Industrial Assessment Center

C I E

Center for Er ble Energy

University of Massachusetts
Department of Mechanical and Industrial Engineering

Resource Conservation Report for

No.

Assessment Date: **February 12, 2001**
Location:

Principal Products: **Specialty Paper**
S.I.C. Code: **2621**
Report Date: **April 1, 2001**

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PREFACE

The work described in this report was performed by the University of Massachusetts Industrial Assessment Center (IAC). The U.S. Department of Energy (DOE) funded the project, with Rutgers, the State University of New Jersey as prime contractor.

The objective of the Center is to identify and evaluate, through visits to industrial sites, opportunities for energy conservation, waste minimization, and productivity enhancement. The evaluation process is normally based on data gathered during a one-day site visit, and is therefore restricted in detail and completeness because of limitations on available time at the site. When energy conservation and waste minimization opportunities involving engineering design and capital investment are found to be attractive to the company, it is recommended that, where in-house capability is not available, the services of a consulting engineering firm be engaged to do detailed engineering design and estimating of implementation costs of the desired assessment recommendations contained in the report.

DISCLAIMER

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EXECUTIVE SUMMARY

Resource consumption at your plant for the twelve-month period represented in the bills received is given in the table below.

Resource Consumption

RESOURCE	UNITS CONSUMED	MILLION BTU'S CONSUMED	COST
Electrical Energy	18,406,926 kWh	62,823 MMBtu	$1,324,931
Electrical Demand	39,617 kW	--	$353,333
Other Electrical Fees			$62,365
Propane	131,123 gal	12,011 MMBtu	$87,744
#6 Oil	1,634,256 gal	248,407 MMBtu	$1,224,997
Water	2,378,300 gal	--	$3,001
Sewer	897,108	--	$2,022
Water & Sewer Charge	--	--	$3,600
Total		**323,241 MMBtu**	**$3,061,993**

The resource assessment recommendations (AR's) described in this report (considered independently) could save an estimated 1,203,000 kWh in electricity, 1,615 kW of demand, 55,060 MMBtu of #6 Oil, and 7,900 MMBtu of propane. This corresponds to total annual savings of $505,300. The recommendations are summarized in the table on the following page. The assumptions and equations used to arrive at the consumption estimates and cost savings for the recommendations are given elsewhere in this report. If the client does not agree with the assumptions made, he or she can adjust them and, using the same equations, arrive at his or her own values for the recommended AR's.

In order to determine the success of our energy conservation and waste minimization program, we would like to discuss with you, in about six months, your opinion of this report and how many of our suggestions you have decided to implement. If there are any questions about our report, you may contact us at (413) 545-4216 for clarification.

Summary of Assessment Recommendations

Assessment Recommendation	Annual Resource Savings	Annual Cost Savings	Implementation Cost	Payback Period
1) Recover Heat From Wastewater	#6 Oil: 59,720 MMBtu Electricity: -251,000 kWh Demand: -360 kW Total:	$275,000 -$18,000 -$3,000 $254,000	$120,000	0.5 years
2) Recover Heat From Coating Dryer	Propane: 7,900 MMBtu	$62,000	$35,000	0.6 years
3) Use Cogeneration For Electricity Production	Electricity: 852,200 kWh Demand: 1,895 kW #6 Oil: -5,100 MMBtu Total:	$61,400 $17,000 -$24,000 $54,400	$290,000	5.3 years
4) Install Variable Speed Drive on Wastewater Pump	Electricity: 215,400kWh	$15,500	$9,500	0.6 years
5) Install Variable Speed Drives on Boiler Feedwater Pump	Electricity: 115,200 kWh	$8,300	$12,000	1.4 years
6) Install Variable Speed Drives on Beater Chest Pumps	Electricity: 170,000 kWh	$12,000	$24,000	2.0 years
7) Utilize Higher Efficiency Lighting	Electricity: 56,400 kWh Demand: 80 kW Total:	$4,100 $700 $4,800	$51,800	10.8 years
8) Install Variable Speed Drives on Machine Chest Stock Pumps	Electricity: 51,000 kWh	$3,700	$0	Immediate

9) Reduce Air Compressor Pressure	Electricity: 44,800 kWh	$3,200	$0	Immediate
10) Insulate Condensate Tank	#6 Oil: 440 MMBtu	$2,000	$3,000	1.5 years
Totals	Electricity: 1,203,000 kWh	$90,200	$545,300	
	Demand: 1,615 kW	$14,700		
	#6 Oil: 55,060 MMBtu	$253,000		
	Propane: 7,900 MMBtu	$62,000		
	Total:	$505,300		

GENERAL PLANT BACKGROUND

Plant Description

The gross floor area of this facility is 231,600 square feet. The space consists of a basement and main level. The exterior walls are of masonry construction. The ceiling is a combination of wood plank and steel beam construction. The windows are single glazed and generally covered with polyethylene to improve the windows thermal efficiency. The original building was constructed in 1904, with ongoing changes and improvements up until the present. Some insulation exists in various locations.

Of the total area, 14,400 square feet is dedicated to office activities. The office generally operates from 8:30am to 5pm, five days per week, and houses 50 employees. Energy efficient fluorescent lighting is in place here. Propane-fired heaters supply hot air in the winter. Summer cooling is accomplished with a packaged rooftop unit. Set points for winter and summer are 70°F. Nighttime setbacks are 60°F and 75°F, respectively.

The remaining 217,200 square feet of floor space is used for the process and support. This area operates 24 hours per day, seven days per week, except for a two-week shutdown in July. A mixture of energy efficient fluorescent and metal halide bulbs provides lighting. This area is not cooled in the summer. Unitary steam heaters provide winter heating. Steam is supplied to these heaters from the main process boilers. Some areas operate exhaust ventilation fans.

The plant operates two paper machine lines. The major energy consuming equipment at the site consists of many electric motors, ranging in size from 5 to 300 hp, used for pumping and refining, and two 600 hp #6 fuel oil fired high-pressure steam boilers. The steam load is balanced between the two. The plant generates approximately 20% of its electric power usage. The plant operates a backpressure steam turbine generator set that expands steam from 150 to 45 psi in order to produce electric power along with the steam needed for the process. The 45 psi steam is used in the drying process, on paper machine #1. A steam drive turbine is also used to drive the steam cans on paper machine #2. The drive turbine expands 150 psi steam down to 45 psi and uses the expanded steam in the drying process for paper machine #2. There is also a hydroelectric turbine that generates electircal power for the plant.

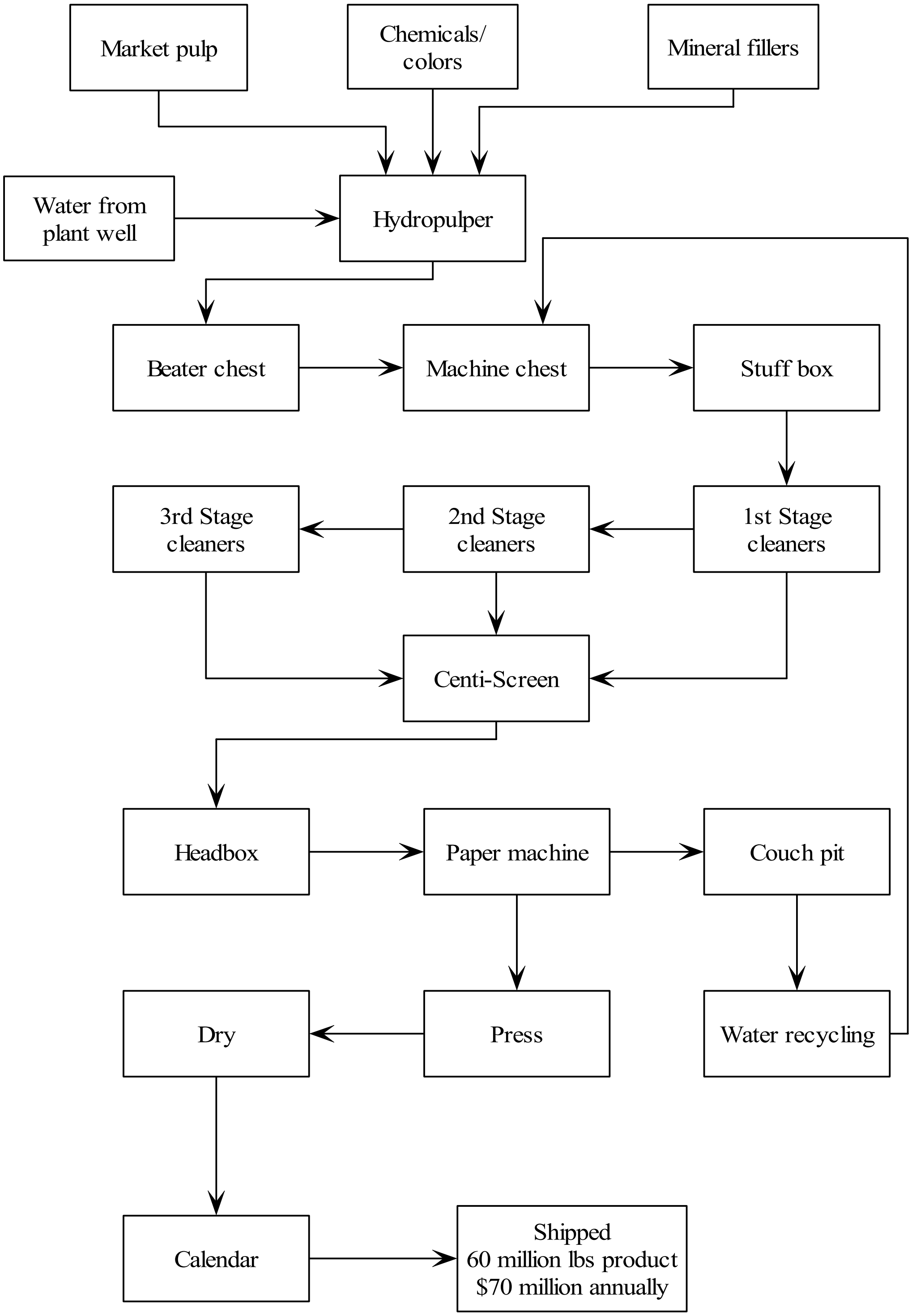
Plant Diagram

Process Description

The facility receives virgin or secondary fiber in rolls or bales and converts the material into finished paper. The plant produces the finished paper by operating two independant paper machines. The process below describes one these machines. The process begins with the combination of pulp and water in large mixing tanks called pulpers. Fibers from other sources are then added to the tanks that are additionally mixed with treatment chemicals, and colors in the pulping tank. The mixture is further refined in a beater chest and then in one of three refiners. From the refiners the pulp-water mixture undergoes a three-stage cleaning process. The water is cleaned at each stage and evaluated to determine if the water is sufficiently cleaned. Water that meets cleaning specification requirements bypasses the remaining cleaning stages. The clean water is then sent through a screening process. The mixture is sent to one of two head boxes located at the beginning of the paper machine lines. The mixture is laid up onto a conveyer where the water drains into the couch pit, and the pulp begins to cohere into a sheet. The water drained into the couch pit undergoes a “Saveall” recycling process. The recycled water is reused in the initial mixing processes.

Water jets are used to cut the sides of the paper. The machine then presses the sheet between felts. After being pressed, the sheet is further dried primarily over metal, steam-filled cylinders however, electric resistance and electric infrared radiation heat is also used in several locations. After the sheet is fully dried, it is collected onto calendar rolls. After the paper is cooled, some of the paper is coated with latex or various other substances. The paper is then transferred into rolls and cut to the customers’ width specifications, warehoused and finally shipped to the respective customer. The plant annually produces 60 million pounds of finished paper.

Process Flow Chart



MAJOR PLANT ENERGY CONSUMING EQUIPMENT/AREAS

A. Electricity:

2 Mixing process motors; 300 & 200 hp
3 Air compressors; 150, 125 & 25 hp
2 Pulper drive motors; 150hp
1 Well pump; 40 hp
2 Clear white water pump; 40 hp
2 Boiler feed water pumps; 50 hp
3 Waste water pump; 40 hp
2 Beater chest pumps; 30 hp
2 Centri screen motors; 50 hp
2 Machine chest stock pumps; 50 hp
Many other electric motors for fans, pumps, etc. used in production

B. Natural Gas/Oil: 2 30,000 lb/hr #6 oil-fired steam boilers

C. Propane: Coating Dryer

Previous Plant Energy Surveys and Conservation Measures Implemented

A. Energy Surveys: Public Service of New Hampshire; February, 1999.

B. Good Practices:

1. Converted to Energy Efficient Lighting
2. VSDs on some supply pumps and fans
3. Utilizing Cogeneration
4. Hydroelectric generation

AUDIT DATA

Audit Report Number: 484/200104

Plant Location: Providence, RI

Auditors:
Lwerence Ambs
Michael Stocki
Saygin Celen
Dragoljub Kasanovic
Daniel Sobrinski
Gregory Leger

Audit Date: 2/12/2001

Total Plant Area: 231,600 ft^2

Principle Products: Specialty Paper

SIC Code: 2621, 2672, 2679

Annual Sale of Services: 7 million

Annual Production Volume: 6 million pounds of finished paper

Number of Employees: 100

Operating Schedule:

Production: 1st shift, 8 hours, 7 days per week
2nd shift, 8 hours, 7 days per week
3rd shift, 8 hours, 7 days per week
Office: 8:30 am to 5:00 pm, M-F

Annual Shut Down: Two Weeks in July

Peak Production Period: No

Annual Plant Operating Hours: 8,425

Energy Sources: Electricity, Propane, #6 Oil

Client Cost for Assisting with Audit:

Management Time (16 hours at $50/hr)	=	$800
Support Staffing (8 hours at $30/hr)	=	$240
Total	=	$1,240

RESOURCE MANAGEMENT

As companies weather rising energy costs and increasingly complex, stringent and costly waste regulations, many of their futures will be determined by how they meet these challenges. A successful company must have an energy management and waste minimization program to consistently take advantage of every conservation opportunity. Several basic steps are required for effective resource management:

- Management Commitment
- Data Acquisition and Analysis
- Analysis of Conservation Opportunities
- Implementation of Conservation Techniques
- Continued Feedback and Analysis

The resource management program must have the commitment of management for it to produce a long-term increase in energy efficiency. A brief, early show of support will only result in small, temporary improvements. Management must design the conservation program as part of its regular, overall company management system. Also, energy costs and the consequence of future energy shortages should be widely disseminated to create an overall energy awareness.

Accounting for energy and its cost is an essential component of any energy management program. It can best be done by keeping up-to-date bar graphs of energy consumption and associated costs on a monthly basis. When the utility bills are received each month it is recommended that the energy used be plotted immediately on the bar graphs. A graph will be required for each type of energy used. The value of the bar graphs can best be understood by examining those plotted for your company on the following pages. It is simple to detect trends and anomalies from these graphs, and much easier to assess the value of energy conserving actions.

Data analysis will be greatly aided if the records use a standard format for all the company's divisions and if the different energy units (such as kilowatt-hours of electricity, gallons of oil, etc.) are converted to a common energy unit, such as the British Thermal Unit (Btu). One Btu is the amount of energy needed to raise the temperature of one pound of water one degree Fahrenheit. By comparing the cost of various fuels on the basis of cost per million Btu's ($/MMBtu), the true cost of each fuel can be determined. The conversion factors required are:

Conversion Factors

ENERGY UNIT	BTU EQUIVALENT
1KJ	0.94782 Btu
1 kWh	3,413 Btu
1 Therm	100,000 Btu
1 CCF Natural Gas	100,000 Btu*
1 Gallon #2 Oil	140,000 Btu*
1 Gallon #4 Oil	144,000 Btu*
1 Gallon #6 Oil	152,000 Btu*
1 Gallon Propane	91,600 Btu*
1 Ton Coal	27,800,000 Btu*
1 Ton Refrigeration	12,000 Btu/hr
1 Boiler Horsepower	33,475 Btu/hr

*Note: these values vary slightly with supplier.

Similarly, the first step of an effective waste minimization plan is to prepare a complete inventory of all plant wastes, both hazardous and non-hazardous; that is, to understand the types and sources of all waste streams, taking account of exact quantities and costs. Once this has been done, it is necessary to analyze this information from economic, legal and technical perspectives, and finally to prepare a comprehensive waste plan that addresses management's concerns in the most effective way.

The Environmental Protection Agency recommends the following four-step process:

Planning and Organization

- get management commitment
- set overall assessment program goals
- organize assessment program task force

Assessment Phase

- collect process and facility data
- prioritize and select assessment targets

- select assessment team members
- review data and inspect site
- generate options
- screen and select options for further study

Feasibility Analysis Phase

- technical evaluation
- economic evaluation
- select options for implementation

Implementation

- justify projects and obtain funding
- install equipment
- implement procedure
- evaluate performance

Often the process is carried out through an environmental audit. The conservation survey represented in this report, including the assessment recommendations on the following pages, should not be construed as a full-scale environmental audit.

Even without an audit, however, a company can easily identify and implement "common sense" waste reduction opportunities, such as eliminating excess water use, if the steps described above are followed. For less obvious measures, it is crucial that the following information be gathered for each stream:

- source
- generation rate
- physical characteristics
- chemical characteristics
- production rate of process generating the waste
- current management method
- cost of management method

In general, waste streams should be segregated and wherever possible, it is preferable to reduce waste generation than to recycle and preferable to recycle than it is to treat waste.

On a regular basis, whether monthly or annually, progress toward conservation goals should be examined and a new set of goals defined. All goal setting will depend on the opportunities for resource conservation which data analysis has uncovered. More detailed information on specific mechanisms may be required as the program continues to develop.

Facility Billing Information

The energy bills for the facility have been summarized in order to determine a concise characteristic of yearly usage. From this summary marginal costs are determined in order to calculate savings. Marginal cost is the cost of the last unit of resource purchased. Marginal costs are generally, but not always, lower than average costs since they do not include the service charges and therefore represent conservative estimates for savings calculations. The total cost of electricity from January 2000 through December 2000 was $1,740,629, including service charges. The total usage during this period was 18,406,926 kWh (62,823 MMBtu) with an average cost of $0.075 per kWh ($22.08 per MMBtu). The site was billed for 39,617 Kva of demand at a total cost of $353,333, or an average cost of $8.92 per Kva.

The total amount of propane used from December 1999 to November 2000 was 131,123 gallons (12,011 MMBtu). Propane costs for this period amounted to $87,744, at an average cost of $7.11 per MMBtu ($0.65 per Gallon).

The total amount of #6 Oil used from February 2000 to December 2000 was 1,634,256 gallons (248,407 MMBtu). #6 Oil costs for this period amounted to $1,224,997, at an average cost of $4.67 per MMBtu ($0.71 per gallon).

From February 2000 to November 2000 city water consumption amounted to 2,378,300 gallons and cost the company $3,001. Average cost of city water for this period was $0.002 per gallon. During the same period sewer consumption amounted to 897,108 gallons and cost the company $2,022. Average cost for sewer services for this period was $0.002 per gallon.

For the purpose of calculating the savings resulting from the recommendations in this report marginal costs are used and are summarized in the following table.

Marginal Costs

Electricity	$0.072/kWh ($21.13/MMBtu)
Electrical Demand	$8.98/Kva
Propane	$7.86/MMBtu
#6 Oil	$4.61/MMBtu
Water	$0.002/gal
Sewer	$0.002/gal

The energy bills for the plant are shown in following Billing Summary.

Billing Summary

ELECTRIC BILLS

Period	**Demand**	**Energy Usage**		**Demand Charges**			**Energy Charge**		**Administration Charge**	**Total Bill**
		Contract	**Outdoor Lighting**	**Contract**	**Billing**	**Total**	**Contract**	**Outdoor Lighting**		
Ending	Kva	KWh	KWh	($)	($)	($)	($)	($)	($)	
Jan-00	3,089	1,186,591	840	$21,720.00	$6,425.12	$28,145.12	$85,410.82	$199.57	$5,000.00	$118,755.51
Feb-00	3,182	1,611,239	840	$21,720.00	$6,618.56	$28,338.56	$115,976.98	$199.57	$5,000.00	$149,515.11
Mar-00	2,988	1,265,370	840	$21,720.00	$6,215.04	$27,935.04	$91,081.33	$199.57	$5,000.00	$124,215.94
Apr-00	2,856	1,164,157	840	$21,720.00	$5,940.48	$27,660.48	$83,796.02	$199.57	$5,000.00	$116,656.07
May-00	2,645	1,232,316	840	$21,720.00	$5,501.60	$27,221.60	$88,702.11	$199.57	$5,000.00	$121,123.28
Jun-00	3,306	1,301,750	840	$21,720.00	$8,265.00	$29,985.00	$93,699.97	$199.57	$5,000.00	$128,884.54
Jul-00	2,999	1,072,398	840	$21,720.00	$7,497.50	$29,217.50	$77,191.21	$199.57	$5,000.00	$111,608.28
Aug-00	3,992	2,081,209	840	$21,720.00	$9,830.00	$31,550.00	$149,805.42	$199.57	$5,000.00	$186,554.99
Sep-00	3,882	2,063,429	840	$21,720.00	$9,705.00	$31,425.00	$148,525.62	$199.57	$5,000.00	$185,150.19
Oct-00	3,711	1,846,874	840	$21,720.00	$9,277.50	$30,997.50	$132,937.99	$189.59	$5,000.00	$169,125.08
Nov-00	3,613	2,050,334	840	$21,720.00	$9,032.50	$30,752.50	$147,583.04	$189.59	$5,000.00	$183,525.13
Dec-00	3,354	1,531,259	840	$21,720.00	$8,385.00	$30,105.00	$110,220.02	$189.59	$5,000.00	$145,514.61
TOTALS	**39,617**	**18,406,926**	**10,080**	**$260,640.00**	**$92,693.30**	**$353,333.30**	**$1,324,930.53**	**$2,364.90**	**$60,000.00**	**$1,740,628.73**

Average Energy Cost = $0.0754 $/kWh
Average Energy Cost = $22.08 $/MMBtu
Marginal Energy Cost = $0.0721 $/kWh
Marginal Energy Cost = $21.13 $/MMBtu

Average Demand Cost = $8.92 $/Kva
Marginal Demand Cost = $8.98 $/Kva

Propane Bills

Period	**Quantity**	**Charges**		
Ending		**Propane**	**Service**	**Total**
	(Gal)	**($)**	**($)**	**($)**
Dec-99	9,487	$88.23	$9.49	$97.72
Jan-00	20,967	$15,751.39	$12.59	$15,763.98
Feb-00	42	$52.30	$0.00	$52.30
Mar-00	0	$0.00	$0.00	$0.00
Apr-00	0	$0.00	$0.00	$0.00
May-00	12,797	$7,542.55	$12.80	$7,555.35
Jun-00	0	$0.00	$0.00	$0.00
Jul-00	30,789	$20,081.88	$1,017.69	$21,099.57
Aug-00	0	$0.00	$0.00	$0.00
Sep-00	9,005	$6,929.35	$9.01	$6,938.36
Oct-00	9,508	$7,249.85	$9.51	$7,259.36
Nov-00	38,528	$27,726.64	$1,250.93	$28,977.57
TOTALS	**131,123**	**$85,422.19**	**$2,322.02**	**$87,744.21**

Average Propane Cost =	$0.65	$/Gal
Average Propane Cost =	**$7.11**	**$/MMBtu**
Marginal Propane Cost =	$0.72	$/Gal
Marginal Propane Cost =	**$7.86**	**$/MMBtu**

#6 Oil Bills

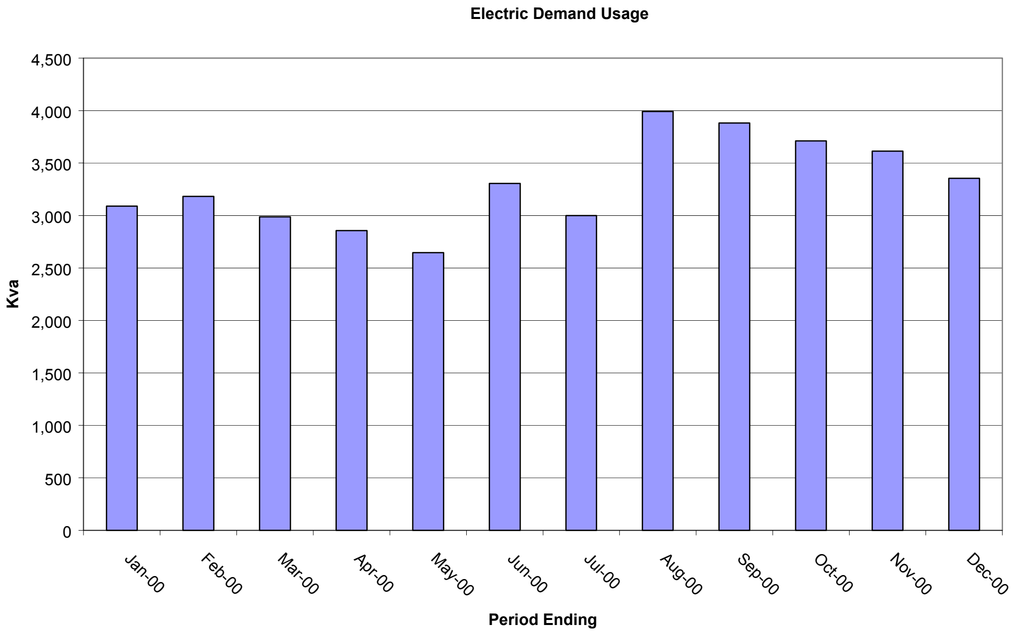
Period	**Quantity**	**Charges**		
Ending		**Fuel**	**Service**	**Total**
	(Gal)	**($)**	**($)**	**($)**
Feb-00	155,497	$88,929.38	$5,940.57	$94,869.95
Mar-00	177,926	$115,208.75	$8,664.38	$123,873.13
Apr-00	202,033	$110,976.92	$8,893.76	$119,870.68
May-00	161,416	$98,800.24	$4,019.68	$102,819.92
Jun-00	169,573	$107,335.64	$5,216.65	$112,552.29
Jul-00	149,239	$95,225.70	$7,189.94	$102,415.64
Aug-00	239,676	$158,201.65	$6,029.48	$164,231.13
Sep-00	130,808	$85,837.72	$4,400.47	$90,238.19
Oct-00	116,046	$83,010.64	$2,194.82	$85,205.46
Nov-00	132,042	$96,324.67	$5,360.00	$101,684.67
Dec-00	170,031	$119,176.31	$8,060.00	$127,236.31
TOTALS	**1,634,256**	**$1,159,027.62**	**$65,969.75**	**$1,224,997.37**

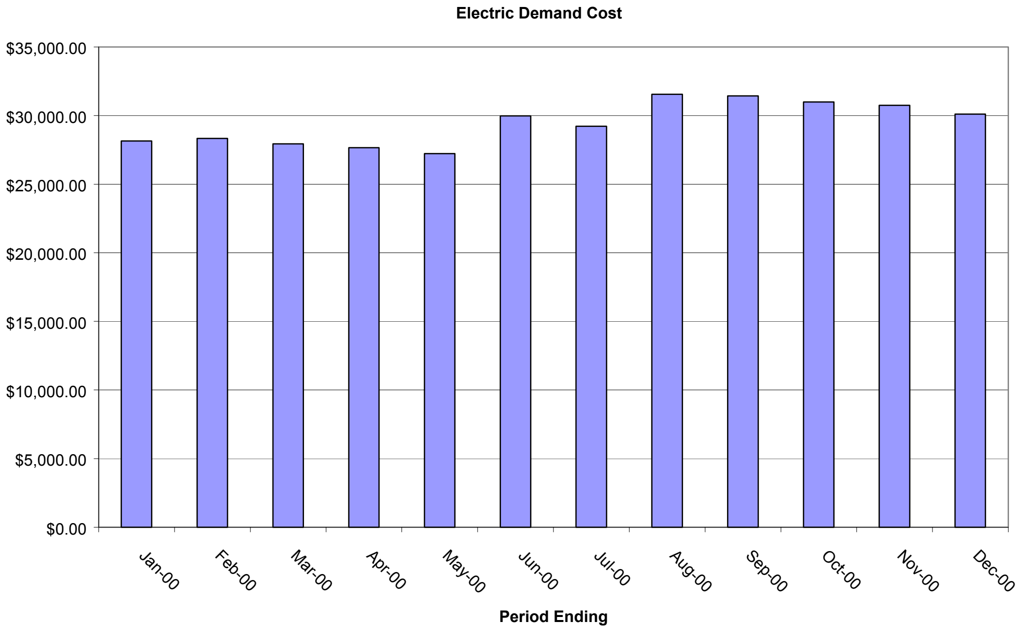
Average #6 Oil Cost =	$0.71	$/Gal
Average #6 Oil Cost =	**$4.67**	**$/MMBtu**
Marginal #6 Oil Cost =	$0.70	$/Gal
Marginal #6 Oil Cost =	**$4.61**	**$/MMBtu**

WATER AND SEWER BILLS

Period	**Usage**		**Charge**			**Total**
Ending	**Water**	**Sewer**	**Water**	**Sewer**	**Hyrdrants**	**Charge**
	(gal)	(gal)	($)	($)	($)	($)
Feb-00	472,600	292,032	$602.60	$625.50	$900.00	$2,128.10
May-00	692,400	245,710	$868.55	$543.51	$900.00	$2,312.06
Jul-00	483,600	183,198	$615.91	$432.86	$900.00	$1,948.77
Nov-00	729,700	176,168	$913.69	$420.42	$900.00	$2,234.11
TOTAL	**2,378,300**	**897,108**	**$3,000.75**	**$2,022.29**	**$3,600.00**	**$8,623.04**

Average Water Cost =	$0.002	$/gal
Marginal Water Cost =	**$0.001**	**$/gal**
Average Sewer Cost =	$0.002	$/gal
Marginal Sewer Cost =	**$0.002**	**$/gal**


Electric Demand Usage
Kva
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Period Ending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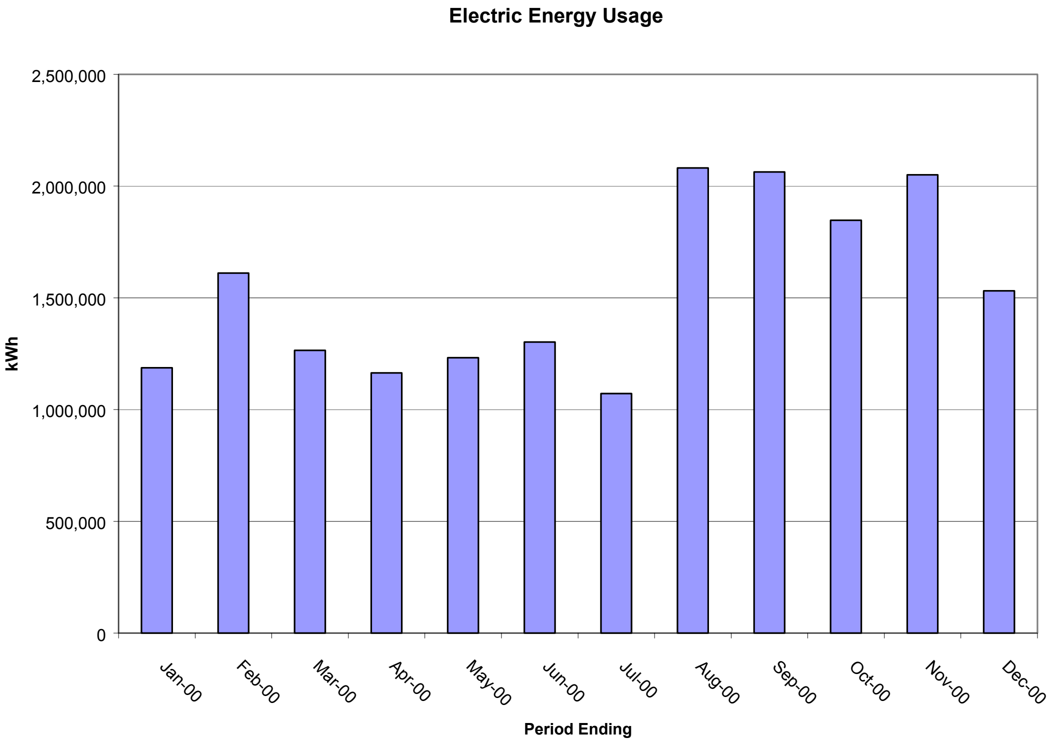
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Period Ending


Electric Energy Usage
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2,000,000
1,500,000
1,000,000
500,000
0
kWh
Jan-00
Feb-00
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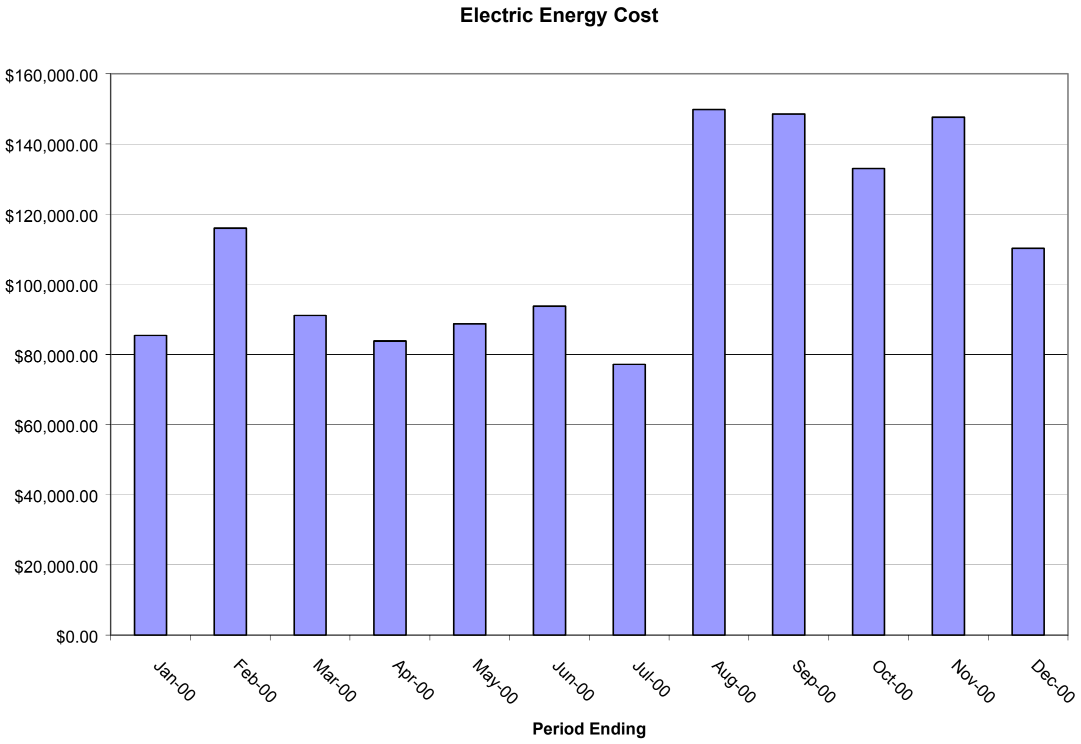
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Period Ending


Electric Energy Cost
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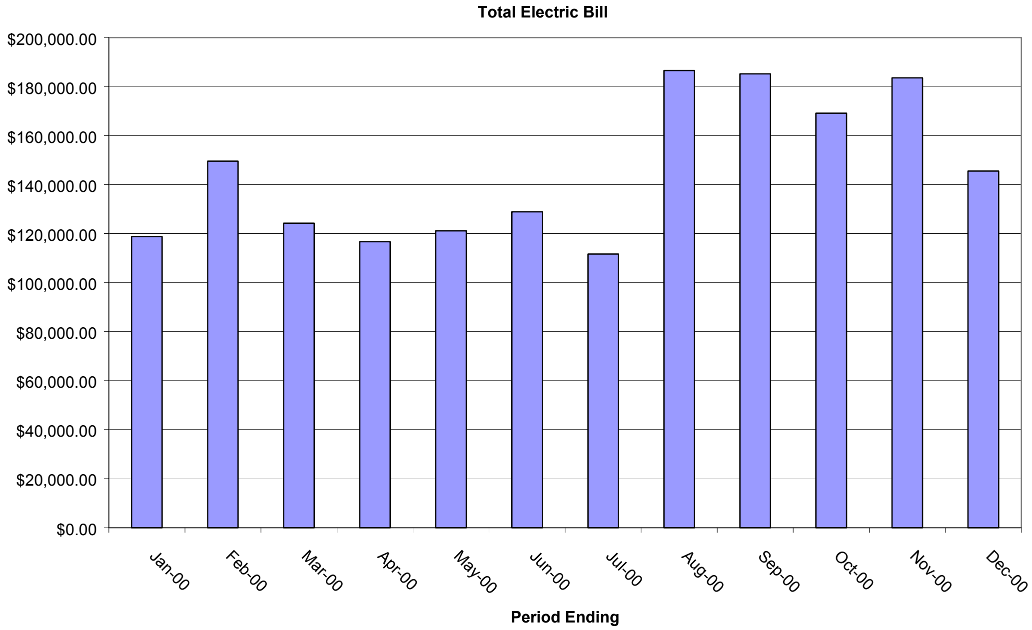
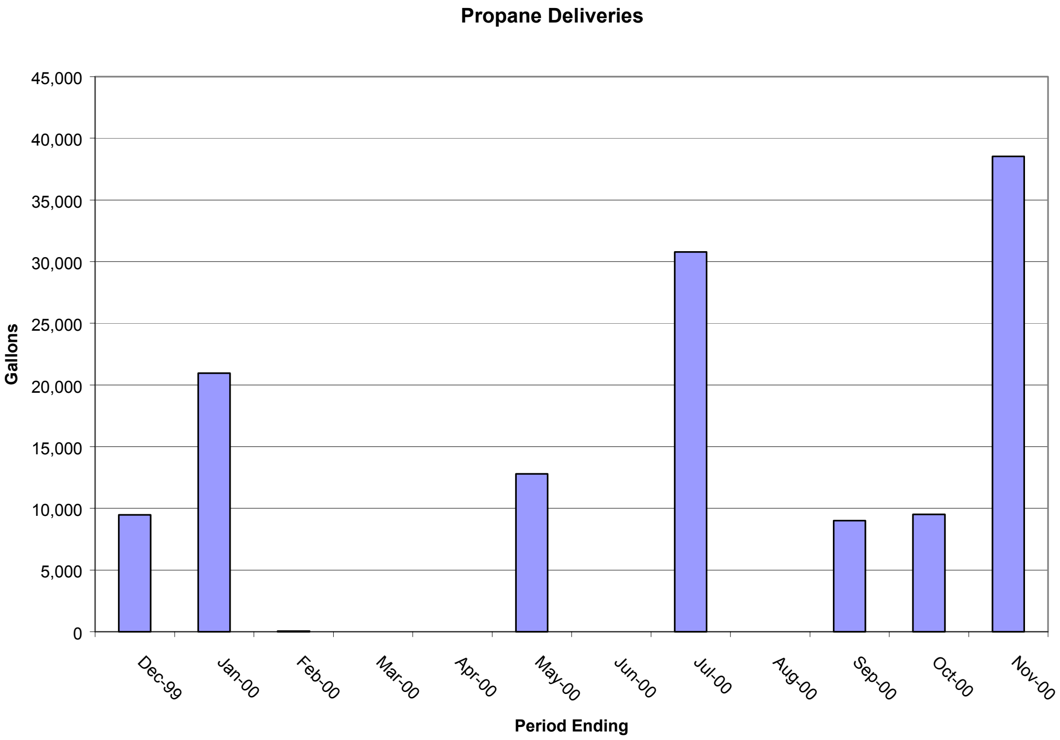
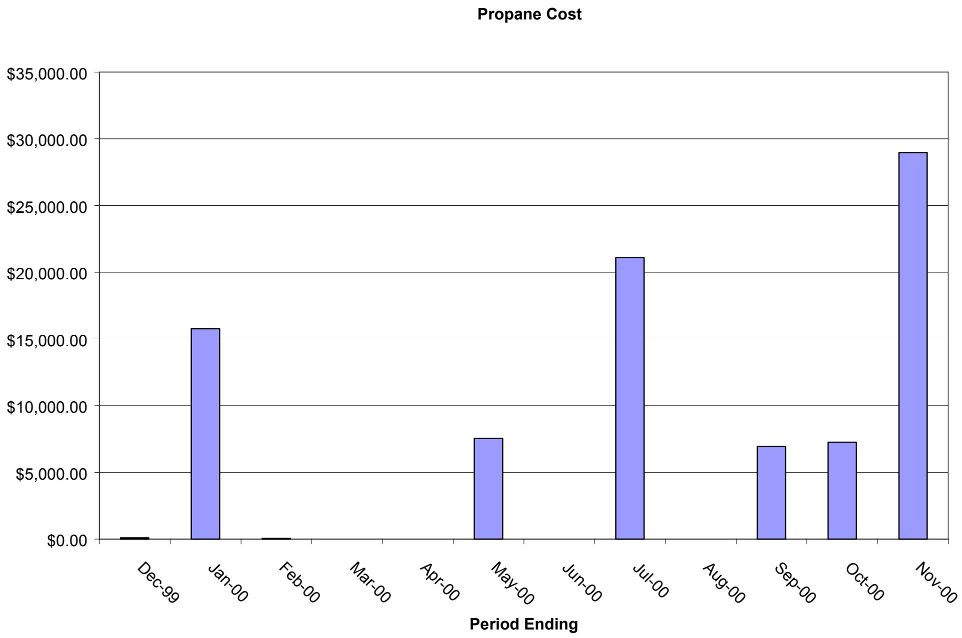
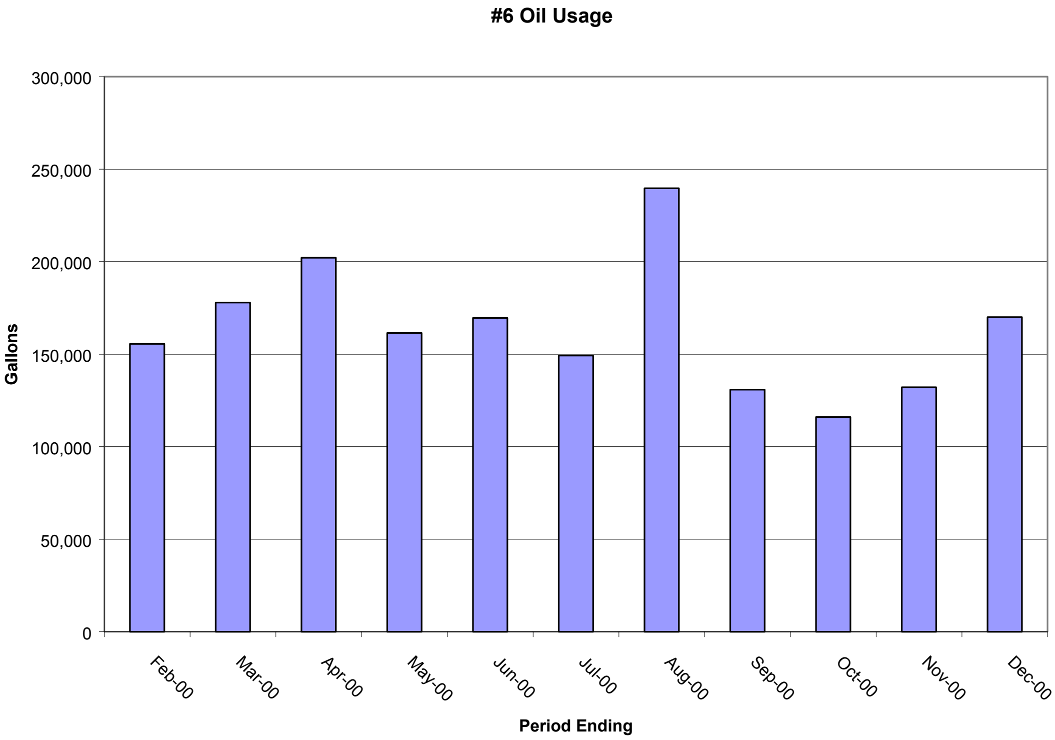
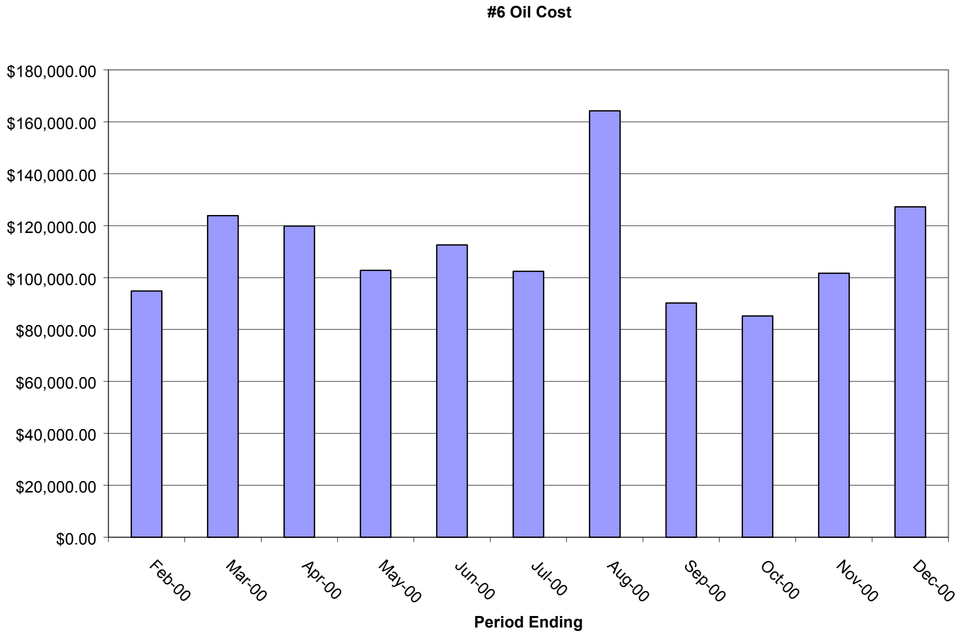
$140,000.00
$120,000.00
$100,000.00
$80,000.00
$60,000.00
$40,000.00
$20,000.00
$0.00
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Period Ending

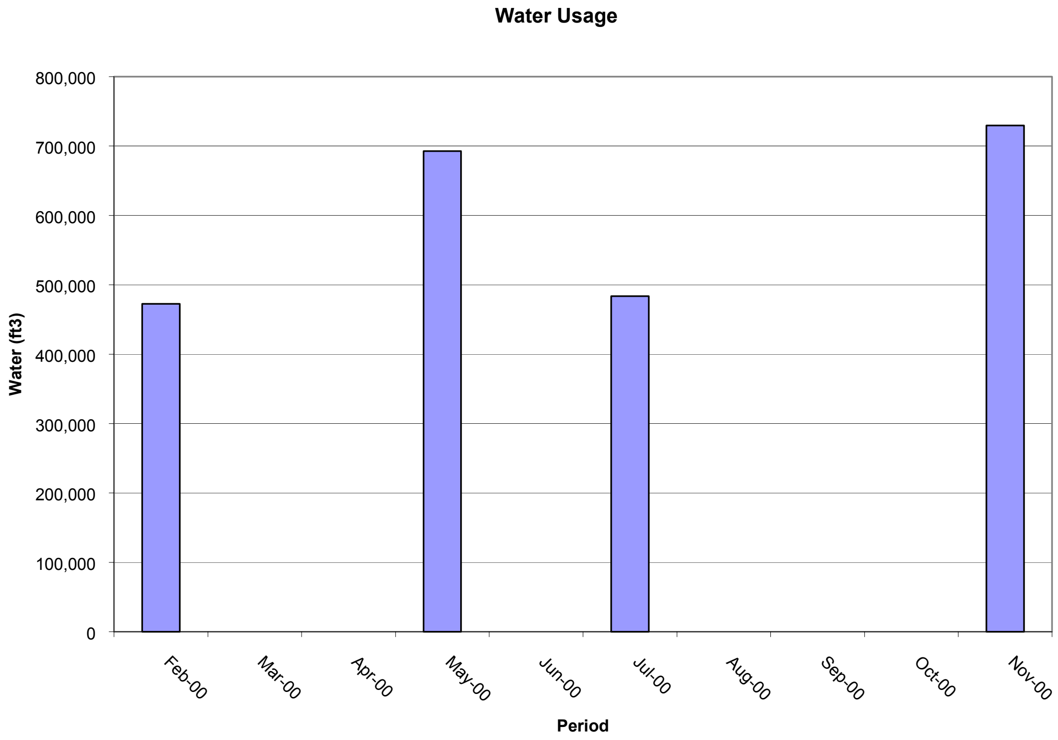

Total Electric Bill
$200,000.00
$180,000.00
$160,000.00
$140,000.00
$120,000.00
$100,000.00
$80,000.00
$60,000.00
$40,000.00
$20,000.00
$0.00
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Period Ending

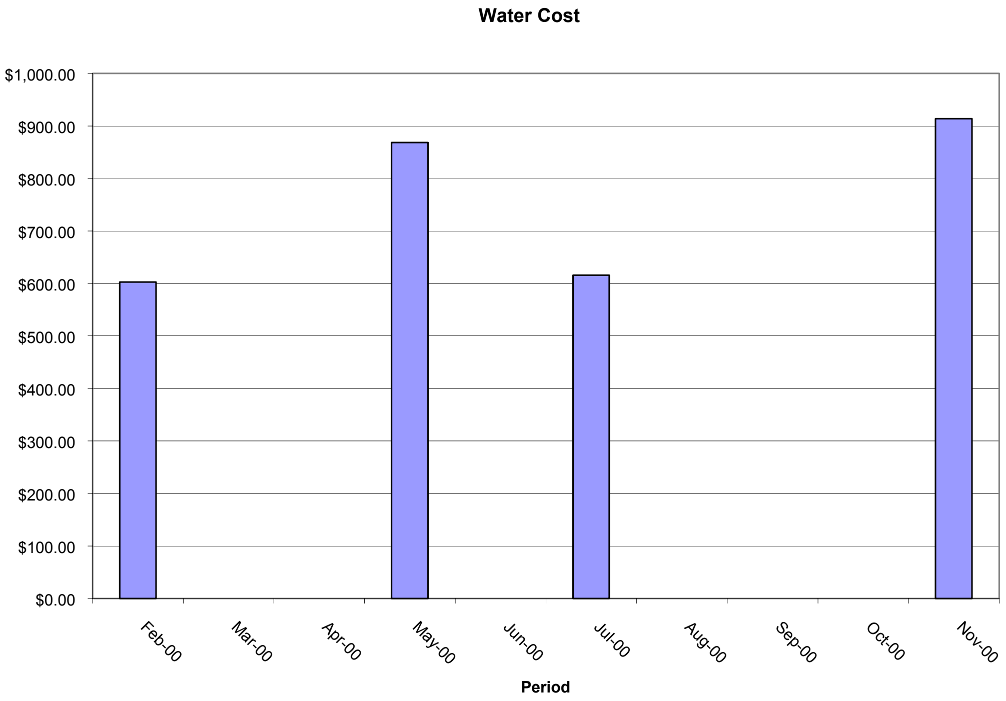

Propane Deliveries
Gallons
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Dec-99
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Period Ending


Propane Cost
$35,000.00
$30,000.00
$25,000.00
$20,000.00
$15,000.00
$10,000.00
$5,000.00
$0.00
Dec-99
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Period Ending


#6 Oil Usage
Gallons
300,000
250,000
200,000
150,000
100,000
50,000
0
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Period Ending


#6 Oil Cost
$180,000.00
$160,000.00
$140,000.00
$120,000.00
$100,000.00
$80,000.00
$60,000.00
$40,000.00
$20,000.00
$0.00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Period Ending


Water Usage
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
Water (ft3)
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Period


Water Cost
$1,000.00
$900.00
$800.00
$700.00
$600.00
$500.00
$400.00
$300.00
$200.00
$100.00
$0.00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Period

ASSESSMENT RECOMMENDATIONS

AR NUMBER 1: Recover Heat From Wastewater

Assessment Recommendation Summary				
ARC #	Annual Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.2444.1	#6 Oil: 59,720 MMBtu Electricity: -251,000 kWh Demand: -360 kW	$275,000 -$18,000 -$3,000 $254,000	$120,000	0.5 years

Current Practice and Observations

Warm wastewater from the process is pumped from the facility to outdoor treatment tanks. The average daily flow rates and temperatures of the wastewater for each month in 2000 are shown in Table 1.1. These values are a summary of data obtained from the facility. In addition to these values, the maximum flow rate based on daily averages was determined to be 760 gpm. Located within the facility are two water storage wells that are supplied from the main water supply. The water from these storage wells is used in the process. Well A has a volume of 37,000 gallons and well B has a volume of 43,000 gallons. The water in these wells is at 55 °F. For use in the process, this water is heated in various process steps. Heat is provided throughout the process by steam from the two oil fired water tube boilers. The wastewater piping runs near these wells. Water is used from these wells during all production hours 8,425 hours annually. The monthly hours are shown in Table 1.1.

Recommended Action

It is recommended that a shell and tube heat exchanger be purchased and installed to recover heat from the wastewater steam. This heat will be used to preheat the well water prior to entering the process. The wastewater piping system will need some modification in order to pipe the wastewater stream through the heat exchanger. In addition, the water from the two wells will require continuous circulation through the exchanger. Thus, two small circulating pumps will also require purchasing and installation along with the additional well water piping.

Month	Flow, DWF (gpm)	Average Flow Temperature, THI (°F)	Monthly Hours of Operation, HRS
January	530	93	744
February	592	93	672
March	537	94	744
April	536	93	720
May	537	96	744
June	561	95	720
July	332	96	409
August	528	99	744
September	538	95	720
October	559	92	744
November	469	93	720
December	421	85	744
TOTAL			**8,425**

Table 1.1: Wastewater Usage in 2000

Anticipated Savings

The energy savings from this recommendation will result in a decrease in boiler energy required, because of the increase in well water temperature. Thus, less boiler steam heat will be needed to bring the well water to the desired temperature. In order to determine the energy savings, a heat transfer analysis is performed on the heating coils. The effectiveness of the heat exchanger, assuming that the wastewater flow rate are equivalent to the well water flow rate, is given by the following:

$$\varepsilon = \frac{\mathrm{THI - THO}}{\mathrm{THI - TCI}}$$

where,

ε = Effectiveness of heat transfer from coils to wells, assumed; 0.6

THI = Temperature of warm wastewater entering well coils, Table 5.1; °F

THO = Temperature of wastewater leaving well coils, °F

TCI = Temperature of cool well water; 55°F

Re-arranging this relationship, the unknown temperature of the leaving wastewater, THO, can be found as follows:

$$\mathrm{THO} = \mathrm{THI} - \varepsilon \times (\mathrm{THI - TCI})$$

The results of this calculation are shown in Table 1.2. Since the amount of heat lost by the wastewater in the coils is equivalent to the amount of heat gained by the water in the two wells, the energy savings per hour for each month can now be determined as follows:

$$\mathrm{ES} = \frac{\rho \times \mathrm{DWF} \times \mathrm{Cp} \times (\mathrm{THI - THO}) \times \mathrm{C1} \times \mathrm{C2}}{\mathrm{C3}}$$

where,

ES = Average hourly energy savings; MMBtu/hr

ρ = Density of wastewater; 62.4 lb/ft^3

DWF = Daily average of wastewater flow, Table 1.1; gpm

Cp = Specific heat of wastewater; 1.0 Btu/lb-R

C1 = Conversion constant; 0.13368 ft^3/gallon

C2 = Conversion constant; 60 minutes/hour

C3 = Conversion constant; 1,000,000 Btu/MMBtu

The results of this calculation are shown in Table 1.2. Now that the average hourly heat gain values for the well water have been determined. The energy savings, due to the decrease in boiler steam energy required to heat the well water, can be determined from the following equation:

$$\mathrm{MES} = \frac{\mathrm{ES} \times \mathrm{HRS}}{\eta}$$

where,

MES = Monthly energy savings; MMBtu

HRS = Monthly hours of operation, Table 1.1; hours

η = Boiler efficiency, measured; 0.85

The results of this calculation are shown in Table 1.2. From the table, the total annual energy savings is 59,720 MMBtu.

	Average Waste Water Temp In, THI, (°F)	Average Waste Water Temp Out, THO, (°F)	Flow, DWF (gpm)	Energy Savings, ES (MMBtu/hr)	Energy Savings, MES (MMBtu)
January	93	70	530	6.1	5,340
February	93	70	592	6.8	5,390
March	94	71	537	6.2	5,410
April	93	70	536	6.2	5,230
May	96	71	537	6.7	5,880
June	95	71	561	6.7	5,710
July	96	71	332	4.2	2,000
August	99	73	528	6.9	6,010
September	95	71	538	6.5	5,470
October	92	70	559	6.2	5,390
November	93	70	469	5.4	4,570
December	85	67	421	3.8	3,320
TOTAL					**59,720**

Table 1.2: Leaving Wastewater Temperature and Energy Savings

Now that the annual energy savings values have been found, the annual cost savings can be determined:

$$ACS = AES \times MC_{\#6}$$

where,

ACS = Annual cost savings of #6 fuel oil; \$
AES = Total annual energy savings, Table 2; 59,720 MMBtu
$MC_{\#6}$ = Marginal cost of #6 fuel oil; \$4.61/MMBtu

Thus,

$$ACS = 59{,}720 \times \$4.61 = \$275{,}000$$

Analyzing the heat transfer to the well water, a few properties are important. Using the above heat gains, it was determined that on average the well water temperature leaving the heat exchanger will be 75°F. This 75°F water, when mixed in the well with the 55°F water, will cause the temperature of the well water to rise. To offset these annual cost savings there will be an increase in the pump power required due to the need to constantly circulate the well water through the heat exchanger at a flow rate roughly equivalent to that of the wastewater. Two 20 hp pumps are estimated to be appropriate for this application. Thus, the annual energy increase due to these pumps can be determined from the following equation:

$$APEI = N \times HP \times THRS \times C4$$

where,

APEI = Annual pump energy required; kWh
N = Number of pumps recommended; 2
HP = Horsepower of each pump; 20 hp
THRS = Total annual hours of operation; 8,425 hours
C4 = Conversion constant; 0.746 kW/hp

Thus,

$$APEI = 2 \times 20 \times 8{,}425 \times 0.746 = 251{,}000 \text{ kWh}$$

The corresponding cost of this pump energy is determined from:

$$\mathrm{APEC} = \mathrm{APEI} \times \mathrm{MC}_{\mathrm{EL}}$$

where,

APEC = Annual pump energy cost; \$

$\mathrm{MC}_{\mathrm{EL}}$ = Marginal cost of electricity; \$0.0721/kWh

Thus,

$$\mathrm{APEC} = 251{,}000 \times \$0.0721 = \$18{,}000$$

There will also be an increase in the electrical demand resulting from the pump use. Assuming that the heat is being recovered during all annual hours of operation, the demand increase due to this recommendation can be determined as follows:

$$\mathrm{APDI} = \mathrm{N} \times \mathrm{HP} \times \mathrm{C4} \times \mathrm{MO}$$

where,

APDI = Annual demand increase due to circulating pump; kW

MO = Months per year demand is charged; 12 months

Thus,

$$\mathrm{APDI} = 2 \times 20 \times 0.746 \times 12 = 360\,\mathrm{kW}$$

The associated cost of this demand is:

$$\mathrm{APDC} = \mathrm{APDI} \times \mathrm{MC}_{\mathrm{D}}$$

where,

APDC = Annual pump demand cost; \$

MC_{D} = Marginal cost of demand; \$8.98/kW

Thus,

$$\mathrm{APDC} = 360 \times \$8.98 = \$3{,}000$$

Finally, the net annual cost savings of this recommendation can be determined from:

$$\begin{aligned} \text{NACS} &= \text{ACS - APEC - APDC} \\ &= \$275{,}000 - \$18{,}000 - \$3{,}000 \\ &= \$254{,}000 \end{aligned}$$

where,

NACS = Net annual cost savings; $

Implementation

The implementation of this recommendation consists of the purchase and installation of shell and tube heat exchanger, two 20 hp circulating pumps, and additional wastewater and well water piping. Based on data presented in *Means Mechanical Cost Data 2001* the costs of this recommendation are outlined in Table 1.3. It is assumed that the current wastewater pumps are capable of transporting this water the additional distance.

ITEM	COST
Heat Exchanger	$70,000
Piping	$20,000
Circulating Pumps	$10,000
Engineering	$20,000
TOTAL	**$120,000**

Table 1.3: Cost Schedule

The simple payback period can now be calculated as follows:

$$\text{Payback Period} = \frac{\text{Implementation Cost}}{\text{Net Annual Cost Savings}} = \frac{\$120{,}000}{\$254{,}000} = 0.5 \text{ years} = 6 \text{ months}$$

AR NUMBER 2: Recover Heat From Coating Dryer

Assessment Recommendation Summary				
ARC #	Annual Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.2432.1	Propane: 7,900 MMBtu	$62,000	$35,000	0.6 years

Current Practice and Observations

The plant operates a propane-fired coating dryer that employs high temperatures in order to dry the freshly coated paper. The coating dryer's stack exhausts temperature and velocity provided by plant management is summarized in Table 2.1. These exhaust stream enters an exhaust stack that measured to have a circumference of 7.5 feet. The ambient room temperature near these ovens is approximately 70°F. According to plant records the annual hours of operation for the coating dryer is approximately 6,080.

Identification	**Exhaust Temperature, TE (°F)**	**Exhaust Velocity, VEL (m/s)**
Coating Dryer	376.5	6.4

Table 2.1: Coating Dryer Exhaust Stream Summary

Recommended Action

It is recommended that a heat exchanger be installed on the coating dryer exhaust stream. With the installation of additional ductwork and an additional fan, the exhaust heat can be recovered and used to preheat the combustion air. This in turn reduces the energy required, in terms of propane, for the drying.

Anticipated Savings

The savings for this recommendation result from the preheated combustion air reducing the amount of fuel needed to maintain the drying temperatures in the coating dryer. In order to calculate the amount of heat that can be recovered, the exhaust flow rate must be calculated from the exhaust velocity. The exhaust flow rate can be calculated by:

$$\mathrm{VOL} = \mathrm{VEL} \times C_1 \times \left(\frac{\pi \times \left(\frac{\mathrm{CIR}}{\pi} \right)^2}{4} \right) \times C_2$$

where,

VOL = Exhaust stream flow rate, ft^3/min

VEL = Exhaust stream velocity, 6.4 m/s

C_1 = Conversion constant, feet per meter, 3.28 ft/m

CIR = Stack circumference, 7.5 ft

C_2 = Conversion constant, second per minute, 60 sec/min

$$\mathrm{VOL} = 6.4 \times 3.28 \times \left(\frac{3.1416 \times \left(\frac{7.5}{3.1416} \right)^2}{4} \right) \times 60 = 5{,}600 \, \frac{\mathrm{ft}^3}{\mathrm{min}}$$

The temperature of the preheated combustion air must now be determined. Assuming that the preheat air stream has the same flow rate and the exhaust stream and assuming a heat exchanger effectiveness, this value can be determined from the following equation:

$$\mathrm{TP} = \varepsilon \times (\mathrm{TE} - \mathrm{TR}) + \mathrm{TR}$$

where,

TP = Temperature of pre-heated air using heat exchanger; °F

ε = Heat exchanger effectiveness, estimated; 0.6

TE = Temperature of exhaust, Table 2.1; 376 °F

TR = Room Temperature; 70°F

thus,

$$\mathrm{TP} = 0.6 \times (376.5 - 70) + 70 = 254^{o}\,\mathrm{F}$$

Now that the potential pre-heat temperature has been calculated, the amount of energy that can be recovered can be determined from the following equation:

$$\mathrm{ARES} = \frac{\rho \times \mathrm{VOL} \times \mathrm{C}_3 \times \mathrm{Cp} \times \mathrm{HRS} \times \mathrm{PO} \times (\mathrm{TP} - \mathrm{TR})}{\mathrm{C}_4}$$

where,

ARES = Annual energy recovery from exhaust stream; MMBtu

ρ = Density of warm air; 0.07 lbs/ft^3

VOL = Volume flow rate, 5,600 ft^3/min

C_3 = Conversion constant, minutes per hour; 60 min/hour

Cp = Specific heat of air; 0.24 Btu/lb °F

HRS = Annual hours of operation; 6,080 hours

C_4 = Conversion constant; 1,000,000 Btu/MMBtu

thus,

$$\mathrm{ARES} = \frac{0.07 \times 5{,}600 \times 60 \times 0.24 \times 6{,}080 \times (254 - 70)}{1{,}000{,}000} = 6{,}310\ \mathrm{MMBtu}$$

From this value, the amount of propane saved can be found using the following equation:

$$\mathrm{AES} = \frac{\mathrm{ARES}}{\eta}$$

where,

AES = Annual energy savings; MMBtu

η = Propane heat conversion efficiency, estimated; 0.8

Thus,

$$AES = \frac{6,310}{0.8} = 7,900 \text{ MMBtu}$$

The annual cost savings of this recommendation can now be calculated as follows:

$$ACS = AES \times MC_{PRO}$$

where,

ACS = Annual cost savings; \$

MC_{PRO} = Marginal cost of propane; \$7.86/MMBtu

Thus,

$$ACS = 7,900 \times \$7.86 = \$62,000$$

Implementation

The implementation of this recommendation will involve the purchase and installation of a heat exchanger, a fan and motor with the same flow rate at the exhaust stream, and all required ducting to bring the air from the room through the heat exchanger and into the coating dryer's air intake. Based on data from *Means Mechanical Cost Data 2001*, the cost of each of these components can be found. These are summarized in Table 2.2.

Item	Cost Per Exhaust Stream
Air to Air Heat Exchanger	$24,000
Fan and Motor	$4,000
Ducting	$5,000
Engineering	$2,000
TOTAL	**$35,000**

Table 2.2: Cost Schedule

Therefore, the payback period can be calculated as:

$$\text{Payback Period} = \frac{\text{Implementation Cost}}{\text{Annual Cost Savings}} = \frac{\$35{,}000}{\$62{,}000} = 0.6 \text{ years}$$

AR NUMBER 3: Use Cogeneration For Electricity Production

Assessment Recommendation Summary				
ARC #	Annual Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.3415.1	Electricity: 852,200 kWh Demand: 1,895 kW #6 Oil: -5,100 MMBtu	$61,400 $17,000 -$24,000 $54,400	$290,000	5.3 years

Current Practice and Observations

The facility currently operates two water tube boilers at 150 psig with maximum capacities of 30,000 lb/hr steam production for each boiler. The steam produced, 251,112,000 lbs annually, is used in a number of ways. When operating, an average of 12,000 lb/hr is sent to a turbine generator to produce electricity. Based on data obtained from the facility, approximately 638,800 kWh are generated annually. The exit steam, at 40 psig, is sent to paper machine #1 for use in the drying process. An average of 10,000 lb/hr is sent to a steam turbine drive, which is used to turn the steam cans on paper machine #2. This steam exits the turbine drive at 45 psig and is subsequently used in the paper drying process in paper machine #2. The exit steam from both turbines is throttled to 35 psig prior to use in the dryers. When extra drying is required, typically for heavier grades of paper, 150 psig steam is sent to a pressure reducing station where it is reduced to 75 psig before being sent to either paper machine. Finally, 150 psig steam is also used for other processes such as water heating. Based on data obtained from the facility, each paper machine operates for approximately 6,770 hours annually. The turbine generator has operated only 4,380 hours per year due to mechanical difficulties related to the age of the turbine and generator. Additionally, there is concern that the generator is operating at low efficiency. The boilers are fired by #6 fuel oil and produce a combined average of 29,000 lb/hr, 150 psig steam. On average 7,000 lb/hr of 150 psig steam is either throttled to 75 psig or is used for water heating at 150 psig. Based on conversation with plant personnel it is assumed that, on average, 3,000 lb/hr of this steam is being reduced to 75 psig. Under certain circumstances there is a need for the maximum boiler capacity of

60,000 lb/hr total. Due to gas side limitations of the boiler economizer, the pressure drop when running at maximum capacity becomes too large and the boilers run out of combustion air, preventing full load operation.

Recommended Action

It is recommended that a new backpressure steam turbine generator set be purchased and installed to generate electricity. It is further recommended that the boiler pressure be increased to 250 psig, the rated pressure, to increase generating capacity. The exit pressure will be 40 psig from the turbine as is required by the process. The current turbine generator and turbine drive system should be removed. New electric drives, similar to that currently used on paper machine #1, will be needed to drive the steam cans on machine #2.

It is recommended that a 350 to 400 kW induction turbine generating set be purchased to achieve the savings outlined below. As an additional recommendation, it is suggested that the current boiler economizer be replaced with one capable of handling the maximum boiler capacity.

Anticipated Savings

The anticipated savings for this recommendation result from the decrease in electric demand and energy that requires purchasing from the utility. There will also be energy savings due to the replacement of the old turbine generator set with a newer more efficient model. To offset these savings, there will be an increase in annual fuel usage due to the increase in steam pressure from 150 psig to 250 psig. It is assumed that maintenance costs will remain the same or decrease due the greater reliability of the newer generating set. To begin the calculations, the current arrangement must be evaluated completely.

The turbine generator set produced 638,800 kWh of energy in 2000. This value is assumed typical. Examining the data further, the total demand saved by the current steam turbine generator set is determined to be 745 kW-months. Due to the manner in which demand is charged, highest 15 to 30 minute peak demand in a month, the turbine generator set must run whenever paper machine #1 is operating in order to reduce the demand charged. Due to generator failures and maintenance problems this has proven quite impossible. Based on a thermodynamic analysis, the current generator efficiency was found to be low, approximately 82% as compared to newer generators which operate near 95%. This calculation was completed assuming a turbine efficiency of 45%. Due to condensation occurring within the turbine, the amount of 40 psig steam reaching paper machine #1, was determined to be 11,753 lb/hr.

In order to evaluate the replacement of the turbine drive used on paper machine #2, the energy produced by this turbine drive, which is later assumed to be equal to the power required to turn the steam cans when a generator set is used, needs to be determined. Based on a thermodynamic analysis the turbine drive was found to produce the equivalent of approximately 716,000 kWh. A turbine efficiency of 45% was assumed in the calculations. The electric demand that this corresponds to is approximately 106 kW. The demand is considered to be reduced by this amount 12 months out of the year since it operates whenever paper machine #2 is running, for a total of 1,272 kW-months per year. Due to condensation occurring within the turbine, the amount of 45 psig steam reaching paper machine #2, was determined to be 9,806 lb/hr.

Now an analysis of the proposed steam turbine generator set is required. Note that the entering steam will be at 250 psig instead of 150 psig. The steam flow rate through the turbines must be first determined. In order to maintain the current flow rates of saturated 40 and 45 psig steam to the two paper machines, a slight increase in steam flow is required due to steam condensation within the turbine. The following values were determined by analyzing the thermodynamics of the turbine:

h_1 = Enthalpy of saturated steam at 250 psig; 1,202.4 Btu/lb_m

x_1 = Quality of steam at 250 psig, saturated vapor; 1.0

h_2 = Enthalpy of steam at 40 psig, turbine exit, assuming 45% turbine efficiency; 1,147.0 Btu/lb_m

x_2 = Quality of steam at 40 psig, turbine exit, assuming 45% turbine efficiency; 0.9683

h_{1C} = Current enthalpy of steam at 150 psig; 1196.2 Btu/lb_m

x_{1C} = Current quality of steam at 150 psig; 1.0

m_{PM1} = Required mass flow rate entering the proposed turbine with exiting steam being sent to paper machine #1; 12,138 lb/hr

m_{PM2} = Required mass flow rate entering the proposed turbine with exiting steam being sent to paper machine #2; 10,127 lb/hr

m_{CM1} = Current mass flow rate of 40 psig saturated vapor leaving the turbine generator and entering paper machine #1; 11,753 lb/hr

m_{CM2} = Current mass flow rate of 45 psig saturated vapor leaving the turbine drive and entering paper machine #2; 9,806 lb/hr

The generator output corresponding to each steam flow can be evaluated from the following equation:

$$GO = \frac{\dot{m}_P \times (h_1 - h_2)}{C1} \times \eta_{gen} \times \eta_{gear}$$

where,

GO = Potential generator output; kW

$\dot{m}$ = Steam flow rates m_{PM1} and m_{PM2}; lb/hr

C1 = Conversion constant; 3413 kW-hr/Btu

η_{gen} = Efficiency of the generator; 95%

η_{gear} = Efficiency of the gears; 95%

The results of this calculation are shown in Table 3.1. The annual electrical energy savings can now be found from the following equation:

$$AEP = GO \times HRS$$

where,

AEP = Annual electrical energy production; kWh

HRS = Annual hours of operation of each paper machine; 6,770 hours

The results of this calculation are shown in Table 3.1.

Paper Machine	**Proposed Steam Production, (lb/hr)**	**Generator Output, GO (kW)**	**Annual Electrical Energy Production, AEP (kWh)**
#1	12,138	178	1,205,000
#2	10,127	148	1,002,000
TOTALS		**326**	**2,207,000**

Table 3.1: Generator Output and Electrical Energy Production

The annual electric energy savings, due to the net increase in annual electric energy produced can now be determined as follows:

$$\text{AES} = \text{AEP} - \text{TGP} - \text{TDP}$$

where,

AES = Net annual electric energy savings; kWh

TGP = Current turbine generator electricity production; 638,800 kWh

TDP = Equivalent turbine drive electricity production; 716,000 kWh

Thus,

$$\text{AES} = 2{,}207{,}000 - 638{,}800 - 716{,}000 = 852{,}200\ \text{kWh}$$

The annual electric cost savings resulting from this increase in electric production on-site can be calculated from the following:

$$\text{AECS} = \text{AES} \times \text{MC}_{\text{EL}}$$

where,

AECS = Annual electrical energy cost savings ; $

MC_{E} = Marginal cost of electricity; $0.072/kWh

Thus,

$$\text{AECS} = 852{,}200 \times \$0.072 = \$61{,}400$$

In addition to the electric energy savings, there will also be an electric demand savings. In order to calculate the demand savings, some assumptions are needed. Assuming that the new turbine generator set can be scheduled to run whenever the paper lines are running, the demand can be reduced by the total power generated each month. Thus, the annual demand savings can be determined from:

$$\mathrm{ADS} = (\mathrm{TGO - TDC}) \times \mathrm{MO - TGC}$$

where,

ADS = Annual demand savings; kW

TGO = Total proposed generator output; 326 kW

TDC = Total current equivalent turbine drive demand saved; 106 kW

MO = Months per year demand is billed; 12 months

TGC = Total current annual generator demand saved; 745 kW-months

Thus,

$$\mathrm{ADS} = (326 - 106) \times 12 - 745 = 1{,}895\ \mathrm{kW}$$

The annual demand cost savings can now be found from:

$$\mathrm{ADCS} = \mathrm{ADS} \times \mathrm{MC_D}$$

where,

ADCS = Annual demand cost savings; \$

$\mathrm{MC_D}$ = Marginal cost of demand; \$8.98/kW

Thus,

$$\mathrm{ADCS} = 1{,}895 \times \$8.98 = \$17{,}000$$

Now that the savings of this recommendation have been evaluated, the cost increase from this recommendation shall be evaluated. The increase in boiler energy required due to both the increase in boiler pressure and flow rate can be determined from the following:

$$\text{BEI} = \frac{\dot{m}_{TP} \times h_1 - \dot{m}_{TC} \times h_{1c}}{\eta_B \times C2}$$

where,

BEI = Boiler energy increase; MMBtu

$\dot{m}_{TP}$ = Total annual steam production under proposed operating conditions; 253,407,000 lbs

$\dot{m}_{TC}$ = Total annual steam production under current operating conditions; 251,112,000 lbs

η_B = Boiler efficiency, as measured; 0.85

C2 = Conversion constant; 1,000,000 Btu/MMBtu

Thus,

$$\text{BEI} = \frac{253{,}407{,}000 \times 1{,}202.4 - 251{,}112{,}000 \times 1{,}196.2}{0.85 \times 1{,}000{,}000} = 5{,}100 \text{ MMBtu}$$

Using this value the cost increase of #6 oil can be found as follows:

$$\text{AOCI} = \text{BEI} \times \text{MC}_{\#6}$$

where,

AOCI = Annual #6 fuel oil cost increase; \$

$\text{MC}_{\#6}$ = Marginal cost of #6 fuel oil; \$4.61/MMBtu

Thus,

$$\text{AOCI} = 5{,}100 \times \$4.61 = \$24{,}000$$

The net annual cost savings, assuming a negligible decrease in annual maintenance costs, can be determined from the following:

$$\begin{aligned} \text{NACS} &= \text{AECS} + \text{ADCS} - \text{AOCI} \\ &= \$61{,}400 + \$17{,}000 - \$24{,}000 \\ &= \$54{,}400 \end{aligned}$$

where,

NACS = Net annual cost savings; $

Implementation

The implementation of this recommendation requires the purchase and installation of a steam turbine induction generator set. Based on vendor information, the cost of this will be approximately $220,000 installed. Note that loss in turbine efficiency at lower flow rates, as would occur when only one paper machine was running, may be significant. Under these circumstances two generator sets may be required or alternatively a single generator connected on a single shaft to two steam turbines. These cases where not considered in this analysis.

Additionally, the removal of the turbine drive system will require the purchase and installation of electric drives on the steam cans, as is used for paper machine #1. It is estimated that five 50 hp motors complete with variable speed control will be adequate. Based on data from *Means Electrical Cost Data 2001,* this cost is estimated to be $70,000. DC motors may be desired for various control reasons. However, this was not considered in the cost analysis.

Therefore, the total implementation cost for this recommendation is $290,000. Finally, it should be noted that in order to assure proper installation of the steam generator system, all existing pipes, fittings and miscellaneous steam items located between the boiler and turbine be rated to handle 250 psig steam. The simple payback period can be determined from the following:

$$\text{Payback Period} = \frac{\text{Implementation Cost}}{\text{Net Annual Cost Savings}} = \frac{\$290{,}000}{\$54{,}400} = 5.3 \text{ years}$$

In addition to the above costs, if the cost of replacing the current boiler economizer with one capable of handling the maximum boiler capacity, approximately $50,000, the simple payback period becomes:

$$\text{Payback Period} = \frac{\text{Implementation Cost}}{\text{Net Annual Cost Savings}} = \frac{\$340{,}000}{\$54{,}400} = 6.3 \text{ years}$$

AR NUMBER 4: Install Variable Speed Drive on Wastewater Pump

Assessment Recommendation Summary				
ARC #	Annual Energy Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.4141.2	Electricity: 215,400kWh	$15,500	$9,500	0.6 years

Current Practice and Observations

The facility operates two wastewater pumps. A third wastewater pump is used as backup. The pumps are designed to supply 800 gpm at 160’ head. Based on the wastewater piping system, it is estimated that the static head component is 40% of the total. Its primary function is to pump the dirty water from the wastewater stream to the treatment pond. Additionally, there is an automatic valve that allows the stream to flow in the determined way and maintain the level of the water in the tank. 40 hp motors run the pumps. Pump 1 operates through all the operating hours while the Pump 2 only operates when 55% of the maximum flow rate is required. From speaking with plant personnel the pump schedule is listed in Table 4.1.

Total Percent of Max Flow	Percent of Annual Hours PH	Percent of Max Flow for Pump 1	Percent of Max Flow for Pump 2
40%	8%	40%	0%
55%	8%	50%	5%
60%	8%	50%	10%
65%	50%	50%	15%
70%	26%	50%	20%
TOTALS	**100%**		

Table 4.1: Wastewater Pump Schedule

Recommended Action

It is recommended that a variable speed drives (VSDs) be installed on the first primary wastewater pump motor. The pump has a flow rate of 800 gpm. As the plant personnel reported, the pump is running most of the time at partial-load. Table 4.1 shows the various essential specifications that are related to the flow rate. The workloads are almost always away from the maximum capacity.

Because the wastewater pump operates so frequently at part-load, a VSD can be used to reduce the flow during these times and will result in the energy savings calculated below. Figure 4.1 shows the power that is required when variable speed control is used.

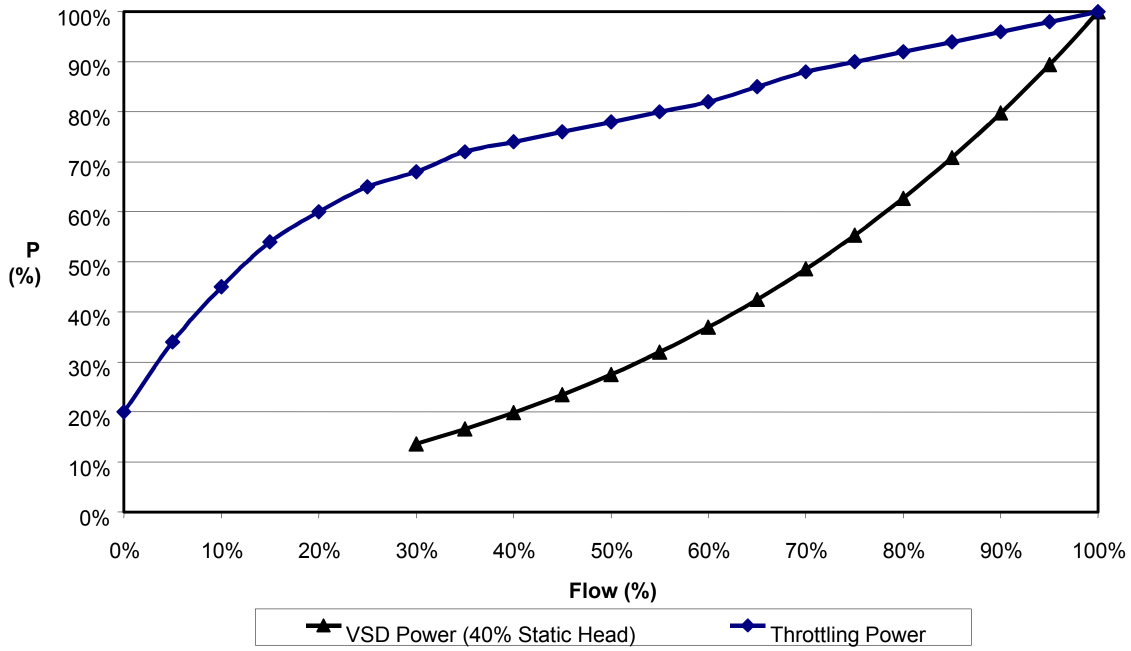


Figure 4.1: Pump Power Versus Speed with Variable Speed Control

Source: ASDMaster User's Guide, Electric Power Research Institute (EPRI), 1996.

Anticipated Savings

The savings associated with this recommendation result from the decrease in pump power required when variable speed control is used to match system demands instead of opening and closing valves. The annual energy savings can be determined from the following.

$$\mathrm{AES} = \sum \left[\left(\mathrm{HP}_1 \times \mathrm{TP}_{1,i} \right) + \left(\mathrm{HP}_2 \times \mathrm{TP}_{2,i} \right) - \left(\mathrm{HP}_1 \times \frac{\mathrm{VP}_{1,i}}{\eta} \right) \right] \times \mathrm{PH}_i \times \mathrm{HRS} \times \mathrm{C}_1$$

where,

AES = Annual energy savings; kWh

C_1 = Conversion constant: 0.746 kW/hp

HP_1 = Horsepower of Pump 1; 40 hp

HP_2 = Horsepower of Pump 2; 40 hp

η = VSD efficiency assumed; 0.85

HRS = Annual hours of operation; 8,425 hours

$VP_{1,i}$ = VSD percentage of power for Pump 1 at the specified flow; Figure 1, Table 4.2

$TP_{1,i}$ = Throttling power of the Pump 1; Figure 4.1, Table 4.2

$TP_{2,i}$ = Throttling power of the Pump 2; Figure 4.1, Table 4.2

PH_i = Percentage of annual hours spent at each flow rate; Table 4.1

Thus, this calculation can be carried as shown in Table 4.2.

Total Percent of Max Flow	Percentage of Throttling Power of Pump 1 TP_1	Percentage of Throttling Power of Pump 2 TP_2	Percentage of Variable Speed Power of Pump 1 VP_1	Annual Energy Savings, AES (kWh)
40%	74%	0%	20%	10,150
55%	80%	34%	32%	15,350
60%	82%	46%	37%	17,000
65%	86%	54%	42%	113,900
70%	88%	60%	49%	59,000
TOTALS				**215,400**

Table 4.2: Wastewater Pump Energy Savings

Thus,

The annual energy cost savings can now be found from:

$$\mathrm{AECS} = \mathrm{AES} \times \mathrm{MC}_{\mathrm{EL}}$$

where,

ACS = Annual energy cost savings; \$

$\mathrm{MC}_{\mathrm{EL}}$ = Marginal cost of electricity; \$0.072/kWh

Thus,

$$\mathrm{ACS} = 215{,}400 \times \$0.072 = \$15{,}500$$

In addition to the energy savings, there may also be a demand savings. This however is neglected in this analysis to be conservative.

Implementation

The implementation of this recommendation involves the purchase and installation of a variable speed drives for the 40 hp wastewater pump motor. Based on data from *Means Mechanical Cost Data 2001* data, the implementation cost is estimated to be \$9,500 for the primary wastewater pump. Therefore, the payback period can be calculated as follows:

$$\text{Payback Period} = \frac{\text{Implementation Cost}}{\text{Annual Energy Cost Savings}} = \frac{\$9{,}500}{\$15{,}500} = 0.6 \text{ years}$$

AR NUMBER 5: Install Variable Speed Drives on Boiler Feedwater Pump

Assessment Recommendation Summary				
ARC #	Annual Energy Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.4141.2	Electricity: 115,200 kWh	$8,300	$12,000	1.4 years

Current Practice and Observations

The facility has two 50 hp boiler feedwater pumps. Typically only one pump operates at a time. Each pump is capable of supplying the maximum required flow for both boilers simultaneously. They provide the feedwater at 250 psig which is throttled to 150 psig prior to entering the boilers. Based on the steam production data for a typical month, the flow schedule was determined as shown in Table 5.1. These pumps operate during the full 8,425 annual hours of operation.

Percent of Max Flow, PF	Percent of Annual Hours, PH
100%	11%
90%	32%
80%	14%
70%	14%
60%	4%
50%	14%
20%	11%
TOTALS	**100%**

Table 5.1: Boiler Feedwater Pump Schedule

Recommended Action

It is recommended that a variable speed drive (VSD) be installed on one of the feedwater pump motors. One VSD is recommended since only one feedwater pump is in use at a time. Instead of using a throttling valve to maintain the required pressure and flow rates, a variable speed drive can accomplish the same results at reduced motor power consumption. Figure 5.1 shows the power that is required when throttling control is used. To compare, a variable speed drive will reduce the motor speed to match the flow and pressure requirements. The required pressure is 60% of the current pressure being produced by the pumps.

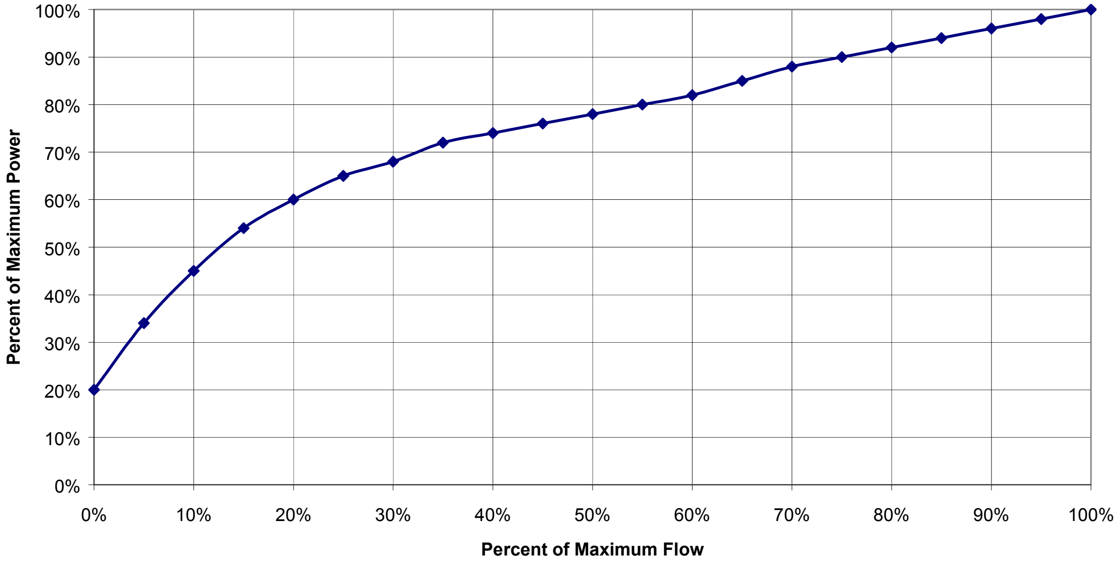


Figure 5.1: Pump Power Versus Speed with Throttling Valve Control

Source: ASDMaster User's Guide, Electric Power Research Institute (EPRI), 1996.

Anticipated Savings

The savings associated with this recommendation result from the decrease in pump power required when variable speed control is used to match system demands instead of using valve control. Pump power in this system is directly proportional to the flow rate multiplied by pressure when variable speed control is used. Thus, the annual energy savings can be determined from the following.

$$AES = HP \times \left(TP - \frac{PF \times PR}{\eta} \right) \times PH \times HRS \times C1$$

where,

AES = Annual energy savings; kWh

HP = Pump horsepower; 50 hp

TP = Throttling fraction of power at given flow rate, Figure 5.1

PF = Fraction of maximum flow at each condition, Table 5.1

PR = Fraction of total pressure required; 0.6

η = VSD efficiency assumed; 0.85

PH = Percentage of annual hours at each flow rate, Table 5.1

HRS = Annual hours of operation; 8,425 hours

C_1 = Conversion constant; 0.746 kW/hp

Thus, this calculation can be carried as shown in Table 5.2.

Percent of Max Flow, PF1	Percent of Annual Hours, PH1	Throttling Power, TP1	Annual Energy Savings, AES (kWh)
100%	11%	1.0	10,200
90%	32%	0.96	32,700
80%	14%	0.92	15,600
70%	14%	0.88	17,000
60%	4%	0.82	5,000
50%	14%	0.78	18,800
20%	11%	0.6	15,900
TOTALS	**100%**		**115,200**

Table 5.2: Boiler Feedwater Pump Energy Savings

Therefore, the annual energy savings will be 115,200 kWh. The annual energy cost savings can now be found from:

$$\text{AECS} = \text{AES} \times \text{MC}_{\text{EL}}$$

where,

AECS = Annual energy cost savings; \$

MC_{EL} = Marginal cost of electricity; \$0.072/kWh

Thus,

$$\text{AECS} = 115{,}200 \times \$0.072 = \$8{,}300$$

In addition to the energy savings, there may also be a demand savings. This however is neglected in this analysis to be conservative.

Implementation

The implementation of this recommendation involves the purchase and installation of a variable speed drive on one of the 50 hp boiler feed water pump motors. Based on data from *Means Mechanical Cost Data 2001* data, the implementation cost is estimated to be \$12,000. Therefore, the payback period can be calculated as follows:

$$\text{Payback Period} = \frac{\text{Implementation Cost}}{\text{Annual Energy Cost Savings}} = \frac{\$12{,}000}{\$8{,}300} = 1.4 \text{ years}$$

AR NUMBER 6: Install Variable Speed Drives on Beater Chest Pumps

Assessment Recommendation Summary				
ARC #	Annual Energy Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.4141.2	Electricity: 170,000 kWh	$12,000	$24,000	2 years

Current Practice and Observations

The facility operates two beater chest pumps, one for each paper machine. They serve the same purpose, however they have different operating schedules, notably flow rates and heads. Pump 1 is designed to supply 1200 gpm, 110 ft and Pump 2 is designed to supply 500 gpm and 110 ft. Based on the beater chest piping system, it is estimated that the static head component is 20% of the total. There is a single valve that can be open to allow the pulp water to be driven by the beater chest valve to the refiners and then to the production process. These pumps are run by 30 hp motors and operate during the full 6,770 annual hours of operation. According to plant personnel, Pump 1 operates in a range of 250 to 450 gpm. Pump 2 operates in the range of 150 to 350 gpm. Based on the above stated data, the flow schedules were determined as shown in Table 6.1

Percent of Max Flow of Pump 1, PF_1	Percentage of Annual Operational Hours, PH_1	Percent of Max Flow of Pump 2, PF_2	Percentage of Annual Operational Hours, PH_2
20%	20%	30%	20%
24%	20%	40%	20%
29%	20%	50%	20%
33%	20%	60%	20%
38%	20%	70%	20%

Table 6.1: Beater Chest Pump 1 & 2 Operating Schedules

Recommended Action

It is recommended that variable speed drives (VSD) be installed on the beater chest pump motors. The system is only running at maximum capacity for 25% of the operating hours. During the other time, it is assumed that the pumps are operating at part load. Considering all of the above considerations, a VSD can be used to reduce the flow during these times and will result in the energy savings calculated below. Figure 6.1 shows the power that is required when variable speed control is used.

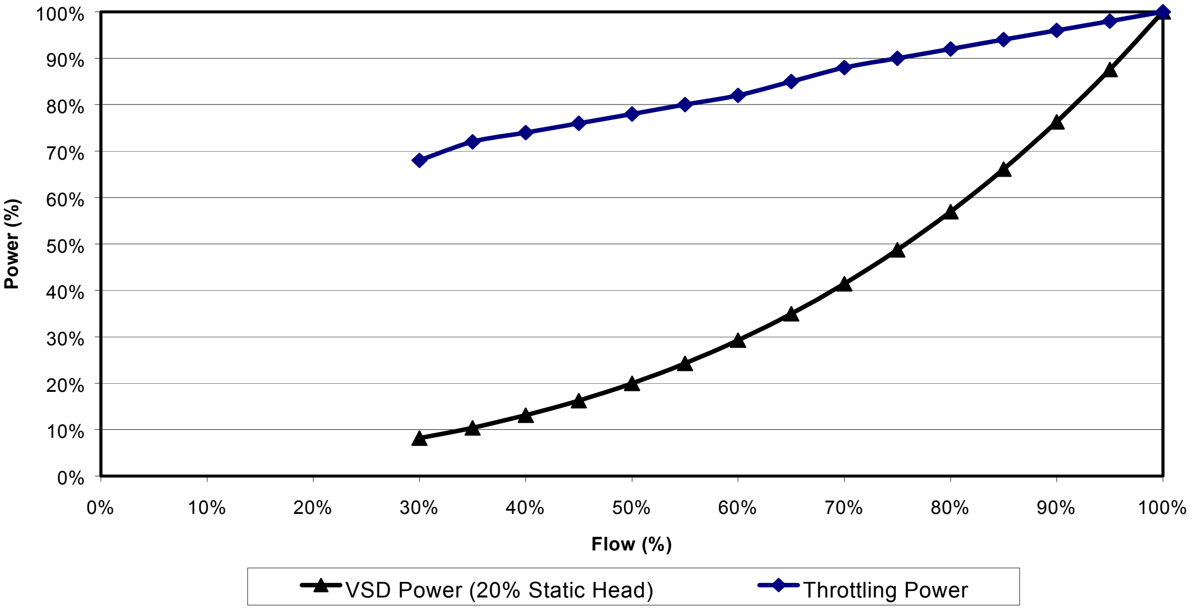


Figure 6.1: Pump Power Versus Speed with Variable Speed Control
Source: ASDMaster User's Guide, Electric Power Research Institute (EPRI), 1996.

Anticipated Savings

The savings associated with this recommendation result from the decrease in pump power required when variable speed control is used to match system demands instead of opening and closing valves. The annual energy savings can be determined from the following equation that is applicable for each of the beater chest pumps. Because the specifications of the pumps are different from each other, the annual energy savings of each has to be calculated separately. Thus, the annual energy savings can be determined from the following.

$$AES_n = HP \times \left[\left(TPn - \frac{VPn}{\eta} \right) \right] \times PH_n \times HRS \times C_1$$

Where,

$AES_{1,2}$ = Annual energy savings; kWh

HP = Pump horsepower; 30 hp

VP_n = VSD percentage of power at n% flow; Figure 6.1, Table 6.3 & Table 6.4

TP_n = Throttling power at n% flow; Figure 6.1,Table 6.3 & Table 6.4

η = VSD efficiency assumed; 0.85

PH_n = Duty factor, fraction of time that the particular flow is required; Table 6.1

HRS = Annual hours of operation; 6,770 hours

C_1 = Conversion constant; 0.746 kW/hp

Percent of Max Flow of Pump 1 PF_1	Percent Of Annual hours PH_1	Percentage of Annual Hours of Operation VP_1	Percentage of Throttling Power, TP_1	Annual Energy Savings, AES_1 (kWh)
20%	20%	8%	68%	18,000
24%	20%	8%	68%	18,000
29%	20%	9%	68%	18,000
33%	20%	10%	70%	19,000
38%	20%	13%	72%	17,000
TOTALS	**100%**			**90,000**

Table 6.3: Beater Chest Pump 1 Annual Energy Savings

The first three VP_1 and TP_1 values are considered to be equal as seen from Figure 6.1, more specifically, the curve acts linearly at these values of flow rates.

Percent of Max Flow of Pump 2 PF_2	Percent Of Annual hours PH_2	Percentage of Annual Hours of Operation VP_2	Percentage of Throttling Power, TP_2	Annual Energy Savings, AES_2 (kWh)
30%	20%	8%	68%	18,000
40%	20%	13%	74%	18,000
50%	20%	20%	78%	17,000
60%	20%	29%	82%	15,000
70%	20%	41%	88%	12,000
TOTALS	**100%**			**80,000**

Table 6.4: Beater Chest Pump 2 Annual Energy Savings

Thus, the combined AES is as follows:

$$AES = AES_1 + AES_2$$

$$AES = 90{,}000 + 80{,}000$$

$$= 170{,}000 \text{ kWh}$$

The annual energy cost savings can now be found from:

$$ACS = AES \times MC_{EL}$$

where,

ACS = Annual energy cost savings; $

MC_{EL} = Marginal cost of electricity; $0.072/kWh

Thus,

$$ACS = 170{,}000 \times \$0.072 = \$12{,}000$$

In addition to the energy savings, there may also be a demand savings. This however is neglected in this analysis to be conservative.

Implementation

The implementation of this recommendation involves the purchase and installation of a variable speed drives for the two 30 hp beater chest pumps. It can also be recommended to replace the pump with another with a lower flow rate that meets the maximum capacity. Based on data from *Means Mechanical Cost Data 2001* data, the implementation cost is estimated to be \$12,000 each pump or \$24,000 total. Therefore, the payback period can be calculated as follows:

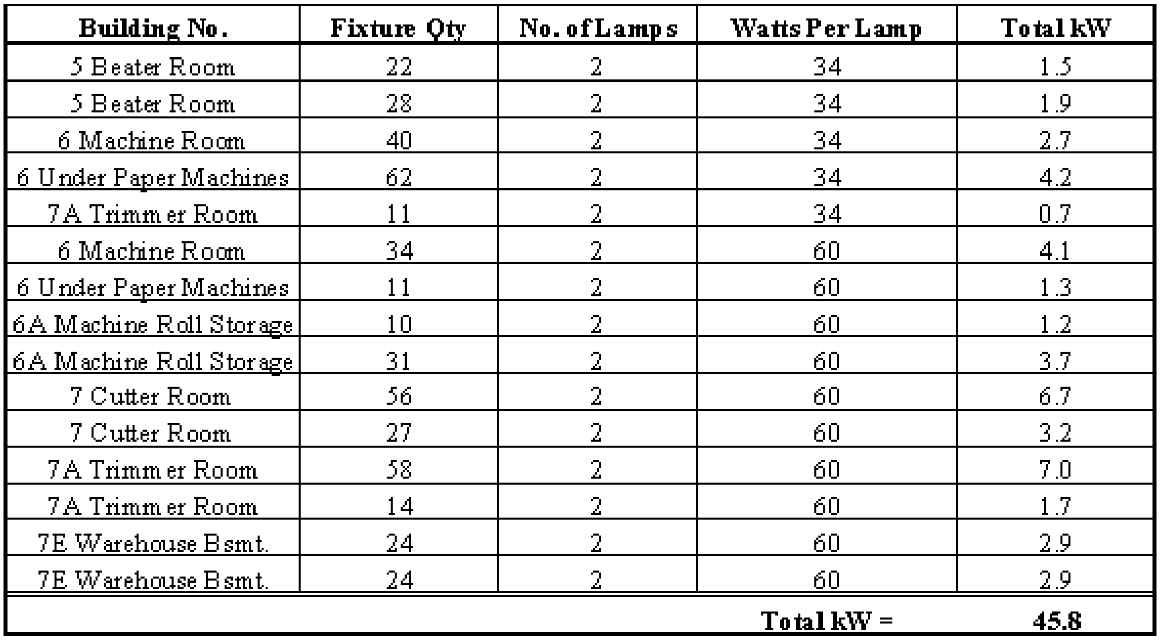
$$\text{Payback Period} = \frac{\text{Implementation Cost}}{\text{Annual Energy Cost Savings}} = \frac{\$24{,}000}{\$12{,}000} = 2 \text{ years}$$

AR NUMBER 7: Utilize Higher Efficiency Lighting

Assessment Recommendation Summary				
ARC #	Annual Energy Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.7142.3	Electricity: 56,400 kWh Demand: 80 kW	$4,100 $700 $4,800	$51,800	10.8 years

Current Practice and Observations

The plant is currently illuminated using a mixture of high efficiency and standard lighting. By surveying the plant and talking to plant personnel, the lights shown in Table 7.1 are in need of retrofitting to more energy efficient bulbs. These lights are currently in use 8,760 hours per year, assuming that all lights are on during the two week plant shutdown period for cleaning and repairing.



Building No.	Fixture Qty	No. of Lamps	Watts Per Lamp	Total kW
5 Beater Room	22	2	34	1.5
5 Beater Room	28	2	34	1.9
6 Machine Room	40	2	34	2.7
6 Under Paper Machines	62	2	34	4.2
7A Trimmer Room	11	2	34	0.7
6 Machine Room	34	2	60	4.1
6 Under Paper Machines	11	2	60	1.3
6A Machine Roll Storage	10	2	60	1.2
6A Machine Roll Storage	31	2	60	3.7
7 Cutter Room	56	2	60	6.7
7 Cutter Room	27	2	60	3.2
7A Trimmer Room	58	2	60	7.0
7A Trimmer Room	14	2	60	1.7
7E Warehouse Bsmt.	24	2	60	2.9
7E Warehouse Bsmt.	24	2	60	2.9
			Total kW =	**45.8**

Table 7.1: Existing Lighting Fixtures

Recommended Action

It is recommended that both the 4-foot and 8-foot T-12 fixtures and bulbs be replaced with higher efficiency T-8 ballasts and bulbs. After the retrofit is complete, the 4-foot and 8-foot fixtures will use 64 W and 100 W respectively.

Anticipated Savings

Energy and demand savings will result as the electric use and demand will decrease after the installation of the higher efficiency T-8 ballasts and bulbs. The annual energy savings can be calculated from:

$$\mathrm{AES} = \llbracket(\mathrm{EW}_4 - \mathrm{PW}_4) \times \mathrm{N}_4] + [\mathrm{EW}_8 - \mathrm{PW}_8) \times \mathrm{N}_8\rrbracket \times \mathrm{HRS} \times \mathrm{C1}$$

where,

AES = Annual energy savings; kWh

EW_4 = Existing wattage per 4-foot fixture; 68 W

PW_4 = Proposed wattage per 4-foot fixture; 64 W

N_4 = Number of 4-foot fixtures; 163

EW_8 = Existing wattage per 8-foot fixture; 120 W

PW_8 = Proposed wattage per 8-foot fixture; 100 W

N_8 = Number of 8-foot fixtures; 289

HRS = Annual hours of operation; 8,760 hrs/year

C1 = Conversion constant; 0.001 kW/W

Thus,

$$\mathrm{AES} = \llbracket(68 - 64) \times 163] + [(120 - 100) \times 289\rrbracket \times 8{,}760 \times 0.001 = 56{,}400\,\mathrm{kWh}$$

Now, the annual electric energy cost savings can be calculated from:

$$\mathrm{AECS} = \mathrm{AES} \times \mathrm{MC}_\mathrm{E}$$

where,

AECS = Annual energy cost savings; $

MC_E = Marginal cost of electricity; \$0.072 /kWh

Thus,

$$\text{AECS} = 56{,}400 \times \$0.072 = \$4{,}100 \text{ /year}$$

In addition to the energy savings, there is also an annual demand savings calculated from:

$$\text{ADS} = \left[\left[(\text{EW}_4 - \text{PW}_4) \times \text{N}_4\right] + \left[\text{EW}_8 - \text{PW}_8) \times \text{N}_8\right]\right] \times \text{BM} \times \text{C1}$$

where,

ADS = Annual demand savings; kW

BM = Billed months per year for demand; 12

Thus,

$$\text{ADS} = \left[\left[(68 - 64) \times 163\right] + \left[(120 - 100) \times 289\right]\right] \times 12 \times 0.001 = 80 \text{ kW/year}$$

The annual demand cost savings found through the following:

$$\text{ADCS} = \text{ADS} \times \text{MC}_\text{D}$$

where,

ADCS = Annual demand cost savings; \$

MC_D = Marginal cost of Demand; \$8.98/kW

Thus,

$$\text{ADCS} = 80 \times \$8.98 = \$700 \text{ /year}$$

The net annual cost savings, NACS, can now be calculated as follows:

$$\text{NACS} = \text{AECS} + \text{ADCS} = \$4{,}100 + \$700 = \$4{,}800\text{/year}$$

Implementation

The cost of implementing this recommendation will include the cost of purchasing 163 new 4-foot ballasts, 289 new 8-foot ballasts, 326 new 32W T-8 bulbs, and 578 new 50W T8 bulbs. Additionally, there will be the cost of installing the new ballasts and bulbs and also the disposal costs for the current ballasts and bulbs. Based on data from the *Grainger Catalogue*, the 4-foot and 8-foot ballasts will cost approximately \$40 and \$55 dollars each, respectively, for a total ballast cost of \$22,415. Correspondingly, from the same catalogue, the 4-foot and 8-foot bulbs cost approximately \$10 and \$20 dollars each for a total bulb cost of \$9,040. Based on data from *Mean's Electrical Cost Data 2001*, the installation cost will be approximately \$45 per ballast, or \$20,340 in total. Many utility companies offer ballast recycling services free of charge thus, no cost is assumed to be incurred with the disposal of the current fixtures. Further, many utility companies offer rebates on lighting conversion costs. For the purposes of this calculation, as a worst case scenario, no rebate is assumed. Thus, the total implementation cost is approximately \$51,800. The simple payback period can now be calculated as:

$$\text{Simple Payback Period} = \frac{\text{Implementation Cost}}{\text{Net Annual Cost Savings}} = \frac{\$51{,}800}{\$4{,}800} = 10.8 \text{ years}$$

AR NUMBER 8: Install Variable Speed Drives on Machine Chest Stock Pumps

Assessment Recommendation Summary				
ARC #	Annual Energy Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.4141.2	Electricity: 51,000 kWh	$3,700	$0	Immediate

Current Practice and Observations

The facility operates two machine chest stock pumps, one for each paper machine. They serve the same purpose and are operated in identical manners for each paper machine. These pumps are each designed to supply 800 gpm at 65' head. Based on the machine chest piping system, it is estimated that the static head component is 30% of the total. Their purpose is to pump the pulp slurry from the machine chest to the stuff box. The overflow of pulp slurry to the stuff box is returned back down a pipe to the machine chest. The estimated flow schedule is shown in Table 8.1. These pumps are run by 15 hp motors and operate the full time that the paper machines are in use, 6,770 annual hours.

Pump 1		Pump 2	
Percent of Max Flow, PF1	Percent of Annual Hours, PH1	Percent of Max Flow, PF2	Percent of Annual Hours, PH2
60%	25%	60%	25%
70%	25%	70%	50%
80%	25%	80%	25%
90%	25%		
TOTALS	**100%**		**100%**

Table 8.1: Machine Chest Stock Pump Schedule

Recommended Action

It is recommended that the current variable speed drives (VSDs) be activated for the machine chest stock pump motors. Instead of having the overflow of pulp slurry in the stuff box return back to the machine chest, a variable speed drive can decrease the flow at reduced motor power consumption while maintained the current flow rates. Figure 8.1 shows the power that is required when variable speed control is used.

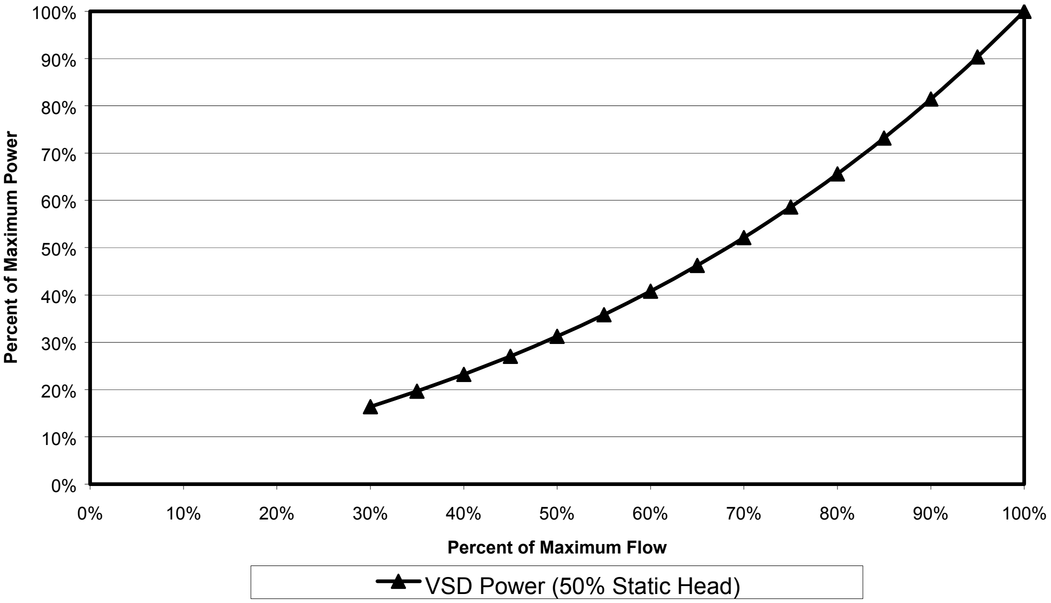


Figure 8.1: Pump Power Versus Speed with Variable Speed Control

Source: ASDMaster User's Guide, Electric Power Research Institute (EPRI), 1996

Anticipated Savings

The savings associated with this recommendation result from the decrease in pump power required when variable speed control is used to match system demands instead of pumping excess pulp slurry. Thus, the annual energy savings can be determined from the following.

$$\mathrm{AES} = \mathrm{HP} \times \left(1 - \frac{\mathrm{VP}}{\eta} \right) \times \mathrm{PH} \times \mathrm{HRS} \times \mathrm{C1}$$

where,

AES = Annual energy savings; kWh

HP = Pump horsepower; 15 hp

VP = VSD percentage of power, Figure 8.1

η = VSD efficiency assumed; 0.85

PH = Percentage of annual hours at each flow rate, Table 8.1

HRS = Annual hours of operation; 6,770 hours

C1 = Conversion constant; 0.746 kW/hp

Thus, this calculation can be carried out for each pump as shown in Tables 8.2 and 8.3.

Percent of Max Flow, PF1	Percent of Annual Hours, PH1	Percentage of VSD Power, VP1	Annual Energy Savings, AES (kWh)
60%	25%	0.41	9,800
70%	25%	0.52	7,400
80%	25%	0.66	4,200
90%	25%	0.81	900
TOTALS	**100%**		**22,300**

Table 8.2: Machine Chest Stock Pump 1 Energy Savings

Percent of Max Flow, PF2	Percent of Annual Hours, PH2	Percentage of VSD Power, VP2	Annual Energy Savings, AES (kWh)
60%	25%	0.41	9,800
70%	50%	0.52	14,700
80%	25%	0.66	4,200
TOTAL	**100%**		**28,700**

Table 8.3: Machine Chest Stock Pump 2 Energy Savings

Therefore, the annual energy savings will be 22,300 kWh and 28,700 kWh on pumps 1 and 2 respectively for a total annual energy savings of 51,000 kWh. The annual energy cost savings can now be found from:

$$\mathrm{AECS} = \mathrm{AES} \times \mathrm{MC}_{\mathrm{EL}}$$

where,

AECS = Annual energy cost savings; \$

MC_{EL} = Marginal cost of electricity; \$0.072/kWh

Thus,

$$AECS = 51{,}000 \times \$0.072 = \$3{,}700$$

In addition to the energy savings, there may also be a demand savings. This however is neglected in this analysis to be conservative.

Implementation

Since the variable speed drives are currently in place and only need to be engaged, the implementation cost is assumed to negligible. Therefore, the packback period is immediate.

AR NUMBER 9: Reduce Air Compressor Pressure

Assessment Recommendation Summary				
ARC #	Annual Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.4231.2	Electricity: 44,800 kWh	$3,200	$0	Immediate

Current Practice and Observation

The plant operates one 125 hp rotary screw compressor and maintains a second 150 hp rotary screw for backup requirements. These compressors supply air to the process floor for controls, air-powered machine tools, and pneumatic actuation. The plant's system pressure is set at 100 psi. The compressor is run continuously during all of the plant's operational hours. Thus the annual operational hours used for this recommendation are 8,425. Average end use pressure was observed to be 98 psi. Figure 9.1 graphically displays the load profile for the rotary screw compressor. This data was used to determine a load factor for the compressor and is used in the subsequent calculations.

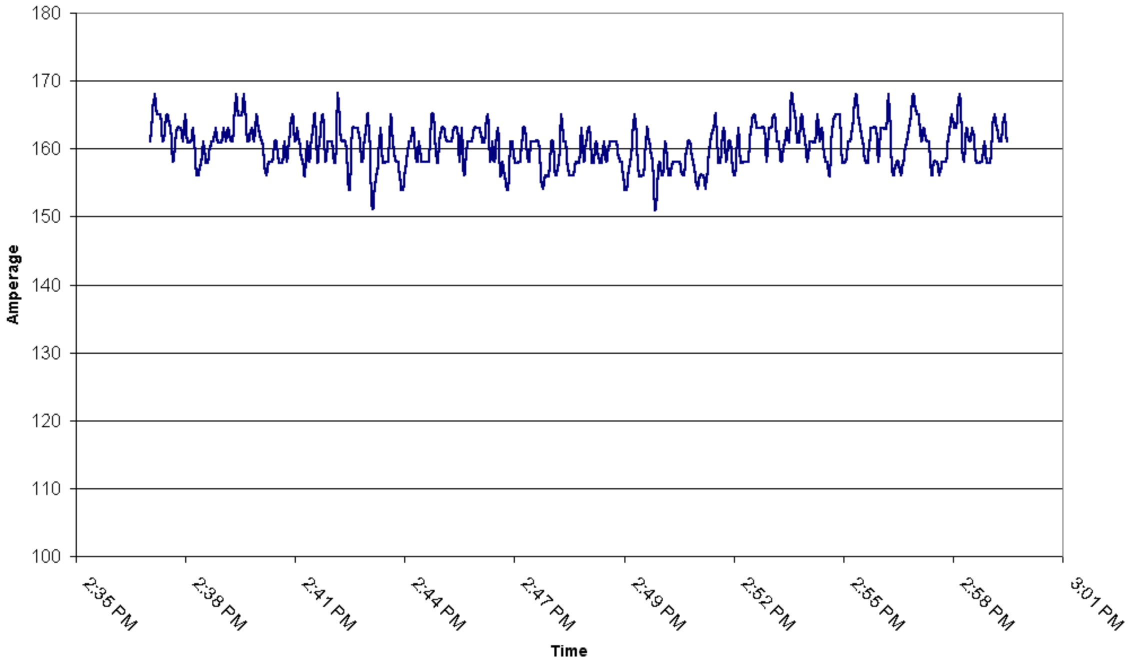


Figure 9.1: Load profile for Rotary Screw Compressor

Recommended Action

From speaking with plant personnel the minimum pressure required in the compressed air lines is 80 psi. Therefore it is conservatively recommended that the system pressure is set so that the end use air pressure is reduced to 85 psi, thus reducing the energy required for compressing the air. The average end use pressure observed during the plant visit was 98 psi thus permitting a maximum reduction of 13 psi. There is a maximum pressure drop of 4 psi due to the air distribution system therefore the system pressure can be conservatively reduced from 100 psi to 90 psi. It should be noted that in order to ensure proper pressure for the process, an accumulator tank can also be added to store the pressurized air in order to meet capacity during peak demands. Ideally the accumulator tank should be located near the press sections, which requires the 80 psi compressed air.

Anticipated Savings

Figure 9.2 shows that reducing the outlet pressure from 100 psi to 90 psi will result in a result in a 6% hp savings.

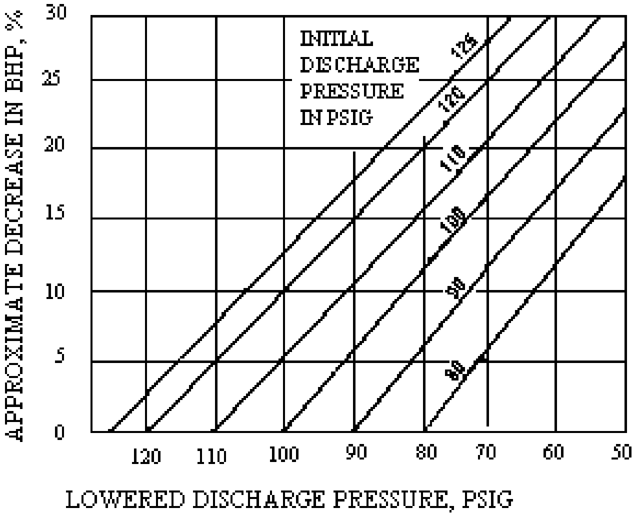


Figure 9.2: Reduction of Hp vs. Pressure Reduction

Source: Gatts, Massesy, & Robertson, "Energy Conservation Program Guide for Industry and Commerce", 1997

The annual energy savings is calculated using the following equation:

$$AES = PD \times LF \times PR \times C_1 \times HRS$$

where,

AES = Annual energy savings; kWh

CP = Power draw of rotary screw compressor, 125 hp

LF = Load factor, 0.95 (measured)

PR = Percentage Reduction in Horsepower, 6%

C_1 = Conversion Factor; 0.746 kW/hp

HRS = Annual Hours of Operation; 8,425

thus:

$$AES = 125 \times 0.95 \times 0.06 \times 0.746 \times 8{,}425 = 44{,}800 \text{ kWh}$$

The annual cost savings is then calculated using the following equation:

$$ACS = AES \times MC$$

where,

ACS = Annual cost savings; \$

MC = Marginal Cost of Electricity; \$0.072/kWh

thus,

$$ACS = 44{,}800 \times \$0.072 = \$3200$$

Implementation

This recommendation requires the compressor pressure to be reduced. It is recommended however that the pressure be reduced in small intervals until the minimum pressure is attained where all equipment is operating properly. It is estimated that plant personnel at no charge to the plant can accomplish this. The simple payback is therefore immediate.

Additional Note

The purchase and installation of an accumulator tank can ensure proper pressure during peak demands for compressed air. The industry standard for accumulator tanks sizing is 1-2 gallons per cfm. The flow rate for the compressors is 300 cfm. Since the end use pressure reduction to 85 psi is still greater than the 80 psi needed, a 600 gallon tank should be sufficient to maintain capacity during peak demands. According to manufacturers of receiver tanks, the purchase of a 600 gallon steel compression tank and accessory kit is approximately $2,500. The installation of the tank is estimated to be 10 hours of labor. At $35 per hour the total implementation cost is $2,850. The simple payback is then:

$$\text{Simple Payback Period} = \frac{\text{Implementation Cost}}{\text{Annual Cost Savings}} = \frac{\$2{,}850}{\$3{,}200} = 0.9\text{ years}$$

AR NUMBER 10: Insulate Condensate Tank

Assessment Recommendation Summary				
ARC #	Annual Energy Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.2123.2	#6 Oil: 440 MMBtu	$2,000	$3,000	1.5 years

Current Practice and Observations

During the plant visit, it was noted that there are two condensate tanks that were not insulated. These tanks, located directly below the paper machines, collect the condensate from the steam cans. Also, there are a number of steam and condensate pipes that are not insulated in the boiler room. A summary of the measured dimensions and temperatures of these tanks and pipes are shown in Table 10.1. The steam used in the facility is produced by two boilers. These boilers use #6 fuel oil and operated an estimated 8,425 hours annually. The annual average temperature surrounding the tanks and pipes is approximately 75°F.

Recommended Action

It is recommended that the uninsulated condensate tanks and pipes shown in Table 10.1 be insulated to reduce the amount of heat escaping from the surface. The recommended thickness of fiberglass insulation is shown in Table 10.1 for the uninsulated surfaces.

	Diameter **(inches)**	**Length, LT and LP** **(ft)**	**Temperature** **(°F)**	**Recommended Insulation Thickness***
Tanks	18	5	220	2”
	24	4	290	3”
Pipes	10	24	150	2”
	4	10	380	4”
	6	4	250	3”
	2	10	180	2”

*Based on data from ASHRAE 1997 Fundamentals

Table 10.1. Measured Tank and Pipe Dimensions and Temperatures

Anticipated Savings

The energy savings for this recommendation results from the decrease in heat loss from the exposed tank and pipe surfaces. The annual energy savings for each condensate tank can be calculated from the following equation:

$$AES_T = \frac{\left[(QT_{WO} - QT_W) \times LT + (QE_{WO} - QE_W) \times AE\ \right] \times HRS \times C1}{\eta}$$

where,

AES_T = Annual energy savings from insulating the condensate tank; MMBtu

QT_{WO} = Heat loss from cylindrical part of the tank without insulation, Table 10.2; Btu/ft/hr

QT_W = Heat loss from the cylindrical part of the tank with insulation, Table 10.2; Btu/ft/hr

LT = Length of condensate tank, Table 10.1; feet

QE_{WO} = Heat loss from tank ends without insulation, Table 10.2; Btu/ft^2/hr

QE_W = Heat loss from tank ends with insulation, Table 10.2; Btu/ft^2/hr

AE = Total surface area of tank ends, Table 10.2; ft^2

HRS = Annual hours of operation; 8,425 hours

η = Average boiler efficiency, measured on-site; 0.847

C_1 = Conversion constant; 10^{-6} MMBtu/Btu

The heat loss values and annual energy savings for each condensate tank is shown in Table 10.2. The total energy savings from the two tanks is 230 MMBtu.

Tank Temp. (°F)	**Heat Loss From Tank Without Insulation*, QT_{WO} (But/ft/hr)**	**Heat Loss From Tank With Insulation*, QT_W (But/ft/hr)**	**Heat Loss From Ends Without Insulation*, QE_{WO} (But/ft^2/ hr)**	**Heat Loss From Ends With Insulation*, QE_W (But/ft2/hr)**	**Area of Tank Ends, AE (ft^2)**	**Annual Energy Savings, AES_T (MMBtu)**
220	1,280	115	317	22	3.5	70
290	3,440	173	543	24	6.3	160
TOTAL						230

*Source: North American Insulation Manufactureres Association (NAIMA), *3E Plus Version 3.0*

Table 10.2: Condensate Tank Heat Loss and Annual Energy Savings

Similarly, the annual energy savings resulting from the insulation of each of the pipes can be calculated from the following equation:

$$AES_P = \frac{[(QP_{WO} - QP_W) \times LP] \times HRS \times C1}{\eta}$$

where,

AES_P = Annual energy savings from insulating the pipe; MMBtu

QP_{WO} = Heat loss from the pipe without insulation, Table 10.2; Btu/ft/hr

QP_W = Heat loss from the pipe with insulation, Table 10.2; Btu/ft/hr

LP = Length of the pipe, Table 10.1; feet

The heat loss values and annual energy savings for each pipe is shown in Table 10.3. The total energy savings from the four pipes is 210 MMBtu.

Pipe Temperature (°F)	**Heat Loss From Tank Without Insulation*, QT_{WO} (But/ft/hr)**	**Heat Loss From Tank With Insulation*, QT_W (But/ft/hr)**	**Annual Energy Savings, AES_T (MMBtu)**
150	351	32	80
380	1,051	60	100
250	672	46	20
180	140	16	10
TOTAL			210

*Source: North American Insulation Manufactureres Association (NAIMA), *3E Plus Version 3.0*

Table 10.3: Pipe Heat Loss and Annual Energy Savings

The total annual energy savings from both the tanks and the pipes can now be found from:

$$\begin{aligned} AES &= AES_T + AES_P \\ &= 230 + 210 = 440 MMBtu \end{aligned}$$

where,

AES = Total annual energy savings; MMBtu

The annual cost savings can now be calculated as follows:

$$\mathrm{ACS} = \mathrm{AES} \times \mathrm{MC}_{\#6}$$

where,

ACS = Annual cost savings; $

$\mathrm{MC}_{\#6}$ = Marginal cost of #6 Fuel Oil; $4.61/MMBtu

Thus,

$$\mathrm{ACS} = 440 \times \$4.61 = \$2{,}000$$

Implementation

In order to implement this recommendation, the tank and pipe insulation outlined in Table 10.1 requires purchasing and installation. Based on data from *Means Mechanical Cost Data 2001*, this will cost approximately, $3,000. Therefore, the payback period can be calculated as:

$$\text{Payback Period} = \frac{\text{Implementation Cost}}{\text{Annual Cost Savings}} = \frac{\$3{,}000}{\$2{,}000} = 1.5 \text{ years}$$

ADDITIONAL CONSIDERATIONS

AC NUMBER 1: Improve Power Factor

Assessment Recommendation Summary				
ARC #	Annual Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.3212.3	Demand: 2,716 kVa	$15,900	$13,000	10 months

Current Practice and Observations

The demand charge in the plant is evaluated each month based on the greater of the following: a) the greatest fifteen-minute peak occurring during the peak hours period within such a month as measured in kilowatts, or b) 90% of the greatest fifteen-minute peak occurring during the peak hours period of such month as measured in kilovolt-amperes. This rate structure implies that there is a power factor penalty when the power factor is lower than 0.9. The electricity bill for the past twelve months showed that the company's power factor was below 0.9, and therefore the company pays a monthly penalty.

Recommended Action

It is recommended that the facility install capacitors to the main power electrical supply to correct the power factor. This will raise the power factor above 0.90 and eliminate the reactive power charge penalty paid to the utility. Based on discussion with plant personnel there were concerns regarding capacitor installation mainly due to previous experiences. Capacitor banks were installed previously, but could not accommodate the voltage fluctuations that the facility sees. The capacitors failed and destroyed electrical panels as a result. Based on our experience with many facilities, the problems they encountered are very rare.

Anticipated Savings

Power factor is a way of quantifying the reaction of alternating current electricity to various types of electrical loads. Inductive loads, such as motors, transformers, and fluorescent lamp ballast's cause the voltage and current they use to shift out of phase.

The utility must supply the additional power to make up for this phase shift, so they charge customers if the additional power requirements are too high. The total power requirement of the load is made up of two components: the resistive (real) component and the reactive component. The resistive component, measured in kilowatts (kW), does the useful work and the reactive component, measured in reactive kilovolt-amperes (kVAR), represents the power required to produce the magnetic field for the operation of inductive devices. It does no useful work and does not register on a power meter, but it contributes to the heating of generators, transformers, and transmission lines. The apparent power, measured in kilovolt-amperes (kVa) is the power that the utility supplies and is always equal to or greater than the real power because it reflects both the resistive and the reactive power components. The relationship between these components of electric power can be visualized as a vector sum, as shown in Figure 2.1. The ratio of real, usable power (kW) to apparent power (kVa) is a measure of reactive losses and is known as the power factor.

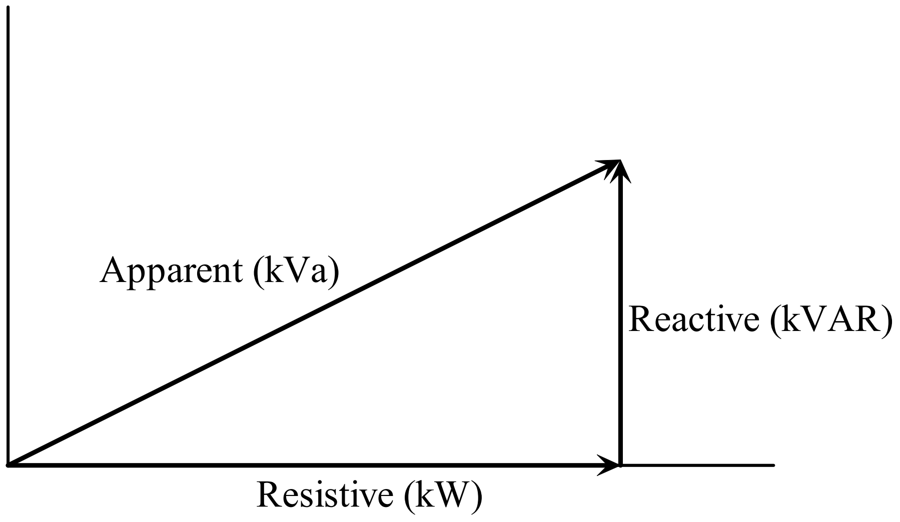


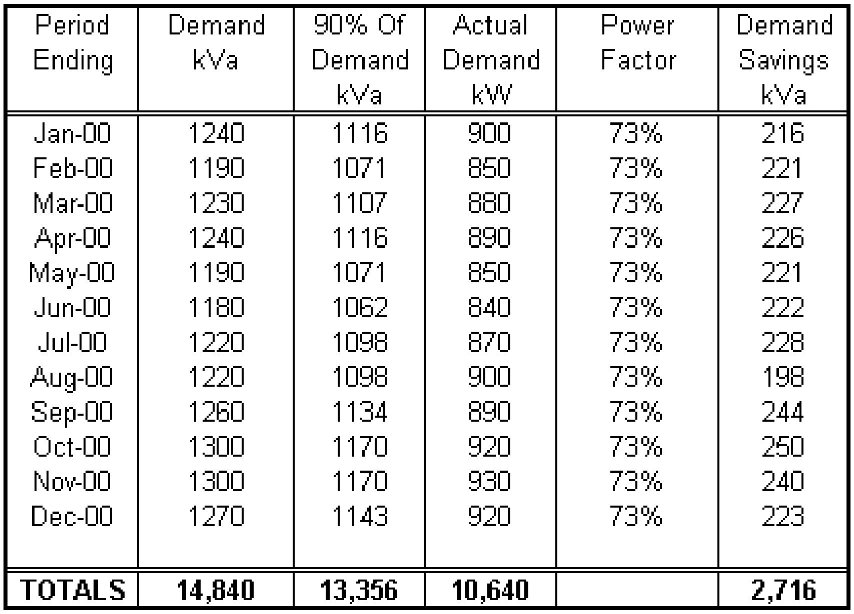
Figure 2.1: Components of Electric Power

Capacitor banks decrease the reactive power (kVAR) and hence the apparent power also decreases. They draw current that leads the voltage while the inductive loads draw current which lags the voltage. The net result is that the current in the supply line is brought more closely into phase with the supply voltage and the power factor increases. A power factor of 1.0 indicates that the current and voltage are exactly in phase.

Improving the power factor would save the company a significant amount of money and save the utility energy. The company's monetary savings would be realized by the elimination of reactive power charges on the utility bill.

The analysis is based on data from January 2000 to December 2000. Examining the power factor calculations shown in Table 2.1, the power factor during this period was always 0.73. Using a power factor correction chart obtained from a manufacturer, a copy of which is included in Figure 2.2, we can determine the capacity of the capacitor bank required. Figure 2.2 indicates that the current kW demand should be multiplied by 0.452 to obtain the required capacitance (in kVa) that will increase the power factor from 0.73 to 0.90 and will eliminate the reactive power charge paid to the utility. To be conservative, the highest demand month of 930 kW will be used in this calculation. Therefore, the capacitance required to correct the power factor to 0.90 is 420 kVAR.

Assuming the power factor profiles for each year are the same, the Annual Demand Savings, ADS, will be 2,716 kVa and the calculation is displayed in Table 2.1.



Period Ending	Demand kVa	90% Of Demand kVa	Actual Demand kW	Power Factor	Demand Savings kVa
Jan-00	1240	1116	900	73%	216
Feb-00	1190	1071	850	73%	221
Mar-00	1230	1107	880	73%	227
Apr-00	1240	1116	890	73%	226
May-00	1190	1071	850	73%	221
Jun-00	1180	1062	840	73%	222
Jul-00	1220	1098	870	73%	228
Aug-00	1220	1098	900	73%	198
Sep-00	1260	1134	890	73%	244
Oct-00	1300	1170	920	73%	250
Nov-00	1300	1170	930	73%	240
Dec-00	1270	1143	920	73%	223
TOTALS	**14,840**	**13,356**	**10,640**		**2,716**

Table 2.1: Demand Savings

The annual cost savings associated with this recommendation is given by:

$$\text{ACS} = \text{MCD} \times \text{ADS}$$

where,

ACS = Annual cost savings; \$

MCD = Marginal cost of demand; \$5.85/kVa

thus,

$$\text{ACS} = \$5.85 \times 2{,}716 = \$15{,}900$$

Implementation

Implementation of this recommendation requires the installation of 420 KVAR of additional capacitance. This is estimated at a total installed cost of \$13,000 (Ref. *Means Electrical Cost Data 2001*). The simple payback is computed as follows

$$\text{Simple Payback} = \frac{\text{Implementation Cost}}{\text{Annual Cost Savings}} = \frac{\$13{,}000}{\$15{,}900} = 0.8\ \text{years} = 10\ \text{months}$$

KW MULTIPLIERS TO DETERMINE CAPACITOR KILOVARS REQUIRED FOR POWER-FACTOR CORRECTION

Original Power Factor	Corrected Power Factor																				
	0.80	0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.89	0.90	0.91	0.92	0.93	0.94	0.95	0.96	0.97	0.98	0.99	1.0
0.50	0.982	1.008	1.034	1.060	1.086	1.112	1.139	1.165	1.192	1.220	1.248	1.276	1.306	1.337	1.369	1.403	1.440	1.481	1.529	1.589	1.732
0.51	0.937	0.962	0.989	1.015	1.041	1.067	1.094	1.120	1.147	1.175	1.203	1.231	1.261	1.292	1.324	1.358	1.395	1.436	1.484	1.544	1.687
0.52	0.893	0.919	0.945	0.971	0.997	1.023	1.050	1.076	1.103	1.131	1.159	1.187	1.217	1.248	1.280	1.314	1.351	1.392	1.440	1.500	1.643
0.53	0.850	0.876	0.902	0.928	0.954	0.980	1.007	1.033	1.060	1.088	1.116	1.144	1.174	1.205	1.237	1.271	1.308	1.349	1.397	1.457	1.600
0.54	0.809	0.835	0.861	0.887	0.913	0.939	0.966	0.992	1.019	1.047	1.075	1.103	1.133	1.164	1.196	1.230	1.267	1.308	1.356	1.416	1.559
0.55	0.769	0.795	0.821	0.847	0.873	0.899	0.926	0.952	0.979	1.007	1.035	1.063	1.093	1.124	1.156	1.190	1.227	1.268	1.316	1.376	1.519
0.56	0.730	0.756	0.782	0.808	0.834	0.860	0.887	0.913	0.940	0.968	0.996	1.024	1.054	1.085	1.117	1.151	1.188	1.229	1.277	1.337	1.480
0.57	0.692	0.718	0.744	0.770	0.796	0.822	0.849	0.875	0.902	0.930	0.958	0.986	1.016	1.047	1.079	1.113	1.150	1.191	1.239	1.299	1.442
0.58	0.655	0.681	0.707	0.733	0.759	0.785	0.812	0.838	0.865	0.893	0.921	0.949	0.979	1.010	1.042	1.076	1.113	1.154	1.202	1.262	1.405
0.59	0.619	0.645	0.671	0.697	0.723	0.749	0.776	0.802	0.829	0.857	0.885	0.913	0.943	0.974	1.006	1.040	1.077	1.118	1.166	1.226	1.369
0.60	0.583	0.609	0.635	0.661	0.687	0.713	0.740	0.766	0.793	0.821	0.849	0.877	0.907	0.938	0.970	1.004	1.041	1.082	1.130	1.190	1.333
0.61	0.549	0.575	0.601	0.627	0.653	0.679	0.706	0.732	0.759	0.787	0.815	0.843	0.873	0.904	0.936	0.970	1.007	1.048	1.096	1.156	1.299
0.62	0.516	0.542	0.568	0.594	0.620	0.646	0.673	0.699	0.726	0.754	0.782	0.810	0.840	0.871	0.903	0.937	0.974	1.015	1.063	1.123	1.266
0.63	0.483	0.509	0.535	0.561	0.587	0.613	0.640	0.666	0.693	0.721	0.749	0.777	0.807	0.838	0.870	0.904	0.941	0.982	1.030	1.090	1.233
0.64	0.451	0.474	0.503	0.529	0.555	0.581	0.608	0.634	0.661	0.689	0.717	0.745	0.775	0.806	0.838	0.872	0.909	0.950	0.998	1.068	1.201
0.65	0.419	0.445	0.471	0.497	0.523	0.549	0.576	0.602	0.629	0.657	0.685	0.713	0.743	0.774	0.806	0.840	0.877	0.918	0.966	1.026	1.169
0.66	0.388	0.414	0.440	0.466	0.492	0.518	0.545	0.571	0.598	0.626	0.654	0.682	0.712	0.743	0.775	0.809	0.846	0.887	0.935	0.995	1.138
0.67	0.358	0.384	0.410	0.436	0.462	0.488	0.515	0.541	0.568	0.596	0.624	0.652	0.682	0.713	0.745	0.779	0.816	0.857	0.905	0.965	1.108
0.68	0.328	0.354	0.380	0.406	0.432	0.458	0.485	0.511	0.538	0.566	0.594	0.622	0.652	0.683	0.715	0.749	0.786	0.827	0.875	0.935	1.079
0.69	0.299	0.325	0.351	0.377	0.403	0.429	0.456	0.482	0.509	0.537	0.565	0.593	0.623	0.654	0.686	0.720	0.757	0.798	0.846	0.906	1.049
0.70	0.270	0.296	0.322	0.348	0.374	0.400	0.427	0.453	0.480	0.508	0.536	0.564	0.594	0.625	0.657	0.691	0.728	0.769	0.817	0.877	1.020
0.71	0.242	0.268	0.294	0.320	0.346	0.372	0.399	0.425	0.452	0.480	0.508	0.536	0.566	0.597	0.629	0.663	0.700	0.741	0.789	0.849	0.992
0.72	0.214	0.240	0.266	0.292	0.318	0.344	0.371	0.397	0.424	0.452	0.480	0.508	0.538	0.569	0.601	0.635	0.672	0.713	0.761	0.821	0.964
0.73	0.186	0.212	0.238	0.264	0.290	0.316	0.343	0.369	0.396	0.424	0.452	0.480	0.510	0.541	0.573	0.607	0.644	0.685	0.733	0.793	0.936
0.74	0.159	0.185	0.211	0.237	0.263	0.289	0.316	0.342	0.369	0.397	0.425	0.453	0.483	0.514	0.546	0.580	0.617	0.658	0.706	0.766	0.909
0.75	0.132	0.158	0.184	0.210	0.236	0.262	0.289	0.315	0.342	0.370	0.398	0.426	0.456	0.487	0.519	0.553	0.590	0.631	0.679	0.739	0.882
0.76	0.105	0.131	0.157	0.183	0.209	0.235	0.262	0.288	0.315	0.343	0.371	0.399	0.429	0.460	0.492	0.526	0.563	0.604	0.652	0.712	0.855
0.77	0.079	0.105	0.131	0.157	0.183	0.209	0.236	0.262	0.289	0.317	0.345	0.373	0.403	0.434	0.466	0.500	0.537	0.578	0.626	0.685	0.829
0.78	0.052	0.078	0.104	0.130	0.156	0.182	0.209	0.235	0.262	0.290	0.318	0.346	0.376	0.407	0.439	0.473	0.510	0.551	0.599	0.659	0.802
0.79	0.026	0.052	0.078	0.104	0.130	0.156	0.183	0.209	0.236	0.264	0.292	0.320	0.350	0.381	0.413	0.447	0.484	0.525	0.573	0.633	0.776
0.80	0.000	0.026	0.052	0.078	0.104	0.130	0.157	0.183	0.210	0.238	0.266	0.294	0.324	0.355	0.387	0.421	0.458	0.499	0.547	0.609	0.750
0.81		0.000	0.026	0.052	0.078	0.104	0.131	0.157	0.184	0.212	0.240	0.268	0.298	0.329	0.361	0.395	0.432	0.473	0.521	0.581	0.724
0.82			0.000	0.026	0.052	0.078	0.105	0.131	0.158	0.186	0.214	0.242	0.272	0.303	0.335	0.369	0.406	0.447	0.495	0.555	0.698
0.83				0.000	0.026	0.052	0.079	0.105	0.132	0.160	0.188	0.216	0.246	0.277	0.309	0.343	0.380	0.421	0.469	0.529	0.672
0.84					0.000	0.026	0.053	0.079	0.106	0.134	0.162	0.190	0.220	0.251	0.283	0.317	0.354	0.395	0.443	0.503	0.646
0.85						0.000	0.027	0.053	0.080	0.108	0.136	0.164	0.194	0.225	0.257	0.291	0.328	0.369	0.417	0.477	0.620
0.86							0.000	0.026	0.053	0.081	0.109	0.137	0.167	0.198	0.230	0.264	0.301	0.342	0.390	0.450	0.593
0.87								0.000	0.027	0.055	0.083	0.111	0.141	0.172	0.204	0.238	0.275	0.316	0.364	0.424	0.567
0.88									0.000	0.028	0.056	0.084	0.114	0.145	0.177	0.211	0.248	0.289	0.337	0.397	0.540
0.89										0.000	0.028	0.056	0.086	0.117	0.149	0.183	0.220	0.261	0.309	0.369	0.512
0.90											0.000	0.028	0.058	0.089	0.121	0.155	0.192	0.233	0.281	0.341	0.484
0.91												0.000	0.030	0.061	0.093	0.127	0.164	0.205	0.253	0.313	0.456
0.92													0.000	0.031	0.063	0.097	0.134	0.175	0.223	0.283	0.426
0.93														0.000	0.032	0.066	0.103	0.144	0.192	0.252	0.395
0.94															0.000	0.034	0.071	0.112	0.160	0.220	0.363
0.95																0.000	0.037	0.079	0.126	0.186	0.329
0.96																	0.000	0.041	0.089	0.149	0.292
0.97																		0.000	0.048	0.108	0.251
0.98																			0.000	0.060	0.203
0.99																				0.000	0.143
																					0.000

Figure 2.2

AC NUMBER 2: Use Boiler Exhaust Gases To Preheat Boiler Feedwater

Assessment Recommendation Summary				
ARC #	Annual Savings	Annual Cost Savings	Implementation Cost	Simple Payback
2.2412.2	Nat. Gas: 1,000 MMbtu	$7,900	$23,000	2.9 years

Current Practice and Observations

The facility operates one 350 hp natural gas fired boiler, which produces 190-psig steam for use throughout the process. Based on boiler nameplate data and observations taken on site, it was found that steam is produced at an average rate of approximately 4,000 lb/hour, approximately 33% of rated capacity. Steam is produced for process use during 6,552 hours annually. In addition to this information, a boiler test was conducted. From this analysis it was found that the boiler is operating with an efficiency of 78.7%, contains about 45% excess air, and has an exhaust temperature of 400°F. Finally, measured feed water temperature was approximately 230°F.

Recommended Action

It is recommended that a boiler feedwater economizer be installed in the stack to recover waste heat from the exhaust gases. The recovered waste heat from the combustion gases, when used to raise the temperature of water entering the boiler reduces the amount of energy required to convert the entering water to the leaving boiler steam conditions.

Anticipated Savings

The savings from this recommendation result from the decrease in fuel usage due to the recovery of some of the heat of combustion. To estimate the savings of this recommendation, both energy and monetary, several assumptions were needed. These are identified as they are used. To start, the amount of natural gas usage per hour is determined from:

$$\mathrm{AFU} = \frac{\mathrm{BHP} \times \mathrm{C1} \times \mathrm{ABC}}{\eta_R \times \mathrm{HHV}}$$

where,

AFU = Average natural gas usage; lb/hr

BHP = Boiler horsepower rating; 350 hp

C1 = Conversion constant; 33,465 Btu/hr·hp

ABC = Average percent boiler capacity used; 33%

η_R = Rated boiler efficiency; 0.85

HHV = Higher heating value of natural gas; 22,000 Btu/lb

Thus,

$$\mathrm{AFU} = \frac{350 \times 33{,}465 \times 0.33}{0.85 \times 22{,}000} = 210\ \mathrm{lb/hr}$$

This value is needed to determine the amount of combustion air that will pass through the economizer. This is determined by the following equation:

$$m_a = \mathrm{AFU} \times \mathrm{AFR}$$

where,

m_a = Amount of combustion air passing through stack; lb/hr

AFR = Air-Fuel ratio, determined from theoretical combustion values and assuming 45% excess air is typical; 25 $\mathrm{lb}_{\mathrm{air}}/\mathrm{lb}_{\mathrm{fuel}}$.

Thus,

$$m_a = 210 \times 25 = 5{,}300\ \mathrm{lb/hr}$$

Now, examining the economizer, the effectiveness of the heat exchange device is given by the following:

$$\varepsilon = \frac{m_w \times Cp_w \times (\mathrm{TFO} - \mathrm{TFI})}{m_a \times Cp_a \times (\mathrm{TAI} - \mathrm{TFI})}$$

where,

ε = Boiler economizer effectiveness, assumed; 0.6

m_w = Average mass flow rate of water into boiler; 4,000 lb/hr

Cp_w = Specific heat of water; 1.0 Btu/lb_mR

TFO = Temperature of feedwater leaving economizer, unknown; °F

TFI = Temperature of feedwater entering economizer; 230°F

Cp_a = Specific heat of air; 0.24 Btu/lb_mR

TAI = Temperature of air entering economizer, measured; 400°F

Re-arranging this relationship, the unknown temperature of feedwater leaving the economizer, TFO, can be found as follows:

$$\begin{aligned} \mathrm{TFO} &= \frac{\varepsilon \times m_a \times Cp_a \times (\mathrm{TAI} - \mathrm{TFI})}{m_w \times Cp_w} + \mathrm{TFI} \\ &= \frac{0.6 \times 5{,}300 \times 0.24 \times (400 - 230)}{4{,}000 \times 1.0} + 230 \\ &= 260^\circ\mathrm{F} \end{aligned}$$

Thus, the heat recovery measure increases the entering boiler water temperature by 30°F. Another important value to calculate, before the energy savings can be computed, is the air temperature leaving the economizer that is exiting the stack. This value must still be hot enough to prevent condensation in the boiler stack, which occurs at approximately 150°F for natural gas. The temperature of air leaving the economizer may be determined through the following relation:

$$\mathrm{TAO} = \mathrm{TAI} - \frac{m_w \times Cp_w \times (\mathrm{TFO} - \mathrm{TFI})}{m_a \times Cp_a}$$

where,

TAO = Temperature of air leaving economizer; °F

Thus,

$$\mathrm{TAO} = 400 - \frac{4{,}000 \times 1.0 \times (260 - 230)}{5{,}300 \times 0.24} = 310°\mathrm{F}$$

Thus, the exiting air temperature is high enough to prevent stack condensation. The hourly energy savings can now be determined by calculating the reduction in boiler energy that occurs due to increased feedwater temperature. This is found from:

$$\mathrm{ES} = \frac{m_w \times Cp_w \times (\mathrm{TFO} - \mathrm{TFI})}{\eta}$$

where,

ES = Energy savings due to increased entering water temperature; Btu/hr

η = Boiler efficiency as measured; 0.787

Thus,

$$\mathrm{ES} = \frac{4{,}000 \times 1.0 \times (260 - 230)}{0.787} = 152{,}000 \text{ Btu/hr}$$

It is now assumed that this energy savings is typical, and can be applied approximately to average boiler operation. Thus, the annual energy savings of natural gas can be determined from:

$$\mathrm{AES} = \mathrm{ES} \times \mathrm{HRS} \times \mathrm{C2}$$

where,

AES = Annual energy savings; MMbtu

HRS = Annual hours of operation; 6,552 hours

C2 = Conversion constant; $1\mathrm{x}10^{-6}$ MMbtu/Btu

Thus,

$$\mathrm{AES} = 152{,}000 \times 6{,}552 \times 10^{-6} = 1{,}000 \text{ MMBtu}$$

Now that the annual energy savings values have been found, the annual cost savings can be determined:

$$\mathrm{ACS} = \mathrm{AES} \times \mathrm{MC}_{\mathrm{NG}}$$

where,

ACS = Annual cost savings of natural gas; \$

$\mathrm{MC}_{\mathrm{NG}}$ = Marginal cost of natural gas; \$7.93/MMbtu

Thus,

$$\mathrm{ACS} = 1{,}000 \times \$7.93 = \$7{,}900$$

Implementation

The implementation of this recommendation consists of the purchase and installation of an economizer in the stack leaving the boiler room. In addition to this, inlet and outlet stack transitions will be required as well as additional feedwater piping. The cost of the economizer is approximately \$15,000 as obtained from suppliers. Using \$8,000 for the additional duct and piping, engineering and installation based on data from *Means Mechanical Cost Data 2001*, the total implementation cost is \$23,000. The payback period can now be calculated as follows:

$$\text{Simple Payback Period} = \frac{\text{Implementation Cost}}{\text{Annual Cost Savings}} = \frac{\$23{,}000}{\$7{,}900} = 2.9 \text{ years}$$