THE POTENTIAL FOR USING GEOTHERMAL ENERGY

FOR SPACE COOLING AT
WILLIAMS AIR FORCE BASE, ARIZONA

 EG&G

PRELIMINARY DRAFT

THE POTENTIAL FOR USING GEOTHERMAL ENERGY

FOR SPACE COOLING AT

WILLIAMS AIR FORCE BASE, ARIZONA

PRELIMINARY DRAFT

AUTHORS AND ACKNOWLEDGEMENTS

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This study analyzes the feasibility of geothermal project development at Williams Air Force Base, Arizona, using the deep hydrothermal resource <u>believed to underlie or</u> be in near proximity to the base. The analysis focuses on a district chilled water loop providing space cooling to most of the central base area. Economic feasibility is presented in conventional terms as well as in relation to DOD's Energy Conservation Investment Program (ECIP). Less comprehensive analyses are also included for alternative energy supply systems including solar, coal, and geothermal electric.

The report includes an assessment of present and projected energy use and distribution systems, a geologic and reservoir evaluation, an examination of drilling options and costs, a discussion of alternative energy systems development including economic evaluations, an identification of regulatory concerns, with conclusions and recommendations.

In view of the considerable sums of public funds implicit in developing extensive alternate energy systems at the base and the important policy decisions involved, caution has been taken to rely on conservative assumptions and cost projections in the calculation of economic benefits. In calculating benefits according to the ECIP format, for example, we have assumed only an 8 percent annual real price increase for purchased electricity at the base. We also neglected recurring material and labor benefit differentials, electricity demand charge reductions, and fuel displacement in a hospital auxiliary boiler. Included in project costs were a 25 percent project contingency and a 6 percent A&E contingency.

The total energy cost for Williams AFB in 1978 was $1.8 million, with the nonhousing cost being $1.3 million. The high price of electricity accounts for approximately 80% of the total base energy cost. The installation's *present* annual energy requirements are approximately 169,000 million BTUs from electricity and 161,000 million BTUs from natural gas. Most of the purchased electrical power is used to supply space cooling requirements. The central base area, including the flight simulator buildings, hospital, BX, commissary, BOQ and BEQ, community activities area, and offices comprise about 850,000 square feet of conditional space within a half square mile area. The total

installed load in the central base area approximates a 4300-ton cooling
and 86.5 million BTU/hr heating requirement. A 16 percent rise in
electrical rates will cause a price increase from $470,172 in 1978,
to $545,000 in 1979 for the cooling energy bill for the central area.
During the cooling season, peak demands escalate the rate at which
electrical power is purchased. Coupled with the population growth of
the Phoenix area (85% to 1985), the efficient use of electric power
is a prime concern. A geothermal resource that could provide space
cooling and heating could greatly reduce the base's total purchased
energy demand and ensure lower electrical rates by reducing peak demand.

The base is situated in the southwestern half of the Higley basin.
Gravity data for the area suggests a depth of 16,000 feet to the
Precambrian basement. The stratigraphic sequence is believed to consist
of an upper sedimentary section and a lower pre-basin volcanic section.
Static water levels at the base are 200-400 ft. *below the surface.* Geothermal Kinetics,
Inc. (GKI) has drilled two wells 2 1/2 miles southwest of the base,
the deepest being 10,454 feet. Temperature data indicate that tem-
peratures in excess of 100°C (212°F) can be expected below 7,000 feet
and that temperatures in excess of 150°C (302°F) can be expected below
9,000 feet. Temperatures approaching 200°C (392°F) might be expected
at depths of 10,000 to 11,000 feet. Recoverable water has been esti-
mated at 29 million acre-feet in the upper basin fill and 900,000 acre-   *recoverable*
feet in the volcanic sequence. Due to this volcanic sequence, withdrawal   *not*
from the deep aquifer system could be achieved without accompanying   *proven*
ground surface *subsidence.* The potable water supply can be adequately
protected by casing the production well(s) and injecting well below
the near surface aquifer system.

Drilling costs have been estimated for a new 10,000 feet production
well (WP-1 or WP-2 on Plate 1) on base property. Ideally, the well
should be located as near as possible to the cooling system loop in
order to minimize fluid distribution line costs. Production well
costs would total $1.933 million, exclusive of contingency. One well
should suffice for production of the required 900 gpm flow rate   *conjecture*
(assuming 350°F) with the existing energy supply system available   *on flow rate
and temperature*

for backup. An injection well, (WR-1) drilled to approximately
5,000 feet would cost about $758,000. An alternative resource develop-
ment option would be to use the existing GKI wells (see Plate), assuming
negotiations could be completed with private parties. Well purchase
and refurbishing costs, including sidetracking the original wellbore~~base~~
by directional drilling, would approximate $2.670 million.

[margin handwriting: not certain to produce]

The district cooling system is based on centralized lithium-
bromide absorption water chillers located within a perimeter loop
circulating chilled water through existing coils located in the
building^of the central area. Six chillers and cooling towers would
supply the required 4300 tons. Accrued energy savings with this system
would be about 168,000 million BTU (pre-generation) or 49,000 million
BTU (purchased electricity). This basic distribution system would be
the same whether fluid production was from the WP or GKI wells. In
either case, injection is assumed to be possible within 1/2 mile of
the perimeter loop.

[margin handwriting: Assuming a successful well and no major reservoir problems]

A heat pump system, based on developing geothermal fluid from an
intermediate depth (~5000) well was evaluated and determined to be
uncompetitive with the deep well options.

[margin handwriting: no indication of risk on deep wells]

Total project costs would be $7.828 million for the most promising
case based on a production well near the perimeter loop. (Excluded
are costs that may be associated with geophysical studies prior to deep
drilling, as well as costs for preliminary and final design.) The
benefit/cost ratio is 1.39, and the energy-to-cost ratio is 23.17.
Based on a 10%, ten-year amortization schedule, total project benefits
are $30.8 million over 25 years, with system payback coming at the
16th year. The development predicated on the GKI wells is less
favorable (B/C = 1.15 and E/C = 19.1) because of the higher well
and piping costs (estimated total capital $9.484 million), and some-
what higher electrical pumping requirements. In this case, we have
also neglected royalty payments which might be 10 percent, based on a
BTU equivalency with alternate fuels.

At the present time, the solar system options for providing the
hot water does not look competitive. Requiring a collector area not
less than 25 acres, the capital, contingency, and operating costs (based
on a similar 10-year, 10 percent schedule) are such that project savings
at the end of 25 years is still $7 million less than project costs.

System payback occurs at the 27th year.

An alternative worth noting is the possibility of geothermal electric development at Williams, probably based on a binary power cycle, provided a resource between 350° and 400°F can be obtained. Project costs scaled-down from a 50 MWe plant to a 9 MWe power plant for the base electric demand, suggest a $ million project, including design as well as project and A&E contingenc~~y~~ies. Using the ECIP format, the benefit/cost ratio is about ~~2.02~~ *1.70* and the energy/cost ratio is 26.01, both higher than the best central chiller system. *The option to pursue geothermal electric development is totally dependent upon the temperature and flow volume of fluids present and accessed by the drill holes.*

It is apparent at this point that geothermal energy development at Williams Air Force Base can and ought to be pursued further, at least programmed through the drilling phase. Life cycle energy cost savings can be achieved in two, perhaps three of the options discussed in this report. If the project were strictly a commercial, private venture, the previous statement would have to be balanced against a considerably longer payback period than the 5-year or so nominal payback expected in the private industrial sector. In addition to achieving significant life cycle energy savings and decreased consumption of conventional fuels at a major defense installation, the project, if successful, would provide an important stimulus to private geothermal exploration and development throughout the rapidly growing southern Arizona metropolitan areas.

irrelevant

011

INTRODUCTION

The purpose of this report is to assess the feasibility of using the geothermal energy source *thought to be present* at Williams Air Force Base, Arizona. The energy source would be used with existing technology to meet cooling and heating requirements for major existing and proposed buildings in the central base area.

The economics of replacing conventional cooling systems with geothermal resource systems are particularly applicable to Williams Air Force Base due to a combination of the steadily increasing electrical utility rates, the replacement of many separate energy-inefficient buildings with consolidated complexes, and an emphasis on using simulator facilities for pilot training.

Williams Air Force Base is located in south-central Arizona, nine miles east of Chandler and approximately 35 miles southeast of Phoenix. The base is the largest undergraduate pilot training base in the Air Force Air Training Command, providing flying training both in the T-37 and the T-38 jet aircraft. The configuration of facilities on the base is very similar to that of light industrial parks which are commonly found throughout the United States and in the Phoenix area. The principal high-investment facilities on base are community support buildings (hospital, service clubs, base exchange/commissary complex), bachelor housing units, and simulator/training facilities. The base has a daytime population of 10,300.

The climate is of a desert type, with low annual rainfall and low relative humidity. Daytime temperatures are high throughout the summer months, while winters are mild. The average daytime relative humidity is about 30 percent, and the valley floor, in general, is rather free of wind. The period of sunshine averages 86 percent annually, ranging from a minimum monthly average of 77 percent in January and December to a maximum of 94 percent in June. A six-year annual average of cooling degree days is approximately 3,950, while the similar period average heating degree days were 1,350.

Due to ever-expanding residential areas and industrial growth, the Phoenix-Superstition Mountain area surrounding Williams AFB should be an area of high potential for using alternate energy sources to supplement a growing population and burgeoning energy demand. There are over 1,020,000 people in the Phoenix urban area northwest of Williams AFB. Williams AFB is directly located within an active geothermal resource area (both low and high temperature), and any application of geothermal resources would demonstrate the potential for the use of similar systems in the Phoenix area.

I.   ENERGY USE AND DISTRIBUTION SYSTEMS AT WILLIAMS AFB

A.   Present Energy Use

The primary requirement for energy at Williams AFB comes from heat-
ing and cooling. Heating is provided to each facility by natural gas
for individual boilers. Cooling is provided to individual facilities
or pairs of common facilities, using electricity to produce and circulate
chilled water. Only the hospital has an alternate fuel source - oil.
During infrequent power failures, small local generators provide power
to key facilities. No central standby generation station exists. At
present, there is no central heating or cooling plant at Williams AFB,
although a plant is programmed for the FY 85 Military Construction Program
(MCP) that could be moved into an earlier year.

The installation's present annual energy requirements are approxi-
mately 169,000 million BTUs from electricity and 161,000 million BTUs
from natural gas. The total cost for all facility energy usage was
$1.8 million, with the nonhousing energy cost being $1.3 million. The
high price of electricity accounts for approximately 80% of the total
energy cost. Do to the increasing prices for electricity and gas, and
due to changing rate schedules, Williams AFB is faced with an escalating
cost for heating and cooling buildings. A 16% rise in electrical rates
will cause a price increase from $470,172 in 1978 to $545,400 in 1979,
and an approximate 40% rise in cost per therm will increase the natural
gas cost by $100,000.

Williams AFB has been reducing energy consumption by eliminating
many of the World War II structures on base. Replacement facilities
and future construction are proposed to use consolidated structures or
complexes. This would replace many separate facilities with one or two
structures. These complexes, along with several existing major facilities
which are already grouped together, are more efficient in their use of
energy on base and also lend themselves to a central heating-cooling
plant system.

The facility replacement program should continue to ensure that the base's overall energy consumption remains at least constant. Based on current and predicted future tight supplies of natural gas and electricity, energy supplies should be presumed to be finite. Although the Williams AFB electrical distribution system has sufficient capacity to handle increased electrical loads, the availability of electricity may be questionable. During the cooling season, peak demands escalate the rate at which electrical power is purchased. Coupled with the Phoenix area's population growth (base year 1970) of 45% to 1978, and a projected growth of 85% to 1985, the efficient use of electrical power is a prime concern. A geothermal resource that provides space heating and cooling could both greatly reduce the base's total purchased energy demand and could also ensure lower electrical rates by reducing the base's peak energy demand.

B.   Present Systems

As shown in Figure 1, the base is effectively divided into three areas: housing and recreation, central base activities, and flightline-support runway. Of prime interest to this study is the high energy load of the central base area, shown in Figure 2, which consists of: 1) bachelor officer quarters (BOQ) area, 2) bachelor enlisted quarters (BEQ) area, 3) flight training-simulators, 4) hospital, 5) base exchange-commissary complex, 6) community activities area, and 7) administrative-support facilities (see area map). As noted from the map, most facilities are grouped together into specific use areas, with the flightline-support facilities acting as the boundary between aircraft operations and the rest of the base.

The main use of energy within the central base area is space conditioning. Flight training-simulator facilities require additional cooling for equipment, while the flightline-support facilities utilize steam and heating for light industrial applications similar to off-base industrial parks.

FLIGHTLINE & RUNWAYS

CENTRAL BASE

HOUSING

HOUSING & RECREATION
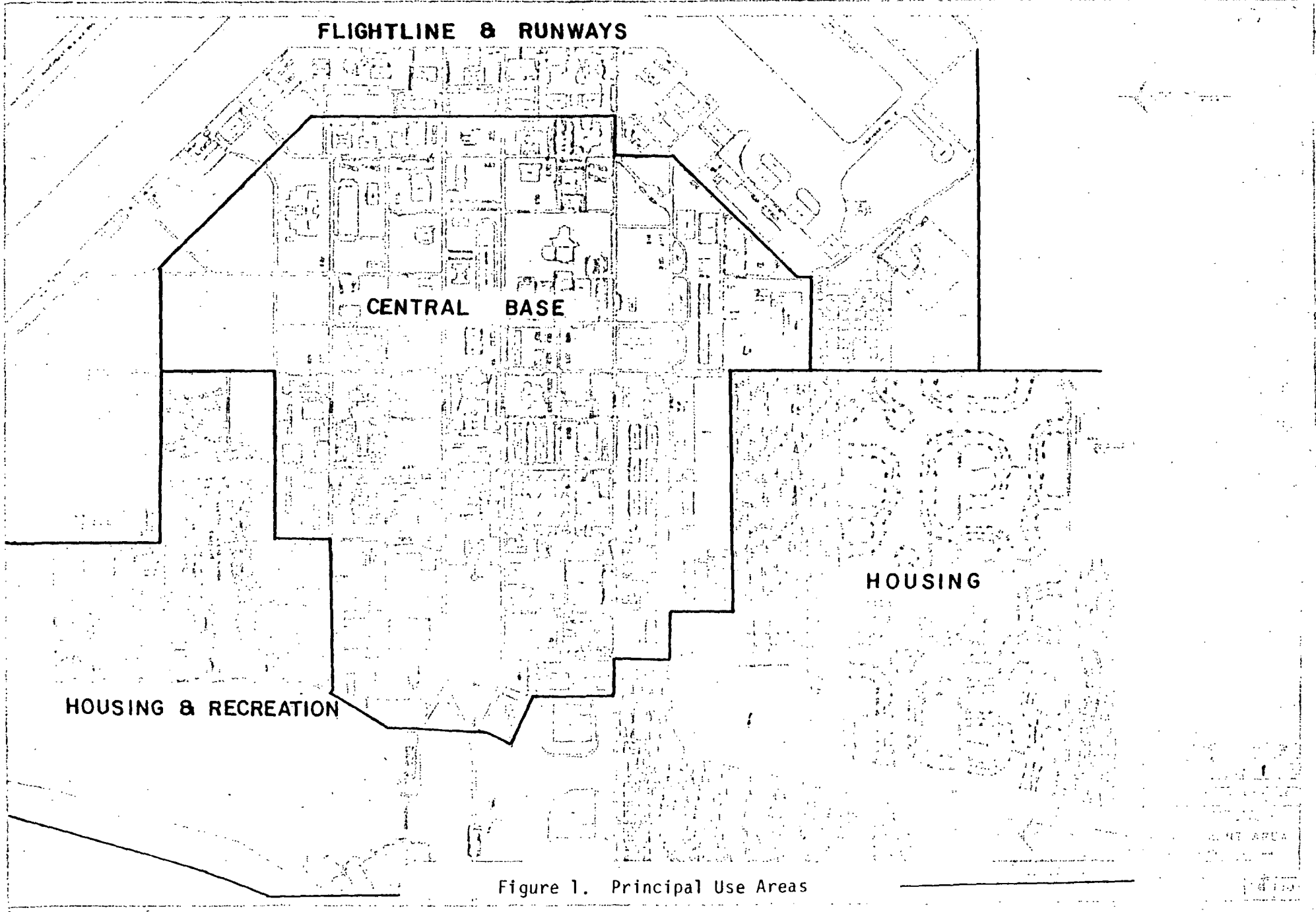
Figure 1. Principal Use Areas
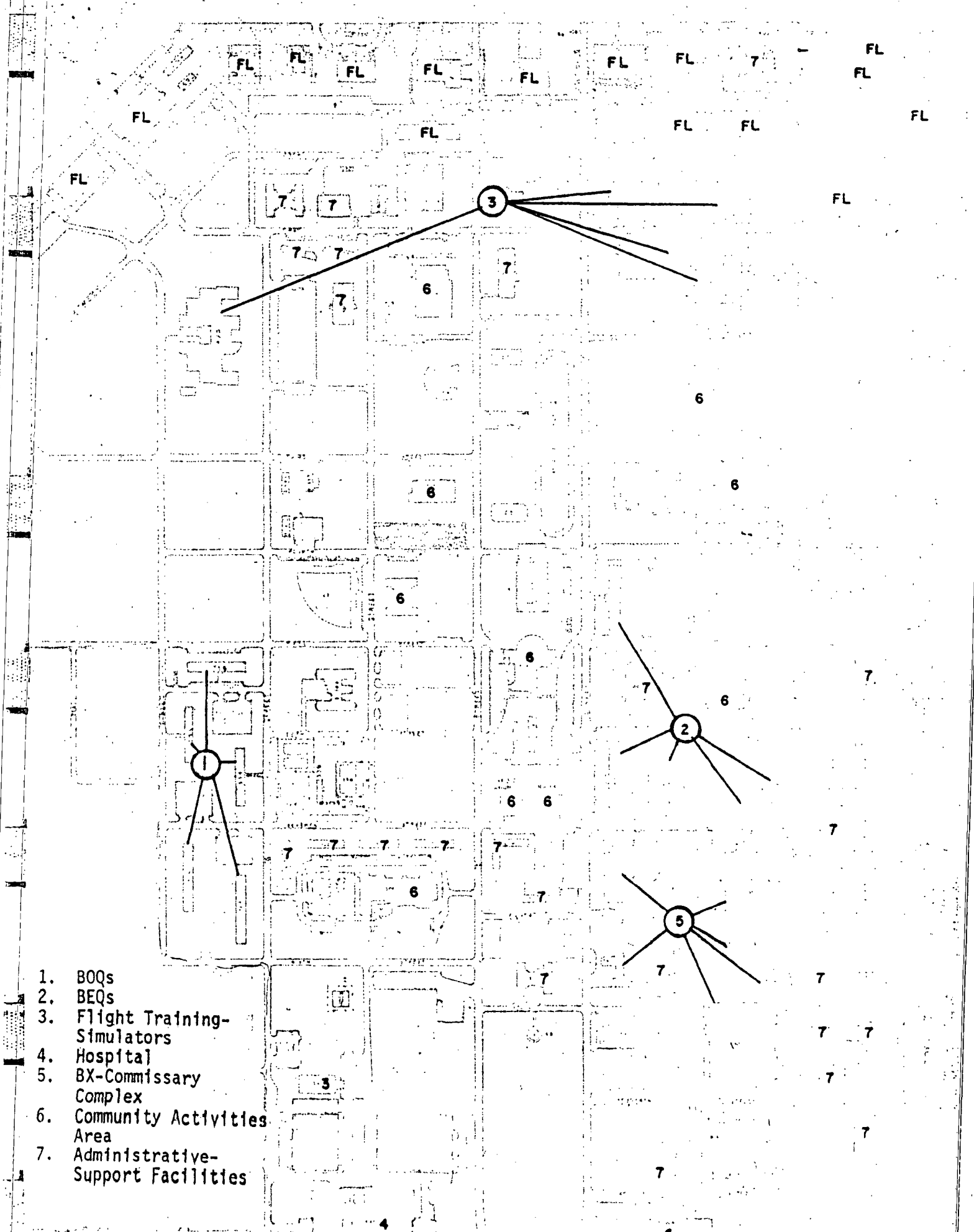
1. BOQs
2. BEQs
3. Flight Training-
   Simulators
4. Hospital
5. BX-Commissary
   Complex
6. Community Activities
   Area
7. Administrative-
   Support Facilities

Figure 2. Central Base Area Facilities

The cooling required by the present major groupings of buildings is:

		Total
1.	BOQ area (5 buildings)	155 tons
2.	BEQ area (5 buildings)	275 tons
3.	Flight training-simulators (6 buildings)	1,150 tons (1,438 tons max)
4.	Hospital (1 building)	430 tons
5.	BX-commissary complex	594 tons

The community activities areas and administrative-support facilities are scheduled for replacement by MCP projects. When the new consolidated complexes are constructed in the east and southeast portions of the central base area, the major facilities of the base will form a U-shaped loop extending from the base's main gate on the west to the flightline on the east.

II.   HYDROTHERMAL RESERVOIR ASSESSMENT

A.   General Geology

Williams Air Force Base is located in the southeastern portion of
Maricopa County, Arizona, just east of the town of Higley and approximately
thirty miles southeast of Phoenix. The base is situated in the south-
western half of the Higley basin (Scarborough and Peirce, 1978), a small
northwest trending basin approximately thirty miles long and fifteen
miles wide. The Higley basin is a part of the Basin and Range physiographic
province of southwestern Arizona. The basin is bounded on the north by
the Usery and Goldfield mountains; on the south by the Santan mountains;
on the east by the Superstition mountains; and on the west by the South
mountains. A study of the Bouguer gravity data for the area (Peterson,
1968) indicates that it could be as much as sixteen thousand-feet to the
Precambrian basement beneath the air base.

The stratigraphic sequence beneath the present valley surface is
believed to be divided into two parts: an upper sedimentary, or basin
fill section and a lower pre-basin volcanic section (see Figure B). The
sediments of the upper section, late Cenozoic in age, consist of coarse
clastics nearer the basin margins derived for the most part from the
surrounding mountains. Nearer the basin center lower energy deposits,
including evaporites, prevail. A portion of Cooley's map (1973) showing
the distribution and estimated thickness of the alluvial deposits in the
Phoenix area is reproduced as part of Plate 1 of this report. The American
Stratigraphic Company stratigraphic logs of Geothermal Kinetics, Inc.
(Plate 1, Figure 3)
Power Ranch No. 1 and 2 drill holes, drilled a few thousand feet south of
the southwest corner of the air base, show an excess of 6,600 feet of
basin fill sediments overlying what is believed to be the top of a volcanic
sequence correlative with the Superstition volcanic complex exposed in
nearby ranges (Stuckless and Sheridan, 1971). In outcrop the Superstition
volcanic complex has been dated as ranging between 15 and 29 million years
in age (Sheridan, 1978). Utilizing these volcanic rocks as a marker, they
have been relatively down dropped several thousands of feet by the late

GENERALIZED STRATIGRAPHIC LOG:
WILLIAMS A.F.B. MARICOPA COUNTY, ARIZONA

DEPTH

0'

1000'
— 1100'

2000'
— 2300'

3000'
— 3500'

4000'

5000'

6000'

— 6620-30'
7000'

8000'
— 8100'

9000'

10000'
— 10000'

— 10454', T.D.

Sandstone, conglomerate

Brown claystone with minor
siltstone and anhydrite

Brown siltstone
Brown and white anhydrite

Red and brown claystone
Siltstone and sandstone with minor anhydrite
in the upper part of section and tuff beds
in the lower part of the section

Top of Superstition (?) volcanic complex

Interbedded red-brown and gray dacite with
minor red and brown sandstone and siltstone

Dacite

Superstition Dacite
Gray and gray brown

Dacite - intense propylitic and weak (?)
argillic alteration to T.D.

WR-1 ⊙

WR-1
⊙

● WP-2

WILLIAMS AIR FORCE BASE

● WP-1

GKT-2 ●

GKT-1 ●

Fig 4

Cenozoic Basin and Range disturbance. It was this event that created
the Higley basin which became filled with basin fill sediments.

Of particular interest is the top of the Superstition volcanic complex
at 6,620 to 6,630, a ten-foot thick section of gray dacite. From 6,620
to approximately 8,100, the lithology is primarily gray dacite interbedded
with minor red, brown, and gray sandstone, siltstone and shale. The
possibility of contamination of the dacite drill cuttings by cuttings from
the overlying basin fill sedimentary section cannot be ruled out. From
8,100 to 10,454, the bottom of the deepest hole, Power Ranch No. 2, the
lithology is all dacite. The log of Power Ranch No. 2 shows a unit of
conglomerate and sandstone from 10,050 to 10,440. An examination of the
cuttings revealed only altered dacite, intense propylitic and weak (?)
argillic alteration, with some silicification. Confirmation of the con-
glomerate and sandstone, therefore, cannot be certain. It is thought that
the base of this massive dacite sheet was not encountered in either drill
hole.

Osterkamp (1973), on a map showing the depth to water in wells in
the Phoenix area, indicates the water level to be between 300 and 400 feet
in the area of Williams Air Force Base. A portion of Osterkamp's map is
reproduced as part of Plate 1 of this report. Information obtained from
the Civil Engineering Squadron at the base shows static water levels of
328 feet, 398 feet, and 411 feet for wells that are currently being
pumped. Well No. 1, which has been abandoned, has a standing water level
of approximately 212 feet. The water level in this abandoned well probably
reflects a perched water table overlying the main zone of groundwater.
Temperature gradient logging was done in this well to a depth of 328 feet.
From a depth of approximately 164 feet, the well was isothermal, with a
temperature of approximately 25°C (77°F).

high risk

The potential for developing geothermal energy at Williams Air Force
Base is excellent. Geothermal Kinetics, Inc., has drilled two wells just
southwest of the base; the deepest being 10,454 feet. Temperature data
furnished by Geothermal Kinetics, Inc. indicate that temperatures in
excess of 100°C (212°F) can be expected below depths of 7,000 feet and

that temperatures in excess of 150°C (302°F) may be expected below 9,000 feet. In fact, temperatures approaching 200°C (392°F) might well be expected at depths of 10,000 to 11,000 feet. The geothermal reservoir most likely will be in the dacitic volcanic rock. The product produced will be superheated water largely from fracture and possible porous pryoclastic zones in the dacite. This type of fracture controlled production *(if fracture porosity and permeability are adequate.)* may ~~will~~ be similar to other geothermal fields in the United States: the Geysers in California, Valles Caldera in New Mexico, and Roosevelt in Utah.

B. Reservoir Estimate

Williams Air Force Base lies within the eastern part of the Salt River Valley groundwater basin. Although this valley is now drained to the ocean by the Salt River, for most of its history the basin has had closed, internal drainage. For the purpose of this estimate, the reservoir area for the Air Force Base has been set at a 5-mile radius centered on the base.

1320' apart,

Two deep wells passing through the full thickness of basin-filling sediments into a volcanic sequence are found within this 5-mile radius. These wells have been assumed to represent the stratigraphic conditions beneath the Air Force Base. The average thickness of the sedimentary sequence was 6,800 feet, and about 3,600 feet of underlying volcanics was penetrated. Neither well encountered pre-volcanic rocks. The mean porosity and specific yield were computed by inspection of the well logs. For the basin fill, the mean porosity was about 20 percent, and specific yield was 10 percent. For the volcanic sequence, the mean porosity was 5 percent, and the specific yield was estimated as 0.5 percent. The water in the uppermost 1,000 feet of the basin fill is now used as agricultureal, municipal, and military water supply in the basin.

58 million The total water in storage within the 5-mile radius amounts to ~~5~~ million acre-feet in the basin fill, and 9 million acre-feet in the volcanic sequence. The upper 1,000 feet of the basin fill has been excluded.

Recoverable water amounts to 29 million acre-feet in the upper basin fill
and 900,000 acre-feet in the volcanic sequence.

Table _
Williams Air Force Base

Sediment Type	Thickness	Area	Porosity	Specific Yield
Basin fill	6,800 ft	78.5 mi.^{2}	20%	10%
Volcanics	3,600 ft	78.5 mi^2	5%	0.5%

Volume of basin fill............................340 million acre-feet
Volume of volcanics............................180 million acre-feet
Water in storage in basin fill.................. 58 million acre-feet
Water in storage in volcanics................... 9 million acre-feet
Fresh water in upper 1,000 ft................... 5 million acre-feet
Recoverable water in basin fill (net)........... 29 million acre-feet
Recoverable water in volcanics..................0.9 million acre-feet

Except for water in the upper 1,000 feet of sediments in the basin,
almost all groundwater in the basin may be expected to occur under confined
(artesian) conditions. Withdrawal of large volumes of geothermal water
from these aquifers may present the same problems as withdrawal of fresh
water under similar conditions. Subsidence resulting from groundwater pump-
ing has been well-documented in many parts of the southwest and is linked to
withdrawal of water from fine-grained, nonindurated sediments. Thus,
the volcanic sequence would not be susceptible to subsidence. An additional
problem involves protection of high quality water in the upper aquifers
from poor quality water produced from geothermal sources. The potable
water supply can be adequately protected using reasonable care and currently
available technology.

III.   RESOURCE DEVELOPMENT OPTIONS

The well development options discussed below are based on the geologic
and hydrologic information presented in the preceding chapter, as well
as on information obtained from the existing wells drilled by Geothermal
Kinetics, Incorporated (GKI).

A.   Drilling New Production Well

In the following chapter, which discusses project costs and payback,
the "Case A" economic analysis is premised on the economic advantages of
drilling a new production well (WP-1, -2 on Plate 1) to near the 10,000 ft depth and hopefully
obtaining a geothermal resource near 300°F. Ideally, the well (WP-1) should be
located as near as possible to the cooling system loop, in order to
minimize additional fluid distribution line costs. Figure 5 presents a
cross section of this new production well.

The well is designed as a vertical completed well, similar to the
existing GKI wells. It would be cased to 8,000 ft to seal out cooler
fluids. We would recommend drilling with mud to 8,000 ft and then using
water as a drilling fluid through the open-hole production interval, to
reduce wellbore damage. Water drilling, as opposed to using mud, has
become a good geothermal drilling practice because of the unstable mud
conditions created by high temperatures. If hole cleaning becomes a
problem, then occasional high viscosity mud "pills" can be pumped down
to clean the wellbore.

Costs associated with drilling a new 10,000ft production well are
as follow (in thousands $):

Figure 3. New Well Cross Section

				$	27
Site Preparation				$	27
Rig Mob-Demob					450
$7K/da for 60 da					420
Casing 20-in	$55/ft	2,500 ft			137
13-3/8-in	$25/ft	5,000 ft			125
9-5/8-in	$23/ft	8,000 ft (3,200 ft)			74
Casing Hardware					10
Liner Hanger					15
Wellhead					75
Mud Logger					50
Mud to 8,000 ft					100
Welding					5
Shocks & Sub-Jars					15
Casing Crews					15
Stabilizers					20
Cement					150
Bits					130
Logs					70
Coring (3) Two in dacite, one bottom hole					15
Testing					30

Total   `$1,933 K

B.   Reworking Existing GKI Wells

In considering the costs of reworking the existing GKI wells and,
in the following chapter, estimating life-cycle economics of using those
wells, we emphasize that we have not fully inquired into the business
or legal problems of acquiring those wells for use by the Air Force. Their
availability is simply a working assumption which enables us to make
cost and economic comparisons with alternative resource development
options.

Figure 6 represents the existing GKI wells and the directional drilling
technique to sidetrack the original wellbore. We suspect that damage
to the original wellbore through the production zone has been so severe
that cleanout methods would be very costly and probably ineffective.
This proposed sidetract method would use the existing wellbore to about
6,000 ft. The kickoff would be made in the 9-5/8-inch casing at that
point.

Directional drilling would commence, using a 2 to 6° buildup angle
to 8,000 ft where temperatures would approach 290°F. The casing would

Fig CROSS SECTION OF DIRECTIONAL DRILLING IN GKI WELLS

be 7 to 7-1/2-inch liner, hung inside the 9-5/8-inch casing. Directional drilling would continue with a 6-3/4-inch bit to total depth of 10,000 ft. The 7 to 7-1/2-inch OD casing should allow for the required production of 900 gpm. This technique would allow a separation of 200 to 400 ft between the old and new wellbores, which places the new wellbore well away from the contaminated area of the old wellbore.

The same sidetracking method could be applied in the lower portion of the 13-3/8-inch casing ($\sim$ 4,000 ft) to increase hole sizes for greater production capacity. This shallower sidetrack would also increase the well cost by $\sim$ $100,000.

The directional drilling technique described has been used for many years in oil well drilling, primarily to drill around tools and other "fish" obstructing the hole. New technology has expanded the use of directional drilling. At the Geysers in California directional drilling techniques are used to drill multiple holes from one platform. Multiple legs sidetracked from a single wellbore have been used as a stimulation method to enhance production in the Raft River, Idaho geothermal wells.

Assuming a purchase price for the wells at $1.4 million, costs associated with this development option are as follow:

Logs				$	15
Directional Drilling					25
Bits					18
Casing	7-inch	2,000 ft	$15/ft		30
Cement					50
Rig	(10,000-ft cap.)	20 da - $7,000/da			140
		Mob - Demob			350
Drilling Supervision					7
					635
		Two wells			1,270
		Assumed Purchase Price			1,400
				Total	$2,670 K

/ /6

C. Injection Well

In addition to the production well costs, an injection well will
be necessary to dispose of the geothermal fluids after heat extraction.
The injection well design, shown in Figure 7 has casing to shallower
depths than the production well. An injection depth of at least 3,700 ft
would be required to eliminate contamination of the groundwater aquifers
and reach a zone where formations would be permeable enough to accept
the fluid. This well design could also be used for shallow production
wells; however, existing data would indicate temperatures less than 150°F
at this intermediate depth.

Costs associated with the injection well are as follow (in thousands
$):

Site Preparation				$ 20
Casing	13-5/8-inch	1500 ft	$30 K	
	9-5/8-inch	3700 ft	63 K	93
Cement	13-5/8-inch		13 K	
	9-5/8-inch		17 K	30
Casing Hardware				7
Wellhead				50
Rig	$5K/da	35 da		175
	Mob - Demob			200
Drilling Supervision				13
Mud				35
Shock Sub-Jars				5
Casing Crews				10
Stabilization				10
Bits				50
Logs				35
Coring (1)				5
Testing				20
			Total	$758 K

17

INJECTION WELL CROSS SECTION

IV.   ALTERNATIVE GEOTHERMAL SYSTEMS DEVELOPMENT AND COSTS

In accordance with national goals to reduce fossil-fuel usage, Williams Air Force Base has been undertaking an active conservation program through replacement of older, inefficient WWII buildings, mandatory conservation practices, and projected goals of a centralized space conditioning system. A primary consumption of energy is through the cooling load supplied by expensive electricity, and the Base is now looking for a more suitable and abundant resource to supply this demand. Several alternatives are abundant in the area and would be available for long-range goals. Coal, solar, and geothermal resources are all viable alternatives that could supplant a large fraction of present energy usage. All of these sources are conventionally used for either direct or steam-generated firing of absorption-type cooling systems.

At the present time, electricity is supplying almost half of the end-consumptive energy, although the cost of this purchased power is nearly 80% of the total base energy cost. The generation of electrical power, therefore, could replace valuable fossil fuels, if generated with alternative resources. Again, coal, solar, and geothermal could be candidates for a power generation project. The high temperatures needed for conventional steam-expansion turbine generators would necessitate concentrating solar collector types, whose higher cost and special design problems have excluded their consideration in this report.

A.   Space Cooling Load

Most of the purchased electrical power is utilized to supply space cooling requirements. This analysis is based on using a centralized cooling system to supply the base's requirements. We excluded from con-sideration the housing areas to the north, west, and south, owing to the high initial capital cost of distribution piping relative to the low bene-fits of replacing a small percentage of the total cooling load. The central base area, including support buildings, hospital, commissary, Bx, maintenances, offices, etc., total approximately 850,000 square feet of

conditioned apace within a half square mile area. All existing buildings
with a cooling system larger than 5 tons were considered for connection
to the centralized space cooling district. The total installed load was
determined to be 4,300 tons cooling and 86.5 million Btu/hr heating within
the central base area.

All of the cooling load is met by electrically driven compression
expansion units, except for one small gas-fired steam absorption chiller
system in the hospital complex. Of the electrically driven units, nearly
90 percent are of the water-chiller type, with the remaining units of
the direct expansion forced-air type. Therefore, the most readily adaptable
centralized space cooling system would be of the water-chiller type to
match existing equipment, with modification of the few direct expansion
units to utilize chilled water. Existing building cooling systems will
remain intact, and presently assigned maintenance personnel will remain
to maintain the existing systems and operate the new centralized system.
Retaining the existing system will provide backup capability and "topping
off", if required, during extreme temperature days.

Many possibilities exist for the layout of piping and one such example
is shown in Figure 2. Final design of the layout would optimize piping
length, diameter, and configuration. As noted in Figure 2, a centralized
absorption water chiller is located within a perimeter loop circulating
chilled water to provide cooling through existing chilled water coils
located in the buildings. The absorption chillers will use water tempera-
tures up to 300°F, and provide chilled water at 43 to 45°F. The chillers
will be the lithium-bromide absorption type and will require a source of
cooling water provided by cooling towers. Included in the capital cost
calculations is a total of six absorption chillers and cooling towers.
The currently installed capacity of 4,300 tons, which includes some redun-
dancy, could be supplied by these six units under full load. Under partial
load conditions, the number of operating chillers can be reduced to most
effectively match required load conditions. Maintenance time and manpower
would also be minimized with a centralized central system. The absorption
chiller sizes selected have a coefficient of performance of approximately
65 percent. Double-staged absorber water chillers are currently on the
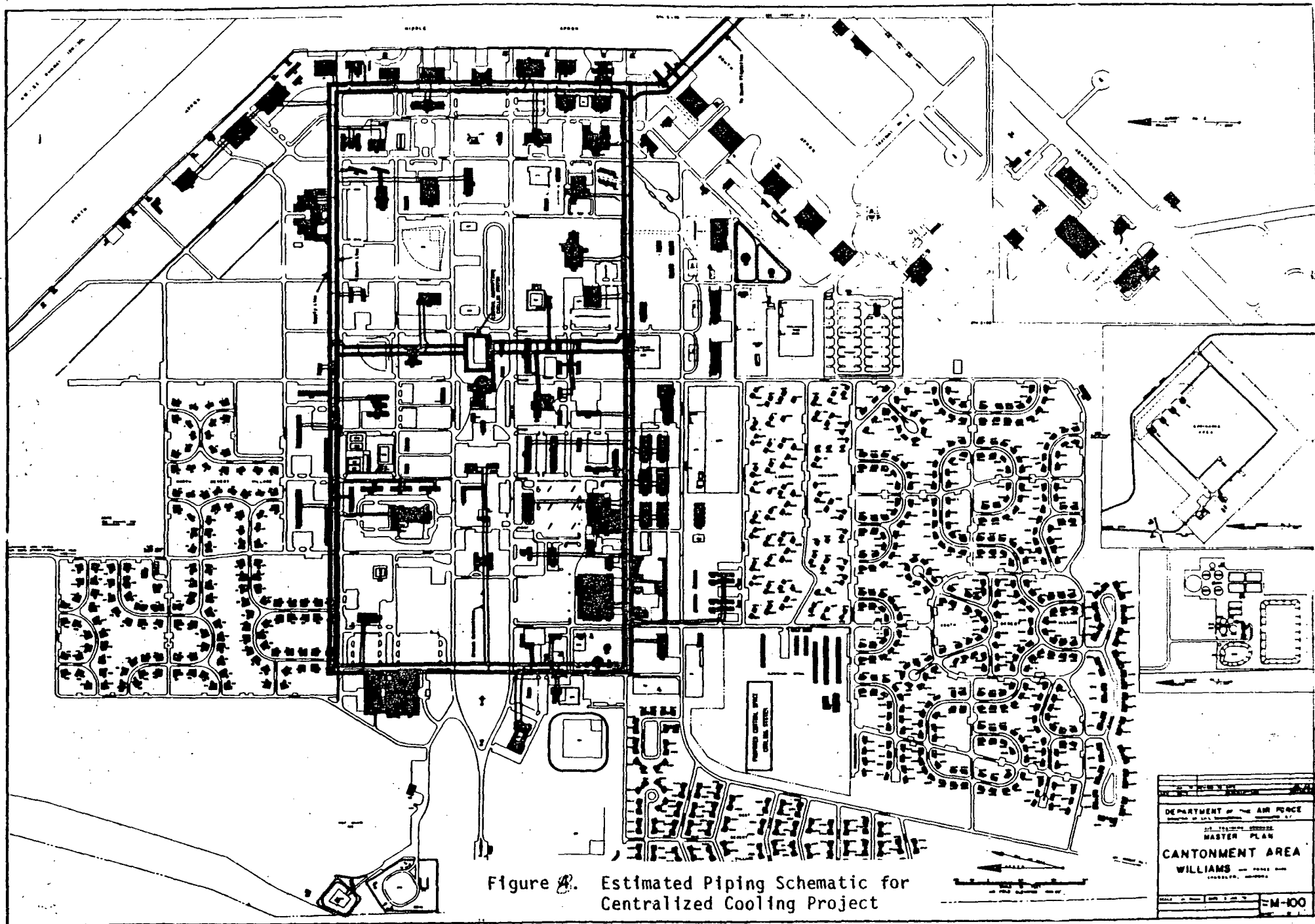
Figure 4. Estimated Piping Schematic for
Centralized Cooling Project

DEPARTMENT OF THE AIR FORCE

MASTER PLAN

CANTONMENT AREA

WILLIAMS

M-100

Fig 9.

EXAMPLE OF DISTRICT SPACE COOLING SYSTEM

market, with reported 95 to 99 percent effiencies, and could improve the overall project economics. Sixty-five percent was used in this report, however, to realistically illustrate energy analysis under partial load and to simulate other losses that might be attributed to heat exchanger fouling. The energy savings is shown in Table 1.

TABLE 1

Cooling System Requirements
(millions of Btu's)

	Pre-Electrical Generation (11,600 Btu/kWhr)	Purchased Electricity (3,414 Btu/kWhr)
Present Cooling System	208,800	61,433
Geothermal District System	40,785	12,000
Savings	168,015	49,433

The energy used in the geothermal system would be from electrical energy used in circulating chilled water, pumping geothermal fluids, operating cooling tower fans, cooling fan motors, and control function requirements. The present cooling system uses approximately 18 million kW/yr. The cooling system energy costs for 1979 are anticipated to be $545,500.

The perimeter chilled water circulation loop selected is a two-pipe design, consisting of double-walled cement asbestos insulated pipe. The majority of main piping is 12-inch diameter, allowing a flow of 2,000 gpm with velocities near 5 feet per second. The choice of this size pipe allows for future expansion of the system for increased velocities should the need arise. The majority of branch line connections is sized with 4-inch diameter pipe, with the exception of those buildings with larger energy loads. Large supply lines were also sized to include several buildings in the south flightline area. Return lines were considered to be run in the same trench as supply piping, and were of identical size. The estimated capital cost, installation, and project contingency costs are provided in Section V.

B.   Space Cooling from New Production Well

Coal, solar, and geothermal resources could be used to provide hot
water for the absorption chillers. Maximum efficiency, though, occurs
at the highest allowable inlet temperature, near 300°F. The geothermal
potential at Williams, as evidenced by two deep wells approximately 0.5
miles to the southwest, could produce water temperatures of 350°F or
higher. The chemical nature of this geothermal resource, with respect to
its effect on materials selection, is known to be moderate. For estimating
purposes, a plate-type heat exchanger was selected, to isolate any possible
harmful effects of the geothermal water from vapor generators in the
absorption water chiller units. As noted in the preceding section on
reservoir assessment, a deep well could be located within a half-mile
radius of the central base area, with high probability for success. The
depth of the new well is estimated to be 10,000 feet, and the estimated
cost is shown in Section V. A reinjection well, 5,000 feet deep, was
also assumed to be located within a half-mile radius of the central base.
Estimated costs were included for well pumps, circulation pumps, and
possible reinjection pumps needed to extract 350°F geothermal fluids,
circulate, and reinject 200°F fluid. An alternative use of this still
relatively hot water is discussed below. A total of 900 gpm would be
needed to displace the present cooling load with water at a temperature
of 350°F. Water temperatures much above 350°F may pose well pump problems,
which at present are undetermined.

C.   District Cooling Option Based on Existing Wells

The possibility exists for the acquisition of two existing geothermal
wells, located on private property 0.5 miles to the southwest of the base.
Section III addressed this option, including estimated costs for well
refurbishment and flow enhancement through directional drilling. An
obvious advantage is apparent with two separate wells, each of which can
supply total flow requirements while one serves as backup. Higher initial
capital costs will be incurred due to additional required supply piping,
circulation pumps, well pumps, and interconnecting well piping. These
costs are tabulated in the following section. The basic centralized
cooling system remains identical, irrespective of well placement.

D. Heat Pump Application

Another option exists to utilize lower-temperature geothermal resources from some intermediate-depth well (perhaps 5,000 ft) to supply the cooling requirements. For this option, a centralized heat pump could be employed, using 140°F water, which could be boosted to 230°F. This output water could then be used to drive the absorption water chillers, although at a somewhat lower efficiency than with 300°F water.

A heat pump operating on 140°F supply water has an overall coefficient of performance of 3.5. (Discounting the electricity needed for pumping supply water, every electrical energy unit supplied yields 3.5 equivalent heat energy units.) The hot water (230°F) thus generated could be used as supply water for absorption water chillers, whose efficiency is 55 percent or less, due to the lower-temperature water. An overall system performance becomes:

overall efficiency = heat pump coefficient x absorption chiller
                         of performance   efficiency

         =   3.5   x   0.55

         =   1.93

Thus, the overall performance is higher than the required electrical input. Typically, a coefficient of performance for conventional electrical compression/expansion water chillers is usually around 4. The replacement, therefore, of existing equipment with a centralized heat pump would actually consume more electricity than is presently used. Other design possibilities do exist. For example, a hot water circulation loop at 150°F could provide each building with the water and temperature needed to drive water/air heat pumps. In comparison, the considerable expense in retrofitting costs will make this system uneconomical and removes the backup capability now provided by the existing equipment. In the system economics chapter which follows, therefore, we have not considered this option as a system competitive with the two deep well options.

E.   Corollary Heating System Development

Space heating at the base accounts for nearly one-quarter of the
annual energy usage and is presently based on hot water heated by natural
gas. Terminal reheat system humidity control accounts for nearly 60 per-
cent of the remaining non-heat natural gas usage for the central base
area. These systems could be converted relatively easily to geothermal
use without major retrofitting costs. The heating and humidity control
system annually consumes about 115 billion Btu's, at a 1978 cost of
$218,500; expected to increase to $299,000 for 1979. These heating systems
have a low annual utilization factor, with the exception of the hospital
complex employing terminal reheat for humidity control. The hospital's
installed capacity accounts for about 40 percent of the large heating
systems installed.

Geothermal water could replace the bulk of the heat currently generated
by fossil fuel. A second perimeter loop, two-pipe system would need to
be installed. Smaller 10-inch supply and return lines could be used for
an assumed $35^\circ F$ temperature exchange across heating system exchangers.
The hospital complex would need a slightly larger supply and return system.
An estimated project cost of $1.4 million, including contingencies, would
be needed for the supply, return, and branch piping, miscellaneous valving,
and heat exchangers. This does not include any retrofitting cost. This
cost would be contingent upon the installation of the piping within the
same trenching as utilized by the centralized cooling system. This heating
system, if provided by geothermal water, could result in an annual $299,000
natural gas cost savings, which needs to be weighed against an increase
in electrical energy for circulation pumps.

The presently assumed geothermal flow rate to meet cooling demands
is 900 gpm. The exit temperature from the cooling system is $200^\circ F$, and
could be applied via a heat exchanger to the centralized heating perimeter
loop. The maximum fraction of heat available, owing to reduced temperature,
is 22.5 million Btu/hr, adequate only for a small part of the total heating
load, yet large enough to provide heat for the hospital complex. A capital
cost of $550,000, including retrofitting, would be needed for piping and

installation for only the hospital complex. The annual natural gas cost savings would be nearly $45,500, and, again, needs to be weighed against increased electrical energy for circulation pumps. This and possibly other alternatives for heating may be considered during project implementation when well temperatures are better defined.

F.   Alternative Development Options

1.   Solar

Solar ~~and coal~~-produced hot water could provide alternatives to the present electrically driven cooling equipment. The solar option, at first glance, might seem especially suitable to the sunny southern Arizona area. An 86 percent annual average of sunshine is available, with a high of 94 percent in June. ASHRAE* data was analyzed for incident solar radiation at 32° N latitude, assuming a north-south axis tracking concentrating collector, with a tilt angle fixed at 40°. The minimum insolation daily total thus calculated was 1,360 Btu/ft^2 during June and July. A further assumption was made that the cooling system, requiring 65 million Btu/hr, operates a total of 14 hrs/day. No extended storage capability was included in the capital cost estimate. Calculations thus assume a storage capable of handling the daily peak load, with no carryover from day to day. However, the inclusion of an 86 percent sun factor for calculating available energy results in a collector area that will have a higher peak output in totally clear weather days that can carry over through part of the next day. Smaller daily cooling loads will also result in carryover. Additionally, winter output should result in carryover, due to the availability of sunlight combined with reduced loads. Cloudy weather will, of course, result in greatly reduced output.

For the solar development option, the collector area and cost is calculated as follows:

* American Society of Heating Refrigeration and Air Conditioning
  Engineers. Handbook of Fundamentals, 1972, p. 389.

$$\text{Total Daily Heat Demand} = 65 \frac{\text{MBTU}}{\text{HR}} (14 \text{ hrs}) = 910 \text{ MBTU}$$

$$\text{Available Collector Energy} = 1360 \frac{\text{BTU}}{\text{FT}^2} (86\% \text{ sun}) (70\% \text{ Collector Efficiency})$$

$$= 820 \frac{\text{BTU}}{\text{FT}^2}$$

$$\text{Collector Area Required} = \frac{910 \frac{\text{MBTU}}{}}{820 \frac{\text{BTU}}{\text{FT}^2}} = 1.1 \times 10^6 \text{ FT}^2$$

$$\text{Installed Collector Cost} = (\sim \$25/\text{FT}^2)(1.1 \times 10^6 \text{ FT}^2)$$

$$= \$27.5 \text{ MILLION}$$

The hot water thus generated can be used in absorption water chillers, as discussed in the preceding geothermal option. Economics of the system are addressed in the following section. The above capital cost does not include installation, collector mounting hardware, or system connection components.

2. Coal

Coal could also provide an available option in the Williams Air Force Base project. Coal is an abundant resource indigenous to the area, and could be used to produce the hot water for the central chiller. An equivalent displacement of fossil fuel-generated electricity could be achieved as with the geothermal option. However, coal priced at $60/ton, or $2.68 per million Btu, would experience a higher annual operating cost than the geothermal system. Capital equipment costs associated with storage, air scrubbers, and handling equipment are anticipated to be high. The payback, perhaps favorable, would be longer than the geothermal system option.

3. Geothermal Electric Development

An additional alternative to purchased power for the present electrically driven cooling equipment is provided by a geothermal electric power plant. It is considered that such a plant should be sized to satisfy the entire base electrical load, not just the portion of the load used for the present cooling system. This option has the advantage of not requiring retrofit of the existing base air conditioning units.

A power plant to meet the entire base electrical load would have a net output of 9 MWe. Monthly base electrical consumption data for 1978 would provide a plant load factor of 63%. Sizing the plant only for the cooling load would result in a much smaller load factor, and would probably not be economically competitive.

Plant design and costing were based upon an assumed geothermal resource temperature of 350°F, which suggests selection of a binary plant cycle using pentane as a working fluid. Accordingly, performance and cost calculations are based upon such a binary plant, although actual well performance data should be factored into final plant selection and design. A higher actual resource temperature that the assumed 350°F will significantly improve the economics of this alternative, while a lower resource temperature will provide power economics. A simplified schematic of a binary plant is shown in Figure 10.

The binary power plant considered in this alternative is not just an R&D experiment, but rather a developed concept using commercially available components, as evidenced by the following activities using this technology:

1. Since April 1978, a 60 kW prototype binary system has been in operation at the INEL's Raft River, Idaho geothermal test site, using a 290°F resource.

2. During the summer of 1979, the first commercial binary-cycle plant will go on-line in the Imperial Valley of California. It will produce 10 MWe of power from a 360°F resource and will be operated by the Imperial Magma Corp.

[handwritten marginal note:] In this power cycle the geothermal fluid is passed through a heat exchanger where it gives its heat to... is transferred to a working fluid. The working fluid is vaporized and used to turn a turbine generator. The vapor is then run through a condenser where it is liquified and returned to the system to repeat the cycle. The working fluid is one which has a low boiling point and therefore has a high vapor pressure.

Brine
boost
pump

Load
cont

Turbine

Cooling
tower

Air

Makeup

LC

Supply
well

TRC

Boiler

Preheater

Condenser

LC

Hot well

PRC

FRC

Injection well

To pond

Brine

Working
fluid

Coolant

INEL-A-8873
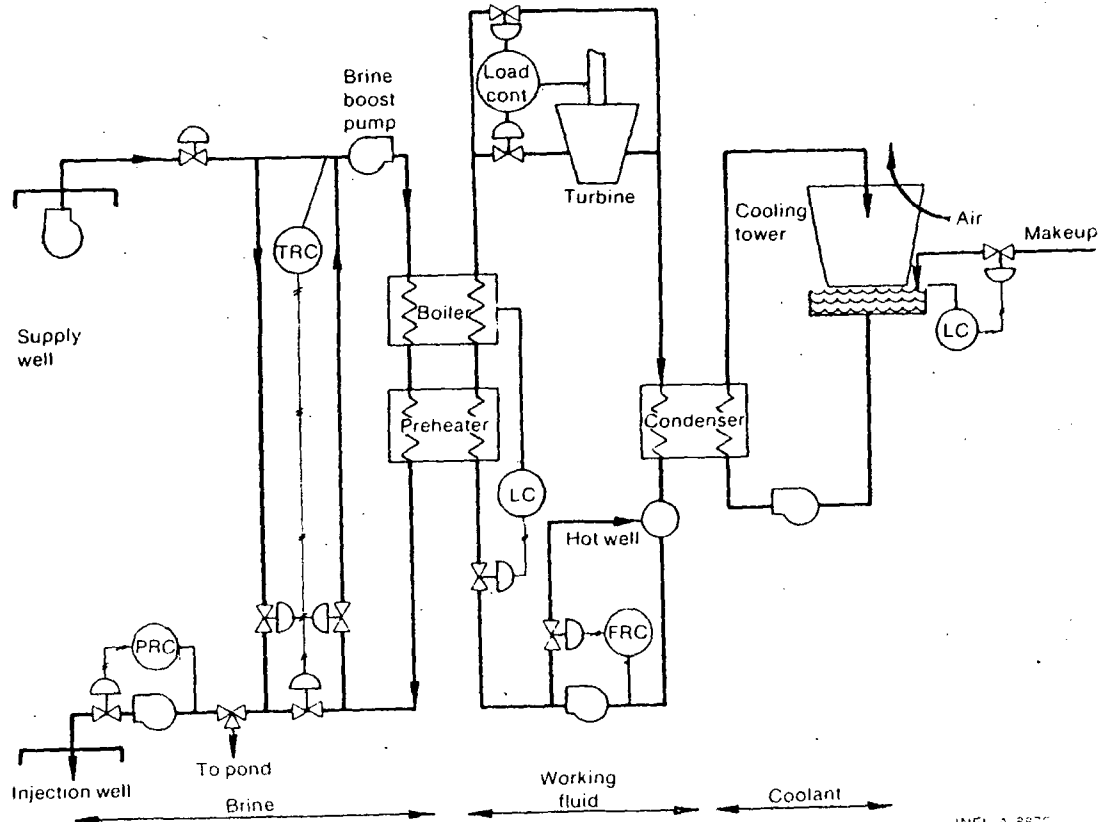
Fig. 10.

3. Construction is presently underway at the Raft River test site on a 5 MW power plant using a 290°F resource, which is scheduled to begin operation in October 1980.

Costs for the geothermal electric plant are broken into four items for use in economic evaluations: (1) well and piping system (field system) capital cost, (2) conversion plant capital cost, (3) field system operations and maintenance, and (4) conversion plant operations and maintenance. These costs are shown in Table 2.

TABLE 2

Geothermal Electric Plant: Basic Costs

Field System Capital Cost	6.14×10^6
Conversion System Captial Cost	12.3×10^6
Field System Operations & Maintenance Cost	$271,000/yr
Conversion System Operations & Maintenance Cost	$628,000/yr

Estimated

V.   SYSTEM ECONOMICS

Provided below are economic analyses of the two principal development
cases. The first development profile is based upon drilling a new pro-
duction well to approximately 10,000 ft and conveying the fluids to a
central chiller plant and district circulation loop (Case A). Fluid
disposal is presumed to be possible near the vicinity of the loop. The
possibility of acquiring, developing, and using the two private wells
located near the southwest corner of the base provides the basis of the
"Case B" analysis. All costs for the circulation loop, components, and
building retrofit (later called mechanical costs) will be the same for
both cases, except Case B will contain about 1.5 miles of additional
piping (since the wells are off base), as well as additional pumping
requirements. Less detailed cost estimates are also provided for alternative
energy systems, including solar, coal, and geothermal electric.

For both principal cases, we have provided two feasibility formats. Since
Williams is a government installation, project feasibility is approached
differently than would be the case for a private commercial or industrial
project. Thus we have followed the guidelines of DOD's Energy Conservation
Investment Program (ECIP) contained in AFR 178-1 to arrive at the several
determinants of feasibility. Since we expect, however, that this report
will also be read by others interested in industrial or commercial geothermal
development in Arizona, we have included a more conventional economic
analysis comparing the sum of amortization of capital expenditures and
operating expenses against projected energy savings over the economic
life of the proposed project.

A.   Project Costs

The project costs (in 1979 dollars) common to both Case A and Case B
are as follows:

1. Piping: *28275*

Chilled water supply and return lines (25,500 ft)	$987,345	
Branch lines (~ ~~25,275~~ ft)	595,900	
Miscellaneous valves, controls	115,000	
Geothermal water supply and return (0.5 mile supply, 0.5 mile reinjection)	227,395	
Geothermal well piping (miscellaneous)	24,000	
Expansion tanks (geothermal)	12,000	
Total 1		$1,961,640

2. Heat Exchangers:

1 Unit (1 smaller unit for standby)	$ 65,000	
Fittings and controls	20,000	
Installation	5,000	
Total 2		90,000

3. A/C Units:

6 units @ 610 tons/unit	$480,000	
Miscellaneous valves, controls	50,000	
Installation @ $35/ton	140,000	
Total 3		670,000

4. Cooling Towers:

6 units @ 9.275 M Btu/hr/unit rejection rate	$115,000	
Miscellaneous valves, controls	20,000	
Installation @ $10/ton	46,375	
Total 4		181,375

5. Retrofitting:

DX coils changeover	$ 73,230	
Installation	17,500	
Valving and controls @ $1,780/building x 35 buildings	62,300	
Total 5		153,030

6. Subtotal of common costs: $3,056,045

3 2

7.	Pumps:	Case A	Case B
	Production pump & wellhead equipment	$125,000	$331,000
	Loop circulation pumps	35,000	35,000
	Supply line circulation pumps	18,000	45,000
	Reinjection pump & wellhead equipment	135,000	150,000
	Total 7	$313,000	$561,000
8.	Project contingency @ 25%	$842,261	$904,261
9.	A&E fee @ 6%	$252,678	$271,278
10.	Subtotal of mechanical dimensions of the project, including contingencies	$4,463,985	$4,792,585

11. **Well Costs:**

		Case A	Case B
	Supply well	$1,933,000	$2,670,000
	Reinjection well	758,000	758,000
	Extra supply line (1.5 mi + 6% A&E fee on 25% contingency)	---	329,658
	Contingency @ 25%	672,750	933,664
	Total 11	$3,363,750	$4,691,322
12.	Total Projected Costs	$7,827,735	$9,483,907

Excluded from the above tabulations are costs associated with additional geophysics studies or exploration prior to deep drilling, as well as costs for preliminary and final system design.

B.   Feasibility Evaluations: ECIP Format

Tables _3_ and _4_ summarize the feasibility evaluation of Cases A and B according to the Air Force's ECIP. Part 1 consists of all capital costs, A&E contingency, and project contingency. The costs for CWE (mechanical plus well expenses) are those from the preceding current year costs escalated to FY 1982, the end of the fiscal year in which construction might be programmed. Contingencies are similarly escalated according to short-term escalation rates stipulated in AFR 178-1.

For recurring benefits or costs differentials (part 2), such as changes in material or labor requirements as a result of the geothermal project, we are assuming negligible differences, although in reality it is quite likely that some present labor and material requirements will be negated with a centralized cooling system.

33

Table 3. Case A

COSTS

1.   Non-recurring Initial Capital Costs

a.	CWE	$ 7,251,656	
b.	Design	$ 1,812,911	
c.	Other	$ 302,363	
d.	Total		$9,366,930

BENEFITS

2.   Recurring Benefit/Cost Differential Other
     Than Energy

a.	Annual Labor Decrease (+)/Increase (-)	$_____	
b.	Annual Material Decrease (+)/Increase (-)	$_____	
c.	Other Annual Decrease (+)/Increase (-)	$_____	
d.	Total Costs	$_____	
e.	10% Discount Factor	$_____	
f.	Discounted Recurring Cost (d x e)		$ -0-

3.   Recurring Energy Benefit/Costs

   a.   Type of Fuel _Electricity_

(1)	Annual Energy Decrease (+)/ Increase (-)	+ 168,015 MBTU
(2)	Cost per MBTU	$ 3.87
(3)	Annual Dollar Decrease/Increase ((1) x (2))	$ 650,218
(4)	Differential Escalation Rate (8 %) Factor	20.05
(5)	Discounted Dollar Decrease/ Increase (3) x (4)	$13,036,872

4.   Total Benefits (Sum 2f + 3a(5)) $ 13,036,872

5.   Discounted Benefit/Cost Ratio (Line 4 ÷ 1d)   1.39

6.   Total Annual Energy Savings   168,015 MBT

7.   E/C Ratio (Line 6 ÷ Line 1a/1000)   23.17

8.   Annual $ Savings (2d+3a(3)) $ 650,218

9.   Payback Period ((Line 1a - Salvage) ÷ Line 8)   11.15

---

(1) Includes all mechanical costs and wells, escalated to end of FY 1982.

(2) Project contingency @ 25% of mechanical costs & wells escalated to end of FY 1982.

(3) A&E contingency @ 6% of mechanical costs of (a) + (b).

Table 4. Case B.

COSTS

1. Non-recurring Initial Capital Costs

a.	CWE	$ 8,797,297
b.	Design	$ 2,199,324
c.	Other	$ 352,143
d.	Total	$11,348,764

BENEFITS

2. Recurring Benefit/Cost Differential Other Than Energy

a.	Annual Labor Decrease (+)/Increase (-)	$_____
b.	Annual Material Decrease (+)/Increase (-)	$_____
c.	Other Annual Decrease (+)/Increase (-)	$_____
d.	Total Costs	$_____
e.	10% Discount Factor	$_____
f.	Discounted Recurring Cost (d x e)	$ -0-

3. Recurring Energy Benefit/Costs

   a. Type of Fuel ___Electricity___

(1)	Annual Energy Decrease (+)/Increase (-)	168,015 MBTU
(2)	Cost per MBTU	$ 3.87
(3)	Annual Dollar Decrease/Increase ((1) x (2))	$ 650,218
(4)	Differential Escalation Rate (8 %) Factor	20.05
(5)	Discounted Dollar Decrease/Increase (3) x (4)	$13,036,872

4. Total Benefits (Sum 2f + 3a(5)) $13,036.872

5. Discounted Benefit/Cost Ratio (Line 4 ÷ 1d)   1.15

6. Total Annual Energy Savings   168,015 MBTU

7. E/C Ratio (Line 6 ÷ Line 1a/1000)   19.1

8. Annual $ Savings (2d+3a(3)) $ 650,218

9. Payback Period ((Line 1a - Salvage) ÷ Line 8)   13.53

---

(1) Includes all mechanical costs and wells, escalated to end of FY 1982.

(2) Project contingency @ 25% of mechanical costs & wells, escalated to end of FY 1982.

(3) A&E contingency @ 6% of mechanical costs of (a) + (b).

3.

Part 3 is a calculation of recurring energy benefits attributed to displacing the use of electric energy for space cooling in the system layout specified in the previous chapter. Annual energy saved is calculated at the front end of the electrical generating plant (11,600 Btu/kWh). Cost per MBTU is also calculated prior to generation ($2.61 MBTU, compared to $8.88 MBTU at the point of use) escalated at 16 percent for FY 1980 and 13 percent each for 1981 and 1982, according to the guidelines. A long-term differential escalation of 8 percent* (resulting from factors unique to the fuel market over and above those experienced by the general economy), with a government discount rate of 10 percent, is then applied over the expected 25-year life of the project, for a total discounted dollar savings of $13,036,872. Under recurring benefits, we have neglected both the demand-charge reduction charged by the electric utility in the present system as well as the value of a small amount of natural gas used in one of the hospital boilers, which would also be replaced by the geothermal system.

A discounted benefit/cost ratio, E/C ratio (energy saved/cost), annual dollar savings, and payback periods are then calculated. The guidelines suggest a minimum E/C ratio of 20 and benefit cost ratio of 1 for project consideration. Table 3 is the analysis for Case A, showing a B/C ratio of 1.39 and E/C ratio of 23.17, and Table 4 for Case B, with a B/C ratio of 1.15 and E/C ratio of 19.1.

C.   Conventional Economic Analysis, Case A

For what appears to be the most cost effective development scenario, Case A, we have included in Table 5 a life cycle cost analysis for the expected 25-year life of the geothermal project. The amortized cost is based on a total project cost of $7,827,735, including mechanical, well development, A&E contingency, and project contingency. Cumulative fuel

---

* Eight percent is probably a very conservative estimate, and it is quite likely that factors indigenous only to the energy supply industry will be reflected in a significantly higher long-term escalation rate. An assumption of 15 percent per year increase in real fuel costs, for example, would suggest a benefit/cost ratio of about 2.08, compared to 1.39.

TABLE 5

COST COMPARISONS OVER PROJECT LIFE

Year	Cumulative Amortized Capital Cost ($) (a)	Cumulative Fuel Savings ($) (b)	Geothermal System Cumulative Electrical Pumping Cost ($) (c)	Total Cumulative Geothermal Cost ($) (Capital & Operating)
1	$1,241,329	$ 438,965	$ 106,560	$ 1,347,889
2	2,482,658	921,827	223,776	2,706,434
3	3,723,988	1,452,975	352,714	4,076,702
4	4,965,317	2,095,664	494,545	5,459,862
5	6,206,646	2,738,353	650,559	6,857,205
6	7,447,975	3,445,311	822,175	8,270,150
7	8,689,304	4,222,964	1,010,953	9,700,257
8	9,930,633	5,078,383	1,218,608	11,149,241
9	11,171,962	6,019,344	1,447,029	12,618,991
10	12,413,292	7,054,401	1,698,292	14,111,584
11	12,413,292	8,192,963	1,974,681	14,387,973
12	12,413,292	9,445,382	2,278,709	14,692,001
13	12,413,292	10,823,042	2,613,140	15,026,432
14	12,413,292	12,338,468	2,981,014	15,394,306
15	12,413,292	14,005,937	3,385,675	15,798,967
16	12,413,292	15,839,103	3,830,802	16,244,094
17	12,413,292	17,856,135	4,320,442	16,733,734
18	12,413,292	20,674,871	4,859,046	17,272,338
19	12,413,292	22,515,480	5,451,511	17,864,803
20	12,413,292	25,200,150	6,103,222	18,516,514
21	12,413,292	28,153,287	6,820,104	19,233,396
22	12,413,292	31,401,738	7,608,675	20,021,967
23	12,413,292	34,975,034	8,476,102	20,889,384
24	12,413,292	38,905,660	9,430,272	21,843,564
25	12,413,292	43,229,348	10,479,859	22,893,151

(a) Cumulative capital cost based upon a loan amortized over 10 years at 10% interest on a total project cost of $7,827,735.

(b) Current cooling electrical energy minus anticipated electrical pumping cost is estimated to save 49,433 million Btu/yr, escalated at 10% per year for the 25-year project life. *Continued use of the present cooling system would cost $53,648,316 over the 25 year project life.*

(c) Electrical energy for circulation pumps and cooling tower fans is estimated to be ~ 12,000 million Btu/yr. A 10% escalation rate is applied over the 25-year project life.

savings are based on present costs of electric energy for space cooling in those facilities included in the district system, less the estimated electric pumping costs for the geothermal system included in the third column.

As noted in the table and from Figure /(the geothermal system crosses the payback point between the 16th and 17th years, longer than in the ECIP format. More attractive, however, is the total life-cycle costing, which shows nearly $32.7 30.8 million in ~~fuel savings~~ project benefits over the 25-year project period. Case B would be less favorable, because of the higher capital requirements ($9,483,907) and a somewhat higher electrical pumping cost. Additionally, we have not included in the Case B analysis, for either format, royalty payments that would probably have to be made to the owner of the land on which the wells are located. Such payments could be expected to approximate 10 percent, based on a BTU equivalency with alternate fuels.
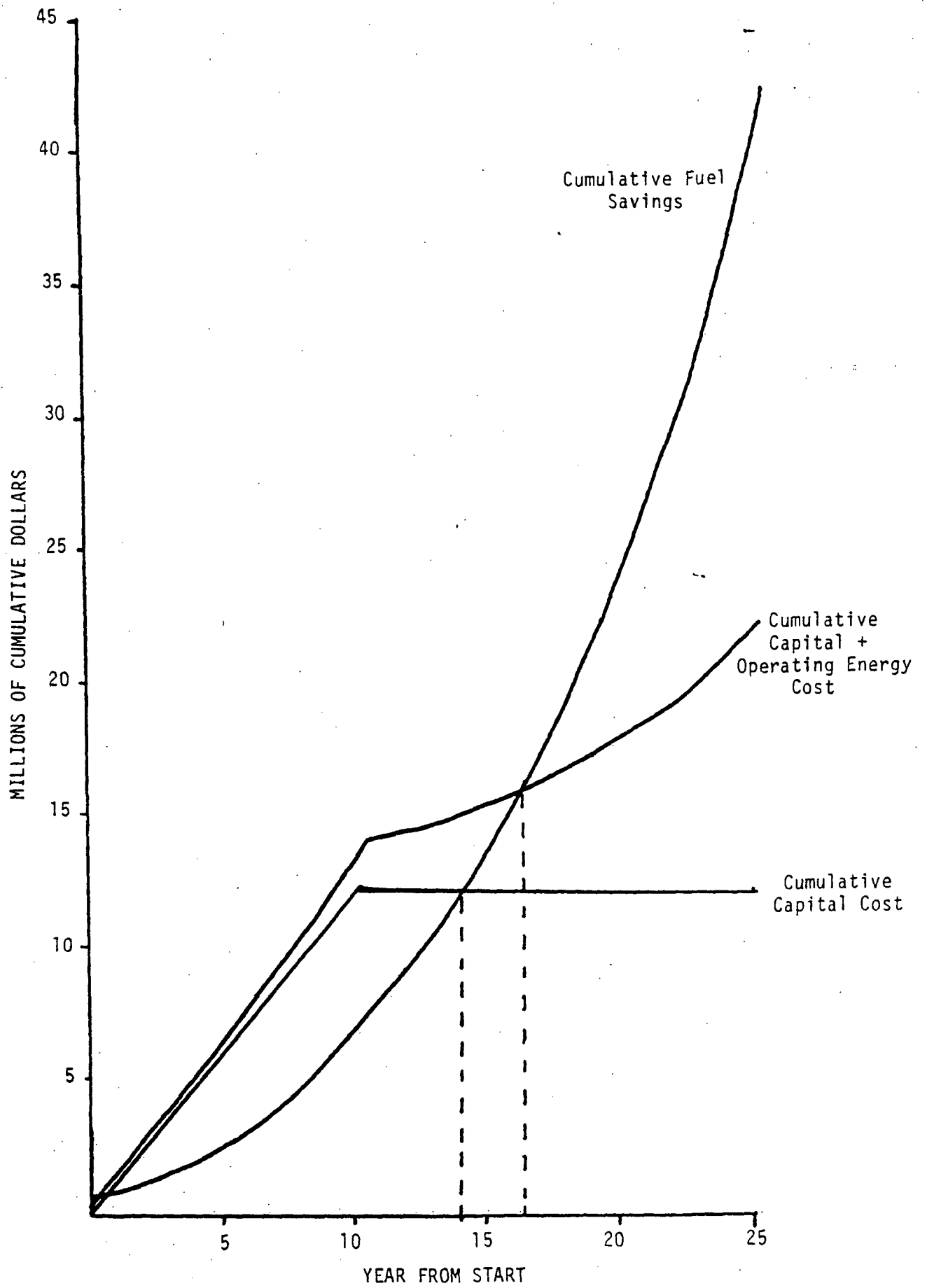
Figure //. Amortized Capital Cost Versus
Escalated Fuel Savings

37

D. Solar System Economic Analysis

The life cycle costs of the solar based hot water system described
in Section IV appear to be less attractive than the geothermal space
cooling system. Using the $27.5 million cost for the collector, as noted
earlier, and including mechanical costs, project and A&E contingencies,
front-end capital costs approximate $42 million. Amortized at 10 percent
over 10 years, project savings at the end of 25 years is still $7 million
less than total operating costs for the solar based system. It would
also be near this 25-year period that equipment replacement would then
become a concern. The capital costs, operating expenses, and savings
are as follow:

- Solar collectors	$27,500,000
- Mechanical (pumps, A/C units, piping, etc.)	4,600,000
Subtotal	32,100,000
Project contingency @ 25%	8,025,000
Subtotal	40,125,000
A&E contingency @6%	2,407,500
TOTAL	$42,532,500

Operating costs = $87,000/yr (includes electricity for pumps)

Table 6. Solar System Costs and Savings

Year	Capital Cost (Cumulative)	Operating Cost (Cumulative)	System Cost (Cumulative Total)	Savings in Cost of Electrical Energy
1	$ 4,416,394	$ 87,000	$ 4,503,394	$ 458,525
2	8,832,789	182,700	9,015,489	962,902
3	13,249,184	287,970	13,537,154	1,517,717
4	17,665,578	403,767	18,069,345	2,128,014
5	22,081,973	531,143	22,613,116	2,799,340
6	26,498,368	671,257	27,169,625	3,537,799
7	30,914,763	825,382	31,740,145	4,350,104
8	35,331,158	994,920	36,326,078	5,243,639
9	39,747,552	1,181,412	40,928,964	6,226,528
10	44,163,947	1,386,553	45,550,500	7,307,706
11	44,163,947	1,612,209	45,776,156	8,497,001
12	44,163,947	1,860,430	46,024,377	9,805,226
13	44,163,947	2,133,473	46,297,420	11,244,273
14	44,163,947	2,433,820	46,597,767	12,827,225
15	44,163,947	2,764,202	46,928,149	14,568,473
16	44,163,947	3,127,622	47,291,569	16,483,855
17	44,163,947	3,527,384	47,691,331	18,540,755
18	44,163,947	3,967,123	48,131,070	20,908,356
19	44,163,947	4,450,836	48,614,783	23,457,717
20	44,163,947	4,982,920	49,146,867	26,262,014
21	44,163,947	5,568,212	49,732,159	29,346,741
22	44,163,947	6,212,034	50,375,981	32,739,940
23	44,163,947	6,920,238	51,084,185	36,472,459
24	44,163,947	7,699,262	51,863,209	40,578,231
25	44,163,947	8,556,189	52,720,136	45,094,580
26	44,163,947	9,498,808	53,662,755	50,062,564
27	44,163,947	10,535,690	54,699,637	55,527,346
28	44,163,947	11,676,260	55,840,207	61,538,607
29	44,163,947	12,930,887	57,094,834	68,150,993
30	44,163,947	14,310,977	58,474,924	75,424,618

E. Cost Comparisons - Geothermal Binary Power Plant versus Projected
    Electricity Cost

As described in Section IV of this report, a 9 MWe (net) power
plant would be required to supply the WAFB electrical needs. To get
a valid approximation of the total cost involved, both the capital,
operations and maintenance (O&M) costs had to be evaluated. These
costs are composed of estimates which were calculated for both the
geothermal field and the conversion (power) plant. These costs were
compared against the cost of power currently being purchased by WAFB.
(Detailed cost estimates and assumptions are presented in the Appendix.)

Based on an assumed project period of 25 years and a cost of
money of 8%, (representative of a publicly owned utility) a capital
recovery rate (CRR) of 9.37%/year was computed from the standard
equation for that entity. Using the CRR and the field and plant
capital costs from Section IV, the fixed annual payout against the
total capital cost was calculated to be $1.728 x 10^6. Broken down,
this amounted to 11.6 mill/kW-hr for the field and 23.2 mill/kW-hr
for the plant. The total O&M cost (field and plant) amounted to
$899,000/yr in 1979 dollars or 18 mill/kW-hr. Collectively, these
costs total for a 1979 electric generation price of 52.8 mill/kW-hr
(see Appendix). The O&M cost is a non-fixed cost and was estimated
to increase at 10% per year over the 25-year project life. The
escalated O&M cost for each year of the geothermal plant operation
was added to the fixed annual cost of invested capital ($1.728 x 10^6,
to determine the annual cost of generated electricity. The amounts
were accumulated over a 25-year period and plotted on Figure /2.

Based on the current average electricity rate (near 30 mill/kW-hr)
and the most recent annual electricity consumption (50 MkW-hr), the
base cost for the presently purchased electricity was calculated at
$1 1/2 million. Using this base figure, the projected annual costs
were determined by escalating the anticipated 1979 costs at 10%/year
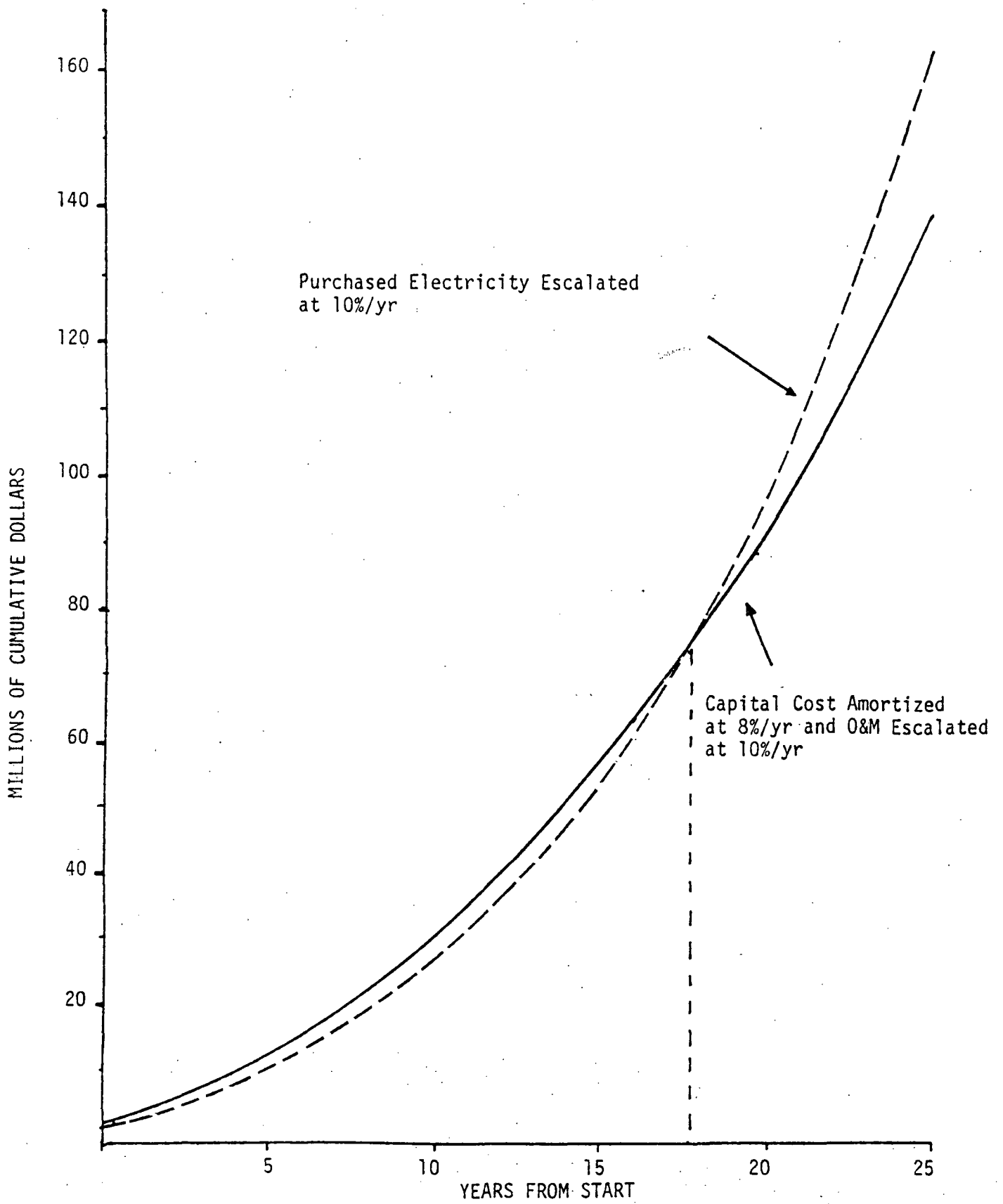over a 25-year period. The cumulative purchased costs are also plotted

Figure 12. Amortized Capital and Escalated O&M versus Escalated Electrical Costs

43

on Figure ^{12}. As can be seen, the breakeven period is 18 years for the geothermal binary power plant. This time span would be shortened substantially if the cost of purchased electricity escalates more rapidly than 10%/year, or if the actual resource temperature is discovered to be significantly greater than the assumed 350°F.

Table 7 summarizes the feasibility evaluation according to the Air Force's ECIP. Part 1 consists of all capital costs, A&E contingency and project contingency escalated to FY-82. These costs were not subdivided and were merely totalled equal for part 1a and 1d. Labor and material increases were included in Part 2 to reflect the additional manpower requirements to initiate and oerate this new project. The benefit/cost ratio thus derived is 1.7, the energy/cost ratio is 26.01, and the payback period is 14.9 years.

Table 7. Geothermal Electric Plant Feasibility Evaluation

COSTS

1. Non-recurring Initial Capital Costs

    a. CWE $ _____
    b. Design $ _____
    c. Other $ _____
    d. Total $ 22,070,717

BENEFITS

2. Recurring Benefit/Cost Differential Other
    Than Energy

    a. Annual Labor Decrease (+)/Increase (-) $ -435,813
    b. Annual Material Decrease (+)/Increase (-) $ -307,911
    c. Other Annual Decrease (+)/Increase (-) $ _____
    d. Total Costs $ -743,724
    e. 10% Discount Factor $ 9.52
    f. Discounted Recurring Cost (d x e) $ -7,080,256

3. Recurring Energy Benefit/Costs

    a. Type of Fuel _____

        (1) Annual Energy Decrease (+)/
             Increase (-)   574,000 MBTU
        (2) Cost per MBTU $ 3.87
        (3) Annual Dollar Decrease/Increase
             ((1) x (2)) $ 2,221,380
        (4) Differential Escalation Rate
             (8 %) Factor   20.05
        (5) Discounted Dollar Decrease/
             Increase (3) x (4) $44,538,669

4. Total Benefits (Sum 2f + 3a(5)) $ 37,458,413

5. Discounted Benefit/Cost Ratio (Line 4 ÷ 1d)   1.70

6. Total Annual Energy Savings   574,000

7. E/C Ratio (Line 6 ÷ Line 1a/1000)   26.01

8. Annual $ Savings (2d+3a(3)) $ 1,477,656

9. Payback Period ((Line 1a - Salvage) ÷ Line 8)   14.9

VI. REGULATORY AND ENVIRONMENTAL CONSIDERATIONS

A. Introduction

The purpose of this section is to outline the role of the State of Arizona in development of geothermal resources at Williams Air Force Base, Arizona. The state legislature has enacted a law that regulates the development of geothermal resources, and that law governs any development on Williams AFB. The development of geothermal resources in Arizona is exempt from water laws unless such resources are comingled with surface waters or groundwaters, or the development of geothermal resources causes impairment of or damage to the groundwater supply.

B. Legal Control of Geothermal Resources in Arizona

1. The regulation of geothermal resources exploration and production, standards, and procedures is accomplished by amendment of Section 2, Title 27, Chapter 4, IRS, with the addition of Article 4, Sections 27-651 through 27-666, as enacted by the state legislature.

2. This law establishes the Oil and Gas Conservation Commission located at 1645 West Jefferson, Suite 420, Phoeniz, Arizona, 85007. The commission controls the drilling of all oil, gas, and geothermal wells in the state.

3. In 1972 the commission published Rules & Regulations - Geothermal Resources, which require a $5,000 per-well bond to be filed with the commission or a blanket bond for $25,000 for all the wells planned to be drilled.

4. The commission rules and regulations require the filing of an application for a permit to drill for each well (fee $25.00). Drilling must start within 90 days after approval unless extension is granted, or permit is null and void. The permit must also be filed if an old well is reentered.

5. The commission approves or prescribes changes or modifications to well spacing plans that it determines necessary for proper development of the area.

6. The rules and regulations have separate casing requirements for surface casing and well casing, and these are inspected closely during installation. They also require blowout preventers, pressure tested to a minimum of 1,000 psig on installation, and the blowout preventer shall be operated at least once every 24 hours. A well completion report must be filed with the commission, along with all logs and surveys, after it has been certified as correct, but within 30 days after completion of the well.

7. Operating practices specify measurement and monthly reporting of production of the well. Disposal in the Williams AFB area will require an injection well to prevent subsidence, which is prevalent in this area. The commission will require that all federal and state air and water quality standards be met to protect the environment, and, as stated above, will require disposal by injection at a level low enough to protect groundwaters. The Oil and Gas Commission provides monitoring during construction and operation.

8. If the site of a well is located south of "D" Street and a line that extends across the airfield as an extension of "D" Street, it will require an archeological clearance.

CONCLUSIONS AND RECOMMENDATIONS

The promising evidence of hydrothermal resources underlying or in
close proximity to Williams AFB, combined with the favorable life
cycle costs and energy savings associated with the geothermal develop-
ment scenarios presented in this report suggest that the project should
continue to be pursued through the drilling phase, subject to the
caution and conditions set forth below.

Although the No. 1 and No. 2 GKI wells encountered promising temperatures
at depth and produced fluids, the flow soon ~~closed~~ _ceased_ and attempts at
stimulation failed. While the required temperatures are there, the
distinction should be made that the existence of a producing reservoir
has not thus far been demonstrated. Furthermore, the geologic controls
on the area of high temperature at depth are not well known, and it
is likely that the production drill hole would be required to encounter
substantial fracture or fault controlled permeability in order to be
assured of producing the required flow volume. Thus, the drilling
should be considered a high risk exploration project. _True, but almost a hidden statement_

In the absence of additional geophysical information, well location
WP-1, being the closest on-base location to the GKI wells, would be
most likely to ~~interest~~ _intersect_ a similar geologic setting. Location WP-2,
while preferable from an engineering and economic sense, would be a
higher risk effort. A resource discovered at either location would
provide the basis for an energy project with positive life cycle cost
effectiveness.

In order to help alleviate some of the exploration risk, and to possibly
obtain more definitive information on the geologic control at depth,
consideration should be given to conducting a reflection seismic survey
on the base. An expenditure on the order of $100,000 for 10-15 line
miles of seismic data to attempt to define control would be a small,
but possibly important investment in view of the high drilling costs _will be located through_
for deep production holes. _There is a definate possibility that no specific fault or fracture zones_ At the conclusion of that task, the
available information should then be reevaluated to form the basis of
selecting WP-1 or WP-2 as the preferred drilling site. A new production
well located on the base property would seem to be a preferable alternative
than attempting to negotiate for and redrill the existing off-base wells.

this work also to absorption or scattering of seismic energy

48

Given the favorable life-cycle cost advantages inherent in the geothermal energy supply systems discussed earlier, firm decisions on system selection should be deferred pending the results of the exploration program and the quality of the resource encountered. When the hydrothermal reservoir is confirmed and if temperatures exceed 350°F, principal consideration should be given to the development of an electrical supply system for the entire base. If the temperatures encountered are less than 350°, the preferred alternative would be a more limited district cooling system for the principal load areas, perhaps including a corollary heating loop. Either development alternative would be cost effective at both WP well sites.

There are no known environmental or regulatory deterrents that would impede pursuance of the project.