



# University of Alaska Fairbanks Utility Development Plan

**Report**

October 25, 2006



## Division of Design and Construction

590 University Avenue

P.O. Box 758160

Fairbanks, Alaska 99775-8160

(907) 474-5299, FAX (907) 474-7554

### *MEMORANDUM*

**TO:** File

**FROM:** Mike Ruckhaus

**DATE:** October 25, 2006

**SUBJECT: Utility Development Plan Final Report**

---

Although UAF has been periodically assessing utility infrastructure capacity and condition, it was decided that a comprehensive Utilities Development Plan should be developed. GLHN Architects and Engineers, Inc. was selected to perform the study. Their team includes Design Alaska (arctic engineering), E3C Consultants (utility economics), and Pacific Consulting (utility management and operation). The goal of the planning effort was to provide UAF recommendations for supporting the academic and research mission of the campus by providing reliable utilities for the future. The study period was 20 years, but the team recognized that utility decisions made today can have impacts on UAF farther into the future than 20 years.

The attached report represents the collective efforts of the GLHN team, UAF Facilities Services and UA Finance. The UDP plan was presented to UAF and UA administration at various stages so that 1) all levels of the administration were aware the study progress and 2) the GLHN team could incorporate comments into the study from those that were not involved on a regular basis. All parties noted that UAF made some decisions about utilities dating back to 1960 that have stood the test of time. UAF is still reaping benefits from those decisions and it is hoped that decisions made based on this study will be just as durable.

#### **UAF acceptance of the Report Recommendations**

The fundamental issues facing UAF's utility system are:

- Campus building and utility consumption growth beyond utility capacity (especially the West Ridge)
- Aging utility infrastructure
- Fuel supply/price risks
- Regulatory compliance
- UAF financial constraints

The GLHN report identified these fundamental issues, developed and analyzed options to address the issues and provided recommendations.

Through a comprehensive process, UAF has accepted the GLHN team recommendations to address these fundamental issues, which can be summarized as:

***In order to continue to reliably serve all campus utility needs over the next twenty years UAF must:***

- ***Invest substantially in utility system capital asset renewal and utility infrastructure improvements almost immediately.***
- ***The best long term utility strategy is renewal and expansion of the Atkinson Plant using coal as the preferred fuel. This strategy is the best strategic, operational and financial fit for UAF.***

### **Implementation of Report Recommendations**

The magnitude of capital funding required to implement the plan creates a challenge to immediate implementation of the plan. UAF has developed a six year implementation plan (attached) that prioritizes and addresses the most critical and immediate needs. In order to develop the six year plan the following guiding principles were developed to keep the long term goals in focus in the six year plan:

- Utilities will be supplied by the Atkinson Plant using combined heat and power principles, and fueled primarily by coal and supplemented with oil and natural gas
- Increase steam distribution capacity delivered to campus
- Upgrade high voltage electrical distribution system to modern standards

Although the Six Year Implementation Plan does not incorporate all the GHLN recommended work, it represents the projects that could be conceivably funded in the overall University capital request.

### **The Next Step**

In order to progress towards the established goals, a comprehensive long term implementation plan needs to be developed. The implementation plan should contain engineering, cost estimating, finance and operational elements. It is recommended that UAF proceed with developing this plan by using consultants.

### SIX YEAR IMPLEMENTATION PLAN

Priority	Project Description	Project Cost	Capital Request Location
1	West Ridge Steam Capacity (new 10" pipe to WR and utilidor from Lola Tilly to SRC)	\$11.0M	FY08 New Constr BIOS
2	High Voltage Electrical Upgrade Phase 2 (new switchboard, central facility upgrade to 12kV and conversion of 1 feeder to WR 12kV)	\$12.0M	FY08 Code/LS UAF Critical Electrical Distribution
3	Coal Boiler Phase 1 (Concept Design and Permitting)	\$1.0M	FY08 R&R Atkinson Revitalization
4	New domestic water aerator	\$1.0M	FY08 R&R Atkinson Revitalization
5	Additional Condenser capacity	\$1.0M	FY08 R&R Atkinson Revitalization
6	Coal Boiler Phase 2 (35% design, site prep, new Ash Silo, interconnect utilidor)	\$8.0M	FY09 R&R Atkinson Revitalization
7	Small Critical Projects (7a through 7l, see attached list for detail)	\$2.5M	FY08 R&R Atkinson Revitalization
8	High Voltage Electrical Upgrade Phase 3 (upgrade campus feeders)	\$5.5M	FY09 Code/LS UAF Critical Electrical Distribution
9	High Voltage Electrical Upgrade Phase 4 (upgrade campus feeders)	\$5.5M	FY10 Code/LS UAF Critical Electrical Distribution
10	High Voltage Electrical Upgrade Phase 5 (upgrade campus feeders)	\$5.5M	FY11 Code/LS UAF Critical Electrical Distribution
<b>TOTAL</b>		<b>\$50.5M</b>	

**SMALL CRITICAL PROJECTS  
(Item 7 from Six Year Implementation Plan)**

<b>Priority</b>	<b>Project Description</b>	<b>Project Cost</b>	<b>Capital Request Location</b>
7a	Convert Boiler No. 4 to Natural Gas	\$200,000	FY08 R&R Atkinson Revitalization
7b	New Control Room	\$260,000	FY08 R&R Atkinson Revitalization
7c	New Turbine controls	\$300,000	FY08 R&R Atkinson Revitalization
7d	New Air Compressors	\$400,000	FY08 R&R Atkinson Revitalization
7e	Redundant DI water Unit	\$110,000	FY08 R&R Atkinson Revitalization
7f	Reconstruct water pumping station Ph. 1	\$160,000	FY08 R&R Atkinson Revitalization
7g	Atkinson grading/paving (fugitive dust control)	\$130,000	FY08 R&R Atkinson Revitalization
7h	Convert Boiler No. 3 to Natural Gas	\$350,000	FY08 R&R Atkinson Revitalization
7i	Replace feedwater heater	\$65,000	FY08 R&R Atkinson Revitalization
7j	Utilidor ventilation Phase 1	\$130,000	FY08 R&R Atkinson Revitalization
7k	Increase RO water capacity	\$195,000	FY08 R&R Atkinson Revitalization
7l	Add Continuous Emissions Monitoring to Boiler No. 4	\$250,000	FY08 R&R Atkinson Revitalization
	<b>TOTAL</b>	<b>\$2,550,000</b>	

**THE UNIVERSITY OF ALASKA FAIRBANKS  
2005 UTILITY DEVELOPMENT PLAN  
FINAL REPORT**

TABLE OF CONTENTS

<b>ACKNOWLEDGEMENTS .....</b>	<b>I</b>
<b>EXECUTIVE SUMMARY .....</b>	<b>II</b>
<b>SECTION I: PROJECT INTRODUCTION AND OVERVIEW .....</b>	<b>1</b>
STUDY OVERVIEW 1	
NEED FOR LONG-TERM UTILITY PLANNING .....	3
<b>SECTION II: UAF UTILITY INFRASTRUCTURE AND CAMPUS GROWTH EXPECTATIONS .....</b>	<b>5</b>
DISTRICT ENERGY SYSTEM (DES) INTRODUCTION .....	5
UAF CURRENT UTILITY CONFIGURATION.....	7
CAMPUS GROWTH PROJECTIONS .....	10
ENERGY LOAD DENSITY .....	14
COMMON UTILITY SYSTEM IMPROVEMENTS AND CAPITAL ASSET RENEWALS .....	15
<b>SECTION III: UTILITY DEVELOPMENT PLAN ASSESSMENT METHODOLOGY .....</b>	<b>18</b>
UDP MODEL OVERVIEW .....	18
ALLOCATIONS OF DIRECT OPERATING COSTS .....	19
ENERGY MARKET ANALYSIS .....	21
SUMMARY OF PROJECTED UTILITIES DEMAND .....	26
ENGINEERING ANALYSIS .....	27
<b>SECTION IV: STRATEGY FORMULATION AND NET PRESENT VALUE RESULTS.....</b>	<b>31</b>
STRATEGY FORMULATION AND DEFINITION .....	31
SUMMARY OF CAPITAL COSTS.....	38
ANNUAL PRODUCTION OUTPUT AND OPERATING COST BY STRATEGY .....	43
PRO FORMA AND NPV RESULTS.....	45
<b>SECTION V: RISK ANALYSIS AND SENSITIVITY CASE RESULTS .....</b>	<b>52</b>
SENSITIVITY CASE DEFINITION, SPECIFICATION AND RESULTS .....	52
RISK ANALYSIS 62	
<b>SECTION VI: ALTERNATIVE BUSINESS MODEL STRUCTURES AND RATE DESIGN.....</b>	<b>66</b>
ALTERNATIVE UAF BUSINESS MODEL STRUCTURES AND RATE DESIGN .....	66
STRUCTURE OF UTILITY SERVICE RATES.....	70
<b>SECTION VII: UDP SUMMARY AND DECISION RECOMMENDATIONS.....</b>	<b>80</b>
SUMMARY AND STUDY RECOMMENDATIONS .....	80
EXISTING UTILITY INFRASTRUCTURE RENEWAL REQUIREMENTS .....	81
UAF FORECASTED UTILITY SERVICE REQUIREMENTS .....	82
ALTERNATIVE UTILITY INFRASTRUCTURE STRATEGIES .....	83
COMPARATIVE ANALYTICAL RESULTS .....	85
FORECASTED UTILITY SERVICE RATES.....	86
UDP “BUSINESS MODEL” ANALYSES.....	87
UDP SENSITIVITY AND RISK ANALYSES .....	88

## **APPENDIX A: FINANCIAL APPENDIX**

SECTION A – COMMON MAJOR MAINTENANCE AND UPGRADE RENEWAL ITEMS  
SECTION B – PRODUCTION EQUIPMENT CAPITAL COST BY STRATEGY  
SECTION C – ANNUAL CAPITAL RENEWAL / DEPRECIATION SCHEDULES BY STRATEGY  
SECTION D – ANNUAL CAPITAL EXPENSE AND BONDING SCHEDULES BY STRATEGY  
SECTION E – MONTHLY OPERATING EXPENSES BY COST – TOTAL DOLLAR AND PER UNIT COSTS BY STRATEGY  
SECTION F – ANNUAL RATE COMPONENT DETAIL SCHEDULES BY COMMODITY - ALL STRATEGIES  
SECTION G – PROFORMA

## **APPENDIX B: TECHNICAL APPENDIX**

SECTION 1 – TECHNICAL PRODUCTION EQUIPMENT PERFORMANCE  
SECTION 2 – UTILITY SERVICE DESIGN MAPS

## **APPENDIX C: HISTORY OF UAF'S UTILITIES DEVELOPMENT**

### **APPENDIX D: TECHNICAL DETAIL**

EQUIPMENT COST SUMMARIES  
COST ESTIMATE: BUDGETARY COST ESTIMATE 150,000 LBS/HR BOILER  
COST ESTIMATE: BUDGETARY COST ESTIMATE 100,000 LBS/HR BOILER  
NARRATIVE: COAL BOILER PLANT ASSUMPTIONS  
COST ESTIMATE: UTILIDOR EXTENSION & STEAM DISTRIBUTION IMPROVEMENTS  
COST ESTIMATE: WEST RIDGE CHILLED WATER DISTRIBUTION & EXTENSION  
COST ESTIMATE: WEST RIDGE CHILLED WATER PLANT  
COST ESTIMATE: WEST RIDGE STEAM PRODUCTION PLANT  
NARRATIVE: UTILIDOR EXTENSION & STEAM DISTRIBUTION IMPROVEMENTS, CHILLED WATER  
DISTRIBUTION & EXTENSION IMPROVEMENTS, WEST RIDGE CHILLED WATER  
PLANT, WEST RIDGE STEAM PRODUCTION PLANT, STRATEGY 3 IMPLEMENTATION  
SUMMARY  
  
DRAWINGS

# THE UNIVERSITY OF ALASKA FAIRBANKS 2005 UTILITY DEVELOPMENT PLAN

## TABLES

TABLE 1 HISTORICAL BUILDING INVENTORIES .....	11
TABLE 2 PROJECTED UAF CAMPUS ANNUAL GROWTH RATES .....	14
TABLE 3 COMMON CAPITAL ASSET RENEWAL EXPENSES BY UTILITY SYSTEM .....	17
TABLE 4 UAF COMMODITY PRICE FORECASTS .....	24
TABLE 5 UAF UTILITY SERVICES PEAK DEMANDS (FY2005).....	27
TABLE 6 SUMMARY PEAK DEMAND (FY2005), BY IDENTIFIED SERVICE REQUIREMENT.....	28
TABLE 7 UTILITY CONFIGURATION FOR STRATEGIES.....	33
TABLE 8 COMPARISON OF UAF UDP BASE YEAR COSTS TO ACTUAL COSTS.....	47
TABLE 9 UAF UDP TOTAL OPERATING EXPENSES AND ASSOCIATED NPVs FOR ALL STRATEGIES .....	50
TABLE 10 ALTERNATIVE FORECASTED TWENTY YEAR GROWTH PROJECTION AND ASSOCIATED PEAK UTILITY SERVICE REQUIREMENTS (FY2026) .....	58
TABLE 11 IMPACT ON UAF OF STRATEGY AND EVENT COMBINATION (FOR FISCAL YEARS PAST 2010).....	65
TABLE 12 UAF UDP STRATEGY 3A ELECTRICITY RATES FY 2005 THROUGH FY 2010 .....	72
TABLE 13 COMMON CAPITAL ASSET RENEWAL EXPENSES BY UTILITY SYSTEM .....	82

## FIGURES

FIGURE 1 UAF UDP MODEL INFORMATION FLOW .....	4
FIGURE 2 UAF DISTRICT ENERGY SYSTEM .....	6
FIGURE 3 UNIVERSITY OF ALASKA FAIRBANKS CAMPUS MAP SHOWING STEAM UTILITY SYSTEM.....	8
FIGURE 4 HISTORIC & PROJECTED UAF BUILDING (SQFT) GROWTH 1965-2005, BY BUILDING .....	11
FIGURE 5 HISTORIC & PROJECTED UAF BUILDING (SQFT) GROWTH 1965-2005, BY LOCATION.....	11
FIGURE 6 PROJECTED UAF BUILDING (SQFT) GROWTH 1965-2025, BY BUILDING .....	13
FIGURE 7 PROJECTED UAF BUILDING (SQFT) GROWTH 1965-2025, BY LOCATION .....	13
FIGURE 8 UAF DISTRICT ENERGY SYSTEM (DES) MODEL FLOWS .....	20
FIGURE 9 UAF DELIVERED COMMODITY PRICE FORECAST (\$ PER MMBTU).....	25
FIGURE 10 UAF CAMPUS ELECTRIC DEMAND .....	26
FIGURE 11 UAF CAMPUS STEAM DEMAND .....	26
FIGURE 12 UAF CAMPUS CHILLED WATER DEMAND .....	27
FIGURE 13 UAF MONTHLY STEAM CONSUMPTION, ACTUAL CONSUMPTION COMPARISON TO UDP MODELED CONSUMPTION .....	29
FIGURE 14 UAF MONTHLY ELECTRICAL CONSUMPTION, ACTUAL CONSUMPTION COMPARISON TO UDP MODELED CONSUMPTION .....	30
FIGURE 15 UAF UDP TIMELINE OF MAJOR CAPITAL INVESTMENTS FOR ALL STRATEGIES .....	40
FIGURE 16 UAF ANNUAL CAPITAL EXPENDITURES FOR STRATEGIES .....	41
FIGURE 17 UAF CUMULATIVE CAPITAL EXPENDITURES FOR STRATEGIES .....	41
FIGURE 18 COMPARATIVE SOURCES OF ELECTRICITY ACROSS NATURAL GAS STRATEGIES.....	44
FIGURE 19 COMPARATIVE SOURCES OF STEAM ACROSS NATURAL GAS STRATEGIES .....	45
FIGURE 20 UAF UDP 20 YEAR NPV OF OPERATING EXPENSES BY STRATEGY DISCOUNTED AT 5% .....	51
FIGURE 21 COMPARISON OF PRICE SENSITIVITY OUTCOMES (FUEL OIL STRATEGIES WITHOUT NATURAL GAS) FOR FORCASTED OPERATING EXPENSES (INCLUDING DEBT) BY STRATEGY .....	56
FIGURE 22 COMPARISON OF PRICE SENSITIVITY OUTCOMES (FUEL OIL STRATEGIES WITH NATURAL GAS) FOR FORCASTED OPERATING EXPENSES (INCLUDING DEBT) BY STRATEGY .....	57

FIGURE 23 UAF UDP – NPV OF OPERATING EXPENSES BY STRATEGY WITH FINANCED COSTS REDUCED BY \$50  
MILLION .....61

FIGURE 24 UAF UDP STRUCTURED ELECTRIC RATE BY STRATEGY WITH NATURAL GAS .....75

FIGURE 25 UAF UDP STRUCTURED BLENDED STEAM (DES & STAND ALONE) RATE BY STRATEGY WITH NATURAL  
GAS .....76

FIGURE 26 UAF UDP STRUCTURED DOMESTIC WATER RATE BY STRATEGY WITH NATURAL GAS .....77

FIGURE 27 UAF UDP STRUCTURED SQUARE FOOT RATE BY STRATEGY WITH NATURAL GAS .....78

FIGURE 28 UAF UDP 20 YEAR NPV OF OPERATING EXPENSES BY STRATEGY DISCOUNTED AT 5% .....85

**THE UNIVERSITY OF ALASKA FAIRBANKS**  
**2005 UTILITY DEVELOPMENT PLAN**  
**ACKNOWLEDGEMENTS**

Utility Development Planning combines elements of the practices of Engineering, Economics, Finance, Accounting, Facility Management and Central Utility Operation. The plan presented in this document was a highly collaborative effort involving the time, energy, knowledge and patience of a diverse group of professionals.

Mike Ruckhaus, P.E., Senior Project Manager, Division of Design and Construction deserves special recognition for his efforts in assembling the UAF working team, coordinating meetings, teleconferences and reviews and assuring university input and feedback into the modeling process. Mike, along with Chilkoot Ward; Facilities Services Director at UAF sustained an intent interest in the planning process and outcome of the work. Their help in informing the consultants and assuring that the data, assumptions, and physics were appropriate was invaluable. Adam Saunders, UAF facilities Services Engineering Assistant is recognized as being a great help to the consultants in the early stages of the process when gathering field data and tracking down fine scale details of the operation were critical.

Key members of the UAF management team whose input in formulating campus strategies, correcting assumptions, and scrutinizing the complex economic and engineering model outputs include:

Kathleen Schedler, P.E. - UAF Associate Vice Chancellor for Facilities and Safety  
Steven C. Meckel, CPA-UAF Facilities Services Financial Manger; Division of Budget and Accounting  
Linda Zanazzo-UAF Facilities Services Director  
Myron J. Dosch, CPA-UAF Assistant Controller, Finance; Statewide Finance-Controller's Office  
Richard L. Schointuch, Ph.D., A.I.A.-UAF Associate Vice President for Facilities; Systemwide Facilities Director; SW Finance  
Michael Hostina-UAF Associate General Counsel; Office of the General Counsel  
Daniel Kaplan-President: Kaplan Financial Consulting, Inc.

The consultant team for the University of Alaska Fairbanks, Utility Development Plan project included:

Design Alaska- Jack Wilbur, Chris Miller, Linda Taylor, Damon Zimmerman  
GLHN- Bill Nelson, Henry Johnstone, Megan McGann, Pat Fisher  
E3c- John Tysseling, Ben Boersma, Melissa Roberts, Daniel Wright  
HRA- Todd Spacek, Scott Lochhead  
Pacific Consulting- Jeff Easton

**THE UNIVERSITY OF ALASKA FAIRBANKS**  
**2005 UTILITY DEVELOPMENT PLAN**  
**EXECUTIVE SUMMARY**

INTRODUCTION

While the University of Alaska Fairbanks' (UAF) utility system operations are highly reliable, efficient, and based on a stable and inexpensive fuel source, substantial capital investment is needed for renewal of aging components. Essential elements of the heating, electric power, cooling and water systems are now operating at capacity. Furthermore, UAF master planning envisions building load growth on the order of thirty percent (30%) over the next twenty (20) years. Much of this growth is anticipated to occur in energy intensive research facilities on the campus' West Ridge.

The Utility Development Plan (UDP) reviewed in this report, contains evaluations of alternative engineering approaches to meeting UAF's projected energy demands, including review of alternative fuel sources and an alternative provision of electric power. Total annual costs of each engineering solution are forecasted over a twenty-year period and are compared on a net present value (NPV) basis.

Expansion of the existing campus' coal fired district energy system results in remarkably low annual fuel costs for on-site cogeneration of electric power and steam when compared to installation of oil or natural gas fired building heating equipment and substantially increased reliance on electric power purchased from the local utility. Additionally, the reliability and maintenance characteristics of additional coal fired cogeneration are superior to those of "stand alone" or "satellite" alternatives. Construction of the coal-fired system does, however, require comparatively higher capital expenses in the near future.

The “stand alone” or “satellite” alternatives, however, require a lower initial capital investment than on-site coal fired generation. Thus, when debt service is factored into the twenty year economic model, the NPV of increasing campus reliance on purchased power and liquid or gaseous fuel boilers is less favorable than the NPV of construction of additional coal fired cogeneration facilities.

## EXISTING CONDITIONS

The UAF campus encompasses close to three million square feet of academic, research, administrative and housing space that serves an on-campus population of approximately 8,000 students, faculty and staff. The duration of extreme cold temperature in Alaska’s sub-arctic interior imposes significant pressure on the reliability and efficiency of the structures and systems necessary to maintain a productive workforce, enable student learning, and advance leading edge scientific research. A reliable and efficient means of production and distribution of electric power, heating, cooling, and water is essential to the operation of this University.

On-campus central utility systems involving power generators and heating boilers have been a part of the UAF campus since its inception as an agricultural college in the early 1920s. Economic evaluation of alternatives in the mid 1960s led to construction of a coal fired cogeneration plant, and a central steam, electric power, water and chilled water utility distribution system.

Substantial campus growth since that time has included build-out in the University’s Lower Campus and development of the campus’ West Ridge precinct. The District Energy System (DES), which currently serves about 2.8 million square feet, has absorbed this growth through extension of its utility service to the new regions and facilities, and through plant expansions, involving addition of equipment and capacity.

The performance of the existing DES at UAF is excellent. In comparison to regional public utilities, reliability of service is remarkably high. Historically, outages have occurred infrequently and have been of limited duration. With regionally mined coal as the base fuel used to cogenerate steam and electric power, the annual cost to operate the system is extremely attractive when compared to the purchase of liquid or gaseous fuel for boiler heat along with the purchase of electric power from the public utility grid. Coal, purchased by the university under a long-term contract, is a stable, reliable commodity when compared to fuel oil or natural gas alternatives. The return on the 1964 investment decision to construct coal-fired cogeneration has been four decades of reliability, stability and comparatively inexpensive operation.

## DEVELOPMENT OF THE UTILITY DEVELOPMENT PLAN

Three converging issues motivated the need for a Utility Development Plan. First, the University recently completed a comprehensive campus master plan. From the planning process, a campus growth projection that added approximately one million square feet over the next twenty years was developed. Much of the anticipated construction is expected to occur in energy intensive research space on the West Ridge.

Next, it is clear that major elements of the UAF District Energy System are approaching full capacity and are unable to support additional campus growth. Symptoms of this include:

- The on-site cogeneration does not have currently enough capacity to cover peak campus demands for either electricity or steam;
- The steam distribution piping cannot maintain set pressure to the West Ridge under high load winter conditions; and
- The coal boilers are fully base loaded and the hours of operation of the “supplemental” fuel oil boilers have increased to the point that the annual supplemental fuel oil costs exceed the annual base load cost of coal.

Finally, significant capital renewal issues in the forty-year-old system have surfaced. Among these issues are:

- Electrical distribution safety and reliability;
- Steam equipment reliability and maintainability; and
- Water system reliability and maintainability.

The purpose of the UDP is to enable informed decision making on improvement of campus infrastructure. Construction cost and operating efficiency of alternative engineering approaches to the problem of system growth are formulated, and an economic scenario model that includes operating costs, fuel costs and financing costs over a twenty year period is used to compute net present value by scenario. These net present value calculations, along with less tangible factors that include reliability and fuel market stability, are the critical components needed for the University to arrive at a long-term plan.

A phased capital renewal plan that sustains operation of the existing heating, electric power, water and chilled water infrastructure is presented. Three alternative engineering solutions to the problem of meeting campus load growth are considered. These scenarios are:

- Purchase all additional electric power from the local utility and install individual fuel oil or natural gas building heating boilers as growth occurs;
- Purchase all additional electric power from the local utility and install a new “satellite” fuel oil or natural gas fired heating plant on the West Ridge; or
- Improve the existing steam distribution system and construct a new coal fired steam cogeneration facility capable of serving all electric power and steam heating needs of the campus.

## ECONOMIC RESULTS

The coal-fired cogeneration alternative has significantly lower annual operating costs than either of the liquid or gas fired “stand alone” or “satellite” options. This is due to both the efficiency of the process and the supply stability of the coal fuel source. Because the coal cogeneration alternative requires substantially higher capital investment, particularly in the early years, that option carries a much greater debt service burden than the other alternatives in which shorter lived equipment is installed (and in many cases subsequently replaced).

The NPV of the “stand alone” building boilers and “satellite” heating plant are close enough to be considered essentially equal on an economic life cycle cost basis. Due to the debt service associated with its higher early capital requirements, the NPV of the coal-fired cogeneration alternative is on the order of six percent (6%) less favorable than these other alternatives. Given the basic modeling assumptions concerning fuel cost, campus growth, and interest and inflation rates, an investment strategy that minimizes initial capital expenses and increases reliance on utility electric power in combination with either fuel oil or natural gas, is demonstrated to have a more favorable total net present value than the centralized coal plant scenario.

## NON-ECONOMIC CONSIDERATIONS

Although the magnitude of difference in NPV between coal-fired cogeneration and increased reliance on public utility power and heating boilers is economically significant, there are other non-economic factors that must be considered in an informed campus utility system investment decision.

Reliability of campus utilities is essential to meeting increasingly demanding educational, computational and research program requirements. In the climate of Fairbanks, an unplanned outage (along the lines of the boiler tube failure in 1996) could cripple campus function for an extended period. Universities across the United States have elected to install on-site power

production and cogeneration systems with the express intent of assuring self-control and reliability for their programs. A project to install a seven (7) Megawatt (MW) gas turbine generator to meet the reliability requirements of Arizona State University's Biotechnology Research Quadrangle is currently in final commissioning in Tempe, Arizona. A similar unit installed at The University of New Mexico in Albuquerque in 2002 includes sophisticated automatic load shedding functions designed specifically to maintain continuous power to research facilities under loss of utility power. Compared to the electric distribution system in Fairbanks, the utility grid in the vicinity of these two campuses is quite robust. In both cases, extended loss of utility power to campus was an historical fact that created significant problems on both campuses. These examples help demonstrate the value in utility control and reliability.

Long-term stability of fuel pricing must also be considered. While the UDP economic model implements U.S. Department of Energy long term commodity price projections, the influence of regional and global factors on the price of natural gas and fuel oil is likely to be much greater than those same factors' influence on the price of locally mined coal. As a result, there is value to the University in the stability of coal pricing.

## SUMMARY AND RECOMMENDATION

The economic model evaluation period reviewed in this analysis is twenty years. From an economic modeling perspective, extending the model forecasts any longer into the future does not substantially alter the NPV results, as the discounted capital expenses and operating costs diminish to an insignificant level beyond twenty years. A business entity or bank, motivated primarily by potential near term yield on alternative investments, would consider NPV as conclusive.

A university, in contrast, does not necessarily possess the same investment motivation—maximizing monetary return—and generally designs its facilities and programs for life cycles well in excess of twenty years. The perspective of the university utility operator is qualitatively different than that of the business investor. Year to year funding to cover fuel and operating and maintenance costs must be carved out from a much larger overall university budget. Near term instability in fuel markets creates havoc in the operating budget and often results in significant compromise (usually in the form of deferred capital renewal) in annual maintenance of the system.

A steward of the university utility system sees great benefit in investment in system improvements, equipment, and infrastructure. Systems that incur low and stable annual fuel costs, that are durable enough to withstand numerous down budget cycles, and whose operations are fully controlled by the university provide great benefit to the university in the long run. The steward of the campus' utility system may not look back now at the 1960s investment in coal-fired cogeneration and district energy infrastructure as a wise and prudent decision without paying consideration to the original present value calculations that compared the coal fired cogeneration investment to lower capital cost alternatives. There is value in establishing utility systems that sustain operational stability and low annual costs over an extended period.

*Based on evaluation and consideration of all business and operational parameters discussed in this UDP, UAF has assessed that the “preferred” solution require development of an implementation plan that focuses on expansion of the central plant facilities, with an emphasis on implementing the coal-fired solution if the capital investment constraints can be overcome. The preferred Strategy chosen is expected to become a “guiding principle” for implementation of UAF’s utility infrastructure renewal and expansion. However, until capital constraints are resolved, the implementation of the UDP concepts will—of necessity—focus on incremental steps.*

*The UDP Project Team strongly recommends that UAF identify and empower a focused Utility Project Team charged with implementation of the UDP Strategy, including an advocacy role seeking to resolve the capital funding issues.*

**THE UNIVERSITY OF ALASKA FAIRBANKS**  
**2005 UTILITY DEVELOPMENT PLAN**  
**SECTION I: PROJECT INTRODUCTION AND OVERVIEW**

## STUDY OVERVIEW

The purpose of this study is to analyze alternative long-term – twenty (20) year – comprehensive utility systems for the University of Alaska Fairbanks’ main campus. The University of Alaska Fairbanks, founded in 1917, is the northernmost Land, Sea and Space Grant university and research center in the United States, and this location poses many unique challenges and opportunities for the University. UAF’s main campus, the focus of this study, spans nearly 2,250 acres and has an enrollment of over 5,500 students. The campus boasts seven major research units, including the Agricultural and Forestry Experiment Station, the Arctic Region Supercomputing Center, the Geophysical Institute, the Institute of Arctic Biology, the Institute of Marine Science, Institute of Northern Engineering, and the International Arctic Research Center. Graduate enrollment has increased thirteen percent (13%) from 2002-2004, largely due to UAF’s ability to attract more than \$112.4 million in research funding over the last several years, and UAF remains the only campus in the state to award doctoral degrees.

The growth of UAF, both in terms of student enrollment and physical building square footage, increases its need for reliable utility services. In virtually all campus planning environments, the development and growth of academic, research and community programs impose crucial utility service requirements that must be met to successfully support the broad mission of the university. The utility services infrastructure comprises a fundamental capital asset of the university that must be carefully managed and planned in order to fulfill these service requirements.

In Fiscal Year (FY) 2005, the UAF central campus consumed over 55 million kilowatt hours of electricity and over 275 million pounds of steam used for heating and cooling. Currently, these utility consumption amounts are supplied primarily by the campus’ central utility plant; however within the next few years, the increase in campus utility service requirements driven by campus growth will exceed the capacity of the existing utility

infrastructure's ability to serve these demands. Additionally, most of the utility systems equipment has been in service for over forty years and is at or near the end of its useful life. If UAF is to maintain a reliable utility system sufficient to meet the needs of its students, faculty, and administration, it is imperative that the University make a substantial investment in the timely renewal of its current utility infrastructure, as well as implement a long-term strategy for development of comprehensive utility system infrastructure improvements in line with the mission and goals of the University as a whole.

Developing a comprehensive long-term master utility plan is a major challenge. Underlying this plan are the concepts of prudent capital investment, long-term strategic planning, and life-cycle cost analysis. As opposed to looking merely at the "first cost" of the project, the analysis considers the total costs, including capital, operating and maintenance, and any associated debt expenses incurred over the economic life of the project. The analysis contemplates the University's critical long-term utility issues, including managing fuel price and supply risks, regulatory risks, and the University's financial constraints. Additionally, the plan addresses the systematic accrual of capital renewal and replacement reserves necessary to provide for fiscally sustainable utility systems required to meet future utility service requirements beyond the expected useful life of the capital asset infrastructure implemented through this strategic plan. The investigation addresses the questions of:

- Which utility services infrastructures should be addressed?
- How the service requirements should be met?
- When should the expenditures be made based on anticipated patterns of growth?
- What are the costs (and pricing) of delivered services from alternative utility system configurations?
- What alternative business structures are available to the University to implement the preferred utility strategy?

## NEED FOR LONG-TERM UTILITY PLANNING

All successful large institutions require a financial plan to conduct their long-term mission requirements. A major component of that plan is the utility infrastructure asset base. Because utility infrastructure is, by nature, a long-term capital-intensive item, it deserves proper attention within the institution's priorities in fiscal and capital planning.

Successful long-term institutional utility services planning requires a comprehensive, strategic and quantitative analysis of various configurations and combinations of utility infrastructure capable of meeting current and future campus utility requirements. Variables such as energy prices, campus growth, and fiscal constraints create complex problems for facilities managers and necessitate the use of comparative analyses in strategic planning evaluations. Equally important is the need for developing a comprehensive funding strategy, which will ensure that the utility project plan chosen can be implemented fully and successfully.

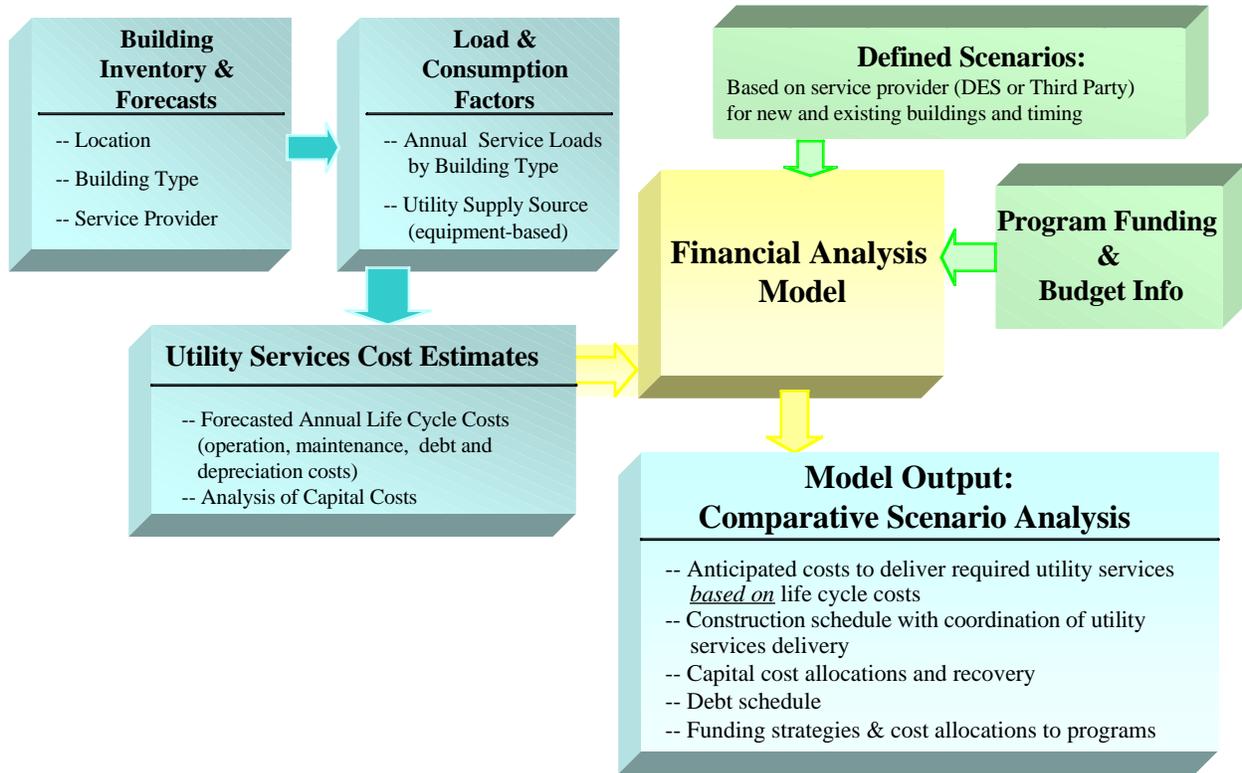
Together, the engineering and economic analyses undertaken for the *2005 Utility Development Plan* (UDP) project are capable of addressing the complex nature of such an endeavor. While the engineering analysis addresses the utility infrastructure, system capacity, and efficiency (among other technical matters), the UDP Model utilizes advanced scenario modeling and data analysis methods. The analytical techniques include capabilities to assess life-cycle cost<sup>1</sup> analysis, the ability to perform "what-if" and sensitivity analysis, the ability to allocate costs to responsible entities (e.g., cost centers), and the ability to incorporate long-term trends in forecasted growth, utility load, and energy prices. A graphical description of information flow within the UDP Model is shown below:

---

<sup>1</sup> Life-cycle costs are defined as the sum of the present values of:

- (a) Investment costs, less salvage values at the end of the study period;
- (b) Non-fuel operation and maintenance costs (both annual and major maintenance renewal);
- (c) Replacement costs less salvage value of replaced building systems; and
- (d) Energy and/or water costs.

**Figure 1 UAF UDP Model Information Flow**



The UDP Model helps to identify the long-term fiscal implications (costs and benefits) associated with each alternative for serving the utility services demand, and presents comparable economic outputs in the form of net present value analysis for each alternative strategy. The purpose of determining the present value of cash flows stems from the basic finance principle, “a dollar today is worth more than a dollar tomorrow.” Performing a net present value analysis is critical for proper comparison of the alternatives in today’s dollars — that is, the comparative value of a project if all of the costs and benefits are stated in common terms of present day dollars. When undertaking a long-term project that spans twenty years, the time value of money concept becomes extremely important. This type of economic/financial analysis is a widely accepted methodology in both the corporate and public policy arenas, and has proven invaluable in dealing with the complex nature of utility planning by providing the critical information university administrators need to make well-informed decisions.

**THE UNIVERSITY OF ALASKA FAIRBANKS**  
**2005 UTILITY DEVELOPMENT PLAN**  
**SECTION II: UAF UTILITY INFRASTRUCTURE AND CAMPUS GROWTH EXPECTATIONS**

## DISTRICT ENERGY SYSTEM (DES) INTRODUCTION

Under a DES, a central plant utilizes purchased fuel (coal, fuel oil, natural gas, etc.) to produce steam, and/or chilled water, and distributes those produced utility commodities to campus buildings.<sup>2</sup> This centralized approach eliminates the need for “stand alone” boiler (heating) and chiller (cooling) facilities in individual buildings, thereby avoiding these costs in new building construction. A central plant may also produce electricity in conjunction with steam production (hence the term cogeneration plant or “cogen”). Thus, DES utility services can dramatically improve overall campus energy use efficiency and fuel utilization, requiring less overall capacity, and potentially lowering long-term utility infrastructure costs.<sup>3</sup>

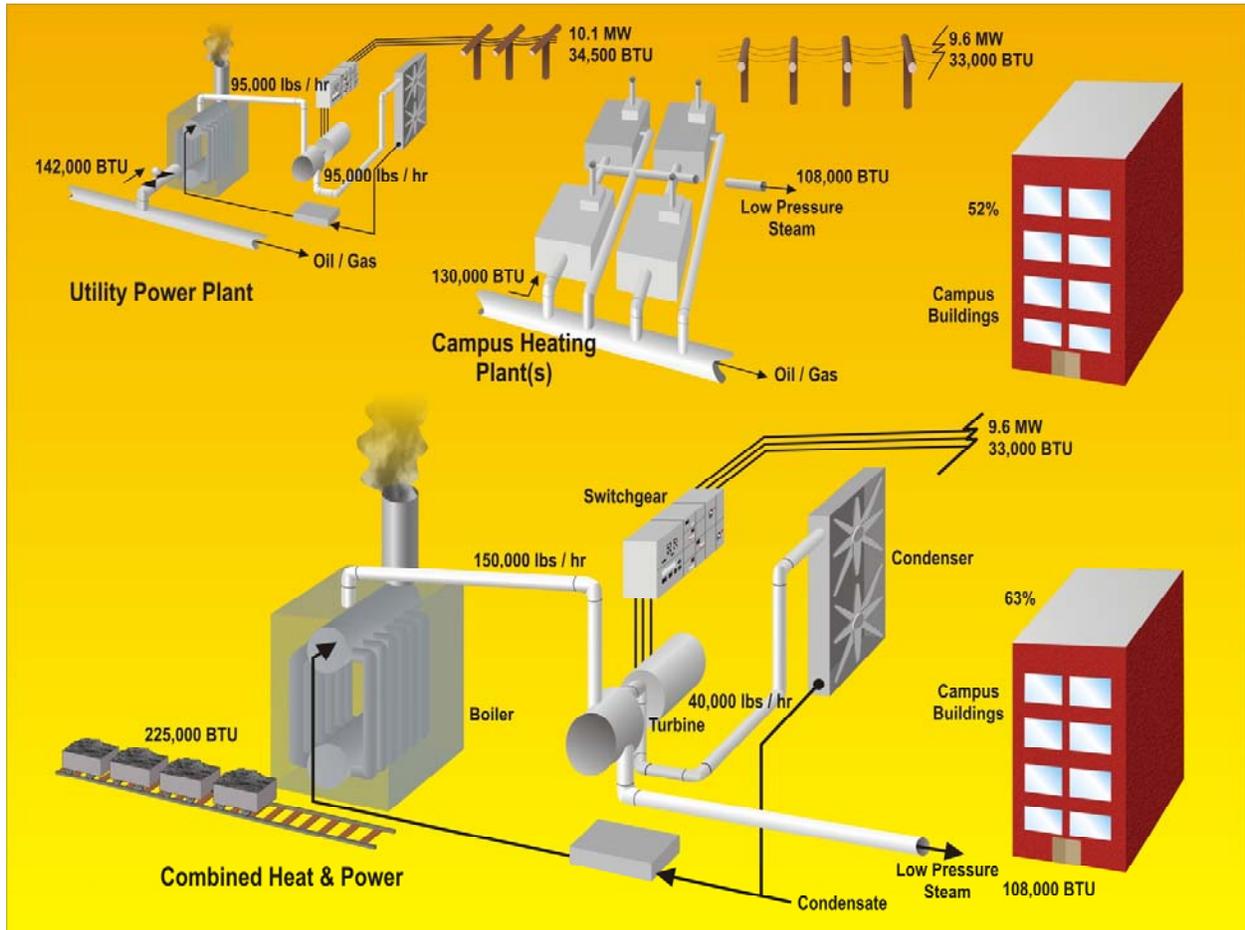
Other benefits include increased service reliability associated with the diversity of load and peaking capacities, as well as operation and maintenance cost savings associated with the DES facilities. Costs associated with district energy systems include the greater upfront capital costs required in the construction of DES facilities and scheduled major maintenance on the plant equipment and infrastructure. However, there are also physical limitations with respect to the geographic distance of distribution and the load density dependency. Figure 2 provides a generalized depiction of combined heat and power DES facility, and contrasts that facility with alternative utility plant configurations in order to illustrate the efficiency benefits of a DES utility plant.

---

<sup>2</sup> International District Energy System Organization, [www.ides.org](http://www.ides.org), accessed September 2005.

<sup>3</sup> Efficiency is gained through both larger-scale production facilities as well as reduced total purchased energy cost. The reduced total purchased energy is largely due to DES load diversity, where coincident (in time) peak energy service loads are “shared” between end-use facilities, thereby reducing the total production requirements for the delivered energy services commodities (as compared to individual building “stand alone” energy service facilities).

**Figure 2 UAF District Energy System**



The important point to be understood from the diagram is the significant gain in the overall efficiency of energy use for the combined heat and power system at the UAF Atkinson Plant as compared to alternative plant configurations. In particular, the output from the plant is substantially higher than the combination of purchased utility power and alternative plant configurations (with the same level of energy input into the system). Additionally, the primary input fuel (coal) is significantly less expensive on a energy content basis (Btu's) than the alternative plant fuel inputs, thereby further increasing the economic efficiency of the combined heat and power DES plant configuration.

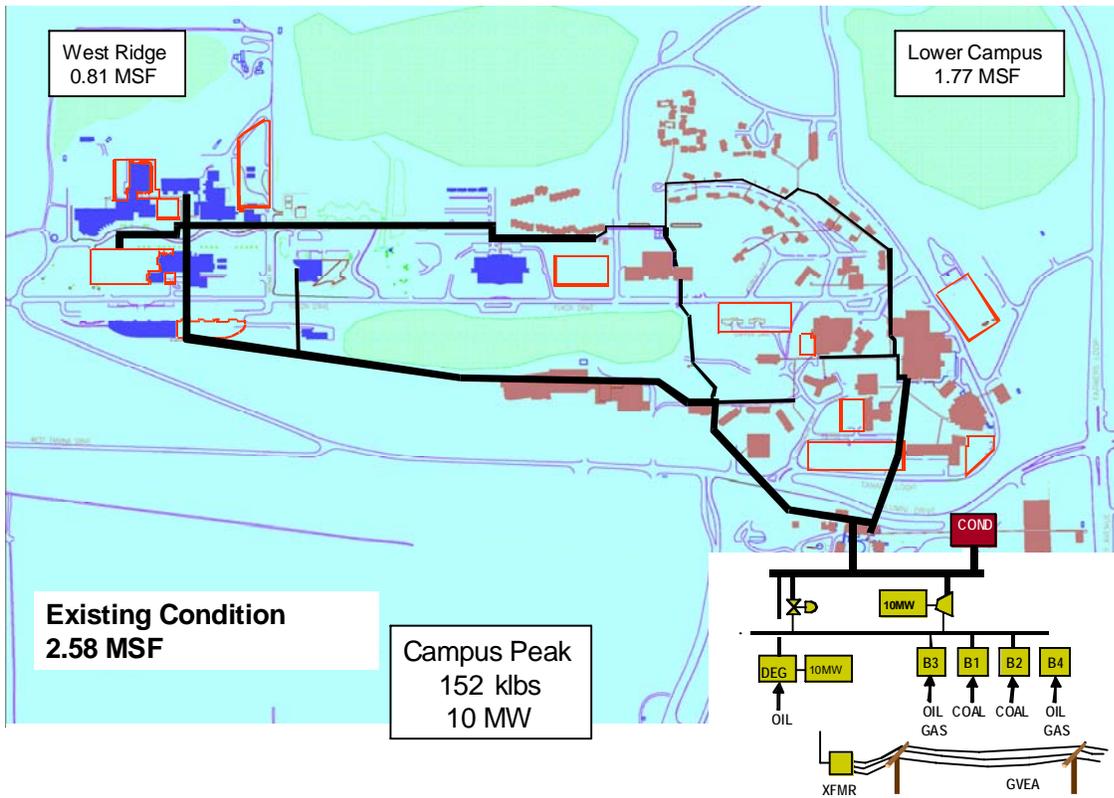
For energy and facilities managers, it is critical to evaluate, through the use of a quantitative, life-cycle analysis, whether the proposed benefits outweigh the costs incurred in installing DES service facilities. In performing such an analysis, this report, through UDP Model, evaluates alternative configurations of DES and non-DES (“stand alone”) utility systems for the University to determine the preferred long-term solution.

The existing UAF central plant facilities—including both coal-fired and fuel oil-fired high pressure steam boilers, and the steam turbines—reflect a DES facility investment decision and utility service strategy that has served the University very effectively for more than forty years. The decision analyzed herein is in large measure the same long-term strategic decision faced by prior university administrators in the early 1960s. The economic trade-off between the strategic decision alternatives may be summarized as trading higher initial capital cost with lower long-term operating and maintenance costs *against* an investment in facilities with lower initial capital costs and higher long-term operating and maintenance costs. A strategic facilities investment decision taken today will define utility service options for decades.

## UAF CURRENT UTILITY CONFIGURATION

The campus of The University of Alaska Fairbanks currently contains approximately 2.8 million square feet of academic, research, housing and administrative space. Soil conditions, topology and planning for open space has limited development of building sites into two regions: the historical core area known as Lower Campus (LC) and an elevated area approximately one-half mile distant known as the West Ridge (WR). The campus map below in Figure 3 shows the physical layout with relevant current statistics.

**Figure 3 University of Alaska Fairbanks Campus Map Showing Steam Utility System**



Significant features of the sub-arctic environment of Fairbanks include wintertime low temperatures of negative sixty degrees Fahrenheit (-60° F) and daylight periods ranging from 3.5 hours in December to 22 hours in June. Long periods of sub-zero ambient temperatures over an eight-month heating season amount to 15,000 heating degree days. Long periods of summertime daylight hours combine with high temperatures in the high-nineties degrees Fahrenheit (99° F) to create a significant need for internal cooling in research and academic facilities. Current peak demand statistics are:

Steam:	152,000 lbs/hr
Electric Power:	10 MW
Chilled Water:	3,000 Tons

The campus' central utility system (DES facilities) provides heating, electrical power, water, and, for the lower campus, chilled water for building cooling. A comprehensive history of the University's utilities systems can be found in Appendix C – History of UAF's Utilities Development. Essential elements of the current DES include:

1. A central utility plant facility for fuel transport and storage, steam generation, electrical power generation and transformation equipment, water treatment chilled water production and distribution equipment, auxiliary equipment and systems and administrative offices;
2. Two coal-fired steam generators with the combined ability to generate approximately 100,000 lbs/hr of high pressure steam;
3. Two fuel oil-fired steam generators with the combined ability to generate approximately 200,000 lbs/hr of high pressure steam;
4. A steam turbine generator capable of converting on the order of 130,000 lbs/hr of high pressure steam into 8.5 MW of electric power and 120,000 lbs/hr of low pressure steam for campus heat;
5. A system of subterranean concrete tunnels, known as utilidors connecting the central power plant to essentially all WR and LC buildings. Piping and conduit for low pressure steam, condensate return, water, electric power, communications, compressed air and other utility services are routed within the system of utilidors;
6. A diesel engine generator (DEG) system, originally intended to demonstrate liquefied coal slurry technology, capable of providing approximately 10 MW of electrical power and 20,000 lbs/hr of low pressure steam;
7. A 4,160 Volt electrical distribution system capable of being fed from the steam turbine generator, the local utility (GVEA), or the diesel engine generator;
8. A low pressure steam absorption chilling plant for distribution to buildings on LC; and
9. A set of water wells, a potable water treatment system and a water distribution system that provides potable and fire protection service to both regions of campus.

Central utility services that are not currently provided to the UAF campus via the DES include:

1. Steam, water and electric power to various UAF owned off-campus buildings and facilities;

2. Central cooling to research and academic facilities on the WR, which are currently cooled by means of “stand alone” air-cooled electric vapor compression machinery;
3. Certain heating and sterilization loads in WR research facilities that are served by “stand alone” fuel oil fired boilers; and
4. Campus sewer collection system and delivery to city public utility services.

While the age and condition of the DES is somewhat variable, a large percentage of the current infrastructure was constructed as a part of major campus growth between 1963 and 1973. Many of the existing utility systems are near or exceed forty years of service. While these systems have generally been maintained in remarkably good condition, prudent management now requires substantial levels of investment for renewal of these systems and equipment. Planned growth in campus building loads along with more stringent indoor environmental demands provides concurrent motivation for investment in additional production and distribution capacity, reliability, and efficiency.

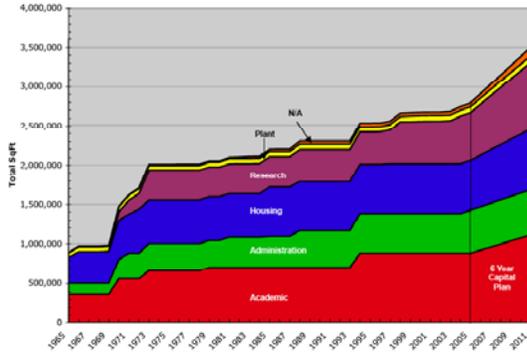
## CAMPUS GROWTH PROJECTIONS

In order to forecast UAF’s future long-range utility requirements, it is necessary to first determine appropriate growth rates for the University’s main campus. For this analysis, growth projections based on square footage of campus buildings are utilized to predict future utility needs and capacities. The UDP Project Team has adopted a Base Case projection of 3.9 million total campus square feet in FY2025 as a justified and reasonable estimate of future UAF growth, based on historical campus growth patterns, the University’s Six-Year Capital Plan growth projections, and discussions and analysis with UAF staff and administrators.

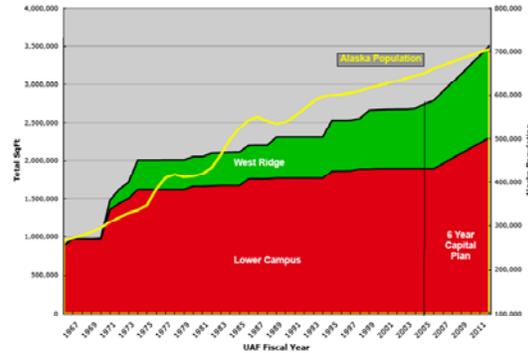
An inventory of FY2005 campus buildings shows total campus building square footage of approximately 2.8 million square feet with the ability to be served by DES utility services. To help determine future campus building growth, historical growth patterns for the campus were analyzed. Campus buildings were categorized by campus location and building type—based on

“primary use” information produced by UAF—and total square footage by building type was summed. Summaries of historical campus square footage by building type and campus location, including forecasts to FY 2012 from the Six-Year Capital Plan, are seen in the two charts below:

**Figure 4 Historic & Projected UAF Building (SqFt) Growth 1965-2005, By Building**



**Figure 5 Historic & Projected UAF Building (SqFt) Growth 1965-2005, By Location**



The UDP Project Team analyzed UAF’s average annual historical growth rates for the campus based on the building inventory data, as well as Alaska state population data. The two graphs demonstrate the uneven pattern of total growth throughout time, including FY2012 square footage growth projections based on the University’s Six-Year Capital Plan.

Table 1 summarizes historical building inventories for each ten year increment beginning in FY1965 and also provides the building inventory anticipated to exist in FY 2012 as a result of the Six-Year Capital Plan.

**Table 1 Historical Building Inventories**

	FY 1965	FY 1975	FY 1985	FY 1995	FY 2005	FY 2012
<b>Lower Campus SqFt</b>	886,187	1,618,781	1,758,188	1,864,219	1,898,616	2,321,116
<b>West Ridge SqFt</b>	5,059	389,580	441,534	667,208	892,759	1,242,611
<b>Total UAF Campus</b>	<b>891,246</b>	<b>2,008,361</b>	<b>2,199,722</b>	<b>2,531,427</b>	<b>2,791,375</b>	<b>3,563,726</b>
<b>Alaska Population</b>	265,200	384,100	543,900	601,581	662,604	713,393

The FY2005 UAF campus square foot calculation of 2.8 million relates to UAF central campus buildings that currently are or could be connected to UAF DES service. Approximately 200,000 square feet of the UAF campus are not served by UAF DES facilities and are ignored by this investigation. To determine appropriate future campus growth, the UDP Project Team first reviewed the University's Six-Year Capital Plan growth prediction. While the Six-Year Plan reflects full implementation of projected growth to FY2012, actual funding and prioritization of building projects constrain current expectations of actual growth. Therefore, to predict more accurate future growth, the UDP Project Team and UAF staff developed a combination of historical growth and expected trends to reach a FY2025 total campus square footage of 3.9 million.

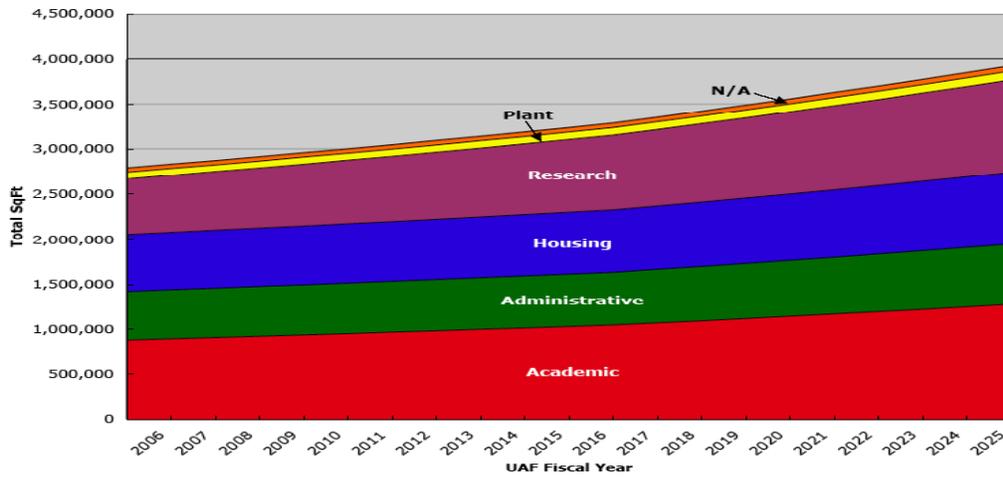
The detailed calculation used to reach the 3.9 million square foot FY 2025 projection assumes:

- Actual build-out of 65% of Six-Year Capital Plan growth projection (i.e., 500,000 square feet of growth) to realistically occur by FY 2016;
- Two percent (2%) annual overall campus growth from FY 2016 to FY 2025; and
- Distribution of campus growth by building type and campus location based on expected specific growth patterns throughout the twenty (20) year study period.

The goal of the growth analysis is to identify a “most likely” strategy for UAF square footage growth, as it relates to delivery of utility services. Within this “most likely” overall campus growth expectation, differing rates are applied to separate areas of campus and individual building types, depending on expected campus trends, priority of program activities within UAF's mission, and physical availability of space. The UDP Project Team believes the estimation of 3.9 million total campus square feet appropriately considers the campus and state's thirty years of past growth, the predicted growth from the University's Six-Year Capital Plan, and the specific campus growth trends expected by UAF staff. This estimation allows for planning of sufficient utility facility capacity to meet future campus needs.

The breakout of percent growth and total forecasted square footages by campus location and building type can be seen in Figure 6, Figure 7, and Table 2 below:

**Figure 6 Projected UAF Building (SqFt) Growth 1965-2025, By Building**



**Figure 7 Projected UAF Building (SqFt) Growth 1965-2025, By Location**

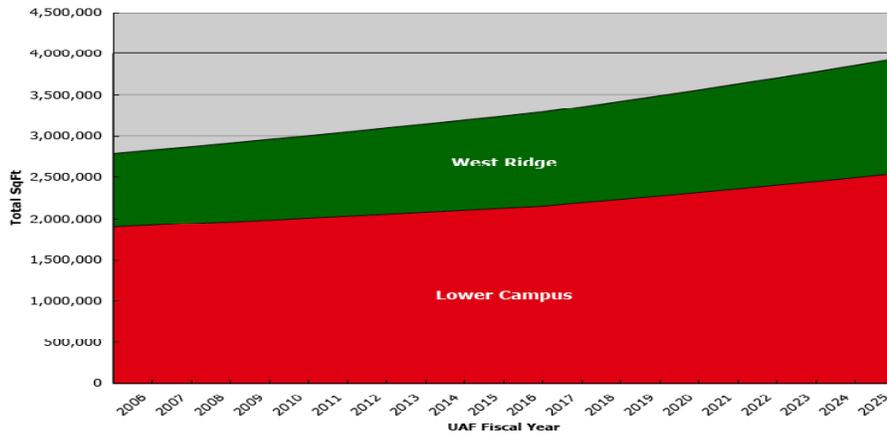


Table 2 Projected UAF Campus Annual Growth Rates

	Lower Campus Growth Rate			West Ridge Growth Rate			UAF Combined Growth Rate		
	Academic	Research	Total	Academic	Research	Total	Academic	Research	Total
<b>FY 2006 - 2016</b>	1.75%	0.30%	1.15%	0.50%	2.93%	2.20%	1.58%	2.84%	1.50%
<b>FY 2017 - 2025</b>	2.25%	1.50%	1.85%	2.00%	2.49%	2.27%	2.22%	2.47%	2.00%

Additional growth strategies derived from the “most likely” case are also analyzed in the UDP Model to provide sensitivity analyses for several campus growth possibilities.

## ENERGY LOAD DENSITY

When discussing campus growth and future energy use projections for the UAF campus, it is important to also consider trends in projected energy load density throughout the campus. In other words, if the campus were to remain identical in population and building square footage size, how much more energy would be consumed each year as a result of increasing needs for energy per square foot of space. To capture the effects of expected electric load density growth on the UAF campus, a factor of 1.5% is applied to the independent building electrical growth for the first ten years in the UDP Model. The decision to use a factor of 1.5% was arrived through historical analysis of UAF electric consumption data from FY1990 to FY2005. This 1.5% electric load density growth factor is also consistent with other electric consumers of similar size and patterns of electric use—specifically other universities.<sup>4</sup> The electric load density growth factor is not applied in the second ten years of the UDP Model, however. The UDP Project Team and UAF facilities staff decided the increasing efficiency of electrical equipment and the leveling off of the increase of additional personal computers on campus made projecting continued load density growth unrealistic in the model. Electrical loads for lighting and car plugs (block heaters), however, remain in proportion with overall campus square footage growth throughout the twenty-year time span of the UDP Model.

<sup>4</sup> Urso, Jack, “The Energy Crunch,” *University Business*, November 2005, <<http://www.universitybusiness.com/page.cfm?p=592>>, accessed on December 6, 2005.

## COMMON UTILITY SYSTEM IMPROVEMENTS AND CAPITAL ASSET RENEWALS

The existing utility system infrastructure at UAF requires significant investment in major maintenance and upgrades in order to continue to provide reliable utility services. The maintenance and systems upgrade requirements are common to any and all future strategies the University considers and are incorporated as part of the UDP analyses. Recent studies and investigations of the forty-plus year old steam production and distribution system have identified single point failure reliability issues in plant auxiliaries, facilities, and aged and undersized components of the system that must be replaced.

A large percentage of the physical infrastructure of the existing University's DES was put in place in a period of rapid campus development between 1963 and 1973. Much of the equipment and systems has therefore provided essentially continuous service on the order of forty years. Evaluation of the infrastructure and equipment under this and several previous engineering studies has generated a set of specific recommendations for utility system renewal. The deficiencies and issues identified here are largely independent of planned campus growth or ongoing operational budget concerns. These are simply the problems that a large scale and complex electro-mechanical system under continuous operation faces after decades of use. Components, equipment and systems wear out and need to be replaced or rebuilt. Technologies, environmental regulations, and minimum standards of safety and reliability improve over time and renewal is necessary to keep the plant from obsolescence.

Several categories of renewal can be discerned. In some cases, the equipment or components have operated well in excess of their original useful service life intent. An example of this form of renewal would be the Atkinson Center feedwater deareator, which serves the function of removing oxygen from condensate before injecting it under pressure into the superheated steam boilers. The deareator is essentially a large tank containing a spray head and a series of trays over which a stream of liquid condensate cascades. The deareator is a very simple two phase flow device. After forty years of service it would be remarkable if the integrity of the trays were not compromised. Because there is only one such unit, it is difficult to isolate

and evaluate the internal condition without a major campus steam outage. Extended operation of the superheated steam system without deaeration subjects the campus to an unacceptable level of risk. High feedwater oxygen levels could lead to pitting within the boiler tubes and the potential for catastrophic failure. Although, logistically, a new unit would have to be installed in parallel with the existing tank, the existing deaerator is an example of a component that simply needs to be replaced.

In other cases, existing systems are fundamentally sound and have the potential to remain in continuous operation for another forty years provided certain major reconditioning and renewal tasks are accomplished in a timely manner. For example, the primary aereator tank of the water treatment system, as currently arranged, is a single upstream component in a parallel water treatment processing train. It is difficult, if not impossible to replace the corroded steel supports or inspect and repair the tank walls without shutting off essential water service to the UAF campus. Renewal funding would allow construction of a second new tank to be installed in parallel with the existing unit. Periodic staging of the two aerators with periodic repair and renewal would, in theory, allow perpetual operation of the system. The water treatment aereator is an example of component renewal within an existing system. Another example is retubing of the existing boilers. Although there is no recent evidence of tube wall degredation, prudent practice indicates that a mechanism for major overhaul needs to be budgeted. Replacement of tubes and/or mechanical components needs to be done before catastrophic or “progressive” failure occurs.

A third category of renewal has to do with evolving conditions and technology. Many of the components that make up plant safety, fire management, and automated control of the power plant involve microprocessors or direct digital components that are subject to obsolescence. As elements of a control or alarm system become obsolete, the efficacy of the system diminishes and ongoing costs to maintain it increase. Replacement of the existing Bailey Net 90 is an example of renewal due to evolving technology.

In addition to items specifically identified through our 2005 UDP effort, three previous engineering studies were incorporated into this analysis. These include: “*University of Alaska Fairbanks Utility Evaluation Study*,” October 2000 by Coffman Engineers; “*UAF Electrical Distribution System Upgrade Study*,” August 2001 by PDC Consulting Engineers; and “*Water Systems Study*,” 2001. Construction cost estimates from the earlier studies were adjusted to reflect current construction project costs.

Table 3 summarizes the common utility system improvements currently required by UAF. These improvements are described in detail in Appendix A Section A, and their associated time schedules are detailed in Appendix A Section B. **These required upgrades to maintain UAF’s utility capabilities and system reliability total approximately \$61.7 Million<sup>5</sup> and are a necessity no matter what long-term utility strategy is chosen for UAF.**

**Table 3 Common Capital Asset Renewal Expenses by Utility System**

<b>Utility System</b>	<b>Estimated 2005 Capital Cost</b>
Electric System	\$ 39,489,000
Steam System	\$ 14,600,000
Chilled Water System	\$ 1,040,000
Domestic Water System	\$ 3,022,000
General Plant	\$ 3,510,000
<b>Total</b>	<b>\$ 61,660,000</b>

---

<sup>5</sup> Total in 2005 dollars.

**THE UNIVERSITY OF ALASKA FAIRBANKS**  
**2005 UTILITY DEVELOPMENT PLAN**  
**SECTION III: UTILITY DEVELOPMENT PLAN ASSESSMENT METHODOLOGY**

## UDP MODEL OVERVIEW

The *2005 Utility Development Plan* is primarily driven by forecasted University square footage growth over the twenty (20) year time span. The UDP Model also incorporates the anticipated timing and location of this growth to predict expected utility commodity (electricity, steam, and chilled water) consumption over the study period. This forecast of utility loads is produced on a monthly basis over the life of the study to most accurately capture both annual and seasonal demand trends.

To verify the accuracy of the output from the Model, the results must be calibrated against actual UAF production data. For the UDP Model, UAF staff and the UDP Project team selected UAF's FY2005 (July 2004 to June 2005) as the Base Year for model comparison. Outputs from the UDP Model are compared and calibrated against actual production and utility service consumption volumes from the UAF utility system as reported in the University's electronic PI Data Archive System and other metered data records (e.g., building-level consumption meters) to assure correctness of the Model production outputs.

The Base Year consumption load forecast for all of the produced utility commodities was verified by UAF facilities staff and determined to be reasonable for use in projecting all future study years. The Base Year production and consumption data were then utilized in the UDP Model to identify and allocate the actual costs of producing the utility commodities. An energy price forecast (discussed in detail below) predicts future delivered fuel prices for the University, and detailed engineering and economic analyses provide cost estimates and allocations for

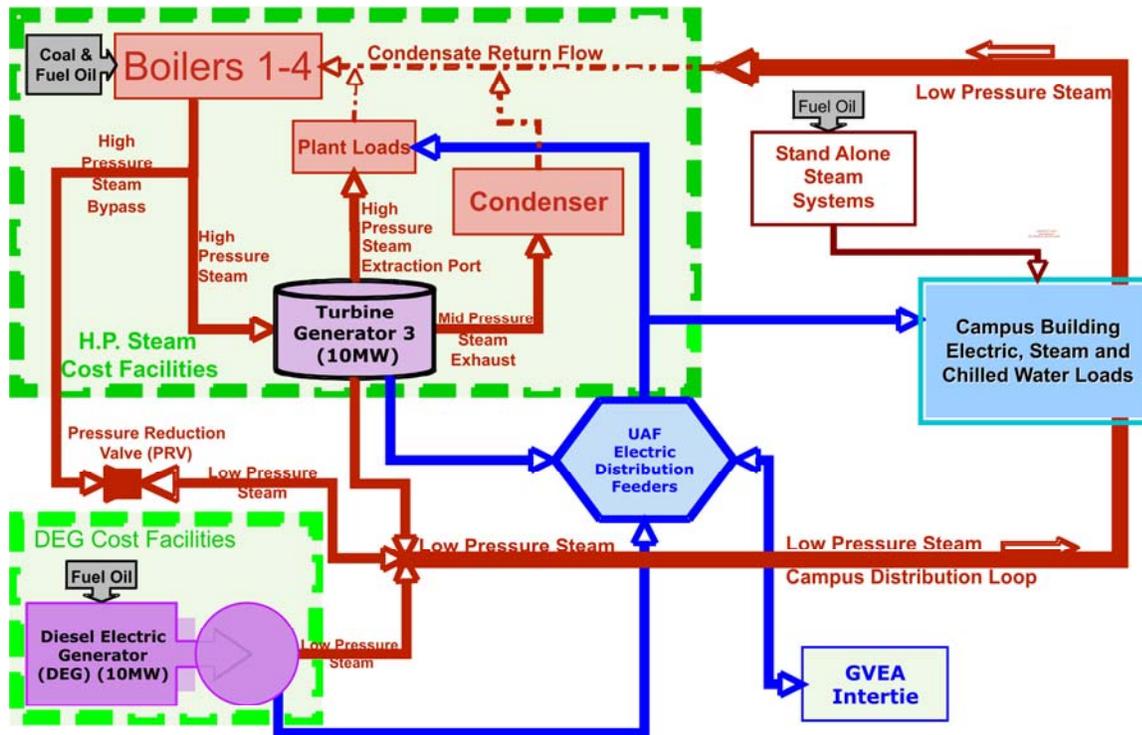
specific equipment performance and outputs. The UDP Model forecasts life-cycle utility operating and maintenance costs, labor costs, fuel costs, debt (including principal and interest) costs, and capital costs for required new infrastructure and renewal of existing utility service facilities.

The overall project methodology evaluates various strategies capable of meeting these utility service requirements. In doing so, the analysis takes into account the life-cycle cost and net benefits associated with various utility service configurations.

## ALLOCATIONS OF DIRECT OPERATING COSTS

Costs that cannot be directly assigned to final delivered utility commodities are generally related to the cogeneration facilities of the UAF. By example, the total costs of coal, fuel oil, general operations and maintenance (O&M) and labor are first allocated in the model's calculation of costs of production of High Pressure Steam (HP Steam). Total costs, including fuel costs from the HP Steam Boilers 1-4, are then allocated between the steam turbine generator *commodity* outputs of Electricity and Low Pressure Steam (LP Steam) on a Btu-equivalent basis of the consumable products (net kWh and LP Steam). The DEG LP Steam and Electricity are also allocated in this fashion. Figure 8 is a generalized depiction of the UAF DES facilities and equipment and reflects the basic allocation of operating costs to the utility systems' commodity services.

**Figure 8 UAF District Energy System (DES) Model Flows**



O&M expenses (other than those directly assignable to domestic water<sup>6</sup>) are allocated to the HP Steam production equipment—the coal and fuel oil HP Steam Boilers (1-4)—on a ninety percent (90%) to coal and ten percent (10%) to fuel oil basis. These costs are divided by the boiler fuel inputs (coal and other fuel) to produce O&M rates (\$ per unit), which are then used to forecast future O&M costs for various plant and facility production configurations.

<sup>6</sup> Based on information obtained from UAF, it was assumed that three percent (3%) of the gallons of water produced in calendar year 2004 were utilized in utility operations. Therefore, three percent (3%) of domestic water expenses in each year have been re-designated as attributable to general utility expenses.

Once fully allocated between electricity and LP steam, these costs are then combined with any assignable distribution costs (e.g., substation, steam and chilled water distribution systems). Production equipment costs are allocated to the consumable commodities—electricity (kWh), heating (Mlbs), cooling (Ton-Hrs) and domestic water (Gallons). These fully-loaded costs are then divided by the consumed commodities to derive commodity rates.

## ENERGY MARKET ANALYSIS

In modeling the University of Alaska Fairbanks' long range utility planning, it is necessary to forecast purchased fuel prices for the University. For the UDP Model, UAF's delivered commodity prices are predicted based on current and expected UAF commodity contracts, locally delivered historical energy price trends, the U.S. Energy Information Administration's (EIA) short and long-range energy price forecasts, Regulatory Commission of Alaska approved tariffs, local market supply and demand influences, and other independent studies of Alaska energy pricing. The forecasts in the Model predict prices for delivered fuel oil, coal, natural gas, and Golden Valley Electric Association (GVEA) electricity.

### *Fuel Oil Price Forecast*

Alaska's significant North Slope oil reserves should provide the state with long-term fuel oil and diesel fuel supplies. The State of Alaska's long-term contract for delivery and refining of its royalty-in-kind oil supplies at the North Pole Refinery, as well as continued operation and expansion of fuel oil fired generation adjacent to the North Pole refinery facilities, will continue to guarantee reliable production and delivery of fuel oil and diesel fuel supplies into the Fairbanks market area.

UAF's current contract price for fuel oil and diesel fuel is tied to the market-driven Oil Price Information Service's (OPIS) Anchorage index Rack Price posting. Fluctuations in the market price for fuel oil are tied to international petroleum market dynamics, and similar price relationships are expected into the future.

In the Model, expected future fuel oil price fluctuations are derived from the 2004 Energy Information Administration's (EIA) 2004 twenty year forecast for PADD V No. 2 Heating Oil.<sup>7</sup> In the Model, UAF's current actual delivered fuel oil price is trended off percentage price increases of the EIA long-range price to predict the price of delivered purchases for the University.

### ***Coal Price Forecast***

UAF's delivered coal price is expected to be the most stable commodity fuel price, with abundant supplies located close to the University and minimal new local demand expected to compete for the supply of reserves. Large reserves also exist in both south-central Alaska and the North Slope, additionally reducing supply pressures.

UAF currently has a ten year contract with the Usibelli Coal Mine to supply coal to the University through FY2011. Coal prices for UAF in the Model are forecasted assuming the University will remain on a similar contract with comparable price adjustment terms for the length of the twenty-year study period.

The purchased price of coal for the University is forecasted using inflationary pricing mechanisms consistent with the existing Usibelli contract. The Model predicts a UAF cost of coal per ton by calculating the percentage change in the Producer Price Index–Industrial Commodities (PPI), plus an adjustment for the coal mine's labor rate. The PPI percentage change is calculated as the simple historical ten year annual average PPI change (+2.9% per annum), and the forecast annually compounds the coal cost component of current pricing by that PPI average increase. To determine an appropriate labor rate adjustment component of prices for the coal mine, the UDP Model assumes labor cost escalation rate of two and one-half percent

---

<sup>7</sup> Energy Information Administration, Annual Energy Outlook 2005,  
<<http://www.eia.doe.gov/oiaf/aeo/demand.html>>, accessed on November 18, 2005.

(2.5%) per annum (utilized also in the UAF UDP Model) for the labor component of the coal price. This rate is consistent with the U.S national ten year historical average wage inflation as reported by the Alaska Department of Labor and Workforce Development.

Escalation of the transportation component of delivered coal price in the UDP Model is forecasted based on the previously discussed projection of UAF's delivered price of fuel oil.

### ***Natural Gas Price Forecast***

While there is currently no significant production of natural gas in close proximity to Fairbanks, several sources of supply are expected to be available to the area within the next decade. With negotiations in the late stages between Alaska state officials and the North Slope oil and gas producers, an Alaska gas pipeline south from the North Slope appears likely—and in all cases the pipeline route is expected to pass near Fairbanks. Local gas in the Nenana Basin is also currently being explored, with producers predicting potential reserves could be available for delivery to the local market by FY2008.

UAF currently does not consume natural gas in its central plant, but has had conversations with and a contract offer from Fairbanks Natural Gas (FNG). UAF staff expects that natural gas supply delivered to the University can be contracted at a price seventeen percent (17%) below the price of fuel oil. The FNG gas supply would be trucked to Fairbanks as liquefied natural gas (LNG) where it would be vaporized and delivered to UAF through a local gas pipeline distribution system. It is presumed that future availability of either North Slope or Nenana Basin natural gas supplies in the Fairbanks area would result in the discontinuation of the trucked LNG supply source.

In the Model, the price for natural gas delivered to UAF is calculated using the EIA's 2004 twenty (20) year forecast for natural gas delivered to the East North Central (Chicago) less \$1.00. The price in the Model represents the expected long-term price for gas at the expected delivery point of North Slope gas, less \$1.00 of transportation differential back to Alaska.<sup>8</sup>

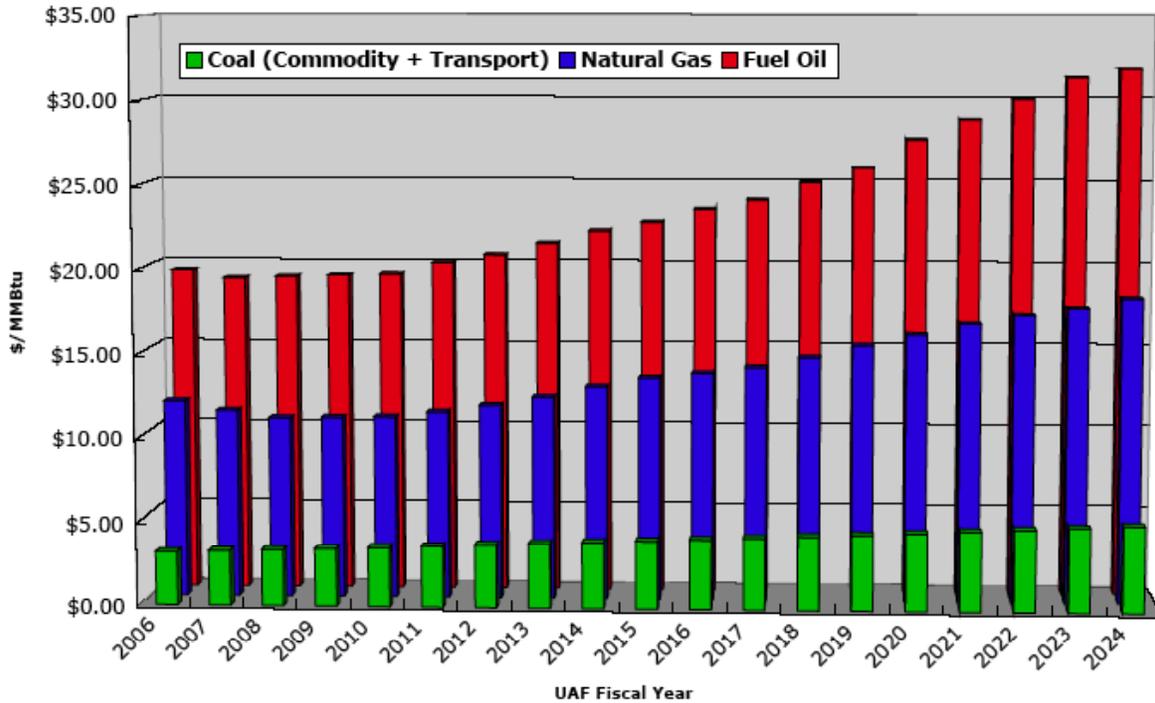
Calculations of the forecast for fuel oil, coal and natural gas commodity delivered to UAF used in the UDP Model, as well as a comparison of the fuel prices, converted into costs per MMBtu are shown in Table 4 and Figure 9 below:

**Table 4 UAF Commodity Price Forecasts**

FY	Coal Price per Ton			Natural Gas per Mcf	Fuel Oil per Gallon	Price per MMBtu			Fuel Oil Less 17%
	Coal Price	Coal Transport	Total Price			Total Coal	Natural Gas	Fuel Oil	
2006	\$40.25	\$8.61	\$48.86		\$2.23	\$3.13		\$18.58	\$15.42
2007	\$41.34	\$8.76	\$50.10	\$11.89	\$2.34	\$3.21	\$11.83	\$19.48	\$16.16
2008	\$42.45	\$8.96	\$51.41	\$11.33	\$2.28	\$3.30	\$11.28	\$19.03	\$15.79
2009	\$43.60	\$9.16	\$52.75	\$10.89	\$2.29	\$3.38	\$10.83	\$19.12	\$15.87
2010	\$44.78	\$9.36	\$54.13	\$10.94	\$2.31	\$3.47	\$10.88	\$19.21	\$15.94
2011	\$45.99	\$9.61	\$55.59	\$10.99	\$2.31	\$3.56	\$10.93	\$19.29	\$16.01
2012	\$47.23	\$9.85	\$57.07	\$11.32	\$2.40	\$3.66	\$11.26	\$19.98	\$16.58
2013	\$48.50	\$10.11	\$58.61	\$11.75	\$2.46	\$3.76	\$11.69	\$20.47	\$16.99
2014	\$49.81	\$10.37	\$60.18	\$12.25	\$2.54	\$3.86	\$12.19	\$21.20	\$17.60
2015	\$51.16	\$10.63	\$61.79	\$12.90	\$2.63	\$3.96	\$12.83	\$21.95	\$18.22
2016	\$52.54	\$10.91	\$63.45	\$13.48	\$2.70	\$4.07	\$13.41	\$22.50	\$18.68
2017	\$53.96	\$11.19	\$65.14	\$13.76	\$2.80	\$4.18	\$13.69	\$23.30	\$19.34
2018	\$55.41	\$11.50	\$66.91	\$14.14	\$2.87	\$4.29	\$14.07	\$23.88	\$19.82
2019	\$56.91	\$11.80	\$68.71	\$14.75	\$3.00	\$4.40	\$14.68	\$24.97	\$20.72
2020	\$58.45	\$12.17	\$70.61	\$15.49	\$3.10	\$4.53	\$15.42	\$25.84	\$21.45
2021	\$60.02	\$12.50	\$72.53	\$16.17	\$3.30	\$4.65	\$16.09	\$27.52	\$22.84
2022	\$61.64	\$12.85	\$74.50	\$16.83	\$3.45	\$4.78	\$16.74	\$28.73	\$23.85
2023	\$63.31	\$13.21	\$76.52	\$17.35	\$3.60	\$4.91	\$17.26	\$29.99	\$24.89
2024	\$65.02	\$13.52	\$78.54	\$17.79	\$3.76	\$5.03	\$17.70	\$31.30	\$25.97
2025	\$66.77	\$13.86	\$80.63	\$18.38	\$3.82	\$5.17	\$18.29	\$31.79	\$26.39

<sup>8</sup> Calculation of the \$1.00 transportation differential was prepared in a report to Alaska officials by Econ One and reported in Petroleum News Vol. 10, No. 36 (September 4, 2005). Current interstate pipeline routes would result in a terminus for delivery of Alaska natural gas into mid-western lower 48 markets.

**Figure 9 UAF Delivered Commodity Price Forecast (\$ per MMBtu)**



***Purchased Electricity Price Forecast (GVEA)***

Forecasted prices for purchased electricity in the UDP Model are based on a GVEA tariff rate for General Service customers (GS-2(2)). The GVEA rate applied to electricity pricing in the UBDP Model is based on GVEA’s proposed new GS-2(2), which includes a customer charge, a two-tiered energy charge, a power adjustment charge and a demand charge, with a minimum bill equal to the highest demand charge of the past twelve months.<sup>9</sup> The purchased electricity rate is escalated in the Model to reflect expected increases in price associated with

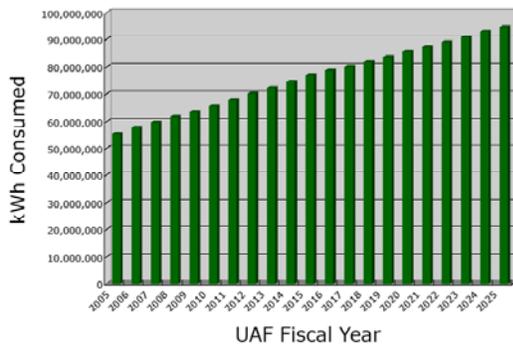
<sup>9</sup> In the matter of the Application of GOLDEN VALLEY ELECTRIC ASSOCIATION, INC. for authority to implement Simplified Rate Filing Procedures and Adjust Rates, Regulatory Commission of Alaska Docket No. U-04-33, “Golden Valley Electric Association, Inc.’s response to the Regulatory Commission of Alaska’s Order No. U-04-33(13),” filed October 21, 2005, Exhibit A, pp 2 and 13. The proposed new rate constitutes an approximately 5.1% increase over the current GS-2(2) rate. Additionally, GVEA is required to file a rate case with the Regulatory Commission of Alaska by September of 2007 per Golden Valley Electric Association, Inc.’s Application for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates, (R.C.A. 2005)

GVEA’s fuel source mix. Currently, GVEA’s generation resources are relatively balanced with respect to coal, fuel oil and natural gas-fired facilities. The UDP Model forecast of GVEA rates incorporates expected changes in commodity prices of these generation fuels pursuant to the specific percentage blend of resources utilized by GVEA.

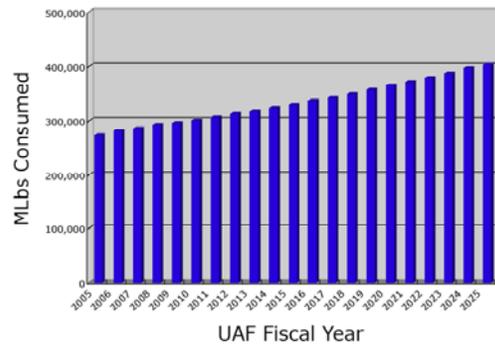
## SUMMARY OF PROJECTED UTILITIES DEMAND

The UDP Model is largely “driven” by the forecasts of final consumption utility service demands. These primary final consumption “commodities” are steam heating services, chilled water cooling services, and electrical services (for building, lighting and auxiliary loads (e.g., headbolt plug load)). The engineering analysis described below provides explanation of the derivation of the specific factors by which the loads were forecast taking account of specific building inventory by “use type” taken for the previously discussed campus growth forecast, and other technical factors considered in the forecasting of the final consumption commodity demands. **Figure 10** through **Figure 12** provide a summary of total forecasted utility service demands for each of the three primary commodities:

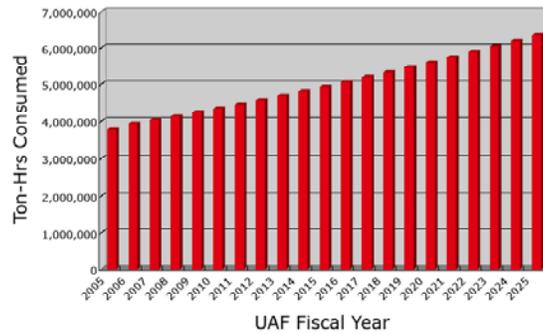
**Figure 10 UAF Campus Electric Demand**



**Figure 11 UAF Campus Steam Demand**



**Figure 12 UAF Campus Chilled Water Demand**



ENGINEERING ANALYSIS

*Peak Demand Model*

A data acquisition system installed in the Atkinson Plant in the late 1990s, known as the PI Data Archive System, provides a rich historical database of the essential information necessary to analyze energy consumption and peak demand, as well as issues relating to energy conversion and equipment efficiencies. The PI database tabulates peak energy use during the Base Year as follows:

**Table 5 UAF Utility Services Peak Demands (FY2005)**

	<b>Peak Service Demand</b>	<b>Peak Demand per Square Foot</b>
<b>Distribution Steam</b>	121 klbs/hr	47 BTU/hr/SF
<b>Electric Power</b>	9.7 MW	3.8 W/SF
<b>Chilled Water</b>	3060 Ton	1185 SF/Tons

Note: Base Year utility service provided to 2.58 million square feet.

In general, it is observed that the overall peak load density for steam and electric power is relatively low for a university campus in such an extreme climate. This indicates proper use of principles of energy conservation in facility design and operation.

In order to better project energy demand in an evolving campus, load factors are developed by building type (i.e., instructional, administrative, research and housing). Metered building steam and electric data, along with consideration of typical building design, served as guides in inferring actual load densities by building type.

The model of annual peak demand for low pressure (distribution) steam was constructed by isolating components of campus steam and electric power and assigning them individual load factors. Peak energy densities are developed by building type using the building square footage and type breakdown provided by UAF. Campus load components not tied directly to building types are identified for steam process loads, electrical station service, engine block heat, and a factor associated with overall campus lighting that is termed a “Daylight Factor.”

**Table 6 Summary Peak Demand (FY2005), By Identified Service Requirement**

<b>Building Consumption Peak Loads</b>		
<b>Building Type</b>	<b>Steam Demand</b>	<b>Electric Demand</b>
Instructional	40 BTU/hr/SF	3.25 W/SF
Administrative	30 BTU/hr/SF	2.25 W/SF
Research	55 BTU/hr/SF	4.50 W/SF
Housing	30 BTU/hr/SF	2.25 W/SF

<b>Campus Service Peak Loads</b>		
<b>Service Type</b>	<b>Steam Demand</b>	<b>Electric Demand</b>
Process Steam	20% of Total Distribution	
Station Service		12% of Total Distribution
Block Heat Load		10% of Total Campus
Lighting Factor		2% of Total Campus

The “process steam” component includes domestic hot water, humidification, cooking and other process uses along with distribution losses. These are largely unmetered loads. The “station service” component corresponds to electric demand within the Atkinson Plant for operation of the pumps, fans, and auxiliaries necessary for plant production activities. These are

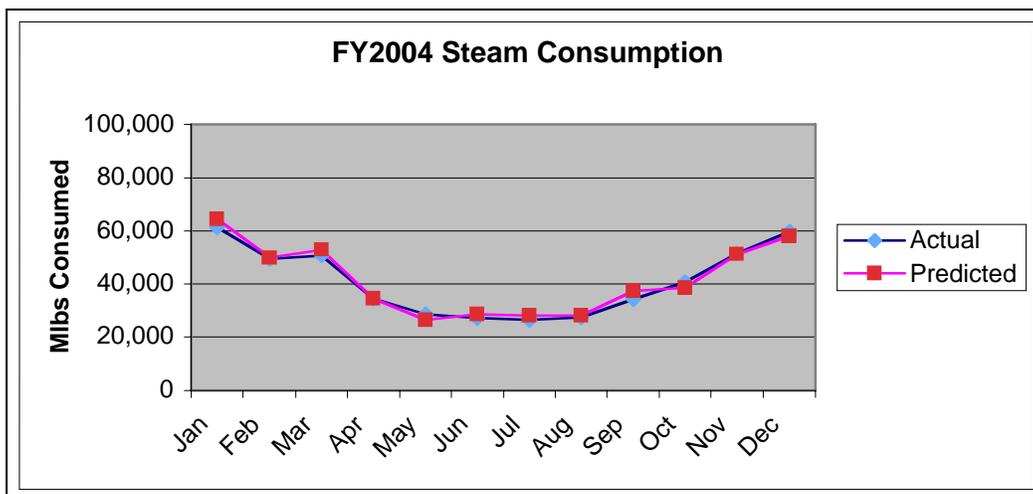
metered loads that are included in the PI database. Engine block heat is a significant component of wintertime electrical demand and is a metered load. The lighting factor was constructed to account for additional campus electric demand that is independent of specific buildings: overall campus lighting of roadways, pedestrian corridors, and building exteriors.

### ***Annual Consumption Model***

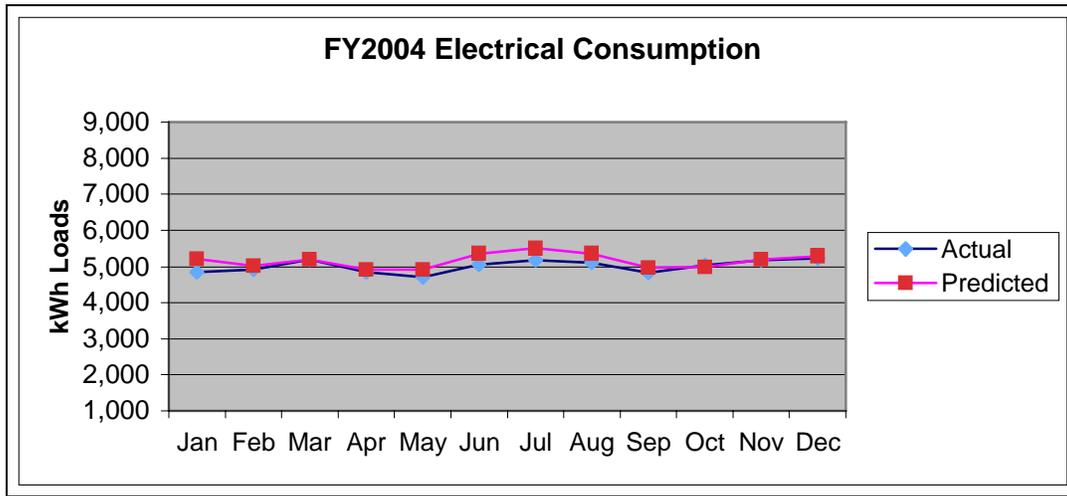
A quantitative model based on peak historical demand, building square footage by type, heating and cooling degree days, number of daylight hours, and estimated hours of occupancy was constructed to project monthly energy consumption. Model results were compared with historical PI data. Based on these comparisons, both load factors and hours of operation were adjusted to achieve relatively close calibration between the model and actual observed loads. Annual results for steam and electric consumption are shown in Figure 13 and Figure 14 below.

It is important to recognize that the model predicts energy consumption for each hour of an average occupied and unoccupied day of each month. These average days are summed to provide monthly steam Klbs and electric MWH total consumption values, which are compared to the actual recorded data in the University’s PI database as shown in Figure 13 and Figure 14 below.

**Figure 13 UAF Monthly Steam Consumption, Actual Consumption Comparison to UDP Modeled Consumption**



**Figure 14 UAF Monthly Electrical Consumption, Actual Consumption Comparison to UDP Modeled Consumption**



***Steam Distribution Model***

A model of the pressure drop through the existing utilidor steam piping system at various flow rates was constructed to evaluate the effect of building load growth on campus distribution. Steam flow to the WR was given particular attention given current pressure shortfalls under peak load conditions. The Excel model uses the Babcock formula method of computing pressure drop with pipe diameter, flow, and specific steam volume. Maximum peak wintertime pressure at the origin (Atkinson Plant) is constrained by the maximum extraction pressure from existing steam turbine generator 3 at 25 psig.

A drawing representing steam service to WR is shown in the Technical Appendix - Section 2. As the load approaches 40 Mlbs/hr, the calculated pressure drop along the pipeline from the Atkinson Plant to WR approaches 15 psig, meaning resultant pressure at the buildings on WR has fallen to approximately 10 psig. As a circumstance of the regulators and heat exchangers in these buildings design for 15 psig steam service, maintaining building setpoints becomes problematic. The predicted distribution pressure drop is within fifteen percent (15%) of observed pressure loss for service to the WR.



**THE UNIVERSITY OF ALASKA FAIRBANKS**  
**2005 UTILITY DEVELOPMENT PLAN**  
**SECTION IV: STRATEGY FORMULATION AND NET PRESENT VALUE RESULTS**

STRATEGY FORMULATION AND DEFINITION

The methodology utilized in the *2005 Utility Development Plan* considers three distinct strategies (with seven sub-options) to meet the present and future utility demands of UAF. These strategies were defined by the UDP Project Team with the assistance of UAF facilities staff, and differ with respect to specified equipment, timing of installations, purchased fuel commodity used, and physical location of new utility infrastructure development.

The strategies range from a fully centralized plant that maximizes the use of coal for both steam and electric production, to individual building boiler heating systems (“stand alone”) that are not connected to the centralized system. Alternative systems are specified to utilize either fuel oil or natural gas for heating, and to supplement UAF’s self-generated electricity production capability with purchases from a third-party utility service provider. For each strategy, the engineering analysis defines the utility systems, its components, and associated capital cost (including the cost for each building to convert to DES service). These analyses are driven by the utility service load consumption forecast, which is identical for all strategies. The strategies are then defined, tested, and adjusted accordingly in order to meet these loads forecasted for UAF for the twenty-year study period.

Table 7 shows in general terms how utility services demands for the UAF LC and the WR campus are to be met in each of the strategies. The three strategies are structured to achieve different objectives. The goal in Strategy 1 is to minimize the *upfront initial capital investment* that is required for UAF to be able to satisfy future utility demands of the campus. Strategy 2 is also designed to minimize capital investment, with a simultaneous goal to minimize the number of “stand alone” heating systems that operated independent of the centralized DES system, recognizing the required individual maintenance and operational support and shorted expended

life of the “stand alone” equipment. The goal of Strategy 3 is to construct a durable coal fuel-based DES utility system that will support the demands of the UAF campus for decades to come with little additional future capital investment. All strategies have natural gas fuel as an alternative to retrofit existing fuel oil-burning steam production equipment, and Strategies 2 and 3 also consider the economic advantage of a central chiller plant facility versus “stand alone” cooling facilities in new building construction.

**Table 7 Utility Configuration for Strategies**

Strategy	Strategy Number	Strategy Name	<u>Lower Campus Utility Services</u>			<u>West Ridge Utility Services</u>		
			<i>Electricity</i>	<i>Heating</i>	<i>Cooling</i>	<i>Electricity</i>	<i>Heating</i>	<i>Cooling</i>
<b>Minimize Initial Capital Investment</b>	1	Stand Alone		New loads after 2015 served by individual building boilers	New loads after 2015 served by Individual Building chiller equipment		New Heating loads served by individual building boilers	New loads served by individual building chiller equipment
	1 (NG)	Stand Alone (with Natural Gas)						
<b>Minimize Long-Term Capital Investment</b>	2A	West Ridge Satellite Heating Plant	New loads served through GVEA purchases	New loads served after 2008 by WR Satellite Heating Plant	New loads served by either current system or new Chiller Plant	New loads served through GVEA purchases	New loads served after 2008 by WR Satellite Heating Plant	New loads served by either current system or new Chiller Plant
	2A (NG)	West Ridge Satellite Heating Plant (NG)						
	2B	West Ridge Satellite Heating Plant w/ Chiller Plant						
	2B (NG)	West Ridge Satellite Heating Plant w/ Chiller Plant (NG)						
<b>Invest in Coal at Current Atkinson Utility Center</b>	3A	Coal Boiler (150Mlb) Plant and New 20 MW Turbine	New loads served through GVEA purchases until New Turbine installed	New loads served by upgraded Atkinson Plant	New loads after 2015 served by Individual Building Chiller Equipment	New loads served through GVEA purchases until New Turbine installed	New loads served by upgraded Atkinson Plant	New loads served by Individual Building Chiller Equipment
	3A (NG)	Coal Boiler (150Mlb) Plant and New 20 MW Turbine (NG)						
	3B	Coal Boiler (100Mlb) Plant and New 10 MW Turbine						
	3B (NG)	Coal Boiler (100Mlb) Plant and New 10 MW Turbine (NG)						

## ***Strategy 1 - Minimize Capital Investment***

### ***Stand Alone Equipment***

Strategy 1 is designed to meet future campus utility needs at the lowest initial capital cost outlays to the University. The strategy maximizes the use of existing plant and utility infrastructure to meet campus steam demand, and relies on the University's ability to purchase electricity from a third party (GVEA) to meet growing electric power demands.

Strategy 1 relies on a several primary assumptions (or strategic decisions) in formulating requirements to meet the campus' future utility needs. First, Strategy 1 assumes all existing Lower Campus and West Ridge heating loads continue to be served under the current coal/fuel oil mix in the Atkinson Plant. In the natural gas sub-option (and this is true for all strategies) the existing fuel oil boilers (Boilers 3 and 4) in the Atkinson Plant are re-fired with natural gas capability, providing for service of heating loads via natural gas fired boilers instead of fuel oil. Either way, in Strategy 1 the current existing campus heating and cooling load demand is supplied by production from the Atkinson Plant.

The next assumption taken in Strategy 1 is that existing power generation capacity remains available to serve existing electricity loads, but all new electricity loads from growth in LC and WR are met through purchases from GVEA. The UDP Model assumes a reasonable expected rate for GVEA calculations of future purchased electricity costs based on GVEA's proposed new standard large commercial customer tariff rates (Tariff GS-2(2)), escalated for anticipated price increases.

Finally, Strategy 1 assumes all future LC heating loads from FY2006 through FY2015 are served using coal/fuel oil (or natural gas) fired steam produced from the Atkinson Plant. However, in FY2016 through FY2025, capacity constraints require additional LC heating loads to be served by fuel oil (or natural gas) boilers installed in individual buildings. In contrast, all

additional WR heating loads are served by fuel oil (or natural gas) boilers installed in individual buildings.<sup>10</sup> Cooling demands in LC are satisfied through FY2015 by the centralized cooling system and afterwards by chiller equipment installed in individual buildings. New cooling demands in WR are satisfied by “stand alone” chiller equipment installed in individual buildings.

Strategy 1 attempts to minimize initial capital requirements costs, with investment outlays providing for “stand alone” boilers in newly constructed facilities throughout the twenty years modeled. However, there are significant replacement costs of these boiler units (expected after fifteen years of service) included in the life-cycle cost model as well as periodic maintenance costs. Newly installed “stand alone” chiller units are also subject to replacement as are existing “stand alone” chiller units, both new and old will also require periodic maintenance. In the natural gas sub-option, Strategy costs include capital expenditures for a pipeline for natural gas transportation to WR “stand alone” boilers.

## ***Strategy 2 – Minimize Long-Term Capital Cost***

### ***West Ridge Satellite Heating Plant***

Strategy 2 focuses on efficiently supplying future WR and a portion of LC steam requirements through a new satellite heating plant on the WR. Strategy 2 incurs more initial capital expenditures than Strategy 1, but balances initial capital costs with lower life-cycle production, distribution, maintenance and capital renewal costs. A variant of Strategy 2 considers installation initially of a chiller plant with 2000 tons of single effect steam absorption chilling, with additional steam capacity added in later years to replace existing “stand alone”

---

<sup>10</sup> “Station Service” energy requirements—defined as the energy requirements for production and operation of the boilers, turbines, water plant and all auxiliary utility plant equipment—are treated as part of the costs of utility services within the UDP analysis, and are modeled to follow LC heating demand growth in Strategy 1.

chiller equipment in WR as well as provided cooling for all new facilities. This variant thus initially includes the chiller plant, a chilled water distribution system, and costs to convert and connect existing stand alone cooling equipment to the new cooling loop.

Similar to Strategy 1, Strategy 2 assumes existing LC and WR heating loads continue to be served under the current coal/fuel oil mix in the Atkinson Plant, with the same Boiler 3 and 4 natural gas re-firing Strategy sub-option analyzed. However, the existing boiler and steam distribution capacity is unable to satisfy the new peak heating load requirements in both the WR and LC, and these additional peak loads are satisfied from boilers in the new WR satellite heating plant.<sup>11</sup>

As in Strategy 1, all existing UAF power generation capacity is assumed capable of serving current campus loads, but all new electrical service requirements for both LC and WR are met either through purchases from GVEA or by the existing diesel engine generator (DEG)—with backup electric reliability requirements provided either by GVEA electric service or DEG generation—depending on the relative economics of the two electric supply sources.

### ***Strategy 3 - Invest in Coal at Atkinson Utility Center***

#### ***Coal Plant addition to Atkinson Plant and New Turbine Generator***

Strategy 3 proposes an increase of coal boiler steam production and electricity self-generation capacity to serve the majority of future campus utility growth from the existing Atkinson Plant location. Strategy 3 incurs the greatest capital requirements, but provides the least expensive long-run production, distribution, maintenance and capital renewal costs.

---

<sup>11</sup> “Station Service” energy requirements in Strategy 2 will scale with total steam production from the two separate plants.

A new steam line would be installed relatively early in the Strategy 3 plan to solve increasing pressure deficiencies associated with growth on the WR. The UDP proposes construction of a new walking utilidor from the vicinity of Lola Tilly to just west of Student Rec. A new 10" steam line, designed for operation at 125 psi, would be routed from the plant headers to Lola Tilly through the existing utilidor, from Lola Tilly to the Student Rec in the new utilidor and then back into the existing utilidor from Student Rec to a pressure regulating station located at approximately The Geist Museum on the WR. Arrangement of the line so that it can be fed from either the 25 psi turbine backpressure header or from a pressure regulator off the 600 psi boiler header enables supplemental steam to be fed to WR in the near term without diminished turbine output. In Strategy 3, all growth in campus electric demand will be served in the near term by generation from a newly installed 20 megawatt (MW) steam turbine at the Atkinson Plant installed in FY2009. Extraction ports on the new steam turbine will be designed to allow discharge at higher pressure. Upgrades to the existing 25 psi steam distribution system are included in the plan to allow distribution at higher pressure (up to 75 psi) under periods of high winter demand. In this strategy, the backup electric reliability requirements will be provided alternatively by GVEA service or generation from the existing diesel engine generator (DEG), depending on the economically preferred source of supply. A sub-option evaluates installing a new 10 MW steam turbine generator for paralleled operation with the existing steam turbine generator and reducing the size of the coal fired boiler capacity to 100Mlbs/hr instead of the more expensive new 20 MW generator and 150Mlb/hr coal fired steam capacity equipment.

As in Strategy 1 and in Strategy 2, cooling demands in LC are satisfied through FY2015 by the centralized cooling system and afterwards by air-cooled, electric-driven chiller equipment installed in individual buildings. New cooling demands in WR are satisfied by air-cooled, electric-driven chiller equipment in individual buildings. The operating cost of steam absorption chilling is substantially less than air-cooled, electric-driven alternatives due to the use of inexpensive summertime turbine exhaust steam and coincident reduction in expensive campus electric power demand. Absorption chilling is clearly a good match for the UAF campus

cogeneration utility. In general however, the life cycle economics are not as promising. Annual consumption of cooling on campus is driven by the number of hours of ambient temperatures above 55 degrees Fahrenheit. In the UDP Model, the average annual consumption of cooling on the WR is not high enough to generate the magnitude of operating cost savings necessary to justify the substantially higher capital costs associated with an absorption chilling plant. The situation is less economical if installation of an extended chilled water piping distribution system must also be considered.

Strategy 3 is the most capital intensive of the modeled strategies, both in initial capital costs and total costs over the twenty year life of the project, with the purchase of a new steam turbine generator and construction of a facility to house the turbine (two year project), as well as the construction and installation of a coal boiler plant addition to the Atkinson Center and related facilities (four year project), and improvements to the campus steam distribution system. This option does provide substantially lower annual fuel costs and provides a useful life well in excess of the twenty (20) year planning time frame. The non-economic benefits include centralized utility control, independence from third-party providers and improved system reliability control.

## SUMMARY OF CAPITAL COSTS

Capital costs have been estimated based on current costs of installation, replacement and maintenance. These current costs have been increased by a factor of thirty percent (30%) as an estimate of the full project cost once implemented. Capital items primarily pertain to one of five different groups of assets and are characterized by their function. These groups are the electric, steam, chilled water, and domestic water production and distribution systems, as well as, the general utility department assets serving multi-function needs.

For each of the capital items within these groups a useful life is estimated and where required, a period of years after which replacement of the capital asset (i.e., capital renewal) will have to be performed. The useful life estimate is the basis upon which annual depreciation expense is calculated, and also is a basis upon which the financing period is determined. Capital items comprising the Common Capital Asset Renewal and Major Maintenance range from a useful life of ten years to as much as thirty and forty years. For Strategy 1, the useful life of items ranges from ten to fifteen years; Strategy 2, ten to twenty-five years (with the Utilidor Extension being forty years); Strategy 3, ten to forty years. Figure 15 shows the major components of capital costs for the first ten years for the Common Capital investments as well as the particular strategy investments. This chart provides a sense of the duration over which some of these capital investments are expected to occur. The current capital costs are inflation-adjusted for the year in which they are to occur and Financial Appendix - Section B shows the current capital costs as well as the inflation-adjusted costs for the Common and Strategy Capital costs.

**Figure 15 UAF UDP Timeline of Major Capital Investments for All Strategies**

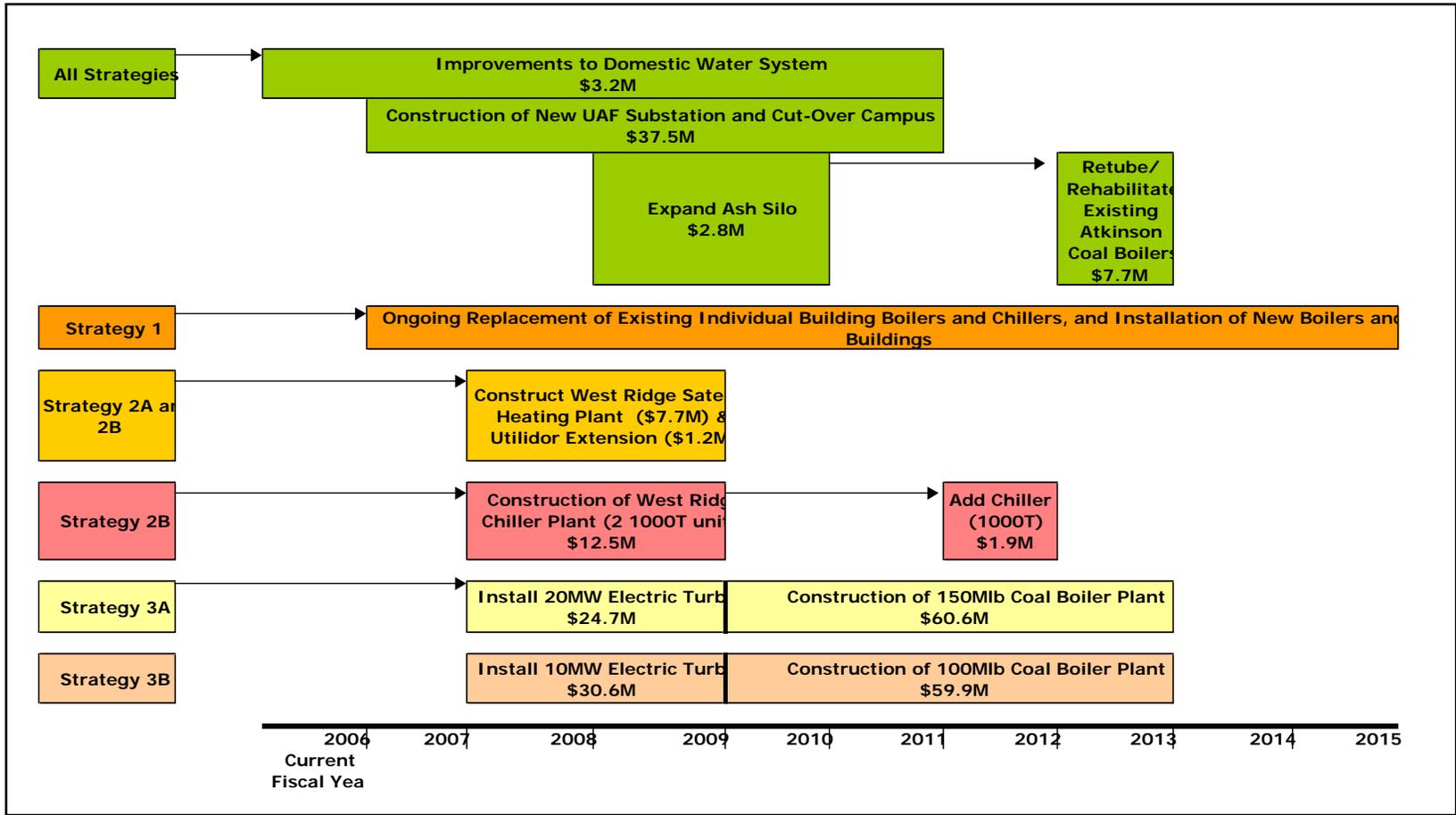


Figure 16 shows the capital expenditures as they occur through time for the common capital investments as well as the particular strategy investments.

### Figure 16 UAF Annual Capital Expenditures for Strategies

(Each Strategy Cost Includes Upgrades and Major Maintenance Costs Common to All Strategies)

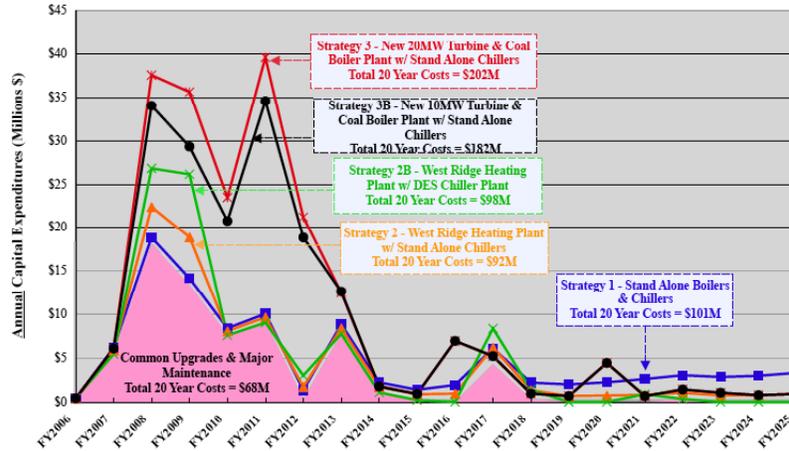
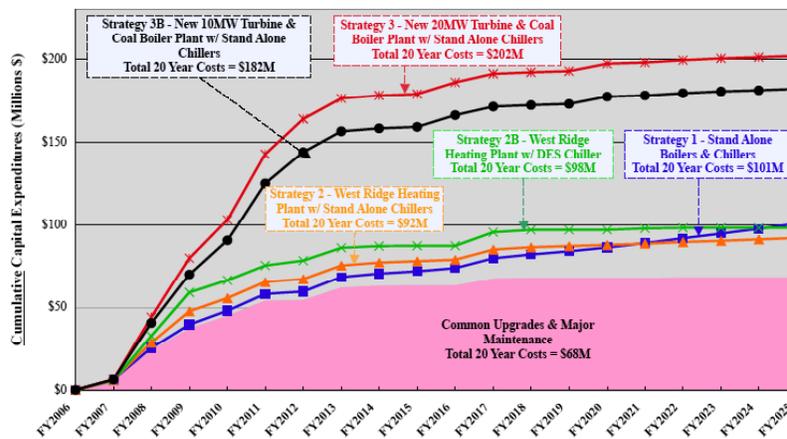


Figure 17 shows the same capital expenditures stated as the cumulative investment expenditures through time.

### Figure 17 UAF Cumulative Capital Expenditures for Strategies

(Each Strategy Cost Includes Upgrades and Major Maintenance Costs Common to All Strategies)



Financial Appendix - Section C shows the annual depreciation expenses for each of the asset groups. These schedules also include capital renewal/depreciation expenses for current Utilities Division assets that have not previously been included as part of the Utilities Division expenses. These current expenses are included as part of the capital renewal/depreciation expenses in all strategies. Depreciation expenses for the general plant assets are allocated to the final utility commodity products in the same manner as other general operating and maintenance expenses (See Section III for further description of this allocation methodology).

In considering the capital assets' expected useful life associated with the utility infrastructure that composes the Strategy (or Common Improvement/Renewal) investment, the debt financing of the required capital investments is modeled as follows:

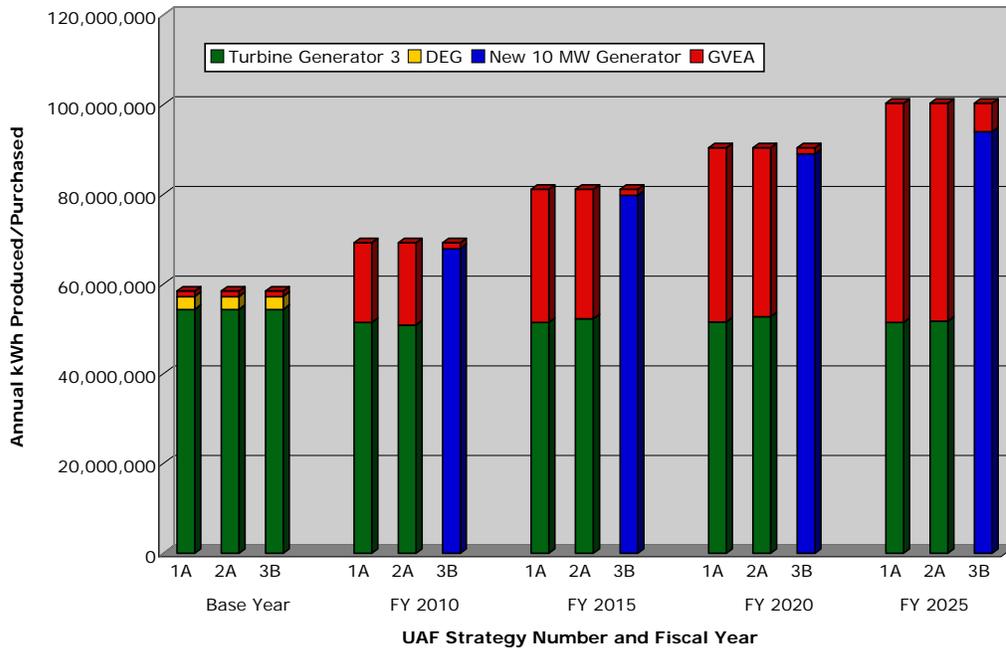
<b>Debt Financing Term (Years)</b>	<b>UAF Utility Systems Investment Strategy</b>
20	Common Improvements and Utility Asset Renewal
15	Strategy 1
20	Strategy 2
30	Strategy 3

It is assumed that bonds are issued for the required capital investments of each Strategy in five-year increments, and bond schedules are calculated separately between the Common Improvements/Renewal capital requirements and the individual capital requirements specified for each Strategy. The necessary debt funding is determined by calculating the interest earned on unexpended bond proceeds (during the five year scheduled capital project expenditure period), and applying that interest revenue as an additional source of funds to reduce the total required bond issue. Therefore, funds (bond proceeds) obtained through financing are somewhat less than the project capital amounts required for asset acquisition. Debt is assumed to be issued at an annual interest rate of five percent (5%), and interest earnings (on unexpended bond proceeds) are assumed to be earned at an annual interest rate of four percent (4%). Financial Appendix - Section D shows the annual capital expenditures for each strategy and the details related to the funding of those expenditures.

## ANNUAL PRODUCTION OUTPUT AND OPERATING COST BY STRATEGY

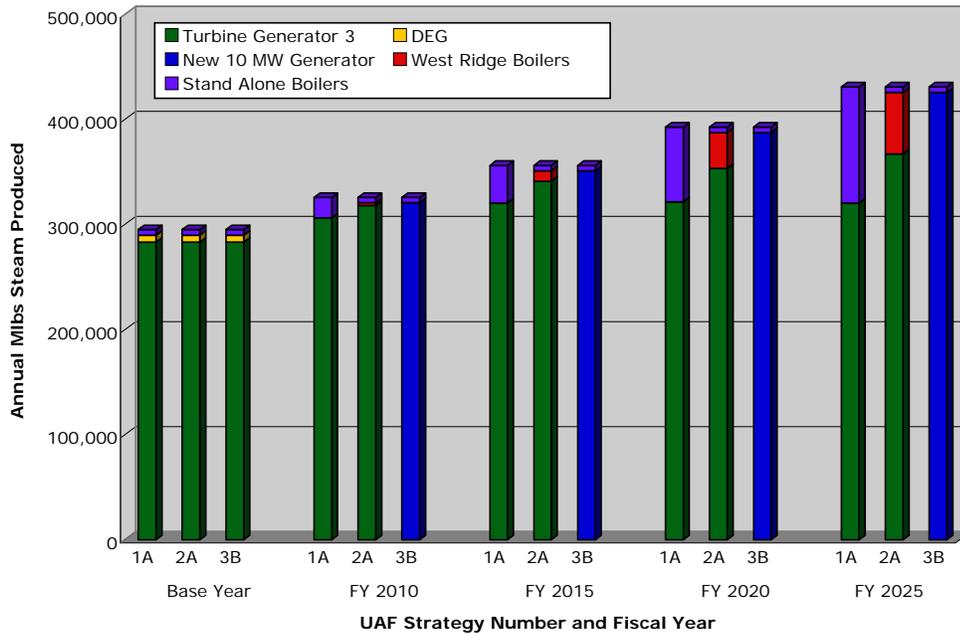
The individual Strategies meet the commodity service requirements of the UAF facilities with different “mixes” of self-production or purchased resources. The production mix associated with each of the different Strategies changes through time as well. Figure 18 demonstrates in five-year increments how the electric service requirements of the UAF campus are met with differing combinations of GVEA purchases, self-generation from the existing Turbine Generator 3 (in the Atkinson Plant), the new 10 MW turbine generator (for Strategy 3 only) and the existing DEG generator. Annual detail of operating costs associated with each of the strategies in implementation years is shown in Financial Appendix - Section E.

**Figure 18 Comparative Sources of Electricity Across Natural Gas Strategies**



Similarly, Figure 19 demonstrates the differences in the production of the campus' steam service requirements as between DES LP Steam and Stand Alone Steam boilers under the different Strategies through the same twenty-year Model period (in five year intervals). It is apparent that the production strategies will certainly result in different cost implications.

**Figure 19 Comparative Sources of Steam Across Natural Gas Strategies**



**PRO FORMA AND NPV RESULTS**

*Pro Forma*

The UAF Utilities Division, organized as a self-sustaining organization, must track its cash expenditures in order to effectively ascertain its actual cost of providing utility services to the UAF campus. These cash expenditures as well as the non-cash item of depreciation expense are summarized in its financial statements. These statements contain the cost categories that any similar ongoing concern would have and encompass five distinct categories:

1. Purchased Fuel Costs
  - a. Coal
  - b. Fuel Oil
  - c. GVEA Electricity
  - d. Natural Gas (*This cost is at present zero*)



2. Operating Expenses related to the production and distribution of electricity, steam, chilled water, and domestic water
3. Personnel Costs
  - a. Salaries
  - b. Benefits
  - c. Travel (This cost is at present negligible)
4. Debt Service
  - a. Interest on debt
  - b. Principal payments associated with debt
5. Depreciation (non-cash expense)

These operational costs for the Utilities Division are part of the UDP Model and as inflation-adjusted costs are contained within the Pro Forma results shown in Financial Appendix - Section G. Inflation adjustment methods for purchased fuel costs are discussed in Section III, Energy Market Analysis. Production and distribution operating expenses, travel and personnel salaries are inflation-adjusted at a rate of 2.5 percent. Personnel benefits are inflation-adjusted at a rate of twenty-five percent (25%) through FY2009 after which they are inflation-adjusted at a rate of five percent (5%). Debt service payments and depreciation expenses are stated at actual cost.

The actual expenses of the UAF Utilities Division for FY2005 are stated as a part of the Pro Forma in order that a comparison can be made between them and the results obtained by the UAF UDP Model. As can be seen Table 8, the UAF UDP Model closely mirrors the UAF Utilities Division's actual expenses.

**Table 8 Comparison of UAF UDP Base Year Costs to Actual Costs**

<b>Operating Expenses</b>	<b>Actual 2005</b>	<b>FY 2005</b>	<b>Variance</b>	<b>% Variance</b>
<i>Fuel Cost</i>				
Coal Commodity	\$2,538,366	\$2,700,786	\$162,420	6.4%
Coal Transport	\$531,838	\$565,747	\$33,909	0.06%
Coal Ash Hauling	\$83,800	\$89,219	\$5,419	0.06%
<b>Total Coal Cost</b>	<b>\$3,154,004</b>	<b>\$3,355,753</b>	<b>\$201,749</b>	<b>6.4%</b>
Fuel Oil Commodity	\$2,621,563	\$1,819,608	(\$801,955)	30.6%
GVEA Purchased Electricity	\$383,632	\$294,983	(\$88,649)	23.1%
Natural Gas Commodity	\$0	\$0		
<b>Total Fuel Cost</b>	<b>\$6,159,199</b>	<b>\$5,470,344</b>	<b>(\$688,855)</b>	<b>11.2%</b>
<i>Operations &amp; Maintenance</i>				
Electric Steam & Chilled Water	\$980,064	\$1,007,085	\$27,021	2.8%
Water & Sewer	\$574,878	\$570,934	(\$3,944)	0.7%
<b>Total Operations &amp; Maintenance</b>	<b>\$1,554,942</b>	<b>\$1,578,019</b>	<b>\$23,077</b>	<b>1.5%</b>
<i>Salaries Benefits &amp; Travel</i>				
Electric Steam & Chilled Water	\$2,144,735	\$2,126,680	(\$18,055)	0.8%
Water & Sewer	\$143,782	\$139,469	(\$4,313)	3.0%
<b>Total Salaries Benefits &amp; Travel</b>	<b>\$2,288,517</b>	<b>\$2,266,149</b>	<b>(\$22,368)</b>	<b>1.0%</b>
<i>Debt Service</i>				
Interest Expense	\$0	\$499,454	\$499,454	N/A
Principal Expense	\$0	\$885	\$885	N/A
<b>Total Debt Expense</b>	<b>\$44,746</b>	<b>\$500,339</b>	<b>\$455,593</b>	<b>N/A</b>
<b>Total Operating Expense Without Depreciation</b>	<b>\$10,027,405</b>	<b>\$9,814,851</b>	<b>(\$212,554)</b>	<b>2.1%</b>
<i>Depreciation</i>				
Depreciation Expense	\$24,061	\$2,412,311	\$2,388,250	N/A
<b>Total Operating Expense</b>	<b>\$10,051,466</b>	<b>\$12,227,162</b>	<b>\$2,175,696</b>	<b>N/A</b>

The variances that are exhibited for fuel costs are due to the change the UAF Utilities Division initiated in FY2006 for dispatching its equipment to meet electric and steam demand as compared with FY2005. The UAF UDP Model is structured to follow the dispatch model in effect in FY2006.

Other variances are shown in the debt and depreciation expenses and these are further discussed in Section VI. Estimated revenues are also contained in the Pro Forma and a discussion of how these have been estimated is also addressed in Section VI.

UAF “transfer” account balances the Utilities Division budget (excluding the non-cash item of depreciation expense), and is essentially the difference between the UAF Utilities Division operating expenses and its directly billed revenues. In FY2005 the “transfer” account revenues were approximately sixty-five percent (65%) of the total operating expenses. By FY2025 in the UAF UDP Model the “transfer” account provides approximately seventy-five percent (75%) of the total operating expenses as new sources of direct billing have not been structured into the Model.

## NPV Results

The UDP Model analysis produces results that forecast operating expenses and revenues for each of the Strategies. Those operating expenses and revenues are summarized in the form of a *Pro Forma* statement of annual cashflows for each of the Strategy, which are presented in Financial Appendix - Section G. As was discussed in the preceding section, the revenue requirements for operation of the UAF Utilities Division are balanced each year by “Transfer” account revenues.

The *Pro Forma* analyses adopt this revenue account balancing of cashflow with respect to all forecasted operating expenses including debt costs (principal and interest), but exclude the “depreciation” costs associated with the “fully-loaded life-cycle” cost concepts previously discussed. In the *Pro Forma* presentation these depreciation costs—required for accumulation of an accumulated fund account balance to provide for the replacement and renewal of capital assets at the end of its expected useful life—are shown as a net revenue shortfall in each model year.

Importantly, this treatment of revenue account balancing of cashflow also requires that the Model’s analytic results be evaluated in the context of the differences in the *total operating expenses*, rather than net cashflow balances. The economic comparison of each Strategy’s

operating expenses can be stated as a total operating cost—but a more useful economic comparison of those operating results is as a *discounted NPV of operating costs*. That is, operating expenses incurred closer to the present time are “weighted” more heavily than those incurred toward the end of the twenty year forecasted time period by a *discount rate* that provides an annual progression that discounts those future expenses. This common financial analysis tool recognizes the time-value of money. The discount rate that is chosen reflects an economic entity’s time preference for cash, and it is commonly asserted that a private entity’s discount rate will generally be higher than a public entity’s.

Thus, Table 9 provides a summary of Strategy results that states the undiscounted total costs and the net NPV of those costs at three different annual discount rates (i.e., 12%, 8% and 5%). Note that because the NPV is presented for operating *expenses*, the economic evaluation is a preference for the *lowest* NPV (i.e., exhibiting the minimization of discounted operating expenses). The NPV results are only a *component* of the economic evaluation of these Strategies, as other intangible and exogenous factors that are not captured by the strict financial modeling of costs must also be considered.

**Table 9 UAF UDP Total Operating Expenses and Associated NPVs for All Strategies**

Strategy	Total Costs FY2006 – FY2025	NPV of Costs at Selected Rates		
		12%	8%	5%
1 Stand Alone	\$511,231,296	\$157,657,485	\$219,978,647	\$293,016,871
2 West Ridge Boiler	\$519,627,751	\$160,842,864	\$224,168,553	\$298,318,450
2B West Ridge Boiler w/ Chiller Plant	\$529,310,189	\$164,001,249	\$228,595,401	\$304,145,794
3 Coal Boiler (150 Mlb) Plant & New 20MW Turbine	\$574,581,361	\$191,600,137	\$261,347,219	\$341,355,769
3B Coal Boiler (100 Mlb) Plant & New 10MW Turbine	\$551,085,175	\$181,204,707	\$248,083,950	\$325,160,352
1 Stand Alone (NG)	\$488,157,011	\$151,647,249	\$211,113,127	\$280,692,617
2 West Ridge Boiler (NG)	\$490,560,103	\$153,461,869	\$213,171,613	\$282,928,293
2B West Ridge Boiler w/ Chiller Plant (NG)	\$500,625,643	\$157,527,958	\$218,448,968	\$289,508,615
3 Coal Boiler (150 Mlb) Plant & New 20MW Turbine (NG)	\$560,756,966	\$183,801,407	\$251,978,394	\$330,551,024
3B Coal Boiler (100 Mlb) Plant & New 10MW Turbine (NG)	\$537,936,720	\$174,491,251	\$239,871,181	\$315,484,116

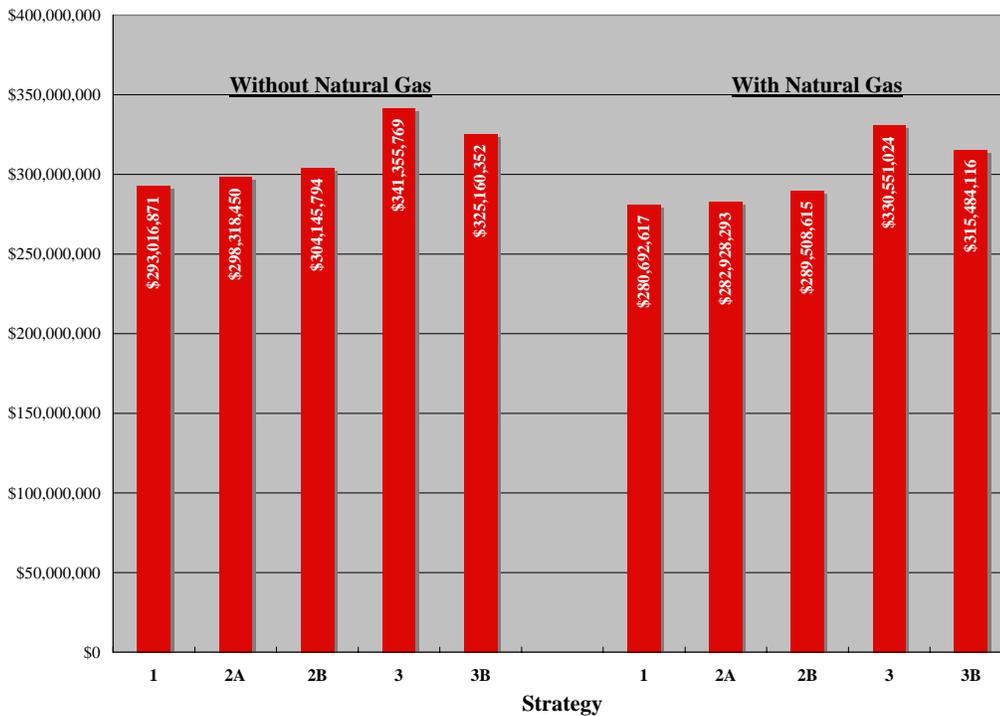
First, these results demonstrate a consistent preference for each of the Strategies with implementation of the natural gas fuel sub-option. Second, regardless of the discount rate utilized, Strategy 1 and Strategy 2 must be evaluated to produce *equivalent* economic results—even though there are several million dollars of difference in the NPV results as between each of those Strategies. This is a very important point. In the context of the kind of economic forecasting and evaluation represented by the UAF UDP Model, inaccuracies, approximations, and estimates inherent to such a model’s development conspire to prevent a level of “certainty” that justifies distinguishing and evaluating NPV results to the last dollar. These NPV results must be understood to provide more of an order of magnitude, rather than a precise dollar cost forecast.

Finally, the general conclusion must be drawn that *within the time period evaluated* (i.e., twenty years), the expanded coal plant investment will produce higher total operating costs. The evaluated costs of Strategy 3 must be interpreted as greater than the Strategy 1 and Strategy 2 costs—even recognizing the economic accuracy limitation of the Model’s forecast. However, as

stated above and discussed subsequently, the strict NPV economic results must also be interpreted in the context of other considerations and risk factors which may suggest that *in spite of the strict NPV evaluation, Strategy 3 may still be a viable long-term utilities system Strategy for UAF.*

Figure 20 summarizes the NPV results (utilizing the 5% discount rate), and groups the Strategies as between those excluding and those implementing the natural gas fuel sub-option.

**Figure 20 UAF UDP 20 Year NPV of Operating Expenses by Strategy Discounted at 5%**



**THE UNIVERSITY OF ALASKA FAIRBANKS**  
**2005 UTILITY DEVELOPMENT PLAN**  
**SECTION V: RISK ANALYSIS AND SENSITIVITY CASE RESULTS**

**SENSITIVITY CASE DEFINITION, SPECIFICATION AND RESULTS**

The UAF UDP models three Strategies. Each of those Strategies includes sub-options that analyze the impact of natural gas boiler firing in lieu of existing fuel oil technology, and the feasibility of a steam absorption chilled water versus electric chilling equipment. These analyses assume various energy price forecasts and growth rates which are applied to each of the three basic Strategies.

An extremely important component of the analyses that may dramatically impact model results relates to the relative cost of alternative fuel resources. For example, a significantly lower cost of fuel oil with relatively higher coal and natural gas costs will modify the comparative results of the three basic Strategies.

The basic purpose of the analyses performed by the UAF UDP Model is to provide a comparison of the net economic benefit of specific alternative configurations of utility infrastructure and equipment in a long-term performance model. In order that the results obtained are robust, there must also be given consideration of the “sensitivity” of the model results to the assumptions that serve as principal model drivers (i.e., fuel prices and campus growth).

***Energy Price Sensitivity Analyses***

Under all foreseeable circumstances Fairbanks energy consumers—including UAF—will be “price takers” who are unable to influence the direction or magnitude of price movements in the local energy markets. That is, with the exception of the rural industrial consumers

(principally mines), no energy consumer in the relevant geographic market will impact prices by expansion or reduction in its energy demands for any available fuels (coal, fuel oil, natural gas and electricity).<sup>12</sup>

Coal is projected to have no significant increase in consumption, and the Usibelli Mine is understood to possess adequate long-term supplies to meet all foreseeable local demand requirements. General price inflation, and potentially limited transportation cost increases (likely tied to diesel fuel costs), are the only factors anticipated to influence the delivered price of coal to UAF. Currently, coal transportation costs comprise approximately fifteen percent (15%) of delivered coal costs to the University. Thus, it would require relatively extraordinary changes in diesel fuel costs to influence delivered coal costs.

Moreover, the University has experienced relatively stable coal prices for many years, and currently has a long term contract in place that assures price stability (except with respect to potential transportation cost increases) that allows coal to be an assured “base load” fuel. Stated differently, it is likely that other fuel costs will move relative to coal, not that coal prices will move relative to the other fuels.

The North Pole Refinery (owned by Flint Hills) has executed a long-term contract with the State for its royalty-in-kind oil, assuring that for at least the next decade it will have a stable source of crude for refining. The current State of Alaska fuel purchase contract (under which UAF has been purchasing its fuel oil supplies) ties forecasted price increases to West Coast (lower 48) market price projections, which are driven primarily by international petroleum market conditions. There is no basis to presume that there will be any lessening of the scarcity of petroleum products in these international markets. The only likely scenario is for petroleum prices to increase more rapidly than is anticipated for other commodities over the next twenty (20) years.

---

<sup>12</sup> It should be noted that UAF has the ability to participate and intervene in all rate case filings GVEA has with the Regulatory Commission of Alaska.

Natural gas prices are understood to be the most uncertain among the energy commodities prices in the Fairbanks geographic markets. The development of the Trans-Alaska Natural Gas Pipeline is looking more likely, but is far from assured. The development of the recently identified Nenana Basin natural gas resources is equally uncertain. UAF's proposed contract with Fairbanks Natural Gas is tied to fuel oil prices, and the ability to consistently deliver liquefied natural gas (LNG) for re-delivery to natural gas consumers is unproven.

Therefore, the primary fuel price "sensitivity" appears to be tied to the relative prices of fuel oil and natural gas, with the price of natural gas potentially "de-coupled" from the price of natural gas in the lower 48.

Likewise, Golden Valley Electric Association (GVEA) has a variety of uncertainties impacting its ability to assure any level of price stability. It currently obtains approximately forty percent (40%) its electricity from Chugach Electric Association under a long-term purchased power agreement (PPA) and delivered through the Northern Intertie. Importantly, those generation resources are principally natural gas fired and located on the State's west coast where available gas supplies are traded in much more competitive market environments.

Of GVEA's 228MW of total owned generation resources, 183MW consist of oil-fired generation (80.3%), 25MW of coal-fired generation (11%), with the remaining 20MW of generation capacity coming from GVEA's share of Bradley Lake's hydroelectric generation capacity.<sup>13</sup> A portion of GVEA's oil-fired generation capacity is provided under a long-term contract with Aurora Energy for electricity from its 27MW Delta Power Plant (formerly Chena Plant) and 36MW Zehnder Plant in Fairbanks. GVEA has also broken ground on an expansion of its North Pole Plant and expects an additional 60MW of naphtha-fired combined cycle generation to be online by December 2006.

---

<sup>13</sup> "GVEA at a Glance," <<http://www.gvea.com/about/ataglance.php>>, accessed December 8, 2005.

Thus, the preceding discussion of the volatility of fuel oil and natural gas prices vis-à-vis coal prices suggests that the existing generation resources relied on by GVEA are subject to relatively high risk of price variance from the base forecast utilized in the UAF UDP model. Add to this the circumstance that GVEA has thirty-five (35) years remaining in its contract with Chugach—and that GVEA’s plant-related costs account for approximately twenty percent (20%) of its total operating costs—it can be easily understood that the addition of new plant to GVEA’s supply mix to meet demand growth will further increase upward pressures on its delivered electric costs.

Given the circumstances just described, the UDP model incorporates the following sensitivity cases with respect to fuel prices.

*SENSITIVITY CASE 1* — Increasing GVEA electricity costs, with no change in forecasted fuel oil, natural gas or coal costs. This sensitivity case would be understood to require significant capital investment in generation, transmission and distribution plant by GVEA due to its inability to meet its load requirements with PPA contracts for generation resources. The price of GVEA electricity is increased five, ten and twenty percent (5%, 10 % and 20%) above the original forecasted GVEA electricity prices.

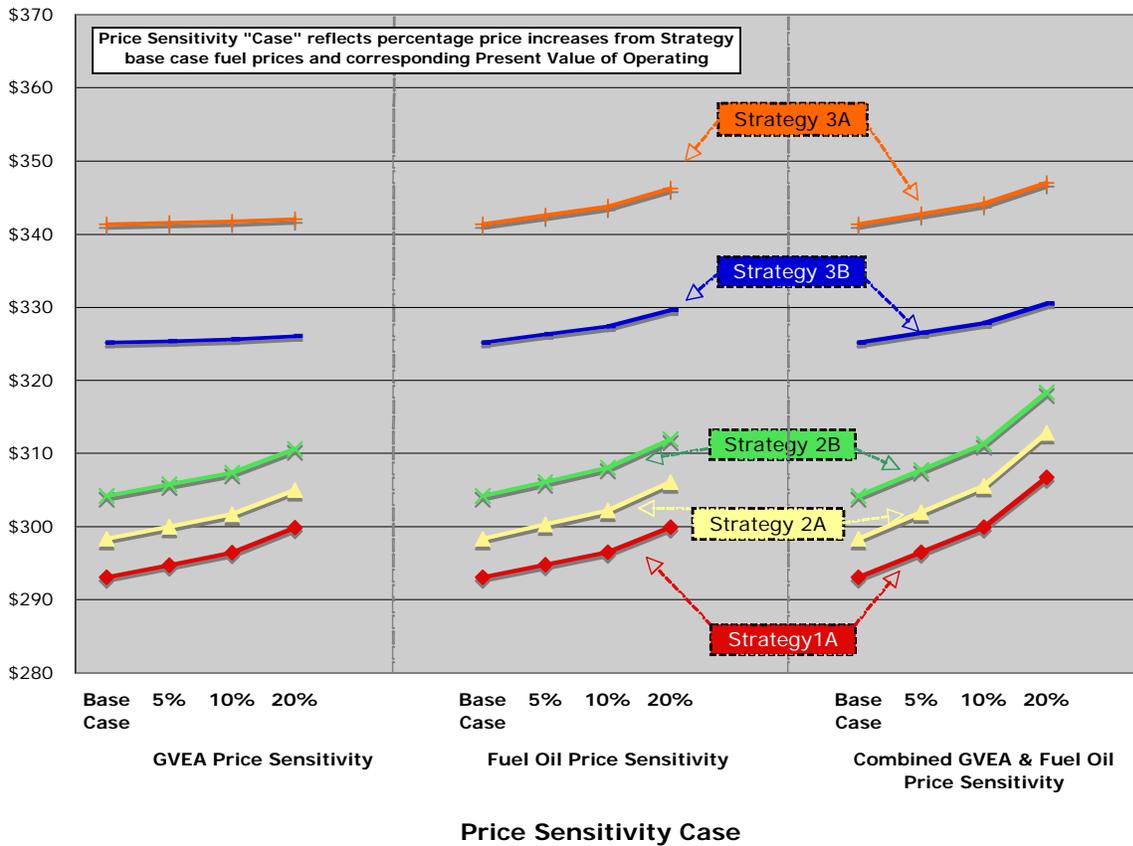
*SENSITIVITY CASE 2* — Increasing natural gas costs, with all other fuel costs held constant. The price of natural gas is increased five, ten and twenty percent (5%, 10 % and 20%) above the original forecast of natural gas prices. Note that this price sensitivity case is only applicable to the Strategy sub-options where natural gas is included in the UAF fuel mix as a result of the natural gas re-firing of the fuel oil production equipment.

*SENSITIVITY CASE 3* — Increasing fuel oil costs, with all other fuel costs held constant. The price of fuel oil is increased five, ten and twenty percent (5%, 10 % and 20%) above the original forecast of fuel oil prices.

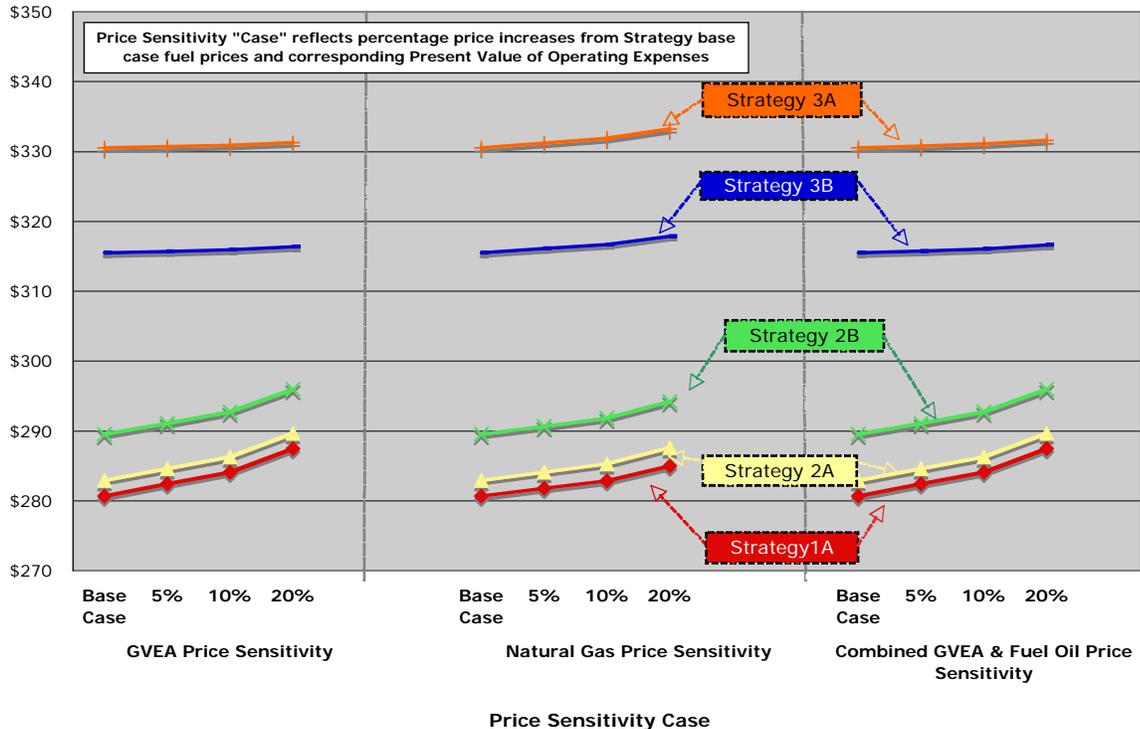
*SENSITIVITY CASE 4* — Increasing fuel oil and GVEA electricity costs, with stable coal natural gas costs. The price of fuel oil and GVEA electricity will be increased five, ten and twenty percent (5%, 10 % and 20%) above the original forecast of fuel oil and GVEA electricity prices.

Figure 21 and Figure 22 of the results from each energy price sensitivity case can be seen below. Figure 21 displays the effects of the price sensitivities on the strategies without natural gas, and Figure 22 shows the results on the strategies with natural gas.

**Figure 21 Comparison of Price Sensitivity Outcomes (Fuel Oil Strategies without Natural Gas) for Forecasted Operating Expenses (Including Debt) by Strategy**



**Figure 22 Comparison of Price Sensitivity Outcomes (Fuel Oil Strategies with Natural Gas) for Forecasted Operating Expenses (Including Debt) by Strategy**



## ***UAF Growth Sensitivity Analyses***

The other primary uncertainty to the fiscal and physical requirements of the UAF utility systems is the assumption as to the pace of campus growth, and corresponding utility service requirements. These growth assumptions can only be tested with respect to the changes in the level of service requirements throughout the twenty-year period modeled, and corresponding levels of capital expenditure on the utility facility required to meet these requirements. That is, the model cannot test the implications of an alternative growth rate for campus facilities utilizing net present value metrics, because the significantly lesser or greater utility service loads would require modeling of differing systems capacity investments and performance—a fundamentally different Strategy to meet different service loads.

*SENSITIVITY CASE 5* — Total service load and capacity requirements are compared to the requirements modeled in the three primary Strategies analyzed. The magnitude of differences in these service loads and capacity requirements forecast for the Strategies modeled (i.e., 3.9 million square feet) are compared to alternative twenty-year campus growth projections of 3.6 million square feet and 4.3 million square feet campus build-outs.

The peak demand projections at year twenty for various growth assumptions are as follows:

**Table 10 Alternative Forecasted Twenty Year Growth Projection and Associated Peak Utility Service Requirements (FY2026)**

<b>Forecasted Campus SF</b>	<b>Peak Distribution System</b>	<b>Peak Electric Demand</b>	<b>Peak Chilled Water</b>
3.6 MSF	176 Mlbs/hr	15.3 MW	5,100 Tons
3.9 MSF	193 Mlbs/hr	16.6 MW	5,500 Tons
4.3 MSF	213 Mlbs/hr	18.8 MW	6,100 Tons

## ***Lower Growth***

The lower growth rate sensitivity case (3.6 MSF at year 20) implies for Strategy 1 that fewer individual “stand alone” units would be installed, and would reduce the future cost for equipment replacement as well as reduce the fuel cost differential when compared to Strategies 2 and 3. Lower growth rates make Strategy 1 more attractive. Under Strategy 2, and the further assumption that lower growth projection applies equally to LC and WR, the capital costs associated with installation of Boiler 3 in the WR Plant would be delayed and the installation of Boiler 4 would not be needed until just beyond the 20 year time frame. If instead only LC growth is retarded, and the pace of WR development is as planned, there would be no change in the development of the WR plant. Lower overall consumption of steam and electric power under the lower growth scenario clearly reduces the fuel cost advantages of the coal resource alternative. Capital costs would certainly be reduced by scaling back the capacity of a new boiler and steam turbine generator in Strategy 3. Lesser economies of scale would not improve construction costs on a \$/klb or \$/MW basis, making the economic comparison of Strategy 3 with alternative Strategies 1 and 2 less attractive.

## ***Higher Growth***

A higher than anticipated growth rate would tend to improve the economic comparison of Strategy 3 against Strategies 1 and 2. The capital expenditures for “stand alone” and WR Satellite Heating Plant would be on the order of ten percent (10%) higher than the base case (with more individual boilers, or larger individual units). The fuel and purchased electric costs would increase in similar proportion. Interestingly, additional capital costs for construction to accommodate a higher than modeled growth rate would not be needed under the coal boiler option (Strategy 3). The Atkinson Plant would house either 400 Mlbs/hr or 450 Mlbs/hr (depending on which of the sub-options was implemented) of steam capacity. With the largest

unit offline, firm capacity would be 300 klbs/hr, well in excess of the projected peak campus demand of 213 klbs/hr the plant. The fuel cost differential would improve throughout the planning time frame, although purchase of GVEA supplemental power in the out years would increase under the 100 klbs/hr boiler sub-option specified for Strategy 3.

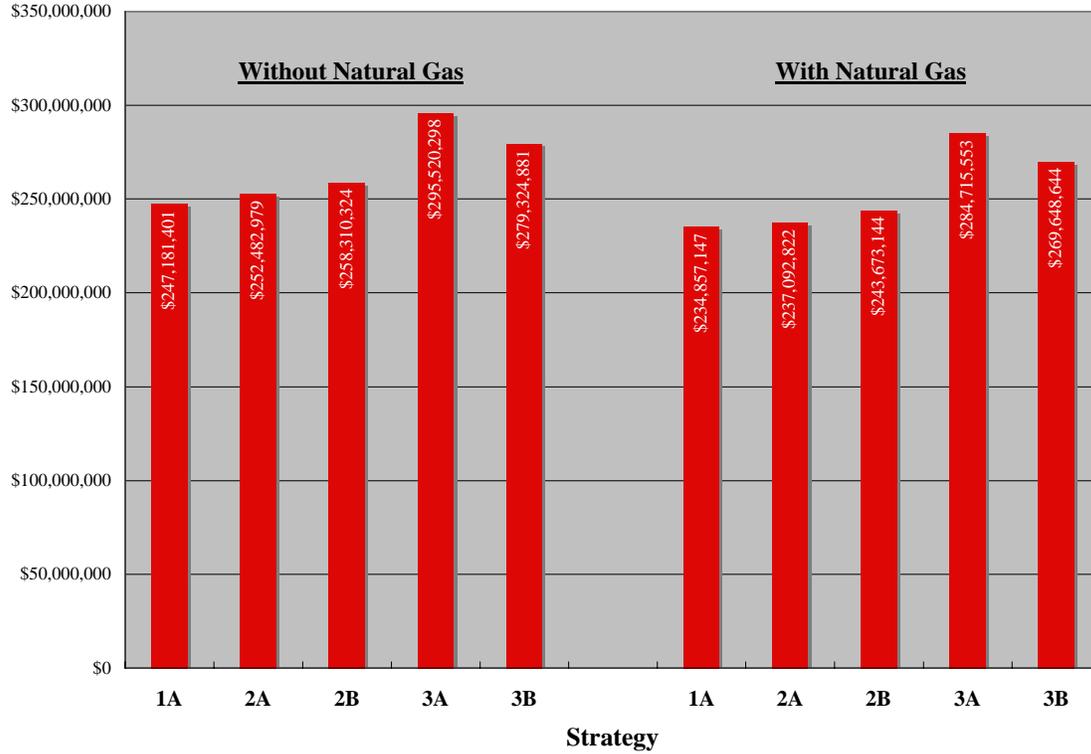
### ***Capital Funding Sensitivity Analysis***

The UAF UDP model analyses evaluate the net economic benefit in terms of *discounted NPV*. The three basic Strategies and the sub-options to those strategies (i.e., alternative configurations of utility equipment and infrastructure required to meet future service requirements) impose differing capital and operating cost outcomes through the twenty-year period that are properly compared on a discounted net present value basis. These comparisons between the scenarios are all performed using the same structuring of debt financing. It is possible that a significant contribution of the initial capital requirements might be available from the State of Alaska, and this contribution is properly considered only with the preferred long-term strategy.

*SENSITIVITY CASE 6* — Test the fiscal impact of a \$50 million capital contribution from the State of Alaska. The analysis investigates the impact on the level of utility service rates, bonding and debt requirements, and other business related issues if the University is not required to debt-finance the entire capital requirements. The sensitivity analysis of \$50 million capital investment not requiring financing assumes that \$50 million of initial Common Improvements and Capital Renewal investment would not be financed. Essentially this means that about \$76 million of debt (principal and interest) payments are avoided in all Strategies. The net present values of each strategy adjusted to reflect the \$50 million contribution is seen in the Figure 23 below.

**Figure 23 UAF UDP – NPV of Operating Expenses by Strategy with Financed Costs  
Reduced by \$50 Million**

(Discounted at 5%)



## RISK ANALYSIS

Risk analysis in the context of the long-term facilities development contemplated in the UAF UDP is a complex and imprecise element of planning. Regardless of the Strategy selected, there are elements of the external environment in which UAF must operate its utility service facilities that are outside its control. These exogenous factors cannot be explicitly modeled within the scope of the UDP, but must be acknowledged and at least identified in the context of the “direction” of impact on the economic evaluations performed by the UDP.

***GVEA Electric Service Reliability***—A concern that the UDP Project Team has been repeatedly confronted with in its analysis is the reliability of electrical service available from GVEA. With a history of numerous short and longer-term interruptions of power supplies within the GVEA service area, UAF has significant concern that such reliability issue must be evaluated to be a negative attribute of any Strategy that increases the reliance on GVEA electricity supplies. Thus, this risk issue has to be treated as a negative impact with respect to Strategies 1 and 2.

***Control of UAF Electric System***—The control of the UAF electrical system by an outside entity is an issue that has greater significance for UAF the greater the percentage of electricity that is obtained from any source other than the UAF self-generation facilities. Thus, this risk issue is evaluated to have negative impacts with respect to both Strategy 1 and 2 infrastructure configurations. This issue is also of particular significance in the consideration of a third-party utility service provider taking operational control of the facilities under any of the three Strategies. The ability of UAF to supply its full electric requirements for the foreseeable future under Strategy 3 allows assertion of this as a positive element of the Strategy’s risk profile.

***Campus Square Feet Growth Over/Understated***—The previous discussion in Sensitivity Case 5 of the changes in the utility infrastructure systems components which would be designed and specified with differing campus growth rates focused on the capital cost component of this risk factor. Consideration of the impacts of different growth rates in the context of any specific

decision taken with respect to a particular modeled Strategy is also an operational question. That is, if the modeled growth is overstated, the Strategy 1 infrastructure decision is most prudent in that the operational capacities are most uniformly matched to actual growth, while all other Strategies would provide excess and unutilized operational capacities. Conversely, if the UDP Model understates the actual growth rates for the UAF campus, then the most dramatic impact would be a negative economic result if Strategy 1 were selected, with Strategies 2 and 3 providing sufficient “excess” capacity to handle the unanticipated growth of the campus utility service loads.

***Requirement for Capital Investment Beyond Twenty Years***—If the UDP were required to anticipate the utility service requirements and associated capital investment for a term greater than the twenty years currently analyzed (e.g., consistent with the forty year expect life of a new coal boiler), greater economic benefit would be obtained from those Strategies that provide the greatest utility service capacity and flexibility in expansion of capacity. This would be consistent with the infrastructure developed in Strategies 2 and 3, where the durable and flexible nature of the utility infrastructure specified would continue to provide economic benefit to UAF, and would serve as a more appropriate foundation for the continued operations of the University’s utility systems.

***Regulatory and Permitting Issues***—If regulatory and permitting issues become an increasing constraint on the citing of utility facilities in Fairbanks, each of the three basic Strategies must be assessed to determine which is economically less advantageous to the University. Each of the Strategies requires permitting of additional fossil fuel-based combustion facilities, and pose similar emissions profiles. The only Strategies modeled that would be less subject to these regulatory and permitting issues are Strategies 1 and 2 with the natural gas sub-option implemented. Certainly the permitting of new coal-fired facilities (Strategy 3) must be understood to have the greatest uncertainty regarding the *extent* of regulatory impacts, including requirements for extremely expensive control technologies (e.g., if significant mercury-related emission control strategies must be implemented).

***UAF Bonding Constraints***—Obviously the lowest initial and total capital cost Strategies are the least impacted by constraints on bonding capacity. Thus, Strategy 1 would be evaluated as least negatively impacted and Strategy 2 could be assessed to be in a relatively neutral economic position with respect to this issue. Strategy 3 is the most capital intensive, and is evaluated with the most negative economic impact as a result of a significant constraint on UAF’s ability to issue bond financing to meet the capital construction requirements.

***UAF Construction Constraints***—The development of the three basic Strategies did not consider any particular construction constraints for the development and installation of the required facilities in Fairbanks. If the requirements for the additional utility systems capacity is being driven by growth in UAF facilities (generally), then it is appropriate to inquire as to the ability to undertake a construction program that is developing tens of millions of dollars of new utility facilities simultaneously with the other UAF construction activities. Put simply, Strategy 1 engenders the least significant construction activities, as the Stand Alone utility solutions are embedded in the construction of the new campus academic and research facilities. Obviously Strategies 2 and 3 impose additional construction beyond the construction of new campus facilities, and at their peaks, could be demanding \$30 to \$50 million in annual construction *in addition to* other campus construction activities.

**Table 11 Impact on UAF of Strategy and Event Combination (for Fiscal Years past 2010)**

Strategy Number	Strategy Name	Issues affecting performance of Utilities Division under Strategy							
		GVEA Electric Reliability	Control UAF Electric System	Campus Square Feet Growth Overstated	Campus Square Feet Growth Understated	Requirement for Capital Investment Beyond 20 Years	Regulatory and Permitting Issues	UAF Bonding Constraints	UAF Construction Constraints
<b>1</b>	Stand Alone	-	-	-	-	-	-	+	+
<b>1 (NG)</b>	Stand Alone (with Natural Gas)	-	-	-	-	-		+	+
<b>2A</b>	West Ridge Satellite Heating Plant	-	-	-	+	+	-		-
<b>2A (NG)</b>	West Ridge Satellite Heating Plant (NG)	-	-	-	+	+			-
<b>2B</b>	West Ridge Satellite Heating Plant w/ Chiller Plant	-	-	-	+	+	-		-
<b>2B (NG)</b>	West Ridge Satellite Heating Plant w/ Chiller Plant (NG)	-	-	-	+	+			-
<b>3A</b>	Coal Boiler (150Mlb) Plant and New 20 MW Turbine	+	+	-	+	+	-	-	-
<b>3A (NG)</b>	Coal Boiler (150Mlb) Plant and New 20 MW Turbine (NG)	+	+	-	+	+	-	-	-
<b>3B</b>	Coal Boiler (100Mlb) Plant and New 10 MW Turbine	+	+	-	+	+	-	-	-
<b>3B (NG)</b>	Coal Boiler (100Mlb) Plant and New 10 MW Turbine (NG)	+	+	-	+	+	-	-	-

Notes: + = Issue does not impact UAF / UAF able to adapt well

- = UAF Utilities performance may be constrained / Possible negative \$\$ impact

■ = Neutral Impact

**THE UNIVERSITY OF ALASKA FAIRBANKS**  
**2005 UTILITY DEVELOPMENT PLAN**  
**SECTION VI: ALTERNATIVE BUSINESS MODEL STRUCTURES AND RATE DESIGN**

ALTERNATIVE UAF BUSINESS MODEL STRUCTURES AND RATE DESIGN

The UAF UDPB addresses the alternative business “models” that may be utilized to structure the operation and financing of the utility services required by the campus. The business practices currently employed by the UAF Utilities Division are relatively common among major universities. Utilities Division expenditures are a separate cost center in UAF accounting; utility rates are analyzed and billed based on annual allocations of actual and estimated utility service costs; and direct billed revenues cover only a *portion* of the utility service costs.

Two alternative UAF utility services business structures are investigated herein. The first retains ownership of the utility facilities within the administration of the UAF, and contemplates the creation of an independent and self-sustaining Utilities Division enterprise that is responsible for recovery of all utility-related costs through its rates. In the second business structure, a third-party obtains ownership and control of the UAF utility facilities, and is charged with the prudent management of those facilities such that the facilities are fiscally self-sustaining in perpetuity. The “third-party utility” business structure is modeled after a regulated public utility business model, but the utility could elect to be non-regulated if it chose to provide services to private contract customers only.

***Overview of Alternative UAF Utilities Division Business Practices***

To date, UAF has been relatively aggressive in implementing financial responsibility for the delivered utility services, particularly with respect to its adoption of the “recharge center” concepts consistent with the direction of OMB Circular No. A-21.<sup>14</sup> As currently structured, the

---

<sup>14</sup> Office of Management and Budget, “Cost Principles for Educational Institutions,” *Circular No. A-21*, revised August 8, 2000, <<http://www.whitehouse.gov/omb/circulars/a021/print/a021.html>>, accessed on September 29, 2005.

UAF Utilities Division allocates costs-of-service to several identified users (e.g., research or auxiliary entities) in an effort to recover that entity’s share of the Division’s full annual operating costs, including fuel, materials, labor, interest on its debt, and a component for a portion of “depreciation” expense.<sup>15</sup> The remaining Utilities Division expenses are paid for by the University as a whole through the “transfer” account line item. There is a major deficiency in the manner by which capital reinvestment and renewal are budgeted, funded, and capitalized.

The current approach falls short of “fiscal sustainability” goals with respect to the full recovery of capital costs, and costs associated with the renewal of capital infrastructure. A full life-cycle cost-of-service model for allocation of utility service costs is specified by the UAF UDP model, which allows for inclusion of all debt costs (i.e., both principal and interest) and asset depreciation costs in defining the utility rates required to sustain the UAF utility business enterprise.

This treatment differs from the current accounting practices employed by UAF (primarily) in its treatment of debt and “depreciation” expenses. Current UAF accounting conventions characterize the “depreciation” expense as the UAF budget element required for payment of the principal component of debt obligations,<sup>16</sup> not the more comprehensive depreciation of capital asset value through the expected life of the assets. The debt component reflected in current UAF accounting is *only* the interest component of debt.<sup>17</sup> Importantly, the

---

<sup>15</sup> UAF has only in the past couple years included this “depreciation” component in its rates. However, it is not tied to the full capital item depreciation expense, and has also been characterized as the principal component of debt. Importantly, there is no consistent treatment of debt principal expense or depreciation in UAF’s current utility service rate definition.

<sup>16</sup> The UAF Utilities Division is currently recognizing “depreciation” expense associated with the newly installed chiller and Intertie assets. For FY 2006 this amounted to approximately \$200,000. The model expands the scope of the assets being depreciated to include Utilities Division specific buildings such as the Reverse Osmosis Water Treatment Station, and also utility infrastructure assets. This expansion increases depreciation expenses for UAF’s Utilities Division in the base year from approximately \$200,000 to \$2.4 million. Similarly, interest expense for all utility related debt is recognized in the model, to include debt associated with the diesel engine generator (DEG). This increases debt service in the base year for the Utilities Division from approximately \$45,000 to \$500,000.

<sup>17</sup> This treatment of debt is consistent with OMB Circular No. A-21 allowing only interest expenses to be charged to short-term government contracts. The notion is simply that the government contract reimbursements should not include compensation for facility asset costs (i.e., principal components of debt-financed facility costs), and thus UAF’s accounting practices currently allocate principal costs to the “depreciation” line item in the Utilities Division’s budget.

existing “Business Model” is structured to meet federal contract and grant utility expense reimbursement requirements, but does not address the long-term sustainability of UAF utilities services in its business practices and (corresponding) rate design.

It is important to note that even with implementation of these expanded concepts of debt expense and accrual of amortized depreciation expense for capital renewal, UAF can continue to calculate a federal utility service reimbursement rate that is based on the debt interest expense and expanded depreciation expense (consistent with OMB Circular No. A-21), i.e., dual bookkeeping similar to private sector’s tax versus managerial accounting bookkeeping. In its future cost recovery environment UAF can utilize the expanded rate design concepts to provide a separate non-federal contract utility service rate for internal billing purposes that more fully captures its total cost-of-service.

Thus, UAF’s Utilities Division cost accounting and utilities expense reimbursement practices currently incorporate the variable operating costs, and a portion of the debt and depreciation costs. The utility rates charged include only the interest costs of debt, while the accounting practices “track” (but do not incorporate in utility rates) the cost associated with principal payments on debt. The identification of “depreciation” expense in the current UAF accounting practices does not fully address the cost of asset depreciation in rates. Thus, the current UAF utility services rates largely *ignore* the cost of replacing a fully depreciated capital asset in the future. Generally speaking, the principal component of bond payments is much lower than straight line depreciation during the first seventy percent (70%) of the term of a bond. The reverse is true in the remaining years, but the university has lost the time value of money if it recovers only debt principal costs rather than the straight-line life-of-asset depreciation costs in its utility rates.

The business enterprise structure and rate design analysis specified in the UAF UDP cost-of-service rate model incorporates consideration of the ongoing “consumption” of the capital assets—and allows definition of utility service rates required for the funding of long-term

capital renewal. This is a common element of public (as well as private) utility rate design. The concept is simply that rates charged for utility services must also accumulate a reserve fund for the replacement of the capital assets at the end of its expected useful life.

It is believed that the strictures of the UAF accounting practices *allow* rate designs that would accumulate a reserve fund within the Utilities Division. Such a capital renewal reserve fund would finance the replacement of the capital assets at the time such capital renewal is required. However, it is unclear whether the University would actually adopt such self-sustaining enterprise business structure and rate design concepts in its actual service rates.

The justification for funding these accumulated reserves for capital renewal in utility rates stems from the continuing utility service obligations that are typically imposed on a regulated public utility, such as those securing utility services to all other campuses in the University of Alaska system. Conceptually, this justification is equally present in the obligations of the UAF utilities systems for its provision of service to the University, which must also be presumed to be a *perpetual* obligation. The rate design analysis of the UDP will look at the implication of implementing such obligation in business structure and design of the cost-of-service utility rates.

### ***Independent Third-Party Utility Enterprise***

It is possible that UAF might choose to remove utility service responsibilities from its administrative burdens, and allow an independent third-party to provide these services to the University. Contracting for these services is potentially complex, but the notion is that there are major components of the utility facilities and operations that are not *necessarily* within the providence of the primary mission of an academic and research university.

Assuming the University was to choose this independent third-party approach, it must also be assumed that the University would seek to have university-friendly owners in the management and operation of the utility facilities. That is, many of the utility facilities (e.g., steam distribution lines) are—and must be—located contiguous to many other UAF facility assets to which a third-party utility service provider would not be granted operational control. Definition of the relationships and responsibilities between UAF and the third-party utility service provider is but one of the contracting obstacles that must be addressed.

The presumption (for this analysis) is that UAF would participate in the third-party corporation, but would play a minority role. The utility facility assets currently utilized would certainly be part of the third-party facilities, and UAF would either sell or make in-kind contribution of these assets to the third-party corporation. It is assumed for comparative purposes that the “Utility Service Corporation” (“USC”) would make the same facility investment decisions taken by the UAF Utilities Division business enterprise model. This is a reasonable model. Thus, the assets of the USC would be the same assets as are analyzed in the UAF Utilities Division business enterprise model, with the only difference being the corporate structure and rate making principles applied to the USC being derived from the regulated public utility model. Labor and benefits costs represent a mere 22% of the total budget; so, the impact of recent/forecasted Public Employees Retirement System (PERS) benefits rates is not deemed significant.

## STRUCTURE OF UTILITY SERVICE RATES

Regardless of the business model relied upon, utility rates are structured and designed to encompass all costs of the operations, including both fixed and variable cost components. To this end, rates, in a manner similar to the financial cost categories of the UAF Utility Division include several components:

1. Purchased fuel costs;

2. Operations and maintenance (to include supplies and contracts);
3. Labor (salaries and benefits); travel is minimal or separately stated elsewhere;
4. Principal and interest on Utilities Division debt;
5. Depreciation of Utilities Division capital assets; and
6. Profit and Risk Premium

Costs that can be directly assignable to a specific delivered and consumed *utility commodity* (e.g., electricity, steam, chilled water, domestic water) are allocated to those products. This pertains to direct fuel costs as well as other charges such as operations and maintenance, labor, debt, and depreciation.

### ***Allocations of Direct Operating Costs***

Costs that cannot be directly assigned to final delivered utility commodities are generally related to the cogeneration facilities of the UAF. By example, the total costs of coal, fuel oil, O&M and labor are first allocated in the model's calculation of costs of production of high pressure steam (HP steam).<sup>18</sup> Total costs, including fuel costs from the HP Steam Boilers 1-4, are then allocated between the steam turbine generator *commodity* outputs of Electricity and Low Pressure Steam (LP Steam) on a Btu-equivalent basis of the consumable products (net kWh and LP Steam). The DEG LP steam and electricity are also allocated in this fashion.

O&M expenses (other than those directly assignable to domestic water<sup>19</sup>) are allocated to the HP steam production equipment—the coal and fuel oil HP steam boilers (1-4)—on a ninety percent (90%) to coal and ten percent (10%) to fuel oil basis. These costs are divided by the boiler fuel inputs (coal and other fuel) to produce O&M rates (\$ per unit), which are then used to forecast future O&M costs for various plant and facility production configurations.

---

<sup>18</sup> Please UAF District Energy System (DES) Model Flows figure in Section I.

<sup>19</sup> Based on information obtained from UAF, it was assumed that three percent (3%) of the gallons of water produced in calendar year 2004 were utilized in utility operations. Therefore, three percent (3%) of domestic water expenses in each year have been re-designated as attributable to general utility expenses.

Once fully allocated between electricity and LP steam, these costs are then combined with any assignable distribution costs (e.g., substation, steam and chilled water distribution systems). Production equipment costs are allocated to the consumable commodities—Electricity (kWh), heating (Mlbs), cooling (Ton-Hrs) and domestic water (Gallons). These fully-loaded costs are then divided by the consumed commodities to derive commodity rates.

### ***UAF Utility Rates and “Sustainable” Rate Design Concepts***

Regardless of the business structure in which the utility rates are developed, it is a common component of rate design that the annual operating expense of the utility services be captured in the utility rates. UAF generally accomplishes this task in its current definition of utility rates. Therefore, the most important discussion point to be considered by the UAF UDP is the element of the rate design defining the extent of full *capital cost recovery* in utility rates, and the recovery of “costs” associated with *asset depreciation and renewal*. The following example of future delivered Electricity rates illustrates the point.

**Table 12 UAF UDP Strategy 3A Electricity Rates FY 2005 through FY 2010**

	<b>FY 2005</b>	<b>FY 2006</b>	<b>FY 2007</b>	<b>FY 2008</b>	<b>FY 2009</b>	<b>FY 2010</b>
<b>UAF Load (kWh)</b>	<b>58,454,986</b>	<b>61,030,610</b>	<b>62,968,634</b>	<b>65,160,908</b>	<b>67,049,772</b>	<b>69,198,059</b>
Electricity Fuel Cost (per kWh)	\$0.050	\$0.062	\$0.054	\$0.055	\$0.082	\$0.087
Electricity O&M Cost (per kWh)	\$0.009	\$0.007	\$0.006	\$0.006	\$0.008	\$0.008
Electricity Labor Cost (per kWh)	\$0.018	\$0.020	\$0.021	\$0.023	\$0.028	\$0.028
<b>Variable Electricity Cost(per kWh)</b>	<b>\$0.077</b>	<b>\$0.089</b>	<b>\$0.081</b>	<b>\$0.084</b>	<b>\$0.118</b>	<b>\$0.123</b>
Electricity Debt Interest Cost (per kWh)	\$0.005	\$0.005	\$0.061	\$0.058	\$0.063	\$0.059
Electricity Debt Principal Cost (per kWh)	\$0.000	\$0.000	\$0.027	\$0.030	\$0.034	\$0.035
<b>“Fully Loaded” Electricity Cost (per kWh)</b>	<b>\$0.082</b>	<b>\$0.094</b>	<b>\$0.170</b>	<b>\$0.172</b>	<b>\$0.215</b>	<b>\$0.217</b>
Electricity Capital Depreciation Cost (per kWh)	\$0.022	\$0.021	\$0.022	\$0.027	\$0.040	\$0.041
<b>“Fully Load Life-Cycle” Electricity Cost (per kWh)</b>	<b>\$0.104</b>	<b>\$0.115</b>	<b>\$0.192</b>	<b>\$0.200</b>	<b>\$0.255</b>	<b>\$0.258</b>

The example provided in the Table 12 is taken from the model outputs for Strategy 3A (with natural gas), but the important point illustrated is the affect of incorporating the capital recovery components in rates. The “variable electricity costs” are a starting point for rates.

Adding the debt-related (interest and principal) costs virtually doubles the effective rate,<sup>20</sup> and can legitimately be characterized as “fully loaded” electricity costs. Annual rate schedules for all strategies are detailed in Financial Appendix - Section F.

However, “fully-loaded life-cycle” rates must also accumulate a depreciation reserve fund for future capital asset renewal and replacement (“R&R”). Table 12 reflects that by the sixth year of the analysis, amortization of the depreciation expenses from the capital investments made during the prior years would increase rates by an additional twenty percent (20%) to provide for the accrual of a capital replacement fund sufficient to replace the electricity-related capital assets at the end of their use life—that is, a statement of the “fully loaded life-cycle” electricity cost.

Note also that in future years of the fully-loaded life-cycle, as the debt financing of infrastructure is repaid and replacement of these capital items is funded by the accumulated depreciation reserve accrual, the component of rates related to debt (including both principal and interest) is eliminated from future rates. In the example just presented this would *significantly reduce* future rates. The only new debt would be related to replacement reserve fund earnings at rates lower than construction inflation, plus the capital expenditure impact of construction of expanded infrastructure capacity to accommodate future growth.

The relatively simple accounting for costs of utility services depicted in the preceding example is a perfectly adequate approach to rate design in the context of the UAF utility services business enterprise that is retained within the administrative structure of the University. The issue is the extent to which UAF wishes the Utilities Division to be self-sustaining through rates charged for utility services. The implication of not incorporating the amortized depreciation expenses for accrual to a fund for future capital replacements is that—at that time in the future

---

<sup>20</sup> Note that there is no principal cost associated with debt in the first two years. This reflects the specific structure of capital financing by UAF implemented with the recent construction of substantial capital improvements, with an interest-only debt structure for those two years. The debt structure for new capital investments specified in the UDP Model presumes a fixed annual payment with annual payment of both principal and interest based on a “normal” debt financing schedule.

that the capital components of the utility facilities reach the end of its useful life—a source of capital or additional debt will be needed to continue the required utility services to the UAF. *Note that this is exactly the position in which UAF currently finds its utility facilities which is juxtaposed with the standing of every other campus of the University of Alaska system.*

### ***UAF Utility Rates—Summary of UDP Model Results***

A very convenient manner in which differences in the individual Strategies may be compared is in the context of delivered utility service rates through time. Although detailed schedules of rates are provided for each of the Strategies in Financial Appendix - Section E, many of the important results are summarized in the following charts.

Figure 24 through Figure 27 provide delivered utility services cost summaries, and include all annual costs of fuel, O&M, major maintenance and debt costs (principal and interest). In Figure 24 it can be seen that the cost (i.e., cost-of-service rates) for delivery of electrical service to the UAF campus is very comparable for Strategies 1 and 2, and as much as \$0.07 per kWh higher in the first ten years modeled by the UDP. The primary differences shown reflect the much higher initial capital costs for Strategy 3, which gradually erode as the higher fuel costs associated with Strategies 1 and 2 eventually equalize the additional debt costs engendered by Strategy 3.

**Figure 24 UAF UDP Structured Electric Rate by Strategy with Natural Gas**

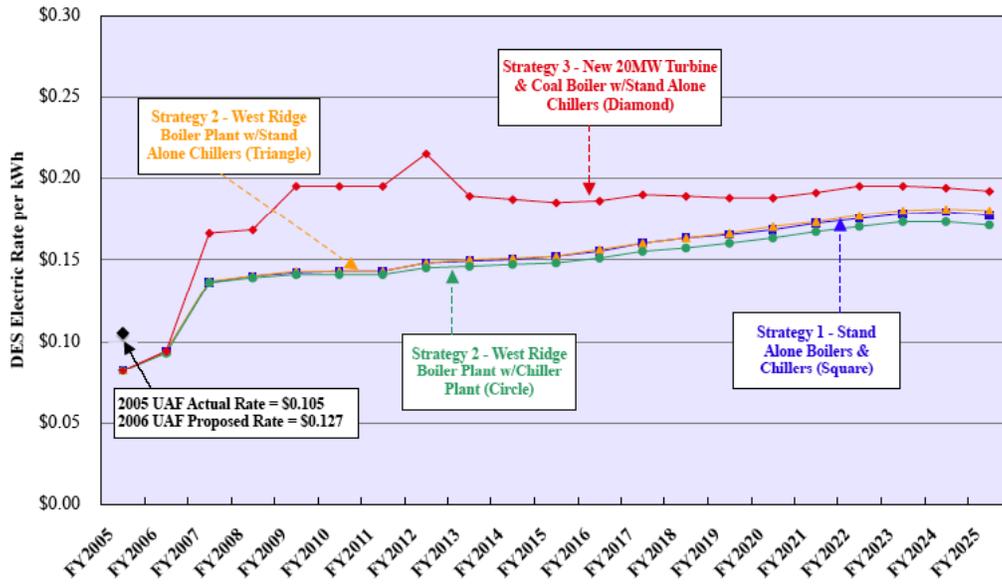


Figure 25 demonstrates the same effects for the overall costs of delivered steam that were just discussed for delivered electricity rates. Note, however, that the advantage of the lower steam rates for Strategy 1 in the first half of the period are overwhelmed by the higher capital and operational costs by the end of the twenty year period for this “stand alone” Strategy.

**Figure 25 UAF UDP Structured Blended Steam (DES & Stand Alone) Rate by Strategy with Natural Gas**

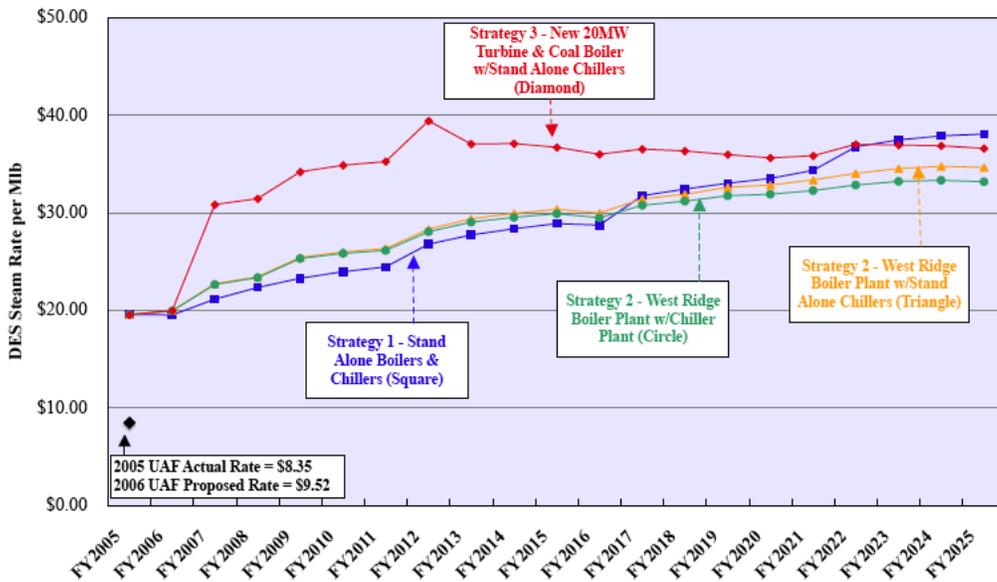


Figure 26 summarizes the forecasted cost of domestic water, which is common to all the Strategies discussed for other utility services.

**Figure 26 UAF UDP Structured Domestic Water Rate by Strategy *with* Natural Gas**

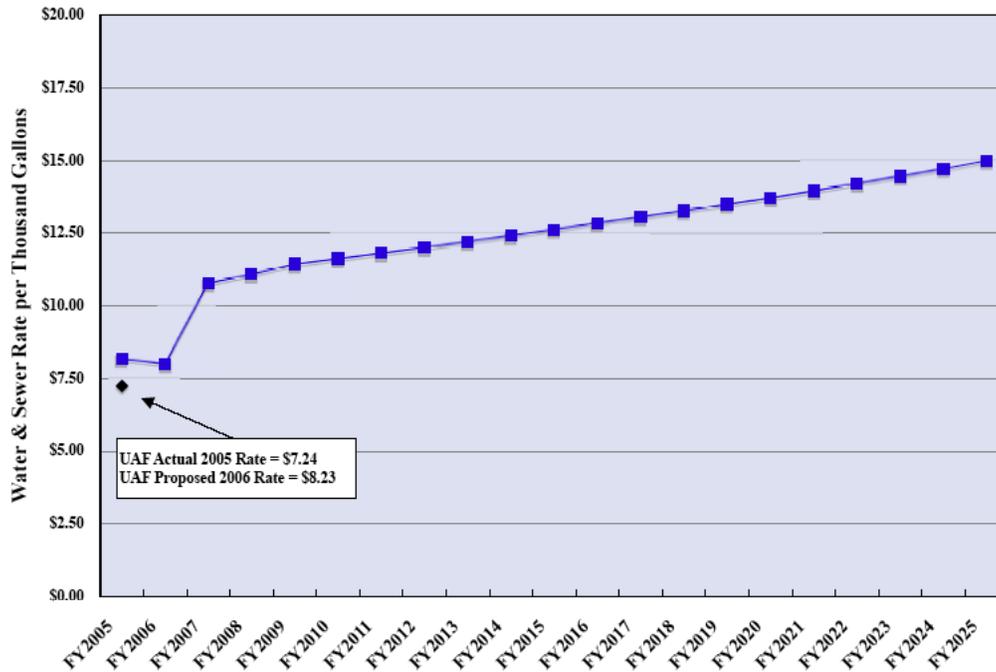
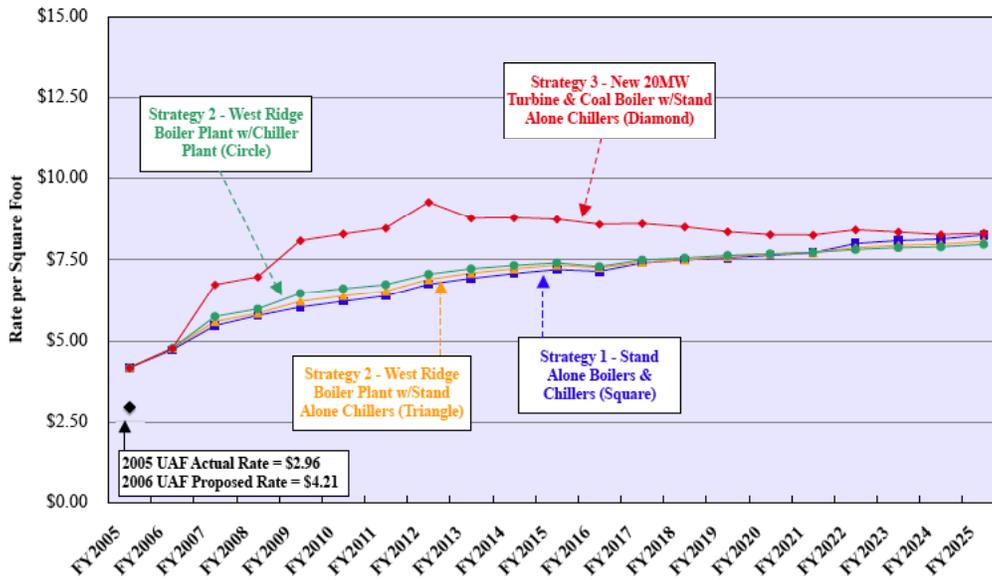


Figure 27 summarizes the overall costs for all UAF utility services on a per square foot served basis. Again, the higher initial capital costs of Strategy 3 cause initial rates to be higher under this Strategy, but towards the end of the twenty year period, the significantly lower forecasted costs of coal (per Btu of delivered energy) eventually cause the Strategy 3 service rates to return to the same level as those forecasted for the other Strategies.

**Figure 27 UAF UDP Structured Square Foot Rate by Strategy *with* Natural Gas**



***Public Utility Rate Design and a Third-Party Provider***

The development of rate designs for utility services provided by a public (or private) utility corporation are significantly more complex as a result of issues related to taxes, cost of capital, and return of and return on capital investments. Although there is no single right or wrong way to define “proper” rate design in a private sector setting, the application of a relatively simplistic public utility rate design model serves to illustrate the impact of providing UAF’s required utility services by transfer of the utility assets to a for-profit third-party utility service provider.

This first component of public utility rate design is determination of the “rate base” established (principally) on the un-depreciated book value of the utility’s capital assets. The rate base is utilized to determine the “return on equity” to be earned by the utility provider. Rate Base is net of the Accumulated Reserve for Depreciation, which is the accumulation of the full capital Depreciation and Amortization Expense that is treated as an annual Operating Expense.

This first element of the public utility rate design model distinguishes the rates obtained from those specified by the preceding analysis of UAF Utility Division business enterprise utility service rates. In today’s capital markets, public utility rate design will generally specify a Return on Equity (ROE) in the range of an eight to twelve percent (8-12%) annual rate. This is a specific addition to rates, which in the context of a UAF new (un-depreciated) capital investment of \$50 to \$100 million dollars over the next decade could increase cost recovery by \$4 to \$12 million dollars per year.

In a for-profit business environment, the utility rates must also recover the costs of various taxes (including wage-related, ad valorem and income taxes), and also account for the various tax benefits (e.g., tax deferrals) that impact private sector utility enterprises. At best, it must be assumed that the consideration of the taxable basis of these utility operations would have no net increase in recoverable costs—however, it is much more likely that these will add to the recovery cost-of-service basis for the utility enterprise.

One final component must be considered in the analysis of a third-party provider of UAF’s utility service requirements. Under the current Alaska Public Utility Regulatory Act<sup>21</sup> a “public utility” must deliver utility services to ten (10) or more customers. This is important to UAF in the context of obtaining utility services from an entity that is not a private provider of utility services, and may allow treatment of these services as “off-balance sheet.” If this enterprise is allowed to serve additional customers, the nature of the services provided (e.g., steam distribution) most likely requires relative close proximity to the UAF campus. Thus, one must imagine that a research park or other compatible economic development would be required to facilitate this “public utility” option for the UAF to receive its utility services. It is also likely that such a development would also bring additional service load requirements and might have the advantage of creating lower service rates through additional utilization of the infrastructure and plant resources (e.g., achieving economies of scale).

---

<sup>21</sup> AS 42.05.990(3)(A) and (4). It should also be noted that under AS 42.05711 the Regulatory Commission of Alaska may exempt a utility from these provisions if it finds such exemption to be “... in the public interest.”

**THE UNIVERSITY OF ALASKA FAIRBANKS**  
**2005 UTILITY DEVELOPMENT PLAN**  
**SECTION VII: UDP SUMMARY AND DECISION RECOMMENDATIONS**

SUMMARY AND STUDY RECOMMENDATIONS

The *2005 Utility Development Plan* analyzes alternative long-term—twenty (20) year—potential solutions for comprehensive utility systems requirements for the University of Alaska Fairbanks’ main campus. Most of the University’s current utility infrastructure has been in service for over forty (40) years and is at or near the end of its useful life. Continued growth of UAF, in terms of student enrollment, research activities, and physical building square footage, expands the need for reliable utility services. The utility services infrastructure comprises a fundamental capital asset of the university that must be carefully managed and planned in order to fulfill these service requirements.

*If UAF is to maintain a reliable utility system sufficient to meet the needs of its students, faculty, and administration, it is imperative that UAF implement a long-term investment strategy for comprehensive utility system infrastructure renewal, replacement, improvement and expansion. This investment requirement ranges from \$48-103 million in the next five years, to a cumulative \$92-202 million over the next twenty years (stated in 2005 dollars).*

The analysis provided by the UDP addresses the requirements for utility infrastructure, system capacity and efficiency (among other technical matters), and relies on engineering analyses and an economic analysis model. The UDP Model utilizes advanced economic scenario modeling and data analysis methods to evaluate the economic performance of utility infrastructure alternatives. Underlying this plan are the concepts of prudent capital investment, long-term strategic planning, and life-cycle cost analysis. As opposed to looking merely at the “first cost” of the project, the analysis considers the total costs, including capital, operating and maintenance, and any associated debt expenses incurred over the economic life of the project.

Alternative engineering solutions, energy prices, campus growth, capital investment versus long-term operating considerations and fiscal constraints are variables that create complex problems for facilities managers and necessitate the use of comparative analyses in strategic planning evaluations. Equally important is the need for developing a comprehensive funding strategy, which will ensure that the utility project plan chosen can be fully and successfully implemented.

*Based on evaluation and consideration of all business and operational parameters discussed in this UDP, UAF has assessed that the “preferred” solution requires development of an implementation plan that focuses on expansion of the central plant facilities (i.e., generally either Strategy 2 or 3), with an emphasis on implementing the coal-fired solution (Strategy 3) if the capital investment constraints can be overcome. The preferred Strategy chosen is expected to become a “guiding principle” for implementation of UAF’s utility infrastructure renewal and expansion. However, until capital constraints are resolved, the implementation of the UDP concepts will—of necessity—focus on incremental steps.*

***The UDP Project Team strongly recommends that UAF identify and empower a focused Utility Project Team charged with implementation of the UDP Strategy, including an advocacy role seeking to resolve the capital funding issues.***

## EXISTING UTILITY INFRASTRUCTURE RENEWAL REQUIREMENTS

The existing utility system infrastructure at UAF requires significant investment in major maintenance, renewals, and upgrades in order to continue to provide reliable utility services. The maintenance, renewal, and system upgrade requirements are common to any and all future growth strategies the University considers, and are incorporated as part of the UDP analyses. Recent studies and investigations of the forty-plus year old electrical and steam production and distribution system have identified single-point failure reliability issues in plant auxiliaries,

facilities, and aged and undersized components of the system that must be replaced. These deficiencies and renewal issues identified are largely independent of planned campus growth or ongoing operational budget concerns, and are simply the problems inherent to a large scale and complex electro-mechanical system under continuous operation for decades.

Table 13 summarizes the common utility system improvements currently required at UAF. *These required upgrades to renew and maintain UAF's current utility capabilities and system reliability total approximately \$61.7 million, and are a necessity no matter what long-term utility strategy is chosen for UAF.*

**Table 13 Common Capital Asset Renewal Expenses by Utility System**

<b>Utility System</b>	<b>Estimated 2005 Capital Cost</b>
Electric System	\$ 39,489,000
Steam System	\$ 14,600,000
Chilled Water System	\$ 1,040,000
Domestic Water System	\$ 3,022,000
General Plant	\$ 3,510,000
<b>Total</b>	<b>\$ 61,660,000</b>

## UAF FORECASTED UTILITY SERVICE REQUIREMENTS

The *2005 Utility Development Plan* is primarily based on forecasted University square footage growth over a twenty-year time span. The UDP analysis anticipates the timing and location of this growth to predict expected utility commodity (electricity, steam, and chilled water) consumption requirements over the study period.

An inventory of FY 2005 campus buildings shows total campus building square footage of approximately 2.8 million square feet that can be served by DES utility services. In projecting square footage of campus buildings to predict future utility needs and capacities, the UDP

Project Team has adopted a Base Case forecast of 3.9 million total campus square feet in FY 2025 as a justified and reasonable estimate of future UAF growth, based on historical campus growth patterns, the University’s Six-Year Capital Plan growth projections, and discussions and analysis with UAF staff and administrators.

The UDP Model is largely “driven” by the forecasts of final consumption utility service demands. These primary final consumption commodities are: steam heating services, chilled water cooling services, and electrical services (for building, lighting and auxiliary loads). The UDP incorporates these demand factors, as well as a forecast of purchased fuel prices delivered to the University, to predict life-cycle utility operating and maintenance costs, labor costs, fuel costs, debt (including principal and interest) costs, depreciation, and capital costs for required new infrastructure and renewal of existing utility service facilities.

## ALTERNATIVE UTILITY INFRASTRUCTURE STRATEGIES

The UDP considers three distinct Strategies to meet the present and future utility service demands of UAF. These Strategies were defined by the UDP Project Team with the assistance of UAF facilities staff, and differ with respect to specified equipment, timing of installations, purchased fuel commodity used, and physical location of new utility infrastructure development. The three Strategies are structured to achieve the same utility-service objectives using different utility engineering approaches and business solutions.

The Strategies range from a fully centralized plant that maximizes the use of coal for both steam and electric production, to individual building boiler heating systems (“stand alone”) that are not connected to the centralized system. Alternative systems are specified to utilize either fuel oil or natural gas for heating, and to supplement UAF’s self-generated electricity production

capability with purchases from a third-party utility service provider. For each Strategy, the engineering analysis defines the utility systems, its components and associated capital costs. The Strategies are then defined, tested and adjusted accordingly in order to meet the predicted loads forecasted for UAF for the twenty (20) year study period.

**STRATEGY 1** minimizes the *upfront initial capital investment* that is required for UAF to be able to satisfy future utility demands of the campus. This goal is accomplished through implementation of "stand alone" heating and cooling systems and increased purchases of electricity to meet future growth in utility service requirements.

**STRATEGY 2** is also designed to minimize capital investment, but has a simultaneous goal to *minimize* the number of "stand alone" heating systems that operate independent of the centralized DES system, recognizing the required individual maintenance, greater operational costs and shorter expected useful life of the "stand alone" equipment as compared to centralized DES equipment.

**STRATEGY 3** focuses on construction of a central, durable and operationally low-cost coal-fired DES utility system that will support the demands of the UAF campus for decades to come with little additional future capital investment beyond the initial investment.

All Strategies have natural gas fuel as an alternative to fuel oil-burning steam production equipment, and Strategy 2 also considers the economic advantage of a central chiller plant facility versus utilizing "stand alone" cooling facilities in new building construction.

Capital costs for all Strategies have been estimated based on current year (2005) costs of installation, replacement and maintenance. These current costs have been increased by a factor of thirty percent (30%) to estimate the full *constructed* project cost.

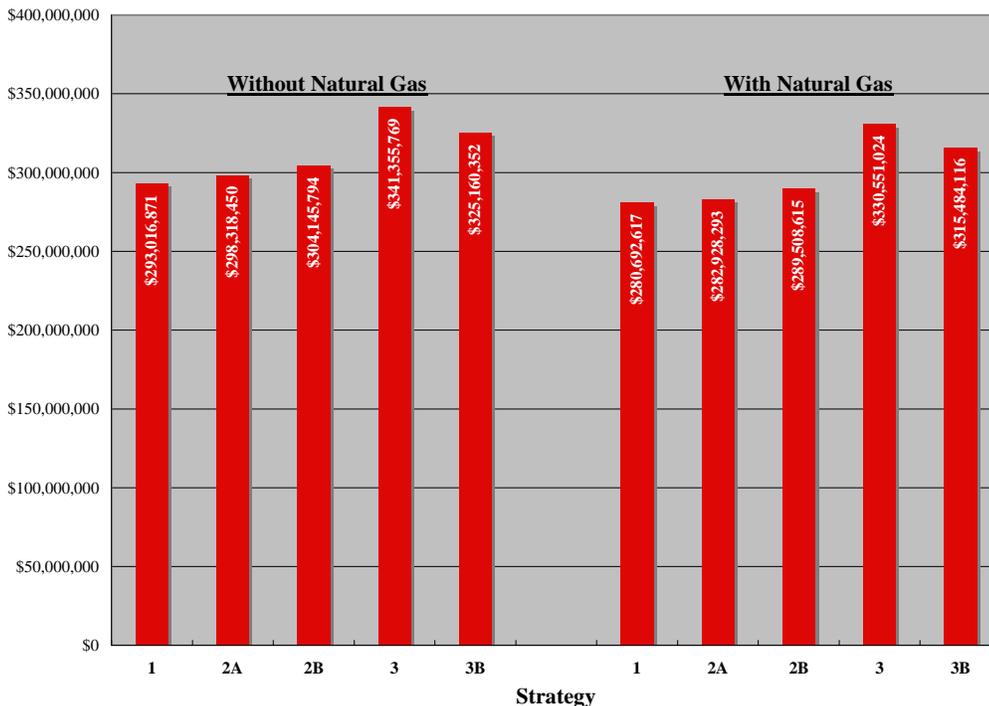
## COMPARATIVE ANALYTICAL RESULTS

The UDP Model analysis produces results that forecast operating expenses and revenues for each of the Strategies. Those operating expenses and revenues are summarized as a *Pro Forma* statement of annual cashflows. The *Pro Forma* statements incorporate revenue account balancing of cashflow with respect to all forecasted operating expenses, including debt costs (principal and interest), and depreciation costs associated with the “fully-loaded life-cycle” cost analysis.

To present a fair economic comparison of the modeled Strategies, the UDP compares each Strategy on the basis of its discounted NPV of expenses. Note that, because the NPV is of *operating expenses*, the economic evaluation is a preference for the *lowest* NPV.

**Figure 28** summarizes the NPV results of each of the Strategies modeled.

**Figure 28 UAF UDP 20 Year NPV of Operating Expenses by Strategy Discounted at 5%**



These results first demonstrate a consistent preference for each of the Strategies with implementation of the natural gas fuel sub-option. The results also demonstrate a significant

economic preference for Strategies 1 and 2. This means that, *within the time period evaluated*, in spite of the substantially lower annual operating costs of Strategy 3, the expanded coal plant investment will produce higher total operating costs as a result of associated debt service.

The NPV results, however, are only a *component* of the economic evaluation of these Strategies, as other intangible and exogenous factors that are not captured by the strict financial modeling of costs must also be considered. The NPV results must also be evaluated in the context of other considerations and risk factors that may suggest Strategy 3 is still the most strategically sound long-term utilities system investment Strategy for UAF.

## FORECASTED UTILITY SERVICE RATES

It is a common component of utility rate design that the annual operating expense of the utility services be captured in the utility rates. UAF generally accomplishes this task in its current definition of utility rates. As a result of UAF's current practice of full recovery of *operating costs* in its current utility rate structures, the most important discussion point to be considered by the UAF UDP is the issue of full *capital cost recovery* in utility rates, and the recovery of "costs" associated with *asset depreciation and renewal*.

This rate design issue arises, as a decision that must be made as to the extent to which UAF wishes the Utilities Division to be self-sustaining through rates charged for utility services. The implication of not incorporating the amortized depreciation expenses for accrual to a fund for future capital replacements is that—at that time in the future that the capital components of the utility facilities reach the end of its useful life—a source of capital or additional debt will be

required to continue the required utility services to the University. *Note that this is exactly the position in which UAF currently finds its utility facilities, which is juxtaposed with the standing of every other campus of the University of Alaska system.*

## UDP “BUSINESS MODEL” ANALYSES

The *2005 Utility Development Plan* addresses several alternative business “models” that may be utilized to structure the operation and financing of the utility services required by the campus in the future. The business practices currently employed by the UAF Utilities Division are relatively common among major universities.

Two alternative UAF utility services business structures are investigated. The first retains ownership of the utility facilities within the administration of the UAF, and contemplates the creation of an independent and self-sustaining Utilities Division enterprise that is responsible for recovery of all utility-related costs through its rates. In the second business structure, a third-party obtains ownership and control of the UAF utility facilities, and is charged with the prudent management of those facilities such that the facilities are fiscally self-sustaining in perpetuity and provide high levels of service capacity and reliability.

The business enterprise structure and rate design analysis specified in the UAF UDP cost-of-service rate model incorporates consideration of the ongoing “consumption” of the capital assets—and allows definition of utility service rates required for the funding of long-term capital renewal. The concept is simply that rates charged for utility services must also accumulate a reserve fund for the replacement of the capital assets at the end of its expected useful life.

The other business model contemplated in the UDP would remove utility service responsibilities from UAF’s administrative burdens, and allow an independent third-party to provide these services to the University. Assuming the University was to choose this independent third-party approach, it must also be assumed that the University would seek to have

university-friendly owners in the management and operation of the utility facilities. Definition of the relationships and responsibilities between UAF and the third-party utility service provider is but one of the contracting obstacles that would need to be addressed.

## UDP SENSITIVITY AND RISK ANALYSES

Risk analysis in the context of the long-term facilities development contemplated in the UAF UDP is a complex and imprecise element of planning. Regardless of the Strategy selected, there are elements of the external environment in which UAF must operate its utility service facilities that are outside its control. These exogenous factors cannot be explicitly modeled within the scope of the UDP, but must be acknowledged and at least identified in the context of the “direction” of impact on the economic evaluations performed by the UDP.

A concern that the UDP Project Team has been repeatedly confronted with in its analysis is the reliability of electrical service available from GVEA. Thus, this risk issue has to be treated as a strong negative impact with respect to Strategies 1 and 2, as they are Strategies that *increase* UAF’s reliance on GVEA electricity supply.

This reliability issue is also of particular significance in the consideration of a third-party utility service provider taking operational control of the facilities under any of the three Strategies. The ability of UAF to supply its full electric requirements for the foreseeable future under Strategy 3 allows assertion of this as a positive element of the Strategy 3’s risk profile.