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AUTHOR	Kirmse, Dale W.; Manyimo, Steve B.
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ABSTRACT

The technical feasibility and economic benefits of an Integrated Utility System (IUS) at the University of Florida are addressed, as are the environmental and institutional factors. This study demonstrates a conservational and economic advantage in supplying the energy necessary for heating and cooling as a by-product of power generation. Contents include: (1) a rationale for on-site power generation; (2) descriptions of the site and existing utility system at the University of Florida; (3) the IUS designs for this institution; (4) economic analysis of the system; and (5) a discussion of the environmental and institutional considerations involved in such a system. (Author/MR)

Integrated Utility Systems

Feasibility Study and Conceptual Design at the University of Florida

DEPARTMENT OF COMMERCE * NATIONAL BUREAU OF STANDARDS *

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AND PROPERTY MANAGEMENT–
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WASHINGTON, D.C. 20201

INTEGRATED UTILITY SYSTEMS
FEASIBILITY STUDY
AND
CONCEPTUAL DESIGN
AT THE
UNIVERSITY OF FLORIDA

Dale W. Kirmse

Steve B. Manyimo

Prepared for the Department of Health, Education, and Welfare, Assistant Secretary for Administration and Management, Office of Facilities Engineering and Property Management, under Contract No. HEW - 100-75-0181.

REYNOLDS, SMITH & HILLS

4019 BOULEVARD CENTER DRIVE

JACKSONVILLE, FLORIDA 32201

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ABSTRACT

The present feasibility study and conceptual design are part of a demonstration project wherein the Federal government has funded this portion of the effort with the understanding that the University will attempt to fund and construct the project through its normal procedures, provided the present study demonstrates to the satisfaction of the University that it is in the best interests of the University to proceed The information presented herein is believed to so demonstrate.

The technical feasibility and the economic benefits of an Integrated Utility System (IUS) at the University of Florida are addressed, as are the environmental and institutional factors. The recommended IUS alternates include select energy systems wherein one fourth to three fourths of the required electrical power is generated on-site with full utilization of the waste heat from the process for heating and cooling purposes. Full integration of the systems is achieved through incineration of solid waste for its heat content, and partial reuse of the effluent from the existing sewage treatment plant for equipment make-up water and for irrigation.

A premise has been made, based on the trend of increasing interruptions in gas service, that the University would have to take some action to provide an alternative fuel for heating and cooling in the reasonably near future. This study demonstrate that there is significant economic advantage in supplying the energy necessary for heating and cooling as a by-product of power generation.

Finally, it is not in any given utility system, but rather in the integration of the subsystems where the University is able to gain conservational and economic advantage. Since the required system modifications will take four years to design and install, the time for planning is now.

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE
OFFICE OF THE SECRETARY
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Office of Facilities Engineering and
Property Management - Planning and Development

PREFACE

This report presents the analysis, findings, and recommendations of an evaluation of the Integrated Utility Systems concept at the University of Florida.

The report is the result of a cooperative effort by the University utility managers, the HEW Project Office and the HEW Consultant Contractor, Reynolds, Smith and Hills, Architects, Engineers and Planners, Inc., Jacksonville, Florida. The involvement of the HEW Office of Facilities Engineering and Property Management is a consequence of its mission of providing architectural and engineering consultant services to the medical and higher education community, and, the University's agreement to collaborate with the HEW team in performing the feasibility study on the Gainesville campus.

The sponsor of the HEW effort was the Experimental Technology Incentives Program (ETIP) Office of the Department of Commerce, National Bureau of Standards. The ETIP involvement is particularly innovative. This program seeks, through very modest fiscal assistance to examine and experiment with governmental policies and practices in order to:

o Identify and remove government related barriers to technological change in the private sector; and

o Correct inherent market imperfections that impede the innovation process.

The objective of the project is to demonstrate that the Integrated Utility Systems (IUS) concept can conserve energy and potable water, effect cost of energy savings, and improve pollution control.

The architectural-engineering hypothesis that lead to the formulation of this objective is based on these considerations:

- Historically, utility services required by a community of buildings developed as separate entities over time beginning with Roman adqueducts and evolving to electric power, gas, and other utility services in the late nineteenth century.
- Changes could be made in perception, custom and law which would reduce constraints on the view that combining those services can produce benefits in an era of increasing costs of capital, fuel, and potable water, and decreasing availability of these resources. Public Law 94-385 of August 14, 1976, is a welcome step in that direction. Among other things it requires the Federal Energy Administration (FEA) to develop proposals for ratemaking policies which discourage inefficient use of fuel.
- There are clear technological opportunities to save costs, save energy, and conserve potable water as well as improve solid and liquid waste handling, if the non-technical constraints can be logically accommodated.

The technological approaches within the IUS concept are not new; pieces and parts of the concept have been in use for many decades. Why did the concept not prosper? Primarily, because the shortage of petroleum and natural gas fuels was not expressed in very high fuel costs until recently.

The Federal effort at the University of Florida, and at Central Michigan University in Mount Pleasant, Michigan, seeks to dramatize and demonstrate that: With a very modest effort, in collaboration with enlightened institutional executives and managers, straight forward problem solving methods and sound architectural-engineering practice can point the way to significant cost and environmental benefits.

What contribution and impact can a successful IUS in Florida and Michigan produce? It is to be expected that many health and education institutions will be interested in the recommendations made to the University of Florida and Central Michigan University.

The Department of Housing and Urban Development is working on a similar project for residential communities; the Energy Research and Development Administration is proceeding with an "Integrated Community Energy System (ICES), Grid Connected." These latter efforts have different strategies, but the entire effort has to do with the integration of systems for energy conservation.

ACKNOWLEDGEMENTS

A number of individuals and organizations have contributed to the project effort. The support and interest of these key executives was especially important: Dr. Robert Q. Marston, President of the University of Florida, Dr. Jordan Lewis, Director of the Experimental Technology Incentives Program (ETIP), and Gerrit D. Fremouw, P.E., Deputy Assistant Secretary for Facilities Engineering and Property Management, Department of Health, Education and Welfare.

UNIVERSITY OF FLORIDA

Dr. Joseph H. Stafford, Vice Chancellor of Planning for the Board of Regents of the Florida State University System
Calvin C. Greene, Director of Physical Plant
D. Neil Webb, Associate Director, Planning and Analysis Division

EXPERIMENTAL TECHNOLOGY INCENTIVES PROGRAM, DEPARTMENT OF COMMERCE - NBS

Richard Penn, Chief, Special Projects and Project Advisor
Jean Taylor, Systems Planning Corporation, Project Historian

DEPARTMENT OF HEALTH, EDUCATION AND WELFARE

Robert Blake, P.E., Director of Planning and Development
Donald Boyle, P.E., AIA, Chief of Development Division and Project Officer
Dr. Max Novinsky, P. E.

HEW UTILITIES CONSULTANT
Stefan L. Geiringer, P.E., Paul Geiringer Associates

HEW CONSULTANT CONTRACTOR
Reynolds, Smith and Hills, Inc.
Ben J. Bucalo, Contract Officer
Dr. Edwin F. Coxe, Project Officer
Dr. Dale Kirmse, Project Officer
Steve Manyimo, Project Engineer

I. INTRODUCTION

A. THE INTEGRATED UTILITY SYSTEM

The objective of an Integrated Utility System (IUS) is to provide required utility services with maximum efficiency and minimal overall costs...and in a manner which is consistent with environmental requirements and institutional constraints. To this end, the IUS concept can become a viable option for medical and educational institutions to offset ever spiralling energy costs. By and large, current utility systems (electrical power generation, heating and cooling, water supply, sewage treatment and solid waste disposal) are typically treated as separate operating entities. The IUS concept combines as many of these utility services as are economically justified in order to achieve maximum utilization of heretofore wasted energy from individual subsystems. Optimization is site-specific, and, this document addresses the multiplicity of subsystems available to maximize the benefits from the IUS concept at the University of Florida.

The essence of an operationally and financially successful IUS is on-site electrical power generation utilizing low quality or waste heat to provide space heating and cooling requirements. Traditionally, large commercial electric generation stations operate at approximately 35 percent thermal efficiency; whereas, an IUS plant can attain and even exceed thermal efficiencies of 70 percent. Due to this fact, the economic benefits often provide for investment payout times of as little as 3 to 5 years...with continuing annual energy savings of 10 to 25 percent.

The increasing cost and decreasing availability of fuels is serving as a catalyst to boost further interest in the IUS concept. Contributing factors are:

(1) continuing escalation of electric utility rates,

(2) shortage and imminent curtailment of fuel supplies (natural gas) in many sectors,

(3) fluctuation in fuel oil prices due to the vagaries of international oil policies, and

(4) increasing environmental/energy conservation awareness.

The IUS concept takes an innovative approach to integrating established and sound engineering practices and proven equipment to provide more efficiently the required utility services.

The appeal of the IUS concept is further enhanced when one considers how it meshes with future planning activities. For example, major equipment items, such as boilers, have to be replaced periodically. When the cash flow picture against which IUS is being compared reflects these replacement items, the economic benefits from an IUS are often dramatic. The justification of an IUS (even partial) lies in the fact that integration of systems affords the user substantial fuel savings, and often a rapid return on investment.

B. RATIONALE FOR ON-SITE POWER GENERATION

Although the IUS concept encompasses all utility services, it should be noted that the majority of the return is going to be achieved from the on-site electric power generation integrated with space heating and cooling requirements, and that this level of system integration alone will often justify an IUS.

Industry long ago recognized that on-site power generation utilizing recovered low level heat could play a major role in reducing operating costs. Consequently, many industries incorporated essentially the same concept under the name of Total Energy. Numerous shopping centers, amusement parks, and other commercial establishments soon followed suit. This took place prior to the Arab oil embargo when fuel costs were low. The savings are now even more dramatic and others are examining the potential benefits of Total Energy. In particular, the military is examining the concept for application at many of their facilities.

In order to explain the principle of improved efficiency through combining space heating and cooling with on-site power generation, it may be helpful to review the concept of availability and reversibility in thermodynamic systems. All thermodynamic systems, e.g. high temperature combustion gases, at a given state defined by such properties as temperature, pressure, velocity and elevation, have the potential for performing a maximum quantity of work in reaching equilibrium with the environment. The maximum quantity of work is achieved by going from the initial state point to a final state point through reversible processes of heat transfer and work.

For example, in a university or medical complex, thermal energy in the temperature range of 100° F to 400° F is required to provide space heating and cooling. The combustion of fuels in a boiler generates hot combustion gases at approximately 3,500° F to satisfy these thermal requirements. If reversible engines could be placed between the heat source (combustion gas) temperature and each of the low temperature heat sinks, the system operation could then approach that of a reversible system and energy requirements could be obtained in the most efficient manner. Although reversible engines exist only in theory, there are available heat engines such as steam turbines that conventionally operate with throttle temperatures of 800° F to 1,000° F and combustion turbines which operate at inlet temperatures in the 2,000° F range. By incorporating one or more of these heat engines into the system, the irreversibility can be reduced and the utilization of thermal energy improved over that of a conventional heating plant which generates steam requirements for the thermal loads with no power generation and maximum irreversibility.

The system which will, in general, look most attractive in terms of highest fuel efficiency is one in which power generation is incorporated and in which the power generation system is selected on the basis of being the optimum size to provide the thermal requirements. Any smaller power generation results in having to use a conventional boiler to produce the additional hot water or low quality steam required for heating or cooling, and any larger unit results in a portion of the on-site electric generation system competing with the high thermal efficiency characteristic of the large power generating units operated by electric utility systems. Put differently, the plant will generally be designed so that the heating and cooling requirements are met by the waste heat from power generation processes. This in turn will usually mean that a significant portion, but not all of the power, will be generated on-site. This relationship is sometimes called a Select Energy System.

C. APPROACH AND CONTENT

The elements to be considered and analyzed to evaluate the potential benefits of an IUS are:

(1) energy requirements,

(2) present and projected electrical rates and consumption,

(3) reliability and adequacy of public power supply,

(4) projected availability of fuels in that region,

(5) capability of burning different fuels,

(6) existing utility plant facilities,

(7) space availability,

(8) economic benefits,

(9) funding capability,

(10) institutional and organizational factors,

(11) environmental desirability, and

(12) impact on the surrounding community.

These elements have been considered for the University of Florida IUS application and are presented in this report as follows:

(1) A description of the University of Florida utility systems is given in the Existing Utility System section. The pertinent utility data provided by the University were examined to develop a baseline conventional design,

(2) The Energy Availability and Cost section assesses the present and future fuel and electrical supply situation,

(3) The Integrated Utility System Conceptual Design section presents the rationale for selection, sizing and integrating the utility subsystems. And, an analysis of the technical feasibility and benefits to be realized by the proposed designs is made,

(4) The financial benefits of implementing an IUS at the University are established in the Economic Analysis section. A life cycle cost analysis of alternate IUS concepts is applied to determine the relative economic return to be expected for an IUS system as compared to conventional utility system counterparts, and

(5) The Environmental and Institutional Factors section assesses the potential environmental impacts as well as institutional factors, other than environmental, which can influence the application of IUS technology at the University of Florida.

II. EXECUTIVE SUMMARY

A. INTRODUCTION

The concept of the Integrated Utility System (IUS) is to consider the interaction and mutual support of five utility subsystems needed by a campus complex of buildings. The subsystems are: (1) Electric Power Service; (2) Heating-Ventilating-Air Conditioning and Hot Water Service; (3) Solid Waste Handling; (4) Liquid Waste Handling; and (5) Potable Water Service. By and large, current institutional utility subsystems are treated as separate entities. "Integration" of the subsystems is a design approach that seeks to establish those aspects of each subsystem that can assist the overall system performance. Said another way, the IUS concept seeks optimum system performance.

The essence of an energy saving and financially feasible IUS is on-site generation of all or part of the needed electric power service and utilization on-site of the cast-off heat normally lost at a large remote power station and also the energy normally lost in transmission to the institution. In addition, IUS considers utilization of the heat values derived from solid waste incinerated on-site.

Within the context of a specific site, liquid waste handling can include extraction and digestion of the solid portion of the waste and treatment to standards that would permit the final effluent to be discharged into the stream system. In addition, the final effluent can be used for such purposes as plant process water and irrigation in order to reduce the demand for potable water. There are potential uses for the solids resulting from the liquid waste handling operation, such as fertilizer. The sterile ash remaining from the solid waste incineration operation can be placed in a landfill.

It is conceptually feasible for an IUS to provide self sufficiency for utility services within the state-of-the-art of proven technology. Furthermore, the system can be designed to accommodate the addition of heat and power from other services, such as solar energy when technological advances so warrant.

In this application of the IUS concept the environmental considerations include:

- Reduction of solid waste by incineration to 5 percent of its original volume, and removal of the sterile ash to a landfill, obviously reducing the volume to be accommodated in the landfill. The ash will not contribute to ground water pollution. Costs of installing and operating this subsystem were included before estimating the net savings or credits.

- Reduction of the potable water demand through utilization of some of the treated liquid waste effluent for plant process water and irrigation. Costs for this aspect of the integration are small and were not included.

- Pollution control devices to meet local and national standards, and the costs of these devices and their operation and maintenance were included before making estimates of net savings.

It is to be emphasized that IUS concept applications are "site-specific" or custom designed to a specific institutional situation.

Finally, the IUS installation recommended provides to the individual campus buildings utility services responsive to present demands. This means that additional energy conserving actions that may be implemented within the buildings will provide additional cost of energy savings associated with the proposed IUS.

B. RECOMMENDATION

As a result of the findings and analysis contained in the report, "Integrated Utility Systems (IUS), Feasibility Study and Conceptual Design at the University of Florida," the following recommendation is made to install an IUS on the Gainesville campus.

Proceed now to budget, design, and install a 12.5 megawatt thermal electric generating plant plus a 25 tons per day, or a 75 tons per day, solid waste incineration plant. In support of that effort act promptly to modify the air conditioning expansion program so that 5, 900 tons of air conditioning is provided by absorption chillers rather than electric motor driven chillers as now planned.

The thermal electric plant would consist of two multi-fuel boilers (coal, oil, or gas) and two steam driven 6.25 megawatt variable extraction turbine generators. Part of the existing steam distribution system would be converted to a "Low Temperature Hot Water" heat distribution system. The existing heating plant should be retained for back-up reserve.

The new power plant and solid waste incinerators would be located nearby and associated with the existing heating plant.

The new equipment and existing plant modifications will provide 85 percent of the electric power requirements for the University, and 100 percent of the space heating, air conditioning and hot water service requirements. The balance of the electric power needed by the University would be supplied from its present sources on the utility electric power grid. Improved pollution control will result for the University and the surrounding community.

The annual energy cost savings beginning in 1981 when the plant would start up is estimated at 41 - 44 percent of the expected annual cost of energy in 1981 if the University were to continue in its present mode of operation. (See also Figure II-1.)

The investment costs and related benefits are state below:

- The capital investment cost for the recommended IUS modification is $18.2 - 19.4 million.
- Annual value of energy savings over the 25 year plant life is 41 - 44 percent per year, this would be $4.2 - 4.4 million in 1981 when the plant is started up.
- Economic Indicators:
  - Payback period as an indication of the risk is 4.8 years.
  - The savings to investment ratio is less than 4 (this number is derived from dividing (1) the estimated total future net savings from 1981 to 2006 discounted to 1981 using the State of Florida bond interest rate of 6.5 percent as a discount rate by, (2) the total investment cost in 1981 dollars.)
  - Interest rate of return on the investment is 23 percent.

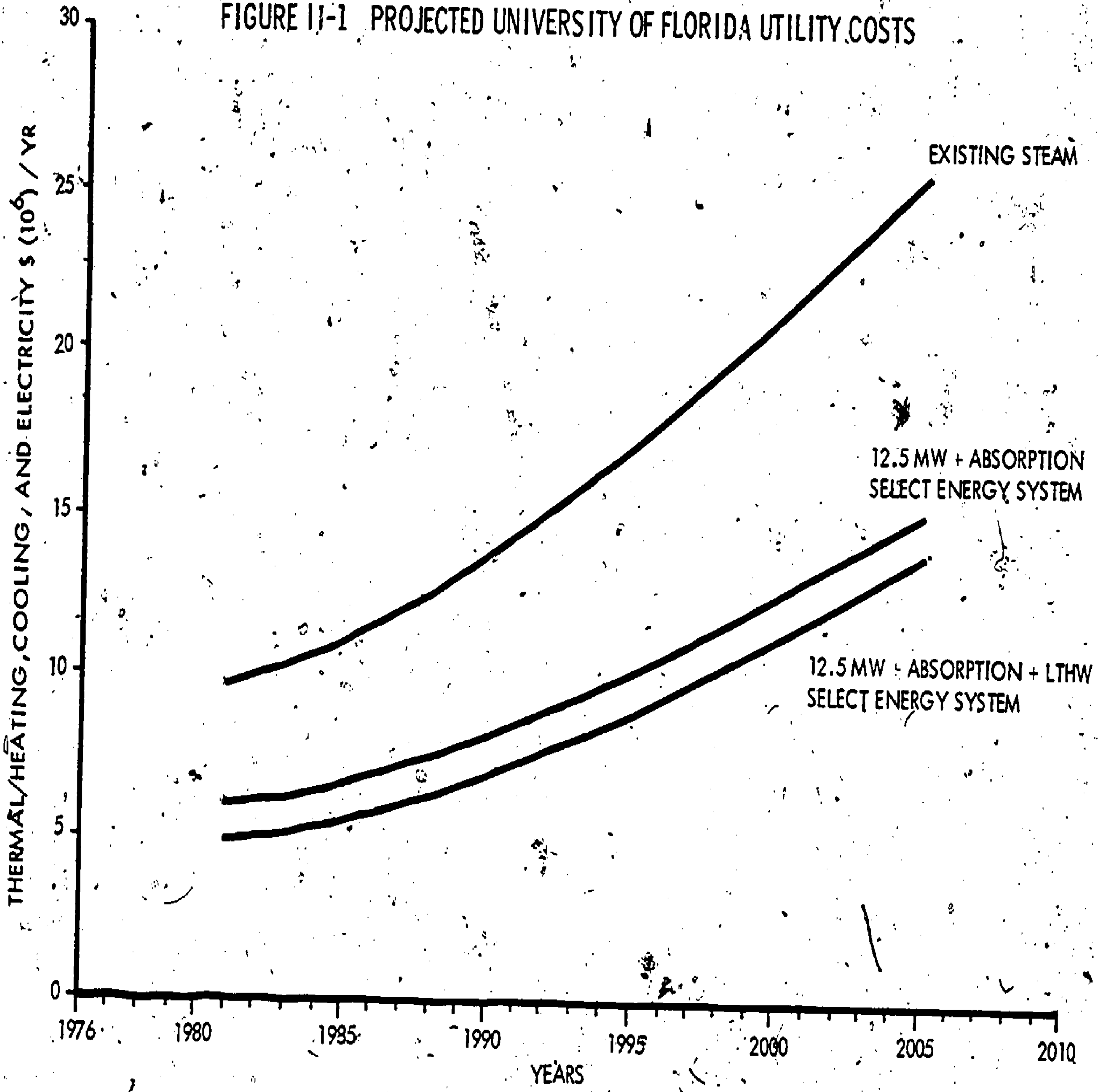
The recommended option costs and benefit details are presented on Table II-1. Table II-2 and II-3 present, for budget purposes, the investment disbursement costs inflated to the pertinent fiscal year for the 12.5 megawatt plant, plus a 25 tons per day or a 75 tons per day solid waste plant.

C. INCREMENTAL ALTERNATIVE RECOMMENDATION

As an alternative to the foregoing recommendation, an incremental installation program is presented on Table II-4. This breaks the recommended IUS into two phases: Phase I, which is approximately one half of the recommended IUS, would be fully operational and would yield roughly half of the benefits if Phase II were never built. In this case, the payback period would be 5 years and the interest rate of return 22 percent.

The purpose of the incrementation as displayed on Table II-5 is to show what the fiscal year expenditures would be if the project were phased. Although Phase II is only splipped one year, it would be possible to slip it any reasonable period of time. The penalty, of course, would be in the escalation of construction costs and more significantly in the loss of about $2,000,000 per year in operational savings.

FIGURE II-1 PROJECTED UNIVERSITY OF FLORIDA UTILITY COSTS



D. OPTIONS FOR SOLID WASTE INCINERATION

The following solid waste incineration options are feasible when made part of the proposed IUS. Waste incinerators are now available that meet air pollution standards and deliver steam useful for reducing other fuel demands. The incinerators can be enclosed to preserve an attractive external appearance; the operation is on an 8-hour, 5 day a week schedule, and does not require highly skilled operators.

The smaller option is based on the University generated solid waste at a rate of 25 tons per day. The larger option includes the University and the City of Gainesville commercial dry waste at a rate of 75 tons per day. Truck traffic would range from 5 truck loads per day to about 15 truck loads per day. The residue of the solid waste is a sterile ash of about 5 percent of the volume of the waste input, and the ash would be trucked to a landfill. Main economic features are (from Table II-1):

		University	City & University
o	Volume (Tons/Day)	25	75
o	Total Expended Dollars at 1981 Start-up	$18,177,000	$19,547,000
o	Annual Operating Credits or Savings	$ 4,223,000	$ 4,373,000
o	Payback Time of Total System	4.7	4.8
o	Savings/Investment Ratio of Total System	3.8	3.4
o	Interest Rate of Return on Investment	23.4	22.9

The larger volume option would require discussions with the City of Gainesville in order to assure a supply of solid waste and a mutually beneficial agreement.

E. CONSIDERATIONS FOR MAKING THE IUS DECISION

In the main body of the report detailed analyses of the current energy posture of the University and the future possibilities are provided. A summary of the basis for making the recommendation is presented.

The University utility managers and the IUS feasibility study team - the HEW Project Office, the ETIP Advisor, and the Consultant contractor - have together endeavored to present a professional technological appraisal of the University situation. The University executives and the State of Florida officials will want to review the recommendation and challenge the basis for the recommendation in order to make their decision.

The following assumptions have been incorporated into the study report:

Item	Assumption
o Natural gas available in 1981 at an attractive relative cost	Not probable
o Fuel availability 1981, burned in the present plant if IUS is not adopted	Fuel Oil
o General inflation	4% per year
o Additional construction cost escalation	1.0% per year
o Additional fuel oil price escalation	2.2% per year
o Additional coal price escalation	-0.7% per year
o Additional electric power price escalation	2.3% per year
o IUS plant life	25 years

Unless otherwise stated, all costs and savings are in dollars brought forward to 1981 using the above assumptions or brought back to 1981 using the State of Florida bond interest rate of 6.5 percent as a discount rate.

The decision making risk for proceeding now in an IUS investment program is clearly associated with error in judgement of what will happen in the future. The team used two prime economic indicators to evaluate the alternatives considered: interest rate of return on the investment, and payback time.

The question is posed: How sensitive are the conclusions and the recommendation to variations in the input data? The changes in payback period and interest rate of return on the investment were tested in a series of sensitivity analyses. The following observations can be made with respect to the recommendation:

(1) The results are relatively insensitive to an error of 20 percent plus

or minus in the capital cost estimate.

(2) A change in the discount rate from 6.5 percent to 5.5 percent or 7.5 percent had little effect because of the rapid payback period — and the low discount rate used.

(3) Since the additional operation and maintenance costs are a small fraction of total annual costs, errors of plus or minus 20 percent have little effect on the economic benefits.

(4) Variations in the economic life of the plant of plus or minus 5 years have negligible effect.

(5) An increase of plus one half or a decrease of one half of the assumed rate of inflation of 4 percent per year will add or deduct only 2 percentages points to the indicated interest rate of return on the investment.

(6) A 20 percent variation in the price of either coal or oil would increase or decrease the interest rate of return by slightly more than a tenth. As oil prices increase the coal fired plant would look more attractive. Within the range of coal price fluctuations tested the economic indicators are excellent.

(7) A general reduction in the escalation of energy costs including purchased electricity to the projected general rate of inflation of 4 percent would make the indicators less attractive. However, the interest rate of return would still exceed 18 percent and the payback period would not exceed 6.8 years.

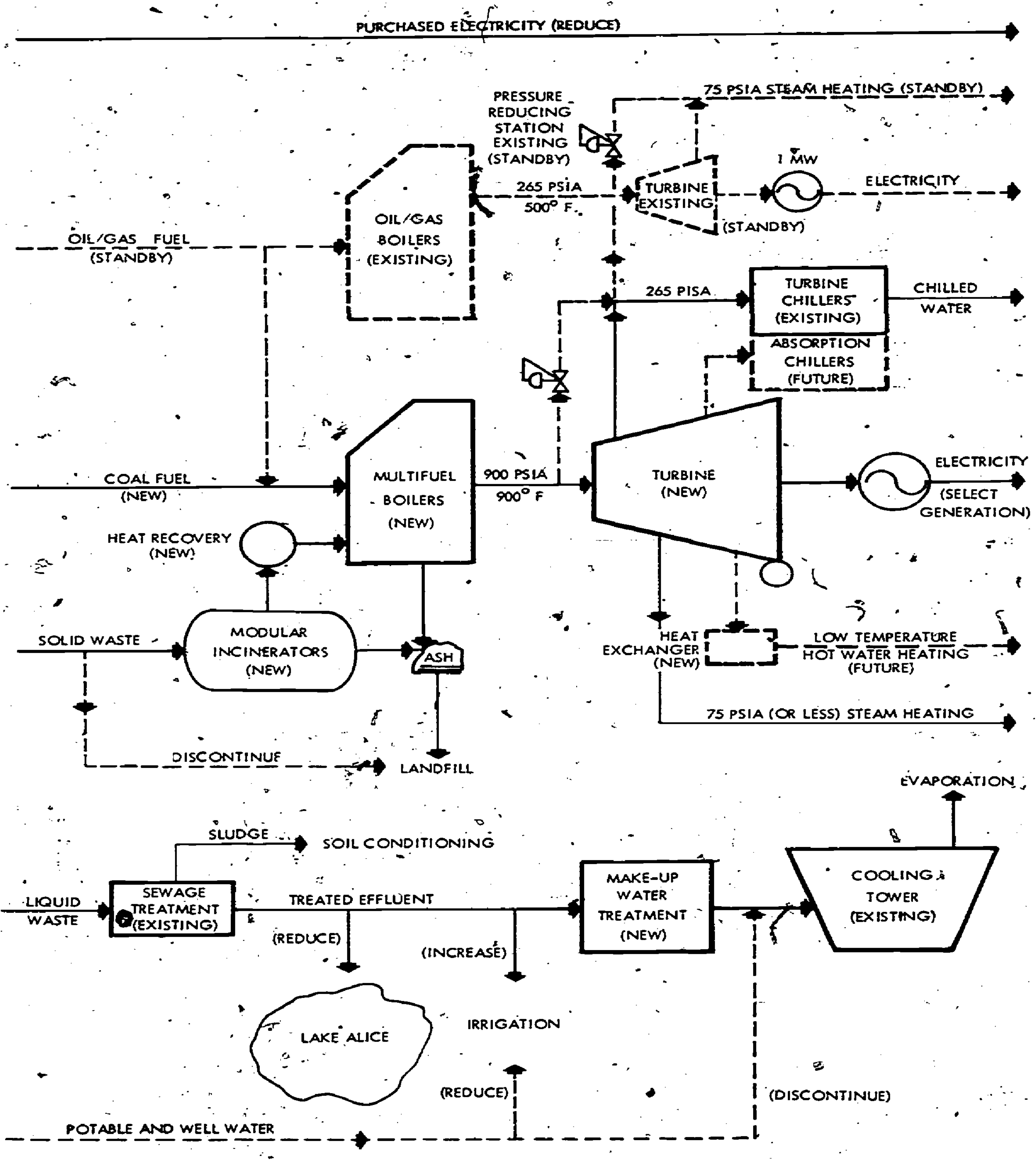
(8) The "base case" against which the comparisons are made assumes the existing plant would be burning oil in 1981. If, in fact, gas is available and is burned either one third or two thirds of the time, the indices are unfavorably effected. However, the interest rate of return still exceeds 20 percent and the payback period does not exceed 6 years.

The penalty for inaction is dramatized in Figure II-1. Energy costs for the University are estimated to be $9 million per year by 1981. If the IUS goes on stream then those costs are estimated to drop 44 percent per year. (If the general inflation and fuel escalation is higher than assumed, then cost savings will be higher than predicted and the penalty for inaction will be higher.) Thereafter the existing system cost performance follows the top curve and the IUS system performance would follow the bottom curve.

F. SCHEDULE FOR CONSTRUCTION

The schedule for construction and major equipment purchases for the recommended option – 12.5 megawatt electric plant and a 25 or 75 tons per day solid waste incineration plant – is presented in Figure II-2. Note that the overall schedule is estimated at 42 months.

In order to relate the budgeting and fiscal material in Tables II-1 through II-4 to the construction schedule in Figure II-2, the reader is reminded that the recommendation is to proceed now to budget, design and install an IUS for start up in 1981. Presuming that the University and the State accept the recommendation, the balance of calendar year 1976 and the first quarter of 1977 should be devoted to University and State review, seeking approval of the capital overlay program and initiating the design and construction contracting process.



INTEGRATED UTILITY SYSTEM
UNIVERSITY OF FLORIDA
FIGURE II-2

TABLE II-1
RECOMMENDED OPTION

12.5 MW Thermal Electric Generation System with Either of Two Levels of Solid Waste Incineration,
25 Tons of Solid Waste Per Day (University Only), or 75 Tons Per Day (University and Commercial Community)

		Base Case as Basis for Comparison ①	12.5 MW + Absorption Chillers + LTHW ② ③	University MSW Incineration 25 TPD Incremental	Combined with University Solid Waste Incineration 25 TPD	University and Commercial MSW Incineration 75 TPD Incremental	Combined with University and Commercial Solid Waste 75 TPD
Capital Cost Required to Plant Startup (1976 dollars)		-	14,745	591	15,336	1,691	16,436
Capital Cost Inflated to Project Date of Disbursement							
	FY 1978	-	2,988	-	2,988	-	2,988
	FY 1979	-	4,898	-	4,898	-	4,898
	FY 1980	-	7,005	-	7,005	-	7,005
	FY 1981	-	2,550	729	3,279	2,066	4,616
	FY 1986	1,158 ④	-	11 ⑤	11 ⑤	23 ⑤	23 ⑤
	FY 1991	1,416 ④		14 ④⑤	14 ④⑤	29 ④⑤	29 ④⑤
	FY 1996	-	-	1,042 ⑥	1,042 ⑥	3,120 ⑥	3,120 ⑥
Cumulative Total of Expended Funds at Plant Startup		-	17,441	729	18,177	2,066	19,547
Capital Cost Required to Plant Startup (1981 dollars)		-	19,789	729	20,549	2,066	21,963
Annual Operating Cost (1981 dollars)		10,017 ⑦	5,967	-183	5,784	-333	5,634
Annual Operating Cost Savings Over Base Case (1981 dollars)		-	4,050	183 ⑧	4,233	333 ⑧	4,383
Present Worth at Net Savings (1981 dollars) ⑨		-	71,047	-	73,423	-	73,895
Savings to Investment Ratio ⑩		-	3.9	-	3.8	-	3.4
Interest Rate of Return (%) ⑪		-	23.3	-	23.4	-	22.9
Payback Time Including Interest (years)		-	4.7	-	4.7	-	4.8

Notes

1. The base case is the existing system with fuel oil as the principle fuel.
2. It is assumed that 5,900 tons of the on-going air conditioning system expansion program will be procured with absorption chillers rather than electric motor driven chillers as originally planned.
3. A small capital cost is included in this project to install a steam distribution line between the steam plant and the medical center to supply low temperature hot water (LTHW).
4. Replace existing boiler.
5. In plant rolling stock replacement.
6. Major plant replacement.
7. Includes solid waste disposal costs.
8. Compared to existing disposal costs.
9. Present value of net savings minus present value of invested capital and interest (1981 point of reference).
10. Present value of incremental savings divided by incremental investment required (1981 point of reference).
11. Discount rate for which payout time equals project operating life (25 years).

ime required to recover the initial investment. Expended dollars divided by net annual savings in 1981 constant dollars.

TABLE II-2

12.5 MW THERMAL ELECTRIC GENERATION WITH INCINERATION OF UNIVERSITY SOLID WASTE

(25 Tons/Day)

Cost Disbursements by Fiscal Year
Based on Plant Start-Up in 1981

Cost Breakdown by Category	Estimated Commitment Date	Disbursements (000) by Fiscal Year				
		FY 1978	FY 1979	FY 1980	FY 1981	TOTAL
Engineering and Fees	Sept. 1977	818	273	109	164	1,364
Turbine Generator	March 1978	208	832	1,976	451	3,467
Steam Generation including Pollution Control	April 1978	1,159	1,626	1,388	464	4,637
General Construction	Nov. 1978	803	2,167	3,532	1,525	8,027
Solid Waste Energy Recovery	Oct. 1980	0	0	0	675	675
TOTAL		2,988	4,898	7,005	3,279	18,170

TABLE II-3
12.5 MW THERMAL ELECTRIC GENERATION SYSTEM WITH UNIVERSITY AND COMMERCIAL COMMUNITY SOLID WASTE INCINERATION (75 Tons/Day)

Cost Disbursement by Fiscal Year Based
on Plant Start-Up in 1981

Cost Breakdown by Category	Estimated Commitment Date	Disbursements (000) by Fiscal Year FY 1978	FY 1979	FY 1980	FY 1981	TOTAL
Engineering and Fees	Sept. 1977	818	273	109	263	1,463
Turbine Generator	March 1978	208	832	1,976	451	3,467
Steam Generation including Pollution Control	April 1978	1,159	1,626	1,388	464	4,637
General Construction	Nov. 1978	803	2,167	3,532	1,525	8,027
Solid Waste Energy Recovery	Oct. 1980	0	0	0	1,913	1,913
TOTAL		2,988	4,898	7,005	4,616	19,907

TABLE II-4

INCREMENT OF RECOMMENDED OPTION

6.25 MW Thermal Electric Generation System with Either of Two Levels of Solid Waste Incineration,
25 Tons of Solid Waste Per Day (University Only), or 75 Tons Per Day (University and Commercial Community)

		Base Case as Basis for Comparison ①	6.25 MW + Absorption Chillers + LTHW ② ③	University MSW Incineration 25 TPD Incremental	Combined with University Solid Waste Incineration 25 TPD	University and Commercial MSW Incineration 75 TPD Incremental	Combined with University and Commercial Solid Waste 75 TPD
Capital Cost Required to Plant Startup (1976 dollars)		-	8,640	591	9,231	1,691	10,331
Capital Cost Inflated to Project Date of Disbursement	FY 1978	-	1,433	-	1,433	-	1,433
	FY 1979	-	2,242	-	2,242	-	2,242
	FY 1980	-	4,748	-	4,748	-	4,748
	FY 1981	-	1,429	729	2,153	2,066	3,490
	FY 1986	1,158 ④	-	11 ⑤	11 ⑤	23 ⑤	23 ⑤
	FY 1991	1,416 ④	1,416 ④	14 ④⑤	1,430 ④⑤	29 ④⑤	1,445 ④⑤
	FY 1996	-		1,042 ⑥	1,042 ⑥	3,120 ⑥	3,120 ⑥
Cumulative Total of Expended Funds at Plant Startup		-	9,847	729	10,576	2,066	11,913
Capital Cost Required to Plant Startup (1981 dollars)		-	11,098	729	11,851	2,066	13,230
Annual Operating Cost (1981 dollars)		10,017 ⑦	8,008	-304	7,704	-463	7,545
Annual Operating Cost Savings Over Base Case (1981 dollars)		-	2,009	304 ⑧	2,313	463 ⑧	2,472
Present Worth of Net Savings (1981 dollars) ⑨		-	34,799	-	39,594	-	40,447
Savings to Investment Ratio ⑩		-	3.4	-	3.4	-	3.0
Interest Rate of Return (%) ⑪		-	22.0	-	22.8	-	22.4
Payback Time Including Interest (years)		-	5.0	-	5.0	-	5.0

See Table 1 for Explanation of Notes.

TABLE I.I-5

IUS TWO PHASE INCREMENTATION WITH COSTS DISBURSEMENTS BY FISCAL YEAR BASED ON PHASE 1 PLANT START-UP IN 1981

PHASE 1 - 6.25 M.W. THERMAL ELECTRIC GENERATION SYSTEM WITH UNIVERSITY SOLID WASTE INCINERATION 925 TONS/DAY)

Cost Breakdown by Category	Estimated Commitment Date	Disbursements (000) by Fiscal Year					
		FY 1978	FY 1979	FY 1980	FY 1981	FY 1982	Total
Engineering and Fees	Sept. 1977	474	153	85	71	0	783
Turbine Generator	March 1978	112	447	1,062	242	0	1,863
Steam Generation including Pollution Control	April 1978	594	813	731	238	0	2,376
General Construction	Oct. 1978	253	829	2,870	927	0	4,879
Solid Waste Energy Recovery	Oct. 1980	0	0	0	675	0	675
Sub Total, Phase I		1,433	2,242	4,748	2,153	0	10,576

PHASE II - 6.25 M.W. THERMAL ELECTRIC GENERATION SYSTEM WITH COMMERCIAL COMMUNITY SOLID WASTE INCINERATION (50 TONS/DAY)

Cost Breakdown by Category	Estimated Commitment Date	FY 1978	FY 1979	FY 1980	FY 1981	FY 1982	Total
Engineering and Fees	Sept. 1978	0	383	118	111	95	707
Turbine Generator	March 1979	0	101	406	963	220	1,690
Steam Generation including Pollution Control	April 1979	0	574	880	671	239	2,364
General Construction	Oct. 1979	0	210	559	1,434	1,085	3,288
Solid Waste Energy Recovery	Oct. 1981	0	0	0	0	1,306	1,306
Sub Total, Phase II		0	1,268	1,963	3,179	2,945	9,355
PHASE I & II TOTAL		1,433	3,510	6,711	5,332	2,945	19,931

III. SITE DESCRIPTION

A. HISTORICAL

The University of Florida is a combined state university and land-grant college located in the northern center of the State. While its beginning goes back to the days previous to Florida being admitted to the Union in 1845, its first college, the College of Arts and Sciences, did not open until 1853. A few years later the passage of the Morrill Act provided lands for state institutions of higher learning which would promote agriculture, mechanical arts and military science, resulting in the beginnings of the College of Agriculture, the College of Engineering, and the Agricultural Experiment Station.

By 1905 there were a half-dozen state supported institutions of higher learning in Florida, located in various parts of the State and struggling for existence. At that time the Florida legislature took a step unprecedented in the history of education in any state by passing the Buckman Act, which abolished the six State Colleges and provided for the establishment of two new institutions of which the University of Florida was one. It was established for men, located in Gainesville and placed under the direction of the Board of Control, a body created by the Buckman Act. In 1947 the University was made coeducational. The nine member Board of Regents replaced the Board of Control in 1965.

B. PRESENT

The University of Florida is currently the largest of the nine universities in the Florida State University System. The seventeen major colleges located on one campus include the University College, College of Agriculture, the College of Architecture and Fine Arts, the College of Arts and Sciences, the College of Business Administration, the College of Dentistry, the College of Education, the College of Engineering, the School of Forest Resources and Conservation, the College of Health Related Professions, the College of Journalism and Communications, the College of Law, the College of Medicine, the College of Nursing, the College of Pharmacy, the College of Physical Education, Health, and Recreation, and the College of Veterinary Medicine.

C. CAMPUS POPULATION PROJECTIONS

Planning at the University of Florida is not based upon the idea of perpetual growth in numbers. In fact, it is evident that enrollment will level off based upon the following observations:

(a) At present there are nine state universities and twenty-eight public community colleges--an enormous increase of such facilities during recent years.

(b) Recent surveys indicate a decrease in the percentage of high school graduates who plan to enter college.

(c) Since 1957, there has been a steady decline in both the relative and absolute birth rates. The country is below the zero population growth level with the relative birth rate being only two-thirds the 1957 figure.

(d) From 1976 to 1990, the projections are that there will be fewer students entering the higher education pool. This is relatively certain because those future students are already born.

Thus, it would appear that the period of accelerated growth in numbers for the university enrollment is over. One advantage is that now it should be possible to have buildings and utilities catch up with the needs. Now the University can concentrate on providing continuing growth, in quality of both the academic programs and the physical plant.

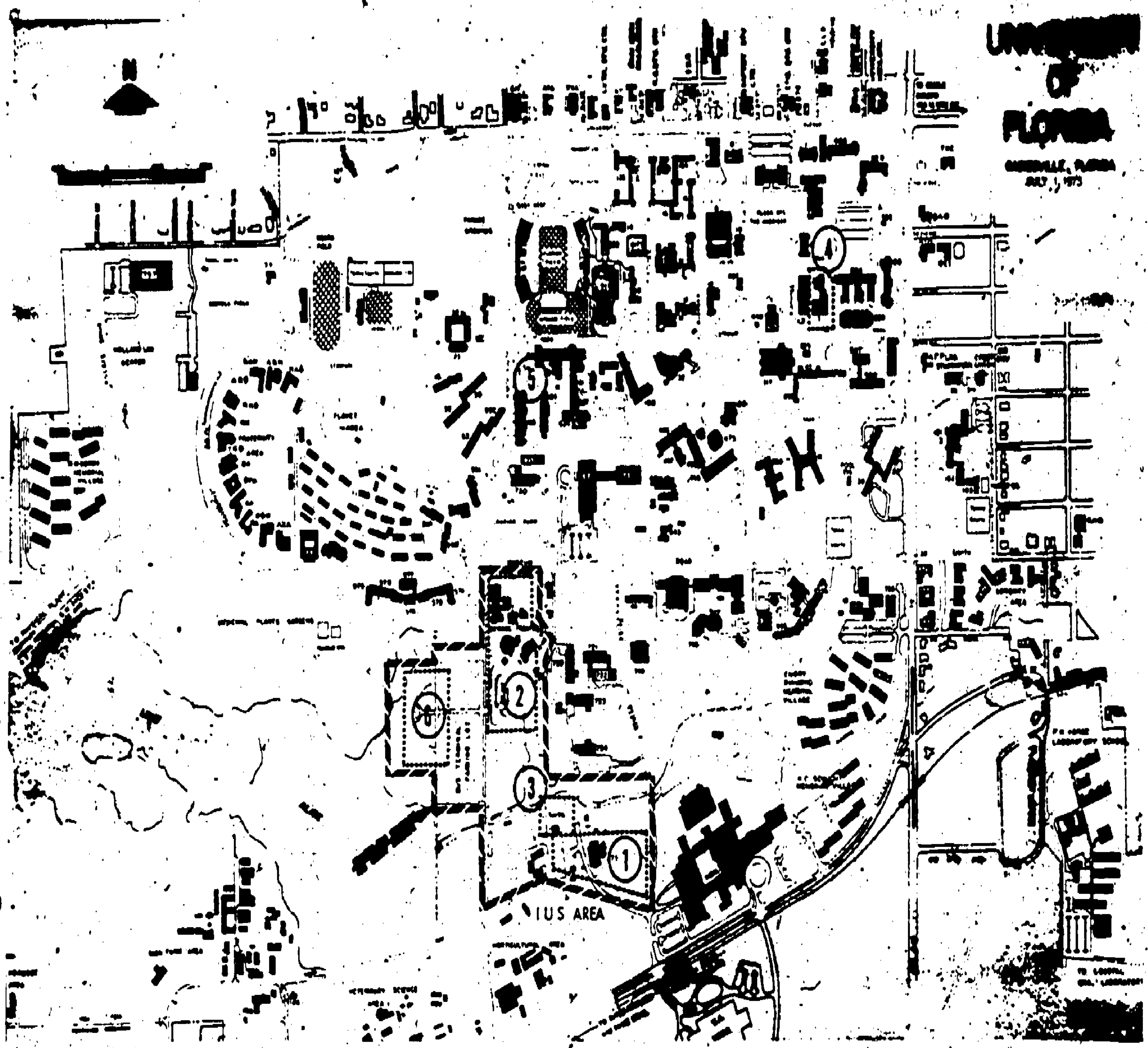
A continued student population growth is anticipated although not at the accelerated rate experienced during the 1960's. Present full time equivalent student enrollment is 24,000 with a faculty of 2,500 and a staff of 7,500. Population projections which have been furnished by the University of Florida indicate a full time equivalent student enrollment of approximately 27,800 in the 1979-1980 school year and a total campus population, considering students, faculty and staff, of 44,000.

D. SETTING

The University of Florida is located in Gainesville, a city of approximately 75,000, excluding the University of Florida students. Situated in north central Florida, midway between the Atlantic Ocean and the Gulf of Mexico, the city is known as an agricultural and small industrial center.

E. CAMPUS LAYOUT

A map of the campus is shown in Figure III-1. The contiguous campus encompasses 1,900 acres with a building floor space of 7,800,000 square feet. The original campus was located in the northeast corner of the present campus with expansion occurring toward the south and west.



① HEATING PLANT NO. 2

② SEWAGE TREATMENT PLANT

③ FLORIDA POWER SUBSTATION

④ WALKER HALL CHILLER PLANT

⑤ HEAT PLANT NO. 1

⑥ REFUSE TRANSFER STATION

FIGURE III-1.

F. EXISTING UTILITY SYSTEMS

The University has steam generating facilities to provide heating and cooling. A small backpressure steam turbine/generator generates a minor portion of the electric power requirements. The University has sewage treatment facilities and operates a solid waste collection and disposal system. The location of these facilities has been identified on the campus map shown in Figure III-1. Additional utility requirements such as electricity and potable water are purchased from outside sources. A detailed description of the existing utility systems is given in the next section.

Expansion plans on utilities and facilities continue to be drawn up while others are executed. A ten year study and expansion program (6) was developed in 1964. The campus facilities have since increased almost two-fold. A second ten year projection and expansion program (2, 4) was initiated in 1973.

G. FUTURE GROWTH OF PHYSICAL FACILITIES

The University of Florida Division of Planning and Analysis has prepared an Anticipated 10-Year Renovation & Replacement Program (2) which describes present planning for the construction of new buildings and the renovation of existing facilities. Since a major portion of this program is for renovation and replacement, future gross building space is not anticipated to increase significantly. However, the renovation program is anticipated to add to the central utility load as local heating and cooling units are retired and the building loads are connected to the central plant.

H. BASIS FOR PROJECTING NEEDS

Forecasts of future requirements for utilities, presented in this report, have been based upon (1) population projections, (2) planning forecasts for future building construction and renovations and (3) historical growth trends in demands for utilities. Each provides data which necessarily influence the other two. Therefore, these data must be carefully analyzed in order to achieve a high degree of accuracy.

Many programs do not follow the historical per student utility needs. The College of Medicine began its operation in 1956 and now accepts 70 students annually in its four year program leading to an M.D. degree. The Medical Center, including Shands Teaching Hospital and related facilities, produced a much higher than normal per student demand on the utilities system. The large increase in research projects carried on at the University produces demands for utilities unrelated to student enrollment. While forecasting utility needs based solely upon enrollment projection has proven unsatisfactory, subsequent experience has demonstrated that utility projections can be made with satisfactory accuracy by properly accounting for the nature of the intended use.

IV. EXISTING UTILITY SYSTEM

A. ELECTRICITY

1. Source of Electricity

A 1,000 kW backpressure turbine/generator at Heating Plant No. 2 generates approximately 5 percent of the total electricity consumed by the University. The remaining electricity is purchased from Florida Power Corporation which supplies the power through two 69/23 kVA transformers at its substation on campus. The substation is located near Heating Plant No. 2 in the southwest section of the campus. Power distribution from the substation to campus distribution vaults is at 23 kV. This voltage is transformed to 4 kV at the vaults and then fed into the campus grid system.

In 1975 the University consumed 124,338,000 kilowatt hours, of which 118,338,000 kilowatt hours were purchased from Florida Power Corporation with the remainder being generated at Heating Plant No. 2. The existing contract between the University and Florida Power Corporation provides for on-site power generation in parallel with purchased power. The contract clause is shown as Exhibit I.

The University has minimum on-site emergency operating capability. When the medical center was constructed in 1956, an emergency power supply was installed. Since that time the facility has tripled in size with no increase in generating capacity. The system was designed to provide power for operating rooms, hall lights and two elevators. There is no emergency power for air conditioning, even in the operating rooms. The University has no other substantial emergency generating capacity.

2. Electrical Loads

The historical and projected electrical loads for the University are presented in Figure IV-1. As is shown, there has been a significant historical annual increase in demand and consumption. The observed decrease in growth of both the peak and the average loads is atrributed to energy conservation measures. The peak purchased electrical demand for 1975 was 24,300 kW. Further reductions in load by conservation measures are not anticipated without implementation of a retrofit program or a load management system. The projected demands on consumption have been made on the basis of previous utility expansion studies, planned building programs and consultation with plant personnel.

The hourly load curves in Figure IV-2 indicate that the kilowatt demand during each season peaks between the hours of 1:00 p.m. and 3:00 p.m. Figure IV-3 gives the daily electrical consumption profile at the University for 1975. The profile is relatively uniform during each season. As indicated in Figure IV-2, there is a significantly

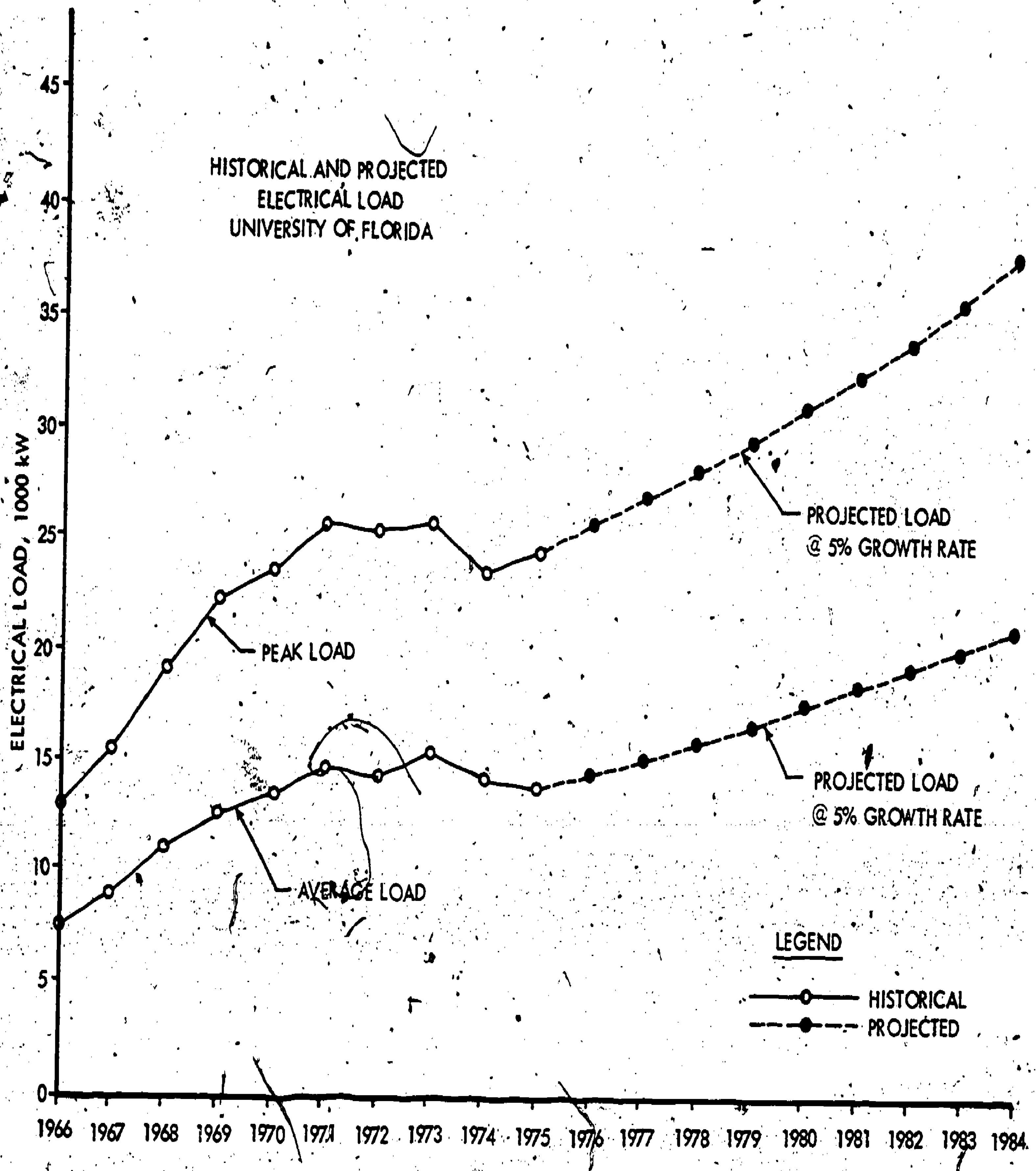
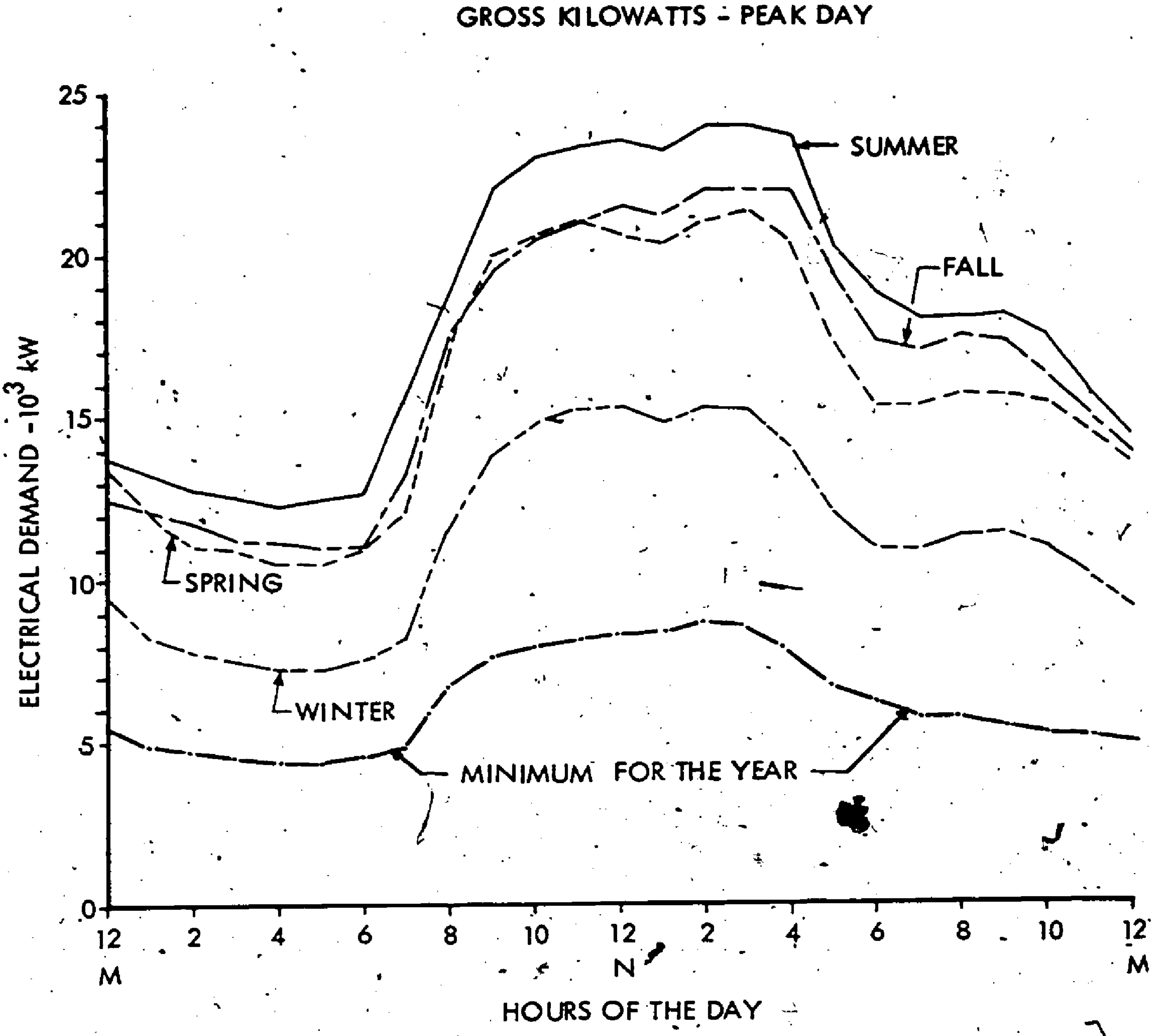

HISTORICAL AND PROJECTED
ELECTRICAL LOAD
UNIVERSITY OF FLORIDA
ELECTRICAL LOAD, 1000 kW
0
5
10
15
20
25
30
35
40
45
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
PEAK LOAD
AVERAGE LOAD
PROJECTED LOAD @ 5% GROWTH RATE
PROJECTED LOAD @ 5% GROWTH RATE
LEGEND
HISTORICAL
PROJECTED

FIGURE IV-1

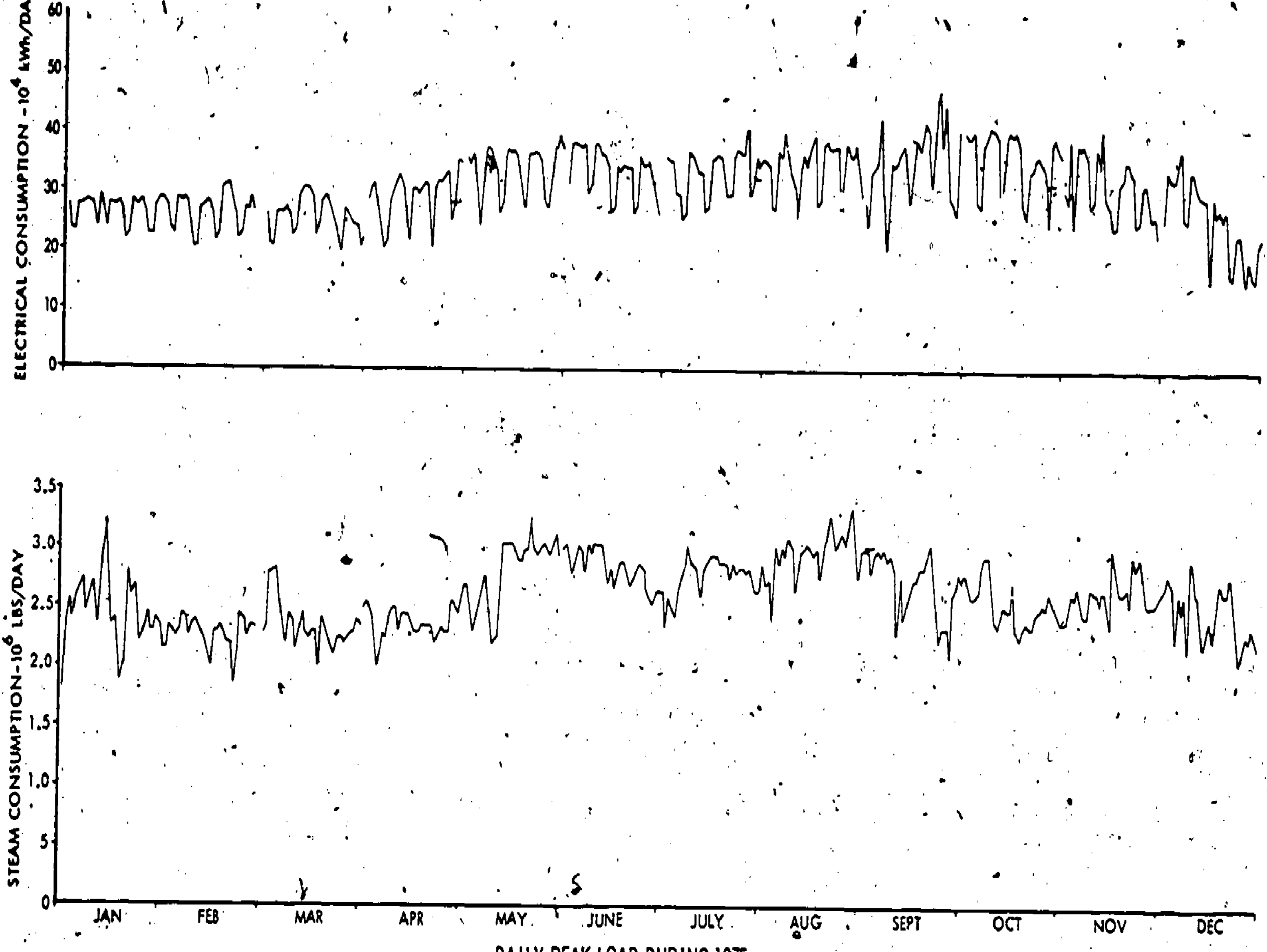


HOURLY LOAD CURVES DURING THE PEAK ELECTRIC
LOAD DAY OF WINTER, SPRING, SUMMER AND FALL OF 1975

LEGEND:

———————— SUMMER, MAXIMUM ELECTRICAL LOAD DAY, SEPTEMBER
———— ——— — FALL, MAXIMUM ELECTRICAL LOAD DAY, OCTOBER
— — — — — — WINTER, MAXIMUM ELECTRICAL LOAD DAY, MARCH
– – – – – – – – SPRING, MAXIMUM ELECTRICAL LOAD DAY, JUNE
—·——·——·— MINIMUM FOR THE YEAR, DECEMBER

FIGURE IV-2



DAILY PEAK LOAD DURING 1975
UNIVERSITY OF FLORIDA GAINESVILLE, FLORIDA
FIGURE IV-3

lower average electrical load during the winter. As is discussed under the chilled water section, this lower load is probably due to the lower air conditioning requirements during the winter. The load duration chart shown in Figure IV-4 indicates that the electric demand is above 10,000 kW for 7,200 hours of the year, and above 16,000 kW for less than 1,600 hours of the year.

3. Cost of Electricity

The existing contract between Florida Power Corporation and the University of Florida (Exhibit 1) outlines the electrical demand charge, average electrical cost and the fuel adjustment charges. Electrical power costs, including fuel adjustments and demand charges to the University, now average $0.0263 per kilowatt hour. Operation and maintenance costs for the electrical distribution system were $162,000 during the 1975/76 season.

B. STEAM

1. Steam Generation

Steam generation was originally at Heating Plant No. 1, located behind Weil Hall. The plant was first installed as a coal-fired operation but was later converted to an oil/gas-fired system when these fuels became readily available. Because of equipment age and economic consideration, the steam generation facilities at Heating Plant No. 1 have been retired. Steam is now produced at Heating Plant No. 2 and distributed through a system of underground mains and branches to the campus buildings. Some buildings that are remote from the central campus have local heating units.

a. Heating Plant No. 1

This plant now operates as a pressure reducing and steam distribution center with Heating Plant No. 2 supplying the steam. Various inter-building steam supply systems are fed from Heating Plant No. 1. The plant also serves as a collection center for condensate from the older section of the campus.

b. Heating Plant No. 2

Heating Plant No. 2 was placed in operation in 1957 and initially served an isolated steam distribution system. Low pressure interconnections were later made allowing limited interchange between Heating Plant No. 2 and Heating Plant No. 1.

A 12 inch, 250 psig steam header was installed to interconnect the two plants in 1967. The plant, whose steam generating equipment is listed in Table IV-1, now generates all the steam used on campus.

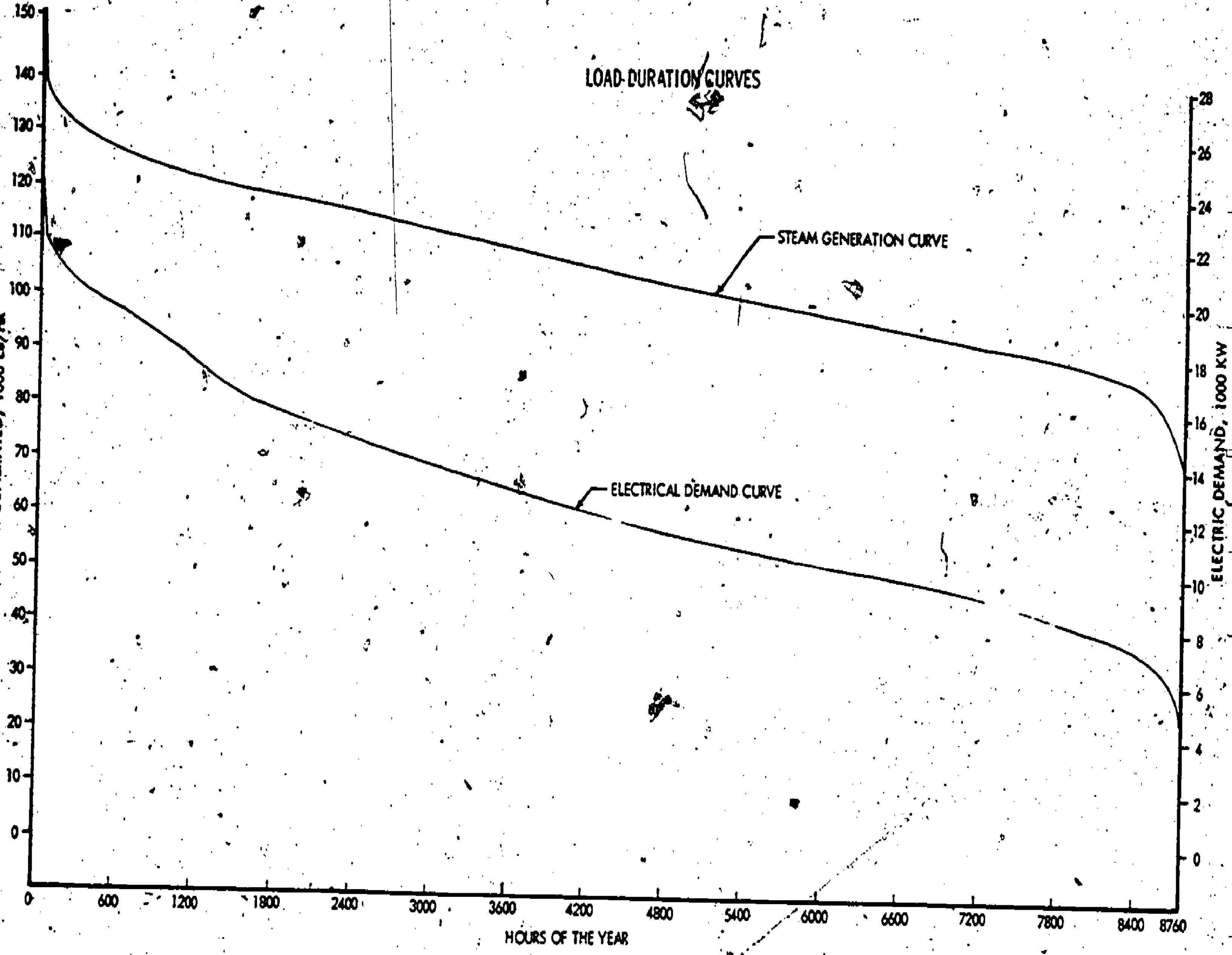

LOAD-DURATION CURVES
STEAM GENERATION CURVE
ELECTRICAL DEMAND CURVE
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
28
26
24
22
20
18
16
14
12
10
8
6
4
2
0
ELECTRIC DEMAND, 1000 KW
0
600
1200
1800
2400
3000
3600
4200
4800
5400
6000
6600
7200
7800
8400
8760
HOURS OF THE YEAR

FIGURE IV-4

TABLE IV-1

EXISTING STEAM AND POWER GENERATING FACILITIES

STEAM GENERATION

BOILER NO.	YEAR INSTALLED	MANUFACTURER	OPERATING PRESSURE, PSIG	STEAM TEMPERATURE °F	BOILER CAPACITY LBS/HR	FUEL
1	1957	COMBUSTION ENGINEERING	250	500	60,000	oil/gas
2	1957	COMBUSTION ENGINEERING	250	500	60,000	oil/gas
3	1967	UNION IRON WORKS	250	500	120,000	oil/gas
4	1973	NEBRASKA BOILER COMPANY	235	500	50,000	oil/gas

POWER GENERATION

TURBO-GENERATOR	YEAR INSTALLED	MANUFACTURER	CAPACITY KW	THROTTLE PRESSURE, PSIG	STEAM TEMPERATURE °F
1	1951	ELLIOT COMPANY	1000	245	404

Present gross installed generating capacity is 290,000 pounds per hour. This capacity will increase to 410,000 pounds per hour when the 120,000 pounds per hour boiler, presently under construction, goes into operation in 1977.

2. Steam Distribution

Steam from Heating Plant No. 2 is supplied to Heating Plant No. 1 at 250 psig pressure. At Heating Plant No. 1, the pressure is reduced to 60 psig and then distributed to the campus. The 1,000 kW steam turbine at Heating Plant No. 2 exhausts into the distribution system at 60 psig. The distribution system includes approximately 20 miles of underground steam and condensate lines. At the buildings, the pressure is reduced to 15 psig and passed through heat exchangers to produce low temperature hot water for intra-building space heating. The central heating plant is estimated to service 7,6 million square feet of space. Some interconnection and looping of the 60 psig distribution system has been installed.

The condensate from most of the northern part and some of the northeastern part of the campus drains to collecting tanks inside Heating Plant No. 1. This condensate is pumped to a storage tank and then flows by gravity to Heating Plant No. 2.

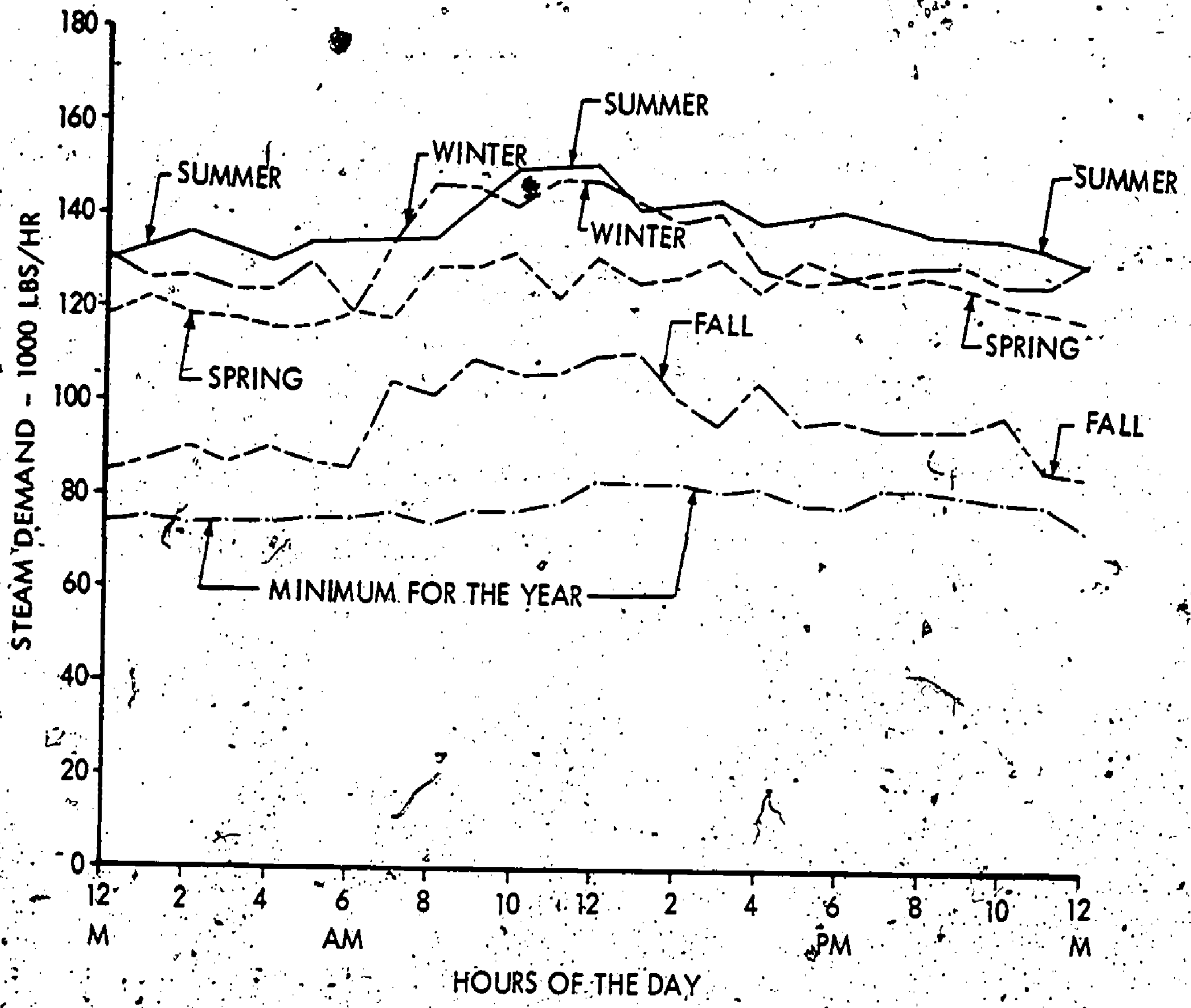
3. Steam Consumption and Demand

Steam demand has been increasing steadily as evidenced by the rise in consumption from 305 million pounds in 1958 to 984 million pounds in 1975. Peak steam demand in 1974/75 was 152,000 pounds per hour. Figure IV-3 shows the daily steam consumption during 1975 with the peak day consumption for each season identified. The relatively flat profile suggests that the steam demand and consumption are uniform throughout the year. The hourly steam load curves in Figure IV-5 also indicate that steam demand for a given day for each season is relatively constant.

The steam load duration curve given in Figure IV-4 shows that for less than 10 percent of the time, the steam load is greater than 125,000 pounds per hour. The curve also shows that for more than 90 percent of the time the steam load is greater than 90,000 pounds per hour.

Figure IV-6 shows the historical and projected steam requirements of the University of Florida combined Heating Plants No. 1 and No. 2. A general upward trend in consumption has been experienced with some reductions due to energy conservation measures which were instituted. Steam consumption is expected to increase with the planned renovation and replacement of University facilities.

Historical peak steam demands are available for only the last four years. Records for the years 1970 and earlier are not available. However, peaks for the years 1958 through 1964 were available in a previous utility report. Peaks for the years

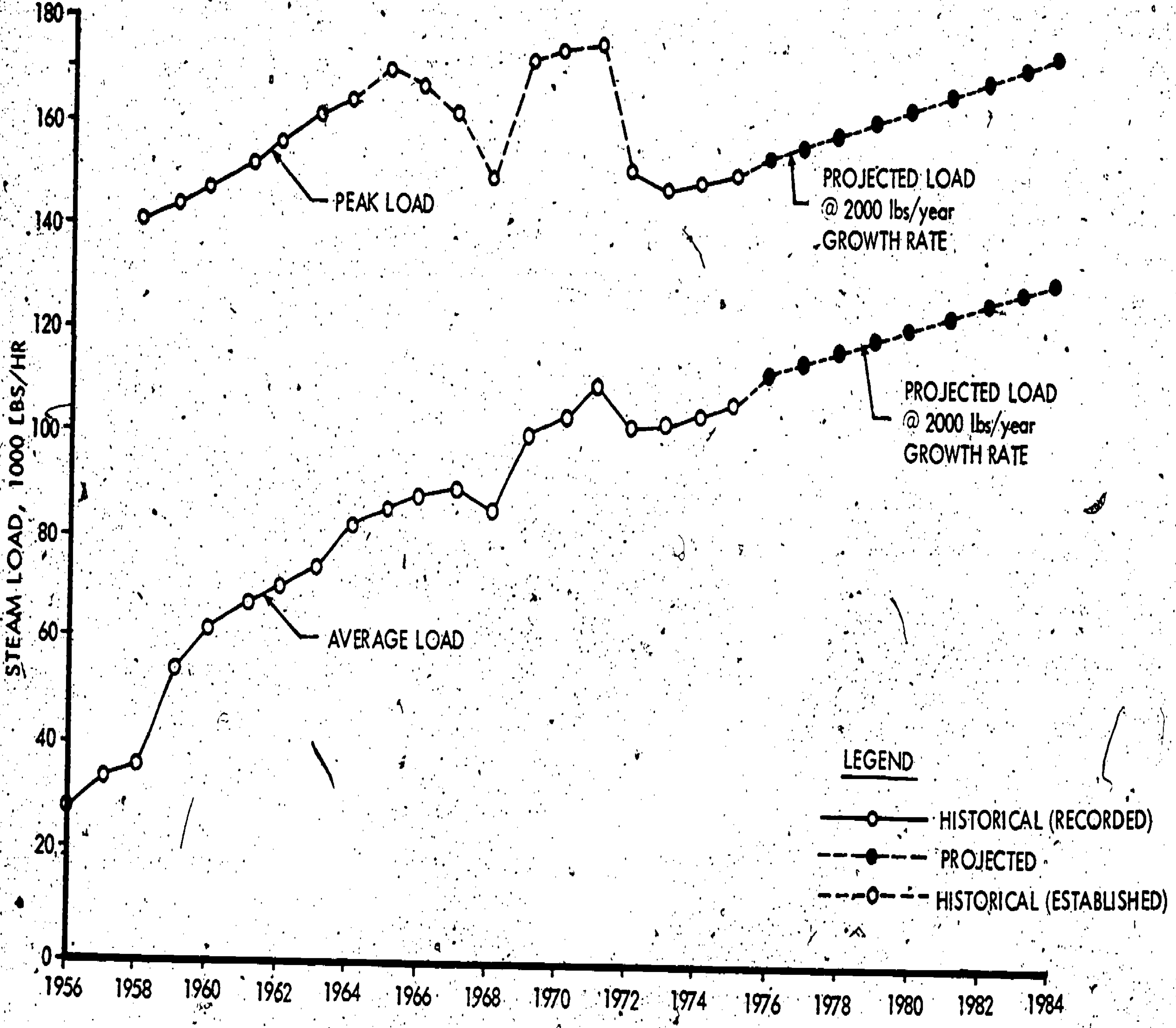


HOURLY LOAD CURVES DURING THE
PEAK STEAM LOAD DAY OF
WINTER, SPRING, SUMMER AND FALL OF 1975

LEGEND:

- ——— – – ——— WINTER, MAXIMUM STEAM PEAK DAY - JANUARY
- – – – – – – – SPRING, MAXIMUM STEAM PEAK DAY - MAY
- ———————— SUMMER, MAXIMUM STEAM PEAK DAY - AUGUST
- — — ——— — — FALL, MAXIMUM STEAM PEAK DAY - NOVEMBER
- —·—·—·—·— MINIMUM FOR THE YEAR, FEBRUARY

FIGURE IV-5



UNIVERSITY OF FLORIDA
FIGURE IV-6

1965 through 1970 have been estimated from generation totals using load factors, the average annual ratio of generation rate to the peak generation rate, starting in 1965 with 51 percent and increasing 2 percent per year. An interesting characteristic of the historical steam load characteristics is the increase in load factors from 25 percent in 1958 to the present 65 percent.

4. Cost of Steam

The cost of fuel for steam generation in 1975/76 was $970,000 while maintenance costs for the steam distribution system in 1975/76 were $100,000. In addition, there is an on-going maintenance and replacement program for steam and condensate piping. The 1973 University of Florida utility study recommends replacement of 10,000 feet of piping in two increments. A design service life of 30 years for field erected boilers suggests that replacement of boilers Nos. 1 and 2 will be required in 1987. A design service life of 25 years for package boilers suggests that boilers Nos. 3 and 4 will require replacement in 1992 and 1998 respectively. Costs for these replacements are included in the Economic Analysis section.

C. CHILLED WATER

1. Cooling System

The policy since 1956 has been to incorporate air conditioning into new classrooms and office buildings. Conversion of older facilities began in 1958 and is continuing. As shown in Table IV-2, central chilled water production is provided by one 2,400 ton steam driven centrifugal chiller, two 1,750 ton steam driven centrifugal chillers and two 400 ton electric driven centrifugals. These chillers are located at the Walker Hall Chiller Plant and Heating Plant No. 2. Two 1,200 ton electric driven chillers are presently being installed at Heating Plant No. 2 to replace three 700 ton steam jet refrigeration units which have been retired.

As a result of a recent central air conditioning feasibility study, the University has begun a ten year program to increase the present combined central chilled water generation capacity of 16,000 tons. This capacity will supply new building loads that are planned for that period. The future plans include the addition of a third central chiller plant located at the site of Heating Plant No. 1 in 1977. While the refrigeration machines presently being installed or scheduled for installation are electric driven centrifugals, future installation could be absorption chillers if they were proven to be advantageous.

2. Chilled Water Distribution

xisting central distribution systems originate from two locations, Heating Plant and the Walker Hall Chiller Plant. They are all underground, two pipe

TABLE IV-2
EXISTING CHILLER EQUIPMENT

CHILLER NO.	YEAR INSTALLED	MANUFACTURER	CAPACITY (TONS)	TYPE (ELECTRIC/STEAM)	LOCATION
1	1957	Worthington	2400	Steam Turbine Centrifugal Chiller	Heating Plant #2
2	1970	Carrier Corporation	1750	Steam Turbine Centrifugal Chiller	Heating Plant #2
3	1970	Carrier Corporation	1750	Steam Turbine Centrifugal	Heating Plant #2
4.	1956	Trane Centravac	400	Electric Driven Centrifugal	Walker Hall
5	1956	Trane Centravac	400	Electric Driven Centrifugal	Walker Hall

systems and they were originally designed to afford sufficient pressure in the distribution pumping system to provide chilled water flow inside connected buildings without building pumps. However, at least two buildings connected to these existing systems have building pumps installed as a result of problems experienced within the distribution loop. Additional chilled water lines are to be installed as the centralization of the chiller plant takes place and the refrigeration machines are installed.

3. Cooling Loads

Present air conditioned space is estimated to cover 6.1 million square feet. Most of this load is not connected to the central chilled water systems but is serviced by unitary building systems. Metering has only recently been installed to record the chilled water production at Heating Plant No. 2. Cooling loads supplied by Heating Plant No. 2, as shown in Table IV-3, have been estimated on the basis of assumed equipment utilization factors and available electrical meter readings at the Walker Hall Chiller Plant.

4. Cost of Chilled Water

Available plant records do not distinguish between steam used to generate chilled water and that used for heating purposes. Both heating and cooling occur throughout the year. The cost of fuel for steam generation is given in the discussion on steam which appears earlier in this report.

The operation and maintenance expenses for the steam distribution system in 1975/76 were $88,000. An increase in the cost of operating and maintaining the system can be expected as new buildings are connected to the system.

D. THERMAL/ELECTRIC LOADS

The monthly electrical and steam loads are given in Table IV-3. The electrical loads include both the purchased power and an average production of 700 kW by the existing 1,000 kW backpressure turbine.

Metering devices have only recently been installed to distinguish the use of steam for distribution for heating and chilled water production by the steam turbine driven centrifugal chillers. An estimate of the heating and cooling provided by Heating Plant No. 2 is included in Table IV-3. To estimate the split in steam use, monthly electrical readings for the Walker Hall Chiller Plant were used to estimate the monthly cooling load profile. The computed steam turbine driven chiller energy requirements and the energy requirements for the 1,000 kW backpressure steam turbine were ...cted from the steam energy to estimate the steam energy distributed to the campus.

TABLE IV-3, THERMAL/ELECTRIC LOADS - UNIVERSITY OF FLORIDA - 1975

	Electricity		Thermal		
	KW, Thousands		Thousand lbs/hr	Million Btu/hr	
	Peak	Average	Steam, Average	Heat, est.	Cooling est.
January	18.1	10.8	110	99	12
February	18.2	13.0	100	96	6
March	21.9	12.5	105	102	5
April	22.3	14.9	107	102	7
May	21.9	14.8	127	102	25
June	22.3	15.8	127	98	30
July	21.5	14.9	125	79	44
August	21.9	15.2	130	75	56
September	25.0	16.4	122	69	52
October	23.6	15.4	115	75	39
November	22.5	14.7	120	89	31
December	20.1	12.5	112	98	15
Year	25.0	14.2	117	90	27

A schematic diagram of the existing thermal distribution system is shown in Figure IV-7.

E. SOLID WASTE MANAGEMENT

Presently the solid waste generated at the University is transported to a sanitary landfill which is under the jurisdiction of Alachua County. Figure IV-8 illustrates the existing solid waste management system. The dependence on this approach to waste management by the University has been largely influenced by operational costs and land availability. However, with operational costs on the increase and land availability no longer a sure commodity, alternate methods for solid waste management are being examined.

1. Collection and Disposal

The University owns and operates its own collection system. Pickup is on a daily basis by three one-man front end loader trucks with two having 31 cubic yards capacity and one having 25 cubic yard capacity. Present figures indicate that approximately 7,000 tons were collected for the year 1974/75. The waste is compacted during the pickup process. No waste segregation is practiced. Resource recovery at present is limited to aluminum cans, which are picked up by an aluminum firm for recycling. Sanitary landfill accounts for all solid waste disposed by the University with exceptions being dried sludge, animal waste, leaves and bushes, and aluminum cans which are disposed of separately. There is limited incineration at the Medical Center and the Animal Husbandry Department. The Medical Center incinerator is used to dispose of toxic and pathogenic materials and the Animal Husbandry Department incinerator is used to dispose of animal carcasses. The rest of the solid waste at these locations is collected and compacted for landfilling. Dried sludge, animal wastes and leaves are used as soil conditioners.

2. Cost

Solid waste disposal costs have been increasing in part because of the increase in land value and also because of the increase in volume of the waste handled. During fiscal year 1974/75, the dump fees to dispose of 7,000 tons of solid waste amounted to $20,000. Operation and maintenance cost during the same period was $47,000.

F. POTABLE WATER

The City of Gainesville presently provides all potable water to the University. The University distributes the water to all on-campus buildings and maintains its own distribution system. The distribution system consists of several thousand feet of 6 to 12 inch mains with average pressure in the system ranging from 50 to 80 psi, depend- on elevation. With water rates scheduled by the city to rise to 67¢ or more per 1,000 gallons, there is the possibility of the University generating its own potable

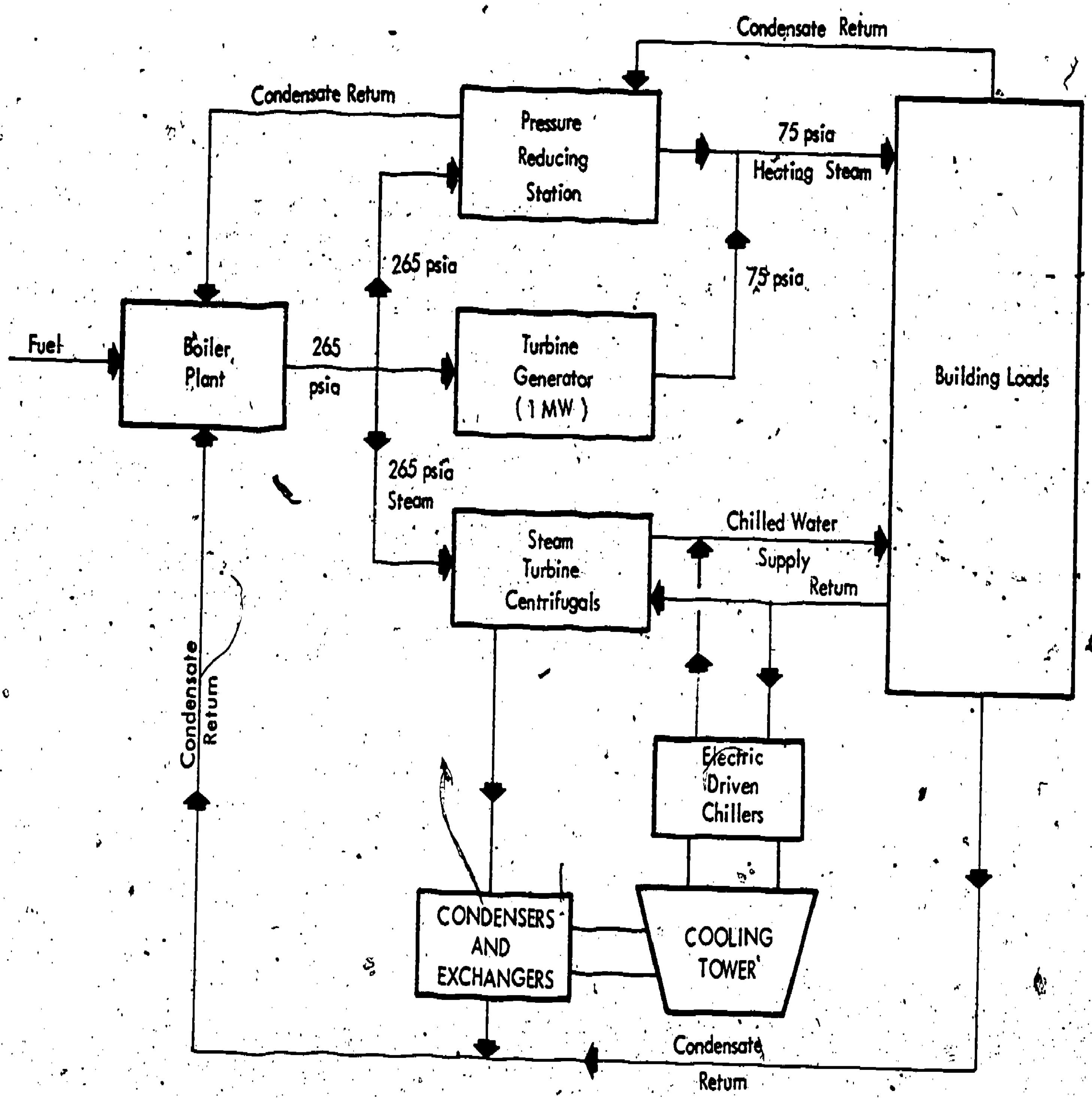


FIGURE IV-7 THERAMAL DISTRIBUTION - EXISTING

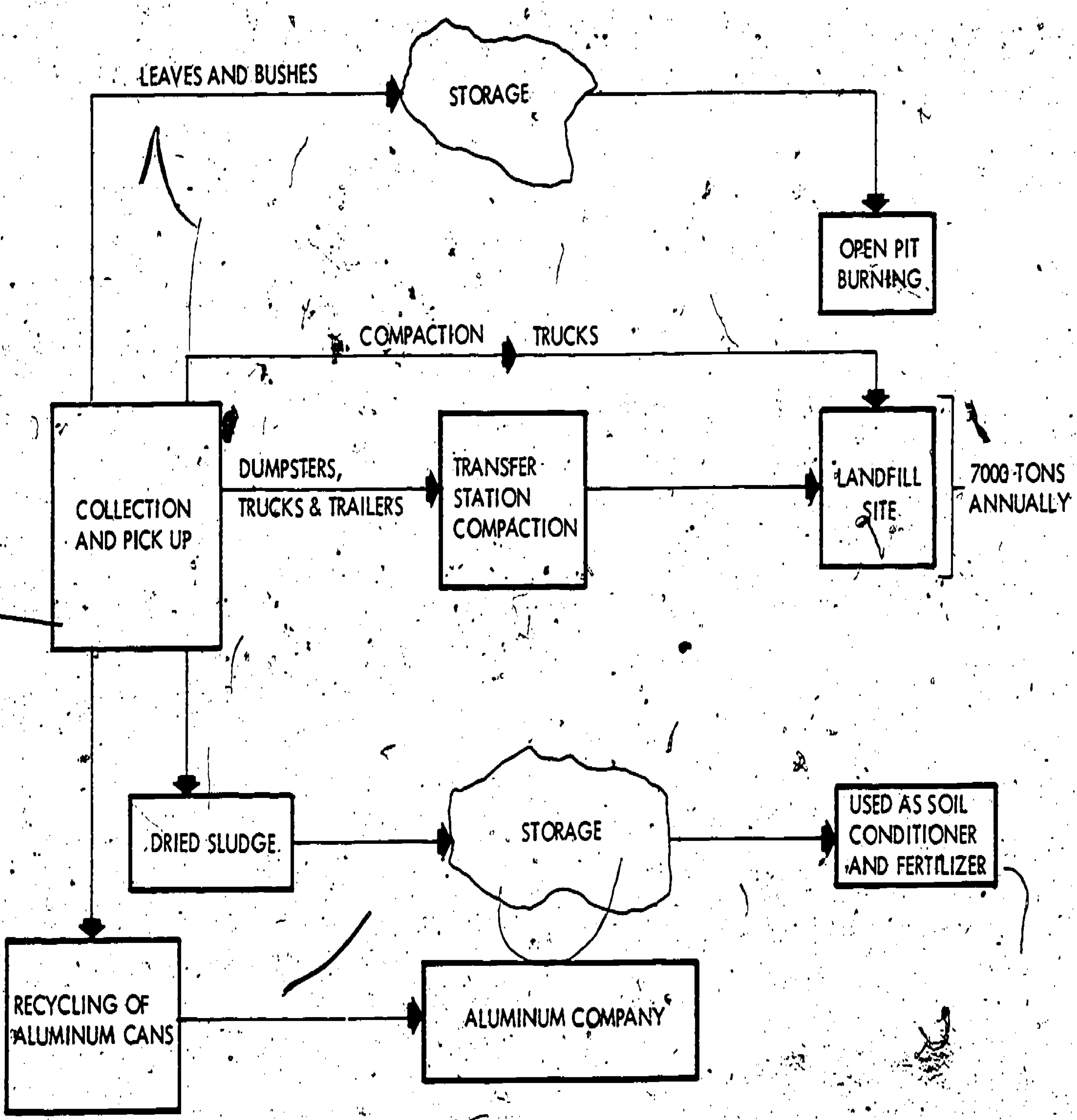


FIGURE IV-8 EXISTING SOLID WASTE MANAGEMENT SYSTEM water, and studies (3) have been performed that show such an option is feasible for the University.

1. Demand

Potable water consumption in 1974/75 was 849 million gallons. Current average daily flow is 2.2 million gallons per day with a peak demand of 2.9 million gallons per day. The peak load has been increasing gradually. It is expected to reach 5,600 gallons per minute in 1978 as compared to 4,700 gallons per minute in 1973. Between 1978 and 1983 a 4 percent increase is estimated with a projected peak demand in 1983 of 5,800 gallons per minute.

2. Cost

The present rate charged by the City of Gainesville to the University is 31.5¢ per 1,000 gallons. Projected operation and maintenance of the distribution system in 1975/76 was $7,000. The cost has not varied significantly in the past. An increase in the cost of operating and maintaining the system can be expected in relation to the number of new buildings being connected to the system.

A new ordinance (2019-0-75-19) adopted on February 17, 1975 by the City of Gainesville provided for a new rate structure. This ordinance also establishes additional monthly charges for fire hydrants, front footage charges and identifiable internal connection charges. The effect of the ordinance will be to increase by approximately 300 percent the water charges the University pays to the City of Gainesville. This prompted the University into making a study to determine the feasibility of the University of Florida constructing and operating its own water treatment facility instead of purchasing water from the City of Gainesville. The study (3) concluded that it would be economically sound for the University of Florida to construct and operate a water treatment facility.

G. SECONDARY WATER

Irrigation at the University of Florida occurs throughout the year. Secondary water pumped from wells, ponds and treated effluent from the sewage plant is used for irrigation. Pond and well water are used for cooling tower makeup.

1. Demand

Although irrigation is intermittent, there is an ever present need for it at the University. There are no records kept on the amount of irrigation water used. The use of well water for irrigation does have a drawback in that it has a high sulfur content. The hydrogen sulfide odor (e.g. rotten eggs) emitted in areas irrigated with well water is quite noticeable.

2. Cost

The operation and maintenance cost for irrigation in 1975/76 was $48,000. An additional cost of $27,300 for watering flowers, trees and other plants was incurred.

H. SEWAGE

1. Sewage Treatment Facilities

The University has its own sewage treatment plant which is located in the central utility area. Its facilities consist of a contact stabilization plant which was expanded in 1967/68, and a trickling filter plant which was placed in full operation in 1948. The plant has undergone considerable upgrading in size and quality since becoming operational. It has also been used for experiments and research by the University of Florida Environmental Engineering Department.

The present average daily flow to the facility is 2.3 million gallons per day with maximum intermittent flows of 196 percent of average. The present design capacity of 3.1 million gallons per day is not expected to be reached until the mid 1980's.

2. Sludge Collection

Sludge from the digesting tanks is discharged into 13,275 square feet of sludge sand drying beds. When dry, the sludge is loaded on trucks and transferred to a storage site to be used as a soil conditioner for landscaping purposes on University grounds. Dried sludge removal from the drying beds is on a weekly basis. An annual volume of 420 cubic yards of this material is removed from the drying beds.

3. Waste Water Usage

Most of the waste water (treated effluent) leaving the treatment facility eventually discharges into Lake Alice. About 5 to 6 percent (37 million gallons per year) of treated effluent is used for irrigation purposes as is shown in Figure IV-9.

4. Discharge Regulations

The treatment facility currently meets all federal and state discharge regulations. Construction improvements are presently being made to ensure high performance levels through the next decade.

A regional waste water treatment facility, Lake Kanapaha Sewage Treatment Plant, w under construction. And, the Florida Department of Pollution Control has ied the University that provisions should be made to connect to the regional

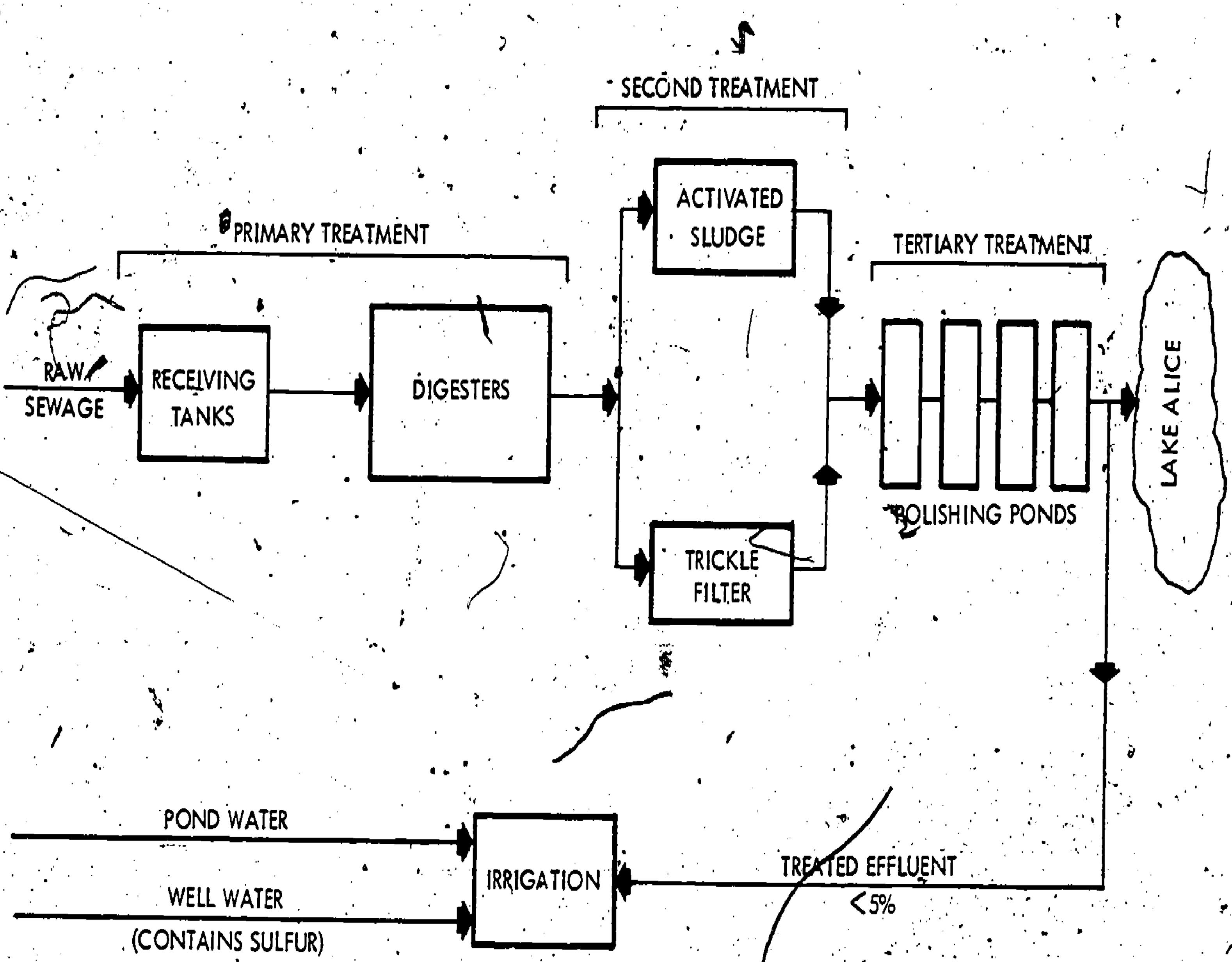


FIGURE IV-9 EXISTING WASTE AND SECONDARY WATER MANAGEMENT waste water system when this facility becomes available. Alternates to constructing the costly interconnection are under study.

The Environmental Protection Agency issues National Pollution Discharge Elimination System (NPDES) permits to facilities in conformance with applicable and approved Section 201 and 208 (of the Federal Water Pollution Control Act (FWPCA)) areawide plans. The Alachua County 208 plan is presently being developed and the role of the University sewage treatment facility in this plan has not been determined. Treated waste water discharge to Lake Alice could possible be limited or denied to allow Lake Alice to meet water quality standards as a receiving water body.

5. Operational Costs

The cost of processing raw sewage to the point where it is discharged into Lake Alice is about $0.24 per thousand gallons. In 1974/75, the cost of treating all the discharged sewage was $132,660, excluding disposal costs.

Dried sludge is collected using the same equipment and personnel used for collection and disposal of solid waste and none of the cost of sludge disposal is included in the total solid waste cost. Operation and maintenance expenses for plant and lift stations amounted to $53,000. No significant increases are expected in the operation and maintenance of the plant.

V. ENERGY AVAILABILITY AND PRICE

This country is in a period which is unique in its history with regard to availability and price of energy. The Arab oil embargo came at a time when domestic reserves were diminishing. The quadrupling of oil prices that resulted has placed greater demands on gas and coal.

Only through federal regulation has the price of interstate gas remained relatively low. However, the increased demand for gas brought about by the price escalations and the shortages of oil, has resulted in significant curtailments in gas delivery over a major portion of this country. It seems likely that future federal legislation will result in deregulation of the price of natural gas, allowing the Btu-equivalent price of gas to reach levels equal to or greater than that of oil.

Natural gas also plays an important role as a chemical feedstock. In fact, there is a strong possibility that the use of natural gas for conventional boiler combustion will be greatly restricted because of its importance in other applications for which there is no practical substitute.

Unlike gas or oil, there are no pricing regulations on coal. Its price has fluctuated with the supply and demand of the market place, with the result that coal prices have increased dramatically in recent years. Even so, the Btu-equivalence price of coal is expected to remain less than that of fuel oil.

The reliability of purchased electric power must also be taken into consideration in planning for future utility needs. Industry and government studies such as that reported by Technical Advisory Committee for the National Reliability Council[9] in 1975 are showing that many areas of the country can expect significant blackout and brownouts during the 1980's, due primarily to curtailment in the construction of new generating facilities that took place subsequent to the Arab Oil embargo.

In summary, there is tremendous speculation as far as the price and availability of any one fuel. The following discussion is an attempt to place in perspective a number of factors that are expected to affect the future fuel picture. One natural conclusion is that if a facility is equipped to burn any of the three fuels, oil, natural gas, or coal, then there will exist the highest probability of fuel availability and at the lowest relative cost. This later consideration played a major role in the assessment of design alternatives.

A. ELECTRICITY

Purchased electricity is supplied by Florida Power Corporation to the University of Florida from two feeder lines. At present, Florida Power Corporation is experiencing a negative 8.9 percent reserve capacity. The Florida power distribution network covers this deficit. Although this could potentially pose a problem with regard to reliability of electric service, Florida Power Corporation is scheduled to bring on line the 825 megawatt Crystal River Nuclear Plant in the spring of 1977, and this should resolve their reserve problems for the foreseeable future.

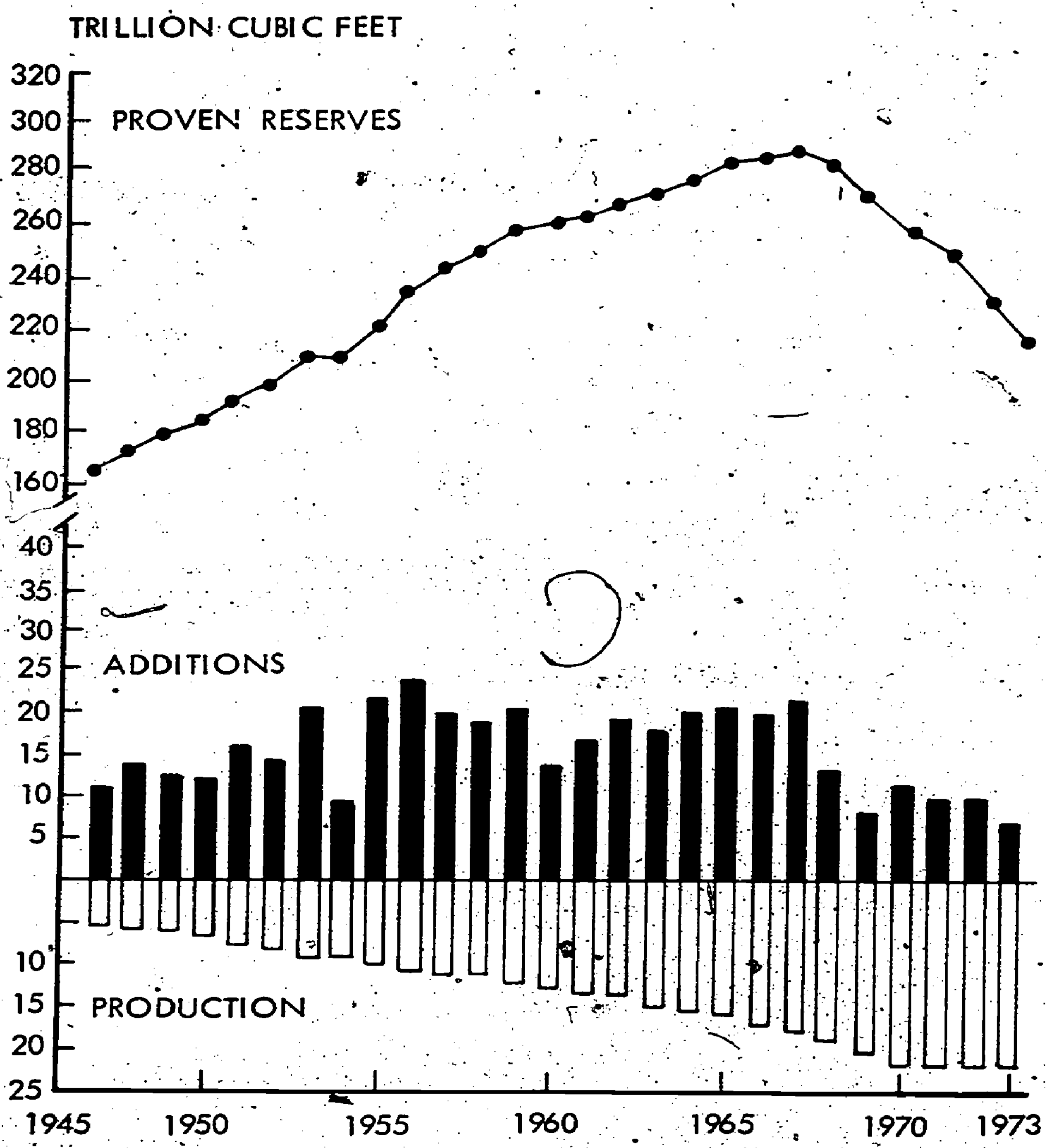
B. NATURAL GAS

A review of the history of natural gas supply shows that the popularity and thus the demand for natural gas has steadily increased because of its low cost, clean burning properties, and until recently, availability. As shown by the production rate on Figure V-1, gas consumption grew at a 6.5 percent average annual rate in the 1950's and 1960's. Natural gas production peaked in 1973 at 22.5 Tcf (trillion cubic feet) and declined (approximately 6 percent) to 21.2 Tcf in 1974 for the first time in history. Reserve additions have failed to equal or exceed production for the seventh straight year. The only significant major reserve addition in recent years has been the Alaskan reserves of 26 Tcf, which was added in 1970.

With the pattern of natural gas demand exceeding supply expected to continue on the national scale, many gas companies have found it necessary to deny gas service to some existing customers. Interrupted natural gas service has become a reality at the University of Florida, while the suppliers projected 40 full days of curtailment during the 1975/76 heating season, the actual curtailment was 89 full days. The situation is not expected to improve. Curtailments projected for next year have more than doubled over the projections for the past year. At a national level, the Federal Power Commission (FPC) has promulgated a uniform, nine-tier curtailment priority schedule (FPC Order 467B) based on the end use of the gas and size of the customer. This schedule is included as Exhibit II. Worthy of note is that under the schedule, the University of Florida falls in the second lowest priority category.

To further complicate this worsening situation, the FPC, in what is considered a landmark decision, has increased the price of new gas 173 percent from its current 52 cents per mcf ceiling to $1.42 per mcf. The price hike which affects new natural gas dedicated to interstate commerce on or after January, 1975, was also accompanied by a decision to increase the price of gas dedicated for interstate commerce between January 1, 1973, and December 31, 1974, to $1.01 per mcf. In addition, the FPC order (Opinion Number 770) provided for a one cent per quarter escalation in price, with the first quarterly increase scheduled to begin on October 1, 1976. The premium nature of natural gas for specialized combustion requirements and as a chemical feedstock seem destined to make natural gas extinct for conventional boilers, either by directive or by price deregulation.

FIGURE V-1
U.S. NATURAL GAS RESERVES (Excluding Alaska)



Source: Federal Energy Administration. The Natural Gas Shortage: A preliminary Report August, 1975.

C. FUEL OIL

Until the oil imports were disrupted by the oil embargo, the United States oil consumption increased 4 to 5 percent per year. Domestic oil production as such peaked in 1970. However, reserves have fallen since 1966; the discovery of the Prudhoe Bay field in the Alaskan North Slope being the only major exception to this trend. With consumption outstripping domestic production, the United States was dependent on foreign sources for 19 percent of its oil supply by 1959. By 1975, this dependence had grown to approximately 40 percent.

In a recent report prepared by the Library of Congress, overall energy shortages will be 9.0 to 9.2 million barrels per day in oil equivalent in 1977; 10 to 10.6 million barrels per day in 1980; and 9.0 to 10 million barrels per day in 1985, assuming an energy growth rate of 2.8 - 3.1 percent yearly over the next ten years. The Library of Congress report also noted that "any additional oil imports to the U. S. will have to come from the Eastern Hemisphere, with most of that from the Middle East and North African countries" which further increases this country's vulnerability to future oil shortages.

Fuel oil costs incurred by the various consuming entities are highly dependent on the type of oil used and its source. For instance, No. 6 oil, a residue which is left after all the light and more profitable cuts have been extracted is sold at the lowest price. The Energy and Oil Act of 1975 set a ceiling of $7.66 on domestic crude oil prices, the Act also has provisions for a 10 percent increase annually, depending upon availability and price.

Currently, the University of Florida is paying $10.60 per barrel of residual oil. It is acknowledged that this is a reduction from the 1975 price of $11.30 barrel which just tends to highlight the unpredictability of oil prices in general. In fact, it should be noted that the OPEC cartel did unilaterally increase crude oil prices some 10 percent in 1975.

The University accrued costs of $411,000 on oil for the heating plant during fiscal year 1974/75, and this figure rose sharply in fiscal year 1975/76 to $600,000. This increase is directly attributable to the rise in the number of days of interruptable natural gas service. By way of highlighting the impact of gas curtailments on the University, an additional daily cost for fuel of $3,100 per day was incurred this past year during natural gas curtailments.

The conclusion to be drawn from these somewhat ominous predictions is that while oil would appear to be available as a fuel for the University, the price will continue to be one of the highest of the available fuels, and the supply might well be vulnerable to further disruptions as occurred with the Arab oil embargo of the not too distant past.

D. COAL

1. Availability

About 83 percent of the known economically recoverable energy reserves in the nation are in the form of coal, and at current coal prices, the mineable reserves are enormous. Even though coal is not presently being produced at rates that can fill the overall energy gap, there is a sufficient supply of both low and high sulfur coal to meet the needs of installations that burn coal.

Coal for the University can be supplied from the West Virginia, Alabama, Kentucky or Tennessee coal fields. Both low as well as high sulfur coals are available from these mines.

2. Transportation

The primary transportation systems for coal are by rail, truck, and barge. An evaluation of rail transport of coal shows that there are good rail connections to the four coal producing states considered, and there is an existing rail line running next to the University which can be used. Should the railway next to the University not be available, the coal could be shipped to the Gainesville area by rail and transported to the campus by truck.

Truck transportation is usually restricted to short distances such as between storage site and power plant or where the coal demand is relatively small. This mode of transportation would not be considered from any of the potential coal fields to Gainesville, Florida.

Barge transportation was found to be more expensive than rail transportation even from the northern Alabama coal fields. The coal first would have to be loaded on rail cars, taken to the nearest barge loading facility, loaded in barges, transported to Mobile, Alabama, loaded to ocean going vessels, transported to Tampa, Florida, unloaded from the vessels into coal rail cars, transported by rail or from Tampa to Gainesville and dumped at the University storage site. At present, there is no barge unloading facility in Tampa for loading directly to rail cars. A facility would have to be built in Tampa or modifications made to the existing unloading facility that belongs to the Tampa Electric Company subsidiary company responsible for coal handling, if barges were to be utilized.

3. Handling

Since the University has not utilized coal for many years, it is appropriate to discuss some of the features of coal handling which are different from other fuels.

a. Loading and Unloading

A main element in coal handling operation is the rail car. Loading and unloading can take place while the cars are continuously moving. However, at the University of Florida unloading would probably be performed by mechanically opening the car doors while the cars are stationary. Weighing will be done at the mines so there will not be need to install additional track scales at Gainesville. Weighing trains on a spot basis to establish average weights for billing purposes will probably be desirable.

b. Storage

Storage is divided into two types. The first is live or active storage under cover, in which the coal is fed directly to the stoker or pulverizer hopper. The second type is reserve or inactive storage, in which the coal is stored outdoors. Active storage facilities would consist of an overhead bunker and/or silo, complete handling equipment that would be self-cleaning and designed for recycling coal that stands for more than a month. Indoor storage would have a live capacity of at least 30 to 72 hours to cover weekends. An outdoor site for locating a storage pile should be raised above the surrounding area, well drained, clean and solid. Coals must be compacted to reduce oxidation and deterioration in heating value. Onsite storage is recommended at the University because it is cheaper and because room is available for such a storage.

At the University, approximately 50,000 tons will be required annually, or an average fuel consumption is 200 T/day. An inactive storage having 90 days reserve capacity is recommended.

c. Conveyance

The conveyance of coal from truck, railroad car or stockpile to the stoker or pulverizer hopper involves a considerable quantity and variety of equipment. Coal usually flows by gravity from the truck or railroad car or is pushed by a bulldozer from the stockpile to a hopper and falls on an apron feeder, bar feeder or reciprocating feeder that moves it to a crusher. It is then discharged to the boot of the coal elevator. The crusher may also be bypassed and the coal fed directly to the elevator boot. The elevator, by means of buckets on an endless chain, lifts the coal to its highest elevation and spills it into a silo. The coal, after reaching the top of the elevator, could also be diverted to a movable chute that by gravity would place the coal in the outdoor stockpile. From the live storage section, it is chuted to a weigh larry, stoker hopper bucket carrier, screw conveyor or belt conveyor for distributing along the length of the bunker gates in the bottom of the bunker allows coal to be fed by gravity to a weigh larry, where it would be weighed and deposited in the burner hopper or through closed chutes with weighing devices to the stoker or pulverizer hoppers.

4. Price

Coal prices reflected the state of the market over the 1973-75 period. Starting at the end of 1973, coal prices began to rise. Spot prices reached record levels in November 1974, during the UMW work stoppage. Long-term contract prices were also negotiated (and renegotiated) at higher levels due to the tightness of the market and cost increases associated with inflation. Starting at the beginning of 1975, spot prices began to drop until they almost reached average long-term contract levels during the summer, where they remained for the rest of the year. This drop reflects the easing of the market during 1975.

That coal prices increased at the same time as oil prices during 1974 led some analysts to conclude that coal would be priced at the Btu-equivalent of oil, with an adjustment for pollution control costs. However, this conclusion was inconsistent with the observations that coal reserves are vast and the industry is composed of enough firms that market forces will push long-term prices to a level reflecting costs plus a fair return on capital; and that even in the short-run (when coal supply is constrained by the time it takes to open new mines), not enough energy consumers have the capacity to burn coal to bid spot prices up to the Btu-equivalent price of oil.

These observations are consistent with actual price behavior. Long-term contract prices were bid up to levels reflecting mining cost with a fair return. Average contract prices include contracts that were negotiated several years ago and are probably lower than the average of contracts signed in the last year. However, there are no indications that new contracts are being signed at a Btu-equivalence with oil. Spot prices were bid up to levels in excess of long-term contract prices, but never to the Btu-equivalent of oil. Most significantly, these spot prices fell as the coal market loosened in 1975, an event totally inconsistent with the argument that coal will be priced equivalent to oil.

The price of low sulfur coal delivered to the University of Florida from West Virginia was estimated at $30 to $40 per ton based on discussions with rail transportation personnel and coal brokers.

7

VI. CONVENTIONAL SYSTEM CONCEPTUAL DESIGNS

To establish the overall potential for implementing an IUS at the University of Florida, comparisons are made between the operations of the existing utility systems, which are termed baseline, and the IUS approach to supplying the utility services. The configuration and load demands of the typical conventional system are established from a review of existing operations. The comparable IUS is sized to provide the same services as are provided by the existing systems.

The University of Florida utility system is typical of many conventional utility installations. Like other community utility systems, the University of Florida may be forced to use coal as the primary fuel in the future. The possible economic impact of converting to coal is examined in the light of proposed legislation.

A. BASELINE (EXISTING) SYSTEM

1. Projected Equipment

The baseline system against which design alternates are compared is the existing system with projected replacements and expansions. Continuation of the present modes of operation is assumed and the all new hardware is assumed to be similar in type and performance to the existing system.

The initial phases of a 10 year utility upgrading program are presently being affected. The anticipated major capital expenditures can be summarized as follows:

(1) Boiler replacements of 120,000 pounds per hour steam generation capacity by 1986 and an additional 120,000 pounds per hour steam generation capacity by 1991.

(2) Steam distribution line replacement.

(3) Chilled water generation capacity expansion.

(4) Central chilled water distribution system.

(5) Sewage connection to regional treatment system.

(6) Replacement and renovation of buildings.

It should be noted that in the cost comparisons between the baseline and IUS alternatives only the cost for replacement of the boilers is shown. The items in (2) through (6) would occur in any case as part of the on-going maintenance program at the University.

2. Equipment Loading Schedules

The equipment loading schedule can substantially effect the electrical and steam requirements and, hence, the performance of a utility system. In the analysis of the existing system and each of the alternates, an equipment loading schedule was chosen which was considered to provide the best performance for the mix of equipment available for the given alternatives. The analysis of the performance of a system involves an hour by hour evaluation of the interactions of the various system components. No attempt was made to optimize the hourly loading schedules.

In the analysis of the existing system, existing and anticipated electric motor driven chillers were base loaded, with the existing steam turbine driven centrifugal chillers providing peaking. This appears to provide the best economical operation of the existing conventional system and is consistent with the anticipated University practice.

In the IUS alternates, the proposed absorption chillers and existing steam turbine driven chillers were base loaded, with the existing electric motor driven centrifugal chillers providing peaking.

3. Performance

The performance of the existing utility system and projected requirements have been given in the previous section. For comparison of alternate design options, the system requirements for the first year of operation (1981) of the proposed IUS have been made for all systems. These projected requirements have been summarized in Table VII-1 of the next section.

B. COAL FIRED CONVENTIONAL SYSTEM

1. Rationale

A conventional alternative to the existing operations is the replacement of the present gas/oil fired boilers with coal/oil/gas fired boilers. Coal supply sources are available to the University of Florida at an energy cost which is highly favorable when compared to oil. Furthermore, there is legislation under consideration which, if enacted, would require that new and, to the extent practicable, existing major boilers which utilize fossil fuels be capable of utilizing coal as their primary energy fuel.

2. Concept

Since the existing gas/oil fired boilers cannot be practically converted to burn coal, it is assumed that coal fired boilers will be installed as replacements. The boilers will have a steam generating capacity of 240,000 pounds per hour at the present operating conditions of 265 psia and 500° F final temperature. Existing boilers would be maintained for standby operation and future peaking requirements.

For ease of comparison to the proposed IUS alternatives, it is assumed that the new coal fired boilers would be operational in 1981. The boilers being replaced will be retired early.

3. Performance

The new boilers would include economizers and air preheaters as heat recovery equipment and, hence, are anticipated to have an average thermal efficiency of 84 percent. This compares to the 80 percent efficiency which has been assumed for the existing boilers without heat recovery devices. The major difference between the baseline system and the coal fired conventional system will be the increased operation and maintenance costs and the decreased fuel costs. The economic analysis for this case is provided in Section VIII.

VII. INTEGRATED UTILITY SYSTEMS CONCEPTUAL DESIGNS

A. POTENTIAL ADVANTAGES OF AN IUS APPLICATION

1. Reduced Costs of Operation

The University of Florida, by virtue of its size, consumes a significant quantity of energy and other resources through its utility system each year. Hence, an increase in the efficiency of utility operations can result in a considerable dollar savings. The reduced energy and operation costs resulting from the utilization of utility subsystems make the implementation of an IUS attractive for the University of Florida.

2. Reduced Energy Requirements

The implementation of an IUS would reduce electrical power purchases and overall energy requirements. Existing steam loads at the University are adequate to permit significant by-product electric power generation throughout the year. The flexibility of a select energy system would permit continued parallel operation with Florida Power Corporation.

3. Multi-Fuel Fired Boilers

An IUS plant can be designed to fire coal, oil and gas, unlike the existing heating plant which is limited to firing oil and gas. The availability of oil and gas is uncertain and the unit cost of each has been increasing dramatically in the past few years. Availability and economics suggest that coal is the preferred fuel choice. A rail line exists next to the University and the coal supply sources are available.

4. Energy Recovery from Solid Waste

Incineration of the University solid waste in incinerators equipped with heat recovery units would reduce primary fuel consumption and the volume of refuse transferred to landfill for burial.

5. Reduced Waste Water Discharges

Increased use of treated waste water to supplement cooling tower makeup water and the irrigation requirements to the campus would provide surface and well water conservation and reduce the discharge of the sewage plant effluent to Lake Alice.

6. Design Basis for Retrofit and Modification

The fundamental principles on which the IUS concept is based give direction to system specifications which can result in a more efficient overall utility operation.

The IUS conceptual designs envisioned for the University of Florida will allow incremental additions to the utility system to realize these increased benefits. While the University of Florida already has existing utility systems that provide the required services, there is a continual replacement and modification of utility hardware as the equipment ~~ages~~ and the system load demands change, fuel price and availability change, and more stringent environmental regulations are promulgated.

B. CONCEPTUAL DESIGNS

1. Objectives

Conceptual designs have been developed with the objectives of (1) meeting existing and projected loads, (2) utilizing as much of the existing systems as possible, (3) allowing phased installation with anticipated replacement programs, (4) having sufficient flexibility to realize economic and environmental benefits to the fullest extent.

2. Basis for Comparison

In this study, the performance of alternate IUS conceptual designs are compared against that of the existing utility system for meeting the utility service requirements projected for 1981. The heating and cooling loads are the same for all cases; however, the electrical loads differ because of the alternate methods used to satisfy the heating and cooling loads. The life style and operation of the University were not changed, only the methods of providing utility service.

3. Performance

The performance of the conceptual design options has been considered under three subsystem groups: (1) Thermal Electric Generating System, (2) Solid Waste Management and (3) Water Management. The conceptual designs and system technical performance are presented for the various options in the present section. The Economic Analysis and Environmental and Institutional Factors have been considered in later sections.

The evaluations of performance were based on IUS configurations in which no effort was made to optimize the utility system through building conservation measures in large pattern and lifestyle, although some variations were studies. The study was not intended to represent the most energy efficient application of an IUS, but rather represents an attempt to achieve an economical and cost effective application of the IUS concept to an existing site. The technologies used are representative of commercially available components as of mid-1976.

4. Scope

a. Systems

Integration of utility systems can embody all aspects of the generation, treatment, distribution, collection, usage, and control function of providing utility services. This study has focused on the integration of the utility generation and treatment functions for more efficiently providing present and projected utility services. Modifications of the utility distribution and control system, which would increase the effectiveness of an IUS, have been observed and recommendations for independent study have been made.

b. Geography

Although the extent of geographic concern included the total campus area, the study is effectively limited to those buildings connected to the central distribution systems. Buildings in remote areas have unitary heating and cooling systems and have not been connected due to the extent of underground distribution piping required. The feasibility of extending the central distribution systems to include these remote thermal loads for increased waste heat utilization should be considered in an independent study.

5. Conservation and Retrofit Integration

The retrofit of buildings to affect conservation measures and the scheduling of occupant activity patterns can be investigated as possibilities for altering utility demands to provide a more optimal integration of subsystems. While there has been no attempt to include these integration possibilities in this study, conservation projects that provide reductions in energy consumption fit into the IUS concept and should be pursued. Any reduction in utility service requirements reduce the equipment size and hence capital outlay of an IUS.

C. THERMAL/ELECTRIC GENERATION SYSTEM

1. Overview

The Thermal/Electric Generation System provides the heating and cooling requirements and generates electricity as a by-product of meeting these thermal needs. Alternate designs have been presented and evaluated for the Thermal/Electric Generation System at the University of Florida. Rather than optimize one system, modifications of the utility system have been explored.

a. Selection of Systems and Generating Conditions

The conceptual design examines the possible modes of combined thermal and power generation. A prime mover is selected on the basis of its flexibility and the potential for integration with the existing system. Operating conditions for the design and performance evaluation of the equipment components are presented.

b. Design Alternates

The approach has been to examine a basic design which could be easily interfaced with and would require a minimum of modification of the existing utility system. Expansion of the basic design and modifications of the existing system were then examined as alternates which could be programmed for immediate installation or be installed in phases.

c. Conceptual Design for Existing Load Characteristics

One alternate considers the possibility of a system which will be fully loaded at all times but generates only a portion of the present thermal needs. A second alternate is sized to generate all the near term thermal needs of the campus; the excess steam generating capacity during non-peak thermal loads is used to generate additional electricity.

d. Conceptual Design for Modified Load Characteristics

The advantages of a dual purpose power plant to the University of Florida can be incrased by improving the match of the electrical to process heat consumption and generation ratios. Since the present University of Florida electrical to process heat consumption ratio is greater than twice the power to process heat ratio of steam turbine cycles with the existing thermal distribution conditions and loads, alternate system designs which would modify the electrical to process heat consumption ratio and/or reduce the pressure at which the steam is extracted from the steam turbine have been proposed.

The power to heat consumption ratio can be favorably modified for a total/select energy system by the proper selections of chilled water generation equipment in the anticipated expansion of the central air conditioning system expansion. An alternate design is presented to compare the performance of absorption chillers against the existing plans for electric motor driven centrifugal chillers.

And, as an alternate to reducing the steam distribution supply pressure to affect a better electrical to heat generation ratio, the conversion of the existing steam thermal distribution system to a low temperature hot water distribution system is considered.

2. Mode of Energy System Operation

There are two concepts possible for supplying electrical power to an IUS facility -- total energy and select energy. The two concepts, as described below, are similar in that each system meets the necessary thermal requirements of the consumer while providing a portion or all of the electrical demands.

a. Total Energy

The Total Energy system allows the user to operate independently of the local utility. The Total Energy system generally has standby generating equipment available to provide all necessary power in the event of scheduled or unscheduled shutdowns of the main generators.

b. Select Energy

The Select Energy system provides as much electricity as can be generated under given steam demands. Power in excess of the turbine generator capacity is purchased from the local utility. The Select Energy system does not require full on-site backup capability, since the local utility would provide necessary power in the event of the system being off-line. Optimization of the turbine generator performance can be accomplished by sizing the system such that for the majority of the time the system operates at full design capacity.

A Select Energy system is recommended for the University of Florida because (1) the Select Energy system can be designed to provide the most economical balance of thermal and electrical generation, (2) a high service reliability can be provided through parallel operation with the present commercial power supplier; the existing contract with Florida Power Corporation allows parallel operation, (3) the present demand charge schedule is such that a significant portion of the power requirements can be generated on-site without subjecting the University to excessive demand charges due to system failure, (4) the Select Energy system provides a flexible design which can be incrementally modified to meet future operation requirements and economic conditions (indeed, the Select Energy system can be later enlarged to a Total Energy system), and (5) the incremental installation will allow a capital outflay flow which can be phased with available funding and University needs.

3. Selection of Prime Mover

A number of prime movers are available in the size range required for application at the University of Florida. These include combustion turbines, internal combustion reciprocating engines and steam turbines.

a. Combustion Turbines

The combustion turbine has relatively quick start capability. And, when coupled to a heat recovery boiler, a combustion turbine can easily produce large quantities of steam. The main drawback of combustion turbines is that they produce large quantities of waste heat relative to the amount of electrical generation. With the existing electrical/thermal requirements at the University of Florida, a large portion of this waste heat would be in excess of that required to satisfy the thermal loads and would have to be exhausted to the atmosphere. The fuel required by combustion turbines is of premium quality and relatively expensive. For these reasons, combustion turbines were not considered as prime movers for the University of Florida.

b. Diesel Engines

Diesel engines are more efficient in terms of heat rate (fuel consumed per unit of electrical generation) than the combustion turbine. These machines are easy to start and can assume load quickly. Diesel generators are readily available in the size range required for application to the University of Florida.

Employment of heat recovery equipment to a diesel generator set can raise the overall thermal efficiency to 75 percent. The majority of the heat is available at relatively low steam pressures of 15 psig or less and/or low water temperatures of 240°F or less. Heat may be recovered at higher temperatures and pressures but the decreased quantities available under these conditions does not make this mode of operation attractive.

Diesel fuel oils can be of a variety of grades but the availability and prices are subject to a number of non-technical conditions.

The present heating system is designed for steam distribution at 75 psia, which effectively rules out the use of a diesel as the prime mover with the present heating system. A diesel engine could be considered as a prime mover if the thermal distribution system were converted to low temperature hot water.

c. Steam Turbines

Steam turbines are the most versatile of the three prime movers under consideration for a number of reasons. The boilers have the capability of firing a multiplicity of fuels which increases the flexibility of the University in seeking the cheapest, most readily available fuel.

Steam turbines are available in two general forms--the backpressure type and the condensing type. The backpressure turbine acts as a pressure reducing valve and generates electricity as a by-product of pressure reduction. The backpressure turbine generator is directly related to the thermal demands. A condensing turbine can generate electricity without a thermal load because the excess steam needed for power generation is passed on to the condenser and not to the steam distribution system. Extraction ports are generally provided for the regenerative boiler feedwater heating system. These extractions may also be used to provide steam for distribution to meet the thermal loads. The specified turbine will be an automatic variable extraction type equipped with internal controls that allow the extraction of as much steam, within the limits of the unit, as is required to meet the thermal demands.

4. Automatic Variable Extraction Steam Turbine Power Plant

The proposed power plant system includes a coal fired boiler with coal and ash handling facilities, automatic variable extraction non-condensing steam turbine generator unit with high, medium, and low pressure extraction points for the stipulated steam demands, steam condenser, circulating water system and forced draft cooling tower. Feedwater heating and deaeration are accomplished by feedwater heaters located at the steam extraction points.

Normal operation will accomplish production of electric power simultaneously with the extraction of steam required for building heating, hot water supply, building cooling and process requirements. On-site electrical power will be generated at 13,400 volts and transformed to 23,000 volts for campus distribution. Additional power, as required, will be purchased from Florida Power Corporation under an existing contract which allows the parallel generation of power. The existing boilers in Heating Plant No. 2 will be maintained and operated to provide backup and supplemental steam generation.

A schematic diagram of the proposed IUS thermal distribution system is shown in Figure VII-1. The system will require piping from the new facility to the existing plant where connections to the present distribution will be made.

a. Energy Balance for Turbine Cycles

The rationale for selection of the conceptual design equipment and operating conditions are given below. The computations of the dual purpose plant heat balances were performed on a digital computer and the results of these computations for specific conditions are given in Exhibit III.

A number of assumptions concerning the expected operation of the steam turbine and associated equipment have been made so that the turbine heat balance could calculated. These assumptions can be refined during the engineering design phase when the detailed characteristics of the power plant equipment are better

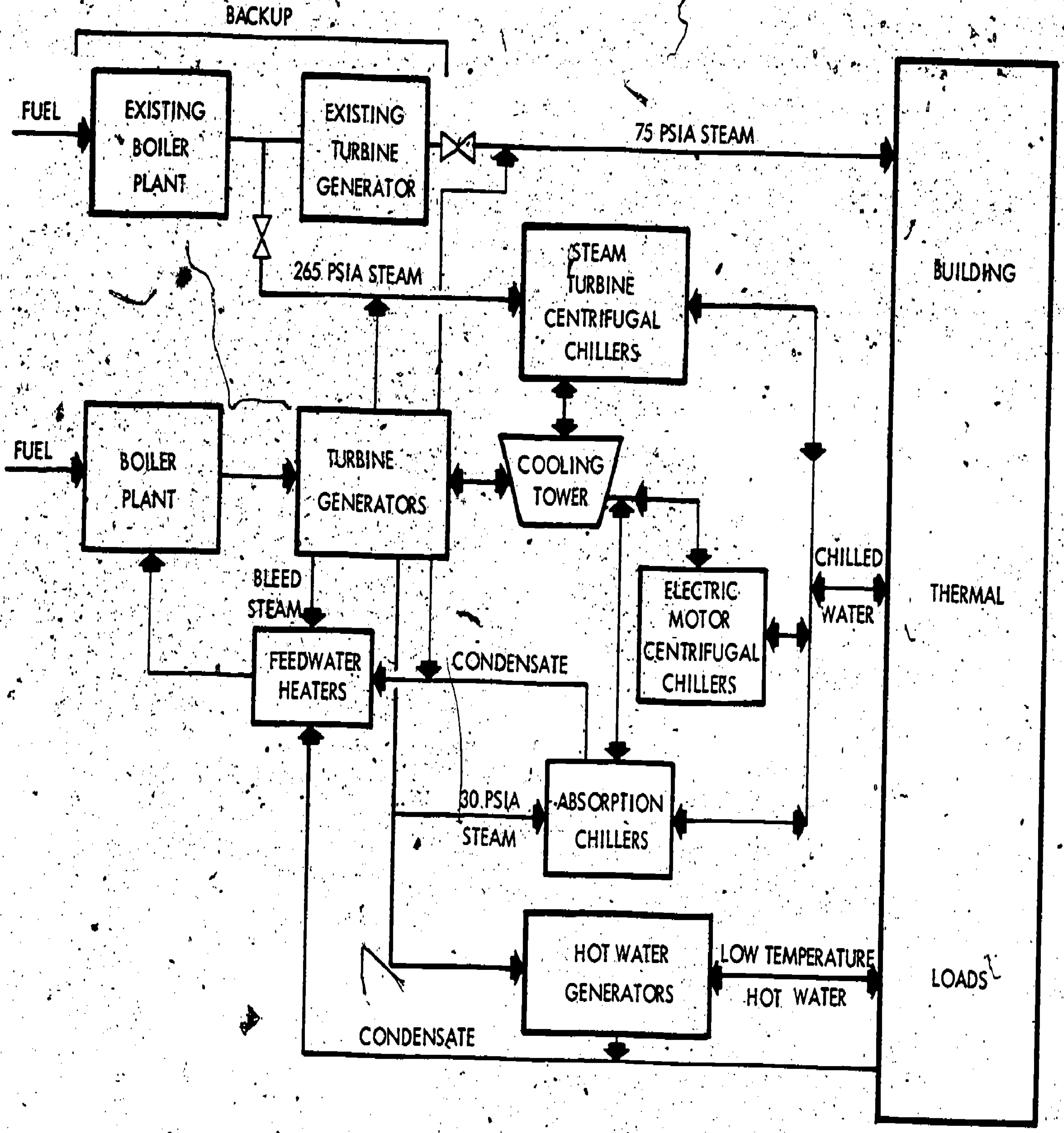


FIGURE VII-1 THERMAL DISTRIBUTION SYSTEM IUS known.

b. Steam Turbine Cycles

Fuel chargeable to power generation in a dual purpose power plant can be as low as 4,500 Btu/kWh when all the heat in steam exhausted and/or extracted from a steam turbine is used for heating and cooling. This power generation is often referred to as by-product power.

The University of Florida requires more power than can be generated as a by-product of providing heating and cooling. Even so, this by-product power can be supplemented with condensing power and/or purchased power and still use appreciably less fuel than the 11,275 Btu/kWh of Florida Power Corporation (FPC) for generating and transmitting power to the University of Florida.

Higher initial steam conditions and lower process steam pressures have the favorable effect of increasing steam turbine by-product power generation per pound of process steam used.

1.) Turbine Inlet Conditions

There are two alternative methods of selecting the inlet steam conditions; one to give the maximum electrical output, and the other to obtain a given exhaust temperature in the steam.

The inlet steam conditions can be chosen to give slightly superheated steam at the pass-out, but this will only occur with one particular flow through the high pressure portion of the turbine. If the flow alters, either due to a change in pass-out demand or to a change in condenser flow, the temperature of the steam in the pass-out will vary. It is, therefore, better to desuperheat the pass-out steam, if necessary, and set the inlet steam conditions from other considerations.

To obtain the maximum output from a given steam quantity, high inlet pressure and temperatures are required. It then becomes necessary to consider the practical limitations on pressure and temperature.

High temperatures require the use of alloy steeks for the boiler, high pressure pipework and the high temperature portion of the turbine. The usual limit for carbon steels is about 750°F for most parts except those which are highly stressed, such as the turbine rotor where the temperature at which the materials must be changed is much lower. For temperatures up to about 850°F, carbon steel containing 0.5 percent molybdenum would be used for the pipework, turbine cylinder and other highly stressed parts with a 3 percent chrome/moly steel for the rotor. At higher temperatures up to about 950°F, a 1 percent chrome/moly steel would be suitable for the pipework, steel for the turbine casing, and 1 percent chrome/moly/vanadium steel for the steam belts of chrome/moly/vanadium steel to prevent high temperature steam coming into contact with the turbine cylinder which can then be made of a cheaper material.

The maximum pressure and temperature of the system will also determine the type of feedwater treatment required. At pressures above 600/650 psig, it becomes necessary to change from a simple ion exchange system to complete demineralization of the feed water. This increases the running costs of the feed water treatment plant by about three times, as well as the capital cost. The advantages to be gained by increasing the pressure above this limit depend on several factors, the most important being the amount of makeup required and the initial condition of the raw makeup water. If complete demineralization is used, there will be a small savings, as continuous blowdown of the boiler will not be required.

Also, the boiler manufacturers have a series of preferred steam conditions. These are, at the turbine stop valve: 400 psig, 750°F, 600 psig, 800°F, 900 psig, 900°F, and 1,500 psig, 950°F. All of these have at least 300°F superheat. It is not necessary to follow these steam conditions exactly.

For this conceptual design, the turbine stop valve steam conditions were chosen to be 850 psia and 900°F to obtain the maximum output and the best boiler operating conditions consistent with the commercial availability of hardware in the size range of the University of Florida IUS.

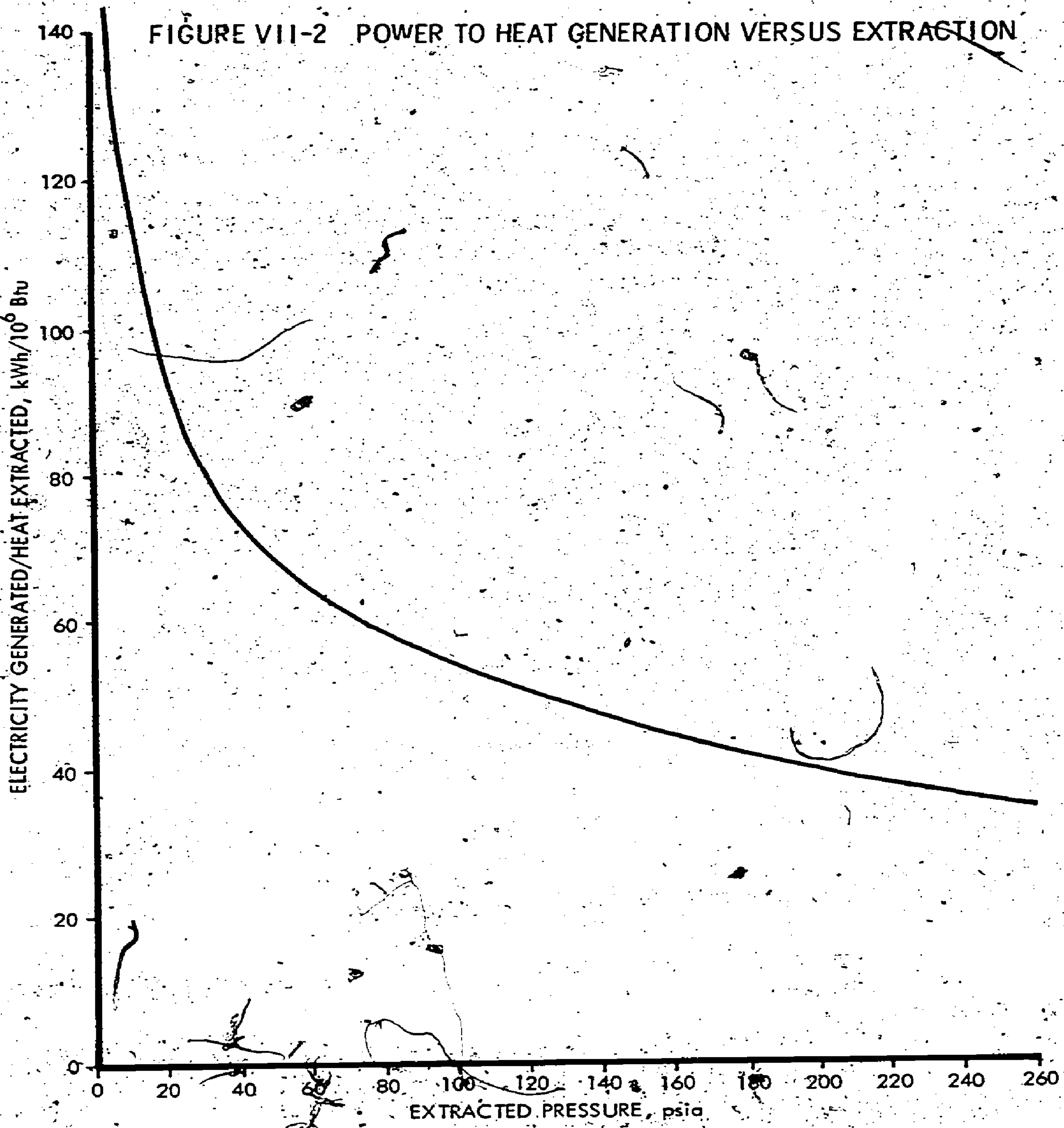
2.) Extraction Pressure

The electrical power produced per unit of heat extracted from a steam turbine cycle is highly dependent on the pressure at which the steam is extracted. Figure VII-2 shows the power production pressure dependence for the steam power cycle shown in Figure VII-7. As lower extraction pressures are chosen, the electrical power production increases substantially. This is particularly true in the lower pressure ranges.

As noted, the extraction steam pressure and, hence, the supply pressure for distribution should be as low as possible. The immediate implication is that the present 265 psia line to Heating Plant No. 1 must be converted to a lower pressure. The present design includes the installation of an additional steam line in the existing steam tunnel connecting Heating Plant No. 1 and No. 2.

For the present feasibility study, the steam distribution supply pressure has been assumed to be 75 psia as it now exists. Improved benefits would accrue with a lowering of the steam distribution pressure. And, the recommendation is made that tests be performed to determine the minimum acceptable operating supply pressure before an engineering design is developed.

FIGURE VII-2 POWER TO HEAT GENERATION VERSUS EXTRACTION



3.) Feedwater Heating

For steam turbine plants generating power only, additional stages of feedwater heating have the favorable effect of decreasing the fuel chargeable-to-power. This gain is reaslized because additional by-product power can be generated with steam extracted from the steam turbine for the extra feedwater heating. And, since all the energy for feedwater heating remains in the cycle, there are no energy losses. Boiler stack temperature (losses) can be kept low by effective use of air heaters with little or no dependence on low temperature feedwater to the economizers.

For dual purpose power plants with steam turbines to generate power and supply process steam, the fuel savings due to feedwater heating are greater than in a utility plant generating power only. This is so because the pounds of boiler feedwater to be heated is often two or three times the boiler feedwater flow for a plant generating power only. In the steam plant with ambient air fired boilers, the boilers are equipped with air heaters so low temperature water to an economizer is not required to achieve the low stack temperatures needed for efficient boiler operation.

The number of feedwater heater stages chosen for a given design depends on an economic balance. Large central station cycles may have 6 to 8 stages of feedwater heaters; small dual purpose power facilities seldom have more than 2 or 3 stages of feedwater heaters.

Three stages of feedwater heating were chosen for the present system. Three extraction pressures are already required to satisfy the process loads and these same extraction points can be used to provide steam to the feedwater heaters.

4.) Turbine By-pass

A pressure reducing valve and desuperheater provided in parallel with the steam turbines to provide process steam when the steam turbines are not in operation.

c. Automatic Variable Extraction Steam Turbine

An automatic variable extraction steam turbine is one in which steam is withdrawn at one (single extraction) or two (double extraction) points between the inlet and exhaust openings at controlled pressures. Bleed steam may also be withdrawn from intermediate points without control of pressure.

As shown in Figure VII-3, a single extraction turbine can be considered as two turbines coupled to a common shaft. The first turbine is the high pressure section, while the second turbine is the low pressure section. The high pressure section expands steam from inlet conditions down to the extraction pressure. The low pressure section expands steam from the extraction pressure down to the exhaust condition. The

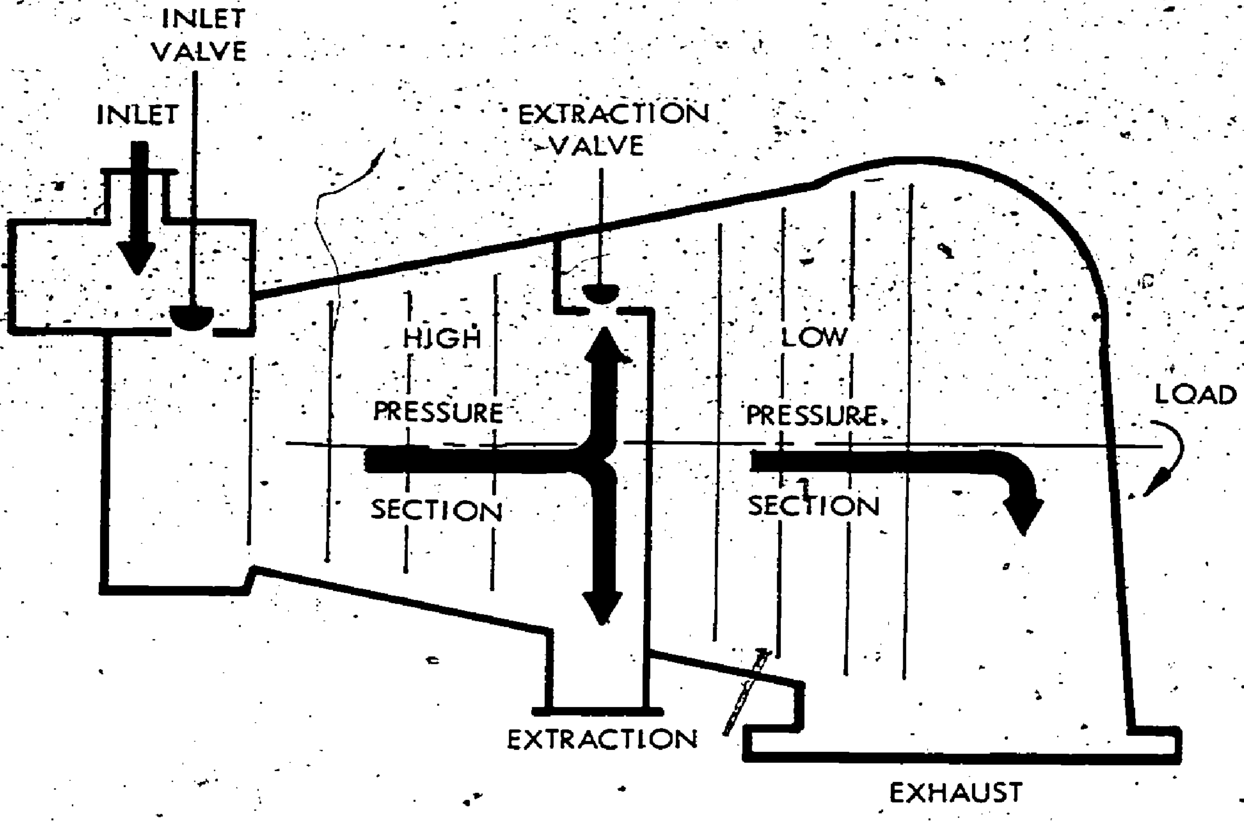


FIGURE VII-3 AUTOMATIC VARIABLE EXTRACTION TURBINE extraction valves act as inlet valves for the low pressure section and regulate flow of steam through that section, but not out of the extraction opening. When the extraction control is in use, it maintains a constant extraction pressure and thus supplies constant inlet pressure for the low pressure section.

Extraction turbines differ in two major respects from straight condensing or non-condensing turbines: (1) Certain areas in the steam path are designed with enlarged sections so that large quantities of steam can be extracted for process requirements. (2) Additional control devices and linkages have been added to maintain extraction pressure, load, and flow control automatically.

Flexibility to meet varying operating conditions is inherent in an extraction turbine, but because of the multiplicity of applications, a thorough knowledge of the present and future requirements of steam and load is necessary in order to determine the best design for the application.

d. Steam Generating Equipment

There has been little standardization of complete unit designs for dual purpose power plant applications primarily because of the distinctive nature of each user's conditions. The variables are not so much steam capacity, pressure and temperature as the types of fuels that are fired and the user's plans for utilizing the steam generating unit within his system. Variations of this type require changes in detail and overall arrangement of components. This, together with ever-changing costs of money, fuel, materials and labor, has made full unit standardization impracticable.

The primary fuel for the University of Florida IUS will be coal. Variations in relative fuel costs because of fluctuations in price and freight rates, seasonal variations in availability of natural gas and temporary shortages of coal and oil make it advantageous to not rely on a single fuel. Hence, the installed steam generation system will be designed to be capable of burning gas or oil as alternate fuels.

The selection of boiler design depends on the type of coal and the steam load characteristics. Pulverized coal fired and stoker fired boilers can be designed to burn practically any bituminous coal or lignite mined in the United States. A pulverized coal system must have coal preparation equipment including that required for the removal of moisture. A stoker fired boiler can be designed for a sized coal and thus require a minimum of coal preparation equipment. Pulverized coal firing systems have higher efficiencies than stoker firing systems because of lower excess air for combustion and lower carbon losses.

Either pulverized coal or stoker fired boilers can be used to generate the steam required by the University of Florida IUS. A stoker fired steam generating system was chosen as the basis of the present feasibility study. The trade-off of greater capital costs for pulverized coal preparation equipment against the lower efficiency of a stoker must, however, be evaluated as part of the engineering design.

The existing boilers in Heating Plant No. 2 will be maintained and operated to provice backup and supplemental steam generation. In the backup role, the existing boilers will be capable of providing the necessary steam to supply the steam distribution and turbine chillers but not for electrical power generation. Gas and oil will continue to be the fuels for the existing boilers since these boilers cannot be practically converted to fire coal.

e. Pollution Control Equipment

1.) Sulfur

Sulfur emission limits will be met initially by the use of low sulfur fuels. The gas sulfur removal units have significant initial and operating costs. And, there is little experience with such units in the boiler size range being considered at the University of Florida. The boiler design configuration will, however, be specified to provide the capability to add flue gas sulfur removal equipment at a later date should such units become technically and economically attractive.

2.) Particulate

In order to meet the rather stringent pollution control requirements imposed by the State of Florida, the University has a choice of two options for controlling stack gas particle emissions; electrostatic precipitators and baghouse filters.

A number of factors eliminate the electrostatic precipitator from application at the University of Florida. The electrostatic precipitator has reduced efficiencies when low sulfur coal is the fuel. Resistivity of the coal fly ash is too high for effective precipitator operation. High temperature electrostatic precipitators located prior to the economizer and air preheater sections have been found useful in applications using low sulfur coal but this is a relatively new approach and has high operation and maintenance costs associated with it.

A baghouse filter has been selected to provide particle emission control for the University of Florida IUS conceptual design. Baghouse filters have historically had lower initial costs but higher operation and maintenance costs than electrostatic filters. The bags are the weakest link in the system. However, recent installations have incorporated design changes such as pulsed flow for bag cleaning and revised flow patterns which have greatly extended the bag life and unit efficiency. Baghouse filtration has had extensive industrial application and is now finding favor in the power industry for use on small systems.

5. Alternate A (5 MW) Select Energy

a. Rationale

The greatest economic advantage from the installation of a dual purpose power plant will occur with full system utilization. While larger systems may show lower returns on investment, the installation of a partial load system may well be a good investment and at the same time provide increased availability and flexibility of operation and expansion. This design alternate is sized to provide a system which operates at full capacity throughout the year. Alternate B considers the expansion of the Alternate A system to provide greater reliability and flexibility of operation.

b. Power Cycles

As shown in Figure VII-4, the power cycle for a minimum configuration includes a backpressure automatic variable single extraction turbine. The extraction at 265 psia supplies the existing steam turbine driven centrifugal chillers and provides bleed steam to the high pressure feedwater heater. The 75 psia exhaust is fed to the existing steam distribution system. Heat balances for energy extractions from this cycle are given in Table X-1 and Exhibit III.

c. System Sizing

From projections made for 1981 utility requirements, the minimum electrical demand of 6,500 kW occurs in December. The steam demand that occurs with this minimum electrical load conditions is 90,500 pounds per hour.

The projected minimum 75 psia steam demand of 80,500 pounds per hour occurs in March. The power generation at this minimum steam load by the proposed power plant cycle would be 5,500 kW.

The high pressure throttle steam flow rate to the steam turbine with a 5,000 kW load would be 90,000 lb/hr and 75 psia steam production would be 72,000 lb/hr Hence, a dual purpose power plant consisting of one 100,000 pounds per hour coal fired boiler using oil and gas as alternate fuels and one 5,000 kW automatic variable extraction backpressure steam turbine/generator was selected.

d. Performance

The University heating and cooling loads are of such magnitude that the proposed system would operate at full capacity. As presented in Table VII-1, 27 percent

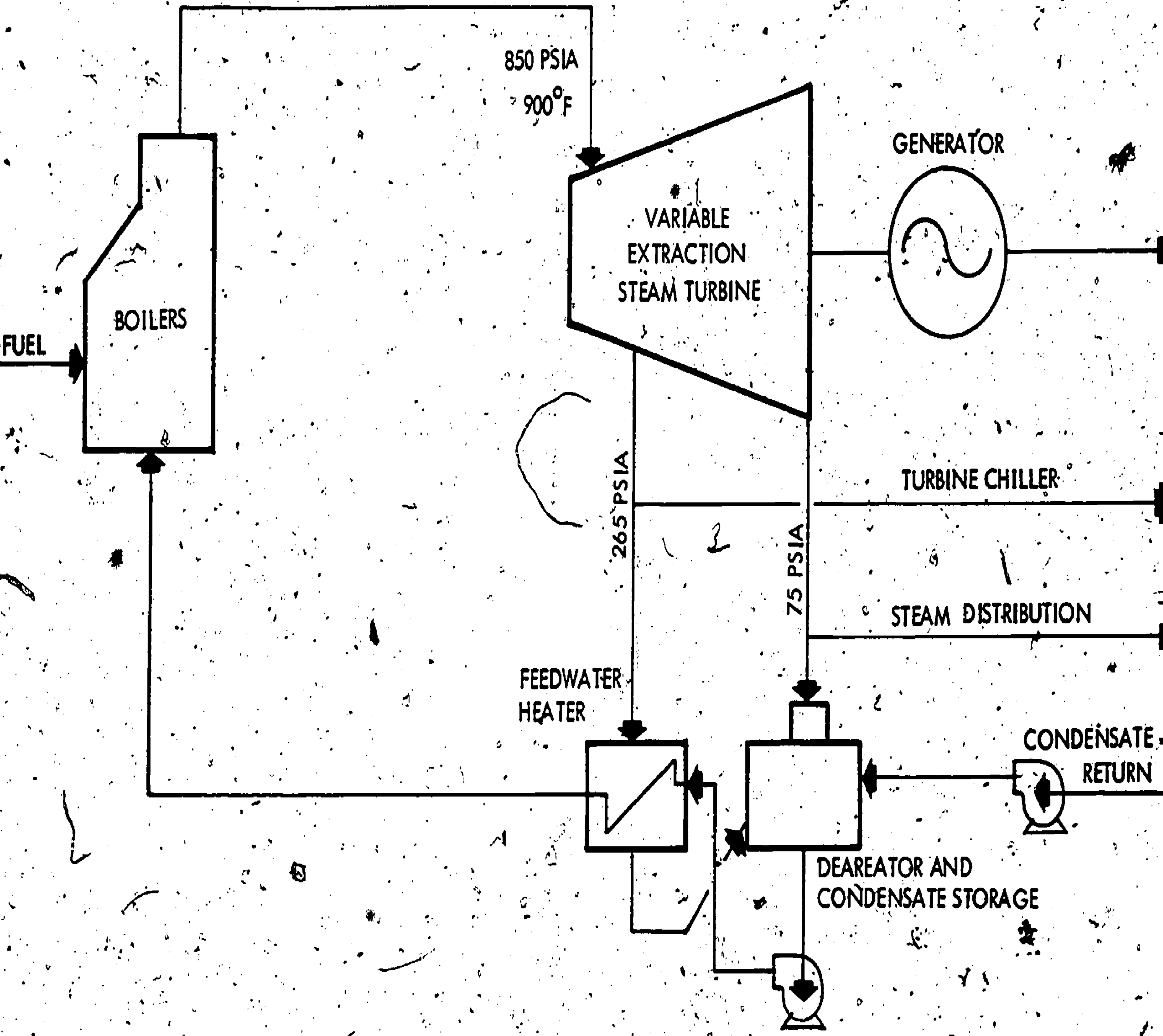


FIGURE VII-4 TWO FEEDWATER HEATER, NON CONDENSING TURBINE/BOILER FLOW DIAGRAM

TABLE VII-1 THERMAL / ELECTRIC ALTERNATE ENERGY REQUIREMENTS - 1981 (1)

	BASE CASE (2,3)	NEW COAL-FIRED BOILERS (2, 3)	OPTION A SELECT ENERGY (2, 4)	OPTION B SELECT ENERGY (2, 4, 5)	OPTION C SELECT ENERGY + ABSORPTION (5, 6, 7)	OPTION D SELECT ENERGY + ABSORPTION + 30% LTHW (5, 6, 7, 8)	INCREMENT OF OPTION D
ELECTRICITY							
New Turbine Rated Capacity, 1000 KW (9)	0	0	5	10	12.5	12.5	6.25
Electricity Consumed, 10^6 kWh	166	166	166	145	138	138	154
Electricity Generated on Site, 10^6 kWh	6	6	44	84	106	118	54
Electricity Purchased, 10^6 kWh	160	160	122	61	32	20	100
Fraction of Power Generated on Site	.04	.04	.27	.56	.77	.85	.35
FUEL							
New Coal Boiler Rated Capacity, 1000 lbs/hr	0	120	100	200	240	240	120
Fuel Fired (10)							
Heating Value, 10^9 Btu	1185	1128	1347	2164	2459	2457	1758
Oil, 10^6 Gal.	8.0		1.6				2.4
Coal, Tons		43.7	42.8	83.2	94.6	94.5	54
Central Station Fuel, 10^9 Btu	1807	1807	1371	688	362	228	1128
Overall Energy Consumed, 10^9 Btu	2992	2935	2718	2852	2821	2685	2886
Energy Savings, 10^9 Btu	—	57	274	128	180	316	106
Fraction Base Case Energy Consumption	1	.98	.91	.95	.94	.89	.96

TABLE VII-1 (CONTINUED)

Solid Waste Energy	12.5 MW with 25 TPD Solid Waste Incineration	12.5 MW with 75 TPD Solid Waste Incineration	6.25 MW with 25 TPD Solid Waste Incineration	6.25 MW with 75 TPD Solid Waste Incineration
ELECTRICITY				
New Turbine Rated Capacity, 1000 KW (9)	12.5	12.5	6.25	6.25
Electricity Consumed, 10^6 kWh	138	138	154	154
Electricity Generated on Site, 10^6 kWh	122	122	54	56
Electricity Purchased, 10^6 kWh	16	16	100	98
Fraction of Power Generated on Site	.88	.88	.35	.36
FUEL				
New Coal Boiler Rated Capacity, 1000 lbs/hr	240	240	120	120
Fuel Fired (10)				
Heating Value, 10^9 Btu	2457	2369	1685	1604
Oil, 10^6 Gal.	0	0	1.9	1.7
Coal, Tons	94.5	91.1	54	52
Central Station Fuel, 10^9 Btu	180	180	1128	1105
Overall Energy Consumed, 10^9 Btu	2637	2549	2813	2709
Energy Savings, 10^9 Btu	355	443	179	283
Fraction Base Case Energy Consumption	.88	.85	.94	.91

NOTES:

1. The existing system energy requirements have been projected to 1981 and an additional 5900 tons of air conditioning have been assumed to have been connected to the central system.

2. An additional 5900 tons of electric motor driven centrifugal chillers installed.

3. The electric motor driven chillers are base loaded and the existing steam turb[illegible]ven chillers provide peaking.

4. The steam turbine driven chillers are loaded to the extent steam is available from the turbine generator after satisfying the heating load.

5. Electricity is generated by condensing steam to the extent steam is available after meeting the heating and chilled water loads. Sufficient steam is condensed at all times to provide blade cooling.

6. Absorption chillers have been installed instead of electric motor driven chillers.

7. The absorption chillers and steam turbine driven chillers are loaded according to the extent steam is available after satisfying the heating load. Existing electric motor driven chillers provide peaking.

8. Thirty percent of the heating load is extracted at 30 psia to provide low pressure steam distribution or generate low temperature hot water.

9. The turbine ratings shown are for standard automatic variable extraction turbines which can generate upwards to 150 percent of the basic frame power ratings in the size ranges considered in this study if the connected generator is so rated.

10. Thermal efficiency of the existing gas/oil-fired boilers is assumed to be 80 percent. The new coal-fired boilers will have air preheaters and economizers and have an efficiency of 84 percent.

of the electrical power and 85 percent of the 75 psiq steam requirements of the University would be satisfied by this system.

6. Alternate B (10 MW) Select Energy

a. Rationale

Alternate B is the logical extension of Alternate A to include greater generating capacity, more reliable service and increased flexibility. The condensing steam turbine, by virtue of the condenser, has the ability to produce electric power irrespective of the heating demand and would be used to reduce demand charges from the Florida Power Corporation during those periods of low steam demand and high electrical demand. Two turbines are incorporated into the design to provide added reliability and the system will have capability for 5 MW output when one unit is off line. During these periods Alternate B would perform similar to Alternate A.

b. Power Cycle

The power cycle for Alternate B includes an additional 5 MW superimposed on the cycle for Alternate A. The additional 5 MW capacity will be provided by a variable extraction condensing steam turbine. The operation of the backpressure turbine will be the same as described in the previous section. Figure VII-7 shows a schematic of the condensing turbine power cycle. The extraction pressures will be the same as for the noncondensing system, 265 psia, 75 psia and 30 psia. Exhaust to the condenser will be at 1.5 psia. Steam extracted at 265 psia will be supplied to the turbine driven centrifugal chillers and a portion will be to the high pressure feedwater heater. The 75 psia extraction steam will supply the present 75 psia steam distribution system and provide bleed steam to the intermediate feedwater heater. The 30 psia extraction port supplies bleed steam to the low pressure contact deaerating feedwater heater.

The heat balances for specific heat extractions from the condensing variable extraction cycle are given in Table E III-2 of Exhibit III.

c. System Sizing

From the projected load duration, the electrical demand will be greater than 10,000 kW for 8,000 hours per year and a 10,000 kW generation capacity will have 98 percent utilization. To provide increased system availability and flexibility of operation, two turbine generators of 5,000 kW rated capacity each were selected. Steam generation will be by two 100,000 pounds per hour boilers.

d. Performance

As shown in Table VII-1, the system will provide all the heating and cooling

FIGURE VII-5 5,000 KW NON-CONDENSING AUTOMATIC VARIABLE EXTRACTION TURBINE GENERATOR PERFORMANCE CURVE

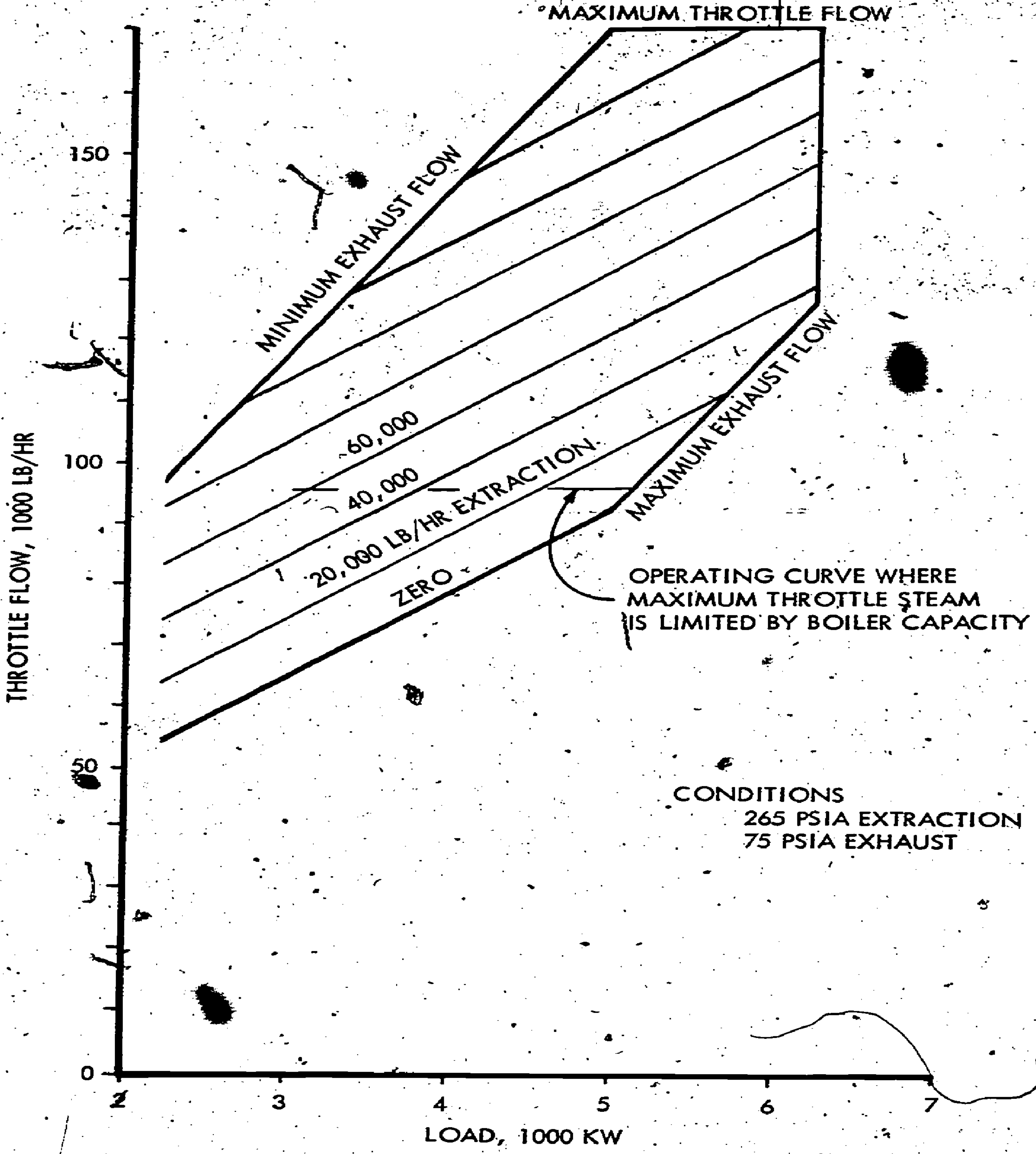
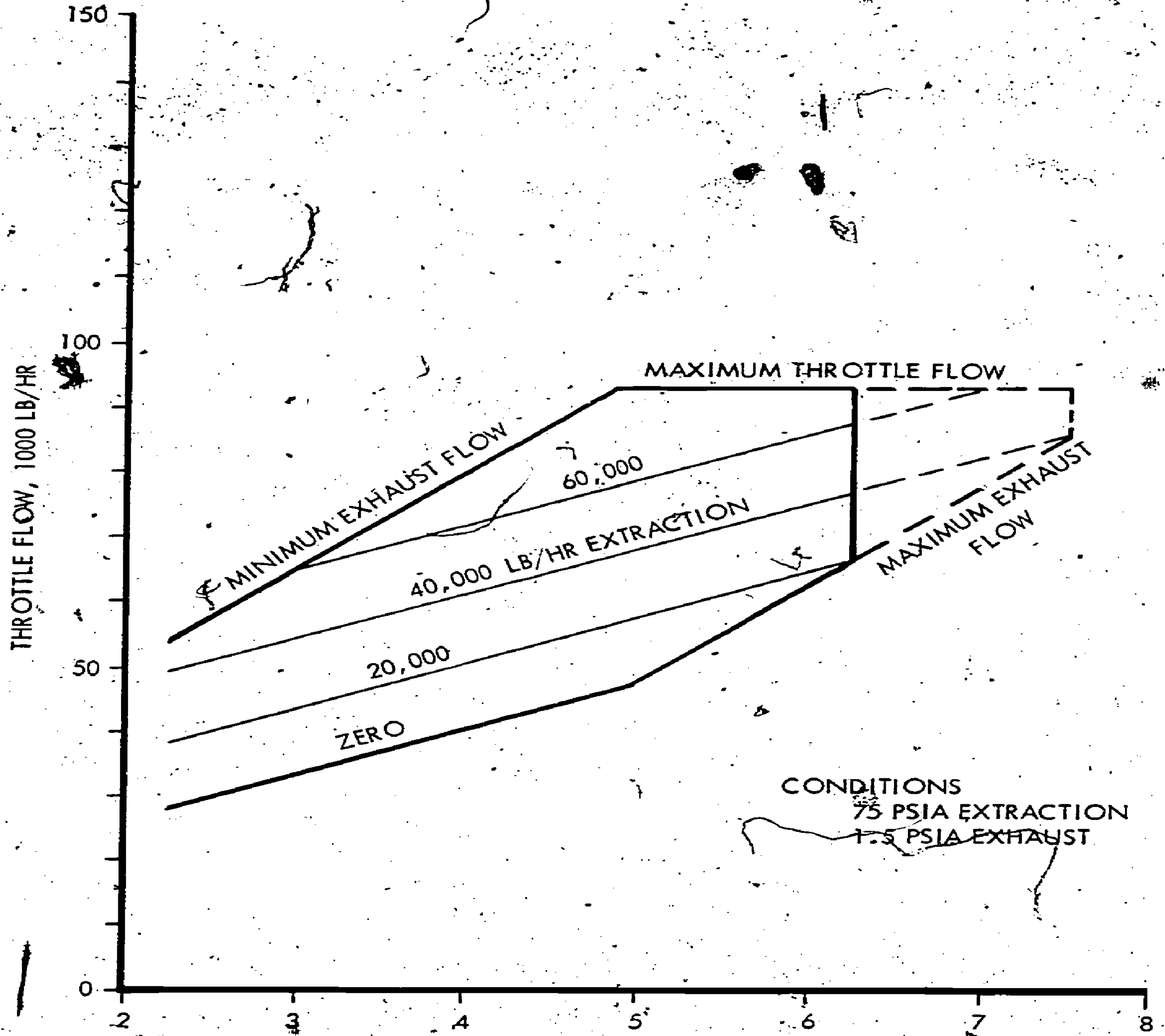


FIGURE VII-6 5,000 KW CONDENSING AUTOMATIC VARIABLE EXTRACTION TURBINE GENERATOR PERFORMANCE CURVE



steam requirements, and will generate 56 percent of the electrical requirements of the University.

The best energy efficiency of the system is realized when sufficient steam is produced and extracted to supply the thermal loads and minimal steam to provide blade cooling is exhausted to the condenser. Fullest utilization of the system is realized when the maximum allowable steam is sent to the condenser after all thermal loads are satisfied. If minimal steam is exhausted to the condenser, the heat rate for the system is less than 5,000 Btu per kWh. For fullest utilization of the system, the heat rate of the system is 7,100 Btu per kWh. Both of these heat rates are considerably less than the 11,275 Btu per kWh of Florida Power Corporation for generating and transmitting the same quantity of electricity to the University of Florida.

System availability will be increased with the dual line of boilers and turbine generators. And, control of the electrical generation is simplified with the flexible operation of the condensing automatic variable extraction turbine. As heating and cooling loads are added to the system, the portion of the power produced by condensing steam will be reduced, thus, providing for system expansion and efficiency through increased utilization of extraction steam.

The backpressure turbine will have the same performance curves as that shown in Figure VII-5 for Alternate A. The full capability of the basic 5,000 kW frame could be used when the condensing turbine is out of service.

The performance curves for the condensing automatic variable extraction turbine are shown in Figure VII-6. The basic 5,000 kW variable extraction turbine frame can support the additional generator capacity shown by the dashed lines of Figure VII-6. This additional capacity and flexibility of operation can be purchased for less than 2 percent of the basic turbine/generator price.

7. Alternate C (12.5 MW Select Energy + Absorption Chillers)

Chilled water production for central air conditioning forms a substantial portion of the energy requirements of the University. Since the refrigeration equipment can use electricity, steam, or hot water as the energy source, the effect of these alternate methods of refrigeration on the performance of a select energy system should be considered. Of particular note is the possibility of significantly altering the power to heat consumption ratio of the utility system by switching from electric motor driven chillers to steam turbine driven chillers or absorption chillers. This change has the effect of reducing electrical demand and energy consumption while increasing the heat consumption by extracting more steam for the absorption chillers.

a. Alternate Chilled Water Energy Requirements

A comparison of the energy requirements of the various possible methods of providing chilled water for cooling the University of Florida is given by Table VII-2.

1.) Conventional System

When there is no by product power generation, absorption chillers will require 2.6 times more overall energy than an electric motor driven centrifugal chiller.

2.) Total/Select Energy System

The electric motor driven centrifugal chillers do require 30 percent less overall fuel than absorption chillers in a select energy system. But, the reduction in purchased electrical energy costs and demand charges of a select system, as shown in Table VII-2 make the use of absorption chillers with a total/selective energy system economically attractive. Further, since the proposed fuel for this system is coal, there still is a reduction in oil consumption proportional to the reductions in electricity purchased and the fraction of fuel oil burned by the commercial power system.

The relative advantage of absorption chillers is dependent on the price of fuel. The rate of increase of the price of coal is expected to be less than that of electricity (1), and hence the advantage of absorption chillers is expected to be maintained.

b. Rationale

The University has begun a 10 year central air conditioning expansion program during which time 8,000 tons of chilled water generation capacity is to be added to the central chilled water system. The additional refrigeration equipment, as recommended in a previous feasibility study (3), is to be electric motor driven centrifugal chillers. Each additional ton of air conditioning by an electric motor driven centrifugal chiller will cause an additional 0.75 kilowatt electrical load. Operation of this equipment could substantially raise the electrical load during the summer months, which is already the peak electrical demand period for the University.

The use of absorption chillers would not increase the electrical demand. Furthermore, the additional power generated in a select energy system while supplying the low pressure steam for the absorption chillers would lower the peak purchased trical power demand.

TABLE VII-2 ENERGY AND COSTS PER MILLION BTU OF CHILLED WATER PRODUCTION

System	Energy				Net Costs, $\$/10^6$ Btu Cooling (9)		
	Fuel Consumed 10^6 Btu	Electricity Consumed KWH (7)	Central Station Fuel Consumed 10^6 Btu (8)	Overall Energy Consumed 10^6 Btu	$\$1.00/10^6$ Btu Fuel	$\$1.50/10^6$ Btu Fuel	$\$2.00/10^6$ Bt Fuel
Conventional System							
Absorption (1, 2)	1.87			1.87	1.87	2.81	3.74
Turbine Centrifugal (1, 3)	1.34			1.34	1.34	2.01	2.68
Electric Centrifugal (4)		64	0.72	0.72	1.66	1.66	1.66
Select Energy System							
Absorption (2, 5)	2.39	-118	-1.33	1.03	-0.67	0.53	1.72
Turbine Centrifugal (3, 6)	1.50	- 36	-0.40	1.10	0.57	1.32	2.07

NOTES:

1. Existing boiler efficiency is assumed to be 80 percent.
2. A lithium bromide absorption chiller with a coefficient of performance (COP) of 0.67.
3. Existing steam turbine driven chillers having a COP of 0.93.
4. Electric motor driven centrifugal chillers with a COP of 4.6.
5. Steam extracted at 30 psia from a select energy system.
6. Steam extracted at 265 psia from a select energy system.
7. Power is purchased from a commercial supply for the conventional system, while on-site byproduct electrical power is generated for the select energy system as given in Table VII-1,
8. The commercial supply central station heat rate for generation to the University is 11,275 Btu/kWh.
9. Consumed electricity prices are $0.026/kWh and consumed fuel prices are as given.

c. Power Cycle

A condensing variable extraction turbine power cycle configured as shown in Figure VII-7 for Alternate B would operate in parallel with a non-condensing extraction turbine power cycle configured as shown in Figure VII-8.

d. System Sizing

For this feasibility study it is assumed that absorption chillers are specified for the 5,900 tons of air conditioning scheduled for installation by 1981 under the central air conditioning system expansion program. The same utilization and demand characteristics are assumed for the additional 5,900 tons of cooling load scheduled for connection to the central air condition system as occurs for the existing chilled water distribution system.

The change of operating conditions to provide controlled extractions at 30 psia reduces the maximum throttle steam flow rates for the 5,000 kW turbine. Furthermore, the absorption chillers provide a substantial increase in steam load. Hence, the next larger turbine generator size (6,250 kW) was selected. The combined steam generation capacity of the boilers selected was 240,000 pounds per hour. The performance curves for the 6,250 kW non-condensing and condensing variable extraction turbines are given as Figure VII-9 and VII-10 respectively.

e. Equipment Loading

The absorption chillers and existing steam turbine driven chillers are loaded according to the extent of steam available after satisfying the heating loads. Existing electric motor driven chillers provide peaking.

Additional electricity is generated by the condensing turbine generator to the extent steam is available after the heating and chilled water production loads are satisfied and there is additional electrical demand. Sufficient steam is condensed at all times to provide blade cooling in the low pressure section of the condensing turbine generator.

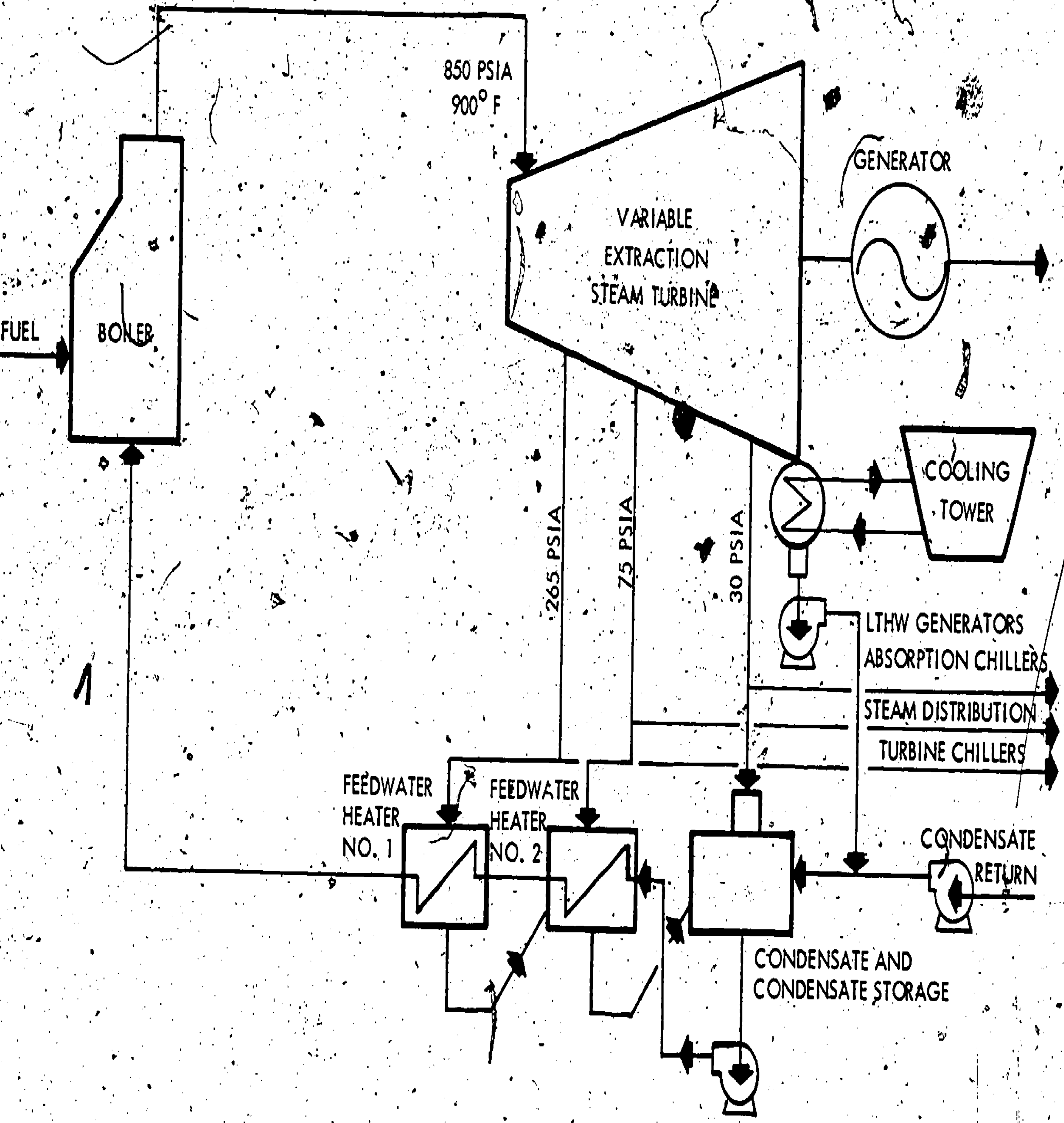


FIGURE VII-7 THREE FEEDWATER HEATERS; CONDENSING TURBINE/BOILER FLOW DIAGRAM

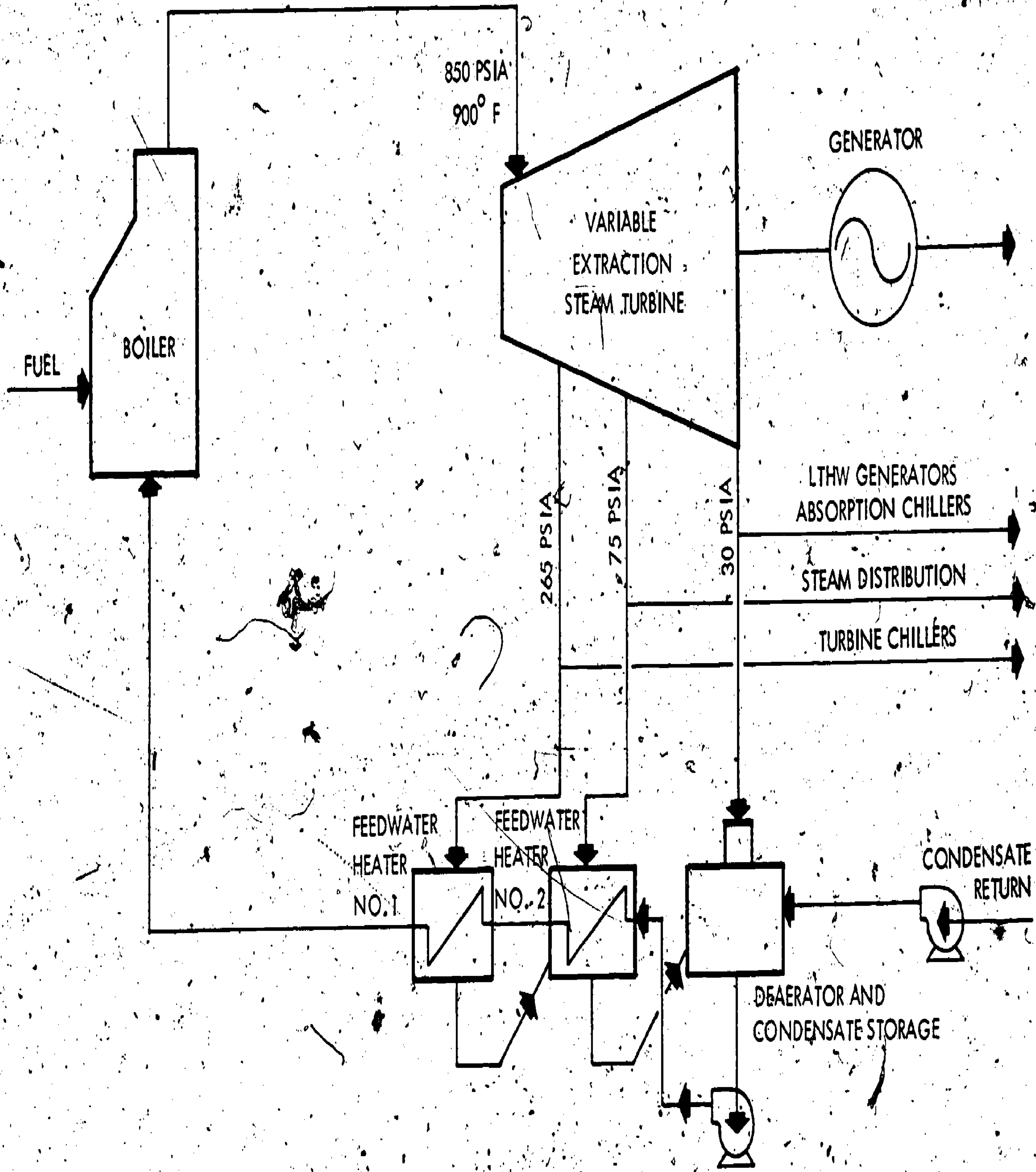


FIGURE VII-8 THREE FEEDWATER HEATER, NON CONDENSING TURBINE/BOILER FLOW DIAGRAM

FIGURE VII-9 6,250 KW NON-CONDENSING AUTOMATIC VARIABLE EXTRACTION TURBINE GENERATOR PERFORMANCE CURVE

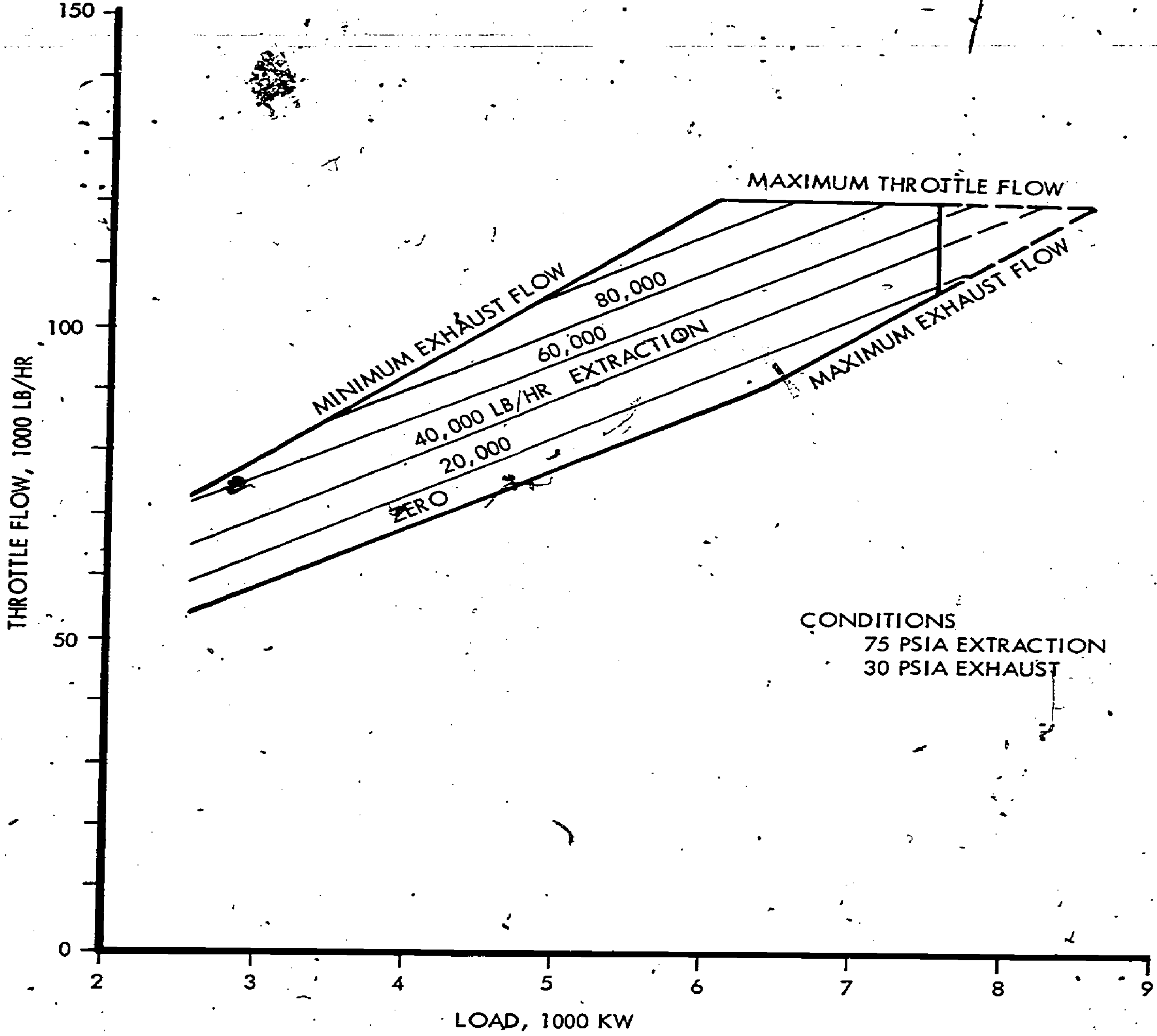
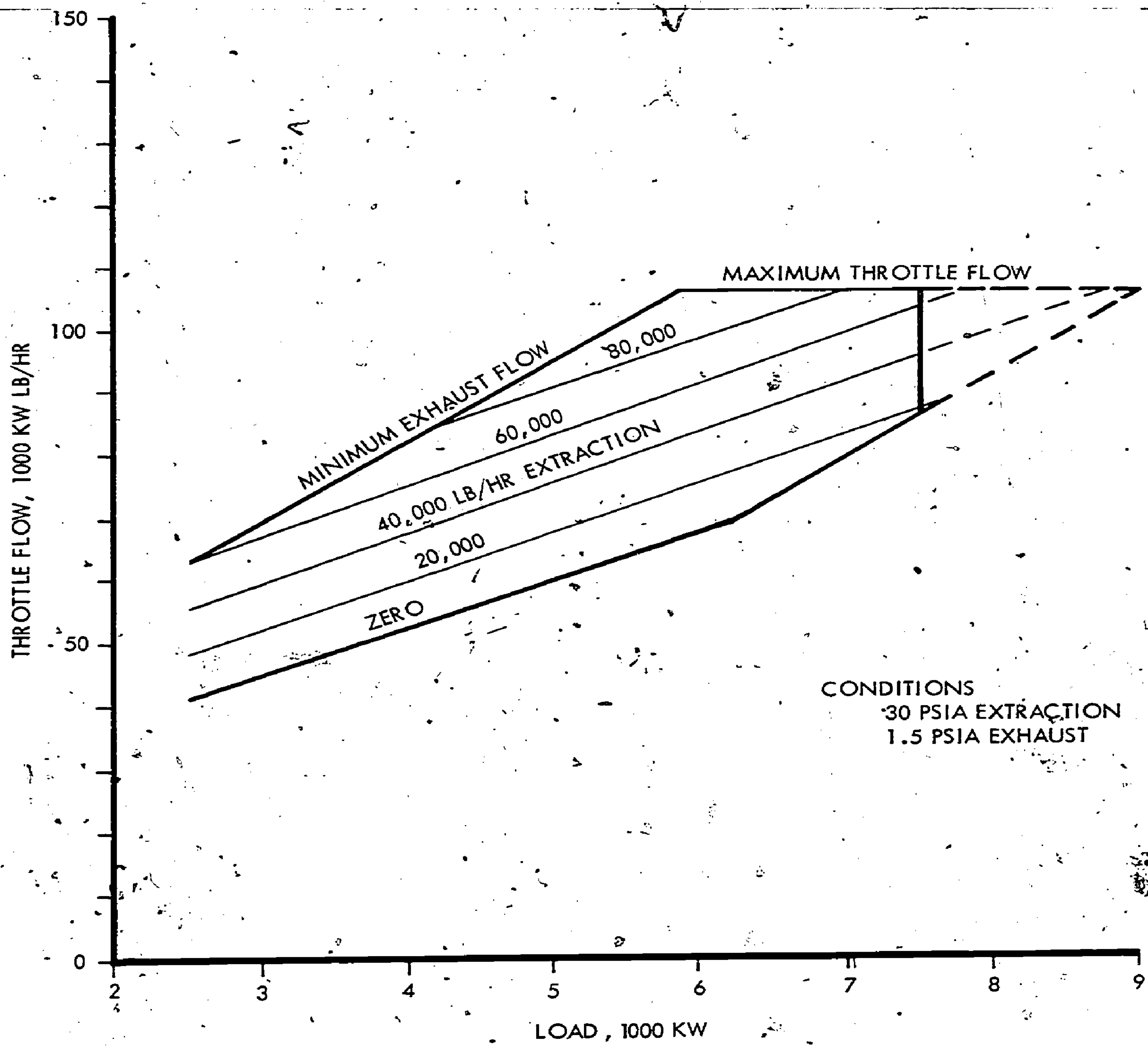


FIGURE VII-10 6,250 KW AUTOMATIC VARIABLE EXTRACTION TURBINE GENERATOR PERFORMANCE CURVE



f. Performance

Under the operating conditions given above, this alternate will meet all the thermal requirements of the University and generate 77 percent of the electrical requirements as is shown in Table VII-1.

The electrical consumption will be reduced by 17 percent relative to the base case and the overall energy requirements are reduced by 6 percent. By using absorption chillers, the overall energy requirements are increased over that for Alternate B. However, the overall fuel oil requirements will be reduced proportional to the purchased electricity and the fuel oil consumed by the commercial power system to generate that electricity.

The design has been sized such that the boiler and turbine throttle flow rates are the limiting factors. There is a substantial portion of the year when the heating and cooling loads cannot be met by the system and it is necessary to resort to operating the electric motor driven centrifugal chillers to provide the additional chilled water production. By increasing the system size to accommodate the additional low pressure steam requirements of the absorption chillers, lower annual utilization of the system generating capacity will be realized. The condensing variable extraction turbine provides considerable flexibility to the system operations in that the additional steam generation capacity when not required to supply steam for heating and cooling will allow the production of additional electrical power.

Also, by converting the present steam distribution system to a low pressure steam distribution system or a low temperature hot water system so that it is possible to extract steam at lower pressures, additional power can be generated for the same heat loads during the heating season. Thus a higher annual utilization of the select energy system would be realized. This possibility is examined by the next section.

8. Alternate D (12.5 MW Select Energy + Absorption Chillers + LTHW)

A vital link of the central heating and air conditioning is the thermal distribution system. The distribution system is also a major part of the utility system investment as there are miles of installed pipe, wire and tunnels to distribute the utilities. And, since a thermal distribution system is likely to still be in use 30 years from the date of its installation, it is essential that the suitability of the system for use with future energy sources be carefully examined.

a. Alternate Heating Energy Requirements

Table VII-3 is a comparison of the overall energy requirements for various methods of providing heat to the University of Florida.

TABLE VII-3 ENERGY AND COSTS PER MILLION BTU OF HEATING

	Energy				Net Costs, $/$10^6$ Btu, Heating (7)		
SYSTEM	FUEL CONSUMED 10^6 Btu	ELECTRICITY CONSUMED (5) kWh	CENTRAL STATION FUEL (6) 10^6 Btu	OVERALL ENERGY 10^6 Btu	$1.00/$10^6$ Btu Fuel	$1.50/$10^6$ Btu Fuel	$2.00/$10^6$ B Fuel
Conventional							
Electric (1)	-	293	3.31	3.31	7.62	7.62	7.62
Steam (2)	1.25	-	-	1.25	1.25	1.88	2.50
Select Energy							
Steam (3)	1.52	-60	-0.68	.84	-0.04	0.72	1.48
LTHW (4)	1.60	-79	-0.89	.71	-0.45	0.35	1.15

NOTES:

1. Electric resistance heating is assumed 100 percent efficient.
2. Existing gas/oil fired boilers are assumed to be 80 percent efficient.
3. Steam is extracted from a select energy system at 75 psia.
4. Steam is extracted from a select energy system at 30 psia to generate low temperature hot water.
5. Electricity is consumed in the conventional system and is generated as a by-product of the production of low pressure steam in the select energy system.
6. Central station power generation and transmission heat rate is 11,275 Btu/kWh.
7. Consumed electricity prices are $0.26/kWh and consumed fuel prices are as given.

1.) Conventional vs Total/Select Energy

The advantage of producing electrical power as a by-product of generating heat is obvious. While the select energy system requires 27 percent more fuel be burned on-site than the conventional system to supply 75 psia steam heating, the overall energy consumption of a select energy system when including credits for fuel not consumed at the commercial central station to generate the equivalent by-product power is 30 percent less than the conventional system.

2.) Conventional vs Total/Select Low Pressure Extraction

When a low pressure (30 psia) steam distribution system or a low temperature (240 F) hot water distribution system is used, the advantages are even more pronounced. A low pressure steam or a low temperature hot water distribution system would require 42 percent less overall fuel for heating than the existing conventional system using steam for thermal conveyance without by-product power generation.

3.) High vs Low Pressure Extraction

A decided advantage accrues to the use of low pressure steam on a low temperature hot water distribution systems as apposed to the present steam distribution systems. Thirty percent more electrical power can be generated by the select energy plant if a low pressure steam distribution system or a low temperature hot water distribution system is used instead of the present 75 psia steam distribution system. Furthermore, the overall energy requirements of a low pressure steam distribution system or a low temperature hot water distribution system would be 17 percent less than the 75 psia steam distribution system when credit is given for the additional by-product electrical generation.

4.) Electrical Resistance Heating

Electrical resistance heating requires almost three times the energy of the conventional steam heating system and almost five times the overall energy of a select energy system with a low pressure steam or a low temperature hot water distribution system. Electrical resistance heating increases the purchased electrical demand, and deprives a select energy system of a heat sink for the use of waste heat from the production of power.

b. Existing Thermal System Compatability to Low Pressure Steam or Low Temperature Hot Water

A select/total energy system extracts as much electrical energy from the steam as possible before the steam is exhausted from the turbine and the waste heat used for space heating and cooling. By lowering the pressure at which the steam is extracted from the turbine, substantially more electricity can be produced per unit of heating.

The pronounced improvement in power to heat generation ratio, particularly at lower pressures, is shown in Figure VII-2.

1.) Low Pressure Steam

Essentially all of the steam distributed to the campus is reduced to 30 psia or less at the building sites. This reduced pressure steam is then further throttled to a lower pressure to control the temperature. As noted earlier in this section, the present distribution system supply pressure could be reduced to increase the power to heat generation ratio of a select energy system. Pipe sizes and pressure drops determine the lowest acceptable steam supply pressure.

2.) Low Temperature Hot Water

Presently low temperature hot water is used as the heating media for approximately 80 percent of the space heating loads connected to the central steam distribution system. Steam is used to heat hot water in thermal converters (heat exchangers) at the building site. And, it is the low temperature hot water which is circulated throughout the building to provide space heating. The existing distribution system can be converted to a low temperature hot water system.

c. Steam vs Hot Water Distribution Systems

There are a number of advantages of hot water distribution systems relative to steam distribution systems which merit consideration.

1.) Dual Purpose Power Generation

Higher overall select energy system efficiencies can be realized by heating and distributing hot water than can be realized by simply extracting and distributing steam. The reason is that steam must be extracted from the turbine at the supply pressure of the steam distribution system. In contrast, water can be heated in stages (regenerative heating) with only the final increment of heat added at the peak temperature. From the standpoint of by-product power generation, hot water systems can have a decided advantage.

2.) Reduced Heat Loss

The following contribute to heat losses in steam heating systems: open vents on condensate receivers; flashout losses and leaks in steam traps; and boiler blowdown. These losses typically require an additional 15 percent in fuel costs than if there were no losses. A hot water system, on the other hand, is a closed circulating loop, with only very minor losses from leakage at valve stems and at pump stuffing boxes. Inasmuch as the amount of makeup water required is only a small fraction of that required for a steam system, this greatly reduces the need for blowdown, thereby doing away with a source of considerable heat loss.

3.) Independence of Contour

Condensate collection systems usually flow by gravity, so all lines are pitched in the direction of the receiver. Forced circulation hot water lines are entirely independent of the distribution system layout. However, since water is much denser than steam, more substantial pipe supports in tunnels and inside buildings will be required with water systems than with steam systems.

4.) Equivalent Pipe Size

The thermal energy conveyed per unit of volume of water is approximately 40 times that for steam at the equivalent saturation temperature. Even after accounting for velocity differences and friction, smaller supply pipes can be used for hot water distribution systems than an equivalent steam distribution system. And, a hot water return line will need only be on or two sizes larger than the condensate line required in a steam system.

5.) Thermal Storage

A hot water distribution system acts as a heat accumulator due to its capacity to store heat. This may be likened to an energy reservoir, which can accommodate sudden heat demands without loss in temperature. Steam systems often suffer a temperature drop when shock or peak loads occur, which cause a drop in the boiler pressure. But because of the heat storage, hot water generators need not be sized for maximum peak loads. Steam boilers require such sizing to prevent pressure losses and accompanying temperature losses.

6.) Isolation of Systems

The steam to water heat exchangers allow isolation of the power generation cycle from the thermal distribution. Any failure of the distribution system will not appreciably affect the backpressures seen by the turbine. And, since the systems are isolated, the water purity of the boiler and turbine can be maintained at a high level while the thermal distribution system can be somewhat lower.

7.) Reduced Maintenance

Condensate lines are usually subject to corrosion, because mineral free water, combined with atmospheric oxygen, becomes very corrosive. The absence of drips and vented receivers and the consequently negligible influx air in a properly operated water system tend toward lower maintenance costs. Furthermore, the internal corrosion that commonly occurs in steam systems can be controlled in hot water systems by the addition of chemical inhibitors not available to steam systems.

8.) Safety

Evaluations of the operational safety of hot water systems and steam systems have indicated that, in the event of line breakage, the water systems are less hazardous than steam systems at equivalent saturation temperatures.

9.) Solar Compatability

A low temperature hot water distribution system would be compatible with a solar booster system while a steam distribution system is not.

d. Rationale

There is an on-going program for the replacement of aging steam supply and condensate return lines throughout the steam distribution system. And, as an alternate to simply replacing an existing steam distribution system consideration is given to developing a master plan to install a low temperature hot water distribution system for supplying space heat to the campus. The installation of this system could be in parallel with the presently planned construction of the central air conditioning chilled water distribution system and could be phased with projected replacement of segments of the present steam distribution system.

e. Conversion Schedule

To be most cost effective, the conversion of a steam heating system should be phased with the need to replace and retrofit existing units. A detailed analysis of the building mechanical systems for the entire university was considered beyond the scope of the present effort. However, to show the feasibility of converting to a low temperature hot water distribution system, a proposed first increment has been analyzed. This increment considers the connection of the medical center adjacent to the proposed select energy site to a low temperature hot water system.

The proposed addition steam line between heating Plant No. 1 and No. 2 could be designed for hot water and extend the distribution of hot water to the main campus. And, the segments of the existing steam distribution system such as the 8 inch steam line (now valved off) running north from the medical center could be converted to distribute hot water. A review of the utility system study (2) and central air conditioning feasibility study (4) along with proposed plans for modification and retrofit of building systems will be necessary to properly program the extension of and conversion to a hot water distribution system.

f. System Specification

The particular design pressure and temperature chosen for the thermal distribution system can limit the amount of waste heat that can be used by the buildings. The maximum power to heat generation ratio occurs for the minimum thermal distribution supply temperature. The low supply temperature can be attained by reducing the system temperature drop and the return temperature. The smaller the temperature drop, the greater the flow rate and pumping requirements. The lower the return temperature, the larger the heat transfer surface required for space heating. Thus, the choice of design conditions requires a detailed analysis of the building mechanical systems and the distribution system.

Low temperature hot water systems are normally designed to operate with supply temperatures in the range of 100 F to 240 F. The lowest practical supply temperature should be chosen. However, for the present feasibility analysis, a maximum supply temperature of 240 F with steam being extracted at 30 psia from the steam turbine to generate the hot water was selected. A supply temperature of 160 F or less is possible and would be compatible with a solar heat collection system. Such a low temperature hot water could not be used to drive a lithium bromide absorption chiller, but it could be used with an ammonia absorption chiller.

g. Increment Load Size

Approximately 40 percent of the distributed steam from Heating Plant No. 2 Medical Center which is located adjacent to the Heating Plant. It is estimated that of this steam load, approximately 5 percent of the steam is used in sterilizers and 20 percent is used for multizone heat-reheat systems. The remainder of the steam is fed to hot water generators to provide heating and domestic hot water. For the present analysis, only the existing hot water distribution system at the medical system is to be considered for connection the proposed IUS low temperature hot water system distribution system. Thus, the load selected for evaluation is 30 percent of the overall heating load of Heating Plant No. 2.

Reductions in energy losses by conversion of steam distribution systems to low temperature hot water distribution systems have been reported in the range of 5 to 20 percent of the system heating load. An assumed 10 percent reduction in load has been used in the present evaluation.

There are four hot water generator stations to which the hot water distribution system would interface. The send out temperature on the space heating water is varied from 100 F to 150 F. Domestic hot water is sent out at 120 F and the temperature is boosted to 180 F in the kitchens.

The power cycle including turbine/generator and boiler size are the same as those given for the previous absorption chiller alternate.

h. Performance

As shown in Table VII-1, there is an 11 percent increase in electrical power generated with no increase in purchased fuel or steam generation. Also, the overall energy use is 11 percent less than the base case and 5 percent less than Alternate C which did not include low temperature hot water handling.

There is greater production of electrical power per unit of heating load and since the power cycle is boiler and trubine throttle flow limited, the decrease in thermal load allows for greater power production by adjusting chiller loadings and exhausting more steam to the condensers.

9. Increment of Alternate D (6.25 MW Select Energy + Absorption Chillers + LTHW)

This increment is offered as a means of phasing the construction of the 12.5 MW Select Energy plant to facilitate the budgeting procedure. However, the profitability indices presented in the following chapter are such that this increment stands alone as a good investment should funding for the full recommended system not become available. This proposed increment allows the University to gain approximately half of the benefits projected for Alternate D.

a. Power Cycle

The incremental approach would consist of a 6.25 MW non-condensing steam turbine generator configured as shown in Figure VII-8. The performance curve for such a unit would be as depicted in Figure VII-9.

Portions of the campus steam distribution system would be converted to low temperature hot water in accordance with the Conversion Schedule of Alternate D.

b. Performance

This system will also operate in an efficient and economical manner, yielding approximately half the benefits of power generation and reduced fuel consumption of the Alternate D system. The system benefits are summarized in Table VII-2.

D. SOLID WASTE MANAGEMENT

1. Resource Recovery

Resource recovery is the technique by which solid waste management is integrated with the other utility services. Two modes of resource recovery, materials recovery and energy recovery, can be practiced and potential for application of each of these at the University of Florida is considered below. A flow diagram of the IUS solid waste management system is shown in Figure VII-11.

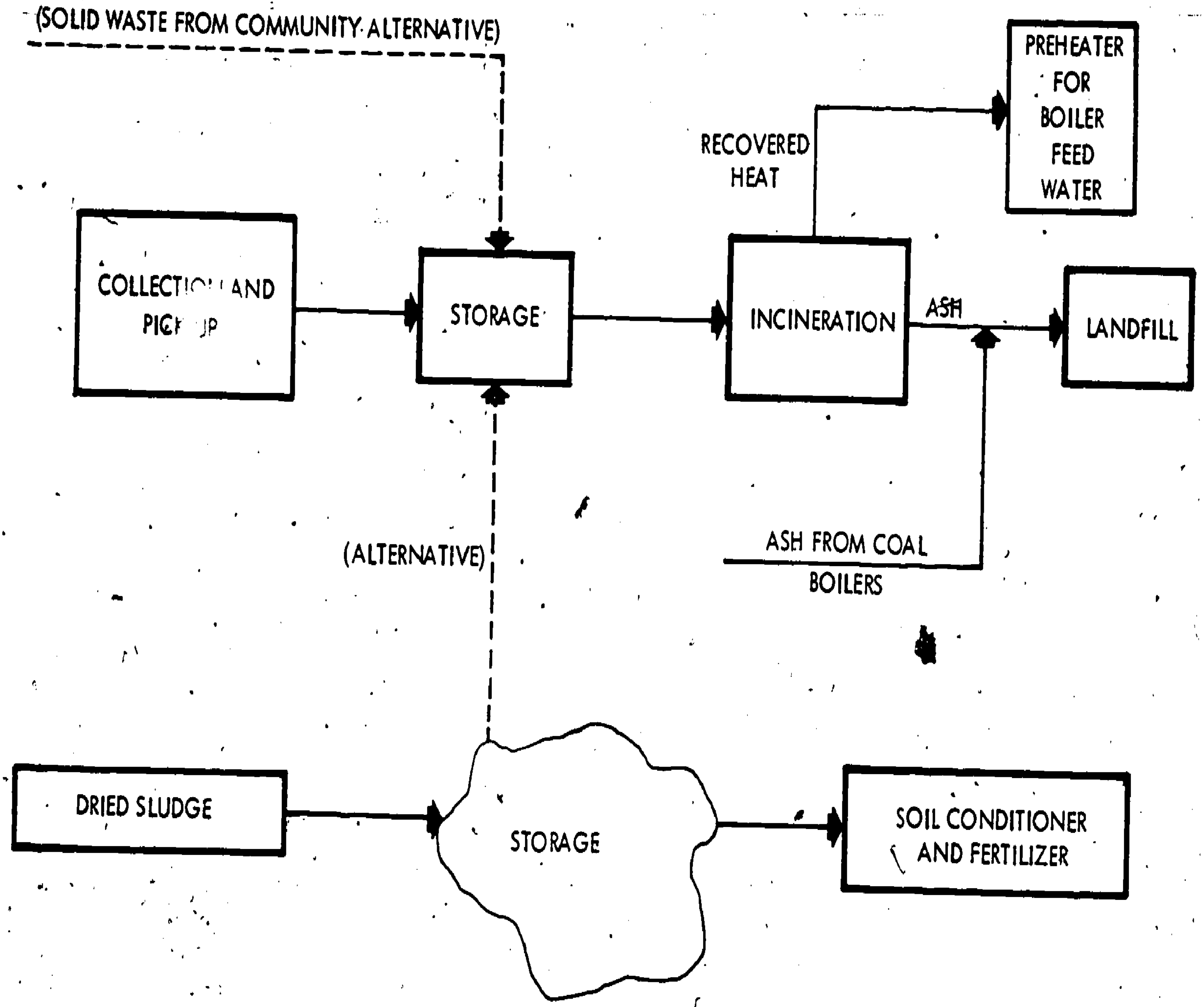


FIGURE VII-11 IUS SOLID WASTE MANAGEMENT SYSTEM

a. Materials Recovery

Successful materials recovery requires a separation scheme and a market for the recovered materials. Ferrous metals, although easily separated, are often not marketable due to depressed local scrap iron demands and the somewhat dirty nature of waste recovered ferrous metals. Other-constituents, such as aluminum tops and organic coatings on steel cans, often preclude direct use of this resource without further processing schemes. Although aluminum can be separated from more dense materials in heavy-media cyclones, it has not been demonstrated to be economically feasible. Glass is easily separated but must be color sorted before glass manufacturers will purchase it. Furthermore, recoverable materials constitute a small fraction of the total waste generated by the University and consist primarily of aluminum cans and bottles.

Hence, for technical and economic reasons, the installation of a materials recovery system is not considered practical on the scale envisioned at the University of Florida.

b. Energy Recovery

Regardless of the degree that materials are recovered, a substantial amount of heating value is available in solid waste. Of the several methods by which the energy of solid waste can be recovered, only incineration with heat recovery is considered practical at the University of Florida. Incineration with heat recovery can be accomplished in a number of ways depending on the unit size and mode of firing. The most likely alternatives are considered below.

1.) Controlled Air Incinerators

This type of incinerator consists of two or more chambers in which waste materials are combusted. Generally, the first or primary chamber is operated with less than the stoichiometric air requirement. This effectively reduces gas velocities near the grate, thus, reducing particulate emissions. Since this chamber is operated under starved air conditions, wastes are partially pyrolyzed into combustible gases. In the secondary chamber, an auxiliary flame provides sufficient heat and oxygen to complete combustion of the gases from the primary chamber.

A schematic diagram of this type of incinerator equipped with waste heat recovery is shown in Figure VII-12. The system has two stacks allowing operational flexibility. The system acts as a simple incinerator when the flue gases exhaust through the dump stack or as an incinerator with heat recovery system when flue gases exhaust through the secondary stack. In the event of control failure, the system immediately directs the hot gases through the dump stack.

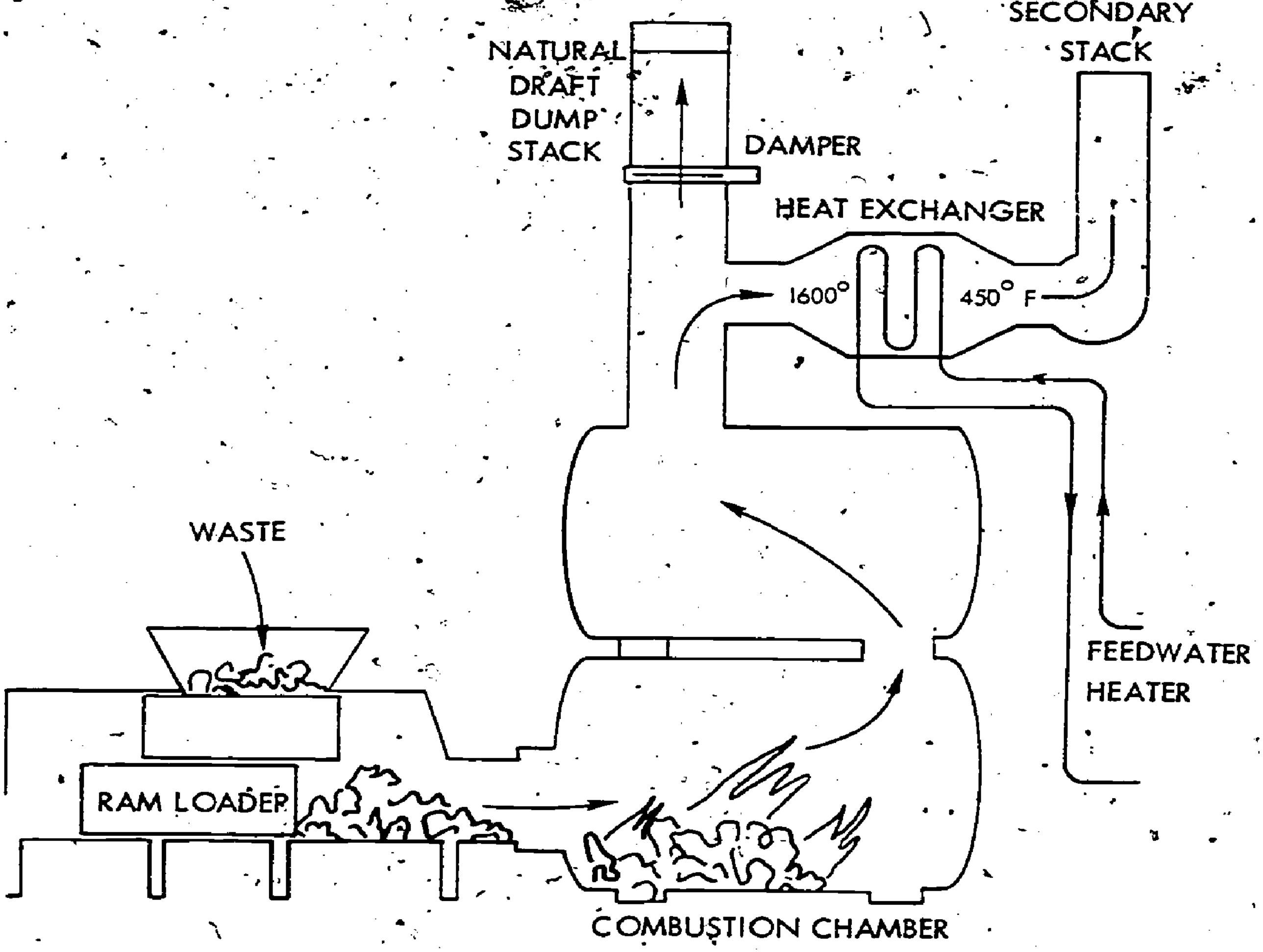


FIGURE VII-12 CONTROLLED AIR INCINERATION EQUIPPED WITH WASTE HEAT RECOVERY

The small modular incinerators have proven that they can efficiently process residential and commercial waste. The efficiency of thermal processing is comparable to the largest municipal incinerators with typical volume reductions of 95 percent and weight reduction of 80 percent. With few moving parts, maintenance problems and hence costs are minimized. As they do not emply waster washers or scrubbers to achieve their low air emission rates or water quenching systems to cool the ash residues, the cost and environmental control from the use of water with large incinerators have been eliminated.

2.) Conventional Incineration with Heat Recovery

Conventional incineration, employing excess air in the primary chamber to reduce the heat in the gases emitted during combustion, produces a much more contaminated gas than results from controlled air machines. Also, the temperature relationships are different between the two designs. To meet air pollution control codes, conventional waterwall incinerators must (or should) install mechanical, or water operated, devices to treat the emitted gases. These devices also drastically cool the gas stream. Any heat extraction for energy recovery must take place before the gas enters the pollution control devices.

The new controlled air incinerator designs are not faced with these constraints. The corrosive elements and particulates are considerably reduced in the gas stream by the high temperatures in the secondary chamber (after-burner) without the use of mechanical pollution control devices.

3. Cofiring

The solid waste and coal could be cofired in the same boiler. This method of incineration with heat recovery was not considered practical at the University of Florida for several reasons.

Cofiring requires preprocessing of the solid waste before injection into the boilers. The preprocessing equipment consisting of shredders, classifiers, and conveyors generally cost more than a separate incinerator with heat recovery equipment. The variability of solid waste composition can easily cause fluctuations in steam generation which can seriously effect the turbine/generator controls. There is a lack of experience in cofiring of solid waste in power generation boilers in the size range contemplated at the University of Florida. The existing cofired operations with power generation are an order of magnitude larger than the boilers being recommended in this study.

2. Operation of Controlled Air Incinerators

This type of incinerator is available in factory assembled units with capacities normally less than 15 tons per day and is installed in multiples of identical units to achieve the desired plant capacity. Such a modular approach provides greater flexibility of design than exists with larger volume plants.

Very few units have automatic ash removal. Without this feature the operation must be cycled with the ash residue being removed by an operator after building up inside the chamber for a given number of hours.

3. Recoverable Heat

The amount of heat recovered from solid waste depends on the heat content of the solid waste and the efficiency of the heat recovery units.

a. Heating Value

The heat content of solid waste is highly dependent on composition. Trash consisting of a mixture of paper, cardboard, cartons, wooden boxes, and combustible floor sweepings from commercial and industrial activities will typically have an as received higher heating value of 8,500 Btu/lb with a 10 percent moisture content and 5 percent incombustible solids.

Refuse from apartment and residential occupancy commonly consists of an even mixture of rubbish and garbage by weight with up to 50 percent moisture and 20 percent incombustible solids. As received higher heating values of 4,300 Btu/lb have been experienced in heat recovery applications.

For this study a higher value of 5,500 Btu/lb has been assumed. This is believed to be a conservative estimate in view of the high paper content of the University solid waste.

b. Heat Recovery Efficiency

The amount of heat recovered is dependent on the efficiency of the heat recovery system. The efficiency of heat recovery is dependent on both equipment design and moisture content of the solid waste. The waste heat recovery boiler efficiency has been assumed to be 70 percent based on the operating experience of a similar sized controlled air incinerator with heat recovery (7).

4. Utilization of Recovered Heat

As with materials recovery, there must be a way to use the recovered heat if this heat recovery is to be worthwhile.

a. Boiler Fuel Reduction

In a conventional system the heat recovered from solid waste incineration can readily be used to generate hot water or steam and thus reduce the fuel consumed in the primary boilers.

With an integrated utility system, the waste heat from power generation is used for space heating and cooling and domestic hot water heating. If the waste heat available from power generation is equal to or greater than that which can be used, then any use of heat recovered from solid waste incineration to supply the thermal loads of the University will reduce the amount of low heat rate power which can be generated.

The steam generated in the heat recovery boiler can be used for boiler feedwater heating. This likewise reduces the amount of steam bled from the turbine/generator and hence reduces the power generated from the highly favorable heat rate of regenerative feedwater heating for a backpressure turbine/generator as in Alternate A. Therefore, boiler fuel credit can only be given to waste heat utilization if the total/select energy system based on a backpressure turbine/generator does not supply the whole thermal load. The possibility of power generation from the recovered heat does exist for a total/select energy system based on a condensing turbine/generator.

Cofiring of solid waste with coal in the main boilers has been dismissed because of potential operational difficulties and cost of preprocessing.

b. Power Generation

An alternate to using the recovered heat for the thermal loads is to generate power. By injecting the recovered heat from the heat recovery boiler to the highest pressure feedwater heater, less steam is bled from the turbine and more steam can pass to the condenser. The power generator for the net recovered heat feed to the 265 psi feedwater heater is 73.4 kWh/10^6 Btu.

Since the boiler capacity and the high pressure throttle steam rates are the limiting factors for the present designs, injection of steam at 265 psi does not reduce the utilization of these units. If additional turbine or generator capacity were required to accommodate the admission of steam at this point in the power cycle, an accounting for the increased capital costs would need to be made.

5. University Solid Waste Incineration

a. Rationale

A solid waste incineration system with heat recovery could be installed with the Select Energy system, Alternates B, C, or D. Credit would be given for the power generated by steam admitted to the high pressure feedwater heater. A 25 ton per day facility consisting of two controlled air incinerators and associated changing and heat recovery units will provide sufficient capacity when changing for 7 hours per day and operated 6 days per week.

b. Performance

The heat recovered from 7,000 tons per year of solid waste will generated 3,970,000 kWh of electricity. At a heat rate of 11,275 Btu/kWh for the commerical power supply, the recovered heat is equivalent to 45 billion Btu's of fuel per year.

Several variations of the solid waste management system are worth noting. First, selective collection of the University solid waste may be beneficial. Secondly, solid waste from the surrounding community could [illegible] included.

The present solid waste management system at the University does not require waste segregation since all refuse is sent to a landfill for burial. Depending on the type of refuse fired, some segregation of wet garbage before incineration may benefit the heat recovery performance. Based on weekly refuse collection data, cafeterias generate about 200 cubic yards of garbage per week as compared to a total University generation of 3,800 cubic yards of refuse per week. The wet garbage could be collected separately and sent to a landfill. There is negligible recoverable heat from wet garbage and the reduced amount of solid waste would allow the University solid waste to be burned in the proposed system on a 5 day per week basis instead of the proposed 6 days per week.

Since the university solid waste heat equivalent is less than 2 percent of the overall energy needs of the University, the possibility of importing solid waste from the surrounding community has been investigated in the next section.

6. Include Community Solid Waste

a. Rationale

Upon learning of the IUS feasibility study being conducted for the University of Florida, the City of Gainesville requested that the possibility of including the community generated solid waste in the IUS solid waste management also be investigated.

The City of Gainesville generates and disposes over 40,000 tons of solid waste to landfill per year. However, only that portion of the community solid waste which is of equivalent quality to that of the University was considered in this study.

A recent survey on the solid waste generation in the Gainesville area shows that there would be available 12,000 tons per year of solid waste from commercial sources, and a 75 ton per day facility would be required to incinerate the combined inputs from the University and selected collection from commercial sources. This refuse would be primarily paper materials and is assumed to have a higher heat value of 5,500 Btu/lb.

b. Performance

The heat recovered from the combined 19,000 tons of solid waste per year would generate 10,800,000 kWh per year of electricity.

E. WATER MANAGEMENT

The central theme to water management is the use of the minimal quality available water which satisfactorily meets the needs of the intended use. Similarly, the treatment level need only be sufficient to satisfy the requirements of the specific use. The proposed IUS water management facility for the University of Florida is shown in Figure VII-13.

1. Potable Water System

The primary mode of integration of potable water systems is by displacement of the use of potable water for irrigation and process water. Since the University has a secondary water distribution system to serve these purposes, the present IUS project does not directly include the potable water system.

The University does own and operate its own potable water distribution system and presently has under consideration a recently completed feasibility study for installing a potable water treatment plant.

2. Sanitary Sewage System

The University owns and operates its own sewage collection system and treatment plant. The treatment facility meets all Federal and State discharge regulations. Construction improvements are presently being made to ensure high performance levels through the next decade.

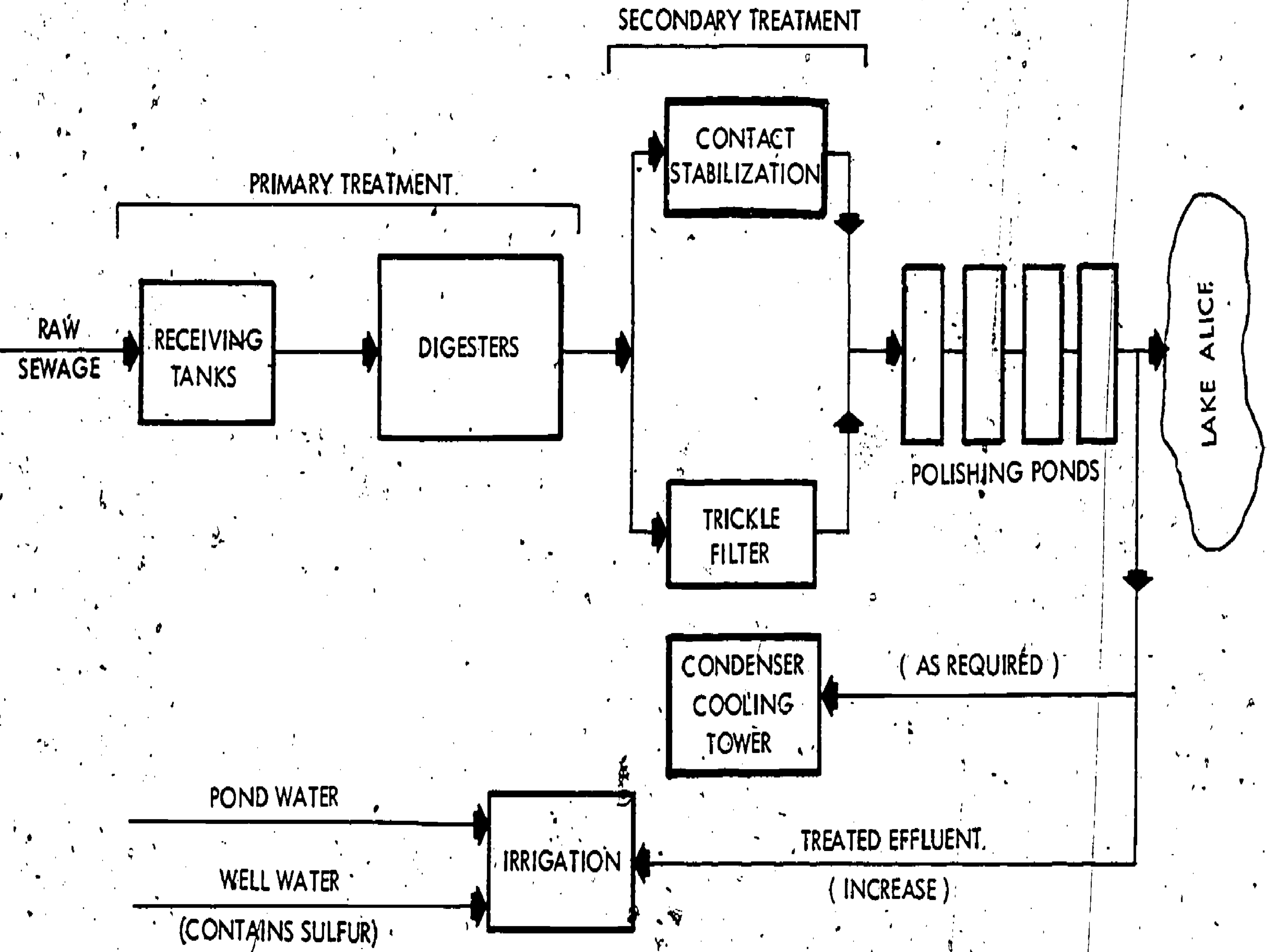


FIGURE VII-13 IUS LIQUID WASTE MANAGEMENT SYSTEM

a. Discharge and Regional Plans

The Environmental Protection Agency issues National Pollution Discharge Elimination System (NPDES) permits to facilities in conformance with applicable and approved Section 201 and 208 (of the Federal Water Pollution Control Act (FWPCA)) area-wide plans. The Alachua County 208 plan is presently being developed and the role of the University sewage treatment facility in this plan has not been determined.

The Department of Pollution Control has notified the University that provisions should be made to connect to the regional waste water treatment system when this facility becomes operational. The regional treatment facility is in construction with project completion still several years in the future. The final decision on the status of the University sewage treatment facility will depend on the outcome of the 208 plan presently being formulated. The University planning is influenced by factors over which it has little control.

b. Available Alternates

In the absence of firm commitments from other authorities, the University has under construction two wastewater treatment programs which may be implemented in the coming decade. The alternative to be followed awaits political and financial decisions of others.

1.) Discontinue Treatment of Sewage on Campus

A prerequisite to following this course of action is the authorization, funding and construction of a truly regional wastewater collection and treatment system with statutory authority to require the University to deliver all or part of its sanitary sewage to that regional system. The date by which this transfer of treatment responsibility will occur, the authority for such action, and the financial questions arising from purchase of the existing University sewage treatment plant and establishing charges for treatment of campus sewage have not been resolved.

The implementation of the alternate will require the installation of a 10,000 ft, 12 to 16 inch pressure line and pumping station to connect with the force main on 34th Street. Estimated construction costs of this alternate are over $1,000,000. Based on the latest ordinance, the anticipated sewage rates for the University to dump its sewage to the regional treatment facility are $1.07 per thousand gallons. This compares to the present operation of the University sewage plant costs of $0.24 per thousand gallons.

2.) Continue Operation of University Sewage Treatment Plant

The continued operation of the University of Florida sewage treatment facility to meet current and possible future effluent standards would require the assignment to the University of responsibility for treating University wastewater under the approved regional plan.

Implementation of this plan would require construction of additional treatment units before and after the existing trickling filter and contact stabilization plants. The upgrading of both plants would achieve organic, suspended solids and nutrient removal efficiencies meeting goals set by 1972 Federal legislation. The project costs for improvements to sanitary sewage facilities have been estimated (2) at $1,300,000.

If the University continues the operation of the existing sewage treatment plant under a regional plan, the reuse of treated wastewater could prove beneficial in that the quality of the renovated water need only be acceptable to the proposed use. Thus, the quantity of wastewater requiring advanced wastewater treatment would be reduced.

3. Water Reuse

The potential exists for an IUS to use renovated wastewater in such non-human contact purposes as cooling tower makeup, flue scrubbers, irrigation, and fire protection. While treated wastewater can be reused, the relative amount that is required for these purposes varies with the utility configuration and weather conditions. In a selective energy system using a non-condensing turbine, there would be no condenser and hence no cooling tower water makeup requirement for power production. Cooling tower makeup for chilled water production varies significantly with seasons as does irrigation water requirements.

a. Cooling Tower Makeup

Sewage plant effluent has been used by a number of plants over the years for cooling tower makeup and first-hand experiences are documented in the literature. No magical skill is required to adapt wastewater streams for cooling tower makeup.

What is normally required is an in-depth investigation, and the application of good water treatment technology.

1.) Operational Characteristics

Corrosion is usually less severe with sewage effluent than with fresh water. Although such effluent typically contains high orthophosphate concentrations, its tendency for calcium phosphate scaling is inhibited by the stabilizing effect of organic material that is also typically present in high concentrations. So, proper control of cycles of concentration and pH, along with the addition of deposit control agents, usually permits higher calcium phosphate loadings than may be carried in fresh water systems.

The nature of sewage effluents presents a severe microbiological fouling problem when such water is used as cooling tower makeup. This can be controlled, but at increased biocide cost. A combined program of chlorine and nonoxidizing biocide addition is typically used to maintain good control.

Although there are reports of some very severe, hard-to-contain foaming problems, most systems can be controlled with a small amount of antifoam.

2.) Treatment and Control

A number of installations now use lime treated and clarified municipal sewage plant effluent for cooling tower makeup and even for boiler feedwater makeup. Early applications of treated sewage for cooling tower makeup showed that the problems that appeared could be minimized by pretreatment with lime. More recently, however, specifically developed chemical treatment programs, together with careful operating control has allowed the successful use of treated sewage plant effluent as cooling tower makeup without lime or other post treatment.

3.) Steps to Successful Reuse

The first step in evaluating a waste stream for cooling water makeup is a thorough analysis of that stream. If the stream passes the analysis test, the next step is usually a feasibility study that would, via various tests, determine the streams potential for corrosion, general fouling, scale formation, biological fouling and foaming, and what treatment would be needed to control such problems.

The next step is to experiment reusing the water in the plant cooling tower, starting at a low percentage of the makeup and building toward the final desired percentage with constant monitoring of corrosion and fouling.

4.) Usage

Presently the cooling towers provide cooling for the condensing steam turbine driven chillers. Given the existing cooling load, approximately 253 billion Btu's are exhausted to the atmosphere per year. Approximately 0.1 gallon of water is evaporated per 1,000 Btu's of cooling tower load. Cooling tower water makeup requirements for evaporation are about 25 million gallons per year. If absorption chillers were installed, the evaporation would be increased by 25 percent. While a significant quantity of water is consumed by evaporation, the reuse of available sewage plant effluent is less than 5 percent.

b. Irrigation

1.) Potential Usage

Currently an estimated 37 million gallons of treated effluent are used annually for irrigation. The potential exists for using about one fourth of the sewage treatment facility effluent for irrigation. An aesthetic benefit will be reduction of the undesirable hydrogen sulfide odors now produced by the use of high sulfur well water.

2.) Secondary Water Distribution System

The ability to use renovated wastewater for irrigation and other purposes presumes that a secondary water system is available for distribution to the points of application. The existing system is a series of wells and distribution networks. Although there are jumpers installed between several of these distribution systems, basically each system is operated individually. Modifications will be necessary to affect increased use of treated wastewater and a hydraulic analysis of the University secondary water system is recommended.

Budgetary estimates of the cost of installing the necessary pumps and piping to make additional irrigation possible are placed at $750,000.

F. THE IUS SITE

1. Site Location

Figure VII-14 shows a plan view of the recommended site for the IUS facility. The close proximity to the Heating Plant No. 2 and the sewage treatment plant offers ease of integration and hence lower associated costs. The site is in the area designated by the University for general utility expansion programs.

2. Interfacing to the Existing System

The primary connections to the steam distribution system will be through a connection to Heating Plant No. 2. The close proximity to the existing facilities will allow the joint use of common equipment such as cooling towers. Furthermore, the drainage canal from the existing sewage plant passes next to the selected site which will minimize pumping costs for the reuse of cooling tower makeup.

3. Fuel Delivery and Storage

A railway presently exists along Archer Road and is the logical choice for transporting coal to the IUS power plant. As shown in Figure VII-14, a spur will be constructed to the coal storage site. There is a 26 foot difference in elevation between the railroad and the proposed storage site. The spur will be constructed between an existing parking lot and Wilmont Gardens onto a trestle which passes over the proposed coal storage facility.

A berm will be constructed and properly landscaped on the exposed sites of the storage area to minimize the dusting and aesthetic problems of coal storage.

Should the railroad not be available or if construction of the proposed spur should not be possible, alternate methods of delivery and storage are available. For example, coal could be delivered by rail, stored at a site on University property to the south of the main campus, and then trucked to the power plant.

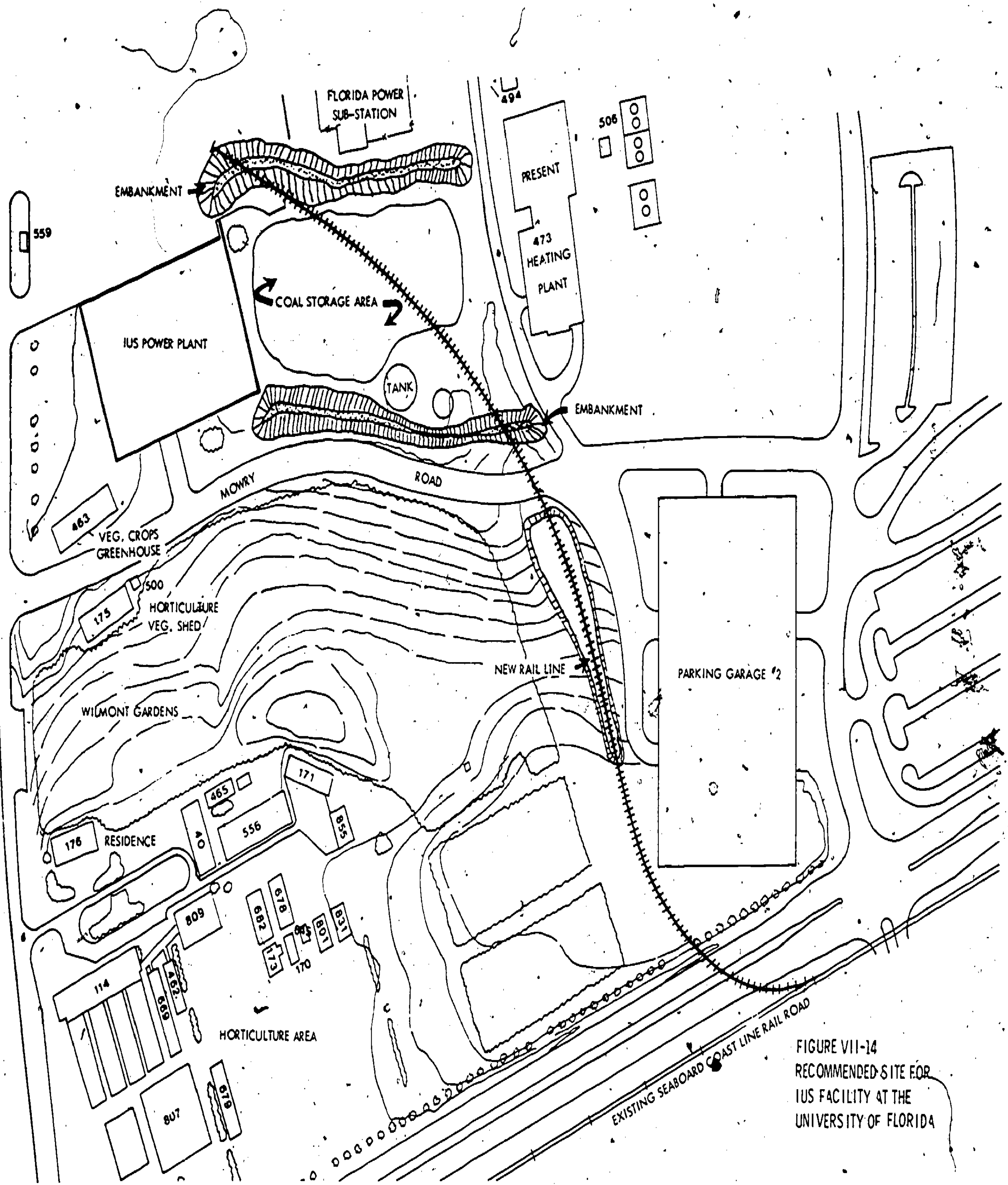


FIGURE VII-14
RECOMMENDED SITE FOR IUS FACILITY AT THE UNIVERSITY OF FLORIDA

VIII. ECONOMIC ANALYSIS

The objective of the economic analysis section is to provide a quantitative picture that shows the dollar savings resulting from an IUS. As in the previous section on Conceptual Designs, the analysis of the IUS alternates is considered under the three subsystem groups: (1) Thermal Electric Generation System, (2) Solid Waste Management, and (3) Water Management.

A. LIFE CYCLE COST ANALYSIS

The life cycle cost analysis presented involves a combination of techniques which form an economic model for long term monetary costs associated with utility systems at the University of Florida.

1. Life Cycle Costs

All sources of cost attributable to the various alternates by time period are considered including initial investment, operation and maintenance; and replacements. The effects of time are incorporated by including allowance for the impact of inflation on costs incurred or revenues generated in future years and allowance for the fact that dollars spent or received in the future are worth less than dollars spent or received today because of the interest expense or lost interest income from those dollars.

2. Incremental Analysis

In analyzing the economic potential of IUS, the baseline (existing) system is considered first. The alternate designs are examined relative to the baseline. The analysis focuses on the incremental costs, that is, the costs actually generated or effected by the alternative.

3. Profitability Measures

Profit is an obvious goal of investment in any enterprise. Although in a service institution, there are many others; profit is the only one quantifiable and therefore useful for economic evaluation. Albeit a cost avoidance type investment, the same profit motivations exist for evaluating the alternates for supplying utilities. Four measures of profitability are used to determine the investment value of each of the IUS alternatives considered in this report, present worth, payback time, savings to investment ratio, and interest rate of return.

a. Present Worth

The present worth of an alternate as evaluated in this report is the present value of the cost savings of an alternate relative to a base case minus the present value of the net investment of the alternate over the base case. The present values are the values of all cash flows, discounted to the start of operations (1981). As such, the present worth provides a measure of the overall savings including allowances for capital and interest that the University will experience by installing the alternative.

b. Payback Time

Payback time is the time required to get back the original investment and is calculated by accumulating, year by year from the beginning of operation, the net savings realized from the investment. The payback time is equal to the number of years required to reach that time when the total accumulated savings equals the net investment. That is, the total invested cost including interest at 6.5 percent divided by the annual savings, both in 1981 constant dollars. The payback time provides a measure of the time period over which the apparent risk of investment occurs.

c. Savings to Investment Ratio

To show the efficiency of savings produced for each dollar of investment, the savings to initial investment ratio has been presented. As defined in the present report, the savings to investment ratio is the ratio of the present value of an incremental savings to the difference in initial investments associated with that savings.

d. Interest Rate of Return

The rate of return on investment has been shown using the interest rate of return as an indicator. The interest rate of return (often called the discounted cash flow rate of return) as calculated in this report is the discount rate for which the payback time, with interest, is equal to the assumed operating life of the project.

4. Economic Factors

The key assumptions which form the basis for evaluating the economic potential of the IUS alternatives are:

a. Energy Prices

Based on the energy assessment presented earlier in this report, the mid-1976 price of fuel and electricity were estimated to be:

Source

Electricity	Unit	$/Unit	$/$10^6$ Btu
Energy	kWh	0.0219	6.42
Demand	kW	2.09	-
Fuel			
Fuel Oil	Gallon	0.31	2.09
Coal	Ton	35.00	1.35
Natural Gas	1000 cubic feet	0.85	0.81

The electrical energy price is an average of those experienced by the University during the first six months of 1976 and includes allowances for fuel adjustments. Both the fuel oil and coal prices are based on low sulfur values. The price of fuel oil is that given by the present supplier for laid-in fuel. The coal prices was typical of those offered by brokers and being paid by similar systems with allowances made for delivery.

The price of natural gas is the average paid by the University during the past year. As discussed in Section V, natural gas is not expected to be available when the proposed IUS becomes operational and fuel oil has been assumed as the primary fuel for the existing boilers. The impact of gas being available is tested in the Sensitivity Analysis section.

b. Time Estimates

The operational time period for the project is 25 years. This is consistent with the life expectancy of the major components such as boilers and turbine generators. Project construction time is 4 years and 1 year is assumed for seeking and receiving funding.

c. Interest Rate

The interest rate on borrowed funds has been assumed to be 6.5 percent. This is the interest rate on recently issued bonds by the State of Florida for University construction. The maximum allowable interest rate paid by the state on borrowed funds is 7.5 percent according to state law. The interest rate on capital funds has been used as the discount rate in the present study.

d. Inflation

The general inflation rate has been assumed to be 4 percent per year.

e. Cost Escalation

Cost escalation is defined as the increase in price/cost of a particular resource relative to those of other resources.

Energy

The Federal Energy Administrations projections(1) for energy escalations relative to general inflation have been assumed. For ten years beginning in 1976, price escalations are projected for the Southeastern United States as follows:

Energy Form	Escalation Rate, Percent
Electricity	2.3
Fuel Oil	2.2
Coal	-0.7
Natural Gas	4.0

After ten years, the escalation rate was assumed to be zero.

Equipment and Construction

A 1 percent escalation rate on capital installation was assumed.

5. Sensitivity Analysis

Sensitivity analysis provides an indication of the risks involved by testing the economic impact of varying key assumptions for each alternative.

B. THERMAL/ELECTRIC GENERATION SYSTEM

The economic feasibility of the alternative conceptual designs for supplying heating, cooling, and electricity to the University of Florida are presented below.

1. Capital Cost Estimates

a. Initial Investments

The estimated capital costs for the initial investment of each alternate are given in Table VIII-1 by equipment category. The items included in each category are given in Table VIII-2.

The boiler turbine and generators design ratings for each alternate were specified as given in Table VIII-3. All other equipment was specified relative to these three units.

TABLE VIII-1 THERMAL/ELECTRIC GENERATION SYSTEM INITAL CAPITAL COSTS ESTIMATES (INSTALLED COSTS, MID - 1976)

	Conventional Alternate	Select Energy Alternates			
Equipment	New Coal Fired Boilers	5 MW	10 MW	12.5 MW + Absorption	12.5 MW + Absorption + LTHW
Boilers	2773	1400	2800	3360	3360
Pollution Control Equipment	821	448	755	855	855
Fuel Handling and Storage	398	318	397	398	398
Turbine Generator	0	1376	2892	3151	3151
Controls and Electrical Equipment	209	706	1227	1290	1290
Heat Exchangers	80	67	340	393	393
Pumps	69	86	172	206	206
Piping Valves and Insulation	193	407	814	978	978
Building	200	150	300	300	300
Miscellaneous Mechanical Equipment	34	75	121	123	123
Distribution Systems	78	438	438	438	640
General Construction	128	164	251	293	294
Contractors Overhead and Profit @ 15%	747	845	1581	1768	1798
Engineering Fees, Contingencies @ 8%	399	451	842	942	959
	6129	6931	12961	14496	14745

TABLE VIII-2 CAPITAL EQUIPMENT CATEGORY DESCRIPTIONS

BOILERS

Spreader stoker boiler at 850 psig, 900° F including all necessary pressure parts, insulation and casing; F.D. and I.D. fans with motor-drives, connecting flues and ducts, stoker, soot blowers with piping, valves and fittings; combustion and feedwater controls, economizer, support steel, platforms and ladders, dust collector.

POLLUTION CONTROL EQUIPMENT

Baghouse filters and induction fans. Ash handling equipment, ash silo and breeching stack.

FUEL HANDLING AND STORAGE

Coal conveyors, storage site preparations, railroad spur and trestle.

TURBINE GENERATOR

Automatic variable extraction steam turbines with 3-phase generator.

CONTROLS AND ELECTRICAL EQUIPMENT

Controls and instrumentation including control panels, boiler controls, data logging, pressure gauges, transducers, and thermometers. Switchgear, transformers, and general electric items.

HEAT EXCHANGERS

Feedwater heaters, deaerator and storage tanks. Condensers, tubes, and cooling towers.

PUMPS

Boiler feed, condensate return, circulation and auxiliary pumps.

PIPING

Heavywall piping, general piping and circulation piping. High pressure and high temperature valves, control valves, and specialties insulation.

BUILDING

Including foundations, electrical work and paint.

MISCELLANEOUS MECHANICAL EQUIPMENT

Water treatment, turbine room crane.

DISTRIBUTION SYSTEMS

Piping, insulation, expansion joints, valves, and connections for hot water and steam distribution.

GENERAL CONSTRUCTION

e preparation, landscape, roadways and survey.

TABLE VIII-3. BOILER, TURBINE, GENERATOR DESIGN RATINGS

	BOILER	AUTOMATIC VARIABLE EXTRACTION TURBINE				GENERATOR
ALTERNATE	STEAM RATING 1000 lbs/hr	THROTTLE CONDITION Pressure psia	Temperature °F	RATING 1000 kW	TYPE	RATING 1000 kVA
CONVENTIONAL ALTERNATE						
New Coal Boilers	120	265	500	-	-	-
SELECT ENERGY ALTERNATIVES						
5 MW	100	850	900	5	Non-Condensing	6.25
10 MW	100	850	900	5	Non-Condensing	6.25
	100	850	900	5	Condensing	6.25
12.5 MW	120	850	900	6.25	Non-Condensing	9.375
+ Absorption	120	850	900	6.25	Condensing	9.375
12.5 MW	120	850	900	6.25	Non-Condensing	9.375
+ Absorption + LTHW	120	850	900	6.25	Condensing	9.375
6.25 MW						
+ Absorption + LTHW	120	850	900	6.25	Non-Condensing	9.375

b. Replacements

To maintain the existing steam generation capability, there will be replacements of 240,000 lb/hr steaming capacity during the 25-year economic evaluation of the project, as shown in Table VIII-4. All boiler replacements are assumed to be packaged oil fired units as per the existing facilities. There will be no replacements required for major equipment installed for each of the alternatives.

c. Basis for Capital Cost Estimates

The estimated capital cost for each Alternate is based on 1976 equipment, material and labor prices. Equipment costs for major items have been obtained from manufacturers of equipment with a proven record of reliability. Installation cost estimates were either furnished by the vendors or were established from prior experience with comparable projects.

1. Annual Operation and Maintenance Costs

The operation and maintenance charges for the first year of operations (1981) are given in Table VIII-5. The basis for these projected costs are as follows.

a. Fuel Charges

Fuel costs are the product of the evaluated requirements and the projected delivered fuel prices. As the amount of electrical power generation is increased, there is also an increase in the fuel costs, but this is more than balanced by the reduced electrical costs.

b. Electrical Charges

The electrical charges have been separated into energy charges and demand charges. The energy charges are the product of the evaluated fuel requirements and projected electrical energy prices including fuel adjustments.

The demand charges are based on the difference of projected electrical demands of the University and the power generation rates of the various alternatives. Compensation for additional demand charges from system failures have been included with the additional operation and maintenance charges.

c. Additional Operation and Maintenance Charges

The additional operation and maintenance costs arising from the operation of the osed alternatives include adjustments for labor, maintenance, purchased utili- and chemicals, ash disposal, personnel upgrading, fuel handling, and potential

TABLE VIII-4 - ESTIMATED REPLACEMENT COSTS
(Installed Costs, Mid - 1976)

Alternative	Year	Boiler Capacity	Cost $(000)
Existing	1986	120	729
	1991	120	729
5 MW Select Energy	1996	140	850
10 MW Select Energy	1996	40	243

VIII-5 - THERMAL/ELEC[illegible]ENERATION SYSTEM

OPERATION : [illegible]981), ($1,000,000)

Expense	Conventional Alternates		Select Energy Alternatives				
	Existing System	New Coal Fired Boilers	5 MW	10 MW	12.5MW +Absorption	12.5MW + Absorption + LTHW	6.25 MW + Absorpl + LTHW
Electricity							
Energy	4.90	4.90	3.74	1.87	0.98	0.61	3.55
Demand	0.87	0.87	0.75	.51	0.43	0.38	0.67
Fuel							
Oil	3.45	0	0.69	0	0	0	0
Coal	0	1.83	1.79	3.50	3.96	3.95	2.25
Additional Operations & Maintenance	0	0.19	0.15	.20	.21	0.24	0.17
Total Annual Costs - 1981	9.22	7.79	7.12	6.08	5.38	5.18	6.64
Percent Savings		15.5	22.8	34	41.6	43.8	27.9
Capital Investment		6,129	6,931	12,961	14,491	14,745	8,640

charges such as increased charges from system failures.

The charges are those over and above those experienced by the existing system. To provide a frame of reference, the magnitude of the 1976/77 budget for operation of the existing heating plant is noted.

Labor	$250,000
Electricity	240,000
Operating Expenses	80,000
	$570,000

The labor charges include wages for 16 operators and 8 mechanics. The electrical charges are for electricity purchased over and above that produced by the existing 1000 kW noncondensing turbine. The operating expenses include $8,000 for make-up water and a like amount for chemicals.

2. Results of Life Cycle Cost

On the basis of balancing thermal to electric loads, energy charges and demand charges, and fuel alternatives six energy subsystems were developed and evaluated. They are:

1. New boilers, coal fired, no power generation
2. 5 MW select energy plant
3. 10 MW select energy plant
4. 12.5 MW select energy and absorption chiller
5. 12.5 MW select energy plant, absorption chillers, and low temperature hot water distribution system
6. 6.25MW S.E. plant, absorption chillers and low temperature hot water dist.

The capital investment for each of these is presented in Table VIII-1 and Tables VIII-2 through VIII-5 present additional information on the equipment description and provide operating and maintenance and other cost data used in evaluating the systems.

Table VIII-6 is a presentation of the profitability indices for the six cases. They are all compared against the baseline, the existing utility system. All show interest rate of return in excess of 20 percent which is very good for a minimum risk project. The savings to investment ratio (SIR) for each is above 3 which is very good. The payback period, another important index, is approximately four years for each. A short payback period gives a high confidence level in the economic success of the project because such important variables as fuel cost can be projected much more accurately for a 4-year project than for a project having a 10-year or more payback. In summary, all of the projects look attractive when compared to the University's

TABLE VIII-6 - INCREMENTAL PROFITABILITY ANALYSIS OF THERMAL ELECTRIC GENERATION ALTERNATES RELATIVE TO THE EXISTING SYSTEM.

	Conventional Alternate	Select Energy Alternates				
Profitability Indicators	New Coal Fired Boilers	5 MW	10 MW	12.5 MW + Absorption	12.5 MW + Absorption + LTHW	6.25 MW + Absorption + LTHW
Present Worth, $ (000,000)	26	38	55	64	71	35
Payback Period, Years	4.2	3.4	4.1	4.0	4.7	5.0
Savings to Investment Ratio	3.3	4.2	3.2	3.5	3.9	3.4
Interest Rate of Return, Percent	24.4	26.0	22.4	23.2	23.3	22.0

existing energy system.

The capital cost for the six alternatives varies from approximately $6 million to $15 million. Therefore, the return on the incremental investment was investigated. Table VIII-7 shows the return on the incremental investment when considering successively higher investment levels. Although the investment for two 120,000 lb/hr. coal fired boilers to replace the existing boilers looks good, the incremental return to go the next level of investment looks even better. The payback period is only 1.1 years for an additional $800,000 to obtain 5 MW of power generation capability. The other profitability indices are equally attractive. Thus, when compared to the option of a coal fired replacement boiler with no power generation addition, a 5 MW select energy plant is the best investment.

Upon examination of the 10 MW select energy option, a similar pattern emerges. The investment in a 10 MW relative to a 5 MW is marginally attractive while requiring a capital expenditure of an additional $6 million. However, for an additional $1.5 million to go to the next higher increment, the profitability indices improve dramatically, resulting in an incremental interest rate of return of over 30 percent and a payback of less than three years.

To this point, there are two attractive options, a 5 MW select energy plant and a 12.5 MW select energy plant with absorption air conditioning. Looking at Table VIII-6, except for present worth the profitability indices for the 5 MW select energy system are better than the 12.5 MW system. However, the question that should be addressed is whether or not the additional investment for the added capability is attractive when compared to other investment opportunities. In general, the profitability indices as reflected in the last column of Table VIII-7 are good, and this additional increment is recommended.

In either case, consideration should be given to converting the existing steam distribution system to low temperature hot water (LTHW). The next to last column in Table VIII-7 shows that a $250,000 investment for the conversion will pay back in less than a year, and yielding over a 30 percent interest rate of return. A similar payback and return can be expected for LTHW on the 5 MW case.

If funding is not available for the total investment, it is possible to achieve the recommended system in increments. For example, the first increment could be 5 MW select energy option evaluated in Table VIII-7. The total 12.5 MW with absorption chillers could be installed when funds become available. The principle loss would be the loss in effective revenue that would have been generated by the larger system. If incremental installation is pursued, it may be desirable to consider two 6.25 MW steam turbines as indicated in Table VIII-3 as opposed to a 5 MW and a 7.5 MW.

TABLE VIII-7 – INCREMENTAL PROFITABILITY ANALYSIS OF SUCCESSIVE INCREMENTS

	Conv. Coal vs. Existing System	5 MW/SE vs. Conv. Coal	10 MW/SE vs. 5 MW/SE	12.5 MW/SE + Absorption vs. 10 MW/SE	12.5 MW/SE + Absorption + LTHW vs. 12.5 MW/SE + Absorption	12.5 MW/SE + Absorption vs. 5 MW/SE
Present Worth $ (000000)	26	11	8	10	7	16.5
Payback Period, Years	4.2	1.1	5.4	2.6	0.9	4.6
Savings To Investment Ratio	3.3	10.1	2.1	6.1	18.5	2.8
Interest Rate of Return, Percent	24.4	29.5	17.8	31.2	59.4	20.4
Incremental Investment, $ (000000)	6.2	0.8	6.0	1.5	0.25	7.5

3. Sensitivity Analysis

Tables VIII-8 and VIII-9 show the effect on two of the key profitability indices to changes in system input data. The input data examined were capital cost, discount rate, operation and maintenance cost (O&M), economic life, general inflation, coal price, oil price, energy escalation above inflation, and natural gas price. The following is a discussion of the five profitability indices and their sensitivity to changes in these values.

a. Capital Cost

The results are relatively insensitive to errors in the capital cost estimates. The reason is that the project does not provide uniform annual savings. This is due to the escalation rates of certain parameters being significantly higher than the general inflation rate.

b. Discount Rate

There was no discernable effect in changing the discount rate plus or minus one percent from the 6.5 percent value used in the study. This is due to the low value of the discount rate and the rapid payout time.

c. O&M Cost

The O&M cost refer to those costs over and above both fuel costs and the cost required to operate the existing system. Since the additional O&M costs, shown in Figure VIII-5, represent only a small fraction of the total annual costs, relatively large errors in O&M costs result in small errors in the economic benefits.

d. Economic Life

Variations in the actual economic life plus or minus five years from the 25-year estimate have no effect on payback since the payback time is shorter than any of these economic analysis periods. There is an approximately 2 percent effect on interest rate of return which is considered negligible.

e. Inflation

A plus or minus 2 percent variation in the general inflation rate has an approximate 10 percent effect on the profitability indices. Although this is not negligible, the profitability indi es are so attractive that the overall attractiveness of the project is not affected.

TABLE VIII-8 – INTEREST RATE OF RETURN SENSITIVITY ANALYSIS (PERCENT)

	Conventional Alternate	Select Energy Alternates			
	Coal Boilers Only	5 MW	10 MW	12.5 MW + Absorption	12.5 MW + Absorption + LTHW
Original Values	24.4	26.0	22.4	23.2	23.3
Capital					
+ 20 percent	21.5	23.2	29.8	20.6	24.4
– 20 percent	28.4	29.9	25.9	26.8	26.8
Discount Rate					
5.5 percent	24.4	26.0	22.4	23.2	23.3
7.5 percent	24.4	26.0	22.4	23.2	23.3
Maint. & Labor					
+ 20 percent	24.0	25.7	22.2	23.1	23.1
– 20 percent	24.8	26.1	22.5	23.4	23.4
Economic Life					
25 years	24.1	25.7	22.0	22.9	22.9
35 years	24.5	26.0	22.5	23.4	23.4
Inflation					
@ 2 percent	22.2	23.6	20.1	21.0	21.0
@ 6 percent	26.7	28.3	24.6	25.5	25.4
Coal Price					
+ 20 percent	20.7	23.4	19.5	20.3	20.6
– 20 percent	27.9	28.3	25.0	26.0	25.8
Oil Price					
+ 20 percent	31.3	29.8	25.2	25.8	25.6
– 20 percent	16.5	21.6	19.2	20.4	20.7
Energy Escalation					
0 percent	17.9	19.9	16.1	16.9	17.4
2 percent	20.5	22.3	18.1	18.9	19.4
4 percent	23.2	24.7	20.1	20.9	21.4
Natural Gas					
33 percent avail.	18.1	24.4	20.1	21.2	21.5
67 percent avail.	9.9	19.7	17.4	19.0	19.5

TABLE VIII-9 – PAYBACK TIME SENSITIVITY ANALYSIS

Sensitivity Test	Conventional Alternate Coal Boilers Only	Select Energy Alternates 5 MW	10 MW	12.5 MW + Absorption	12.5 MW + Absorption + LTHW
Original Values	4.2	3.4	4.1	4.0	4.7
Capital					
+ 20 percent	4.6	4.0	4.6	4.5	5.4
- 20 percent	3.6	2.8	3.4	3.3	3.9
Discount Rate					
5.5 percent	4.2	3.4	4.1	4.0	4.7
7.5 percent	4.2	3.4	4.1	4.0	4.7
Additional O&M					
+ 20 percent	4.3	3.5	4.2	4.0	4.7
- 20 percent	4.2	3.4	4.1	3.9	4.7
Economic Life					
25 years	4.2	3.4	4.1	4.0	4.7
35 years	4.2	3.4	4.1	4.0	4.7
Inflation					
@ 2 percent	4.4	3.7	4.3	4.2	4.5
@ 6 percent	4.1	3.3	3.9	3.7	4.4
Coal Price					
+ 20 percent	4.8	4.0	4.8	4.6	5.4
- 20 percent	3.6	3.0	3.5	3.4	4.0
Oil Price					
+ 20 percent	3.2	2.8	3.5	3.4	4.0
- 20 percent	6.1	4.3	4.8	4.5	5.3
Energy Escalation					
0 percent	5.3	4.4	5.6	5.3	6.2
2 percent	4.8	4.1	4.9	4.8	5.6
4 percent	4.4	3.7	4.5	4.4	5.2
Natural Gas					
33 percent avail.	5.4	3.7	4.5	4.3	5.2
67 percent avail.	9.4	4.6	5.2	4.8	5.6

f. Coal Price

Variation in the price of fuel has a significant effect on the IUS profitability indices. This is due to the major effect of fuel price on the IUS annual operating costs. As stated before, because of the overall economic attractiveness of the project, within the range of coal prices fluctuations expected, the project still represents an excellent investment.

g. Oil Price

Oil prices effect a coal burning IUS because IUS profitability is measured against an oil fired baseline system. Thus, as oil prices go up, the coal fired IUS looks more attractive. The major effect of oil price variation was in the evaluation of a conventional coal fired thermal energy plant.

h. Fuel and Electricity Escalation

A major escalation of all energy prices would have only a minor effect on an IUS for the University of Florida. The effect that is noted is due to the increase in coal prices being projected to be less than the increase in fuel oil prices in the southeast. However, even if the escalation rates increase above normal inflation, within the range investigated, the project remains very attractive.

i. Natural Gas

The availability of natural gas has a surprisingly small effect on the profitability indices for the select energy alternatives. The highly efficient on-site generation of electric power has a major tempering effect on what would otherwise have been a significant adverse effect. Examination of the first column in Tables VIII-8 and VIII-9 reflects the effect on natural gas competing with coal in conventional steam generation for thermal loads. As would be expected, this effect can be significant if natural gas continues to be available.

In summary, although the various sensitivity parameters investigated had, in some cases, a significant effect on the relative profitability values, the absolute values are so attractive that the conclusions and recommendations are not affected.

4. Conclusions and Recommendations

A multitude of electric power generation sizes were considered in optimizing the overall system. Although a recommendation is made on the calculated values of profitability indices, it is recognized that there may be other constraints that may exist or be imposed as the project proceeds through the funding process. For example, it is recognized that there is a limit on the availability of funds, and that this project will be competing with other projects for the funds available. Furthermore, some of these competing projects will be associated with the mission objectives of the University and will not have a measure of profitability associated with them.

To provide some flexibility to the University in selecting options which are within their budget, two basic options for achieving advantages of IUS are discussed in some detail. For both the profitability indices are very attractive. However, the capital cost requirements vary over a range of $8 million to $15 million. For this reason, the return on the incremental investment in going from one level of capital investment to the next has been investigated.

The recommended system is the 12.5 MW Select Energy system incorporating absorption air conditioning and a low temperature hot water thermal distribution system. This system has a $71 million present worth in 1981 dollars, a 23.3 percent interest rate of return and is projected to pay for itself in 4.7 years. The capital investment is rather large, $14.75 million in 1976 dollars.

Should it not be possible to budget the 12.5 MW system immediately, the system can be incremented and installed in two phases. A 6.25 MW non-condensing turbine would be the first of the two equally sized units to go on-line. The first increment has a $34.8 million present worth in 1981 dollars, a 22 percent interest rate of return and a capital cost of $8.6 million in 1976 dollars. Payback will be in 5 years. The disadvantage of incrementation over the recommended system would be lost savings during the interim period. Conversion of the steam distribution system to low temperature hot water and the addition of absorption chillers would procede as funds allow.

C. SOLID WASTE MANAGEMENT

Incineration with heat recovery of the solid waste generated by the University of Florida and the community was examined. The recovered energy would be used to supplement the fuel requirements of the boilers.

The system capital costs are given in Table VIII-10 for systems incinerating only the University solid waste and a system sized to burn both the Universitys and the community wastes. Operating and maintenance expenses and credits are shown in Table VIII-11. Based on these costs the economic benefits were calculated on an incremental basis using the present landfill as the basis for the profitability analysis. The results of the incremental profitability analysis are presented in Table VIII-12.

As shown in this table, the advantages of solid waste incineration with heat recovery are significant. The interest rate of return or investment ranges from 18 to 20 percent depending on the size of the system. The payback period is relatively insensitive to system size with less than a half year between the highest and lowest. In

TABLE VIII-10 - SOLID WASTE MANAGEMENT SYSTEM - CAPITAL COST ESTIMATES $(000) - (Installed Costs, Mid - 1976)

	Estimated Life, Years	University Waste 25 T/D	University & Community Waste 75 T/D
Incinerators	15	205	616
Ram Loaders	15	29	88
Heat Recovery Units	15	119	357
Cleanout Tools		2	2
Front end loader	5	6	12
Building, Fence & Utilities	25	120	300
Contractors Overhead & Profit @ 15%		72	206
Engineering Fees, Contingencies @ 8%		38	110
		591	1,691

TABLE VIII-11 OPERATION CREDIT AND COSTS FOR SOLID WASTE HEAT RECOVERY ALTERNATIVES (1981) ($1000)

Credits and Expenses	University	University Plus Community
<u>Credits</u>		
Heat Recovery (Additional Electrical Generation)	175*	325
Reduced Dump Fees	27	24
Reduced Road Hauling	16	14
Dump Fees Charged City	--	44
<u>Expenses</u>		
Labor	15	27
Auxiliary Fuel	4	14
Utilities	8	11
Supplies	4	10
Maintenance	4	12
<u>Net Annual Credits – 1981</u>	183	333

* Assumes solid waste displacing more expensive fuel oil.

TABLE VIII-12 INCREMENTAL PROFITABILITY ANALYSIS OF SOLID WASTE HEAT RECOVERY ALTERNATIVE

Profitability Indicators	University Heat Recovery vs. Landfill	University Plus Community Heat Recovery vs. Landfill	University Plus Community Heat Recovery vs. University Heat Recovery
Present Worth, $(000,000) (1981)	1.3	3.3	2.0
Payback Period, Years	5.2	5.5	5.6
Savings to Investment Ratio	1.7	.96	.89
Interest Rate of Return, Percent	20.0	18.8	18.[illegible]

any case, the payback is within 6 years.

1. Conclusions and Recommendations

Incorporation of solid waste management through incineration with heat recovery appears quite feasible and should be given serious consideration as an addition to Alternates B, C and D.

D. ECONOMIC BENEFITS OF COMBINING CONVENTIONAL PROGRAMS WITH AN IUS

The design and installation of a Total/Select Energy system as envisioned in the present study can require 5 years. The short term conservation project can be implemented and often paid back within the installation period of a Total/Select system. The apparent investment risk is thus reduced by coupling short term benefits with the long term benefits of an IUS.

Generally there are several options possible in a retrofit program which can provide similar conservation and economic advantages. While the immediate benefits may be equal, the long term benefits, when coupled with an IUS, can be distinctly different.

With coordinated planning of the short term investments of utility usage, long term investments of an IUS can reduce the energy required to generate utility services. The conservation and economic benefits of the overall system are compounded. For example, if conservational measures reduce the utility requirements to 70 percent of the original load and the energy requirements to produce a unit of utility service is reduced to 80 percent, the overall energy requirements will be 56 percent of the original system.

IX. ENVIRONMENTAL AND INSTITUTIONAL FACTORS

As shown in the previous sections, the implementation of the integrated utility system concept can offer technical and economic advantages to the University of Florida. Environmental and institutional factors which can impact the successful application of the IUS at the University of Florida are considered in the present section.

A. ENVIRONMENTAL FACTORS

The purpose of this section is to point out those areas of environmental impact which are peculiar or important to the IUS, rather than be a complete environmental impact statement. The permits required for construction of the proposed IUS are discussed in the Regulatory Agencies and Permit Applications Section.

1. Energy Conservation

Energy Savings

The energy savings afforded by an IUS are in several forms. Overall energy savings including fuel and purchased electricity is 316 billion Btu per year for Alternate D. The energy savings relative to that portion of the existing system which the IUS is replacing is 23 percent for select energy Alternate A.

Reduced Oil Consumption

The coal burning boilers to be implemented as a part of the IUS will displace the burning of 8 million gallons of oil per year for select energy Alternates B, C and D. a reduction of up to 3 million gallons of oil per year by the commercial power supply occurs due to the reduced electrical power purchases.

Energy Recovery from Solid Waste

Heat recovery from incineration of the University solid waste will be equivalent to 4 percent of the present University heating requirements. Heat recovery from the incineration of the City of Gainesville solid waste would be equivalent to 6 percent of the present University heating requirements.

2. Emissions

The requirements for environmental standards published by the EPA and state agencies define minimum levels of air and water quality which regulatory agencies judge necessary to protect the public health. The standards contain emission limits and regulations which in turn determine the limits of equipment performance allowed.

a. Reduced Thermal Pollution

Since the efficiency of an IUS is gained by utilizing exhaust heat normally expelled to the atmosphere, the reductions in thermal pollution are proportional to the savings in energy.

b. Reduced Air Emissions

Particulate and sulfur emissions are determined by regulations and operations. Given the same equipment performance the reduction in atmospheric pollution will be proportional to the energy savings.

Boilers

The pollutants of primary concern from fossil-fuel power plants are sulfure dioxide, nitrogen oxides, particulates and hydrocarbons. The coal fired IUS plant at the University of Florida will generate these select energy pollutants. With approximately 50,000 tons of coal burned 30,000,000 kWh of electricity generated annually in the IUS plant, estimated atmospheric emissions for such an operation are given in Table IX-1. The emissions are based on collection efficiencies of 99.5 percent for baghouse filters on coal fired boilers.

For the purpose of comparison, emissions from heating plant No. 2 and a conventional power plant are presented in Table IX-2. Estimated emissions for nearest Florida Power Corporation generating station (Crystal River), have been used. The Crystal River Plant is presently oil fired but has been directed to convert to coal firing. And, the emissions calculated for the equivalent power production at the Crystal River Plant in Table IX-2 are for a coal fired plant. Comparison between the two tables shows that an IUS plant will substantially lower the total emissions of particulates, SO_2, and oxides of nitrogen. Hydrocarbons and carbon monoxide emissions will increase by factors of three and four respectively. However, applicable state and federal emission equivalents will be met by the IUS power plants.

Incinerators

The University of Florida will incinerate 7,000 tons of solid waste annually with a potential of increasing the tonnage from community sources. The emissions generated from solid waste incinerators are shown in Table IX-1. All applicable Federal, State and local emission standards can be met by the recommended incinerators.

Table IX-1. Estimated Atmospheric Emissions
For An IUS At The
University of Florida

Category	Boiler Emissions		Incinerator(b)		Total
	TPY	Lb/MM Btu	TPY	Lb/MM Btu	TPY
Particulates	16.8(a)	0.02	0.3	0.01	17.1
SO_2	740	0.99	9.1	0.19	749.1
NO_x	471	0.60	11.0	0.23	482
CO	63	0.08	36.5	0.77	99.5
HC	31	0.04	11.0	0.23	42
Aldehydes	0.02	---	---	---	0.2

(a) Controlled emissions with 99.5% baghouse filters based on spreader stoker emissions without fly ash reinvection.

(b) Emissions based on multiple chamber industrial/commercial incinerator standards.

Table IX-2. Estimated Atmospheric Emissions
For Conventional System At The
University of Florida

Category	Heating Plant Emissions		Crystal River Emissions		
	TPY	Lb/MM Btu	TPY	Lb/MM Btu	Total
Particulates	10.5	0.02	58.9	0-10(a)	69.4
SO_2	9.4	0.001	3,630	6.17(a)	3,630
NO_x	135	0.23	1,408	2.39	1,543
CO	9.9	0.02	25.6	0.04	35.5
HC	1.8	0.003	7.7	0.01	9.5
Aldehydes	---	---		---	---

(a) Based on State of Florida Emission Regulations.

3. Water Management

a. Reduced Waste Water Discharge

EPA standards are directed towards plant effluent, without regard for the final disposal point, whereas in state regulations, the effluent quality that is required depends on the existing and desired quality of the water body used for final disposal. Both the current EPA regulations of 90 percent pollutant removal before discharge and the state water quality requirements for Lake Alice are met. Reduction in sewage plant discharges will be proportional to the increase in treated waste water for irrigation and process purposes.

b. Water Conservation

The increased use of treated waste water for irrigation purposes can simultaneously reduce the discharge to Lake Alice by 20 percent and conserve a like quantity of ground water. The final decisions for action will depend on the Section 208 regional plant now being formulated.

4. Traffic

The proposed method of transporting coal to the IUS site will be by rail. This will require the construction of a rail spur crossing Archer Road. An average of about four cars of coal per day will be required. This is expected to provide minimal interference with traffic.

Should the construction of the rail spur not be possible, coal can be trucked to the campus. The truck traffic experienced would not be significantly different from that required to truck fuel oil to the campus for the existing boilers.

The on-campus truck traffic for incineration of the University solid waste would be no different than present. The off-campus truck traffic solid waste transportation to the Alachua County landfill would be reduced by 80 percent. If some portion of City of Gainesville solid waste were also incinerated for heat recovery, the additional on-campus traffic would be proportional to the amount of solid waste received.

5. Land Usage

The proposed site for IUS is in an area designated for future utility expansion adjacent to the existing sewage treatment plant and Heating Plant No. 2. The installation of IUS will require removal of several small temporary buildings and a metal shed. Also an existing asphalt-paved parking lot will be reduced in size. If coal is trucked to campus, the reserve coal pile can be maintained off-campus and thus reduce the on-campus space requirements.

Incineration of the University solid waste will reduce the volume of landfill requirements by 95 percent and the ash sent to the landfill will be a dense sterile material. Ash from the burning of coal can be used for landscaping and landfill cover.

6. Aesthetics

Siting of the coal fired plant and incinerators will be on University property next to the existing Heating Plant No. 2 in an area designated for utility expansion. The coal storage site will be located between Heating Plant No. 2 and the new power plant and will be hidden from sight by earth embankments. Since the projected rail spur will pass between an existing parking garage and the Wilmont Gardens, care in the construction will be necessary to minimize the impact on the landscape of that area.

B. INSTITUTIONAL FACTORS

1. Economic Impacts

The installation of an IUS will require considerable capital outlay. Thus, the IUS will be in competition for funds within the University, the State University System and the State as a whole. In contrast, increased utility costs with the present system will place pressures on operating budgets of academic programs. The important economic impact of an IUS is that the IUS will pay for itself in a short time and reduce future utility costs.

2. Labor and Personnel

The operation and maintenance of an integrated utility system will require highly qualified personnel. This will be particularly true for the operation of high pressure steam boilers and variable extraction turbine generators. Present heating plant operators are knowledgeable in the operation and maintenance of the existing gas/oil fired boilers and the existing 1,000 kW backpressure turbine. However, since the IUS will include a change in primary fuels, an increase in boiler operating temperatures and pressures, training of present and additional personnel will be required.

3. Management and Control

The integrated operation of utility systems will make management and control more complex than when the subsystems are operated independently. A closer coordination of the supervisory personnel will be required, and new accounting procedures may need to be instituted.

4. Fuel Supply and Purchase Contracts

Coal supply and transportation to the University of Florida are available. And, while the University has previously burned coal, the establishment of purchasing procedures will require due consideration.

5. Permit Applications and Hearings

The implementation of an IUS will require construction and operation permits. The state and Federal agencies responsible for reviewing and approving the permit applications have been identified in the next section and the requisite permit application and hearing procedures are noted.

6. Dump Fees and Agreements

The proposed IUS does not specifically involve the surrounding community except in the area of solid waste management. If the University should incinerate solid waste from the city and county, a satisfactory working arrangement must be reached on how to handle difficulties that can arise in such an operation. The handling of bulk materials and dump fees are particularly important. For example, if a bulk item such as a refrigerator is dumped at the University, the problem arises as to who is responsible for the removal and disposal.

Heat recovery from the incineration of the University solid waste is economically attractive when the credits for lower dump fees and less transportation are considered. For the incineration of community wastes to be economically attractive to the University, a dump fee payment rate to the University will need to be established.

7. National Model

The IUS would be of national interest as a model demonstration of cost effective energy conservation and pollution control. Besides being an operating system providing economic advantages to the University, the system can be used in research and education programs.

Engineering performance and design data can be determined by the careful evaluation of the IUS operation. Engineering students could obtain real life experience with advanced systems concepts in power production and energy conservation. The presentation of workshops and seminars based on the experience gained with the IUS could be used to nationally promote the beneficial concepts of an IUS.

C. REGULATORY AGENCIES AND PERMITS APPLICATIONS

The permits required for the installation of an IUS at the University of Florida and the regulatory agencies responsible for approving the applications for permits are noted below. An activity chart for obtaining the necessary environmental permits is shown in Figure IX-1.

1. Florida Department of Environmental Regulations (DER)

No stationary installation which will reasonably be expected to be a source of air or water pollution shall be operated, maintained, constructed, expanded, or modified without an appropriate currently valid permit issued by the Department of Environmental Regulations unless exempted by department rules.

a. Air

No person shall commence construction or modification of any complex air pollution sources without a permit from the department, or other governmental agency authorized by the DER to issue such a permit.

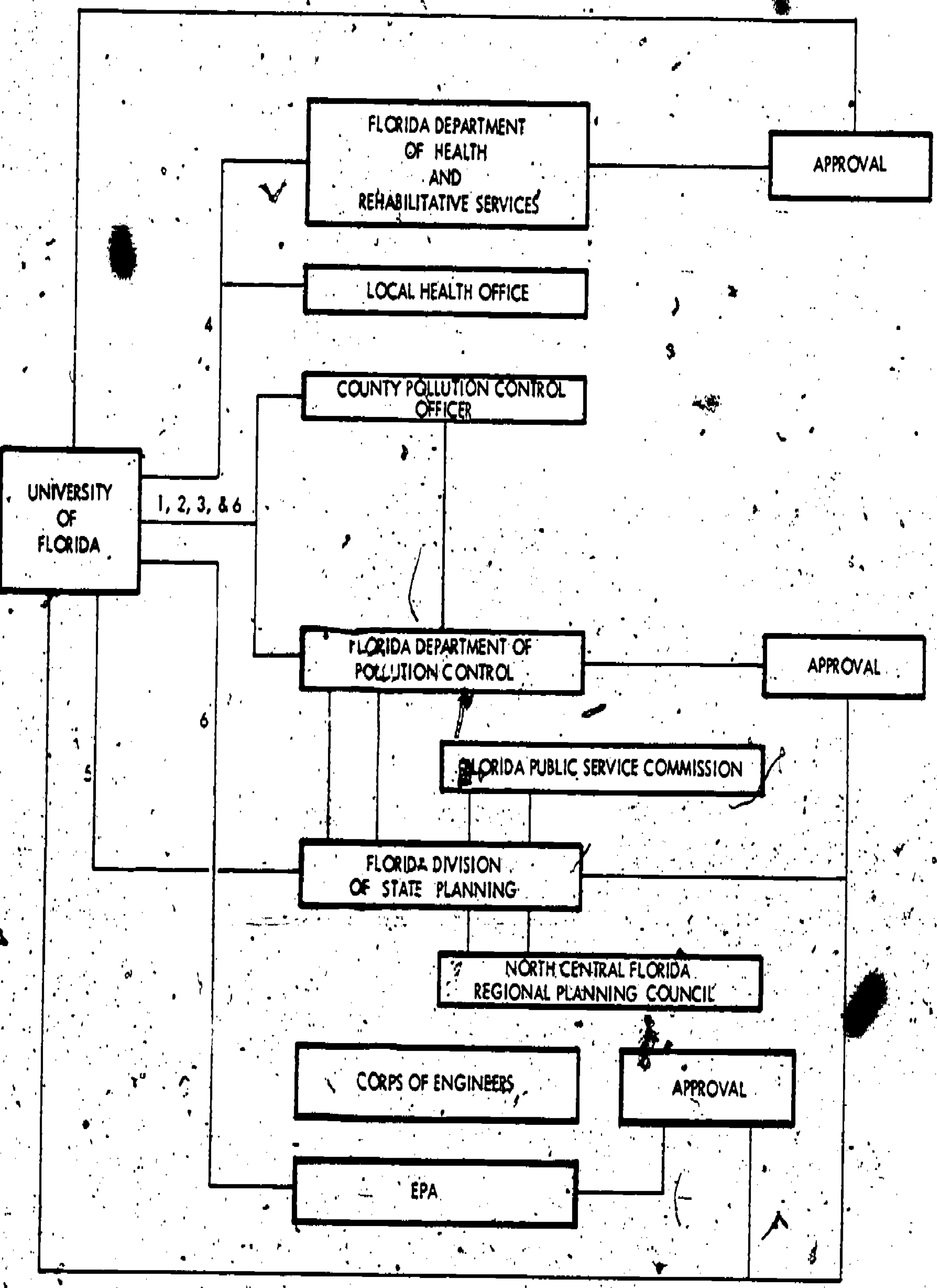
If the DER finds, after notice, the projected emissions associated with any proposed complex source may result in the failure of the Ambient Air Quality Standards being achieved and maintained, the DER may require an application to be submitted and a permit required prior to construction.

b. Water

No person, without written authorization of the DER, shall discharge into waters within the state any waste which, by itself or in combination with other waste sources, reduces the quality of receiving waters below the classification established for them.

Water quality certificates are issued by the DER when a project discharges any material (sewage, industrial effluent, runoff from spoil entrapments, storm drainage, and other actions potentially affecting water quality) during construction, or after completion of the project. Applying for a permit to dredge or fill constitutes a request for the DER to issue a water quality certificate, in accordance with PF91-224 and Chapter 403, Florida Statutes.

PERMIT ACTIVITY CHART FOR ENVIRONMENTAL PERMITS



SCHEDULE OF DOCUMENTS

1. APPLICATION FOR PERMIT TO CONSTRUCT WATER POLLUTION SOURCES.
2. APPLICATION FOR PERMIT TO OPERATE WATER POLLUTION SOURCES.
3. APPLICATION FOR APPROVAL OF PLANS AND SPECIFICATIONS FOR THE CONSTRUCTION OF SANITARY FACILITIES
4. APPLICATION FOR APPROVAL OF PLANS AND SPECIFICATIONS FOR A PUBLIC WATER SUPPLY SYSTEM.
5. APPLICATION FOR APPROVAL OF PLANS AND SPECIFICATIONS FOR ELECTRICAL GENERATING FACILITIES
6. APPLICATION FOR PERMIT TO DISCHARGE WASTES IN NAVIGABLE WATERS.

FIGURE IX-1

c. **Electrical Generating Facilities**

Sections 403.501 – 403.516, Florida Statutes, require certification for sites for construction of new electrical generating facilities, encompassing both new sites and expansions on existing sites. The DER, as the agency responsible for certification, has promulgated guidelines for preparing an application for certification which essentially parallels the ERDA guidelines for environmental impact statements required for licensing of nuclear power plants. Under these guidelines, an extensive environmental assessment is required to identify possible effects of both fossil fueled and nuclear power plant construction and operation on the air quality, water quality, and ecology of the site to be certified. By law, construction of the power plant cannot commence before a site has been certified. The DER may take up to 12 months to review and act upon an application.

d. **Permits**

Department of Environmental Regulation permits are required for the following:

Air Pollution Sources:	Includes complex air pollution sources.
Water Pollution Sources:	Sewage treatment plant effluent, industrial waste discharge, thermal discharge, leachate from treatment systems, dredge and fill, primary water control structures, solid waste disposal site, etc.
Sewage Works:	Permit to construct and operate such a facility
Collection Systems:	Sewage collection systems.

The types of permits issued by the DER are as follows:

1) Construction Permit

2) Operating a New Source Permit

3) Operating an Air Pollution Source Permit

4) Operating a Water Pollution Source Permit

5) Water Pollution Temporary Operating Permit

6) Construction of Collection System Permit

7) Operation of Collection System Permit

The application original, plus four copies are transmitted. The process time is 60 days.

2. Florida Division of State Planning

a. Electrical Generating Facilities

Section 403.505 of the Florida Electrical Power Siting Act requires that each electrical utility in the State of Florida is required to submit a 10-year site plan to the Division of State Planning annually on April 1st. The plan shall date from April 1st of the year in which it is submitted and will include:

- A description of existing facilities.
- A forecast of electrical power demand.
- A forecast of facilities requirement.
- A description of proposed sites and facilities.
- A preliminary assessment of environmental effects of proposed facility sitings.

The Division of State Planning is required to make a preliminary study of each plan submitted, and to classify each plan as suitable or unsuitable within 12 months of receipt. The review process itself will involve participation by several agencies under the coordination of the Division of State Planning.

The electrical power generation facilities of the University of Florida are not expected to be subject to the Florida Power Siting Act, and an official opinion from the Florida Division of Planning should be obtained. The Division of State Planning should, however, be informed as to the plans for an IUS at the University of Florida.

b. Development of Regional Impact

Development of Regional Impact (DRI) means any development which, because of its character, magnitude or location, would have a substantial affect on the health, safety or welfare of citizens of more than one county, as defined in Section 380.06 Florida Statutes. DRI applications are submitted to the local authorities for zoning or rezoning purposes. Copies of the application are also to be submitted to the Regional Planning Council, and the State Division of Land Planning. The North Central Florida Regional Planning Council, State Division of Land Planning and other such agencies are supposed to supply a feedback to the local authorities within 30 days of submittal. They only serve an advisory role and do not have the power to deny an application. Plans developed by the North Central Florida Regional Planning Council as to the future transportation systems (both railroads and roads) in the vicinity of the IUS facility should also be noted.

3. Florida Department of Health and Rehabilitative Services Division of Welfare

a. Public Water Supply Systems

No person, persons, firm, corporation, company, institution, municipality or community shall install, extend or alter any public water supply system without having first received written approval from the Division of Health.

Upon request, the Division of Health shall provide application forms necessary for approval of water supply systems. All applications shall be submitted in quadruplicate. An additional set of all documents shall be furnished to local health authorities.

b. Wells

No water supply well shall be constructed or used until a written permit from the Division of Health has first been received by the owner and driller of the well. Before commencing the construction of a water supply well, it shall be the responsibility of the well drilling contractor to make application and obtain permit to do so from the Division of Health. Form for application for permit shall be obtained from the Division upon request. The application shall be signed by the driller of the proposed well and also by the person, municipal or public utility official, corporation president or other owner of the proposed well.

4. Environmental Protection Agency

Under the Federal Water Pollution Control Act Amendments of 1972 (Public Law 92-500) all discharges of pollutants or combinations of pollutants from all point sources into the navigable waters, the waters of the contiguous zone, or the ocean are unlawful and subject to penalties, unless the discharger has a NPDES permit or is specifically relieved by law or regulation from the obligation of obtaining a permit.

b. The EPA Permit Process

After receiving the completed permit application, the EPA Regional Office evaluates it. EPA sends a copy of the permit application to other Federal agencies for comments. The application must also receive certification from the Florida DER. After analyzing all information and comments on the proposed discharge, the EPA Regional Office makes a preliminary decision to issue or deny the permit. EPA then issues a public notice of the permit application and its intention to issue or deny the permit

When this process is complete, and after giving the public 30 days to comment on its preliminary decision or to request a public hearing, the EPA Regional Administration issues or denies the permit.

X EXHIBITS

EXHIBIT I

UF/FPC ELECTRIC SERVICE CONTRACT (EXCERPTS)

Amendment to Agreement dated November 10, 1948, as amended, between Florida Power Corporation and the Board of Regents, acting for and in behalf of the University of Florida.

Said contract covers furnishing electric service to University of Florida at the University Substation in Gainesville, Florida

(1) Rate Per Month:

Article II is hereby superseded and revised to read as follows:

Demand Charge:

$15,184 for first 6,000 kW
$2.09 per kW for all in excess of 6,000 kW

Energy Charge

23.40 mills per kilowatt-hour

It is understood that the energy charge of 23.40 mills per kilowatt-hour includes the base fossil fuel cost of 18.80 mills per kilowatt-hour as set forth in the Company's standard filed retail Billing Adjustment BA-1, effective August 22, 1975. It is further understood that in the event said base cost of fossil fuel is increased or decreased pursuant to future Orders of the Florida Public Service Commission, the energy charge set forth above shall be evidenced by a letter of explanation from the Company to the Board, a copy of which shall be attached to the Agreement as an exhibit.

Billing Adjustments:

All charges under this rate are subject to the Company's Billing Adjustments as filed with and approved by the Florida Public Service Commission from time to time.

Minimum Monthly Bill

The minimum monthly bill shall be Two Dollars and Fifty-Three Cents ($2.53) per kW based on the highest demand established during the preceding twelve (12) months' period, plus equipment rental charges occasioned by University's request for additional facilities.

Determination of Billing Demand:

The billing demand will be the maximum thirty-minute measured demand in kW during the month, but for not less than seventy percent (70%) of the highest demand established during the preceding twelve (12) months.

(2) Term of Contract:

The term of this contract shall be for a ten-year period from the effective date of this amendment (January 5, 1966) and thereafter shall be automatically renewable on an annual basis. This contract may be terminated at the end of any contract period by either party notifying the other party in writing of its intention to terminate, which notification shall be given not latter than nine months prior to date of termination. Such notification shall be given by the Company to the Board by serving same upon the Board of Regents at its office in Tallahassee, Florida, and shall be given to the Company by the Board by serving same upon the President of the Company at the general office in St. Petersburg, Florida. Such notices may be served by depositing same in the United States mail, under registered or certified cover, addressed as aforesaid.

(3) Character and Point of Service:

The character of service shall be continuous service, alternating current, 60 cycle, 3 phase wye furnished at the Company's University of Florida substation with transmission furnished to the voltage of the University's distribution system and measured by metering equipment furnished and installed by the Company at the voltage furnished to the University's distribution system.

(4) Facilities To Be Provided By the Company

The Company will provide two-way transmission service with automatic sectionalizing to the University of Florida substation.

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The Company will install and maintain necessary transformers, regulating equipment and circuit breakers, together with apparatus required to provide regulated voltage at the point of delivery.

(5) Equipment Rental:

Equipment and facilities beyond the Company's University of Florida substation shall be furnished and maintained by the Board. The Board may request the Company to furnish such additional equipment and the Company may furnish, install and maintain such additional equipment charging the Board for the use thereof at the rate of 1¼% per month of the installed cost of such additional equipment.

The Board at its pleasure may purchase all or part of the equipment and facilities rented from the Company at their depreciated value. Depreciation will be calculated at an annual depreciation rate of 3.043% per year.

In the event of the termination of this agreement by the Board of Regents and the Company's service to the main campus of the University being discontinued, the Board shall purchase from the Company any rental facilities installed under this provision affective as of the termination of the agreement.

(6) Right to Operate Generating Facilities:

Parallel operation of the University's electric generators with the Company's system is permissible provided an adequate protection scheme is installed by the University and that such protection scheme meets with the approval of the Company's engineers. The University shall notify the Company of any changes in its generating capacity prior to any changes being made.

EXHIBIT II

FEDERAL POWER COMMISSION GAS CURTAILMENT PRIORITIES ORDER NO. 467-B

(1) Residential, small commercial (less than 50 Mcf on a peak day).

(2) Large commercial requirements (50 Mcf or more on a peak day), firm industrial requirements for plant protection, feedstocks and process needs, and pipeline customer storage injection requirements.

(3) All industrial requirements not specified in (2), (4), (5), (6), (7), (8) or (9).

(4) Firm industrial requirements for boiler fuel use at less than 3,000 Mcf per day, but more than 1,500 Mcf per day, where alternate fuel capabilities can meet such requirements.

(5) Firm industrial requirements for large volume (3,000 Mcf or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements.

(6) Interruptible requirements of more than 300 Mcf per day, but less than 1,500 Mcf per day, where alternative fuel capabilities can meet such requirements.

7) Interruptible requirements of intermediate volumes (from 1,500 Mcf per day through 3,000 Mcf per day), where alternate fuel capabilities can meet such requirements.

(8) Interruptible requirements of more than 3,000 Mcf per day, but less than 10,000 Mcf per day, where alternate fuel capabilities can meet such requirements.

(9) Interruptible requirements of more than 10,000 Mcf per day, where alternative fuel capabilities can meet such requirements.

EXHIBIT III - HEAT BALANCES

The starting point for a steam power plant design is the preparation of a turbine/boiler heat balance. This heat balance is an extensive calculation yielding the expected state and quantity of steam and water flows in all parts of the cycle. Given the design conditions for each item of steam cycle equipment, the performance of the power plant as a whole can be determined.

The preparation of turbine/boiler heat balances for a modern dual purpose unit is an extensive process. Furthermore, with the emphasis on energy conservation, the need arises for evaluating various alternatives to determine plant cycles which maximize the plant efficiency. A computer program which can be readily arranged to simulate power cycle flow sheets was used to calculate the heat balances for the case evaluated in this feasibility study.

A. HARDWARE CHARACTERISTICS AND OPERATING CONDITIONS

Before the calculation of a heat balance can be performed, the turbine/boiler and associated equipment characteristics as well as operating conditions must be specified.

1. Automatic Variable Extraction Turbine/Generator

The heart of a steam power station is the steam turbine. It controls the state of the steam at each point of the cycle and produces the power required to generate electrical output. A complete description of the turbine characteristics is included in the program for calculating turbine heat balances. The design parameters selected are given in the energy balance tables.

2. Feedwater Heating Cycles

The feedwater heater arrangements shown in Figures VII-4 and VII-6 were used in the feedwater heating cycle. The selection of economical feedwater heating cycles is discussed in Section VII.

3. Operating Pressures and Temperatures

The conditions for flows at the important points of the turbine cycle are given in the energy balance table. Turbine inlet and extraction condition selection have been discussed in Section VII. The condenser pressure is that expected to be obtained from available circulating water and assumed condenser design.

B. BASIS OF CALCULATIONS

The heat balances shown in Tables E III-1 and E III-2 are based on a net heat extraction of 100,000,000 BTU/hr from four different points of the cycles shown in Figures VII-4 and VII-6.

The net heat supplied to the process is total heat in the steam fed to the process at the given extraction pressure minus the heat in returns from the process that include process condensate plus makeup boiler feedwater required to replace steam condensate lost in the process and in boiler blowdown.

The individual load heat balances have been used to evaluate the performance of the combined loads by linear superposition. This is possible because the equipment used in the options presented in this report will have full utilization as base loaded units. Hence, the design operating conditions can be used to evaluate the system performance and partial load characteristics need not be considered within the accuracy of the present knowledge of the expected equipment performance.

C. PLANT PERFORMANCE

The computer calculations evaluate the performance of all components of a power cycle. They include numerical data on size, quantity, pressure, temperature, enthalpy, power and the like to each piece of apparatus used in the plant. Being simulations of real equipment, the calculations contain all necessary allowances for the actual performance of each component. Heat balances can be no more exact than the understanding, interpretation, and correctness of the equipment performance data which are used. A summary of the plant performance for the assumed extraction heat loads is given by the final portions of Tables E III-1 and E III-2.

1. Net Plant Power Send Out

The net plant power send out is the power available at the generator terminals minus the auxiliary power requirements.

2. Plant Realization Ratio

Since no heat balance calculation can include allowance for all losses that occur in a real plant, such as soot blowing, blowdown, makeup, gland leakage, steam driven auxiliaries, and banking, it is necessary to apply an overall plant realization ratio to the computed figures.

3. Boiler Steam Rate

The boiler capacity can be determined from the required boiler steam rate which is the throttle steam rate divided by the plant realization ratio.

4. Plant Fuel Requirement

The plant fuel requirement is the boiler fuel required to provide the throttle steam divided by the plant realization ratio.

5. Fuel Chargeable to Process

The fuel chargeable to providing process heat is defined as the net heat supplied to the process divided by the boiler efficiency and the plant realization ratio. This is a conservative value when compared to the equivalent overall fuel requirements to supply the same heat to the process with a conventional boiler since all auxiliary power requirements have been charged against the electrical power production.

6. Fuel Chargeable to Power

Fuel chargeable to power generation in a dual purpose power plant is a good measure of how effectively heat is converted to shaft power or kilowatts. By definition, the fuel chargeable to power is the incremental fuel that must be supplied to the boiler to generate power while supplying the specified net process heat.

7. Thermal Efficiency

The thermal efficiency of the cycle is defined as the sum of the net heat to the process and the Btu equivalent of the net plant power send out divided by the plant fuel requirements.

8. Electrical Heat Rate

The electrical heat rate is a parameter that can be used to compare the efficiency of power generation for different energy supply systems.

The fuel energy required to generate by-product power is less than half that required by a conventional power station to generate the same quantity of electricity. For the present case, the bus bar heat rate of Florida Power Corporation is 10,372 Btu/kWh. Hence, the 11,275 Btu of fuel are required to generate and transmit one kilowatt of electricity to the University of Florida if the transmission losses are assumed as being typically 8 percent. The heat rates for by-product power for the process steam extractions are about 4,500 Btu/kWh. These highly favorable by-product power heat rates are the key to the energy savings and economic advantage of a select or total energy system.

9. Power to Heat Generation Ratio

The power to heat generation heat ratio is defined as the net plant power send out divided by the net useful process heat supplied from the turbine and boiler cycle.

The power to process heat generation ratio is a parameter that can be used to compare different dual purpose energy supply sytems. As may be noted from heat balances shown in Tables EIII-1 and EIII-2, the heat rates for power production are about the same for the various extraction pressures, but the amount of power produced per unit of process heat is dramatically different.

TABLE E X-1 TWO FEEDWATER HEATER, NONCONDENSING TURBINE, BOILER HEAT BALANCES

BASIS: 100,000 Btu/hr Net Heat Extracted from Cycle

PROCESS EXTRACTION STEAM		
Pressure, psia	265	75
Steam Flow Rate, lbs/hr.	81,367	90,144
TURBINE		
Throttle Steam Flow, lbs/hr.	103,560	11,273
Pressure at Stop Valve, psia	850.0	850.0
Temperature at Stop Valve, F.	900	900
Steam Enthalpy, Btu/lb.	1,454	1,454
Engine Efficiency, %	75	75
EXTRACTION – DRAIN COOLED FEEDWATER HEATER		
Water Flow to Heater, lb/hr.	103,560	11,273
Turbine Stage Pressure, psia	265	265
Heater Shell Pressure, psia	238.5	238.5
Terminal Temperature Diff., F.	-3	-3
Drain Cooler Approach, F.	10	10
Feedwater Temperature Out, F.	399.8	399.8
Water Enthalpy Out., Btu/lb.	374.5	374.5
Extraction Enthalpy, Btu/lb.	1,344.5	1,344.5
Drain Enthalpy, Btu/lb.	283.6	283.6
Extraction Required, lb./hr.	9,705	10,583

TABLE E X-1 (Continued)

EXHAUST – CONTACT FEEDWATER HEATER AND DEAREATOR		
Turbine Stage Pressure, psia	30	30
Extraction Enthalpy, Btu/lb.	1,188	1,188
Heater Shell Pressure, psia	28.5	28.5
Water Temperature In, F.	148.1	148.1
Drain Temperature, F.	247.4	247.4
Water Enthalpy In, Btu/lb.	116.1	138.6
Drain Enthalpy, Btu/lb.	215.8	215.8
Extraction Required, lb./hr.	12,716	12,009
TURBINE GENERATOR		
Turbine Shaft Power by Section		
1st Extraction, KW	3,308	3,618
Exhaust, KW	3,622	2,909
Total Shaft Power, KW	3,670	6,527
Generator Losses, KW	147	261
Gross Load, Generator Terminals, KW	3,523	6,266
BOILER		
Degrees Superheat, °F	374.8	374.8
Enthalpy At Feed, Btu/lb.	374.5	374.5
Heat Added to Steam, 10^6 Btu/hr.	111.8	121.7
Boiler Efficiency, %	84	84
Heat Supplied in Fuel, 10^6 Btu/hr.	133.1	144.9
PLANT PERFORMANCE		
Auxiliary Power, KW	371	404
Net Plant Electric Send-Out, KW	3,152	5,862
Plant Realization Ratio	.96	.96

TABLE E X-1 (Continued)

Boiler Steam Rate, 10^3 lb./hr.	107.9	117.4
Plant Fuel Requirements, 10^6 Btu/hr.	138.6	150.9
Fuel Chargeable to Process, 10^6 Btu/hr.	124	124
Fuel Chargeable to Power, 10^6 Btu/hr.	14.6	26.9
Thermal Efficiency, %	80.0	79.5
Electrical Heat Rate, Btu/KWH	4,632	4,589
Power to Heat Generation Ratio, KWH/10^6 Btu	31.5	58.6

TABLE E X-2 THREE FEEDWATER HEATER, CONDENSING TURBINE, BOILER HEAT BALANCES

BASIS: 100,000 Btu/hr Net Heat Extracted from Cycle

PROCESS EXTRACTION STEAM				
Pressure, psia	265	75	30	1.5
Steam Flow Rate, lbs/hr.	81,367	90,144	95,238	104,629
TURBINE				
Throttle Steam Flow, lbs/hr.	104,326	113,157	119,553	138,150
Pressure at Stop Valve, psia	850.0	850.0	850.0	850.0
Temperature at Stop Valve, F.	900.0	900.0	900.0	900.0
Steam Enthalpy, Btu/lb.	1,454.0	1,454.0	1,454.0	1,454.0
Engine Efficiency, %	75	75	75	75
1st EXTRACTION - DRAIN COOLED FEEDWATER HEATER				
Water Flow to Heater, lb/hr.	104,326	113,157	119,553	138,150
Turbine Stage Pressure, psia	265.0	265.0	265.0	265.0
Heater Shell Pressure, psia	238.5	238.5	238.5	238.5
Terminal Temperature Diff., F.	-3.0	-3.0	-3.0	-3.0
Drain Cooler Approach, F.	10.0	10.0	10.0	10.0
Feedwater Temperature Out, F.	399.8	399.8	399.8	399.8
Water Enthalpy Out., Btu/lb.	374.5	374.5	374.5	374.5
Extraction Enthalpy, Btu/lb.	1,344.5	1,344.5	1,344.5	1,344.5
Drain Enthalpy, Btu/lb.	283.6	283.6	283.6	283.6
Extraction Required, lb./hr.	9,943	10,785	11,395.5	13,167

TABLE E X-2 (Continued)

2nd EXTRACTION - DRAIN COOLED FEEDWATER HEATER

Water Flow to Heater, lb/hr.	104,326	113,157	119,553	138,150
Turbine Stage Pressure, psia	75.0	75.0	75.0	75.0
Heater Shell Pressure, psia	67.5	67.5	67.5	67.5
Terminal Temperature Diff., F.	-3.0	-3.0	-3.0	-3.0
Drain Cooler Approach, F.	10.0	10.0	10.0	10.0
Water Temperature Out, F.	303.5	303.5	303.5	303.5
Water Enthalpy Out, Btu/lb.	273.4	273.4	273.4	273.4
Extraction Enthalpy, Btu/lb.	1,247.3	1,247.3	1,247.3	1,247.3
Drain Enthalpy, Btu/lb.	231.2	231.2	231.2	231.2
Extraction Required, lb/hr.	4,902	5,317	5,617	6,491

3rd EXTRACTION - CONTACT FEEDWATER HEATER AND DEAREATOR

Turbine Stage Pressure, psia	30.0	30.0	30.0	30.0
Extraction Enthalpy, Btu/lb.	1,188.0	1,188.0	1,188.0	1,188.0
Heater Shell Pressure, psia	28.5	28.5	28.5	28.5
Water Temperature In, F.	148.1	170.0	170.0	116.2
Drain Temperature, F.	247.4	247.4	247.4	247.4
Water Enthalpy In, Btu/lb.	116.1	138.6	138.6	84.1
Drain Enthalpy, Btu/lb.	215.8	215.8	215.8	215.8
Extraction Required, lb./hr.	8,116	6,911	7,301	13,862

CONDENSER

Exhaust Enthalpy	-	-	-	1,039.3
Steam Flow, lb./hr.	0	0	0	104,629
Pressure, psia	-	-	-	1.5
Hot-Well Temperature, F.	-	-	-	115.7
Hot-Well Enthalpy, Btu/lb.	-	-	-	83.6

TABLE E X-2 (Continued)

TURBINE GENERATOR				
Turbine Shaft Power by Section				
1st Extraction, KW	3,348	3,631	3,836	4,433
2nd Extraction, KW	371	2,915	3,080	3,599
3rd Extraction, KW	141	120	1,783	2,061
Exhaust, KW	0	0	0	4,559
Total Shaft Power, KW	3,860	6,666	8,699	14,652
Generator Losses, KW	155	266	347	625
Gross Load, Generator Terminals, KW	3,705	6,400	8,352	14,027
BOILER				
Degrees Superheat, °F	374.8	374.8	374.8	374.8
Enthalpy At Feed, Btu/lb	374.5	374.5	374.5	374.5
Heat Added to Steam, 10^6 Btu/hr.	112.6	122.2	129.1	149.1
Boiler Efficiency, %	84	84	84	84
Heat Supplied in Fuel, 10^6 Btu/hr.	134.0	145.8	153.7	177.5
PLANT PERFORMANCE				
Auxiliary Power, KW	379	412	436	491
Net Plant Electric Send-Out, KW	3,326	5,988	7,917	13,536
Plant Realization Ratio	.96	.96	.96	.96
Boiler Steam Rate, 10^3 lb./hr.	108.6	117.9	124.6	143.9
Plant Fuel Requirements, 10^6 Btu/hr.	139.6	151.9	160.1	184.9
Fuel Chargeable to Process, 10^6 Btu/hr.	124.0	124.0	124.0	0
Fuel Chargeable to Power, 10^6 Btu/hr.	15.6	27.9	35.2	184.9
Thermal Efficiency, %	79.8	79.3	79.3	23.0
Electrical Heat Rate, Btu/KWH	4,691	4,659	4,446	13,659
Power to Heat Generation Ratio, KWH/10^6 Btu	33.3	59.9	79.2	---

TABLE E X-2 (Continued)

PROCESS EXTRACTION STEAM				
Pressure, psia	265	75	30	1.5
Steam Flow Rate, lbs/hr.	81,367	90,144	95,238	104,629
TURBINE				
Throttle Steam Flow, lbs/hr.	104,326	113,157	119,553	138,150
Pressure at Stop Valve, psia	850.0	850.0	850.0	850.0
Temperature at Stop Valve, F.	900.0	900.0	900.0	900.0
Steam Enthalpy, Btu/lb.	1,454.0	1,454.0	1,454.0	1,454.0
Engine Efficiency, %	75	75	75	75
1st EXTRACTION - DRAIN COOLED FEEDWATER HEATER				
Water Flow to Heater, lb/hr.	104,326	113,157	119,553	138,150
Turbine Stage Pressure, psia	265.0	265.0	265.0	265.0
Heater Shell Pressure, psia	238.5	238.5	238.5	238.5
Terminal Temperature Diff., F.	-3.0	-3.0	-3.0	-3.0
Drain Cooler Approach, F.	10.0	10.0	10.0	10.0
Feedwater Temperature Out, F.	399.8	399.8	399.8	399.8
Water Enthalpy Out., Btu/lb.	374.5	374.5	374.5	374.5
Extraction Enthalpy, Btu/lb.	1,344.5	1,344.5	1,344.5	1,344.5
Drain Enthalpy, Btu/lb.	283.6	283.6	283.6	283.6
Extraction Required, lb./hr.	9,943	10,785	11,395.5	13,167

TABLE E X-2 (Continued)

2nd EXTRACTION - DRAIN COOLED FEEDWATER HEATER				
Water Flow to Heater, lb/hr.	104,326	113,157	119,553	138,150
Turbine Stage Pressure, psia	75.0	75.0	75.0	75.0
Heater Shell Pressure, psia	67.5	67.5	67.5	67.5
Terminal Temperature Diff., F.	-3.0	-3.0	-3.0	-3.0
Drain Cooler Approach, F.	10.0	10.0	10.0	10.0
Water Temperature Out, F.	303.5	303.5	303.5	303.5
Water Enthalpy Out, Btu/lb.	273.4	273.4	273.4	273.4
Extraction Enthalpy, Btu/lb.	1,247.3	1,247.3	1,247.3	1,247.3
Drain Enthalpy, Btu/lb.	231.2	231.2	231.2	231.2
Extraction Required, lb/hr.	4,902	5317	5,617	6,491
3rd EXTRACTION - CONTACT FEEDWATER HEATER AND DEAREATOR				
Turbine Stage Pressure, psia	30.0	30.0	30.0	30.0
Extraction Enthalpy, Btu/lb.	1,188.0	1,188.0	1,188.0	1,188.0
Heater Shell Pressure, psia	28.5	28.5	28.5	28.5
Water Temperature In, F.	148.1	170.0	170.0	116.2
Drain Temperature, F.	247.4	247.4	247.4	247.4
Water Enthalpy In, Btu/lb.	116.1	138.6	138.6	84.1
Drain Enthalpy, Btu/lb.	215.8	215.8	215.8	215.8
Extraction Required, lb./hr.	8,116	6,911	7,301	13,862
CONDENSER				
Exhaust Enthalpy	-	-	-	1,039.3
Steam Flow, lb./hr.	0	0	0	104,629
Pressure, In Hg. ABS.	-	-	-	3.0
Hot-Well Temperature, F.	-	-	-	115.7
Hot-Well Enthalpy, Btu/lb.	-	-	-	83.6

TABLE E X-2 (Continued)

TURBINE GENERATOR				
Internal Generation Up to:				
1st Extraction, KW	3,348.0	3,631.0	3,836.0	4,433.2
2nd Extraction, KW	371.0	2,915.0	3,080.0	3,599.2
3rd Extraction, KW	141.0	120.0	1,783.0	2,060.5
Exhaust, KW	0	0	0	4,558.6
Total Generation, KW	3,860.0	6,666.0	8,699.0	14,651.5
Generator Efficiency, %	.96	.96	.96	.96
Gross Load, Generator Terminals, KW	3,705	6,400	8,352	14,027
BOILER				
Temperature At Superheater Outlet, °F	900.0	900.0	900.0	900.0
Pressure At Superheater Outlet, psia	900.0	900.0	900.0	900.0
Enthalpy At Feed, Btu/lb.	374.5	374.5	374.5	374.5
Heat Added to Steam, 10^6 Btu/hr.	114.0	123.5	130.6	150.8
Boiler Efficiency, %	86	86	86	86
Heat Supplied in Fuel, 10^6 Btu/hr.	132.5	143.6	151.8	175.4
PLANT PERFORMANCE				
Auxiliary Power				
Feed Pumps, KW	160.1	174.0	183.8	211.8
Fans, KW	219.4	238.2	251.7	279.0
Net Plant Electric Send-Out, KW	3,325.5	5,987.8	7,916.5	13,536.2
Plant Steam Realization Ratio	.96	.96	.96	.96
Boiler Steam Rate, 10^3 lb./hr.	108.6	117.9	124.6	143.9
Plant Fuel Requirements, 10^6 Btu/hr.	138.0	149.6	158.1	182.7
Fuel Chargeable to Process, 10^6 Btu/hr.	121.1	121.1	121.1	0
Fuel Chargeable to Power, 10^6 Btu/hr.	17.9	28.5	37.0	182.7
Plant Heat Rate, Btu/KWH	5,383	4,760	4,674	13,497

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