		65	Pkg. stoker		X	2.46	1.357	1.113	0.887
16,339 tons/year		91	Coal/water	X		3.00	1.293	1.062	0.859
		95	Field FBC		X	1.97	1.286	1.053	0.821
		101	Pulverized		X	1.97	1.263	1.034	0.804
		107	Field stoker		X	2.46	1.248	1.023	0.808
		113	Circ. FBC		X	1.97	1.231	1.007	0.783
		121	Gasifier	X		2.46	1.196	0.981	0.781
Pease[a]	Natural gas	26	Micronized	X		2.07	1.540	1.196	0.917
(SAC)	$3.80/MBtu	57	Slagging	X		2.07	1.390	1.079	0.822
		61	Coal/water	X		3.00	1.369	1.066	0.834
		64	FBC refit	X		2.07	1.359	1.055	0.804
Potential coal use =		100	Pkg. FBC		X	2.07	1.266	0.983	0.747
13,057 tons/year		110	Pkg. stoker		X	2.56	1.245	0.968	0.744
		120	Field FBC		X	2.07	1.198	0.930	0.703
		122	Field stoker		X	2.56	1.195	0.928	0.709
		129	Pulverized		X	2.07	1.170	0.908	0.686
		135	Circ. FBC		X	2.07	1.134	0.880	0.664
		138	Gasifier	X		2.56	1.110	0.863	0.663
Tinker	Natural gas	28	Field FBC		X	1.68	1.532	1.151	0.840
(AFLC)	$2.85/MBtu	31	Pkg. FBC		X	1.68	1.523	1.145	0.839
		44	Circ. FBC		X	1.68	1.451	1.090	0.793
		72	Pulverized		X	1.68	1.337	1.004	0.727
Potential coal use =		79	Field stoker		X	1.99	1.317	0.990	0.725
45,682 tons/year		89	Pkg. stoker		X	1.99	1.298	0.976	0.717
		105	Coal/water	X		3.00	1.252	0.945	0.717
Elmendorf[b]	Natural gas	29	Micronized	X		1.63	1.527	1.146	0.851
(AAC)	$2.05/MBtu	56	Slagging	X		1.63	1.403	1.052	0.775
		59	FBC refit	X		1.63	1.379	1.034	0.762
		75	Field FBC		X	1.63	1.326	0.994	0.729
Potential coal use =		109	Circ. FBC		X	1.63	1.247	0.934	0.681
154,374 tons/year		115	Pkg. FBC		X	1.63	1.221	0.915	0.669
		127	Pulverized		X	1.63	1.174	0.879	0.638
		141	Stoker refit	X		2.16	1.100	0.826	0.615
		145	Field stoker		X	2.16	1.064	0.798	0.590
		147	Coal/water	X		3.00	1.010	0.760	0.581
		148	Pkg. stoker		X	2.16	0.979	0.734	0.541
		149	Gasifier	X		2.16	0.849	0.636	0.468
Hill	Natural gas	36	Pkg. FBC		X	1.20	1.486	1.141	0.848
(AFLC)	$2.97/MBtu	53	Field FBC		X	1.20	1.414	1.085	0.803
		71	Circ. FBC		X	1.20	1.338	1.026	0.758
		88	Pkg. stoker		X	1.30	1.298	0.996	0.740
Potential coal use =		103	Field stoker		X	1.30	1.260	0.967	0.716
23,560 tons/year		123	Pulverized		X	1.20	1.190	0.913	0.672
		139	Coal/water	X		3.00	1.110	0.855	0.661
Scott	Natural gas	39	Pkg. FBC		X	1.24	1.473	1.141	0.854
(MAC)	$3.80/MBtu	66	Pkg. stoker		X	1.26	1.357	1.051	0.785
		78	Field FBC		X	1.24	1.322	1.023	0.762
		93	Circ. FBC		X	1.24	1.292	1.000	0.744
Potential coal use =		111	Coal/water	X		3.00	1.243	0.966	0.750
13,731 tons/year		114	Field stoker		X	1.26	1.231	0.952	0.709
		134	Pulverized		X	1.24	1.141	0.882	0.654

Table 6.3 (continued)

Base (Major command)	Current fuel and price	Rank	Coal technology	Technology type: Refit	Technology type: New	Coal price ($/MBtu)	Benefit/cost ratio: Parameters = nominal values	Benefit/cost ratio: Fuel real escalation = AEO 1987	Benefit/cost ratio: Fuel real escalation = zero
Dover	No. 6 oil	47	Micronized	X		1.84	1.434	1.188	0.947
(MAC)	$3.67/MBtu	77	Stoker refit	X		2.19	1.324	1.098	0.882
		83	Slagging	X		1.84	1.308	1.083	0.859
		84	Pkg. FBC		X	1.84	1.304	1.080	0.858
Potential coal use =		92	Pkg. stoker		X	2.19	1.292	1.071	0.860
12,468 tons/year		96	FBC refit	X		1.84	1.285	1.064	0.843
		117	Coal/water	X		3.00	1.216	1.010	0.826
		130	Field stoker		X	2.19	1.164	0.964	0.767
		131	Field FBC		X	1.84	1.153	0.954	0.752
		132	Gasifier	X		2.19	1.143	0.947	0.760
		137	Pulverized		X	1.84	1.127	0.932	0.733
		142	Circ. FBC		X	1.84	1.100	0.910	0.715
Andrews	No. 6 oil	49	Micronized	X		1.84	1.431	1.185	0.945
(MAC)	$3.67/MBtu	80	Stoker refit	X		2.19	1.315	1.091	0.877
		90	Slagging	X		1.84	1.296	1.074	0.851
		97	FBC refit	X		1.84	1.269	1.051	0.833
Potential coal use =		118	Coal/water	X		3.00	1.211	1.006	0.823
12,935 tons/year		124	Pkg. FBC		X	1.84	1.182	0.979	0.775
		125	Pkg. stoker		X	2.19	1.179	0.977	0.780
		133	Field stoker		X	2.19	1.142	0.946	0.752
		136	Field FBC		X	1.84	1.130	0.935	0.737
		140	Pulverized		X	1.84	1.102	0.912	0.717
		144	Circ. FBC		X	1.84	1.074	0.889	0.699
		146	Gasifier	X		2.19	1.061	0.879	0.702
USAF Acad.	Natural gas	70	Pkg. FBC		X	1.17	1.339	1.038	0.784
(USAFA)	$2.56/MBtu	73	Pkg. stoker		X	1.45	1.333	1.035	0.790
		102	Field stoker		X	1.45	1.262	0.979	0.743
		106	Field FBC		X	1.17	1.252	0.970	0.729
Potential coal use =		116	Pulverized		X	1.17	1.220	0.945	0.709
24,992 tons/year		126	Circ. FBC		X	1.17	1.179	0.913	0.685
		143	Coal/water	X		3.00	1.091	0.850	0.675
Hanscom	No. 6 oil	99	Coal/water	X		3.00	1.267	1.035	0.828
(AFSC)	$3.67/MBtu								
Potential coal use =									
20,143 tons/year									

[a]LCC results for Pease may be optimistic because of questionable access to inexpensive rail delivery for coal.

[b]LCC results for Elmendorf may be optimistic because of questionable availability of inexpensive coal.

Table 6.4. Summary of Air Force-financing results for best coal technologies

Base	Parameters = nominal values			Fuel escalation = AEO 87			Fuel escalation = zero		
	Best coal technology	Benefit/ cost ratio	Rank	Best coal technology	Benefit/ cost ratio	Rank	Best coal technology	Benefit/ cost ratio	Rank
Arnold	Micronized	2.141	1	Micronized	1.616	1	Micronized	1.191	1
Kelly	Pkg. stoker	1.798	2	Pkg. stoker	1.369	2	Pkg. stoker	1.022	3
Minot	Micronized	1.743	3	Micronized	1.348	3	Micronized	1.018	4
Robins	Micronized	1.737	4	Micronized	1.330	5	Micronized	1.003	6
McGuire	Micronized	1.643	5	Micronized	1.264	7	Micronized	0.950	7
Grand Forks	Micronized	1.632	6	Micronized	1.345	4	Micronized	1.057	2
Plattsburgh	Micronized	1.562	7	Micronized	1.281	6	Micronized	1.011	5
Pease[a]	Micronized	1.540	8	Micronized	1.196	8	Micronized	0.917	10
Tinker	Field FBC	1.532	9	Field FBC	1.151	11	Field FBC	0.840	14
Elmendorf[b]	Micronized	1.527	10	Micronized	1.146	12	Micronized	0.851	12
Hill	Pkg. FBC	1.486	11	Pkg. FBC	1.141	14	Pkg. FBC	0.848	13
Scott	Pkg. FBC	1.473	12	Pkg. FBC	1.141	13	Pkg. FBC	0.854	11
Dover	Micronized	1.434	13	Micronized	1.188	9	Micronized	0.947	8
Andrews	Micronized	1.431	14	Micronized	1.185	10	Micronized	0.945	9
USAF Academy	Pkg. FBC	1.339	15	Pkg. FBC	1.038	15	Pkg. stoker	0.790	16
Hanscom	Coal/water	1.267	16	Coal/water	1.035	16	Coal/water	0.828	15

[a]LCC results for Pease may be optimistic because of questionable access to inexpensive rail delivery for coal.

[b]LCC results for Elmendorf may be optimistic because of questionable availability of inexpensive coal.

the lowest-cost option at most of the bases (10 of 16). At the remaining six bases (Kelly, Tinker, Hill, Scott, USAF Academy, and Hanscom), micronized coal and the other dry coal refit technologies were not evaluated because of space limitations inside and near the existing heating plants. The lowest-cost options at these six bases are either coal/water slurry refit or one of the replacement boiler technologies.

It is observed from Table 6.4 that Arnold is ranked first in each case. The sites ranked 2 through 7 include Kelly, Minot, Robins, McGuire, Grand Forks, and Plattsburgh in each case, although the respective order changes. Beyond the top seven sites, it is somewhat more difficult to generalize.

The most basic issue that needs to be addressed is whether coal will be more economical than the existing gas or oil fuels. The results in Table 6.4 indicate that the answer to this question depends strongly on the fuel escalation assumptions. For the "nominal values" case of fuel escalation, coal appears to be a good choice at all of the bases because all of the benefit/cost ratios are significantly >1.0. For the zero fuel escalation case, most of the bases have benefit/cost ratios that are <1.0, and at the bases that do have benefit/cost ratios >1.0, the savings in gas or oil costs may not be significant enough to justify conversion to coal.

6.2.2 Private Financing and Ownership

The same type of analysis presented above for the Air Force-ownership cases is repeated here for the private-ownership scenarios. Tables 6.5 and 6.6 summarize these results. It was found that the ranking of the sites is very similar to the previously discussed Air Force-ownership cases. Again, it is observed that Arnold is ranked first in each case. The sites ranked 2 through 7 include Kelly, Robins, Minot, McGuire, Grand Forks, and Plattsburgh.

When the private-financing results in Table 6.6 are compared to the Air Force-financing results in Table 6.4, it appears that Air Force financing is more attractive because the benefit/cost ratios are all slightly greater than those for private financing. This conclusion is contrary to the common belief that a private company can work less

Table 6.5. Private-financing results with ranking according to "nominal values"

Base (Major command)	Current fuel and price	Rank	Coal technology	Technology type: Refit	Technology type: New	Coal price ($/MBtu)	Benefit/cost ratio: Parameters = nominal values	Benefit/cost ratio: Fuel real escalation = AEO 1987	Benefit/cost ratio: Fuel real escalation = zero
Arnold	Natural gas	1	Micronized	X		1.75	1.946	1.468	1.077
(AFSC)	$3.97/MBtu	2	Slagging	X		1.75	1.717	1.294	0.942
		3	FBC refit	X		1.75	1.663	1.254	0.912
		5	Pkg. stoker		X	1.97	1.597	1.204	0.882
Potential coal use =		8	Pkg. FBC		X	1.75	1.552	1.169	0.849
23,652 tons/year		10	Coal/water	X		3.00	1.526	1.155	0.872
		11	Field stoker		X	1.97	1.487	1.121	0.815
		14	Field FBC		X	1.75	1.451	1.092	0.788
		17	Pulverized		X	1.75	1.417	1.067	0.768
		18	Gasifier	X		1.97	1.416	1.068	0.782
		25	Circ. FBC		X	1.75	1.353	1.018	0.732
Kelly	Natural gas	4	Pkg. stoker		X	1.98	1.608	1.223	0.909
(AFLC)	$4.00/MBtu	9	Pkg. FBC		X	1.87	1.545	1.175	0.868
		16	Coal/water	X		3.00	1.419	1.082	0.822
		20	Field stoker		X	1.98	1.398	1.063	0.781
Potential coal use =		27	Field FBC		X	1.87	1.339	1.017	0.744
16,014 tons/year		32	Pulverized		X	1.87	1.306	0.992	0.724
		45	Circ. FBC		X	1.87	1.264	0.960	0.700
Robins	Natural gas	6	Micronized	X		1.77	1.586	1.213	0.911
(AFLC)	$3.19/MBtu	35	Pkg. stoker		X	1.99	1.294	0.989	0.741
		43	Pkg. FBC		X	1.77	1.274	0.974	0.724
		47	Coal/water	X		3.00	1.262	0.968	0.748
Potential coal use =		57	Field stoker		X	1.99	1.213	0.927	0.690
17,268 tons/year		63	Field FBC		X	1.77	1.186	0.906	0.669
		70	Pulverized		X	1.77	1.157	0.883	0.651
		89	Circ. FBC		X	1.77	1.114	0.850	0.626
Minot	Natural gas	7	Micronized	X		1.48	1.567	1.211	0.912
(SAC)	$3.60/MBtu	19	Stoker refit	X		1.87	1.398	1.082	0.821
		23	Slagging	X		1.48	1.360	1.050	0.786
		24	Pkg. FBC		X	1.48	1.353	1.045	0.784
Potential coal use =		26	Pkg. stoker		X	1.87	1.349	1.043	0.790
12,176 tons/year		31	FBC refit	X		1.48	1.308	1.011	0.756
		50	Coal/water	X		3.00	1.249	0.969	0.754
		52	Gasifier	X		1.87	1.247	0.965	0.732
		78	Field stoker		X	1.87	1.141	0.882	0.661
		81	Field FBC		X	1.48	1.131	0.873	0.649
		95	Pulverized		X	1.48	1.093	0.844	0.626
		107	Circ. FBC		X	1.48	1.065	0.822	0.610
McGuire	Natural gas	12	Micronized	X		1.89	1.482	1.140	0.854
(MAC)	$4.00/MBtu	29	Pkg. FBC		X	1.89	1.314	1.010	0.754
		30	Slagging	X		1.89	1.314	1.009	0.752
		36	Coal/water	X		3.00	1.290	0.994	0.763
Potential coal use =		40	FBC refit	X		1.89	1.285	0.987	0.735
13,217 tons/year		66	Stoker refit	X		2.25	1.175	0.903	0.677
		76	Field FBC		X	1.89	1.143	0.878	0.650
		77	Pkg. stoker		X	2.25	1.143	0.879	0.658
		96	Gasifier	X		2.25	1.092	0.840	0.631
		101	Circ. FBC		X	1.89	1.081	0.830	0.613
		121	Field stoker		X	2.25	1.010	0.776	0.576
		131	Pulverized		X	1.89	0.974	0.748	0.551
Grand Forks	No. 6 oil	13	Micronized	X		1.48	1.474	1.213	0.951
(SAC)	$3.67/MBtu	28	Stoker refit	X		1.87	1.319	1.087	0.859
		38	Slagging	X		1.48	1.288	1.059	0.825
		41	Pkg. FBC		X	1.48	1.285	1.057	0.825
Potential coal use =		42	Pkg. stoker		X	1.87	1.274	1.050	0.829
13,495 tons/year		53	FBC refit	X		1.48	1.245	1.025	0.797
		68	Coal/water	X		3.00	1.162	0.960	0.778
		73	Gasifier	X		1.87	1.149	0.947	0.747
		97	Field stoker		X	1.87	1.089	0.896	0.700
		100	Field FBC		X	1.48	1.083	0.890	0.689
		110	Pulverized		X	1.48	1.049	0.863	0.666
		119	Circ. FBC		X	1.48	1.018	0.836	0.646

Table 6.5 (continued)

Base (Major command)	Current fuel and price	Rank	Coal technology	Technology type Refit	New	Coal price ($/MBtu)	Benefit/cost ratio Parameters = nominal values	Fuel real escalation = AEO 1987	Fuel real escalation = zero
Plattsburgh	No. 6 oil	15	Micronized	X		1.97	1.425	1.168	0.918
(SAC)	$3.67/MBtu	44	Slagging	X		1.97	1.266	1.037	0.809
		48	Pkg. FBC		X	1.97	1.257	1.029	0.806
		54	FBC refit	X		1.97	1.232	1.009	0.787
Potential coal use =		56	Pkg. stoker		X	2.46	1.222	1.002	0.794
16,339 tons/year		60	Coal/water	X		3.00	1.192	0.979	0.787
		98	Field FBC		X	1.97	1.086	0.889	0.688
		103	Gasifier	X		2.46	1.074	0.881	0.697
		105	Field stoker		X	2.46	1.071	0.877	0.687
		108	Pulverized		X	1.97	1.061	0.868	0.671
		116	Circ. FBC		X	1.97	1.021	0.835	0.645
Elmendorf[a]	Natural gas	21	Micronized	X		1.63	1.386	1.039	0.767
(AAC)	$2.05/MBtu	55	Slagging	X		1.63	1.228	0.920	0.672
		61	FBC refit	X		1.63	1.191	0.892	0.651
		84	Field FBC		X	1.63	1.124	0.842	0.611
Potential coal use =		113	Circ. FBC		X	1.63	1.031	0.771	0.556
154,374 tons/year		114	Pkg. FBC		X	1.63	1.030	0.771	0.558
		128	Stoker refit	X		2.16	0.983	0.737	0.545
		129	Pulverized		X	1.63	0.981	0.733	0.528
		137	Coal/water	X		3.00	0.941	0.708	0.539
		143	Field stoker		X	2.16	0.915	0.686	0.501
		148	Pkg. stoker		X	2.16	0.842	0.631	0.460
		149	Gasifier	X		2.16	0.740	0.554	0.404
Pease[b]	Natural gas	22	Micronized	X		2.07	1.384	1.075	0.820
(SAC)	$3.80/MBtu	51	Coal/water	X		3.00	1.249	0.972	0.757
		58	Slagging	X		2.07	1.196	0.928	0.703
		71	FBC refit	X		2.07	1.153	0.895	0.677
Potential coal use =		99	Pkg. stoker		X	2.56	1.083	0.842	0.643
13,057 tons/year		106	Pkg. FBC		X	2.07	1.071	0.831	0.628
		124	Field stoker		X	2.56	0.996	0.773	0.586
		127	Field FBC		X	2.07	0.984	0.763	0.573
		133	Gasifier	X		2.56	0.963	0.748	0.571
		135	Pulverized		X	2.07	0.956	0.741	0.556
		144	Circ. FBC		X	2.07	0.911	0.706	0.529
Tinker	Natural gas	33	Pkg. FBC		X	1.68	1.304	0.979	0.711
(AFLC)	$2.85/MBtu	37	Field FBC		X	1.68	1.288	0.967	0.700
		59	Circ. FBC		X	1.68	1.192	0.895	0.644
		74	Coal/water	X		3.00	1.148	0.866	0.653
Potential coal use =		83	Pkg. stoker		X	1.99	1.124	0.845	0.616
48,086 tons/year		88	Field stoker		X	1.99	1.116	0.838	0.608
		90	Pulverized		X	1.68	1.111	0.833	0.598
Dover	No. 6 oil	34	Micronized	X		1.84	1.295	1.073	0.851
(MAC)	$3.67/MBtu	62	Stoker refit	X		2.19	1.188	0.985	0.788
		75	Pkg. stoker		X	2.19	1.148	0.951	0.759
		80	Slagging	X		1.84	1.135	0.939	0.741
Potential coal use =		82	Pkg. FBC		X	1.84	1.129	0.935	0.739
12,468 tons/year		87	Coal/water	X		3.00	1.117	0.928	0.755
		93	FBC refit	X		1.84	1.100	0.910	0.717
		120	Gasifier	X		2.19	1.012	0.838	0.669
		130	Field stoker		X	2.19	0.980	0.811	0.641
		134	Field FBC		X	1.84	0.960	0.793	0.622
		140	Pulverized		X	1.84	0.933	0.771	0.603
		146	Circ. FBC		X	1.84	0.898	0.742	0.580
Andrews	No. 6 oil	39	Micronized	X		1.84	1.287	1.066	0.846
(MAC)	$3.67/MBtu	64	Stoker refit	X		2.19	1.176	0.975	0.779
		86	Slagging	X		1.84	1.118	0.925	0.730
		91	Coal/water	X		3.00	1.108	0.920	0.749
Potential coal use =		102	FBC refit	X		1.84	1.079	0.893	0.704
12,935 tons/year		115	Pkg. stoker		X	2.19	1.026	0.849	0.674
		122	Pkg. FBC		X	1.84	1.003	0.830	0.653
		136	Field stoker		X	2.19	0.954	0.790	0.623
		141	Field FBC		X	1.84	0.932	0.771	0.604
		142	Gasifier	X		2.19	0.920	0.762	0.605
		145	Pulverized		X	1.84	0.905	0.749	0.585
		147	Circ. FBC		X	1.84	0.869	0.718	0.561

Table 6.5 (continued)

Base (Major command)	Current fuel and price	Rank	Coal technology	Technology type Refit	New	Coal price ($/MBtu)	Benefit/cost ratio Parameters = nominal values	Fuel real escalation = AEO 1987	Fuel real escalation = zero
Scott	Natural gas	46	Pkg. FBC		X	1.24	1.263	0.978	0.729
(MAC)	$3.80/MBtu	65	Pkg. stoker		X	1.26	1.176	0.910	0.678
		79	Coal/water	X		3.00	1.135	0.882	0.681
		94	Field FBC		X	1.24	1.097	0.849	0.630
Potential coal use =		109	Circ. FBC		X	1.24	1.050	0.812	0.602
13,731 tons/year		117	Field stoker		X	1.26	1.020	0.789	0.585
		138	Pulverized		X	1.24	0.938	0.726	0.536
Hill	Natural gas	49	Pkg. FBC		X	1.20	1.252	0.961	0.710
(AFLC)	$2.97/MBtu	69	Field FBC		X	1.20	1.159	0.889	0.654
		92	Pkg. stoker		X	1.30	1.104	0.847	0.626
		104	Circ. FBC		X	1.20	1.073	0.823	0.604
Potential coal use =		112	Field stoker		X	1.30	1.037	0.795	0.585
23,560 tons/year		125	Coal/water	X		3.00	0.994	0.766	0.588
		132	Pulverized		X	1.20	0.968	0.742	0.543
Hanscom	No. 6 oil	67	Coal/water	X		3.00	1.168	0.954	0.760
(AFSC)	$3.67/MBtu								
Potential coal use =									
20,143 tons/year									
USAF Acad.	Natural gas	72	Pkg. stoker		X	1.45	1.152	0.894	0.678
(USAFA)	$2.56/MBtu	85	Pkg. FBC		X	1.17	1.124	0.871	0.654
		111	Field stoker		X	1.45	1.040	0.806	0.608
		118	Field FBC		X	1.17	1.018	0.788	0.589
Potential coal use =		123	Coal/water	X		3.00	0.998	0.777	0.613
24,310 tons/year		126	Pulverized		X	1.17	0.987	0.764	0.570
		139	Circ. FBC		X	1.17	0.936	0.725	0.540

[a]LCC results for Elmendorf may be optimistic because of questionable availability of inexpensive coal.

[b]LCC results for Pease may be optimistic because of questionable access to inexpensive rail delivery for coal.

expensively than the government. In the LCC analysis, the private-financing scenarios were not given any special treatment. Because of a lack of better information, it was assumed that a private company would have to invest the same amount of capital as the Air Force and incur the same O&M costs. Private financing is therefore more expensive because the private company must also be payed a profit.

6.2.3 Overall Observations

Some meaningful observations can be made by examining the results for all six of the economic scenarios in Table 6.7. The top candidate for coal utilization is Arnold. Kelly, Grand Forks, Minot, Robins, Plattsburgh, and McGuire are ranked 2 through 7 for all six scenarios. Certain sites that do not appear above a ranking of 11 for any case include the USAF Academy, Hanscom, Hill, and Scott.

Table 6.6. Summary of private-financing results for best coal technologies

Base	Parameters = nominal values			Fuel escalation = AEO 87			Fuel escalation = zero		
	Best coal technology	Benefit/cost ratio	Rank	Best coal technology	Benefit/cost ratio	Rank	Best coal technology	Benefit/cost ratio	Rank
Arnold	Micronized	1.946	1	Micronized	1.468	1	Micronized	1.077	1
Kelly	Pkg. stoker	1.608	2	Pkg. stoker	1.223	2	Pkg. stoker	0.909	6
Robins	Micronized	1.586	3	Micronized	1.213	4	Micronized	0.911	5
Minot	Micronized	1.567	4	Micronized	1.211	5	Micronized	0.912	4
McGuire	Micronized	1.482	5	Micronized	1.140	7	Micronized	0.854	7
Grand Forks	Micronized	1.474	6	Micronized	1.213	3	Micronized	0.951	2
Plattsburgh	Micronized	1.425	7	Micronized	1.168	6	Micronized	0.918	3
Elmendorf[a]	Micronized	1.386	8	Micronized	1.039	11	Micronized	0.767	11
Pease[b]	Micronized	1.384	9	Micronized	1.075	8	Micronized	0.820	10
Tinker	Pkg. FBC	1.304	10	Pkg. FBC	0.979	12	Pkg. FBC	0.711	14
Dover	Micronized	1.295	11	Micronized	1.073	9	Micronized	0.851	8
Andrews	Micronized	1.287	12	Micronized	1.066	10	Micronized	0.846	9
Scott	Pkg. FBC	1.263	13	Pkg. FBC	0.978	13	Pkg. FBC	0.729	13
Hill	Pkg. FBC	1.252	14	Pkg. FBC	0.961	14	Pkg. FBC	0.710	15
Hanscom	Coal/water	1.168	15	Coal/water	0.954	15	Coal/water	0.760	12
USAF Academy	Pkg. stoker	1.152	16	Pkg. stoker	0.894	16	Pkg. stoker	0.678	16

[a]LCC results for Elmendorf may be optimistic because of questionable availability of inexpensive coal.

[b]LCC results for Pease may be optimistic because of questionable access to inexpensive rail delivery for coal.

Table 6.7. Summary of ranking results for Air Force and private financing

Base	Rank for Air Force financing			Rank for private financing			Average rank
	Nominal	AEO	Zero	Nominal	AEO	Zero	
Arnold	1	1	1	1	1	1	1.0
Kelly	2	2	3	2	2	6	2.8
Grand Forks	6	4	2	6	3	2	3.8
Minot	3	3	4	4	5	4	3.8
Robins	4	5	6	3	4	5	4.5
Plattsburgh	7	6	5	7	6	3	5.7
McGuire	5	7	7	5	7	7	6.3
Pease[a]	8	8	10	9	8	10	8.8
Dover	13	9	8	11	9	8	9.7
Andrews	14	10	9	12	10	9	10.7
Elmendorf[b]	10	12	12	8	11	11	10.7
Tinker	9	11	14	10	12	14	11.7
Scott	12	13	11	13	13	13	12.5
Hill	11	14	13	14	14	15	13.5
Hanscom	16	16	15	15	15	12	14.8
USAF Academy	15	15	16	16	16	16	15.7

[a]LCC results for Pease may be optimistic because of questionable access to inexpensive rail delivery for coal.

[b]LCC results for Elmendorf may be optimistic because of questionable availability of inexpensive coal.

The process of ranking the Air Force sites in the manner described above is simple from a mathematical viewpoint. However, all economic analyses should be viewed with skepticism because of the uncertainty associated with predicting future events. An appropriate level of skepticism is especially important when interpreting the results of this study because the recent trend of unstable energy prices will probably continue into the future. The results of the LCC analysis should therefore be used only to identify general trends, while small differences should be considered insignificant.

6.3 SENSITIVITY TO SELECTED ECONOMIC ASSUMPTIONS

The sensitivity of the results to some important economic assumptions has been examined. The effect of fuel escalation has already been examined in the main body of results. Other important parameters to be examined in this section include the discounted payback period and the effect of discount rate.

It was found that reasonable variations in the assumed values of key economic parameters can have significant effects on the absolute magnitudes of the benefit/cost ratios (or other measures of economic benefit). However, these parametric variations generally do not have a significant effect on the ranking or ordering of the Air Force sites examined in this study.

6.3.1 Ranking by Discounted Payback Period

The discounted payback period is used in this study only as a secondary figure-of-merit for the reasons discussed in Sect. 5.3.3. Discounted payback periods were calculated for all Air Force-financed projects, and selected results are summarized in Table 6.8 for the top 12 Air Force sites from Table 6.7. The discounted payback periods follow the same trends as the benefit/cost ratios (i.e., the projects with the highest benefit/cost ratios tend to have the shortest payback periods), although there are some minor differences. The use of discounted payback periods for comparisons will tend to favor coal-conversion projects that are less capital intensive.

The answer to the question of whether coal will be a more attractive fuel than gas or oil is again strongly influenced by the fuel escalation assumptions. For the "nominal values" escalation case, most of the coal-conversion projects have discounted payback periods that are <10 years. For zero fuel escalation, the payback periods for most of the projects are greater than the economic life of the projects. The notable exception for zero fuel escalation is the micronized coal refit option at Arnold, which has a payback period <10 years.

Table 6.8. Discounted payback periods for selected Air Force-financed projects

Base (Major command)	Coal technology	Technology type: Refit	Technology type: New	Parameters = nominal values: Benefit/cost ratio	Parameters = nominal values: Discounted payback (years)	Fuel escalation = AEO 1987: Benefit/cost ratio	Fuel escalation = AEO 1987: Discounted payback (years)	Fuel escalation = zero: Benefit/cost ratio	Fuel escalation = zero: Discounted payback (years)
Arnold (AFSC)	Micronized	X		2.141	3.9	1.616	4.7	1.191	6.4
	Slagging	X		1.963	5.7	1.480	7.3	1.085	12.8
	FBC refit	X		1.927	6.2	1.453	8.0	1.064	15.2
	Pkg. stoker		X	1.811	6.4	1.367	8.6	1.008	25.2
Kelly (AFLC)	Pkg. stoker		X	1.798	5.9	1.369	7.9	1.022	19.3
	Pkg. FBC		X	1.760	6.8	1.339	9.2	0.995	>31
Grand Forks (SAC)	Micronized	X		1.632	5.4	1.345	7.8	1.057	12.9
	Slagging	X		1.485	8.1	1.223	12.3	0.957	>31
	Pkg. FBC		X	1.483	8.1	1.221	12.3	0.958	>31
	Stoker refit	X		1.469	7.1	1.211	11.3	0.962	>31
Minot (SAC)	Micronized	X		1.743	6.0	1.348	8.0	1.018	19.8
	Slagging	X		1.577	8.9	1.219	12.6	0.917	>31
	Pkg. FBC		X	1.570	9.0	1.214	12.8	0.915	>31
	Stoker refit	X		1.564	7.9	1.210	11.5	0.923	>31
Robins (AFLC)	Micronized	X		1.737	5.6	1.330	7.7	1.003	26.0
	Pkg. FBC		X	1.470	10.6	1.124	16.8	0.842	>31
	Pkg. stoker		X	1.463	10.0	1.119	16.5	0.844	>31
Plattsburgh (SAC)	Micronized	X		1.562	5.6	1.281	8.7	1.011	21.3
	Slagging	X		1.440	8.3	1.180	13.4	0.926	>31
	Pkg. FBC		X	1.431	8.5	1.172	13.8	0.923	>31
McGuire (MAC)	Micronized	X		1.643	6.8	1.264	9.7	0.950	>31
	Pkg. FBC		X	1.513	9.7	1.163	14.6	0 873	>31
Pease[a] (SAC)	Micronized	X		1.540	7.9	1.196	11.7	0.917	>31
	Slagging	X		1.390	12.0	1.079	19.9	0.822	>31
	Coal/water	X		1.369	10.4	1.066	19.4	0.834	>31
	FBC refit	X		1.359	13.1	1.055	22.6	0.804	>31
	Pkg. FBC		X	1.266	15.8	0.983	>31	0.747	>31
Dover (MAC)	Micronized	X		1.434	7.3	1.188	11.8	0.947	>31
	Stoker refit	X		1.324	9.4	1.098	17.1	0.882	>31
Andrews (MAC)	Micronized	X		1.431	7.5	1.185	12.1	0.945	>31
	Stoker refit	X		1.315	9.8	1.091	17.8	0.877	>31
Elmendorf[b] (AAC)	Micronized	X		1.527	8.5	1.146	14.3	0.851	>31
	Slagging	X		1.403	12.0	1.052	22.9	0.775	>31
	FBC refit	X		1.379	12.9	1.034	25.3	0.762	>31
	Field FBC		X	1.326	14.7	0.994	>31	0.729	>31
Tinker (AFLC)	Field FBC		X	1.532	10.7	1.151	16.5	0.840	>31
	Pkg. FBC		X	1.523	10.4	1.145	16.3	0.839	>31

[a]LCC results for Pease may be optimistic because of questionable access to inexpensive rail delivery for coal.

[b]LCC results for Elmendorf may be optimistic because of questionable availability of inexpensive coal.

6.3.2 Effect of Discount Rate

Lowering the discount rate will affect the LCC analysis because the influence of costs incurred in early years will become less important, and those incurred in later years will become more important. Another way to view this effect is that the influence of the initial capital investment will lessen in comparison to annual fuel and O&M costs. Lower discount rates will therefore cause coal projects to look more attractive.

A value of 10% was used for the discount rate in the main body of results. The LCC model was recalculated with a 7% discount rate for the top seven Air Force sites from Table 6.7. Because coal appears to be the least attractive relative to gas or oil for the zero fuel escalation case, this fuel escalation scenario was the only one evaluated. The results in Table 6.9 for Air Force-financed projects show that the 7% discount rate increases the magnitude of the benefit/cost ratios by about 3 or 4%, but it does not affect the ranking of the bases.

6.4 SUMMARY OF LEADING SITES FOR COAL UTILIZATION

The most important objective of this report is to conclude which Air Force sites have the greatest potential for economical utilization of coal. From the results given in Tables 6.3 to 6.9, seven bases can be identified as leading sites. This section summarizes the pertinent information for the seven leading sites: Arnold Air Force Station (AFS), Kelly AFB, Grand Forks AFB, Minot AFB, Robins AFB, Plattsburgh AFB, and McGuire AFB.

6.4.1 Arnold AFS

The main heating plant in Bldg. 1411 at Arnold consists of three 72-MBtu/h and one 24-MBtu/h boilers, all of which were designed for bituminous coal. The large boilers were designed for pulverized coal-firing. All of the boilers have been converted, and they now fire natural gas with No. 2 oil used as a secondary fuel. The boilers were installed in 1951, but they are still in good condition. The capacity factor for refitting or replacing one 72-MBtu/h boiler is estimated to be about 72%, based on FY 1986 fuel-use data.

Table 6.9. Effect of discount rate on Air Force-financing results for zero fuel escalation

Base	10% discount rate				7% Discount rate			
	Best coal technology	Rank	Benefit/cost ratio	Discounted payback (years)	Best coal technology	Rank	Benefit/cost ratio	Discounted payback (years)
Arnold	Micronized	1	1.191	6.4	Micronized	1	1.230	5.9
Kelly	Pkg. stoker	3	1.022	19.3	Pkg. stoker	3	1.065	13.8
Grand Forks	Micronized	2	1.057	12.9	Micronized	2	1.096	10.6
Minot	Micronized	4	1.018	19.8	Micronized	4	1.057	14.0
Robins	Micronized	6	1.003	26.0	Micronized	6	1.034	15.9
Plattsburgh	Micronized	5	1.011	21.3	Micronized	5	1.042	14.6
McGuire	Micronized	7	0.950	>31	Micronized	7	0.984	>31

Some of the original coal-storage and -handling equipment is still in place, but it is in poor condition and could not be used again. Removal of this equipment would provide adequate space to install new coal-handling equipment. Because the large boilers were designed for pulverized coal-firing, the most convenient conversion would be to install micronized coal-firing equipment. The technical risk would be minimal, because the environmental regulations require no SO_2 control for a boiler with a fuel input <100 MBtu/h. A micronized coal system refit to one of the existing boilers is estimated to be the lowest-cost conversion option.

The economics of converting to coal-firing appear to be attractive based on both current and future escalated fuel prices. The current reported prices for fuels at the base are $3.97/MBtu for natural gas and $1.75/MBtu for ROM bituminous coal with 1.5% sulfur content. Overall, Arnold appears to be the leading candidate for conversion of one of the large boilers in the central steam plant back to coal-firing.

6.4.2 Kelly AFB

The main steam plant in Bldg. 376 at Kelly consists of two 54.5-MBtu/h, two 50-MBtu/h, and one 49.6-MBtu/h boilers that were designed for gas-/oil-firing. They use natural gas as the primary fuel with No. 2 oil as a secondary fuel. The boilers were installed from 1954 through 1976 and are in good condition. The capacity factor for refitting or replacing one 54.5-MBtu/h boiler, but derated to 43.5 MBtu/h, is estimated to be about 82%, based on FY 1985 fuel-use data. Derating is necessary because the boilers were not designed for coal-firing.

There is not enough available space at the existing boiler house to install dry coal-firing equipment or a coal pile. It should be possible to install coal/water mixture combustion equipment at the present boiler house. The technical risk would be fairly high because of limited experience with firing coal/water mixtures in No. 2 oil-designed boilers. A packaged shell-type stoker replacement boiler at another site on base is estimated to be the lowest-cost coal-conversion option. The environmental control regulations require no SO_2 control for boilers with ratings <100 MBtu/h fuel input.

Based on future escalated fuel prices, the economics of converting to coal-firing with a replacement boiler appear to be attractive. There is only a slight cost advantage at present fuel prices. The current reported prices for fuels at the base are \$4.00/MBtu for natural gas and \$1.98/MBtu for stoker bituminous coal with 1.3% sulfur. Kelly is among the top six candidates for potential conversion to coal-firing, in this case by means of a replacement boiler.

6.4.3 Grand Forks AFB

The central heating plant in Bldg. 423 at Grand Forks consists of two 42-MBtu/h and three 25-MBtu/h HTHW boilers, all of which were designed for stoker coal-firing. They were later converted to burn No. 6 oil. Presently, HTHW is being obtained from electrically heated boilers (owned by the electric utility) with a special low electric power rate of 2.15¢/kWh. However, No. 6 oil was assumed to be the primary fuel in the economic analysis because the contract to purchase this low-priced electric power from the utility will expire soon. The base also has recently acquired access to natural gas, but it has never been burned in the central heating plant. The capacity factor for refitting or replacing one 42-MBtu/h boiler is estimated to be ~72%, based on FY 1985 and 1986 fuel-use data.

The original coal-handling equipment has been removed, but there is space available to install new equipment. The boiler was originally designed for stoker-firing, so it should be feasible to refit it with any of the technology options. A refit to stoker-firing would have the least technical risk. The risk for the other options should be only slightly higher because the environmental regulations require no SO_2 control when burning low-sulfur coal (<1.6% sulfur) in a boiler with a fuel input <100 MBtu/h. A micronized coal system refit to one of the existing 42-MBtu/h boilers is estimated to be the lowest-cost conversion option.

The economics of converting to coal-firing appear to be favorable based on future escalated fuel prices. There is only a slight cost advantage at present fuel prices. The current reported prices for fuels at the base are \$3.67/MBtu for No. 6 oil or natural gas, and \$1.48/MBtu for ROM bituminous coal with 1% sulfur. Grand Forks is among the top six candidates for conversion back to coal-firing, with the lowest-cost option being conversion of one of the 42-MBtu/h boilers to micronized coal.

6.4.4 Minot AFB

The central heating plant in Bldg. No. 413 at Minot consists of five 25-MBtu/h and one 42-MBtu/h HTHW boilers. Two boilers (42- and 25-MBtu/h) were designed to burn coal but have since been converted to burn gas or oil. Gas is the primary fuel, and No. 6 oil is the secondary fuel for these boilers. The 42-MBtu/h boiler was installed in 1963 and is in good condition. The capacity factor for refitting or replacing this boiler is estimated to be about 65%, based on FY 1985 and 1988 fuel-use data.

The original coal-handling equipment has been removed, but there is space available to install new equipment. The boiler was originally designed for stoker-firing, so it should be feasible to refit it with any of the technology options. A refit to stoker-firing would have the least technical risk. The risk for the other technology options should be only slightly higher because the environmental regulations require no SO_2 control when burning low-sulfur (<1.6%) coal in a boiler with a fuel input <100 MBtu/h. A micronized coal system refit to the existing 42-MBtu/h boiler is estimated to be the lowest-cost conversion option.

The economics of converting to coal-firing appear to be attractive based on future escalated fuel prices. There is only a slight cost advantage at present fuel prices. The current reported prices for fuels at the base are $3.60/MBtu for natural gas and $1.48/MBtu for ROM bituminous coal with 1% sulfur. Minot is one of the top six candidates for conversion back to coal-firing of the large boiler in the central heating plant.

6.4.5 Robins AFB

There are two major heating plants at Robins, but only one has large enough boilers to merit consideration for conversion. The larger heating plant in Bldg. 177 consists of three 98-MBtu/h, three 54-Btu/h, and one 5-MBtu/h boilers. The three 54-MBtu/h boilers were originally designed for coal but have been converted to burn natural gas with No. 2 oil used as a secondary fuel. The boilers were installed in 1953 and are in fair condition. The capacity factor for refitting or replacing one 54-MBtu/h boiler is estimated to be ~81%, based on FY 1985 and 1986 fuel-use data.

The original coal-handling equipment has been removed, and cooling towers have been installed in much of this space. The space for new coal-handling equipment is limited, and the only technologies that could probably be used for refit would be micronized coal or coal/water slurry-firing. The micronized coal option would have the lowest technical risk because the environmental regulations require no SO_2 control for a boiler with a fuel input <100 MBtu/h. A micronized coal system refit to one of the existing 54-MBtu/h boilers is estimated to be the lowest-cost conversion option.

The economics of converting to coal-firing appear to be attractive based on future escalated fuel prices. There is only a slight cost advantage at present fuel prices. The current reported prices for fuels at the base are $3.19/MBtu for natural gas and $1.77/MBtu for ROM bituminous coal with 0.8% sulfur. Robins is one of the top six candidates for potential conversion back to coal-firing of one of the coal-designed boilers.

6.4.6 Plattsburgh AFB

The main heating plant in Bldg. 2658 at Plattsburgh consists of six 50-MBtu/h HTHW boilers, all of which were designed for firing No. 6 oil. The primary fuel is still No. 6 oil. The boilers were installed in 1955 and 1957 and are in fair to good condition. The capacity factor for refitting or replacing one 50-MBtu/h boiler is estimated to be about 76%, based on FY 1987 and 1988 fuel-use data.

There is enough space available to install coal-handling equipment and for a coal pile at the existing boiler house. Because the boilers were originally designed for No. 6 oil, the return to stoker option is not possible, but the other refit technologies should be feasible. The technical risk would be moderate for all of the refit options because of limited experience with firing coal in boilers designed for No. 6 oil. A micronized coal system refit to one of the existing boilers is estimated to be the lowest-cost conversion option.

The economics of converting to coal-firing appear to be favorable based on future escalated fuel prices. There is only a slight cost advantage at present fuel prices. The current reported prices for fuels at the base are \$3.67/MBtu for No. 6 oil and \$1.97/MBtu for ROM bituminous coal with 2% sulfur. Plattsburgh is among the top seven candidates for conversion back to coal-firing, with the lowest-cost option being conversion of one of the 50-MBtu/h boilers to micronized coal.

6.4.7 McGuire AFB

The main heating plant in Bldg. 2101 at McGuire consists of four 50-MBtu/h and two 31.2-MBtu/h HTHW boilers, all of which were designed for stoker-firing of bituminous coal. All of the boilers have been converted and now burn natural gas with No. 2 oil used as a secondary fuel. The larger boilers were installed in 1953 and the smaller ones in 1960. The capacity factor for refitting or replacing one 50-MBtu/h boiler is estimated to be about 62% based on calendar year (CY) 1985 and FY 1986 fuel-use data.

Most of the coal-handling equipment is still in place, but some of it is in very bad condition and could not be used again. Removal of the unusable equipment would provide adequate space to install the necessary new coal-handling equipment. It would be feasible to refit one or more of the larger boilers with any of the technology options. The environmental regulations require strict SO_2 control, so the technical risk is fairly high for all of the combustion options. A micronized coal system refit to one of the 50-MBtu/h boilers is estimated to have the lowest cost of the conversion options, but low-sulfur (<1.5%) coal may be required in combination with limestone addition to meet the 0.3-lb/MBtu SO_2 emission limit.

The economics of converting to coal-firing appear to be favorable for future escalated fuel prices but unfavorable for current fuel prices. The current reported prices for fuels at the base are \$4.00/MBtu for natural gas and \$1.89/MBtu for ROM bituminous coal.

McGuire is among the top seven candidates for potential conversion to coal-firing.

7. CONCLUSIONS AND RECOMMENDATIONS

The major goal of this report was to rank the Air Force installations that presently burn natural gas and/or oil for steam/HTHW production according to their suitability for economical use of coal. It is recommended that the following seven installations be considered as the leading candidates for conversion of heating plants to coal-firing:

1. Arnold AFS,
2. Kelly AFB,
3. Grand Forks AFB,
4. Minot AFB,
5. Robins AFB,
6. Plattsburgh AFB,
7. McGuire AFB.

They are listed in order of rank, with Arnold AFS being the site with the highest estimated benefit/cost ratio for a coal-conversion/-utilization project. The ranking of all 16 Air Force sites examined in this report is given in Table 6.7.

Even though three levels of fuel escalation and two types of financing were considered, the economic results consistently identified Arnold AFS as the top site for coal conversion. The analysis also ranked Kelly, Grand Forks, Minot, Robins, Plattsburgh, and McGuire AFBs in positions 2 through 7, although their respective order was not always consistent. It is recommended that any possible demonstration projects be conducted at one of these seven bases. A micronized coal refit system would be a logical choice for a demonstration project because it is a fairly new technology that appears to have very favorable economics.

The three sets of fuel escalation assumptions used in the analysis did have a very significant effect on the calculated LCCs and benefit/cost ratios for the various coal-conversion projects. One fuel escalation scenario was based on DOD guidelines and resulted in rather high escalation rates for gas and oil prices relative to coal prices. It is recommended that these DOD escalators be updated as soon as new information is available and that the current method for estimating fuel escalation beyond the year 2000 be improved. To address this issue, a second set of fuel escalators was developed and used in the LCC analysis for comparison. This second set of fuel price escalators was designated as the "AEO 1987" case, and it resulted in escalation rates that were approximately midway between the DOD fuel escalation rates and a third case of zero fuel escalation.

The results given in Tables 6.3 to 6.6 show a large spread in the benefit/cost ratios for the three different fuel price escalation scenarios. A large number of coal-conversion projects appear to be economically viable when the DOD fuel escalators are used; only a few appear economical when zero fuel escalation is assumed; and the middle "AEO 1987" fuel escalation case gives results between these extremes. It is very difficult to decide which fuel price scenario is most applicable because the fuel escalation projections are, at best, only educated guesses of future events. It can be concluded, however, that at least a few Air Force sites are good candidates for coal-conversion projects based on the results for zero fuel escalation, which is a very conservative assumption.

When compared to the DOD target of 1,600,000 tons/year, the coal-utilization projects considered in this report would result in a relatively small amount of coal use. Projects at all seven of the leading sites (listed previously) would consume only ~112,000 tons/year (~7% of DOD target). Projects at all 16 bases examined in the report would consume ~433,000 tons/year (~27% of DOD target). Other types of projects that would use greater amounts of coal should be examined if meeting the DOD target is desired. Coal-utilization projects that could potentially be larger than those examined in this study, such as cogeneration and increasing heating loads through distribution system extensions, will be examined in later reports.

Up to this point, noneconomic factors, such as Air Force energy security, aesthetics, and possible effects on base missions, have not been considered. These types of considerations must eventually be factored into the decision-making process.

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APPENDIX

AIR FORCE BASE INFORMATION SUMMARIES

Information summaries concerning the heating plants for each of the 16 Air Force facilities examined in the economic analysis are presented in this appendix. The information in these summaries was used to model coal-conversion projects. Results from the LCC model are included with each information summary.

The summaries are grouped according to the major commands and arranged alphabetically in the following order:

ELMENDORF AFB: AAC

1. BACKGROUND

Elmendorf Air Force Base is located near Anchorage, Alaska, and has one of the largest central heating plants in the Air Force. The annual average fuel consumption is ~300 MBtu/h. Only the primary heating plant is of significance to this study. All boilers were built to burn bituminous or subbituminous coals. They are described as field-erected, two-drum, bent-tube, water-tube units with economizers, fitted with Peabody ring-type gas burners and Peabody steam atomizing oil burners. Natural gas is now the main fuel with distillate (Arctic diesel) oil as a backup fuel. The boilers previously burned Matanuska bituminus coal (12,900 Btu/lb) with spreader stoker traveling grate systems. Conversion to natural gas (with Arctic diesel as secondary fuel) took place in 1968. The Matanuska mines went out of business because the remaining coal seam dipped steeply, causing mining to be uneconomical, especially in comparison to natural gas.

Presently, cogeneration is employed for this steam plant. The 415-psig superheated steam passes through three Westinghouse, 9375-kVA, condensing, single-automatic-extraction turbogenerators. Steam is extracted at 100 psig.

2. HEATING PLANT UNITS

Heating Plant No. 22-004:

6 × 150 MBtu/h, Erie City, 1954

3. IDEAL CAPACITY FACTOR ANALYSIS

The maximum possible capacity factors listed below were calculated from monthly fuel-use data for plant No. 22-004.

Fuel input (MBtu/hr)	FY 1986 ideal capacity factor
250	0.97
300	0.91
350	0.84
400	0.75
450	0.67

4. ENERGY PRICES

FY 1986 Price Data:

Natural gas = \$1.94/MBtu
Distillate oil = \$5.90/MBtu
Electricity = 8.0¢/kWh

The price of electricity is probably for the purchased amount only, which is rather small because of the cogeneration system.

C. H. Guernsey and Co. Survey:

Natural gas = \$2.05/MBtu
Distillate oil = \$5.90/MBtu
Electricity = 3.5¢/kWh

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin		
HHV, Btu/lb	7650	7650
Ash, %	13.9	13.9
Sulfur, %	0.17	0.17
Nitrogen, %	1.0	1.0
Ash-softening temperature °F	2130	2130
Swelling index		
Top size, in.	2 × 0	
Bottom size, in.		
Fines, %		
Grindability index	32	32
Cost at mine, \$/ton	31.00 (estimated)	23.00
Delivered cost, \$/ton	33.00	25.00
Energy price, \$/MBtu	2.16	1.63

The prices quoted are very optimistic because they are from a new company that is not yet in operation. If the above coal is not available when a coal-conversion project is completed, then coal would have to be purchased from the only supplier that is currently in operation, at a delivered price of about \$44.00/ton (\$2.81/MBtu) for ROM coal. This would make coal conversion unattractive because coal would cost more than gas.

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

The Air Quality Control Regulations of Alaska require that fuel-burning equipment of the capacity being considered for Elmendorf (one or more boilers) be operated only after a permit is granted. The application for a permit must include, in addition to other requirements (1) plans and specifications, (2) an engineering report, and (3) a description of air-quality-control devices. The Air Quality Control Regulations classify the Anchorage urban area (adjacent to the base) as a nonattainment area (Class I) for carbon monoxide levels in the ambient air. Hence, carbon monoxide emissions may not increase significantly from current levels at the base unless an offset is adopted for another pollutant. A significant increase is defined in the national standards as 100 tpy. It is very unlikely that a return to coal-firing would violate this emission rate; hence, the increase in CO emission would in all probability not be significant.

With the exception of limited nonattainment areas for carbon monoxide, the air and water quality in Alaska compare favorably with most areas in the country. Therefore, the State government has not legislated Alaska air emission or coal runoff water standards but relies on applicable national standards for emission control.

SO_2. For boilers >100 MBtu/h: FBC — 90% reduction to meet limit of 1.2 lb/MBtu; emerging technology — 50% reduction to meet limit of 0.6 lb/MBtu.

NO_x. For boilers >100 MBtu/h: spreader stoker and FBC — 0.6 lb/MBtu; pulverized coal — 0.7 lb/MBtu.

Particulates. For boilers >100 MBtu/h: 0.05 lb/MBtu; opacity must be <20% except for one 6-min period per hour of no more than 27%.

6.2 Coal-Pile Runoff

EPA regulations for coal-pile rainfall runoff specify that the pH of all discharges, except once-through cooling water, shall be within the range of 6.0 to 9.0. The total suspended solids limitation for the point source discharges of coal-pile runoff is 50 mg/L.

6.3 Ash Disposal

The national standards for solid wastes classify coal ash as a nonhazardous solid waste. The EPA does not regulate fly ash and bottom ash waste. The only regulations Alaska has pertaining to or affecting coal ash disposal are (1) general requirements for a solid-waste facility and (2) rules for issuing a general permit for solid-waste disposal.

The general requirements for a solid-waste facility are designed to protect other standards governing the purity of surface- and drinking-water supplies. Problems should not arise in this area if care is exercised in selecting a disposal site. Obtaining a general permit from the state of Alaska for disposal of solid waste should not present a problem since the waste is nonhazardous.

7. OTHER CONSIDERATIONS

Wages for steam plant personnel look very high, about $17/h in 1980. Nineteen people were listed for this 900-MBtu/h boiler plant.

No doubt coal has some special problems in Alaska because of freezing temperatures. Also transportation difficulties and costs must be considered carefully. Railroad trackage is in poor condition and has been partially removed. No locomotive is available on base. The base has an expandable landfill to satisfy solid-waste disposal requirements.

8. COAL-CONVERSION PROJECT OUTLOOK

Based on the capacity factor analysis, the most economical coal options would probably be to replace/refit two boilers. The maximum load factor for conversion/replacement of two 150-MBtu/h units (375 MBtu/h fuel input for both units) would be ~0.80. If 90% coal system availability is assumed, then the estimated overall capacity factor for coal-firing will be $0.8 \times 0.9 = 0.72$.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

$\underline{SO_2}$. SO_2 removal is required because the proposed project is larger than 100 MBtu/h.

$\underline{NO_x}$. No special NO_x reduction methods will be required for any of the combustion technologies.

Particulates. Bag filters or electrostatic precipitators will be required.

8.2 Physical Space and Aesthetics

Heating Plant. The existing plant was originally designed for coal. There is space available for reinstalling combustion equipment at the existing boiler or for constructing a new boiler at another site on base.

Coal-Handling Equipment. There is space available for coal-handling equipment at the existing boiler.

Coal Pile. There is space available for a coal pile at the existing plant or at a new site on base.

8.3 Technical Risk of Combustion Technologies

The boilers were originally designed for coal, and the lowest risk is for refit of stoker firing. However, the need for SO_2 control increases the overall risk for that option, as well as the other coal-combustion technologies.

9. COGENERATION PROJECT OUTLOOK

Cogeneration is currently being used at Elmendorf; hence, an evaluation of its potential is not provided.

10. INPUT AND LCC SUMMARY SPREADSHEETS

ELMENDORF AFB: 2 X 150 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 300.0 MBtu/hr
Boiler capacity factor = .719
Number of units for refit = 2
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 3.50
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.05
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.139	.139
Sulfur fraction =	.002	.002
HHV (Btu/lb) =	7650.	7650.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.63
Stoker coal ($/MBtu) = 2.16
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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ELMENDORF AFB: 2 X 150 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 300.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .719   Primary fuel = NATURAL GAS

Number of units for refit = 2

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.05	.0	4841.9	443.2	817.8
#2 Oil fired boiler	--	.800	4.71	.0	11124.6	443.2	817.8
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	2	.800	1.63	9386.9	3849.9	724.1	1573.8
Slagging burner refit	2	.800	1.63	16028.4	3849.9	724.1	1573.8
Modular FBC refit	2	.790	1.63	18351.6	3898.7	667.9	1486.4
Stoker firing refit	2	.740	2.16	16257.6	5515.4	1060.0	1567.3
Coal/water slurry	2	.750	3.00	8696.0	7558.1	667.9	1361.9
Coal/oil slurry	2	.780	3.50	7728.6	8478.7	531.9	1133.6
Low Btu gasifier refit	6	.659	2.16	27376.7	6197.1	616.0	3377.1
Packaged shell stoker	6	.740	2.16	26976.7	5515.4	1060.0	1806.2
Packaged shell FBC	6	.760	1.63	25097.4	4052.5	667.9	1737.8
Field erected stoker	1	.780	2.16	24711.4	5232.6	1055.9	1396.5
Field erected FBC	1	.800	1.63	22309.6	3849.9	775.7	1358.8
Pulverized coal boiler	1	.800	1.63	28117.7	3849.9	1175.9	1480.6
Circulating FBC	1	.810	1.63	28500.3	3802.4	663.9	1470.6

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	95,354	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	179,723	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	2	154,374	62,462	1.527	8.5	68,800	1.386
Slagging burner refit	2	154,374	67,951	1.403	12.0	77,676	1.228
Modular FBC refit	2	156,328	69,143	1.379	12.9	80,032	1.191
Stoker firing refit	2	166,890	86,653	1.100	23.2	97,019	.983
Coal/water slurry	2	164,665	94,382	1.010	30.0	101,288	.941
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	6	187,517	112,341	.849	>31	128,846	.740
Packaged shell stoker	6	166,890	97,373	.979	>31	113,259	.842
Packaged shell FBC	6	162,498	78,115	1.221	18.2	92,541	1.030
Field erected stoker	1	158,332	89,630	1.064	25.9	104,194	.915
Field erected FBC	1	154,374	71,929	1.326	14.7	84,823	1.124
Pulverized coal boiler	1	154,374	81,256	1.174	20.3	97,241	.981
Circulating FBC	1	152,468	76,471	1.247	17.6	92,507	1.031

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ELMENDORF AFB: 2 X 150 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 300.0 MBtu/hr			
Boiler capacity factor = .719			
Number of units for refit = 2			
Hydrated lime price($/ton) = 40.00	**COAL PROPERTIES**		
Ash disposal price ($/ton) = 10.00		R.O.M.	Stoker
Electric price (cents/kWh) = 3.50	Ash fraction =	.139	.139
Labor rate (k$/yr) = 35.00	Sulfur fraction =	.002	.002
Limestone price ($/ton) = 20.00	HHV (Btu/lb) =	7650.	7650.
FUEL PRICES	**FUEL PRICES**		
Natural gas price ($/MBtu) = 2.05	R.O.M. coal ($/MBtu) = 1.63		
#2 Oil price ($/MBtu) = 4.71	Stoker coal ($/MBtu) = 2.16		
#6 Oil price ($/MBtu) = .00	Coal/H2O mix ($/MBtu) = 3.00		
OPTIONS	Coal/oil mix ($/MBtu) = 3.50		
Soot blower multiplier = .0			
Tube bank mod multiplier = .0	**Primary fuel is 3**		
Bottom ash pit multiplier = 1.0	NATURAL GAS		
SO2 control multiplier = 1.0	1=#6 Oil, 2=#2 Oil, 3=NG		
LIMESTONE/LIME			
Inert fraction = .05			

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
	TYPE OF FUEL	1988	1990	1995	2000 AND
FUEL	ESCALATION	-1990	-1995	-2000	BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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ELMENDORF AFB: 2 X 150 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 300.0 MBtu/hr Cost base year = 1988
Boiler capacity factor = .719 Primary fuel = NATURAL GAS
Number of units for refit = 2

					ANNUAL COSTS		
TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.05	.0	4841.9	443.2	817.8
#2 Oil fired boiler	--	.800	4.71	.0	11124.6	443.2	817.8
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	2	.800	1.63	9386.9	3849.9	724.1	1573.8
Slagging burner refit	2	.800	1.63	16028.4	3849.9	724.1	1573.8
Modular FBC refit	2	.790	1.63	18351.6	3898.7	667.9	1486.4
Stoker firing refit	2	.740	2.16	16257.6	5515.4	1060.0	1567.3
Coal/water slurry	2	.750	3.00	8696.0	7558.1	667.9	1361.9
Coal/oil slurry	2	.780	3.50	7728.6	8478.7	531.9	1133.6
Low Btu gasifier refit	6	.659	2.16	27376.7	6197.1	616.0	3377.1
Packaged shell stoker	6	.740	2.16	26976.7	5515.4	1060.0	1806.2
Packaged shell FBC	6	.760	1.63	25097.4	4052.5	667.9	1737.8
Field erected stoker	1	.780	2.16	24711.4	5232.6	1055.9	1396.5
Field erected FBC	1	.800	1.63	22309.6	3849.9	775.7	1358.8
Pulverized coal boiler	1	.800	1.63	28117.7	3849.9	1175.9	1480.6
Circulating FBC	1	.810	1.63	28500.3	3802.4	663.9	1470.6

			AIR FORCE PROJECT			PRIVATE PROJECT	
TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	70,854	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	141,045	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	2	154,374	61,850	1.146	14.3	68,170	1.039
Slagging burner refit	2	154,374	67,339	1.052	22.9	77,046	.920
Modular FBC refit	2	156,328	68,523	1.034	25.3	79,395	.892
Stoker firing refit	2	166,890	85,776	.826	>31	96,117	.737
Coal/water slurry	2	164,665	93,180	.760	>31	100,052	.708
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	6	187,517	111,355	.636	>31	127,832	.554
Packaged shell stoker	6	166,890	96,496	.734	>31	112,357	.631
Packaged shell FBC	6	162,498	77,470	.915	>31	91,878	.771
Field erected stoker	1	158,332	88,798	.798	>31	103,339	.686
Field erected FBC	1	154,374	71,317	.994	>31	84,194	.842
Pulverized coal boiler	1	154,374	80,644	.879	>31	96,611	.733
Circulating FBC	1	152,468	75,867	.934	>31	91,885	.771

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ELMENDORF AFB: 2 X 150 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 300.0 MBtu/hr
Boiler capacity factor = .719
Number of units for refit = 2
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 3.50
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.05
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.139	.139
Sulfur fraction =	.002	.002
HHV (Btu/lb) =	7650.	7650.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.63
Stoker coal ($/MBtu) = 2.16
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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ELMENDORF AFB: 2 X 150 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 300.0 MBtu/hr   Cost base year = 1988
Boiler capacity factor = .719   Primary fuel = NATURAL GAS
Number of units for refit = 2

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	2.05	.0	4841.9	443.2	817.8
#2 Oil fired boiler	--	.800	4.71	.0	11124.6	443.2	817.8
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	2	.800	1.63	9386.9	3849.9	724.1	1573.8
Slagging burner refit	2	.800	1.63	16028.4	3849.9	724.1	1573.8
Modular FBC refit	2	.790	1.63	18351.6	3898.7	667.9	1486.4
Stoker firing refit	2	.740	2.16	16257.6	5515.4	1060.0	1567.3
Coal/water slurry	2	.750	3.00	8696.0	7558.1	667.9	1361.9
Coal/oil slurry	2	.780	3.50	7728.6	8478.7	531.9	1133.6
Low Btu gasifier refit	6	.659	2.16	27376.7	6197.1	616.0	3377.1
Packaged shell stoker	6	.740	2.16	26976.7	5515.4	1060.0	1806.2
Packaged shell FBC	6	.760	1.63	25097.4	4052.5	667.9	1737.8
Field erected stoker	1	.780	2.16	24711.4	5232.6	1055.9	1396.5
Field erected FBC	1	.800	1.63	22309.6	3849.9	775.7	1358.8
Pulverized coal boiler	1	.800	1.63	28117.7	3849.9	1175.9	1480.6
Circulating FBC	1	.810	1.63	28500.3	3802.4	663.9	1470.6

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	48,057	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	97,005	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	2	154,374	56,488	.851	>31	62,656	.767
Slagging burner refit	2	154,374	61,977	.775	>31	71,532	.672
Modular FBC refit	2	156,328	63,093	.762	>31	73,811	.651
Stoker firing refit	2	166,890	78,094	.615	>31	88,218	.545
Coal/water slurry	2	164,665	82,653	.581	>31	89,227	.539
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	6	187,517	102,724	.468	>31	118,957	.404
Packaged shell stoker	6	166,890	88,814	.541	>31	104,457	.460
Packaged shell FBC	6	162,498	71,826	.669	>31	86,074	.558
Field erected stoker	1	158,332	81,510	.590	>31	95,844	.501
Field erected FBC	1	154,374	65,955	.729	>31	78,679	.611
Pulverized coal boiler	1	154,374	75,282	.638	>31	91,097	.528
Circulating FBC	1	152,468	70,571	.681	>31	86,439	.556

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HILL AFB: AFLC

1. BACKGROUND

Hill AFB is located near Ogden, Utah. There are about 13 steam plants located on this base, with plant No. 260 being by far the largest fuel user (yearly average is ~115 MBtu/h). Boiler plant No. 825 is the second largest fuel-using heating facility, but it is probably too small for coal to be an economic option.

Boilers at both heating plants are water-tube-type units which produce 100 psi steam and are designed for distillate oil and natural gas-firing. Natural gas is presently the primary fuel.

2. HEATING PLANT UNITS

Heating Plant No. 260:

2 × 28.5 MBtu/h, Cleaver Brooks, 1975
4 × 33.5 MBtu/h, Union Iron Works, 1955
2 × 33.5 MBtu/h, Erie City, 1962

Heating plant No. 825:

3 × 40.2 MBtu/h, Murray Iron, 1957

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly fuel use data for plant No. 260.

Fuel input (MBtu/h)	FY 1985 ideal capacity factor
30	0.83
50	0.81
70	0.75
90	0.71
120	0.67
150	0.64
180	0.61

4. ENERGY PRICES

FY 1986 Price Data:

Electricity = 5.2¢/kWh
Distillate = $5.92/MBtu
Natural gas = $2.85/MBtu

C. H. Guernsey and Co. Survey:

Electricity = none given
Distillate = \$5.63/MBtu
Natural gas = \$2.97/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Ogden, Utah	Ogden, Utah
HHV, Btu/lb	11,900	11,650
% Ash	8	8
% Sulfur	0.6	0.6
% Nitrogen	1.4	1.4
Ash-softening temperature, °F	2300	2300
Swelling index	2–2.5	2–2.5
Top size, in.	1 1/2	2
Bottom size, in.	1/4	0
Fines, %	7	35
Grindability index	48–50	48–50
Cost at mine, \$/ton	23	20
Delivered cost, \$/ton	31	28
Energy cost, \$/10^6 Btu	1.30	1.20

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

Best Available Control Technology (BACT) is required on all sources for all types of air emissions. The EPA New Source Performance Standards are considered as the minimum control, and BACT may be more stringent. This is determined on a case-by-case basis.

6.2 Coal-Pile Runoff

The coal pile will have to be contained within the property, and the runoff will have to drain into a wastewater system (or pond) for treatment. No discharge into rivers will be permitted.

6.3 Ash Disposal

There are no specific rules for coal ashes, and they may be disposed of in an approved sanitary landfill.

7. OTHER CONSIDERATIONS

A study should be done to see if some of the smaller steam plants could be eliminated by using a better steam distribution system. Air-quality constraints appear to be strict.

8. COAL-CONVERSION PROJECT OUTLOOK

The most probable project for plant No. 260 would involve refit/replacement of three 33.5-MBtu/h boilers. The boilers would have to be derated to 25 MBtu/h each because they were originally designed for No. 2 oil. Low gas prices will probably prevent any coal conversion project from being economical at this time.

An overall load factor of about 64% is estimated for refit/replacement of three 25-MBtu/h units (equivalent to ~94 MBtu/h total fuel input), assuming 90% availability.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2. Since the best available Control Technology is required, 90% SO_2 reduction will be required for dry coal combustion, or deep-cleaned, coal-water mixture will be required.

NO_x. Measures will have to be taken to minimize NO_x for any of the combustion technologies employed.

Particulates. Bag filters or electrostatic precipitators will be required.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for No. 2 oil. There is only enough space available for installing coal-water-mixture combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. There is no space available for installing dry coal-handling equipment at the existing boiler plant, but there is enough space for installing coal-water-mixture equipment.

Coal Pile. There is no available space for a coal pile at the existing boiler plant, but there is space at another site on base for a coal pile and a new coal-fired boiler.

8.3 Technical Risk of Combustion Technologies

The existing boilers are designed for No. 2 oil- or gas-firing and therefore are only suitable for conversion to coal-water-mixture firing. The technical risk is fairly high because of limited experience of coal-water-mixture firing of No. 2 oil-designed boilers.

9. COGENERATION PROJECT OUTLOOK

The prospects for a coal-fired cogeneration system appear to be somewhat marginal. The base has a high minimum monthly average electric load, 15 MWe, but the price of electricity is moderate (5.2¢/kWh). Based on the FY 1986 energy-use data, a cogeneration plant with a boiler rating of 91-MBtu/h output and a 6.7-MWe turbine generator would have an electrical power capacity factor of 90% and a peak thermal output of 68 MBtu/h, with a thermal energy capacity factor of about 65% if used as a baseload heating plant. A water-tube boiler with a steam rating of 1450 psia and 950°F would be the most suitable boiler for this cogeneration system.

10. INPUT AND LCC SUMMARY SPREADSHEETS

HILL AFB: 3 X 25 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 75.0 MBtu/hr
Boiler capacity factor = .635
Number of units for refit = 3
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.20
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.97
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.080	.080
Sulfur fraction =	.006	.006
HHV (Btu/lb) =	11650.	11900.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.20
Stoker coal ($/MBtu) = 1.30
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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HILL AFB: 3 X 25 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 75.0 MBtu/hr Cost base year = 1988

Boiler capacity factor = .635 Primary fuel = NATURAL GAS

Number of units for refit = 3

					ANNUAL COSTS		
TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.97	.0	1548.8	206.8	535.6
#2 Oil fired boiler	--	.800	4.71	.0	2456.2	206.8	535.6
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	3	.800	1.20	5449.5	625.8	440.8	935.9
Slagging burner refit	3	.800	1.20	8867.9	625.8	440.8	935.9
Modular FBC refit	3	.790	1.20	10055.0	633.7	405.5	905.2
Stoker firing refit	3	.740	1.30	8072.0	732.9	630.7	923.6
Coal/water slurry	3	.750	3.00	5411.4	1668.8	405.5	802.2
Coal/oil slurry	3	.780	3.50	4453.0	1872.0	322.9	738.2
Low Btu gasifier refit	3	.659	1.30	8971.8	823.5	374.0	1310.5
Packaged shell stoker	2	.740	1.30	7747.4	732.9	630.7	860.1
Packaged shell FBC	2	.760	1.20	7263.5	658.7	405.5	844.0
Field erected stoker	1	.780	1.30	10158.7	695.3	628.2	750.3
Field erected FBC	1	.800	1.20	9245.3	625.8	470.9	744.7
Pulverized coal boiler	1	.800	1.20	11543.5	625.8	701.0	802.7
Circulating FBC	1	.810	1.20	11141.2	618.1	403.0	800.8

			AIR FORCE PROJECT			PRIVATE PROJECT	
TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	33,218	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	43,422	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boilers were designed for #2 oil						
Coal/water slurry	3	23,874	29,939	1.110	22.0	33,420	.994
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	2	23,688	25,590	1.298	15.0	30,085	1.104
Packaged shell FBC	2	23,560	22,358	1.486	11.0	26,526	1.252
Field erected stoker	1	22,473	26,355	1.260	16.8	32,045	1.037
Field erected FBC	1	22,382	23,500	1.414	13.0	28,664	1.159
Pulverized coal boiler	1	22,382	27,909	1.190	19.5	34,317	.968
Circulating FBC	1	22,105	24,824	1.338	15.1	30,949	1.073

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HILL AFB: 3 X 25 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 75.0	MBtu/hr
Boiler capacity factor = .635	
Number of units for refit = 3	
Hydrated lime price($/ton) = 40.00	
Ash disposal price ($/ton) = 10.00	
Electric price (cents/kWh) = 5.20	
Labor rate (k$/yr) = 35.00	
Limestone price ($/ton) = 20.00	

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.080	.080
Sulfur fraction =	.006	.006
HHV (Btu/lb) =	11650.	11900.

FUEL PRICES

Natural gas price ($/MBtu) = 2.97
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.20
Stoker coal ($/MBtu) = 1.30
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

LIMESTONE/LIME

Inert fraction = .05

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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HILL AFB: 3 X 25 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 75.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .635   Primary fuel = NATURAL GAS

Number of units for refit = 3

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.97	.0	1548.8	206.8	535.6
#2 Oil fired boiler	--	.800	4.71	.0	2455.2	206.8	535.6
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	3	.800	1.20	5449.5	625.8	440.8	935.9
Slagging burner refit	3	.800	1.20	8867.9	625.8	440.8	935.9
Modular FBC refit	3	.790	1.20	10055.0	633.7	405.5	905.2
Stoker firing refit	3	.740	1.30	8072.0	732.9	630.7	923.6
Coal/water slurry	3	.750	3.00	5411.4	1668.8	405.5	802.2
Coal/oil slurry	3	.780	3.50	4453.0	1872.0	322.9	738.2
Low Btu gasifier refit	3	.659	1.30	8971.8	823.5	374.0	1310.5
Packaged shell stoker	2	.740	1.30	7747.4	732.9	630.7	860.1
Packaged shell FBC	2	.760	1.20	7263.5	658.7	405.5	844.0
Field erected stoker	1	.780	1.30	10158.7	695.3	628.2	750.3
Field erected FBC	1	.800	1.20	9245.3	625.8	470.9	744.7
Pulverized coal boiler	1	.800	1.20	11543.5	625.8	701.0	802.7
Circulating FBC	1	.810	1.20	11141.2	618.1	403.0	800.8

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	25,381	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	34,882	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boilers were designed for #2 oil						
Coal/water slurry	3	23,874	29,673	.855	>31	33,147	.766
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	2	23,688	25,473	.996	>31	29,965	.847
Packaged shell FBC	2	23,560	22,254	1.141	16.7	26,419	.961
Field erected stoker	1	22,473	26,244	.967	>31	31,931	.795
Field erected FBC	1	22,382	23,400	1.085	20.8	28,562	.889
Pulverized coal boiler	1	22,382	27,809	.913	>31	34,214	.742
Circulating FBC	1	22,105	24,726	1.026	26.9	30,848	.823

5:04 PM   Oct 19, 1988

HILL AFB: 3 X 25 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 75.0 MBtu/hr
Boiler capacity factor = .635
Number of units for refit = 3
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.20
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.97
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.080	.080
Sulfur fraction =	.006	.006
HHV (Btu/lb) =	11650.	11900.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.20
Stoker coal ($/MBtu) = 1.30
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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HILL AFB: 3 X 25 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 75.0 MBtu/hr Cost base year = 1988

Boiler capacity factor = .635 Primary fuel = NATURAL GAS

Number of units for refit = 3

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.97	.0	1548.8	206.8	535.6
#2 Oil fired boiler	--	.800	4.71	.0	2456.2	206.8	535.6
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	3	.800	1.20	5449.5	625.8	440.8	935.9
Slagging burner refit	3	.800	1.20	8867.9	625.8	440.8	935.9
Modular FBC refit	3	.790	1.20	10055.0	633.7	405.5	905.2
Stoker firing refit	3	.740	1.30	8072.0	732.9	630.7	923.6
Coal/water slurry	3	.750	3.00	5411.4	1668.8	405.5	802.2
Coal/oil slurry	3	.780	3.50	4453.0	1872.0	322.9	738.2
Low Btu gasifier refit	3	.659	1.30	8971.8	823.5	374.0	1310.5
Packaged shell stoker	2	.740	1.30	7747.4	732.9	630.7	860.1
Packaged shell FBC	2	.760	1.20	7263.5	658.7	405.5	844.0
Field erected stoker	1	.780	1.30	10158.7	695.3	628.2	750.3
Field erected FBC	1	.800	1.20	9245.3	625.8	470.9	744.7
Pulverized coal boiler	1	.800	1.20	11543.5	625.8	701.0	802.7
Circulating FBC	1	.810	1.20	11141.2	618.1	403.0	800.8

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	18,089	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	25,158	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boilers were designed for #2 oil						
Coal/water slurry	3	23,874	27,349	.661	>31	30,757	.588
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	2	23,688	24,453	.740	>31	28,915	.626
Packaged shell FBC	2	23,560	21,336	.848	>31	25,475	.710
Field erected stoker	1	22,473	25,276	.716	>31	30,935	.585
Field erected FBC	1	22,382	22,529	.803	>31	27,666	.654
Pulverized coal boiler	1	22,362	26,938	.672	>31	33,318	.543
Circulating FBC	1	22,105	23,865	.758	>31	29,963	.604

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KELLY AFB: AFLC

1. BACKGROUND

Kelly AFB is located near San Antonio, Texas. The central heating plant (building No. 376) has five water-tube boilers that burn natural gas or No. 2 oil as the backup fuel; 125-psi steam is produced. The yearly average fuel use is about 59 MBtu/h. Boiler efficiency is 79–82%. No boilers were designed for coal. All other boiler plants at Kelly are too small for consideration.

2. HEATING PLANT UNITS

Heating Plant No. 376:

2 × 54.5 MBtu/h, Babcock & Wilcox, 1971
49.6 MBtu/h, Babcock & Wilcox, 1976
2 × 50 MBtu/h, Vogt, 1954

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly fuel-use data for plant No. 376.

Fuel input (MBtu/h)	FY 1985 ideal capacity factor
40	0.99
50	0.95
60	0.87
70	0.80
80	0.72
90	0.65
100	0.59

4. ENERGY PRICES

FY 1986 Price Data:

Electricity = 5.2¢/kWh
Natural gas = $3.88/MBtu

C. H. Guernsey and Co. Survey:

Electricity = 5.1¢/kWh
Natural gas = $4.0/MBtu
Distllate oil = $5.88/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Laredo, Tex.	Laredo, Tex.
HHV, Btu/lb	12,900	12,300
% Ash	10–12	12
% Sulfur	1–1.5	1.1–5
% Nitrogen		
Ash-softening temperature, °F	2250	2250
Swelling index	0	0
Top size, in.	1 3/8	2 1/2
Bottom size, in.	1/8	0
Fines, %	10–15	15
Grindability index	28	28
Cost at mine, $/ton	40	35
Delivered cost, $/ton	51	46
Energy cost, $/10^6 Btu	1.98	1.87

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. For boilers <100 MBtu/h: 3 lb/MBtu; for boilers >100 MBtu/h: FBC – 90% reduction to meet limit of 1.2 lb/MBtu; emerging technology – 50% reduction to meet limit of 0.6 lb/MBtu.

NO_x. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: spreader stoker and FBC – 0.6 lb/MBtu; pulverized coal – 0.7 lb/MBtu.

Particulates. For 50 MBtu/h: 0.3 lb/MBtu; for boilers >100 MBtu/h: 0.05 lb/MBtu.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

In most cases, coal ash is classified as nonhazardous solid waste and may be disposed of in an approved sanitary landfill, with approval by the State.

7. OTHER CONSIDERATIONS

None.

8. COAL-CONVERSION PROJECT OUTLOOK

The most likely project would be to refit/replace one boiler unit. Existing boilers were designed for distillate oil and natural gas, which may make refitting an existing boiler for coal-firing quite difficult, unless it is derated.

If one of the 54.5-MBtu/h units were converted to coal and derated to 43.5 MBtu/h output (~54.5 MBtu/h fuel input), the maximum capacity factor based on monthly data would be roughly 91%. If equipment availability is assumed to be 90%, the overall capacity factor would be somewhere near 82%.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed (with 1.5% sulfur coal) without requiring any measures for NO_x or SO_2 reduction because the proposed conversion project is smaller than 100 MBtu/h.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for No. 2 oil. There is only space available for installing coal-water-mixture combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. There is no space available for installing dry coal-handling equipment at the existing boiler plant, but there is enough space for installing coal-water-mixture equipment.

Coal Pile. There is no space available for a coal pile at the existing boiler plant, but there is space at another site on base for a coal pile and a new coal-fired boiler.

8.3 Technical Risk of Combustion Technologies

The existing boilers are designed for No. 2 oil- or gas-firing and therefore are only suitable for conversion to coal-water-mixture firing. The technical risk is fairly high because of limited experience with coal-water-mixture firing of No. 2 oil-designed boilers.

9. COGENERATION PROJECT OUTLOOK

The prospects for a coal-fired cogeneration plant appear to be somewhat marginal. The base has a high minimum monthly average electric load, 24 MWe, but the price of electricity is moderate (5.1¢/KWh). Based on the FY 1986 energy-use data, a cogeneration plant with a boiler rating of 68 MBtu/h output and a 5-MWe turbine generator would have an electrical capacity factor of 90% and a peak thermal output of 50 MBtu/h, with a thermal energy capacity factor of about 75% if used as a baseload heating plant. A water-tube boiler with a steam rating of 1450 psia and 950°F would be the most suitable boiler for this cogeneration system.

10. INPUT AND LCC SUMMARY SPREADSHEETS

KELLY AFB: 1 X 43.5 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 43.5 MBtu/hr
Boiler capacity factor = .824
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.10
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 4.00
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.120	.110
Sulfur fraction =	.013	.013
HHV (Btu/lb) =	12300.	12900.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.87
Stoker coal ($/MBtu) = 1.98
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
	TYPE OF FUEL	1988	1990	1995	2000 AND
FUEL	ESCALATION	-1990	-1995	-2000	BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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KELLY AFB: 1 X 43.5 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 43.5 MBtu/hr — Cost base year = 1988

Boiler capacity factor = .824 — Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS: FUEL k$	ANNUAL COSTS: MAINT O & M k$	ANNUAL COSTS: OTHER O & M k$
Natural gas boiler	--	.800	4.00	.0	1570.0	153.2	463.4
#2 Oil fired boiler	--	.800	4.71	.0	1848.6	153.2	463.4
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.87	2599.2	734.0	350.2	635.9
Slagging burner refit	1	.800	1.87	4341.3	734.0	350.2	635.9
Modular FBC refit	1	.790	1.87	4958.8	743.3	333.3	617.5
Stoker firing refit	1	.760	1.98	2872.6	818.0	333.3	606.0
Coal/water slurry	1	.750	3.00	2620.3	1256.0	333.3	538.0
Coal/oil slurry	1	.780	3.50	2180.8	1408.9	265.4	508.2
Low Btu gasifier refit	1	.679	1.98	3898.5	916.2	307.4	734.8
Packaged shell stoker	1	.760	1.98	3343.0	818.0	333.3	606.0
Packaged shell FBC	1	.760	1.87	4210.3	772.6	333.3	618.3
Field erected stoker	1	.800	1.98	5971.2	777.1	331.3	597.9
Field erected FBC	1	.800	1.87	6545.1	734.0	387.1	617.2
Pulverized coal boiler	1	.820	1.87	6944.2	716.1	391.1	645.2
Circulating FBC	1	.810	1.87	7732.0	724.9	331.3	675.4

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT: BENEFIT/ COST RATIO	AIR FORCE PROJECT: DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT: BENEFIT/ COST RATIO
Natural gas boiler	--	--	32,548	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	33,129	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boiler was designed for #2 oil						
Coal/water slurry	1	17,019	21,071	1.545	7.3	22,943	1.419
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	1	16,014	18,107	1.798	5.9	20,247	1.608
Packaged shell FBC	1	16,795	18,495	1.760	6.8	21,067	1.545
Field erected stoker	1	15,213	19,815	1.643	8.7	23,283	1.398
Field erected FBC	1	15,955	20,536	1.585	9.7	24,303	1.339
Pulverized coal boiler	1	15,566	20,953	1.553	10.2	24,926	1.306
Circulating FBC	1	15,758	21,387	1.522	11.0	25,755	1.264

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KELLY AFB: 1 X 43.5 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 43.5 MBtu/hr
Boiler capacity factor = .824
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.10
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 4.00
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.120	.110
Sulfur fraction =	.013	.013
HHV (Btu/lb) =	12300.	12900.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.87
Stoker coal ($/MBtu) = 1.98
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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KELLY AFB: 1 X 43.5 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 43.5 MBtu/hr   Cost base year = 1988
Boiler capacity factor = .824   Primary fuel = NATURAL GAS
Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	4.00	.0	1570.0	153.2	463.4
#2 Oil fired boiler	--	.800	4.71	.0	1848.6	153.2	463.4
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.87	2599.2	734.0	350.2	635.9
Slagging burner refit	1	.800	1.87	4341.3	734.0	350.2	635.9
Modular FBC refit	1	.790	1.87	4958.8	743.3	333.3	617.5
Stoker firing refit	1	.760	1.98	2872.6	818.0	333.3	606.0
Coal/water slurry	1	.750	3.00	2620.3	1256.0	333.3	538.0
Coal/oil slurry	1	.780	3.50	2180.8	1408.9	265.4	508.2
Low Btu gasifier refit	1	.679	1.98	3898.5	916.2	307.4	734.8
Packaged shell stoker	1	.760	1.98	3343.0	818.0	333.3	606.0
Packaged shell FBC	1	.760	1.87	4210.3	772.6	333.3	618.3
Field erected stoker	1	.800	1.98	5971.2	777.1	331.3	597.9
Field erected FBC	1	.800	1.87	6545.1	734.0	387.1	617.2
Pulverized coal boiler	1	.820	1.87	6944.2	716.1	391.1	645.2
Circulating FBC	1	.810	1.87	7732.0	724.9	331.3	675.4

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	24,604	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	26,702	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boiler was designed for #2 oil						
Coal/water slurry	1	17,019	20,871	1.179	11.7	22,738	1.082
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	1	16,014	17,977	1.369	7.9	20,113	1.223
Packaged shell FBC	1	16,795	18,372	1.339	9.2	20,941	1.175
Field erected stoker	1	15,213	19,692	1.249	12.3	23,155	1.063
Field erected FBC	1	15,955	20,419	1.205	13.9	24,183	1.017
Pulverized coal boiler	1	15,566	20,839	1.181	15.0	24,809	.992
Circulating FBC	1	15,758	21,272	1.157	16.4	25,637	.960

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KELLY AFB: 1 X 43.5 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 43.5 MBtu/hr
Boiler capacity factor = .824
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.10
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 4.00
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.120	.110
Sulfur fraction =	.013	.013
HHV (Btu/lb) =	12300.	12900.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.87
Stoker coal ($/MBtu) = 1.98
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

9:10 AM Oct 20, 1988

KELLY AFB: 1 X 43.5 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 43.5 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .824   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	4.00	.0	1570.0	153.2	463.4
#2 Oil fired boiler	--	.800	4.71	.0	1848.6	153.2	463.4
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.87	2599.2	734.0	350.2	635.9
Slagging burner refit	1	.800	1.87	4341.3	734.0	350.2	635.9
Modular FBC refit	1	.790	1.87	4958.8	743.3	333.3	617.5
Stoker firing refit	1	.760	1.98	2872.6	818.0	333.3	606.0
Coal/water slurry	1	.750	3.00	2620.3	1256.0	333.3	538.0
Coal/oil slurry	1	.780	3.50	2180.8	1408.9	265.4	508.2
Low Btu gasifier refit	1	.679	1.98	3898.5	916.2	307.4	734.8
Packaged shell stoker	1	.760	1.98	3343.0	818.0	333.3	606.0
Packaged shell FBC	1	.760	1.87	4210.3	772.6	333.3	618.3
Field erected stoker	1	.800	1.98	5971.2	777.1	331.3	597.9
Field erected FBC	1	.800	1.87	6545.1	734.0	387.1	617.2
Pulverized coal boiler	1	.820	1.87	6944.2	716.1	391.1	645.2
Circulating FBC	1	.810	1.87	7732.0	724.9	331.3	675.4

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	17,212	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	19,383	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boiler was designed for #2 oil						
Coal/water slurry	1	17,019	19,122	.900	>31	20,939	.822
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	1	16,014	16,838	1.022	19.3	18,941	.909
Packaged shell FBC	1	16,795	17,296	.995	>31	19,835	.868
Field erected stoker	1	15,213	18,610	.925	>31	22,042	.781
Field erected FBC	1	15,955	19,397	.887	>31	23,132	.744
Pulverized coal boiler	1	15,566	19,842	.867	>31	23,783	.724
Circulating FBC	1	15,758	20,262	.849	>31	24,599	.700

9:10 AM Oct 20, 1988

ROBINS AFB: AFLC

1. BACKGROUND

Robins Air Force base is located near Warner Robins, Georgia. There are two major heating plants on the base, but only the larger plant (building No. 177) should be considered for coal conversion. The B&W and Wicks units (see list below) were originally designed for coal. In 1967, the coal-burning boilers were converted to burn gas with distillate oil as backup. The yearly average fuel use at plant No. 177 is about 100 MBtu/h. Heat plant No. 177 produces 125 psi steam, and boiler efficiencies range from about 69% at low loads to 78% at full load. No coal-handling equipment still remains.

2. HEATING PLANT UNITS

Heating Plant No. 177:

2 × 98 MBtu/h, Erie City, 1966
2 × 54 MBtu/h, Babcock & Wilcox, 1953
54 MBtu/h, Wicks, 1954
5 MBtu/h, Superior (oil only), 1977

Heating Plant No. 644:

24 MBtu/h, Erie City, 1966
2 × 24 MBtu/h, Trane, 1975
21 MBtu/h, Babcock & Wilcox, 1955

3. IDEAL CAPACITY FACTOR ANALYSIS

The maximum possible capacity factors listed below were calculated from monthly fuel-use data for plant No. 177.

Fuel input (MBtu/hr)	FY 1985 ideal capacity factor	FY 1986 ideal capacity factor
30	0.83	1.00
50	0.83	1.00
70	0.83	0.96
90	0.78	0.85
120	0.68	0.72
150	0.59	0.63

4. ENERGY PRICES

FY 1986 Price Data:

	Year average	End of year
Distillate	\$5.50/MBtu	\$5.90/MBtu
Natural gas	\$3.90/MBtu	\$3.90/MBtu
Electric	\$12.96/MBtu = 4.4¢/kWh	4.4¢/kWh

Comments from HQ AFLC (11/21/88):

Natural gas = \$3.19/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Benedict, Va.	Benedict, Va.
HHV, Btu/lb	13,790	13,790
Ash, %	4.23	4.23
Sulfur, %	0.79	0.79
Nitrogen, %	1.45	1.45
Ash-softening temperature, °F	2700+	2700+
Swelling index		
Top size, in.		2 × 0
Bottom size, in.		100 mesh
Fines, %		40
Grindability index	48	48
Cost at mine, \$/ton	34.00	28.00
Delivered cost, \$/ton	54.85	48.85
Energy cost, \$/MBtu	1.99	1.77

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

The air-quality-control regulations of Georgia require that a fuel-burning plant such as that being considered for Robbins AFB meet federal EPA air emission standards for an attainment area.

SO_2. For boilers >100 MBtu/h: FBC — 90% reduction to meet limit of 1.2 lb/MBtu; emerging technology — 50% reduction to meet limit of 0.6 lb/MBtu.

NO_x. For boilers >100 MBtu/h: spreader stoker and FBC — 0.6 lb/MBtu; pulverized coal — 0.7 lb/MBtu.

Particulates. Regulations pertaining to fly ash and/or other particulate matter from newly (beginning CY 1972) constructed equipment limit emissions according to the following expression:

$$P = 0.5 \left(\frac{10}{R}\right)^{0.5} \text{ lb/MBtu},$$

where R = heat input of fuel-burning equipment in MBtu/h.

Therefore, for one 54-MBtu/h boiler at plant No. 177, P = 0.215 lb/MBtu.

A state opacity regulation also became effective in 1972, stating that the opacity of the visible emissions be <20% except for one 6-min period per hour of no more than 27% opacity.

6.2 Coal-Pile Runoff

The state of Georgia has adopted EPA federal regulations for coal-pile runoff. The regulations state that the pH of all discharges, except once-through cooling water, shall be within the range of 6.0 to 9.0. The effluent limitation for the point source discharges of coal-pile runoff is 50 mg/L total suspended solids.

6.3 Ash Disposal

The state, as well as the EPA, considers fly ash waste to be nonhazardous. Use of an existing landfill is desirable because only a permit is required. A new site or landfill is costly and requires a long procedure.

7. OTHER CONSIDERATIONS

None.

8. COAL-CONVERSION PROJECT OUTLOOK

The most attractive project would be to refit/replace one of the 54-MBtu/h output (69-MBtu/h fuel input) boiler units, which are coal designed, in plant 177. If a single 54-MBtu/h unit were involved in a project, an overall capacity factor of about 81% would be expected, assuming 90% equipment availability.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed without any SO_2 or NO_x controls because the proposed project is smaller than 100 MBtu/h.

Particulates. Bag filters or electrostatic precipitators would be required.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for coal. The original coal-combustion equipment has been removed, and there is now only enough space for micronized coal or coal-water-mixture combustion equipment at the existing boiler.

Coal-Handling Equipment. There is limited space available at the existing heating plant so that only micronized coal or coal-water-mixture equipment could probably be installed.

Coal Pile. There is room for a coal pile near the existing boiler plant, so coal could be supplied by truck to a silo at the existing boiler plant or to a new coal-fired boiler plant near the coal pile.

8.3 Technical Risk of Combustion Technologies

The boilers were originally designed for coal. The least technical risk would be for conversion to micronized coal-firing because no SO_2 reduction measures will be required.

9. COGENERATION PROJECT OUTLOOK

The prospects for a coal-fired cogeneration system are poor because of low electric rates and the mild climate that exists at Robbins AFB. Although the base has a sizable minimum monthly average electric load, 15.7 MWe, the price of electricity is only 4.4¢/kWh. The 15.7-MWe minimum monthly load would be met primarily by a coal-fired electric plant sized for about 15 MWe and producing 45 MWt. An 80% cycle efficiency would require a boiler rated at 56 MW. December, January, February, and March have thermal consumption levels exceeding the available thermal capacity. The thermal demands at Robbins AFB remain high enough during the year to result in a high overall thermal load factor of 73% (assuming that the cogeneration plant has a 90% availability).

10. INPUT AND LCC SUMMARY SPREADSHEETS

ROBINS AFB: 1 X 54 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 54.0 MBtu/hr
Boiler capacity factor = .806
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.40
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.19
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.042	.042
Sulfur fraction =	.008	.008
HHV (Btu/lb) =	13800.	13800.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.77
Stoker coal ($/MBtu) = 1.99
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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ROBINS AFB: 1 X 54 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 54.0 MBtu/hr Cost base year = 1988
Boiler capacity factor = .806 Primary fuel = NATURAL GAS
Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.19	.0	1520.3	172.6	485.3
#2 Oil fired boiler	--	.800	4.71	.0	2244.7	172.6	485.3
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.77	2546.7	843.6	378.6	649.3
Slagging burner refit	1	.800	1.77	4521.4	843.6	378.6	649.3
Modular FBC refit	1	.790	1.77	5220.0	854.2	360.3	629.8
Stoker firing refit	1	.760	1.99	3063.9	998.3	360.3	620.1
Coal/water slurry	1	.750	3.00	2272.1	1525.1	360.3	546.3
Coal/oil slurry	1	.780	3.50	2043.6	1710.8	286.9	523.3
Low Btu gasifier refit	1	.679	1.99	4260.9	1118.1	332.3	754.9
Packaged shell stoker	2	.760	1.99	4605.5	998.3	360.3	710.8
Packaged shell FBC	2	.760	1.77	5618.1	888.0	360.3	720.9
Field erected stoker	1	.800	1.99	6809.0	948.4	358.1	612.0
Field erected FBC	1	.800	1.77	7481.8	843.6	418.4	629.7
Pulverized coal boiler	1	.820	1.77	7928.3	823.0	422.8	659.0
Circulating FBC	1	.810	1.77	8915.1	833.1	358.1	690.5

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	32,020	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	39,504	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	17,268	18,429	1.737	5.6	20,191	1.586
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because of space limitations						
Coal/water slurry	1	18,419	23,604	1.357	10.3	25,378	1.262
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	2	18,176	21,892	1.463	10.0	24,754	1.294
Packaged shell FBC	2	18,176	21,776	1.470	10.6	25,127	1.274
Field erected stoker	1	17,268	22,458	1.426	11.9	26,407	1.213
Field erected FBC	1	17,268	22,712	1.410	12.5	26,996	1.186
Pulverized coal boiler	1	16,847	23,156	1.383	13.2	27,670	1.157
Circulating FBC	1	17,054	23,733	1.349	14.3	28,744	1.114

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ROBINS AFB: 1 X 54 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 54.0 MBtu/hr			
Boiler capacity factor = .806			
Number of units for refit = 1			
Hydrated lime price($/ton) = 40.00	**COAL PROPERTIES**		
Ash disposal price ($/ton) = 10.00		R.O.M.	Stoker
Electric price (cents/kWh) = 4.40	Ash fraction =	.042	.042
Labor rate (k$/yr) = 35.00	Sulfur fraction =	.008	.008
Limestone price ($/ton) = 20.00	HHV (Btu/lb) =	13800.	13800.
FUEL PRICES	**FUEL PRICES**		
Natural gas price ($/MBtu) = 3.19	R.O.M. coal ($/MBtu) =	1.77	
#2 Oil price ($/MBtu) = 4.71	Stoker coal ($/MBtu) =	1.99	
#6 Oil price ($/MBtu) = .00	Coal/H2O mix ($/MBtu) =	3.00	
OPTIONS	Coal/oil mix ($/MBtu) =	3.50	
Soot blower multiplier = .0			
Tube bank mod multiplier = .0	**Primary fuel is 3**		
Bottom ash pit multiplier = 1.0	NATURAL GAS		
SO2 control multiplier = .0	1=#6 Oil, 2=#2 Oil, 3=NG		
LIMESTONE/LIME			
Inert fraction = .05			

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
	TYPE OF FUEL	1988	1990	1995	2000 AND
FUEL	ESCALATION	-1990	-1995	-2000	BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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ROBINS AFB: 1 X 54 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 54.0 MBtu/hr — Cost base year = 1988

Boiler capacity factor = .806 — Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	3.19	.0	1520.3	172.6	485.3
#2 Oil fired boiler	--	.800	4.71	.0	2244.7	172.6	485.3
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.77	2546.7	843.6	378.6	649.3
Slagging burner refit	1	.800	1.77	4521.4	843.6	378.6	649.3
Modular FBC refit	1	.790	1.77	5220.0	854.2	360.3	629.8
Stoker firing refit	1	.760	1.99	3063.9	998.3	360.3	620.1
Coal/water slurry	1	.750	3.00	2272.1	1525.1	360.3	546.3
Coal/oil slurry	1	.780	3.50	2043.6	1710.8	286.9	523.3
Low Btu gasifier refit	1	.679	1.99	4260.9	1118.1	332.3	754.9
Packaged shell stoker	2	.760	1.99	4605.5	998.3	360.3	710.8
Packaged shell FBC	2	.760	1.77	5618.1	888.0	360.3	720.9
Field erected stoker	1	.800	1.99	6809.0	948.4	358.1	612.0
Field erected FBC	1	.800	1.77	7481.8	843.6	418.4	629.7
Pulverized coal boiler	1	.820	1.77	7928.3	823.0	422.8	659.0
Circulating FBC	1	.810	1.77	8915.1	833.1	358.1	690.5

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	24,327	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	31,699	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	17,268	18,295	1.330	7.7	20,053	1.213
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because of space limitations						
Coal/water slurry	1	18,419	23,361	1.041	22.3	25,129	.968
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	2	18,176	21,734	1.119	16.5	24,590	.989
Packaged shell FBC	2	18,176	21,635	1.124	16.8	24,982	.974
Field erected stoker	1	17,268	22,307	1.091	19.6	26,252	.927
Field erected FBC	1	17,268	22,577	1.077	20.9	26,858	.906
Pulverized coal boiler	1	16,847	23,025	1.057	22.9	27,535	.883
Circulating FBC	1	17,054	23,601	1.031	26.1	28,607	.850

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ROBINS AFB: 1 X 54 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 54.0 MBtu/hr
Boiler capacity factor = .806
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.40
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.19
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.042	.042
Sulfur fraction =	.008	.008
HHV (Btu/lb) =	13800.	13800.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.77
Stoker coal ($/MBtu) = 1.99
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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ROBINS AFB: 1 X 54 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 54.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .806   Primary fuel = NATURAL GAS

Number of units for refit = 1

					ANNUAL COSTS		
TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.19	.0	1520.3	172.6	485.3
#2 Oil fired boiler	--	.800	4.71	.0	2244.7	172.6	485.3
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.77	2546.7	843.6	378.6	649.3
Slagging burner refit	1	.800	1.77	4521.4	843.6	378.6	649.3
Modular FBC refit	1	.790	1.77	5220.0	854.2	360.3	629.8
Stoker firing refit	1	.760	1.99	3063.9	998.3	360.3	620.1
Coal/water slurry	1	.750	3.00	2272.1	1525.1	360.3	546.3
Coal/oil slurry	1	.780	3.50	2043.6	1710.8	286.9	523.3
Low Btu gasifier refit	1	.679	1.99	4260.9	1118.1	332.3	754.9
Packaged shell stoker	2	.760	1.99	4605.5	998.3	360.3	710.8
Packaged shell FBC	2	.760	1.77	5618.1	888.0	360.3	720.9
Field erected stoker	1	.800	1.99	6809.0	948.4	358.1	612.0
Field erected FBC	1	.800	1.77	7481.8	843.6	418.4	629.7
Pulverized coal boiler	1	.820	1.77	7928.3	823.0	422.8	659.0
Circulating FBC	1	.810	1.77	8915.1	833.1	358.1	690.5

			AIR FORCE PROJECT			PRIVATE PROJECT	
TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	17,169	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	22,813	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	17,268	17,120	1.003	26.0	18,844	.911
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because of space limitations						
Coal/water slurry	1	18,419	21,237	.808	>31	22,945	.748
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	2	18,176	20,343	.844	>31	23,161	.741
Packaged shell FBC	2	18,176	20,398	.842	>31	23,710	.724
Field erected stoker	1	17,268	20,986	.818	>31	24,894	.690
Field erected FBC	1	17,268	21,403	.802	>31	25,650	.669
Pulverized coal boiler	1	16,847	21,879	.785	>31	26,357	.651
Circulating FBC	1	17,054	22,440	.765	>31	27,414	.626

2:02 PM   Jan 11, 1989

TINKER AFB: AFLC

1. BACKGROUND

Tinker is near Oklahoma City, Oklahoma. The available information for Tinker is poor, and it was not considered in the C. H. Guernsey and Co. survey. There are two boiler plants at Tinker AFB that are large enough for some consideration. The heating plant in building No. 3001 is the largest of these, with a yearly average fuel use of roughly 150 MBtu/h. The heating plant in building No. 208 appears to use a year-round average of about 75 MBtu/h of fuel. Natural-gas-firing is used with distillate oil as the secondary fuel. No boilers at the base were designed for coal burning. Only plant No. 3001 was considered in the LCC analysis.

2. HEATING PLANT UNITS

Heating Plant No. 3001:

3 × 97 MBtu/h, Riley Stoker, 1942

Heating Plant No. 208:

4 × 41 MBtu/h, Wickes, 1942

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly fuel-use data for plant No. 3001.

Fuel input (MBtu/h)	FY 1986 ideal capacity factor
100	1.00
120	0.99
140	0.94
160	0.87
180	0.82
200	0.76
220	0.70

4. ENERGY PRICES

FY 1986 Price Data:

Electricity = \$14/MBtu = 4.8¢/kWh
Natural gas = \$2.85/MBtu

Note: Gas prices dropped during FY 1986 and apparently were near \$2.0/MBtu in the latter portion of the year.

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin		McCallister, Okla.
HHV, Btu/lb	12,800	12,800
% Ash	6–7	6–7
% Sulfur	0.77	0.77
% Nitrogen		
Ash-softening temperature, °F		2080
Swelling index		3.5–5
Top size, in.		2
Bottom size, in.		0
Fines, %		
Grindability index		55
Cost at mine, $/ton	43 (assumed)	35
Delivered cost, $/ton	51	43
Energy cost, $/10^6 Btu	1.99	1.68

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. For boilers <100 MBtu/h: 1.2 lb/MBtu; for boilers >100 MBtu/h: FBC – 90% reduction to meet limit of 1.2 lb/MBtu; emerging technology – 50% reduction to meet limit of 0.6 lb/MBtu.

NO_x. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: spreader stoker and FBC – 0.6 lb/MBtu; pulverized coal – 0.7 lb/MBtu.

Particulates. For 99 MBtu/h: 0.3 lb/MBtu; for boilers >100 MBtu/h: 0.05 lb/MBtu.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L, pH of 6.0–9.0.

6.3 Ash Disposal

The ash will have to be analyzed to determine if it is hazardous. If nonhazardous, the ash may be disposed of in an existing or new landfill that has a lining of 3 ft of clay with a bottom that is at least 5 ft above groundwater.

7. OTHER CONSIDERATIONS

The boilers in heating plant No. 3001 were identified for upgrading in 1982.

8. COAL-CONVERSION PROJECT OUTLOOK

Tinker may be a poor candidate according to the AFLC MAJCOM. Tinker does seem to be a large fuel user, however, and it is not clear what would make it a poor candidate. Low gas prices make coal unattractive at this time.

A likely project would be to refit or replace two of the 97-MBtu/h units in plant No. 3001. The boilers would have to be derated to 75 MBtu/h output each (~188 MBtu/h total fuel input) because they were originally designed for No. 2 oil. An overall capacity factor of 71% is expected, assuming 90% availability.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2. The SO_2 emission limits will require the use of low sulfur coal or SO_2 reduction measures with high-sulfur coal.

NO_x. No special NO_x reduction measures will be required for any of the combustion technologies.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for No. 2 oil. There is only space available for installing coal-water-mixture combustion equipment at the existing boiler.

Coal-Handling Equipment. There is no information on the space available at the existing plant, but it is probable that there is not enough space available for installing dry coal-handling equipment. There should be adequate space available for installing coal-water-mixture equipment.

Coal Pile. There is no information as to how much space is available for a coal pile at the existing boiler plant.

8.3 Technical Risk of Combustion Technologies

The existing boilers are designed for No. 2 oil- or gas-firing and therefore are only suitable for conversion to coal-water-mixture firing. The technical risk is only moderate because the boilers would be derated.

9. COGENERATION PROJECT OUTLOOK

The prospects for a coal-fired cogeneration system appear to be somewhat marginal. The base has a high minimum monthly average electric load, 26 MWe, but the price of electricity is moderate (4.8¢/kWh). Based on the FY 1986 energy-use data, a cogeneration plant with a boiler rating of 180-MBtu/h output and a 13-MWe turbine generator would have an electrical power capacity factor of 90% and a peak thermal output of 135 MBtu/h with a thermal energy capacity factor of about 90% if used as a baseload heating plant. A water-tube boiler with a steam rating of 1450 psia and 950°F would be the most suitable boiler for this cogeneration system.

10. INPUT AND LCC SUMMARY SPREADSHEETS

TINKER AFB: 2 X 75 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 150.0 MBtu/hr
Boiler capacity factor = .712
Number of units for refit = 2
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.80
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.85
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.065	.065
Sulfur fraction =	.008	.008
HHV (Btu/lb) =	12800.	12800.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.68
Stoker coal ($/MBtu) = 1.99
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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TINKER AFB: 2 X 75 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 150.0 MBtu/hr   Cost base year = 1988
Boiler capacity factor = .712   Primary fuel = NATURAL GAS
Number of units for refit = 2

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.85	.0	3333.0	302.7	672.7
#2 Oil fired boiler	--	.800	4.71	.0	5508.2	302.7	672.7
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	2	.800	1.68	6643.9	1964.7	557.2	1180.1
Slagging burner refit	2	.800	1.68	11066.9	1964.7	557.2	1180.1
Modular FBC refit	2	.790	1.68	12597.3	1989.6	520.4	1112.6
Stoker firing refit	2	.740	1.99	10292.7	2515.9	817.5	1143.0
Coal/water slurry	2	.750	3.00	6793.5	3742.3	520.4	1007.8
Coal/oil slurry	2	.780	3.50	5667.4	4198.1	414.4	887.7
Low Btu gasifier refit	3	.659	1.99	13413.2	2826.9	480.0	2019.5
Packaged shell stoker	3	.740	1.99	13237.9	2515.9	817.5	1215.0
Packaged shell FBC	3	.760	1.68	12571.5	2068.1	520.4	1190.1
Field erected stoker	1	.780	1.99	15787.4	2386.9	814.4	1006.9
Field erected FBC	1	.800	1.68	14323.9	1964.7	604.4	1001.8
Pulverized coal boiler	1	.800	1.68	17958.5	1964.7	907.9	1076.6
Circulating FBC	1	.810	1.68	17761.7	1940.4	517.3	1074.5

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	66,471	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	91,817	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boilers were designed for #2 oil						
Coal/water slurry	2	48,728	53,082	1.252	14.9	57,892	1.148
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	3	49,386	51,221	1.298	15.0	59,114	1.124
Packaged shell FBC	3	48,086	43,637	1.523	10.4	50,991	1.304
Field erected stoker	1	46,853	50,474	1.317	15.0	59,586	1.116
Field erected FBC	1	45,682	43,403	1.532	10.7	51,603	1.288
Pulverized coal boiler	1	45,682	49,702	1.337	14.9	59,849	1.111
Circulating FBC	1	45,118	45,805	1.451	12.6	55,745	1.192

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TINKER AFB: 2 X 75 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 150.0 MBtu/hr
Boiler capacity factor = .712
Number of units for refit = 2
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.80
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.85
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.065	.065
Sulfur fraction =	.008	.008
HHV (Btu/lb) =	12800.	12800.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.68
Stoker coal ($/MBtu) = 1.99
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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TINKER AFB: 2 X 75 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 150.0 MBtu/hr   Cost base year = 1988
Boiler capacity factor = .712   Primary fuel = NATURAL GAS
Number of units for refit = 2

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.85	.0	3333.0	302.7	672.7
#2 Oil fired boiler	--	.800	4.71	.0	5508.2	302.7	672.7
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	2	.800	1.68	6643.9	1964.7	557.2	1180.1
Slagging burner refit	2	.800	1.68	11066.9	1964.7	557.2	1180.1
Modular FBC refit	2	.790	1.68	12597.3	1989.6	520.4	1112.6
Stoker firing refit	2	.740	1.99	10292.7	2515.9	817.5	1143.0
Coal/water slurry	2	.750	3.00	6793.5	3742.3	520.4	1007.8
Coal/oil slurry	2	.780	3.50	5667.4	4198.1	414.4	887.7
Low Btu gasifier refit	3	.659	1.99	13413.2	2826.9	480.0	2019.5
Packaged shell stoker	3	.740	1.99	13237.9	2515.9	817.5	1215.0
Packaged shell FBC	3	.760	1.68	12571.5	2068.1	520.4	1190.1
Field erected stoker	1	.780	1.99	15787.4	2386.9	814.4	1006.9
Field erected FBC	1	.800	1.68	14323.9	1964.7	604.4	1001.8
Pulverized coal boiler	1	.800	1.68	17958.5	1964.7	907.9	1076.6
Circulating FBC	1	.810	1.68	17761.7	1940.4	517.3	1074.5

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT: BENEFIT/ COST RATIO	AIR FORCE PROJECT: DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT: BENEFIT/ COST RATIO
Natural gas boiler	--	--	49,607	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	72,667	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boilers were designed for #2 oil						
Coal/water slurry	2	48,728	52,487	.945	>31	57,280	.866
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	3	49,386	50,821	.976	>31	58,703	.845
Packaged shell FBC	3	48,086	43,308	1.145	16.3	50,653	.979
Field erected stoker	1	46,853	50,094	.990	>31	59,196	.838
Field erected FBC	1	45,682	43,090	1.151	16.5	51,281	.967
Pulverized coal boiler	1	45,682	49,390	1.004	30.2	59,528	.833
Circulating FBC	1	45,118	45,496	1.090	20.7	55,428	.895

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TINKER AFB: 2 X 75 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 150.0 MBtu/hr
Boiler capacity factor = .712
Number of units for refit = 2
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.80
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.85
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.065	.065
Sulfur fraction =	.008	.008
HHV (Btu/lb) =	12800.	12800.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.68
Stoker coal ($/MBtu) = 1.99
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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TINKER AFB: 2 X 75 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 150.0 MBtu/hr Cost base year = 1988

Boiler capacity factor = .712 Primary fuel = NATURAL GAS

Number of units for refit = 2

					ANNUAL COSTS		
TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.85	.0	3333.0	302.7	672.7
#2 Oil fired boiler	--	.800	4.71	.0	5508.2	302.7	672.7
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	2	.800	1.68	6643.9	1964.7	557.2	1180.1
Slagging burner refit	2	.800	1.68	11066.9	1964.7	557.2	1180.1
Modular FBC refit	2	.790	1.68	12597.3	1989.6	520.4	1112.6
Stoker firing refit	2	.740	1.99	10292.7	2515.9	817.5	1143.0
Coal/water slurry	2	.750	3.00	6793.5	3742.3	520.4	1007.8
Coal/oil slurry	2	.780	3.50	5667.4	4198.1	414.4	887.7
Low Btu gasifier refit	3	.659	1.99	13413.2	2826.9	480.0	2019.5
Packaged shell stoker	3	.740	1.99	13237.9	2515.9	817.5	1215.0
Packaged shell FBC	3	.760	1.68	12571.5	2068.1	520.4	1190.1
Field erected stoker	1	.780	1.99	15787.4	2386.9	814.4	1006.9
Field erected FBC	1	.800	1.68	14323.9	1964.7	604.4	1001.8
Pulverized coal boiler	1	.800	1.68	17958.5	1964.7	907.9	1076.6
Circulating FBC	1	.810	1.68	17761.7	1940.4	517.3	1074.5

			AIR FORCE PROJECT			PRIVATE PROJECT	
TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	33,914	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	50,861	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boilers were designed for #2 oil						
Coal/water slurry	2	48,728	47,275	.717	>31	51,920	.653
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	3	49,386	47,317	.717	>31	55,100	.616
Packaged shell FBC	3	48,086	40,428	.839	>31	47,690	.711
Field erected stoker	1	46,853	46,770	.725	>31	55,777	.608
Field erected FBC	1	45,682	40,354	.840	>31	48,467	.700
Pulverized coal boiler	1	45,682	46,653	.727	>31	56,714	.598
Circulating FBC	1	45,118	42,793	.793	>31	52,649	.644

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ARNOLD AFS: AFSC

1. BACKGROUND

Arnold AFB is located near Manchester, Tennessee. The main steam plant consists of 3 × 72-MBtu/h and a 24-MBtu/h boiler, all of which were designed for medium volitile bituminous coal but now fire natural gas and distillate (No. 2) oil (secondary fuel). Coal-firing was replaced by gas and oil in 1970.

All units are Edgemoor Iron Works waterwall sterling-type boilers with air preheaters manufactured by Edgemoor installed on the three larger units. Saturated steam at 200 psig is produced. According to C. H. Guernsey and Co., the large boilers have efficiencies of 76%, and the small boiler's efficiency is 71%. Peak load is reported to be 210 MBtu/h, and the yearly fuel use ranges from 600,000 to 700,000 MBtu/year (an average of 69–80 MBtu/h).

2. HEATING PLANT UNITS

Heating Plant No. 1411:

24 MBtu/h, 3 × 72 MBtu/h, Edgemore Iron Works, 1951

3. IDEAL CAPACITY FACTOR ANALYSIS

The maximum possible capacity factors as a function of project size are given below for plant No. 1411.

Fuel input (MBtu/h)	FY 1986 ideal capacity factor
60	0.99
70	0.94
80	0.89
90	0.83
100	0.77
110	0.72
120	0.66

4. ENERGY PRICES

FY 1986 Price Data:

Electricity = \$13.0/MBtu = 4.44¢/kWh
Distillate = \$6.88/MBtu
Natural gas = \$3.81/MBtu

C. H. Guernsey and Co. Survey:

Electricity = 4.5¢/kWh
Natural gas = $3.97/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Harlan, Ky.	Sarah, Ky.
HHV, Btu/lb	13,200	12,000
% Ash	6–8	10
% Sulfur	1.3	1.5
% Nitrogen		
Ash-softening temperature, °F	2600	2600
Swelling index	4–6	3.5–4
Top size, in.	1 1/4	2
Bottom size, in.	1/4	0
Fines, %	5	35
Grindability index	46	47
Cost at mine, $/ton	33	23
Delivered cost, $/ton	52	42
Energy cost, $/$10^6$ Btu	1.97	1.75

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: FBC – 90% reduction to meet limit of 1.2 lb/MBtu; emerging technology – 50% reduction to meet limit of 0.6 lb/MBtu.

NO_x. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: spreader stoker and FBC – 0.6 lb/MBtu; pulverized coal – 0.7 lb/MBtu.

Particulates. For boilers <100 MBtu/h: $E = 0.6[10/(\text{MBtu/h})]^{0.5566}$; for 72 MBtu/h: 0.2 lb/MBtu; for boilers >100 MBtu/h: 0.05 lb/MBtu.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

Coal ash is classified as solid waste. An extraction procedure (EP) will be required to determine if the waste is nonhazardous. If the test is negative, the ash will be classified as special waste. The Nashville Field Office will issue a "Special Waste Approval," necessary to dispose of the ash in an existing landfill.

7. OTHER CONSIDERATIONS

None

8. COAL-CONVERSION PROJECT OUTLOOK

It appears to be most economical to convert one 72-MBtu/h unit back to coal. This corresponds to a fuel input of about 95 MBtu/h. The maximum possible capacity factor based on monthly FY 1986 data is about 80%. With a 90% equipment availability, a realistic capacity factor would be about 72%.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed without requiring any measures for NO_x or SO_2 reduction because the proposed conversion project is smaller than 100 MBtu/h.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for coal. There is space available for reinstalling combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. There is space available for installing coal-handling equipment at the existing boilers.

Coal Pile. There is space available for a coal pile at the existing boiler plant or at a new site on base.

8.3 Technical Risk of Combustion Technologies

These boilers were originally designed for pulverized coal-firing. The least technical risk would be for conversion to micronized coal-firing, because no SO_2 reduction measures will be required for one boiler because it is <100 MBtu/h.

9. COGENERATION PROJECT OUTLOOK

Cogeneration would probably not be economical at this base because of the reasonably low electric power rates that are available from TVA.

10. INPUT AND LCC SUMMARY SPREADSHEETS

ARNOLD AFS: 1 X 72 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 72.0 MBtu/hr
Boiler capacity factor = .720
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.50
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.97
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.100	.070
Sulfur fraction =	.015	.013
HHV (Btu/lb) =	12000.	13200.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.75
Stoker coal ($/MBtu) = 1.97
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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ARNOLD AFS: 1 X 72 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 72.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .720   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.97	.0	2253.6	202.2	525.0
#2 Oil fired boiler	--	.800	4.71	.0	2673.6	202.2	525.0
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.75	3139.6	993.4	420.3	719.5
Slagging burner refit	1	.800	1.75	5474.2	993.4	420.3	719.5
Modular FBC refit	1	.790	1.75	6299.9	1006.0	399.6	695.9
Stoker firing refit	1	.760	1.97	3653.3	1177.1	399.6	675.2
Coal/water slurry	1	.750	3.00	2842.2	1816.5	399.6	607.3
Coal/oil slurry	1	.780	3.50	2536.6	2037.7	318.2	573.0
Low Btu gasifier refit	2	.679	1.97	6343.5	1318.3	368.5	944.7
Packaged shell stoker	2	.760	1.97	5475.5	1177.1	399.6	770.8
Packaged shell FBC	2	.760	1.75	6908.8	1045.7	399.6	792.5
Field erected stoker	1	.800	1.97	8119.7	1118.3	397.2	664.6
Field erected FBC	1	.800	1.75	8950.4	993.4	464.1	695.6
Pulverized coal boiler	1	.820	1.75	9468.3	969.2	468.9	724.4
Circulating FBC	1	.810	1.75	10790.0	981.1	397.2	762.9

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	45,468	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	46,608	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	23,652	21,239	2.141	3.9	23,368	1.946
Slagging burner refit	1	23,652	23,168	1.963	5.7	26,489	1.717
Modular FBC refit	1	23,951	23,600	1.927	6.2	27,334	1.663
Stoker firing refit	Not applicable because existing boiler was designed for pulverized coal						
Coal/water slurry	1	25,229	27,624	1.646	5.8	29,789	1.526
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	25,348	28,215	1.612	8.3	32,101	1.416
Packaged shell stoker	2	22,633	25,101	1.811	6.4	28,476	1.597
Packaged shell FBC	2	24,897	25,226	1.802	7.1	29,303	1.552
Field erected stoker	1	21,502	25,887	1.756	7.9	30,572	1.487
Field erected FBC	1	23,652	26,247	1.732	8.4	31,346	1.451
Pulverized coal boiler	1	23,075	26,716	1.702	8.9	32,080	1.417
Circulating FBC	1	23,360	27,578	1.649	9.7	33,610	1.353

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ARNOLD AFS: 1 X 72 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 72.0 MBtu/hr
Boiler capacity factor = .720
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.50
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.97
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.100	.070
Sulfur fraction =	.015	.013
HHV (Btu/lb) =	12000.	13200.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.75
Stoker coal ($/MBtu) = 1.97
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
	TYPE OF FUEL	1988	1990	1995	2000 AND
FUEL	ESCALATION	-1990	-1995	-2000	BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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ARNOLD AFS: 1 X 72 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 72.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .720   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.97	.0	2253.6	202.2	525.0
#2 Oil fired boiler	--	.800	4.71	.0	2673.6	202.2	525.0
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.75	3139.6	993.4	420.3	719.5
Slagging burner refit	1	.800	1.75	5474.2	993.4	420.3	719.5
Modular FBC refit	1	.790	1.75	6299.9	1006.0	399.6	695.9
Stoker firing refit	1	.760	1.97	3653.3	1177.1	399.6	675.2
Coal/water slurry	1	.750	3.00	2842.2	1816.5	399.6	607.3
Coal/oil slurry	1	.780	3.50	2536.6	2037.7	318.2	573.0
Low Btu gasifier refit	2	.679	1.97	6343.5	1318.3	368.5	944.7
Packaged shell stoker	2	.760	1.97	5475.5	1177.1	399.6	770.8
Packaged shell FBC	2	.760	1.75	6908.8	1045.7	399.6	792.5
Field erected stoker	1	.800	1.97	8119.7	1118.3	397.2	664.6
Field erected FBC	1	.800	1.75	8950.4	993.4	464.1	695.6
Pulverized coal boiler	1	.820	1.75	9468.3	969.2	468.9	724.4
Circulating FBC	1	.810	1.75	10790.0	981.1	397.2	762.9

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	34,065	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	37,312	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	23,652	21,081	1.616	4.7	23,206	1.468
Slagging burner refit	1	23,652	23,010	1.480	7.3	26,326	1.294
Modular FBC refit	1	23,951	23,440	1.453	8.0	27,169	1.254
Stoker firing refit	Not applicable because existing boiler was designed for pulverized coal						
Coal/water slurry	1	25,229	27,335	1.246	9.0	29,492	1.155
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	25,348	28,005	1.216	12.4	31,885	1.068
Packaged shell stoker	2	22,633	24,914	1.367	8.6	28,284	1.204
Packaged shell FBC	2	24,897	25,060	1.359	9.6	29,132	1.169
Field erected stoker	1	21,502	25,709	1.325	10.7	30,389	1.121
Field erected FBC	1	23,652	26,089	1.306	11.5	31,183	1.092
Pulverized coal boiler	1	23,075	26,562	1.282	12.2	31,922	1.067
Circulating FBC	1	23,360	27,422	1.242	13.6	33,450	1.018

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ARNOLD AFS: 1 X 72 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output	= 72.0 MBtu/hr
Boiler capacity factor	= .720
Number of units for refit	= 1
Hydrated lime price($/ton)	= 40.00
Ash disposal price ($/ton)	= 10.00
Electric price (cents/kWh)	= 4.50
Labor rate (k$/yr)	= 35.00
Limestone price ($/ton)	= 20.00

FUEL PRICES

Natural gas price ($/MBtu)	= 3.97
#2 Oil price ($/MBtu)	= 4.71
#6 Oil price ($/MBtu)	= .00

OPTIONS

Soot blower multiplier	= .0
Tube bank mod multiplier	= .0
Bottom ash pit multiplier	= 1.0
SO2 control multiplier	= .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.100	.070
Sulfur fraction =	.015	.013
HHV (Btu/lb) =	12000.	13200.

FUEL PRICES

R.O.M. coal ($/MBtu)	= 1.75
Stoker coal ($/MBtu)	= 1.97
Coal/H2O mix ($/MBtu)	= 3.00
Coal/oil mix ($/MBtu)	= 3.50

Primary fuel is 3

NATURAL GAS

1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year	= 1988
Gen infla index (1987 to base yr)	= 1.040
Gas infla index (1988 to base yr)	= 1.000
Oil infla index (1988 to base yr)	= 1.000
Coal infla index (1988 to base yr)	= 1.000
Project start year	= 1990
Project life (yr)	= 30
Depreciation life (yr)	= 15
General inflation rate (%/yr)	= 0
Type of gas escalation	= zero
Type of oil escalation	= zero
Type of coal escalation	= zero
Discount rate (%/yr)	= 10
Rate of return on invest (%/yr)	= 17
Amount of working capital (month)	= 2
Federal income tax rate (%)	= 34
Local prop tax (& insur) rate (%)	= 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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ARNOLD AFS: 1 X 72 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 72.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .720   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	3.97	.0	2253.6	202.2	525.0
#2 Oil fired boiler	--	.800	4.71	.0	2673.6	202.2	525.0
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.75	3139.6	993.4	420.3	719.5
Slagging burner refit	1	.800	1.75	5474.2	993.4	420.3	719.5
Modular FBC refit	1	.790	1.75	6299.9	1006.0	399.6	695.9
Stoker firing refit	1	.760	1.97	3653.3	1177.1	399.6	675.2
Coal/water slurry	1	.750	3.00	2842.2	1816.5	399.6	607.3
Coal/oil slurry	1	.780	3.50	2536.6	2037.7	318.2	573.0
Low Btu gasifier refit	2	.679	1.97	6343.5	1318.3	368.5	944.7
Packaged shell stoker	2	.760	1.97	5475.5	1177.1	399.6	770.8
Packaged shell FBC	2	.760	1.75	6908.8	1045.7	399.6	792.5
Field erected stoker	1	.800	1.97	8119.7	1118.3	397.2	664.6
Field erected FBC	1	.800	1.75	8950.4	993.4	464.1	695.6
Pulverized coal boiler	1	.820	1.75	9468.3	969.2	468.9	724.4
Circulating FBC	1	.810	1.75	10790.0	981.1	397.2	762.9

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	23,455	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	26,728	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	23,652	19,697	1.191	6.4	21,783	1.077
Slagging burner refit	1	23,652	21,627	1.085	12.8	24,903	.942
Modular FBC refit	1	23,951	22,038	1.064	15.2	25,729	.912
Stoker firing refit	Not applicable because existing boiler was designed for pulverized coal						
Coal/water slurry	1	25,229	24,805	.946	>31	26,891	.872
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	25,348	26,169	.896	>31	29,997	.782
Packaged shell stoker	2	22,633	23,274	1.008	25.2	26,598	.882
Packaged shell FBC	2	24,897	23,603	.994	>31	27,634	.849
Field erected stoker	1	21,502	24,152	.971	>31	28,787	.815
Field erected FBC	1	23,652	24,705	.949	>31	29,761	.788
Pulverized coal boiler	1	23,075	25,212	.930	>31	30,534	.768
Circulating FBC	1	23,360	26,056	.900	>31	32,045	.732

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HANSCOM AFB: AFSC

1. BACKGROUND

Hanscom AFB is located near Boston, in Bedford, Massachusetts. There is a central heating plant with four boilers, each with a capacity near 50 MBtu/h. All boilers were designed for residual (No. 6) oil combustion and are two-drum sterling water-tube boilers. The primary fuel is No. 6 oil, with natural gas as the secondary fuel. The steam plant produces 100 psig saturated steam. The yearly average fuel use is roughly 85 MBtu/h.

2. HEATING PLANT UNITS

Heating Plant No. 1201:

3 × 51.3 MBtu/h, Erie City Iron Works, 1953
1 × 49.4 MBtu/h, E. Keeler Co., 1961

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly fuel-use data for plant No. 1201.

Fuel input (MBtu/h)	FY 1986 ideal capacity factor
60	0.99
70	0.94
80	0.90
90	0.84
100	0.80
120	0.70
150	0.56

4. ENERGY PRICES

FY 1986 Price Data:

Electricity = 6.8¢/kWh
Natural gas = varied from \$2.4 to \$3.9/MBtu
Residual oil = \$5.13/MBtu

C. H. Guernsey and Co. Survey:

Electricity = 6.07¢/kWh
Natural gas = \$6.2/MBtu (looks like an error)
Residual oil = \$4.67/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Slago, Pa.	Slago, Pa.
HHV, Btu/lb	13,000	12,800
% Ash	7–9	8–10
% Sulfur	1.8–2.2	1.8–2.2
% Nitrogen	1.32	1.30
Ash-softening temperature, °F	2500	2300
Swelling index	6–8	6–8
Top size, in.	1 5/8	2
Bottom size, in.	1/2	0
Fines, %	5	
Grindability index	50–55	50–55
Cost at mine, $/ton	40	26.50
Delivered cost, $/ton	66.00	52.50
Energy cost, $/$10^6$ Btu	2.54	2.05

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. 0.55 lb/MBtu.

No_x. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: spreader stoker and FBC – 0.6 lb/MBtu; pulverized coal – 0.7 lb/MBtu.

Particulates. For boilers >3 and <100 MBtu/h: 0.1 lb/MBtu; for boilers >100 MBtu/h: 0.05 lb/MBtu.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

Ashes are classified as rubbish and may be disposed of in any approved sanitary landfill.

7. OTHER CONSIDERATIONS

In 1980, the planned retirement date for these units was 1985, and the condition of the plant was described as poor. According to the C. H. Guernsey and Co. survey, the same boilers are still in place, but an upgrade of the plant is in progress.

There are discrepancies in the fuel prices and which fuel is used for the boilers. It appears that gas is burned when available, and the cost is $2.4–3.9/MBtu. From examining the DEIS data, the gas supply seems to be interruptible and becomes unavailable in the winter months. The price of gas reported in the C. H. Guernsey and Co. survey seems to be an error.

8. COAL-CONVERSION PROJECT OUTLOOK

A likely conversion project would involve conversion or replacement of one unit. If a unit with a coal-firing output capacity of 50 MBtu/h (roughly 62.5 MBtu/h fuel input) were installed, an overall capacity factor of about 88% would be expected (assuming a 90% equipment availability).

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

$\underline{SO_2}$. The strict SO_2 emission limit will require 86% SO_2 reduction while burning 2% sulfur coal, which will necessitate the use of limestone addition with micronized coal or the use of deep-cleaned, coal-water-mixture fuel.

$\underline{NO_x}$. Micronized coal or coal-water-mixture firing reportedly can meet the NO_x limit of 0.7 lb/MBtu for pulverized fuel firing.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was designed for No. 6 oil. There is space available for installing coal-water-mixture or micronized coal, but not stoker or FBC, combustion equipment at the existing boiler. There is not enough space available for a new coal-fired boiler at the existing plant, nor is there any site available within a reasonable distance of the heat-distribution system for a new plant.

Coal-Handling Equipment. There is not enough space available for installing coal-handling equipment at the existing boiler. Coal-water mixture fuel could probably be used.

Coal Pile. There is not enough space available for a coal pile on base.

8.3 Technical Risk of Combustion Technologies

Because of space limitations, the only technology available for conversion is coal-water-mixture fuel, and this would be limited to deep-cleaned fuel because of the strict SO_2 limits. The technical risk is moderately high because of the limited experience with this fuel for firing oil-designed boilers at full rated load.

9. COGENERATION PROJECT OUTLOOK

There is not enough space available for locating a new coal-fired cogeneration plant on base within a reasonable distance of the existing heat-distribution system.

10. INPUT AND LCC SUMMARY SPREADSHEETS

HANSCOM AFB: 1 X 50 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .883
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 6.10
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.50
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.090	.080
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 2.05
Stoker coal ($/MBtu) = 2.54
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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HANSCOM AFB: 1 X 50 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 50.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .883   Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.50	.0	1692.0	165.4	494.9
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1774.2	165.4	494.9
Micronized coal refit	1	.800	2.05	2887.4	991.1	368.2	814.6
Slagging burner refit	1	.800	2.05	4775.9	991.1	368.2	814.6
Modular FBC refit	1	.790	2.05	5420.1	1003.6	350.4	771.3
Stoker firing refit	1	.740	2.54	4418.7	1327.5	541.9	764.4
Coal/water slurry	1	.750	3.00	2928.1	1547.0	350.4	709.9
Coal/oil slurry	1	.780	3.50	2375.5	1735.4	279.0	602.8
Low Btu gasifier refit	1	.659	2.54	4997.5	1491.6	323.2	1067.6
Packaged shell stoker	1	.740	2.54	4931.2	1327.5	541.9	764.4
Packaged shell FBC	1	.760	2.05	4837.0	1043.2	350.4	776.5
Field erected stoker	1	.780	2.54	7877.2	1259.4	539.8	749.5
Field erected FBC	1	.800	2.05	7229.0	991.1	407.0	769.7
Pulverized coal boiler	1	.800	2.05	8942.1	991.1	602.7	801.6
Circulating FBC	1	.810	2.05	8554.6	978.8	348.3	804.5

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	35,046	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	32,350	1.000	<--- Existing system, primary fuel		
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boiler was designed for #6 oil						
Coal/water slurry	1	20,143	25,537	1.267	10.1	27,686	1.168
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	Not applicable because of space limitations						
Packaged shell FBC	Not applicable because of space limitations						
Field erected stoker	Not applicable because of space limitations						
Field erected FBC	Not applicable because of space limitations						
Pulverized coal boiler	Not applicable because of space limitations						
Circulating FBC	Not applicable because of space limitations						

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HANSCOM AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .883
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 6.10
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.50
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.090	.080
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 2.05
Stoker coal ($/MBtu) = 2.54
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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HANSCOM AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 50.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .883   Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	3.50	.0	1692.0	165.4	494.9
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1774.2	165.4	494.9
Micronized coal refit	1	.800	2.05	2887.4	991.1	368.2	814.6
Slagging burner refit	1	.800	2.05	4775.9	991.1	368.2	814.6
Modular FBC refit	1	.790	2.05	5420.1	1003.6	350.4	771.3
Stoker firing refit	1	.740	2.54	4418.7	1327.5	541.9	764.4
Coal/water slurry	1	.750	3.00	2928.1	1547.0	350.4	709.9
Coal/oil slurry	1	.780	3.50	2375.5	1735.4	279.0	602.8
Low Btu gasifier refit	1	.659	2.54	4997.5	1491.6	323.2	1067.6
Packaged shell stoker	1	.740	2.54	4931.2	1327.5	541.9	764.4
Packaged shell FBC	1	.760	2.05	4837.0	1043.2	350.4	776.5
Field erected stoker	1	.780	2.54	7877.2	1259.4	539.8	749.5
Field erected FBC	1	.800	2.05	7229.0	991.1	407.0	769.7
Pulverized coal boiler	1	.800	2.05	8942.1	991.1	602.7	801.6
Circulating FBC	1	.810	2.05	8554.6	978.8	348.3	804.5

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT: BENEFIT/ COST RATIO	AIR FORCE PROJECT: DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT: BENEFIT/ COST RATIO
Natural gas boiler	--	--	26,484	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	26,182	1.000	<--- Existing system, primary fuel		
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boiler was designed for #6 oil						
Coal/water slurry	1	20,143	25,291	1.035	23.6	27,433	.954
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	Not applicable because of space limitations						
Packaged shell FBC	Not applicable because of space limitations						
Field erected stoker	Not applicable because of space limitations						
Field erected FBC	Not applicable because of space limitations						
Pulverized coal boiler	Not applicable because of space limitations						
Circulating FBC	Not applicable because of space limitations						

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HANSCOM AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .883
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 6.10
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.50
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.090	.080
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 2.05
Stoker coal ($/MBtu) = 2.54
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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HANSCOM AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 50.0 MBtu/hr   Cost base year = 1986

Boiler capacity factor = .883   Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.50	.0	1692.0	165.4	494.9
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1774.2	165.4	494.9
Micronized coal refit	1	.800	2.05	2887.4	991.1	368.2	814.6
Slagging burner refit	1	.800	2.05	4775.9	991.1	368.2	814.6
Modular FBC refit	1	.790	2.05	5420.1	1003.6	350.4	771.3
Stoker firing refit	1	.740	2.54	4418.7	1327.5	541.9	764.4
Coal/water slurry	1	.750	3.00	2928.1	1547.0	350.4	709.9
Coal/oil slurry	1	.780	3.50	2375.5	1735.4	279.0	602.8
Low Btu gasifier refit	1	.659	2.54	4997.5	1491.6	323.2	1067.6
Packaged shell stoker	1	.740	2.54	4931.2	1327.5	541.9	764.4
Packaged shell FBC	1	.760	2.05	4837.0	1043.2	350.4	776.5
Field erected stoker	1	.780	2.54	7877.2	1259.4	539.8	749.5
Field erected FBC	1	.800	2.05	7229.0	991.1	407.0	769.7
Pulverized coal boiler	1	.800	2.05	8942.1	991.1	602.7	801.6
Circulating FBC	1	.810	2.05	8554.6	978.8	348.3	804.5

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	18,517	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	19,158	1.000	<--- Existing system, primary fuel		
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boiler was designed for #6 oil						
Coal/water slurry	1	20,143	23,137	.828	>31	25,217	.760
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	Not applicable because of space limitations						
Packaged shell FBC	Not applicable because of space limitations						
Field erected stoker	Not applicable because of space limitations						
Field erected FBC	Not applicable because of space limitations						
Pulverized coal boiler	Not applicable because of space limitations						
Circulating FBC	Not applicable because of space limitations						

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ANDREWS AFB: MAC

1. BACKGROUND

Andrews AFB is located near Washington, D.C. There are three steam plants on the base, all of which were upgraded in some manner in 1985. The specifics of this upgrade effort are not known and probably should be investigated. Two of these plants may be large enough to get some consideration for coal conversion. Each steam plant consists of water-tube boilers producing saturated steam at 100 psig.

All boilers, with the exception of three built after 1964 (see the lists that follow), are designed for bituminous coal. Residual oil (No. 6) is the primary fuel for all the boilers, and there is apparently no secondary fuel. Some coal storage silos and receiving hoppers are still on site.

Data are inconsistent with regard to annual fuel use. Data for plant No. 1515 average fuel consumption range from 22 to 49 MBtu/h, with the larger value reported by C. H. Guernsey and Co. The data for plant No. 1732 range from 15 to 40 MBtu/h, with the smaller value reported by C. H. Guernsey and Co. It is assumed that plant No. 1515 and plant No. 1732 are interconnected.

2. HEATING PLANT UNITS

Heating Plant No. 1515:

2 × 59.8 MBtu/h, Bigelow, 1958
2 × 29.9 and 15.9 MBtu/h, Union Iron Works, 1946

Heating Plant No. 1732:

3 × 33.5 MBtu/h; Keeler Co.; 2-1961, 1-1965

Heating Plant No. 3409:

2 × 16 MBtu/h, Keeler Co., 1971
3 × 15 MBtu/h, Keeler Co., 1960

3. IDEAL CAPACITY FACTOR ANALYSIS

Maximum possible load factors as a function of project size are given below. Load information was calculated assuming two boiler plants (No. 1515 and No. 1732) are interconnected.

Plant Nos. 1515 and 1732
interconnected

Fuel input (MBtu/h)	CY 1985 ideal capacity factor	FY 1986 ideal capacity factor
30	0.92	0.73
50	0.76	0.57
70	0.67	0.49
90	0.60	0.43
120	0.51	0.39

4. ENERGY PRICES

FY 1986 Price Data

	Average	Year end
Electricity	5.4¢/kWh	
Residual oil	\$3.8/MBtu	\$2.6/MBtu ?
Distillate oil	\$5.9/MBtu	\$3.3/MBtu ?

C. H. Guernsey and Co. Survey:

Electricity = 5.0¢/kWh
Residual oil = \$4.67/MBtu
Distillate oil = \$5.56/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Clearfield Co., Pa.	Clearfield Co., Pa.
HHV, Btu/lb	13,000	12,800
% Ash	10	13
% Sulfur	2	2
% Nitrogen	1.5	1.5
Ash-softening temperature, °F	2450	2450
Swelling index	8–9	8–9
Top size, in.	1 1/4	2
Bottom size, in.	3/8	0
Fines, %	15	
Grindability index	90+	90+
Cost at mine, \$/ton	40	30
Delivered cost, \$/ton	57	47
Energy cost, $\$/10^6$ Btu	2.19	1.84

6. ENVIRONMENTAL REGULATIONS

No solid-fuel-burning plant smaller than 35 MBtu/h is allowed.

6.1 Air Pollution Emission Limits for New Sources

SO_2. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: FBC – 90% reduction to meet limit of 1.2 lb/MBtu; emerging technology – 50% reduction to meet limit of 0.6 lb/MBtu.

NO_x. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: spreader stoker and FBC – 0.6 lb/MBtu; pulverized coal – 0.7 lb/MBtu.

Particulates. For boilers >100 MBtu/h: 0.05 lb/MBtu; for 60 MBtu/h – 0.25 lb/MBtu.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

Ashes are classified as nonhazardous industrial solid waste and may be disposed of in any approved sanitary landfill.

7. OTHER CONSIDERATIONS

Andrews apparently uses a lot of electricity: 100,235 MWh in FY 1986, an average of about 11.4 MW. Residual oil use in FY 1986 was ~568,000 MBtu, an average of about 65 MBtu/h. The highest monthly steam load is about 150 MBtu/h.

A previous study was done (Roy Weston Study) to examine connecting the three boiler plants and building a single coal plant for $75M. Andrews has also been the subject of a coal-oil-mixture study.

This base is within range of anthracite sources.

8. COAL-CONVERSION PROJECT OUTLOOK

Because load factors are low, only conversion of one 60-MBtu/h output (~75-MBtu/h fuel input) boiler would be practical. The overall load factor for this size of project is expected to be about 50%, assuming a 90% equipment availability, and the two plants are interconnected.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed without requiring any measures for SO_2 or NO_x reduction because the proposed conversion project is smaller than 100 MBtu/h.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for coal. There is space available for reinstalling coal-combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. The coal-storage silo and the outside receiving hopper and silo are still in place at plant 1515. There is space available for installing the other coal-handling equipment.

Coal Pile. There is space available for a coal pile near the existing boiler plant 1515 or at a new site on base.

8.3 Technical Risk of Combustion Technologies

The least technical risk would be for refit of stoker firing to one of the existing coal-designed boilers or installation of a new stoker-fired boiler. The other technologies would have greater technical risks because of lack of operating experience, and all of them would be of the same order because the existing boilers are designed for coal-firing.

9. COGENERATION PROJECT OUTLOOK

The prospects for a coal-fired cogeneration system appear to be somewhat marginal. Andrews has a high minimum monthly average electric load, 7.8 MWe, but the price of electricity is only moderately high (5¢/kWh). Another negative factor is the relatively low average heat load compared to the electric load, so that it is difficult to achieve a high overall load factor for a cogeneration plant. Based on the FY 1986 energy-use data, a cogeneration plant with a boiler rating of 68 MBtu/h output and a 5-MWe turbine-generator would have an electrical power capacity factor of 90% and a peak thermal output of 50 MBtu/h, with a thermal energy capacity factor of about 50% if used as a baseload heating plant. To achieve as high an efficiency as practical, a 1450-psia, 950°F water-tube boiler should be employed for such a cogeneration plant.

The information provided by the base energy-use questionnaire indicated that natural gas is not available at the base.

10. INPUT AND LCC SUMMARY SPREADSHEETS

ANDREWS AFB: 1 X 60 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 60.0 MBtu/hr
Boiler capacity factor = .504
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.00
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.130	.100
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.84
Stoker coal ($/MBtu) = 2.19
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
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		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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ANDREWS AFB: 1 X 60 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 60.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .504   Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1215.2	182.9	493.1
Micronized coal refit	1	.800	1.84	2882.7	609.3	393.3	663.7
Slagging burner refit	1	.800	1.84	4982.0	609.3	393.3	663.7
Modular FBC refit	1	.790	1.84	5725.4	617.0	374.2	648.5
Stoker firing refit	1	.760	2.19	3377.7	763.3	374.2	636.8
Coal/water slurry	1	.750	3.00	2603.5	1059.6	374.2	566.3
Coal/oil slurry	1	.780	3.50	2309.9	1188.7	298.0	536.9
Low Btu gasifier refit	2	.679	2.19	5804.5	854.9	345.1	865.4
Packaged shell stoker	2	.760	2.19	5060.9	763.3	374.2	729.3
Packaged shell FBC	2	.760	1.84	6250.7	641.3	374.2	741.7
Field erected stoker	1	.800	2.19	7261.2	725.2	371.9	628.5
Field erected FBC	1	.800	1.84	7988.0	609.3	434.6	648.3
Pulverized coal boiler	1	.820	1.84	8459.5	594.4	439.1	678.0
Circulating FBC	1	.810	1.84	9558.8	601.8	371.9	702.9

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	23,980	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	12,935	16,762	1.431	7.5	18,640	1.287
Slagging burner refit	1	12,935	18,497	1.296	11.7	21,445	1.118
Modular FBC refit	1	13,098	18,895	1.269	12.8	22,216	1.079
Stoker firing refit	1	13,406	18,230	1.315	9.8	20,390	1.176
Coal/water slurry	1	13,797	19,809	1.211	12.0	21,637	1.108
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	15,014	22,612	1.061	23.6	26,077	.920
Packaged shell stoker	2	13,406	20,342	1.179	15.5	23,381	1.026
Packaged shell FBC	2	13,615	20,282	1.182	16.1	23,898	1.003
Field erected stoker	1	12,736	20,998	1.142	18.4	25,126	.954
Field erected FBC	1	12,935	21,231	1.130	19.4	25,719	.932
Pulverized coal boiler	1	12,619	21,753	1.102	21.2	26,486	.905
Circulating FBC	1	12,775	22,324	1.074	23.4	27,608	.869

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ANDREWS AFB: 1 X 60 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 60.0 MBtu/hr
Boiler capacity factor = .504
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.00
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.130	.100
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.84
Stoker coal ($/MBtu) = 2.19
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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ANDREWS AFB: 1 X 60 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 60.0 MBtu/hr   Cost base year = 1988
Boiler capacity factor = .504   Primary fuel = #6 FUEL OIL
Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1215.2	182.9	493.1
Micronized coal refit	1	.800	1.84	2882.7	609.3	393.3	663.7
Slagging burner refit	1	.800	1.84	4982.0	609.3	393.3	663.7
Modular FBC refit	1	.790	1.84	5725.4	617.0	374.2	648.5
Stoker firing refit	1	.760	2.19	3377.7	763.3	374.2	636.8
Coal/water slurry	1	.750	3.00	2603.5	1059.6	374.2	566.3
Coal/oil slurry	1	.780	3.50	2309.9	1188.7	298.0	536.9
Low Btu gasifier refit	2	.679	2.19	5804.5	854.9	345.1	865.4
Packaged shell stoker	2	.760	2.19	5060.9	763.3	374.2	729.3
Packaged shell FBC	2	.760	1.84	6250.7	641.3	374.2	741.7
Field erected stoker	1	.800	2.19	7261.2	725.2	371.9	628.5
Field erected FBC	1	.800	1.84	7988.0	609.3	434.6	648.3
Pulverized coal boiler	1	.820	1.84	8459.5	594.4	439.1	678.0
Circulating FBC	1	.810	1.84	9558.8	601.8	371.9	702.9

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	19,755	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	12,935	16,665	1.185	12.1	18,540	1.066
Slagging burner refit	1	12,935	18,400	1.074	20.4	21,346	.925
Modular FBC refit	1	13,098	18,796	1.051	22.9	22,115	.893
Stoker firing refit	1	13,406	18,109	1.091	17.8	20,266	.975
Coal/water slurry	1	13,797	19,641	1.006	29.3	21,464	.920
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	15,014	22,476	.879	>31	25,938	.762
Packaged shell stoker	2	13,406	20,221	.977	>31	23,256	.849
Packaged shell FBC	2	13,615	20,180	.979	>31	23,794	.830
Field erected stoker	1	12,736	20,882	.946	>31	25,007	.790
Field erected FBC	1	12,935	21,134	.935	>31	25,620	.771
Pulverized coal boiler	1	12,619	21,659	.912	>31	26,389	.749
Circulating FBC	1	12,775	22,228	.889	>31	27,509	.718

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ANDREWS AFB: 1 X 60 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 60.0 MBtu/hr
Boiler capacity factor = .504
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.00
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.130	.100
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.84
Stoker coal ($/MBtu) = 2.19
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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ANDREWS AFB: 1 X 60 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 60.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .504   Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1215.2	182.9	493.1
Micronized coal refit	1	.800	1.84	2882.7	609.3	393.3	663.7
Slagging burner refit	1	.800	1.84	4982.0	609.3	393.3	663.7
Modular FBC refit	1	.790	1.84	5725.4	617.0	374.2	648.5
Stoker firing refit	1	.760	2.19	3377.7	763.3	374.2	636.8
Coal/water slurry	1	.750	3.00	2603.5	1059.6	374.2	566.3
Coal/oil slurry	1	.780	3.50	2309.9	1188.7	298.0	536.9
Low Btu gasifier refit	2	.679	2.19	5804.5	854.9	345.1	865.4
Packaged shell stoker	2	.760	2.19	5060.9	763.3	374.2	729.3
Packaged shell FBC	2	.760	1.84	6250.7	641.3	374.2	741.7
Field erected stoker	1	.800	2.19	7261.2	725.2	371.9	628.5
Field erected FBC	1	.800	1.84	7988.0	609.3	434.6	648.3
Pulverized coal boiler	1	.820	1.84	8459.5	594.4	439.1	678.0
Circulating FBC	1	.810	1.84	9558.8	601.8	371.9	702.9

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT: BENEFIT/ COST RATIO	AIR FORCE PROJECT: DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT: BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	14,944	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	12,935	15,817	.945	>31	17,667	.846
Slagging burner refit	1	12,935	17,552	.851	>31	20,473	.730
Modular FBC refit	1	13,098	17,937	.833	>31	21,231	.704
Stoker firing refit	1	13,406	17,046	.877	>31	19,172	.779
Coal/water slurry	1	13,797	18,165	.823	>31	19,946	.749
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	15,014	21,285	.702	>31	24,713	.605
Packaged shell stoker	2	13,406	19,157	.780	>31	22,163	.674
Packaged shell FBC	2	13,615	19,287	.775	>31	22,875	.653
Field erected stoker	1	12,736	19,872	.752	>31	23,969	.623
Field erected FBC	1	12,935	20,285	.737	>31	24,747	.604
Pulverized coal boiler	1	12,619	20,831	.717	>31	25,538	.585
Circulating FBC	1	12,775	21,390	.699	>31	26,648	.561

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DOVER AFB: MAC

1. BACKGROUND

Dover AFB is located near Dover, Delaware. The four central heating plant boilers are high-temperature, hot-water (414°F, 275-psi) units. All boilers burn No. 6 oil. The three Combustion Engineering units were designed for coal. In CY 1985 average fuel use was about 46 MBtu/h, and the January 1985 average fuel use was 88 MBtu/h. In FY 1986, average fuel input was about 44 MBtu/h. Boiler efficiency at peak load is about 77%.

2. HEATING PLANT UNITS

<u>Heating Plant No. 617</u>:

3 × 50 MBtu/h, Combustion Engineering, 1953
1 × 50 MBtu/h, International Lamont, 1972

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly fuel-use data for plant No. 617.

Fuel input (MBtu/h)	CY 1985 ideal capacity factor	FY 1986 ideal capacity factor
20	1.00	1.00
30	0.94	0.90
40	0.84	0.80
50	0.76	0.73
60	0.69	0.67
70	0.63	0.61
80	0.57	0.55

4. ENERGY PRICES

<u>FY 1986 Price Data</u>:

Electricity = $16.5/MBtu = 5.6¢/kWh
Distillate = $5.87/MBtu
Residual = $5.00/MBtu

<u>C. H. Guernsey and Co. Survey</u>:

Electricity = 6.6¢/kWh
Residual = $4.67/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Clearfield Co., Pa.	Clearfield Co., Pa.
HHV, Btu/lb	13,000	12,800
% Ash	10	13
% Sulfur	2	2
% Nitrogen	1.5	1.5
Ash-softening temperature, °F	2450	2450
Swelling index	8–9	8–9
Top size, in.	1 1/4	2
Bottom size, in.	3/8	0
Fines, %	15	
Grindability index	90+	90+
Cost at mine, $/ton	40	30
Delivered cost, $/ton	57	47
Energy cost, $/10 Btu	2.19	1.84

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. No emission limits for boilers <100 MBtu/h; 1.2 lb/MBtu and 90% reduction for >100 MBtu/h.

NO_x. No emission limits for boilers <100 MBtu/h; 0.6 lb/MBtu for >100 MBtu/h.

Particulates. 0.3 lb/MBtu for boilers 1–100 MBtu/h; 0.05 lb/MBtu for >100 MBtu/h.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

Ashes are classified as "Solid Waste Refuse" and may be disposed of in any approved sanitary landfill. Disposal cost is 45¢/ton.

7. OTHER CONSIDERATIONS

Dover is the current site for a coal-oil-water-mixture demonstration project. Fuel will be supplied by Coaliquid Inc. About $4 million was spent to alter one boiler and to add peripheral equipment. The altered boiler may be quite ideal for a micronized coal burner system or some other coal technology.

8. COAL-CONVERSION PROJECT OUTLOOK

This is a candidate for conversion of one unit, based on the load data. Also note that one boiler has been reworked for coal-oil-water-mixture firing and may be cheaply converted to some type of 100% coal firing.

If one 50-MBtu/h output (~65-MBtu/h fuel input) unit was converted to coal, the maximum capacity factor would be about 65%. Assuming a 90% equipment availability, an overall capacity factor of about 58% is obtained.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed without requiring any measures for SO_2 or NO_x reduction because the proposed conversion project is smaller than 100 MBtu/h.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for coal. There is space available for reinstalling coal combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. There is space available for installing coal-handling equipment at the existing boiler.

Coal Pile. There is space available for a coal pile at the existing boiler plant or at a new site on base.

8.3 Technical Risk of Combustion Technologies

The least technical risk would be for refit of stoker firing to the existing boiler, since it was originally designed for this, or installation of a new stoker-fired boiler. The other technologies would have greater technical risks because of lack of operating experience, and all of them would be of the same order because the existing boiler is designed for coal-firing.

9. COGENERATION PROJECT OUTLOOK

The prospects look interesting for a coal-fired cogeneration system. The minimum monthly average electric load is about 4.7 MWe, and the price of electricity is high (6.6¢/kWh). Based on the FY 1986 energy-use data, a cogeneration plant with a boiler rating of

68-MBtu/h output and a 5-MWe turbine-generator would have an electrical power capacity factor of about 90% and a peak thermal output of 50 MBtu/h, with a thermal energy capacity factor of about 70% if used as a baseload heating plant. A cogeneration plant of this capacity should be near the optimum size for base needs. A water-tube boiler with a steam rating of 1450 psia and 950°F would be the most suitable type of boiler for a high-efficiency cogeneration system.

The information provided by the base energy-use questionnaire indicated that natural gas was not available at the base, and therefore a gas-fired cogeneration system is not an available option.

10. INPUT AND LCC SUMMARY SPREADSHEETS

DOVER AFB: 1 X 50 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .583
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 6.60
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.130	.100
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.84
Stoker coal ($/MBtu) = 2.19
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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DOVER AFB: 1 X 50 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 50.0 MBtu/hr Cost base year = 1988

Boiler capacity factor = .583 Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1171.4	165.4	484.6
Micronized coal refit	1	.800	1.84	2616.3	587.3	368.2	662.0
Slagging burner refit	1	.800	1.84	4504.8	587.3	368.2	662.0
Modular FBC refit	1	.790	1.84	5173.9	594.7	350.4	642.6
Stoker firing refit	1	.760	2.19	3070.2	735.8	350.4	628.9
Coal/water slurry	1	.750	3.00	2353.1	1021.4	350.4	560.6
Coal/oil slurry	1	.780	3.50	2081.4	1145.8	279.0	532.2
Low Btu gasifier refit	1	.679	2.19	4206.8	824.1	323.2	788.3
Packaged shell stoker	1	.760	2.19	3582.7	735.8	350.4	628.9
Packaged shell FBC	1	.760	1.84	4587.0	618.2	350.4	643.3
Field erected stoker	1	.800	2.19	6497.4	699.0	348.3	619.2
Field erected FBC	1	.800	1.84	7133.3	587.3	407.0	642.4
Pulverized coal boiler	1	.820	1.84	7562.3	573.0	411.2	669.7
Circulating FBC	1	.810	1.84	8473.6	580.1	348.3	701.4

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	---	23,091	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	12,468	16,099	1.434	7.3	17,829	1.295
Slagging burner refit	1	12,468	17,660	1.308	11.2	20,352	1.135
Modular FBC refit	1	12,626	17,972	1.285	12.2	20,999	1.100
Stoker firing refit	1	12,923	17,445	1.324	9.4	19,433	1.188
Coal/water slurry	1	13,300	18,989	1.216	11.6	20,672	1.117
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	14,473	20,207	1.143	16.9	22,827	1.012
Packaged shell stoker	1	12,923	17,868	1.292	10.7	20,118	1.148
Packaged shell FBC	1	13,125	17,712	1.304	11.3	20,446	1.129
Field erected stoker	1	12,277	19,839	1.164	17.1	23,563	.980
Field erected FBC	1	12,468	20,026	1.153	18.0	24,065	.960
Pulverized coal boiler	1	12,164	20,497	1.127	19.5	24,758	.933
Circulating FBC	1	12,315	21,001	1.100	21.5	25,719	.898

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DOVER AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .583
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 6.60
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.130	.100
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.84
Stoker coal ($/MBtu) = 2.19
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
	TYPE OF FUEL	1988	1990	1995	2000 AND
FUEL	ESCALATION	-1990	-1995	-2000	BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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DOVER AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 50.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .583   Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1171.4	165.4	484.6
Micronized coal refit	1	.800	1.84	2616.3	587.3	368.2	662.0
Slagging burner refit	1	.800	1.84	4504.8	587.3	368.2	662.0
Modular FBC refit	1	.790	1.84	5173.9	594.7	350.4	642.6
Stoker firing refit	1	.760	2.19	3070.2	735.8	350.4	628.9
Coal/water slurry	1	.750	3.00	2353.1	1021.4	350.4	560.6
Coal/oil slurry	1	.780	3.50	2081.4	1145.8	279.0	532.2
Low Btu gasifier refit	1	.679	2.19	4206.8	824.1	323.2	788.3
Packaged shell stoker	1	.760	2.19	3582.7	735.8	350.4	628.9
Packaged shell FBC	1	.760	1.84	4587.0	618.2	350.4	643.3
Field erected stoker	1	.800	2.19	6497.4	699.0	348.3	619.2
Field erected FBC	1	.800	1.84	7133.3	587.3	407.0	642.4
Pulverized coal boiler	1	.820	1.84	7562.3	573.0	411.2	669.7
Circulating FBC	1	.810	1.84	8473.6	580.1	348.3	701.4

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	19,019	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	12,468	16,006	1.188	11.8	17,733	1.073
Slagging burner refit	1	12,468	17,567	1.083	19.4	20,256	.939
Modular FBC refit	1	12,626	17,878	1.064	21.5	20,902	.910
Stoker firing refit	1	12,923	17,328	1.098	17.1	19,313	.985
Coal/water slurry	1	13,300	18,826	1.010	28.2	20,505	.928
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	14,473	20,076	.947	>31	22,692	.838
Packaged shell stoker	1	12,923	17,751	1.071	19.7	19,998	.951
Packaged shell FBC	1	13,125	17,614	1.080	19.7	20,345	.935
Field erected stoker	1	12,277	19,728	.964	>31	23,449	.811
Field erected FBC	1	12,468	19,933	.954	>31	23,969	.793
Pulverized coal boiler	1	12,164	20,406	.932	>31	24,664	.771
Circulating FBC	1	12,315	20,909	.910	>31	25,624	.742

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DOVER AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .583
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 6.60
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.130	.100
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.84
Stoker coal ($/MBtu) = 2.19
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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DOVER AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 50.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .583   Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1171.4	165.4	484.6
Micronized coal refit	1	.800	1.84	2616.3	587.3	368.2	662.0
Slagging burner refit	1	.800	1.84	4504.8	587.3	368.2	662.0
Modular FBC refit	1	.790	1.84	5173.9	594.7	350.4	642.6
Stoker firing refit	1	.760	2.19	3070.2	735.8	350.4	628.9
Coal/water slurry	1	.750	3.00	2353.1	1021.4	350.4	560.6
Coal/oil slurry	1	.780	3.50	2081.4	1145.8	279.0	532.2
Low Btu gasifier refit	1	.679	2.19	4206.8	824.1	323.2	788.3
Packaged shell stoker	1	.760	2.19	3582.7	735.8	350.4	628.9
Packaged shell FBC	1	.760	1.84	4587.0	618.2	350.4	643.3
Field erected stoker	1	.800	2.19	6497.4	699.0	348.3	619.2
Field erected FBC	1	.800	1.84	7133.3	587.3	407.0	642.4
Pulverized coal boiler	1	.820	1.84	7562.3	573.0	411.2	669.7
Circulating FBC	1	.810	1.84	8473.6	580.1	348.3	701.4

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	14,381	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	12,468	15,188	.947	>31	16,891	.851
Slagging burner refit	1	12,468	16,749	.859	>31	19,415	.741
Modular FBC refit	1	12,626	17,050	.843	>31	20,050	.717
Stoker firing refit	1	12,923	16,303	.882	>31	18,259	.788
Coal/water slurry	1	13,300	17,404	.826	>31	19,042	.755
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	14,473	18,929	.760	>31	21,512	.669
Packaged shell stoker	1	12,923	16,727	.860	>31	18,944	.759
Packaged shell FBC	1	13,125	16,753	.858	>31	19,459	.739
Field erected stoker	1	12,277	18,754	.767	>31	22,447	.641
Field erected FBC	1	12,468	19,115	.752	>31	23,128	.622
Pulverized coal boiler	1	12,164	19,608	.733	>31	23,844	.603
Circulating FBC	1	12,315	20,101	.715	>31	24,794	.580

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McGUIRE AFB: MAC

1. BACKGROUND

McGuire AFB is located near Trenton, New Jersey. The main boiler plant at McGuire used coal until 1970 when all boilers were switched to natural gas and distillate oil (backup fuel). All boilers are water-tube, high-temperature, hot-water units and have Cleaver Brooks electrostatic precipitators. Boiler efficiencies are reported as 74–70%. Fuel use is about 500,000 MBtu/year, for a yearly average of ~57 MBtu/h. Earlier data indicate that fuel use was previously much higher. Probably no coal-handling equipment is repairable.

2. HEATING PLANT UNITS

Heating Plant No. 2101:

4 × 50 MBtu/h, Combustion Engineering, 1953
2 × 31.2 MBtu/h, Erie City, 1960

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly fuel-use data for plant No. 2101.

Fuel input (MBtu/h)	CY 1985 ideal capacity factor	FY 1986 ideal capacity factor
30	0.93	0.92
40	0.82	0.82
50	0.76	0.76
60	0.71	0.71
70	0.67	0.66
80	0.63	0.62

4. ENERGY PRICES

FY 1986 Price Data:

	Average	Year end
Electricity	7.0¢/kWh	Same
Distillate	$6.85/MBtu	Same
Natural gas	$3.85/MBtu	$2.70/MBtu

C. H. Guernsey and Co. Survey:

Electricity = 7.8¢/kWh
Distillate = $5.56/MBtu
Natural gas = $5.40/MBtu (this is apparently a mistake)

An inquiry into the gas price revealed that the price fluctuates and the gas supply is interruptible. The gas supply is only rarely interrupted, and a cost of about $4.00/MBtu would be representative.

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Clearfield Co., Pa.	Clearfield Co., Pa.
HHV, Btu/lb	13,000	12,800
% Ash	10	13
% Sulfur	2	2
% Nitrogen	1.5	1.5
Ash-softening temperature, °F	2450	2450
Swelling index	8–9	8–9
Top size, in.	1 1/4	2
Bottom size, in.	3/8	0
Fines, %	15	
Grindability index	90+	90+
Cost at mine, $/ton	40	30
Delivered cost, $/ton	58.50	48.50
Energy cost, $/$10^6$ Btu	2.25	1.89

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. For boilers >250 MBtu/h: 0.6 lb/MBtu and 70% reduction; for boilers >1 and <250 MBtu/h: 0.3 lb/MBtu.

NO_x. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: spreader stoker and FBC – 0.6 lb/MBtu; pulverized coal – 0.7 lb/MBtu.

Particulates. 0.03 lb/MBtu (state-of-the-art technology required).

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

Ashes are classified as nonhazardous solid waste and may be disposed of in any approved sanitary landfill.

7. OTHER CONSIDERATIONS

Electric use in FY 1986 was 55,000 MWh, an average of 6.3 MW.

8. COAL-CONVERSION PROJECT OUTLOOK

A conversion project using coal to generate 50 MBtu/h of steam (~65 MBtu/h fuel input) may be feasible. Assuming 90% equipment availability, an overall capacity factor of about 62% could be expected. The price of natural gas is very important to the economics of such a project; the discrepancy in price must be investigated further.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2. The strict SO_2 emission limit will require 90% or greater SO_2 reduction while burning 2% sulfur coal, which will necessitate the use of a flue gas scrubber with stoker firing, limestone addition with micronized coal or FBC, or the use of deep-cleaned coal-water-mixture fuel.

NO_x. No special measures will be required for NO_x reduction because the proposed conversion project is smaller than 100 MBtu/h.

Particulates. Bag filters or electrostatic precipitators will be required to comply with the strict particulate emission limits except for the case of using a wet scrubber for SO_2 control. Electrostatic precipitators are still in place and may be reusable.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for coal. There is space available for reinstalling coal-combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. Most of the auxiliary equipment is still in place, but some of it is in very bad condition and cannot be used.

Coal Pile. There is space available for a coal pile at the existing boiler plant or at a new site on base.

8.3 Technical Risk of Combustion Technologies

Because of the need for strict SO_2 control, the technical risk is about equal for all the coal-combustion technologies. Refit of stoker firing would be the lowest risk for the combustion process, but the need for a flue gas scrubber increases the overall risk for that option.

9. COGENERATION PROJECT OUTLOOK

The prospects appear to be potentially favorable for a coal-fired cogeneration system. The minimum monthly average electric load is about 5.2 MWe and the price of electricity is high (7.8¢/kWh). Based on the FY 1986 energy-use data, a cogeneration plant with a boiler rating of 68 MBtu/h output and a 5-MWe turbine-generator would have an electrical power capacity factor of about 90% and a peak thermal output of 50 MBtu/h with a thermal energy capacity factor of about 72% if used as a baseload heating plant. A water-tube boiler with a steam rating of 1450 psia and 950°F would be the most suitable type of boiler for such a cogeneration plant.

10. INPUT AND LCC SUMMARY SPREADSHEETS

MCGUIRE AFB: 1 X 50 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .618
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 7.80
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 4.00
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.130	.100
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.89
Stoker coal ($/MBtu) = 2.25
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.66	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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MCGUIRE AFB: 1 X 50 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 50.0 MBtu/hr　　Cost base year = 1988

Boiler capacity factor = .618　　Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	4.00	.0	1353.4	165.4	496.2
#2 Oil fired boiler	--	.800	4.71	.0	1593.7	165.4	496.2
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.89	2907.2	639.5	368.2	776.5
Slagging burner refit	1	.800	1.89	4795.6	639.5	368.2	776.5
Modular FBC refit	1	.790	1.89	5442.3	647.6	350.4	741.0
Stoker firing refit	1	.740	2.25	4454.4	823.0	541.9	740.4
Coal/water slurry	1	.750	3.00	2651.5	1082.7	350.4	673.7
Coal/oil slurry	1	.780	3.50	2294.9	1214.6	279.0	590.0
Low Btu gasifier refit	1	.659	2.25	5034.9	924.7	323.2	1008.5
Packaged shell stoker	1	.740	2.25	4966.9	823.0	541.9	740.4
Packaged shell FBC	1	.760	1.89	4859.5	673.1	350.4	744.8
Field erected stoker	1	.780	2.25	7877.2	780.8	539.8	726.0
Field erected FBC	1	.800	1.89	7216.3	639.5	407.0	739.8
Pulverized coal boiler	1	.800	1.89	8942.1	639.5	602.7	779.0
Circulating FBC	1	.810	1.89	8543.9	631.6	348.3	779.9

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	29,110	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	29,610	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	13,217	17,719	1.643	6.8	19,636	1.482
Slagging burner refit	1	13,217	19,280	1.510	9.7	22,160	1.314
Modular FBC refit	1	13,384	19,454	1.496	10.3	22,654	1.285
Stoker firing refit	1	14,069	21,984	1.324	13.1	24,774	1.175
Coal/water slurry	1	14,098	20,689	1.407	9.6	22,566	1.290
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	15,808	23,547	1.236	16.2	26,665	1.092
Packaged shell stoker	1	14,069	22,407	1.299	14.1	25,459	1.143
Packaged shell FBC	1	13,913	19,241	1.513	9.7	22,151	1.314
Field erected stoker	1	13,347	24,288	1.199	18.6	28,809	1.010
Field erected FBC	1	13,217	21,341	1.364	13.5	25,457	1.143
Pulverized coal boiler	1	13,217	24,823	1.173	19.9	29,877	.974
Circulating FBC	1	13,054	22,152	1.314	15.2	26,938	1.081

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MCGUIRE AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .618
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 7.80
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 4.00
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.130	.100
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.89
Stoker coal ($/MBtu) = 2.25
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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MCGUIRE AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 50.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .618   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	4.00	.0	1353.4	165.4	496.2
#2 Oil fired boiler	--	.800	4.71	.0	1593.7	165.4	496.2
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.89	2907.2	639.5	368.2	776.5
Slagging burner refit	1	.800	1.89	4795.6	639.5	368.2	776.5
Modular FBC refit	1	.790	1.89	5442.3	647.6	350.4	741.0
Stoker firing refit	1	.740	2.25	4454.4	823.0	541.9	740.4
Coal/water slurry	1	.750	3.00	2651.5	1082.7	350.4	673.7
Coal/oil slurry	1	.780	3.50	2294.9	1214.6	279.0	590.0
Low Btu gasifier refit	1	.659	2.25	5034.9	924.7	323.2	1008.5
Packaged shell stoker	1	.740	2.25	4966.9	823.0	541.9	740.4
Packaged shell FBC	1	.760	1.89	4859.5	673.1	350.4	744.8
Field erected stoker	1	.780	2.25	7877.2	780.8	539.8	726.0
Field erected FBC	1	.800	1.89	7216.3	639.5	407.0	739.8
Pulverized coal boiler	1	.800	1.89	8942.1	639.5	602.7	779.0
Circulating FBC	1	.810	1.89	8543.9	631.6	348.3	779.9

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	22,261	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	24,070	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	13,217	17,618	1.264	9.7	19,531	1.140
Slagging burner refit	1	13,217	19,178	1.161	14.7	22,055	1.009
Modular FBC refit	1	13,384	19,351	1.150	15.6	22,548	.987
Stoker firing refit	1	14,069	21,853	1.019	26.8	24,640	.903
Coal/water slurry	1	14,098	20,517	1.085	17.6	22,388	.994
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	15,808	23,400	.951	>31	26,513	.840
Packaged shell stoker	1	14,069	22,277	.999	>31	25,325	.879
Packaged shell FBC	1	13,913	19,134	1.163	14.6	22,041	1.010
Field erected stoker	1	13,347	24,164	.921	>31	28,681	.776
Field erected FBC	1	13,217	21,239	1.048	23.7	25,353	.878
Pulverized coal boiler	1	13,217	24,721	.901	>31	29,773	.748
Circulating FBC	1	13,054	22,052	1.009	29.2	26,834	.830

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MCGUIRE AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .618
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 7.80
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 4.00
#2 Oil price ($/MBtu) = 4.71
#6 Oil price ($/MBtu) = .00

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.130	.100
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.89
Stoker coal ($/MBtu) = 2.25
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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MCGUIRE AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 50.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .618   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	4.00	.0	1353.4	165.4	496.2
#2 Oil fired boiler	--	.800	4.71	.0	1593.7	165.4	496.2
#6 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
Micronized coal refit	1	.800	1.89	2907.2	639.5	368.2	776.5
Slagging burner refit	1	.800	1.89	4795.6	639.5	368.2	776.5
Modular FBC refit	1	.790	1.89	5442.3	647.6	350.4	741.0
Stoker firing refit	1	.740	2.25	4454.4	823.0	541.9	740.4
Coal/water slurry	1	.750	3.00	2651.5	1082.7	350.4	673.7
Coal/oil slurry	1	.780	3.50	2294.9	1214.6	279.0	590.0
Low Btu gasifier refit	1	.659	2.25	5034.9	924.7	323.2	1008.5
Packaged shell stoker	1	.740	2.25	4966.9	823.0	541.9	740.4
Packaged shell FBC	1	.760	1.89	4859.5	673.1	350.4	744.8
Field erected stoker	1	.780	2.25	7877.2	780.8	539.8	726.0
Field erected FBC	1	.800	1.89	7216.3	639.5	407.0	739.8
Pulverized coal boiler	1	.800	1.89	8942.1	639.5	602.7	779.0
Circulating FBC	1	.810	1.89	8543.9	631.6	348.3	779.9

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	15,889	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	17,761	--			
#6 Oil fired boiler	--	--	0	--			
Micronized coal refit	1	13,217	16,727	.950	>31	18,615	.854
Slagging burner refit	1	13,217	18,288	.869	>31	21,139	.752
Modular FBC refit	1	13,384	18,449	.861	>31	21,620	.735
Stoker firing refit	1	14,069	20,707	.767	>31	23,461	.677
Coal/water slurry	1	14,098	19,009	.836	>31	20,838	.763
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	15,808	22,112	.719	>31	25,189	.631
Packaged shell stoker	1	14,069	21,130	.752	>31	24,146	.658
Packaged shell FBC	1	13,913	18,197	.873	>31	21,077	.754
Field erected stoker	1	13,347	23,076	.689	>31	27,563	.576
Field erected FBC	1	13,217	20,349	.781	>31	24,437	.650
Pulverized coal boiler	1	13,217	23,830	.667	>31	28,857	.551
Circulating FBC	1	13,054	21,172	.750	>31	25,930	.613

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SCOTT AFB: MAC

1. BACKGROUND

Scott AFB is located near Belleville, Illinois. There are four steam plants on this base, but only the major one is of any interest. The capacity of this plant is about 250 MBtu/h (the others are about 20, 31, and 14 MBtu/h) and is composed of four Erie City Iron Works boilers. The boilers in the main steam plant burned coal previously but were converted to No. 6 oil. Currently, the main plant burns natural gas, and the yearly average fuel use is roughly 40 MBtu/h.

2. HEATING PLANT UNITS

Heating Plant No. 45:

83 MBtu/h, Erie City Iron Works, 1955
40 MBtu/h, Erie City Iron Works, 1952
84 and 45 MBtu/h, Erie City Iron Works, 1939

3. IDEAL CAPACITY FACTOR ANALYSIS

The maximum possible capacity factors listed below were calculated from monthly fuel-use data for plant No. 45.

Fuel input (MBtu/h)	CY 1985 ideal capacity factor	FY 1986 ideal capacity factor
30	0.90	0.87
40	0.79	0.77
50	0.70	0.69
60	0.63	0.63
70	0.56	0.57
80	0.50	0.52
90	0.44	0.46

4. ENERGY PRICES

FY 1986 Price Data:

	Average	Year end
Electricity	4.1¢/kWh	4.9¢/kWh
Residual oil	$5.28/MBtu	Same
Distillate oil	$5.90/MBtu	Same
Natural gas	$3.64/MBtu	$3.80/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	Run of Mine
Origin	Belleville, Ill.	Belleville, Ill.
HHV, Btu/lb	10,888	10,509
Ash, %	10.70	11.18
Sulfur, %	3.74	3.70
Nitrogen, %		
Ash-softening temperature, °F		
Swelling index		
Top size, in.	1	1.5 × 0
Bottom size, in.	28 mesh	
Fines, %	9–12	25
Grindability index		
Cost at mine, $/ton	23.50	22.00
Delivered cost, $/ton	27.50	26.00
Energy cost, $/MBtu	1.26	1.24

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2: The Illinois emission limit for sulfur dioxide is 1.8 lb/MBtu in any 1-h period.

NO_x: The State does not have limits on nitrogen oxide emissions for fuel-burning sources of this size (<250 MBtu/h).

Particulates. Scott AFB is located in a nonattainment area for particulates. The State of Illinois particulate limit applicable to a plant boiler converted to coal firing is 0.1 lb/MBtu actual heat input. Nonattainment regulations require the base to operate the boiler at the lowest achievable emission rate (LAER). The operator must demonstrate that the control equipment and process measures will produce the LAER. Emission offsets are also applicable; however, in cases where no practical offsets are found, certain exemptions may be obtainable.

The opacity limits for new fuel-combustion sources of this size (≤250 MBtu/hr) is ≤30% with the exception that the opacity may range between 30 and 60% for a period or periods aggregating 8 min in a 60-min period.

6.2 Coal-Pile Runoff

The State of Illinois requires that coal storage yards obtain a National Pollutant Discharge Elimination System (NPDES) permit if coal-pile runoff is discharged into waters of the State. During the permit application review, the State Agency determines if a facility will cause or threaten to cause water pollution by its location, geology, operation, and abandonment plan.

The State of Illinois utilizes EPA federal regulation for coal-pile runoff. The regulations state the the pH of all discharges, except once-through cooling water, shall be within the range of 6.0 to 9.0. The effluent limitation for the point source discharges of coal-pile runoff is 50 mg/L total suspended solids.

6.3 Ash Disposal

Coal ash is classified as a special waste by the State of Illinois and requires a special permit for handling. A permit for special waste handling must be obtained by existing disposal sites that accept the ash or, for new disposal sites, an operating permit must be issued.

7. OTHER CONSIDERATIONS

None

8. COAL-CONVERSION PROJECT OUTLOOK

A conversion project would probably involve conversion of one 40-Btu/h output (50-MBtu/h fuel input) boiler. A realistic overall capacity factor for a 40-MBtu/h coal-burning unit would be about 63%, assuming 90% availability.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2. Sulfur dioxide removal will be required for all combustion technologies because of the high-sulfur (3.7%) coal.

NO_x. No special nitrogen oxide controls will be required for any of the combustion technologies.

Particulates. Bag filters or electrostatic precipitators will be required.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boilers were originally designed for coal, but there is no information about availability of space for reinstalling coal-combustion equipment.

Coal-Handling Equipment. There is not enough room for installing dry coal-handling equipment at the existing site, but there is space for coal-water-mixture equipment.

Coal Pile. There is no space available for a coal pile at the existing plant, but there is space at another site on base for a coal pile and a new coal-fired boiler.

8.3 Technical Risk of Combustion Technologies

The existing boilers were designed for coal, but the technical risk of burning a coal-water mixture would be moderate because of the need for SO_2 removal. The least technical risk would be for a new stoker or FBC boiler.

9. COGENERATION PROJECT OUTLOOK

The prospects for coal-fired cogeneration systems appear to be poor because of the low cost of electricity (4.1¢/kWh in FY 1986; however, by the year's end, about 4.9¢/kWh). The monthly minimum average electric demand was 2453 MWh in April. A 3.4-MW electric cogeneration plant would produce 10.2 MW(t) and require a 12.75-MW boiler because of the 80% boiler efficiency. The plant would generate 22,560 MBtu(t) each month based on a 90% plant availability. The overall thermal energy capacity factor for a year would be fairly high (61%).

10. INPUT AND LCC SUMMARY SPREADSHEETS

SCOTT AFB: 1 X 40 MBtu/hr, ECONOMIC PARAMETERS - NOMINAL VALUES

Total steam output = 40.0 MBtu/hr
Boiler capacity factor = .626
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.90
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.80
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.112	.107
Sulfur fraction =	.037	.037
HHV (Btu/lb) =	10510.	10890.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.24
Stoker coal ($/MBtu) = 1.26
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

3:12 PM Oct 24, 1988

SCOTT AFB: 1 X 40 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 40.0 MBtu/hr | Cost base year = 1988

Boiler capacity factor = .626 | Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.80	.0	1041.9	146.3	445.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1006.3	146.3	445.0
Micronized coal refit	1	.800	1.24	2779.1	340.0	339.8	765.6
Slagging burner refit	1	.800	1.24	4438.7	340.0	339.8	765.6
Modular FBC refit	1	.790	1.24	4995.3	344.3	323.4	732.8
Stoker firing refit	1	.740	1.26	3958.8	373.5	498.5	694.7
Coal/water slurry	1	.750	3.00	2545.7	877.4	323.4	688.7
Coal/oil slurry	1	.780	3.50	2166.5	984.3	257.5	562.1
Low Btu gasifier refit	1	.659	1.26	4448.1	419.7	298.3	817.5
Packaged shell stoker	1	.740	1.26	4405.5	373.5	498.5	694.7
Packaged shell FBC	1	.760	1.24	4437.1	357.9	323.4	739.2
Field erected stoker	1	.780	1.26	6856.2	354.3	496.5	683.8
Field erected FBC	1	.800	1.24	6321.2	340.0	375.6	730.8
Pulverized coal boiler	1	.800	1.24	7777.9	340.0	554.6	727.0
Circulating FBC	1	.810	1.24	7407.7	335.8	321.4	734.8

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	23,070	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	20,097	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because of space limitations						
Coal/water slurry	1	13,914	18,558	1.243	14.6	20,323	1.135
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	1	13,610	17,000	1.357	12.9	19,626	1.176
Packaged shell FBC	1	13,731	15,661	1.473	10.6	18,264	1.263
Field erected stoker	1	12,912	18,744	1.231	17.5	22,611	1.020
Field erected FBC	1	13,044	17,453	1.322	14.7	21,023	1.097
Pulverized coal boiler	1	13,044	20,227	1.141	21.4	24,585	.938
Circulating FBC	1	12,883	17,858	1.292	15.9	21,968	1.050

3:12 PM Oct 24, 1988

SCOTT AFB: 1 X 40 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 40.0 MBtu/hr
Boiler capacity factor = .626
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.90
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.80
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.112	.107
Sulfur fraction =	.037	.037
HHV (Btu/lb) =	10510.	10890.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.24
Stoker coal ($/MBtu) = 1.26
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

3:18 PM Oct 24, 1988

SCOTT AFB: 1 X 40 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 40.0 MBtu/hr　　Cost base year = 1988

Boiler capacity factor = .626　　Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.80	.0	1041.9	146.3	445.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1006.3	146.3	445.0
Micronized coal refit	1	.800	1.24	2779.1	340.0	339.8	765.6
Slagging burner refit	1	.800	1.24	4438.7	340.0	339.8	765.6
Modular FBC refit	1	.790	1.24	4995.3	344.3	323.4	732.8
Stoker firing refit	1	.740	1.26	3958.8	373.5	498.5	694.7
Coal/water slurry	1	.750	3.00	2545.7	877.4	323.4	688.7
Coal/oil slurry	1	.780	3.50	2166.5	984.3	257.5	562.1
Low Btu gasifier refit	1	.659	1.26	4448.1	419.7	298.3	817.5
Packaged shell stoker	1	.740	1.26	4405.5	373.5	498.5	694.7
Packaged shell FBC	1	.760	1.24	4437.1	357.9	323.4	739.2
Field erected stoker	1	.780	1.26	6856.2	354.3	496.5	683.8
Field erected FBC	1	.800	1.24	6321.2	340.0	375.6	730.8
Pulverized coal boiler	1	.800	1.24	7777.9	340.0	554.6	727.0
Circulating FBC	1	.810	1.24	7407.7	335.8	321.4	734.8

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	17,798	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	16,599	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because of space limitations						
Coal/water slurry	1	13,914	18,419	.966	>31	20,179	.882
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	1	13,610	16,941	1.051	22.7	19,565	.910
Packaged shell FBC	1	13,731	15,604	1.141	16.1	18,205	.978
Field erected stoker	1	12,912	18,687	.952	>31	22,553	.789
Field erected FBC	1	13,044	17,399	1.023	26.9	20,967	.849
Pulverized coal boiler	1	13,044	20,173	.882	>31	24,530	.726
Circulating FBC	1	12,883	17,804	1.000	>31	21,914	.812

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SCOTT AFB: 1 X 40 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 40.0 MBtu/hr
Boiler capacity factor = .626
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.90
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.80
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = 1.0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.112	.107
Sulfur fraction =	.037	.037
HHV (Btu/lb) =	10510.	10890.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.24
Stoker coal ($/MBtu) = 1.26
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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SCOTT AFB: 1 X 40 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 40.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .626   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	3.80	.0	1041.9	146.3	445.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1006.3	146.3	445.0
Micronized coal refit	1	.800	1.24	2779.1	340.0	339.8	765.6
Slagging burner refit	1	.800	1.24	4438.7	340.0	339.8	765.6
Modular FBC refit	1	.790	1.24	4995.3	344.3	323.4	732.8
Stoker firing refit	1	.740	1.26	3958.8	373.5	498.5	694.7
Coal/water slurry	1	.750	3.00	2545.7	877.4	323.4	688.7
Coal/oil slurry	1	.780	3.50	2166.5	984.3	257.5	562.1
Low Btu gasifier refit	1	.659	1.26	4448.1	419.7	298.3	817.5
Packaged shell stoker	1	.740	1.26	4405.5	373.5	498.5	694.7
Packaged shell FBC	1	.760	1.24	4437.1	357.9	323.4	739.2
Field erected stoker	1	.780	1.26	6856.2	354.3	496.5	683.8
Field erected FBC	1	.800	1.24	6321.2	340.0	375.6	730.8
Pulverized coal boiler	1	.800	1.24	7777.9	340.0	554.6	727.0
Circulating FBC	1	.810	1.24	7407.7	335.8	321.4	734.8

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	12,893	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	12,615	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because of space limitations						
Coal/water slurry	1	13,914	17,197	.750	>31	18,923	.681
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	1	13,610	16,421	.785	>31	19,030	.678
Packaged shell FBC	1	13,731	15,105	.854	>31	17,693	.729
Field erected stoker	1	12,912	18,194	.709	>31	22,045	.585
Field erected FBC	1	13,044	16,925	.762	>31	20,481	.630
Pulverized coal boiler	1	13,044	19,700	.654	>31	24,043	.536
Circulating FBC	1	12,883	17,337	.744	>31	21,433	.602

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GRAND FORKS AFB: SAC

1. BACKGROUND

Grand Forks AFB is located near Grand Forks, North Dakota. The central steam plant is the only one of interest to this study. There are five boilers sized at 3 × 25 MBtu/h and 2 × 42 MBtu/h. Hot water is produced at 395°F. All boilers in this steam plant were designed for stoker coal-firing but were later converted to burn No. 6 oil.

Currently an electric boiler system is supplying steam by a special agreement with the local utility. Apparently, the utility will supply electricity for steam generation at a very reduced price ($0.0215/kWh). Because Tim Fry says this may not last much longer, the LCC analysis was performed assuming that No. 6 oil is the primary fuel.

The yearly average electric use is roughly 45 MBtu/h. Boiler efficiency is reported to be about 65–76%. No coal equipment is left.

2. HEATING PLANT UNITS

Heating Plant No. 423:

2 × 25 MBtu/h, Combustion Engineering, 1956
25 and 42 MBtu/h, International Boiler Works, 1958
42 MBtu/h, International Boiler Works, 1964

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly electric-use data for plant No. 423.

Electric input (MBtu/h)	FY 1985 ideal capacity factor	FY 1986 ideal capacity factor
40	0.81	0.82
50	0.74	0.76
60	0.68	0.70
70	0.63	0.64
90	0.51	0.53

4. ENERGY PRICES

FY 1986 Price Data:

Electricity = 4.2¢/kWh (regular price)
Distillate = $5.41/MBtu
Natural gas = $3.64/MBtu

C. H. Guernsey and Co. Survey:

Electricity = 2.15¢/kWh ($6.3/MBtu, special price for steam generation)
Distillate = $6.07/MBtu ($0.91/gal)

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Morhland, Utah	Morhland, Utah
HHV, Btu/lb	12,300	12,200
% Ash	8	8
% Sulfur	1	1
% Nitrogen	1.2	1.2
Ash-softening temperature, °F	2300	2300
Swelling index	1	1
Top size, in.	1 1/4	1 1/2
Bottom size, in.	1/4	0
Fines, %	10	45
Grindability index	41	41
Cost at mine, $/ton	32	22
Delivered cost, $/ton	46	36
Energy cost, $/$10^6$ Btu	1.87	1.48

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. For boilers >30 and <100 MBtu/h: 3 lb/MBtu.

NO_x. For boilers >30 and <100 MBtu/h: No emission limit.

Particulates. For boilers >30 and <100 MBtu/h:

$E = 0.811\ (\text{MBtu/h})^{0.131}$.
For 42 MBtu/h: 0.5 lb/MBtu.

6.2 Coal-Pile Runoff

Limit: Total suspended solids - 50 mg/L.

6.3 Ash Disposal

Ashes are classified as nonhazardous industrial solid waste and may be disposed of in any approved sanitary landfill.

7. OTHER CONSIDERATIONS

This base is located near sources of lignite. The low-cost electricity scheme for the electric system boiler may stop in the near future.

8. COAL-CONVERSION PROJECT OUTLOOK

A refit/replacement project for one of the 42-MBtu/h output (equivalent to 43 MBtu/h electric input) boilers may be economically attractive. An overall capacity factor near 72% is expected, assuming a 90% availability.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed without requiring any measures for NO_x or SO_2 reduction since the proposed conversion project is smaller than 100 MBtu/h and the coal has a low sulfur content.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for coal. There is space available for reinstalling coal-combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. There is space available for installing coal-handling equipment at the existing boiler.

Coal Pile. There is space available for a coal pile at the existing boiler plant or at a new site on base.

8.3 Technical Risk of Combustion Technologies

The least technical risk would be for refit of stoker firing to the existing boiler, since it was originally designed for this, or installation of a new stoker-fired boiler. The other technologies would have greater technical risks because of lack of operating experience, and all of them would be of the same order since the existing boiler is designed for coal firing.

9. COGENERATION PROJECT OUTLOOK

Cogeneration would not be economical at this base because of the very low electric power rates.

10. INPUT AND LCC SUMMARY SPREADSHEETS

GRAND FORKS AFB: 1 X 42 MBtu/hr #6 BOILER, ECONOMIC PARAM = NOMINAL VALUES

Total steam output = 42.0 MBtu/hr
Boiler capacity factor = .716
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.20
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.080	.080
Sulfur fraction =	.010	.010
HHV (Btu/lb) =	12200.	12300.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.48
Stoker coal ($/MBtu) = 1.87
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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GRAND FORKS AFB: 1 X 42 MBtu/hr #6 BOILER, ECONOMIC PARAM = NOMINAL VALUES

Total steam output = 42.0 MBtu/hr — Cost base year = 1988

Boiler capacity factor = .716 — Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1208.5	150.3	448.5
Micronized coal refit	1	.800	1.48	2319.2	487.3	345.8	600.0
Slagging burner refit	1	.800	1.48	4026.2	487.3	345.8	600.0
Modular FBC refit	1	.790	1.48	4631.1	493.5	329.1	587.2
Stoker firing refit	1	.760	1.87	2779.8	648.2	329.1	580.9
Coal/water slurry	1	.750	3.00	2068.4	1053.7	329.1	510.6
Coal/oil slurry	1	.780	3.50	1835.9	1182.1	262.1	486.2
Low Btu gasifier refit	1	.679	1.87	3777.4	725.9	303.5	675.7
Packaged shell stoker	1	.760	1.87	3240.1	648.2	329.1	580.9
Packaged shell FBC	1	.760	1.48	4060.1	513.0	329.1	587.6
Field erected stoker	1	.800	1.87	5845.8	615.8	327.1	575.0
Field erected FBC	1	.800	1.48	6405.1	487.3	382.2	587.1
Pulverized coal boiler	1	.820	1.48	6797.0	475.5	386.2	616.8
Circulating FBC	1	.810	1.48	7556.0	481.3	327.1	637.7

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	23,239	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	13,495	14,236	1.632	5.4	15,768	1.474
Slagging burner refit	1	13,495	15,647	1.485	8.1	18,050	1.288
Modular FBC refit	1	13,666	15,956	1.456	8.9	18,661	1.245
Stoker firing refit	1	14,090	15,822	1.469	7.1	17,623	1.319
Coal/water slurry	1	14,395	18,475	1.258	9.9	20,005	1.162
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	15,780	17,882	1.300	10.8	20,227	1.149
Packaged shell stoker	1	14,090	16,202	1.434	7.9	18,238	1.274
Packaged shell FBC	1	14,206	15,669	1.483	8.1	18,089	1.285
Field erected stoker	1	13,386	17,989	1.292	12.6	21,343	1.089
Field erected FBC	1	13,495	17,838	1.303	12.8	21,460	1.083
Pulverized coal boiler	1	13,166	18,318	1.269	13.8	22,145	1.049
Circulating FBC	1	13,329	18,634	1.247	14.8	22,839	1.018

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GRAND FORKS AFB: 1 X 42 MBtu/hr #6 BOILER, FUEL REAL ESCALATION = AEO 1987

Total steam output = 42.0 MBtu/hr
Boiler capacity factor = .716
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.20
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.080	.080
Sulfur fraction =	.010	.010
HHV (Btu/lb) =	12200.	12300.

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.48
Stoker coal ($/MBtu) = 1.87
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

LIMESTONE/LIME

Inert fraction = .05

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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GRAND FORKS AFB: 1 X 42 MBtu/hr #6 BOILER, FUEL REAL ESCALATION = AEO 1987

Total steam output = 42.0 MBtu/hr — Cost base year = 1988

Boiler capacity factor = .716 — Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1208.5	150.3	448.5
Micronized coal refit	1	.800	1.48	2319.2	487.3	345.8	600.0
Slagging burner refit	1	.800	1.48	4026.2	487.3	345.8	600.0
Modular FBC refit	1	.790	1.48	4631.1	493.5	329.1	587.2
Stoker firing refit	1	.760	1.87	2779.8	648.2	329.1	580.9
Coal/water slurry	1	.750	3.00	2068.4	1053.7	329.1	510.6
Coal/oil slurry	1	.780	3.50	1835.9	1182.1	262.1	486.2
Low Btu gasifier refit	1	.679	1.87	3777.4	725.9	303.5	675.7
Packaged shell stoker	1	.760	1.87	3240.1	648.2	329.1	580.9
Packaged shell FBC	1	.760	1.48	4060.1	513.0	329.1	587.6
Field erected stoker	1	.800	1.87	5845.8	615.8	327.1	575.0
Field erected FBC	1	.800	1.48	6405.1	487.3	382.2	587.1
Pulverized coal boiler	1	.820	1.48	6797.0	475.5	386.2	616.8
Circulating FBC	1	.810	1.48	7556.0	481.3	327.1	637.7

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	19,038	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	13,495	14,159	1.345	7.8	15,689	1.213
Slagging burner refit	1	13,495	15,570	1.223	12.3	17,970	1.059
Modular FBC refit	1	13,666	15,877	1.199	13.5	18,581	1.025
Stoker firing refit	1	14,090	15,719	1.211	11.3	17,517	1.087
Coal/water slurry	1	14,395	18,307	1.040	22.5	19,833	.960
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	15,780	17,767	1.072	20.1	20,108	.947
Packaged shell stoker	1	14,090	16,099	1.183	12.8	18,132	1.050
Packaged shell FBC	1	14,206	15,588	1.221	12.3	18,005	1.057
Field erected stoker	1	13,386	17,891	1.064	21.9	21,242	.896
Field erected FBC	1	13,495	17,760	1.072	21.5	21,380	.890
Pulverized coal boiler	1	13,166	18,243	1.044	24.4	22,067	.863
Circulating FBC	1	13,329	18,558	1.026	26.8	22,761	.836

3:07 PM Oct 19, 1988

GRAND FORKS AFB: 1 X 42 MBtu/hr #6 BOILER, FUEL REAL ESCALATION = ZERO

Total steam output = 42.0 MBtu/hr
Boiler capacity factor = .716
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 4.20
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.080	.080
Sulfur fraction =	.010	.010
HHV (Btu/lb) =	12200.	12300.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.48
Stoker coal ($/MBtu) = 1.87
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

3:13 PM Oct 19, 1988

GRAND FORKS AFB: 1 X 42 MBtu/hr #6 BOILER, FUEL REAL ESCALATION = ZERO

Total steam output = 42.0 MBtu/hr　　Cost base year = 1988
Boiler capacity factor = .716　　Primary fuel = #6 FUEL OIL
Number of units for refit = 1

					ANNUAL COSTS		
TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1208.5	150.3	448.5
Micronized coal refit	1	.800	1.48	2319.2	487.3	345.8	600.0
Slagging burner refit	1	.800	1.48	4026.2	487.3	345.8	600.0
Modular FBC refit	1	.790	1.48	4631.1	493.5	329.1	587.2
Stoker firing refit	1	.760	1.87	2779.8	648.2	329.1	580.9
Coal/water slurry	1	.750	3.00	2068.4	1053.7	329.1	510.6
Coal/oil slurry	1	.780	3.50	1835.9	1182.1	262.1	486.2
Low Btu gasifier refit	1	.679	1.87	3777.4	725.9	303.5	675.7
Packaged shell stoker	1	.760	1.87	3240.1	648.2	329.1	580.9
Packaged shell FBC	1	.760	1.48	4060.1	513.0	329.1	587.6
Field erected stoker	1	.800	1.87	5845.8	615.8	327.1	575.0
Field erected FBC	1	.800	1.48	6405.1	487.3	382.2	587.1
Pulverized coal boiler	1	.820	1.48	6797.0	475.5	386.2	616.8
Circulating FBC	1	.810	1.48	7556.0	481.3	327.1	637.7

			AIR FORCE PROJECT			PRIVATE PROJECT	
TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	14,253	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	13,495	13,480	1.057	12.9	14,991	.951
Slagging burner refit	1	13,495	14,891	.957	>31	17,272	.825
Modular FBC refit	1	13,666	15,190	.938	>31	17,874	.797
Stoker firing refit	1	14,090	14,816	.962	>31	16,588	.859
Coal/water slurry	1	14,395	16,840	.846	>31	18,323	.778
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	15,780	16,755	.851	>31	19,068	.747
Packaged shell stoker	1	14,090	15,196	.938	>31	17,203	.829
Packaged shell FBC	1	14,206	14,873	.958	>31	17,270	.825
Field erected stoker	1	13,386	17,033	.837	>31	20,360	.700
Field erected FBC	1	13,495	17,082	.834	>31	20,682	.689
Pulverized coal boiler	1	13,166	17,581	.811	>31	21,386	.666
Circulating FBC	1	13,329	17,887	.797	>31	22,071	.646

3:13 PM　Oct 19, 1988

MINOT: SAC

1. BACKGROUND

Minot AFB is located near Minot, North Dakota. The central heating plant is of interest for this study. The base hospital also has a heating plant which is far too small for coal-firing consideration.

The central heating plant has six water-tube boilers that burn natural gas or No. 6 oil (for backup) to produce 400°F hot water. Two boilers (42 and 25 MBtu/h) originally burned coal and were later converted to burn gas or oil; the remaining boilers were designed for residual oil. No coal equipment is still present. Yearly average fuel use is about 50 MBtu/h.

2. HEATING PLANT UNITS

Heating Plant No. 413:

2 × 25 MBtu/h, International Boiler Works, 1956
25 MBtu/h, International Boiler Works, 1960
2 × 25 MBtu/h, Combustion Engineering, 1957
42 MBtu/h, Babcock & Wilcox, 1963

3. IDEAL CAPACITY FACTOR ANALYSIS

Based on monthly fuel-use data, the ideal capacity factors listed below were calculated for plant No. 413.

Fuel input (MBtu/h)	FY 1985 ideal capacity factor	FY 1988 ideal capacity factor
40	0.79	0.78
50	0.75	0.73
60	0.70	0.68
70	0.66	0.63
80	0.61	0.58
90	0.57	0.53
100	0.53	0.48

4. ENERGY PRICES

FY 1986 Price Data:

Electricity = 3.2¢/kWhr
Distillate = $5.90/MBtu
Natural gas = $3.90/MBtu

The data show no residual oil was purchased in FY 1986.

C. H. Guernsey and Co. Survey:

Electricity = 1.45¢/kWh
Residual = $2.53/MBtu (looks suspect)
Natural gas = $4.18/MBtu

The C. H. Guernsey and Co. survey gives No. 6 as the secondary fuel, costing only $0.38/gal. The survey also gives electricity as being very cheap. It is possible that the oil was purchased when oil prices were very low.

Letter from HQ SAC (10/27/88):

Electricity = 1.52¢/kWhr
Natural gas = $3.60/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Morhland, Utah	Morhland, Utah
HHV, Btu/lb	12,300	12,200
% Ash	8	8
% Sulfur	1	1
% Nitrogen	1.2	1.2
Ash-softening temperature, °F	2300	2300
Swelling index	1	1
Top size, in.	1 1/4	1 1/2
Bottom size, in.	1/4	0
Fines, %	10	45
Grindability index	41	41
Cost at mine, $/ton	32	22
Delivered cost, $/ton	46	36
Energy cost, $/$10^6$ Btu	1.87	1.48

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. For boilers >30 and <100 MBtu/h: 3 lb/MBtu.

NO_x. No emission limits for boilers >30 and <100 MBtu/h.

Particulates. For boilers >30 and <100 MBtu/h:
$E = 0.811\ (\text{MBtu/h})^{-0.131} = 0.5$ lb/MBtu for 42 MBtu/h.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

Ashes are classified as nonhazardous industrial solid waste and may be disposed of in any approved sanitary landfill.

7. OTHER CONSIDERATIONS

This base is situated near sources of lignite.

8. COAL-CONVERSION PROJECT OUTLOOK

An obvious project would be to convert/replace the 42-MBtu/h unit (~54 MBtu/h fuel input). The overall capacity factor, assuming a 90% availability, is estimated to be about 65%.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed without requiring any measures for NO_x or SO_2 reduction since the proposed conversion project is smaller than 100 MBtu/h and the coal has a low sulfur content.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for coal. There is space available for reinstalling combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. There is space available for installing coal-handling equipment at the existing boiler.

Coal Pile. There is space available for a coal pile at the existing boiler plant or at a new site on base.

8.3 Technical Risk of Combustion Technologies

The least technical risk would be for refit of stoker firing to the existing boiler, since it was originally designed for this, or installation of a new stoker-fired boiler. The other technologies would have greater technical risks because of lack of operating experience, and all of them would be of the same order since the existing boiler is designed for coal firing.

9. COGENERATION PROJECT OUTLOOK

Cogeneration would not be economical at this base because of the very low electric power rates from the electric utility company.

10. INPUT AND LCC SUMMARY SPREADSHEETS

MINOT AFB: 1 X 42 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 42.0 MBtu/hr
Boiler capacity factor = .646
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 1.50
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.60
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.080	.080
Sulfur fraction =	.010	.010
HHV (Btu/lb) =	12200.	12300.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.48
Stoker coal ($/MBtu) = 1.87
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

2:06 PM Jan 4, 1989

MINOT AFB: 1 X 42 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 42.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .646   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.60	.0	1069.5	150.3	427.6
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1090.3	150.3	427.6
Micronized coal refit	1	.800	1.48	2319.2	439.7	345.8	557.4
Slagging burner refit	1	.800	1.48	4026.2	439.7	345.8	557.4
Modular FBC refit	1	.790	1.48	4631.1	445.3	329.1	553.4
Stoker firing refit	1	.760	1.87	2779.8	584.8	329.1	551.6
Coal/water slurry	1	.750	3.00	2068.4	950.7	329.1	481.3
Coal/oil slurry	1	.780	3.50	1835.9	1066.5	262.1	457.5
Low Btu gasifier refit	1	.679	1.87	3777.4	655.0	303.5	584.5
Packaged shell stoker	1	.760	1.87	3240.1	584.8	329.1	551.6
Packaged shell FBC	1	.760	1.48	4060.1	462.8	329.1	553.8
Field erected stoker	1	.800	1.87	5845.8	555.6	327.1	549.2
Field erected FBC	1	.800	1.48	6405.1	439.7	382.2	553.3
Pulverized coal boiler	1	.820	1.48	6797.0	429.0	386.2	586.4
Circulating FBC	1	.810	1.48	7556.0	434.3	327.1	593.2

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	23,456	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	21,278	--			
Micronized coal refit	1	12,176	13,460	1.743	6.0	14,970	1.567
Slagging burner refit	1	12,176	14,871	1.577	8.9	17,251	1.360
Modular FBC refit	1	12,330	15,241	1.539	9.8	17,927	1.308
Stoker firing refit	1	12,713	15,001	1.564	7.9	16,779	1.398
Coal/water slurry	1	12,988	17,284	1.357	10.5	18,780	1.249
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	14,238	16,509	1.421	10.8	18,815	1.247
Packaged shell stoker	1	12,713	15,381	1.525	8.8	17,394	1.349
Packaged shell FBC	1	12,817	14,937	1.570	9.0	17,336	1.353
Field erected stoker	1	12,077	17,226	1.362	13.4	20,558	1.141
Field erected FBC	1	12,176	17,130	1.369	13.6	20,732	1.131
Pulverized coal boiler	1	11,879	17,647	1.329	14.7	21,455	1.093
Circulating FBC	1	12,026	17,848	1.314	15.4	22,031	1.065

2:06 PM Jan 4, 1989

MINOT AFB: 1 X 42 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 42.0 MBtu/hr
Boiler capacity factor = .646
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 1.50
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.60
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.080	.080
Sulfur fraction =	.010	.010
HHV (Btu/lb) =	12200.	12300.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.48
Stoker coal ($/MBtu) = 1.87
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
	TYPE OF FUEL	1988	1990	1995	2000 AND
FUEL	ESCALATION	-1990	-1995	-2000	BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

11:13 AM Jan 11, 1989

MINOT AFB: 1 X 42 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 42.0 MBtu/hr — Cost base year = 1988

Boiler capacity factor = .646 — Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.60	.0	1069.5	150.3	427.6
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1090.3	150.3	427.6
Micronized coal refit	1	.800	1.48	2319.2	439.7	345.8	557.4
Slagging burner refit	1	.800	1.48	4026.2	439.7	345.8	557.4
Modular FBC refit	1	.790	1.48	4631.1	445.3	329.1	553.4
Stoker firing refit	1	.760	1.87	2779.8	584.8	329.1	551.6
Coal/water slurry	1	.750	3.00	2068.4	950.7	329.1	481.3
Coal/oil slurry	1	.780	3.50	1835.9	1066.5	262.1	457.5
Low Btu gasifier refit	1	.679	1.87	3777.4	655.0	303.5	584.5
Packaged shell stoker	1	.760	1.87	3240.1	584.8	329.1	551.6
Packaged shell FBC	1	.760	1.48	4060.1	462.8	329.1	553.8
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Field erected FBC	1	.800	1.48	6405.1	439.7	382.2	553.3
Pulverized coal boiler	1	.820	1.48	6797.0	429.0	386.2	586.4
Circulating FBC	1	.810	1.48	7556.0	434.3	327.1	593.2

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	18,044	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	17,487	--			
Micronized coal refit	1	12,176	13,390	1.348	8.0	14,898	1.211
Slagging burner refit	1	12,176	14,801	1.219	12.6	17,179	1.050
Modular FBC refit	1	12,330	15,171	1.189	14.1	17,854	1.011
Stoker firing refit	1	12,713	14,908	1.210	11.5	16,683	1.082
Coal/water slurry	1	12,988	17,132	1.053	20.7	18,624	.969
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	14,238	16,405	1.100	17.8	18,707	.965
Packaged shell stoker	1	12,713	15,288	1.180	13.1	17,298	1.043
Packaged shell FBC	1	12,817	14,863	1.214	12.8	17,260	1.045
Field erected stoker	1	12,077	17,137	1.053	23.1	20,467	.882
Field erected FBC	1	12,176	17,060	1.058	22.9	20,660	.873
Pulverized coal boiler	1	11,879	17,579	1.026	26.5	21,385	.844
Circulating FBC	1	12,026	17,779	1.015	28.4	21,960	.822

11:13 AM Jan 11, 1989

MINOT AFB: 1 X 42 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 42.0 MBtu/hr
Boiler capacity factor = .646
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 1.50
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.60
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.080	.080
Sulfur fraction =	.010	.010
HHV (Btu/lb) =	12200.	12300.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.48
Stoker coal ($/MBtu) = 1.87
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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MINOT AFB: 1 X 42 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 42.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .646   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	3.60	.0	1069.5	150.3	427.6
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1090.3	150.3	427.6
Micronized coal refit	1	.800	1.48	2319.2	439.7	345.8	557.4
Slagging burner refit	1	.800	1.48	4026.2	439.7	345.8	557.4
Modular FBC refit	1	.790	1.48	4631.1	445.3	329.1	553.4
Stoker firing refit	1	.760	1.87	2779.8	584.8	329.1	551.6
Coal/water slurry	1	.750	3.00	2068.4	950.7	329.1	481.3
Coal/oil slurry	1	.780	3.50	1835.9	1066.5	262.1	457.5
Low Btu gasifier refit	1	.679	1.87	3777.4	655.0	303.5	584.5
Packaged shell stoker	1	.760	1.87	3240.1	584.8	329.1	551.6
Packaged shell FBC	1	.760	1.48	4060.1	462.8	329.1	553.8
Field erected stoker	1	.800	1.87	5845.8	555.6	327.1	549.2
Field erected FBC	1	.800	1.48	6405.1	439.7	382.2	553.3
Pulverized coal boiler	1	.829	1.48	6797.0	429.0	386.2	586.4
Circulating FBC	1	.810	1.48	7556.0	434.3	327.1	593.2

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	13,008	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	13,170	--			
Micronized coal refit	1	12,176	12,777	1.018	19.8	14,268	.912
Slagging burner refit	1	12,176	14,188	.917	>31	16,549	.786
Modular FBC refit	1	12,330	14,551	.894	>31	17,216	.756
Stoker firing refit	1	12,713	14,093	.923	>31	15,845	.821
Coal/water slurry	1	12,988	15,808	.823	>31	17,263	.754
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	14,238	15,492	.840	>31	17,769	.732
Packaged shell stoker	1	12,713	14,474	.899	>31	16,461	.790
Packaged shell FBC	1	12,817	14,219	.915	>31	16,597	.784
Field erected stoker	1	12,077	16,363	.795	>31	19,672	.661
Field erected FBC	1	12,176	16,447	.791	>31	20,030	.649
Pulverized coal boiler	1	11,879	16,981	.766	>31	20,770	.626
Circulating FBC	1	12,026	17,174	.757	>31	21,338	.610

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PEASE AFB: SAC

1. BACKGROUND

Pease AFB is located near Portsmouth, New Hampshire. The steam plant consists of two 110-MBtu/h water-tube units firing natural gas as the primary fuel and No. 6 oil as the secondary fuel. A refuse-derived fuel has also been used in these boilers. These boilers were originally designed for residual fuel oil combustion. Average annual fuel use was about 42 MBtu/h for FY 1986. Refuse-derived fuel was about 45% of the total.

2. HEATING PLANT UNITS

Heating Plant No. 124:

2 × 110 MBtu/h, Combustion Engineering, 1955

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly fuel-use data for plant No. 124.

Fuel input (MBtu/h)	FY 1986 ideal capacity factor
40	0.68
50	0.64
70	0.56
90	0.47
110	0.39

4. ENERGY PRICES

FY 1986 Price Data:

Electricity = \$15.5/MBtu = 5.3¢/kWh
Distillate = \$5.91/MBtu
Residual = \$4.54/MBtu
Natural gas = \$3.8/MBtu

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Slago, Pa.	Slago, Pa.
HHV, Btu/lb	13,000	12,800
% Ash	7–9	8–10
% Sulfur	1.8–2.2	1.8–2.2
% Nitrogen	1.32	1.30
Ash-softening temperature, °F	2500	2300
Swelling index	6–8	6–8
Top size, in.	1 5/8	2
Bottom size, in.	1/2	0
Fines, %	5	
Grindability index	50–55	50–55
Cost at mine, $/ton	40	26.50
Delivered cost, $/ton	66.60	53.10
Energy cost, $/10^6 Btu	2.56	2.07

The coal prices quoted above assume rail delivery to Pease AFB. The base is currently removing its rail connection because it crosses a major highway. If coal has to be delivered by truck, delivered costs could be higher by as much as $0.50/MBtu.

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: FBC – 90% reduction to meet limit of 1.2 lb/MBtu; emerging technology – 50% reduction to meet limit of 0.6 lb/MBtu.

No_x. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: spreader stoker and FBC – 0.6 lb/MBtu; pulverized coal – 0.7 lb/MBtu.

Particulates. For boilers >100 MBtu/h: 0.05 lb/MBtu.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

Ashes are classified as nonhazardous industrial solid waste and may be disposed of in any approved sanitary landfill.

7. OTHER CONSIDERATIONS

None

8. COAL-CONVERSION PROJECT OUTLOOK

Replacement/refit of one boiler may be attractive. It is estimated that the overall capacity factor for conversion of one 110-MBtu/h unit to coal, but derated to 75 MBtu/h output (~94 MBtu/h fuel input) to avoid environmental regulations, would be roughly 41% assuming 90% availability.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed without requiring any measures for NO_x or SO_2 reduction since the proposed conversion project is smaller than 100 MBtu/h.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for No. 6 oil, so return to stoker is not possible. There is space available for installing coal combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. There is space available for installing coal-handling equipment at the existing boiler.

Coal Pile. There is space available for a coal pile at the existing boiler plant or at a new site on base.

8.3 Technical Risk of Combustion Technologies

The existing boilers are designed for No. 6 oil-firing and therefore are not sutiable for conversion to stoker-firing, but they could be converted to coal-water mixture or micronized coal-firing. Since the peak winter fuel use is about 85 MBtu/h, one of the 110-MBtu/h boilers could be derated to 68% capacity and meet the peak load. This would make the technical risk low for either coal-water-mixture or micronized coal.

9. COGENERATION PROJECT OUTLOOK

The prospects for a coal-fired cogeneration system appear to be marginal. The minimum average monthly electrical load is fairly low, 3.2 MWe, and the price of electricity is only moderately high, 5.3¢/kWh. Based on the FY 1986 energy-use data, a cogeneration plant with a boiler rating of 64 MBtu/h output and a 3-MWe turbine-generator would have an electrical power capacity factor of 90% and a peak thermal output of 40 MBtu/h, with a thermal energy capacity factory of about 65% if used as a baseload heating plant. A water-tube boiler with a steam rating of 1200 psia and 900°F would be the most suitable boiler for this cogeneration system.

10. INPUT AND LCC SUMMARY SPREADSHEETS

PEASE AFB: 1 X 75 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 75.0 MBtu/hr
Boiler capacity factor = .407
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.30
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.80
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.090	.080
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 2.07
Stoker coal ($/MBtu) = 2.56
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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PEASE AFB: 1 X 75 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 75.0 MBtu/hr   Cost base year = 1988
Boiler capacity factor = .407   Primary fuel = NATURAL GAS
Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.80	.0	1270.1	206.8	522.8
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1226.7	206.8	522.8
Micronized coal refit	1	.800	2.07	3177.7	691.9	426.6	696.3
Slagging burner refit	1	.800	2.07	5568.5	691.9	426.6	696.3
Modular FBC refit	1	.790	2.07	6413.8	700.7	405.5	680.0
Stoker firing refit	1	.760	2.56	3759.5	900.7	405.5	670.4
Coal/water slurry	1	.750	3.00	2875.4	1069.6	405.5	593.8
Coal/oil slurry	1	.780	3.50	2573.8	1199.9	322.9	566.9
Low Btu gasifier refit	2	.679	2.56	6532.0	1008.8	374.0	931.3
Packaged shell stoker	2	.760	2.56	5631.0	900.7	405.5	766.7
Packaged shell FBC	2	.760	2.07	7033.5	728.3	405.5	776.8
Field erected stoker	1	.800	2.56	8326.1	855.7	403.0	660.5
Field erected FBC	1	.800	2.07	9182.0	691.9	470.9	679.8
Pulverized coal boiler	1	.820	2.07	9710.9	675.0	475.9	709.6
Circulating FBC	1	.810	2.07	11087.6	683.4	403.0	736.1

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	28,224	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	24,600	--			
Micronized coal refit	1	13,057	18,330	1.540	7.9	20,395	1.384
Slagging burner refit	1	13,057	20,306	1.390	12.0	23,591	1.196
Modular FBC refit	1	13,222	20,770	1.359	13.1	24,479	1.153
Stoker firing refit	Not applicable because existing boiler was designed for #6 oil						
Coal/water slurry	1	13,927	20,621	1.369	10.4	22,605	1.249
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	15,156	25,423	1.110	22.3	29,322	.963
Packaged shell stoker	2	13,532	22,667	1.245	15.8	26,050	1.083
Packaged shell FBC	2	13,744	22,294	1.266	15.8	26,349	1.071
Field erected stoker	1	12,856	23,625	1.195	18.6	28,346	.996
Field erected FBC	1	13,057	23,560	1.198	18.8	28,696	.984
Pulverized coal boiler	1	12,738	24,115	1.170	20.0	29,524	.956
Circulating FBC	1	12,895	24,887	1.134	22.0	30,987	.911

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PEASE AFB: 1 X 75 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 75.0 MBtu/hr
Boiler capacity factor = .407
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.30
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.80
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.090	.080
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 2.07
Stoker coal ($/MBtu) = 2.56
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
	TYPE OF FUEL	1988	1990	1995	2000 AND
FUEL	ESCALATION	-1990	-1995	-2000	BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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PEASE AFB: 1 X 75 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 75.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .407   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.80	.0	1270.1	206.8	522.8
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1226.7	206.8	522.8
Micronized coal refit	1	.800	2.07	3177.7	691.9	426.6	696.3
Slagging burner refit	1	.800	2.07	5568.5	691.9	426.6	696.3
Modular FBC refit	1	.790	2.07	6413.8	700.7	405.5	680.0
Stoker firing refit	1	.760	2.56	3759.5	900.7	405.5	670.4
Coal/water slurry	1	.750	3.00	2875.4	1069.6	405.5	593.8
Coal/oil slurry	1	.780	3.50	2573.8	1199.9	322.9	566.9
Low Btu gasifier refit	2	.679	2.56	6532.0	1008.8	374.0	931.3
Packaged shell stoker	2	.760	2.56	5631.0	900.7	405.5	766.7
Packaged shell FBC	2	.760	2.07	7033.5	728.3	405.5	776.8
Field erected stoker	1	.800	2.56	8326.1	855.7	403.0	660.5
Field erected FBC	1	.800	2.07	9182.0	691.9	470.9	679.8
Pulverized coal boiler	1	.820	2.07	9710.9	675.0	475.9	709.6
Circulating FBC	1	.810	2.07	11087.6	683.4	403.0	736.1

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	21,797	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	20,335	--			
Micronized coal refit	1	13,057	18,220	1.196	11.7	20,282	1.075
Slagging burner refit	1	13,057	20,195	1.079	19.9	23,477	.928
Modular FBC refit	1	13,222	20,659	1.055	22.6	24,365	.895
Stoker firing refit	Not applicable because existing boiler was designed for #6 oil						
Coal/water slurry	1	13,927	20,451	1.066	19.4	22,430	.972
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	15,156	25,262	.863	>31	29,157	.748
Packaged shell stoker	2	13,532	22,524	.968	>31	25,903	.842
Packaged shell FBC	2	13,744	22,179	.983	>31	26,230	.831
Field erected stoker	1	12,856	23,489	.928	>31	28,206	.773
Field erected FBC	1	13,057	23,450	.930	>31	28,582	.763
Pulverized coal boiler	1	12,738	24,008	.908	>31	29,413	.741
Circulating FBC	1	12,895	24,778	.880	>31	30,875	.706

4:25 PM   Oct 21, 1988

PEASE AFB: 1 X 75 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 75.0 MBtu/hr
Boiler capacity factor = .407
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 5.30
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 3.80
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = .0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.090	.080
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 2.07
Stoker coal ($/MBtu) = 2.56
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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PEASE AFB: 1 X 75 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 75.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .407   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	3.80	.0	1270.1	206.8	522.8
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1226.7	206.8	522.8
Micronized coal refit	1	.800	2.07	3177.7	691.9	426.6	696.3
Slagging burner refit	1	.800	2.07	5568.5	691.9	426.6	696.3
Modular FBC refit	1	.790	2.07	6413.8	700.7	405.5	680.0
Stoker firing refit	1	.760	2.56	3759.5	900.7	405.5	670.4
Coal/water slurry	1	.750	3.00	2875.4	1069.6	405.5	593.8
Coal/oil slurry	1	.780	3.50	2573.8	1199.9	322.9	566.9
Low Btu gasifier refit	2	.679	2.56	6532.0	1008.8	374.0	931.3
Packaged shell stoker	2	.760	2.56	5631.0	900.7	405.5	766.7
Packaged shell FBC	2	.760	2.07	7033.5	728.3	405.5	776.8
Field erected stoker	1	.800	2.56	8326.1	855.7	403.0	660.5
Field erected FBC	1	.800	2.07	9182.0	691.9	470.9	679.8
Pulverized coal boiler	1	.820	2.07	9710.9	675.0	475.9	709.6
Circulating FBC	1	.810	2.07	11087.6	683.4	403.0	736.1

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	15,817	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	15,479	--			
Micronized coal refit	1	13,057	17,256	.917	>31	19,291	.820
Slagging burner refit	1	13,057	19,232	.822	>31	22,486	.703
Modular FBC refit	1	13,222	19,683	.804	>31	23,361	.677
Stoker firing refit	Not applicable because existing boiler was designed for #6 oil						
Coal/water slurry	1	13,927	18,962	.834	>31	20,898	.757
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	2	15,156	23,857	.663	>31	27,712	.571
Packaged shell stoker	2	13,532	21,270	.744	>31	24,612	.643
Packaged shell FBC	2	13,744	21,164	.747	>31	25,186	.628
Field erected stoker	1	12,856	22,297	.709	>31	26,980	.586
Field erected FBC	1	13,057	22,486	.703	>31	27,591	.573
Pulverized coal boiler	1	12,738	23,068	.686	>31	28,447	.556
Circulating FBC	1	12,895	23,826	.664	>31	29,897	.529

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PLATTSBURGH AFB: SAC

1. BACKGROUND

Plattsburgh AFB is located near Plattsburgh, New York. The main boiler plant (building 2658) has 6 × 50-MBtu/h boilers firing the design fuel, No. 6 oil. The boiler plant produces pressurized hot water with temperatures up to about 400°F. The yearly average fuel use is roughly 83 MBtu/h.

2. HEATING PLANT UNITS

Heating Plant No. 2658:

4 × 50 MBtu/h, International Boiler Works, 1955
2 × 50 MBtu/h, Combustion Engineering, 1957

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly fuel-use data for plant No. 2658.

Fuel input (MBtu/h)	FY 1987 ideal capacity factor	FY 1988 ideal capacity factor
40	0.96	0.95
50	0.90	0.90
70	0.83	0.81
90	0.76	0.75
100	0.73	0.72

4. ENERGY PRICES

FY 1986 Price Data:

	Year average	End of year
Distillate	\$5.90/MBtu	Same
Residual	\$5.08/MBtu	Same
Electric	\$17.3/MBtu = 5.91¢/kWh	6.3¢/kWh

C. H. Guernsey and Co. Survey:

The most recent costs from the C. H. Guernsey and Co. survey agree with the FY 1986 costs.

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Slago, Pa.	Slago, Pa.
HHV, Btu/lb	13,000	12,800
% Ash	7–9	8–10
% Sulfur	1.8–2.2	1.8–2.2
% Nitrogen	1.32	1.30
Ash-softening temperature, °F	2500	2300
Swelling index	6–8	6–8
Top size, in.	1 5/8	2
Bottom size, in.	1/2	0
Fines, %	5	
Grindability index	50–55	50–55
Cost at mine, $/ton	40	26.50
Delivered cost, $/ton	64.00	50.50
Energy cost, $/10^6 Btu	2.46	1.97

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: FBC – 90% reduction to meet limit of 1.2 lb/MBtu; emerging technology – 50% reduction to meet limit of 0.6 lb/MBtu.

NO_x. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: spreader stoker and FBC – 0.6 lb/MBtu; pulverized coal – 0.7 lb/MBtu.

Particulates. For boilers >100 MBtu/h: 0.05 lb/MBtu.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

Ashes are classified as nonhazardous solid waste and may be disposed of in any approved sanitary landfill.

7. OTHER CONSIDERATIONS

None

8. COAL CONVERSION PROJECT OUTLOOK

Based on load data, a refit/replacement project would probably involve one 50-MBtu/h output (~63 MBtu/h fuel input) boiler. The overall capacity factor is estimated to be about 76%, assuming 90% equipment availability.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed without requiring any measures for NO_x or SO_2 reduction since the proposed conversion project is smaller than 100 MBtu/h.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for No. 6 oil, so return to stoker is not possible. There is space available for installing coal-combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. There is space available for installing coal-handling equipment at the existing boiler.

Coal Pile. There is space available for a coal pile at the existing boiler plant or at a new site on base.

8.3 Technical Risk of Combustion Technologies

The existing boilers are designed for No. 6 oil-firing and therefore are not suitable for conversion to stoker-firing. The least teachnical risk would be for installation of a new stoker boiler. The refit technologies would have greater technical risks because of lack of operating experience, and all of them would be of the same order since no SO_2 removal is necessary.

9. COGENERATION PROJECT OUTLOOK

The prospects for a coal-fired cogeneration system appear to be interesting. The minimum average monthly electrical load is fairly low, 3.2 MWe, but the price of electricity is moderately high, 6.3¢/kWh. Based on the FY 1986 energy-use data, a cogeneration plant with a boiler rating of 64-MBtu/h output and a 3-MWe turbine-generator would have an electrical power capacity factor of 90% and a peak thermal output of 40 MBtu/h, with a thermal energy capacity factor of about 65% if used as a baseload heating plant. A water-tube boiler with a steam rating of 1200 psia and 900°F would be the most suitable boiler for this cogeneration system.

10. INPUT AND LCC SUMMARY SPREADSHEETS

PLATTSBURGH AFB: 1 X 50 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .764
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 6.30
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.090	.080
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.97
Stoker coal ($/MBtu) = 2.46
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
	TYPE OF FUEL	1988	1990	1995	2000 AND
FUEL	ESCALATION	-1990	-1995	-2000	BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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PLATTSBURGH AFB: 1 X 50 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 50.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .764   Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1535.1	165.4	491.1
Micronized coal refit	1	.800	1.97	2554.4	824.0	368.2	674.7
Slagging burner refit	1	.800	1.97	4442.8	824.0	368.2	674.7
Modular FBC refit	1	.790	1.97	5111.7	834.5	350.4	650.3
Stoker firing refit	1	.760	2.46	3034.9	1083.2	350.4	636.2
Coal/water slurry	1	.750	3.00	2586.4	1338.5	350.4	565.7
Coal/oil slurry	1	.780	3.50	2131.1	1501.6	279.0	538.2
Low Btu gasifier refit	1	.679	2.46	4169.9	1213.1	323.2	810.4
Packaged shell stoker	1	.760	2.46	3547.4	1083.2	350.4	636.2
Packaged shell FBC	1	.760	1.97	4523.8	867.4	350.4	650.9
Field erected stoker	1	.800	2.46	6497.4	1029.0	348.3	625.7
Field erected FBC	1	.800	1.97	7133.3	824.0	407.0	650.1
Pulverized coal boiler	1	.820	1.97	7562.3	803.9	411.2	676.6
Circulating FBC	1	.810	1.97	8473.6	813.9	348.3	716.2

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	28,680	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	16,339	18,358	1.562	5.6	20,121	1.425
Slagging burner refit	1	16,339	19,919	1.440	8.3	22,645	1.266
Modular FBC refit	1	16,546	20,220	1.418	9.1	23,280	1.232
Stoker firing refit	Not applicable because existing boiler was designed for #6 oil						
Coal/water slurry	1	17,429	22,183	1.293	9.1	24,070	1.192
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	18,966	23,983	1.196	13.9	26,692	1.074
Packaged shell stoker	1	16,935	21,141	1.357	8.8	23,467	1.222
Packaged shell FBC	1	17,199	20,047	1.431	8.5	22,816	1.257
Field erected stoker	1	16,088	22,972	1.248	13.4	26,785	1.071
Field erected FBC	1	16,339	22,298	1.286	12.8	26,401	1.086
Pulverized coal boiler	1	15,941	22,709	1.263	13.7	27,033	1.061
Circulating FBC	1	16,138	23,301	1.231	15.0	28,085	1.021

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PLATTSBURGH AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 50.0 MBtu/hr			
Boiler capacity factor = .764			
Number of units for refit = 1			
Hydrated lime price($/ton) = 40.00	**COAL PROPERTIES**		
Ash disposal price ($/ton) = 10.00		R.O.M.	Stoker
Electric price (cents/kWh) = 6.30	Ash fraction =	.090	.080
Labor rate (k$/yr) = 35.00	Sulfur fraction =	.020	.020
Limestone price ($/ton) = 20.00	HHV (Btu/lb) =	12800.	13000.
FUEL PRICES	**FUEL PRICES**		
Natural gas price ($/MBtu) = .00	R.O.M. coal ($/MBtu) = 1.97		
#2 Oil price ($/MBtu) = .00	Stoker coal ($/MBtu) = 2.46		
#6 Oil price ($/MBtu) = 3.67	Coal/H2O mix ($/MBtu) = 3.00		
OPTIONS	Coal/oil mix ($/MBtu) = 3.50		
Soot blower multiplier = .0			
Tube bank mod multiplier = 1.0	**Primary fuel is 1**		
Bottom ash pit multiplier = 1.0	#6 FUEL OIL		
SO2 control multiplier = .0	1=#6 Oil, 2=#2 Oil, 3=NG		
LIMESTONE/LIME			
Inert fraction = .05			

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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PLATTSBURGH AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 50.0 MBtu/hr Cost base year = 1988

Boiler capacity factor = .764 Primary fuel = #6 FUEL OIL

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1535.1	165.4	491.1
Micronized coal refit	1	.800	1.97	2554.4	824.0	368.2	674.7
Slagging burner refit	1	.800	1.97	4442.8	824.0	368.2	674.7
Modular FBC refit	1	.790	1.97	5111.7	834.5	350.4	650.3
Stoker firing refit	1	.760	2.46	3034.9	1083.2	350.4	636.2
Coal/water slurry	1	.750	3.00	2586.4	1338.5	350.4	565.7
Coal/oil slurry	1	.780	3.50	2131.1	1501.6	279.0	538.2
Low Btu gasifier refit	1	.679	2.46	4169.9	1213.1	323.2	810.4
Packaged shell stoker	1	.760	2.46	3547.4	1083.2	350.4	636.2
Packaged shell FBC	1	.760	1.97	4523.8	867.4	350.4	650.9
Field erected stoker	1	.800	2.46	6497.4	1029.0	348.3	625.7
Field erected FBC	1	.800	1.97	7133.3	824.0	407.0	650.1
Pulverized coal boiler	1	.820	1.97	7562.3	803.9	411.2	676.6
Circulating FBC	1	.810	1.97	8473.6	813.9	348.3	716.2

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	23,343	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	16,339	18,227	1.281	8.7	19,987	1.168
Slagging burner refit	1	16,339	19,788	1.180	13.4	22,510	1.037
Modular FBC refit	1	16,546	20,087	1.162	14.6	23,144	1.009
Stoker firing refit	Not applicable because existing boiler was designed for #6 oil						
Coal/water slurry	1	17,429	21,970	1.062	19.7	23,852	.979
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	18,966	23,790	.981	>31	26,493	.881
Packaged shell stoker	1	16,935	20,969	1.113	16.1	23,290	1.002
Packaged shell FBC	1	17,199	19,909	1.172	13.8	22,674	1.029
Field erected stoker	1	16,088	22,809	1.023	26.6	26,617	.877
Field erected FBC	1	16,339	22,167	1.053	23.1	26,266	.889
Pulverized coal boiler	1	15,941	22,581	1.034	25.4	26,901	.868
Circulating FBC	1	16,138	23,172	1.007	29.6	27,951	.835

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PLATTSBURGH AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 50.0 MBtu/hr
Boiler capacity factor = .764
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 6.30
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = .00
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = .0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.090	.080
Sulfur fraction =	.020	.020
HHV (Btu/lb) =	12800.	13000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.97
Stoker coal ($/MBtu) = 2.46
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 1
#6 FUEL OIL
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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PLATTSBURGH AFB: 1 X 50 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 50.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .764   Primary fuel = #6 FUEL OIL

Number of units for refit = 1

					ANNUAL COSTS		
TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	.00	.0	.0	.0	.0
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1535.1	165.4	491.1
Micronized coal refit	1	.800	1.97	2554.4	824.0	368.2	674.7
Slagging burner refit	1	.800	1.97	4442.8	824.0	368.2	674.7
Modular FBC refit	1	.790	1.97	5111.7	834.5	350.4	650.3
Stoker firing refit	1	.760	2.46	3034.9	1083.2	350.4	636.2
Coal/water slurry	1	.750	3.00	2586.4	1338.5	350.4	565.7
Coal/oil slurry	1	.780	3.50	2131.1	1501.6	279.0	538.2
Low Btu gasifier refit	1	.679	2.46	4169.9	1213.1	323.2	810.4
Packaged shell stoker	1	.760	2.46	3547.4	1083.2	350.4	636.2
Packaged shell FBC	1	.760	1.97	4523.8	867.4	350.4	650.9
Field erected stoker	1	.800	2.46	6497.4	1029.0	348.3	625.7
Field erected FBC	1	.800	1.97	7133.3	824.0	407.0	650.1
Pulverized coal boiler	1	.820	1.97	7562.3	803.9	411.2	676.6
Circulating FBC	1	.810	1.97	8473.6	813.9	348.3	716.2

			AIR FORCE PROJECT			PRIVATE PROJECT	
TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	0	--			
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	17,265	1.000	<--- Existing system, primary fuel		
Micronized coal refit	1	16,339	17,079	1.011	21.3	18,806	.918
Slagging burner refit	1	16,339	18,640	.926	>31	21,330	.809
Modular FBC refit	1	16,546	18,925	.912	>31	21,949	.787
Stoker firing refit	Not applicable because existing boiler was designed for #6 oil						
Coal/water slurry	1	17,429	20,106	.859	>31	21,934	.787
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	1	18,966	22,101	.781	>31	24,756	.697
Packaged shell stoker	1	16,935	19,461	.887	>31	21,738	.794
Packaged shell FBC	1	17,199	18,701	.923	>31	21,432	.806
Field erected stoker	1	16,088	21,375	.808	>31	25,143	.687
Field erected FBC	1	16,339	21,019	.821	>31	25,086	.688
Pulverized coal boiler	1	15,941	21,462	.804	>31	25,750	.671
Circulating FBC	1	16,138	22,038	.783	>31	26,786	.645

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USAF ACADEMY: USAFA

1. BACKGROUND

The USAF Academy is located 10 miles north of Colorado Springs, Colorado. There are two boiler plants of significance at the Academy, both of which produce pressurized hot water. Natural gas is the primary fuel, and No. 5 fuel oil (150,000 MBtu/gal) is the reserve fuel. All boilers are water-tube type, and were designed for No. 5 oil/gas firing. Only plant No. 2560 was considered in the LCC analysis. The yearly average fuel use at plant No. 2560 is roughly 64 MBtu/h.

2. HEATING PLANT UNITS

<u>Heating Plant No. 2560</u>:

3 × 100 MBtu/h, Combustion Engineering, 1957
80 MBtu/h, Boiler Engineering and Supply Co., 1968

<u>Heating Plant No. 8026</u>:

2 × 30 MBtu/h, Combustion Engineering, 1957

3. IDEAL CAPACITY FACTOR ANALYSIS

The ideal capacity factors listed below were calculated from monthly fuel-use data for plant No. 2560.

Fuel input (MBtu/h)	FY 1986 ideal capacity factor	FY 1987 ideal capacity factor
50	0.87	0.90
60	0.82	0.86
70	0.79	0.81
80	0.75	0.76
90	0.70	0.72
100	0.64	0.65
110	0.58	0.59

4. ENERGY PRICES

<u>FY 1986 Price Data</u>:

Electricity = 3.5¢/kWh at year end
Natural gas = $3.8/MBtu
No. 5 oil = very little purchased

C. H. Guernsey and Co. Survey:

Electricity = 3.5¢/kWh
Natural gas = $3.5/MBtu
No. 5 oil = no value given

Letter from USAF Academy (10/5/88):

Electricity = 3.76¢/kWh
Natural gas = $2.56/MBtu
No. 5 oil = $0.65/gal = $4.33/MBtu

The gas contract is interruptible, but the gas supply is rarely interrupted.

5. COAL PROPERTIES AND PRICES

	Stoker	ROM
Origin	Axial, Colo.	Axial, Colo.
HHV, Btu/lb	11,000	10,700
% Ash	4.3	4.9
% Sulfur	0.42	0.36
% Nitrogen	1.39	1.39
Ash-softening temperature, °F	2300	2300
Swelling index	0	0
Top size, in.	1 1/2	2
Bottom size, in.	3/8	0
Fines, %		10–15
Grindability index	50	50
Cost at mine, $/ton	22	15
Delivered cost, $/ton	32	25
Energy cost, $/$10^6$ Btu	1.45	1.17

6. ENVIRONMENTAL REGULATIONS

6.1 Air Pollution Emission Limits for New Sources

SO_2. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: FBC – 90% reduction to meet limit of 1.2 lb/MBtu; emerging technology – 50% reduction to meet limit of 0.6 lb/MBtu.

NO_x. No emission limits for boilers <100 MBtu/h; for boilers >100 MBtu/h: spreader stoker and FBC – 0.6 lb/MBtu; pulverized coal – 0.7 lb/MBtu.

Particulates. For boilers >100 MBtu/h: 0.05 lb/MBtu.

6.2 Coal-Pile Runoff

Limit: Total suspended solids – 50 mg/L.

6.3 Ash Disposal

Ashes may be disposed of in special disposal sites owned by private contractors with a permit called "Certificate of Designation."

7. OTHER CONSIDERATIONS

Heat plant No. 2560 is capable of producing 425 psig hot water but operates at about 185 psig. The design pressure for heat plant No. 8026 is 275 psig.

8. COAL-CONVERSION PROJECT OUTLOOK

A coal refit/replacement project would involve the 80-MBtu/h output (~100-MBtu/h fuel input) unit in plant No. 2560. The overall capacity factor for a project of this size is estimated to be 58%, assuming 90% availability.

8.1 Effect of Environmental Regulations on Selection of Combustion Technologies

SO_2 and NO_x. Any of the combustion technologies being considered could be employed without requiring any measures for NO_x or SO_2 reduction since the proposed conversion project is smaller than 100 MBtu/h.

Particulates. Bag filters or electrostatic precipitators would be required to comply with the particulate emission limits.

8.2 Physical Space and Aesthetics

Heating Plant. The existing boiler plant was originally designed for No. 5 oil. There is only space available for installing coal-water-mixture combustion equipment at the existing boiler or for construction of a new boiler at another site on base.

Coal-Handling Equipment. There is no space available for installing dry coal-handling equipment at the existing boiler plant, but there is enough space for installing coal-water-mixture equipment.

Coal Pile. There is no space available for a coal pile at the existing boiler plant, but there is space at another site on base for a coal pile and a new coal-fired boiler.

8.3 Technical Risk of Combustion Technologies

The existing boilers are designed for No. 5 oil or gas firing. The technical risk is fairly high because of limited experience of coal-water-mixture firing of No. 5 oil-designed boilers.

9. COGENERATION PROJECT OUTLOOK

Cogeneration would probably not be economical at this base because of the low electric power rates.

10. INPUT AND LCC SUMMARY SPREADSHEETS

USAF ACADEMY: 1 X 80 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 80.0 MBtu/hr
Boiler capacity factor = .580
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 3.60
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.56
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.049	.043
Sulfur fraction =	.004	.004
HHV (Btu/lb) =	10700.	11000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.17
Stoker coal ($/MBtu) = 1.45
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	3.89	8.87	5.77	5.77
Oil	eoil	4.86	7.87	4.16	4.16
Coal	ecoal	1.16	2.31	1.19	1.19

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USAF ACADEMY: 1 X 80 MBtu/hr, ECONOMIC PARAMETERS = NOMINAL VALUES

Total steam output = 80.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .580   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	ANNUAL COSTS MAINT O & M k$	ANNUAL COSTS OTHER O & M k$
Natural gas boiler	--	.800	2.56	.0	1300.7	214.2	522.7
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1864.7	214.2	522.7
Micronized coal refit	1	.800	1.17	3469.2	594.5	436.9	692.0
Slagging burner refit	1	.800	1.17	5951.8	594.5	436.9	692.0
Modular FBC refit	1	.790	1.17	6828.9	602.0	415.0	675.1
Stoker firing refit	1	.760	1.45	3815.8	775.5	415.0	665.0
Coal/water slurry	1	.750	3.00	3552.0	1625.9	415.0	587.8
Coal/oil slurry	1	.780	3.50	2996.5	1823.9	330.5	560.6
Low Btu gasifier refit	2	.679	1.45	6668.1	868.5	382.8	901.1
Packaged shell stoker	2	.760	1.45	5720.5	775.5	415.0	762.4
Packaged shell FBC	2	.760	1.17	7205.4	625.7	415.0	773.0
Field erected stoker	1	.800	1.45	8663.7	736.7	412.5	656.6
Field erected FBC	1	.800	1.17	9561.0	594.5	482.0	675.0
Pulverized coal boiler	1	.820	1.17	10107.7	580.0	487.0	706.6
Circulating FBC	1	.810	1.17	11575.8	587.1	412.5	734.1

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	AIR FORCE PROJECT BENEFIT/ COST RATIO	AIR FORCE PROJECT DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	PRIVATE PROJECT BENEFIT/ COST RATIO
Natural gas boiler	--	--	28,827	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	34,380	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boiler was designed for #5 oil						
Coal/water slurry	1	25,325	26,416	1.091	22.7	28,892	.998
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	2	24,310	21,623	1.333	13.3	25,020	1.152
Packaged shell FBC	2	24,992	21,534	1.339	13.9	25,651	1.124
Field erected stoker	1	23,095	22,847	1.262	16.4	27,710	1.040
Field erected FBC	1	23,742	23,024	1.252	17.1	28,329	1.018
Pulverized coal boiler	1	23,163	23,632	1.220	18.3	29,220	.987
Circulating FBC	1	23,449	24,460	1.179	20.1	30,786	.936

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USAF ACADEMY: 1 X 80 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 80.0 MBtu/hr
Boiler capacity factor = .580
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 3.60
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.56
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.049	.043
Sulfur fraction =	.004	.004
HHV (Btu/lb) =	10700.	11000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.17
Stoker coal ($/MBtu) = 1.45
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = egas
Type of oil escalation = eoil
Type of coal escalation = ecoal
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	egas	2.28	4.70	5.49	2.75
Oil	eoil	.17	4.16	5.55	2.77
Coal	ecoal	1.46	1.76	1.61	.81

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USAF ACADEMY: 1 X 80 MBtu/hr, FUEL REAL ESCALATION = AEO 1987

Total steam output = 80.0 MBtu/hr   Cost base year = 1988

Boiler capacity factor = .580   Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.56	.0	1300.7	214.2	522.7
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1864.7	214.2	522.7
Micronized coal refit	1	.800	1.17	3469.2	594.5	436.9	692.0
Slagging burner refit	1	.800	1.17	5951.8	594.5	436.9	692.0
Modular FBC refit	1	.790	1.17	6828.9	602.0	415.0	675.1
Stoker firing refit	1	.760	1.45	3815.8	775.5	415.0	665.0
Coal/water slurry	1	.750	3.00	3552.0	1625.9	415.0	587.8
Coal/oil slurry	1	.780	3.50	2996.5	1823.9	330.5	560.6
Low Btu gasifier refit	2	.679	1.45	6668.1	868.5	382.8	901.1
Packaged shell stoker	2	.760	1.45	5720.5	775.5	415.0	762.4
Packaged shell FBC	2	.760	1.17	7205.4	625.7	415.0	773.0
Field erected stoker	1	.800	1.45	8663.7	736.7	412.5	656.6
Field erected FBC	1	.800	1.17	9561.0	594.5	482.0	675.0
Pulverized coal boiler	1	.820	1.17	10107.7	580.0	487.0	706.6
Circulating FBC	1	.810	1.17	11575.8	587.1	412.5	734.1

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT: LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	22,246	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	27,897	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boiler was designed for #5 oil						
Coal/water slurry	1	25,325	26,157	.850	>31	28,627	.777
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	2	24,310	21,500	1.035	24.7	24,893	.894
Packaged shell FBC	2	24,992	21,435	1.038	24.8	25,548	.871
Field erected stoker	1	23,095	22,730	.979	>31	27,589	.806
Field erected FBC	1	23,742	22,929	.970	>31	28,232	.788
Pulverized coal boiler	1	23,163	23,540	.945	>31	29,125	.764
Circulating FBC	1	23,449	24,366	.913	>31	30,690	.725

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USAF ACADEMY: 1 X 80 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 80.0 MBtu/hr
Boiler capacity factor = .580
Number of units for refit = 1
Hydrated lime price($/ton) = 40.00
Ash disposal price ($/ton) = 10.00
Electric price (cents/kWh) = 3.60
Labor rate (k$/yr) = 35.00
Limestone price ($/ton) = 20.00

FUEL PRICES

Natural gas price ($/MBtu) = 2.56
#2 Oil price ($/MBtu) = .00
#6 Oil price ($/MBtu) = 3.67

OPTIONS

Soot blower multiplier = 1.0
Tube bank mod multiplier = 1.0
Bottom ash pit multiplier = 1.0
SO2 control multiplier = .0

LIMESTONE/LIME

Inert fraction = .05

COAL PROPERTIES

	R.O.M.	Stoker
Ash fraction =	.049	.043
Sulfur fraction =	.004	.004
HHV (Btu/lb) =	10700.	11000.

FUEL PRICES

R.O.M. coal ($/MBtu) = 1.17
Stoker coal ($/MBtu) = 1.45
Coal/H2O mix ($/MBtu) = 3.00
Coal/oil mix ($/MBtu) = 3.50

Primary fuel is 3
NATURAL GAS
1=#6 Oil, 2=#2 Oil, 3=NG

ECONOMIC PARAMETERS

Inflation & discounting base year = 1988
Gen infla index (1987 to base yr) = 1.040
Gas infla index (1988 to base yr) = 1.000
Oil infla index (1988 to base yr) = 1.000
Coal infla index (1988 to base yr) = 1.000
Project start year = 1990
Project life (yr) = 30
Depreciation life (yr) = 15
General inflation rate (%/yr) = 0
Type of gas escalation = zero
Type of oil escalation = zero
Type of coal escalation = zero
Discount rate (%/yr) = 10
Rate of return on invest (%/yr) = 17
Amount of working capital (month) = 2
Federal income tax rate (%) = 34
Local prop tax (& insur) rate (%) = 2

		REAL ESCALATION RATE (%/yr)			
FUEL	TYPE OF FUEL ESCALATION	1988 -1990	1990 -1995	1995 -2000	2000 AND BEYOND
Gas	zero	0	0	0	0
Oil	zero	0	0	0	0
Coal	zero	0	0	0	0

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USAF ACADEMY: 1 X 80 MBtu/hr, FUEL REAL ESCALATION = ZERO

Total steam output = 80.0 MBtu/hr Cost base year = 1988

Boiler capacity factor = .580 Primary fuel = NATURAL GAS

Number of units for refit = 1

TECHNOLOGY	# OF UNITS	FUEL/ STEAM EFF	FUEL PRICE $/MBtu	TOTAL CAPITAL k$	ANNUAL COSTS FUEL k$	MAINT O & M k$	OTHER O & M k$
Natural gas boiler	--	.800	2.56	.0	1300.7	214.2	522.7
#2 Oil fired boiler	--	.800	.00	.0	.0	.0	.0
#6 Oil fired boiler	--	.800	3.67	.0	1864.7	214.2	522.7
Micronized coal refit	1	.800	1.17	3469.2	594.5	436.9	692.0
Slagging burner refit	1	.800	1.17	5951.8	594.5	436.9	692.0
Modular FBC refit	1	.790	1.17	6828.9	602.0	415.0	675.1
Stoker firing refit	1	.760	1.45	3815.8	775.5	415.0	665.0
Coal/water slurry	1	.750	3.00	3552.0	1625.9	415.0	587.8
Coal/oil slurry	1	.780	3.50	2996.5	1823.9	330.5	560.6
Low Btu gasifier refit	2	.679	1.45	6668.1	868.5	382.8	901.1
Packaged shell stoker	2	.760	1.45	5720.5	775.5	415.0	762.4
Packaged shell FBC	2	.760	1.17	7205.4	625.7	415.0	773.0
Field erected stoker	1	.800	1.45	8663.7	736.7	412.5	656.6
Field erected FBC	1	.800	1.17	9561.0	594.5	482.0	675.0
Pulverized coal boiler	1	.820	1.17	10107.7	580.0	487.0	706.6
Circulating FBC	1	.810	1.17	11575.8	587.1	412.5	734.1

TECHNOLOGY	# OF UNITS	COAL USE, ton/yr	AIR FORCE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO	DISCOUNTED PAYBACK PERIOD, yr	PRIVATE PROJECT LIFE CYCLE COST, DISCOUNTED AS SPENT k$	BENEFIT/ COST RATIO
Natural gas boiler	--	--	16,122	1.000	<--- Existing system, primary fuel		
#2 Oil fired boiler	--	--	0	--			
#6 Oil fired boiler	--	--	20,515	--			
Micronized coal refit	Not applicable because of space limitations						
Slagging burner refit	Not applicable because of space limitations						
Modular FBC refit	Not applicable because of space limitations						
Stoker firing refit	Not applicable because existing boiler was designed for #5 oil						
Coal/water slurry	1	25,325	23,893	.675	>31	26,298	.613
Coal/oil slurry	Not evaluated						
Low Btu gasifier refit	Not applicable because of space limitations						
Packaged shell stoker	2	24,310	20,420	.790	>31	23,782	.678
Packaged shell FBC	2	24,992	20,563	.784	>31	24,652	.654
Field erected stoker	1	23,095	21,703	.743	>31	26,534	.608
Field erected FBC	1	23,742	22,101	.729	>31	27,380	.589
Pulverized coal boiler	1	23,163	22,732	.709	>31	28,295	.570
Circulating FBC	1	23,449	23,549	.685	>31	29,849	.540

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