Georgia Institute of Technology
Energy and Environmental Management Center

PLANT-WIDE ASSESSMENT REPORT

for

Shaw Industries, Plant #78
Aiken, SC

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PREFACE

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1. EXECUTIVE SUMMARY

Overview

A plant-wide energy assessment sponsored by the U.S. Department of Energy was conducted at Shaw Industries Group, plant #78 in Aiken, SC. The assessment team consisted of Georgia Tech faculty from the Energy & Environmental Management Center and Shaw personnel from plant #78 and the corporate energy group. The purpose of this assessment was to uncover as many opportunities for saving energy usage and costs using techniques that have been established as best practices in the energy engineering field. In addition, these findings are to be shared with similar plants in Shaw Industries Group to multiply the lessons learned. The findings from this assessment are included in this report.

A summary of energy use at plant #78 and the potential savings uncovered by the assessment team are shown in Table 1.1, below. Management of energy at industrial facilities varies greatly, but all facilities have opportunities to use their energy resources more efficiently, and reduce their energy costs. The savings opportunities are summarized at the end of the executive summary, and explored in more detail in Section 5.

Table 1.1. Energy consumption and proposed cost savings.

Resource	Current Annual Consumption*		
Electricity	136,540,684	kWh	$ 5,632,427
Natural Gas	176,542	MMBtu	$ 1,345,077
Total:			$ 6,977,504
Proposed Savings			$ 1,020,000
			14.6%

* January 2004 to December 2004

The success of this effort has been due in a large part to the cooperation of Shaw Industries personnel. Both the plant maintenance and engineering staff and the corporate energy engineers have participated fully in this effort, providing data, information, technical expertise, as well as uncovering energy savings opportunities.

Facility Energy Consumption

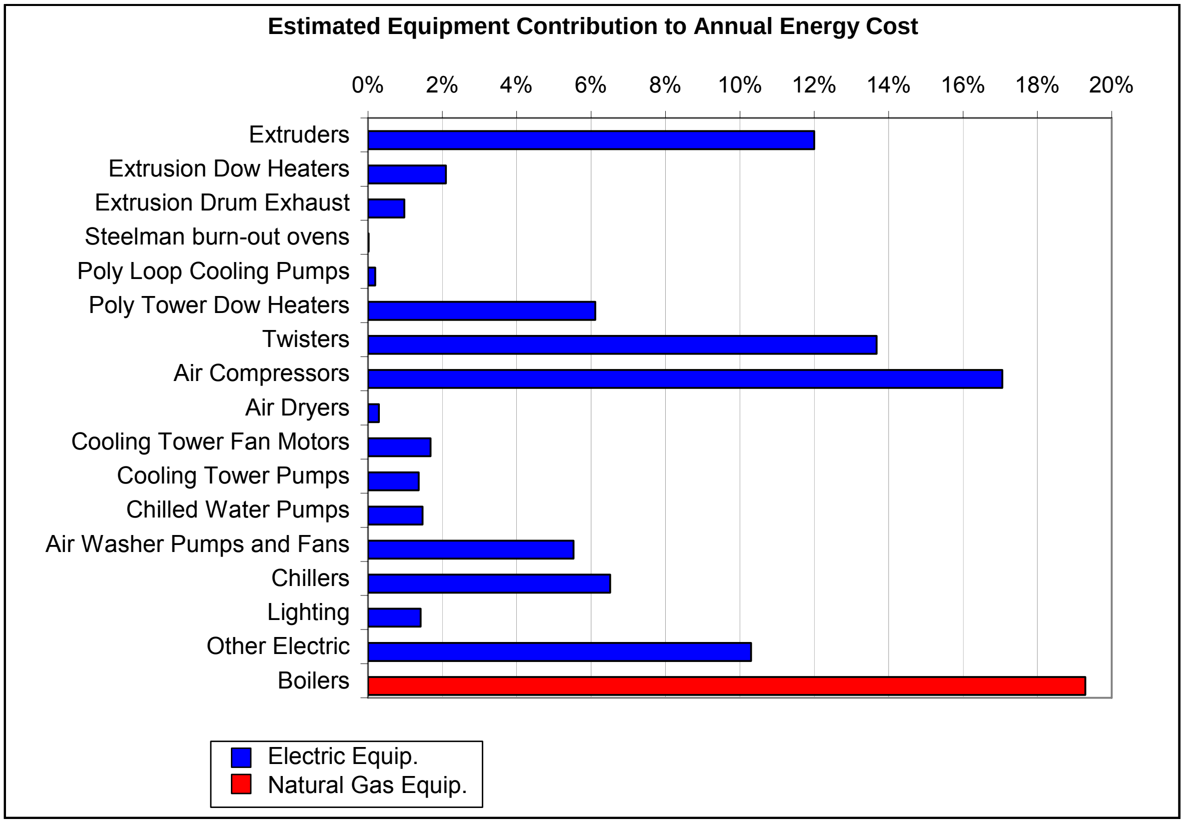

Figure 1.1. Energy balance in terms of percentage of total energy cost.

Figures 1.1 shows an approximation for how this facility utilizes energy resources. This approximation is displayed as an energy balance that is normalized in terms of a percentage of dollar cost. This baseline was estimated using equipment ratings, efficiencies, and load factors that were based upon data obtained at the time of the visit or from reasonable assumptions.

Those systems with the largest percentages of energy cost typically represent the largest opportunities for energy savings, and should be targeted for energy cost conservation efforts. Many of the energy saving opportunities (ESOs) considered in this report focus on these more costly systems.

Assessment Recommendations Summary

Tables 1.2 and 1.3 summarize the ESOs considered in this report. Table 1.2 includes a brief description of each opportunity. Table 1.3 details the projected energy and resource savings and the implementation cost for each recommendation.

Table 1.2. Description of Energy Savings Opportunities.

ESO #	ESO	ESO Description
1	Extrusion: Replace DC Motors with AC VSD	The extruders are driven by fan cooled, SCR-controlled DC motors. Replacing these motors with efficient, adjustable speed drive AC induction motors will reduce extruder maintenance costs and make the drives easier to operate.
2	Extrusion: Upgrade Belts to Cogged V-belts	The standard V-belts on the extruder drive motors should be replaced with cogged V-belts.
3	Extrusion: Use Synthetic Oil in Gear Box	Synthetic lubricants yield reduced frictional losses in numerous process applications.
4	Extrusion: Replace Electric Bake-off with Natural Gas	Replace the two electric bakeoff ovens used in extrusion with a single, more economical gas-fired oven.
5	Extrusion: Upgrade Dowtherm Pipe Insulation	Replace the existing calcium silicate insulation on the Extrusion Dowtherm with cellular glass insulation. This recommendation has a long payback when only energy savings is considered as was done here. However, this recommendation was included because there may also be financial benefits because of risk levels the insurance company currently associates with the use of calcium silicate insulation on Dowtherm systems. This benefit of reduced risk to the insurance company was not quantified here.
6	Steam: Repair/replace Traps / Add Drip Legs to Poly-tower Steam Supply Header	Adding steam trapping to the steam header serving the poly-tower will improve steam quality at the tower and allow increased condensate recovery and return to the boiler.
7	Steam: Evaluate Savings of RO Water Treatment	Substitution of reverse osmosis (RO) treated water for softened water as boiler makeup will allow an increase in the cycles of concentration and reduction in boiler blowdown.
8	Steam: Verify Proper Operation of O2 Sensor	Adjust the boiler O2 trim system to reduce the excess oxygen level of the steam boilers from their present level to 2.0 percent. Annual cleaning and calibration of the oxygen sensors is recommended to maintain proper operation.
9	Reduce Flash Losses from Condensate Tank	Condensate in the polytower receiver is currently being lost as the pressure is reduced to atmospheric and it flashes through the exhaust stack. The flash can be eliminated and makeup water heated by installing a heat exchanger in the condensate receiver vent stack.

Table 1.2. Description of Energy Savings Opportunities (Continued).

ESO #	ESO	ESO Description
10	Compressed Air: Repair Air Leaks	Repair compressed air leaks throughout the plant. An air balance indicates that approximately 30% of the compressed air supplied to the plant is lost through leaks. A dedicated leak repair program should be able to reduce and maintain a leakage rate of 10%.
11	Compressed Air: Evaluate Primary Air Storage	The plant operates a 1000 hp centrifugal compressor to satisfy demand fluctuations. Adding additional primary storage and a 220 hp screw compressor will satisfy variations in air demand. Coupled with an aggressive air leak repair program, these changes will solve concerns about compressed air capacity.
12	Compressed Air: Lower Plant Pressure with the Use of Demand-side Storage	Reduce the air pressure control setting on the plant air compressors from 145 psig to 125 psig to decrease the energy consumption. Compressing the air to the current pressure requires about 10% more energy than is necessary to compress the air to the suggested pressure.
13	Compressed Air: Install Compressor Controller	Install integrated sequence controls on the air compressors to improve compression efficiency. The controller generates savings by turning off unneeded units and optimizing the load on part-load units.
14	Replace Heat Set Compressed Air Supply with Dedicated Low Pressure Compressed Air Supply	Replace high pressure compressed air use in the heat set tunnels with a dedicated compressor supplying lower pressure air. Low pressure compressed air takes less energy to produce and will reduce heat set operating cost.
15	HVAC: ASD Spray Pumps	Install a variable frequency drive on each spray pump in the air washers. The variable speed drive will eliminate the need for throttling the water flow resulting in energy savings.
16	HVAC: Enthalpy Controls on Airwashers	Install enthalpy controls on air washers 1 through 6 such that outdoor air is used whenever the internal energy of the outdoor air is lower than the internal energy of the return air.
17	HVAC: Cover Entrance for AGV	Install a plastic curtain or an automatic roll-up door in the AGV passageway between the warehouse and the main facility. This barrier will reduce the infiltration losses due to the opening.
18	Lighting: Retrofit in warehouse w/ Occupancy Sensor	Install 6-lamp T5 fixtures in the warehouse. These fixtures should come with occupancy sensors installed.

Table 1.3. Resource Breakdown of Assessment Recommendations.

ESO #	Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)*
1	0	0	0	$ 43,200	$43,200	$256,000	5.9	$139,000	21.1%
2	401,000	47.7	0	$ -	$16,800	$7,280	0.4	$146,000	NA
3	427,000	50.8	0	$ -	$17,500	$1,280	0.1	$159,000	NA
4	154,000	53.3	-140	$ -	$9,690	$32,600	3.4	$55,100	43.2%
5	146,000	16.7	0	$ -	$6,020	$63,000	10.5	-$7,900	8.5%
6	0	0	7,230	$ 46,800	$101,000	$10,100	0.1	$908,000	NA
7	0	0	856	$ 5,350	$11,900	$2,250	0.2	$104,000	NA
8	0	0	3,490	$ -	$25,900	$0	0.0	$237,000	NA
9	0	0	12,100	$ -	$92,400	$9,920	0.1	$835,000	NA
10	4,550,000	519	0	$ -	$187,000	$25,000	0.1	$1,640,000	NA
11	2,040,000	466	0	$ -	$113,000	$39,900	0.4	$995,000	NA
12	2,480,000	284	0	$ -	$102,000	$51,400	0.5	$885,000	NA
13	4,540,000	518	0	$ -	$187,000	$20,000	0.1	$1,690,000	NA
14	231,000	26.4	0	$ -	$9,530	$14,500	1.5	$72,700	197%
15	363,000	0	0	$ -	$9,800	$36,400	3.7	$53,300	39.3%
16	2,760,000	0	0	$ -	$74,500	$94,100	1.3	$587,000	390%
17	24,500	0	0	$ -	$663	$517	0.8	$5,540	NA
18	422,000	15.0	0	$ -	$13,300	$35,200	2.7	$86,100	63.7%
Total	**18,500,000**	**2,000**	**23,600**	**95,300**	**1,020,000**	**700,000**	**0.7**		

* NA, Not Applicable, indicates that IRR cannot be calculated because simple payback is less than 1 year.

2. ENERGY MANAGEMENT

Introduction

This report presents many opportunities to reduce costs at your facility. The technical solutions proposed and the cost reductions associated with them will not be long lasting unless there is a management system in place to sustain these gains. Effective energy management requires an organization to implement an energy program that adopts best management practices.

The energy management program at Shaw Industries was evaluated using the tool – Energy Management Performance Scorecard. This scorecard matrix and the background questions associated with it provide a snapshot of the strengths and weaknesses of an organization's energy program, and provide a direction for further improvement. The following discussion presents the results of the evaluation of the Shaw energy program at the corporate level and provides direction for further improvements to the program.

This scorecard was developed by Georgia Tech's Energy & Environmental Management Center and David Mahoney (GEM Management Consultants, Inc.). It incorporates the ANSI/MSE 2000 national energy management standard developed at Georgia Tech. This standard is designed to help organizations sustain energy savings and to continually improve their energy management practices. For further reading and additional information on this standard please see the following website, www.edi.gatech.edu/energy/.

Energy Management Performance

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Shaw Industries' energy management performance is specifically evaluated in each of the five major categories on the performance scorecard. Recommendations for improvement include those best practices that would move the program to an advanced level that is compatible with ANSI/MSE 2000.

Figure 2.1: Energy Mgt. Performance Scorecard

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Energy Data Management

The maxim, “you can’t manage what you can’t measure”, is certainly true in energy management. Data management best practices are intended to guide organizations into manipulating energy data into useful information that provides a picture of an organizations current performance as well as trends which help evaluate the energy programs effectiveness.

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Strengths

Directions for Improvement

Energy Supply Management

Wading through all the tariffs and purchasing options for electricity and different fuels requires significant expertise. This is a very important effort, because many times large cost savings can be achieved by simply optimizing energy supply purchasing which requires no or very little capital expenditure. Supply-side management also requires intimate knowledge of demand-side energy use. Best Practices in Energy Supply Management take all of these subjects into account.

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Strengths

Directions for Improvement

Demand Side Management

Demand-side management refers to the operation and maintenance of an organization’s significant energy systems. Significant energy savings can be achieved with little capital expenditure by simply operating equipment consistently and maintaining it for peak efficiency.

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Strengths

Directions for Improvement

Energy Project Management

Developing and implementing energy projects is one of the most significant ways that a company can advance energy efficiency and control costs. These projects should use a best practice methodology to insure that appropriate projects are identified, selected, and results verified.

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Strengths

Directions for Improvement

Organizational Integration

Many energy programs fall apart or lose their effectiveness because the program has not been institutionalized, that is fully embraced into everyday corporate culture, or regularly checked for effectiveness. Conducting a few projects which lead to short term gains is typical of most organizations. Long term, sustainable and effective energy management requires that adequate resources, planning, procedures, and processes are incorporated into everyday business practice. Most importantly, however, is the continued support of upper management which is defined by an established energy policy and manual.

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Strengths

Directions for Improvement

3. ENERGY RATES AND DATA

Overview

Managing energy data is a vital part of an effective energy management program. Energy data properly massaged can show trends, anomalies, price signals, and energy and cost allocations. If the data is normalized properly, then the resulting trends in key performance indicators will be a direct measure of the success of the energy management program. The charts, graphs, and discussion below show the type of data and information that needs to be collected, analyzed, and reported on a regular basis. The number of figures and discussion is not meant to be exhaustive, but to provide highlights of the energy information for this facility. The tables and charts shown below are from the Georgia Tech software package Energy Profiler.

Overall Facility Energy Use

A table of all the utility costs for calendar year 2004 is shown in Figure 3.1. During this time period, $7,328,112 was spent on electricity, natural gas, and water. Seasonal trends and productivity anomalies appear on the bar charts. Because the entire plant is air-conditioned, the expected peak usage and costs in the summer are expected.

Figures 3.1 and 3.2 show trends in total energy use for calendar years 2003 to 2004. Energy use and costs are trending up and show a 5.8% rise in energy use and a 12.5% rise in energy costs. Unit electricity prices remained stable but natural gas costs rose significantly in 2004 and contributed to the significantly higher cost increase over and above the usage increase.

Figure 3.4 is an energy balance. It shows the energy usage by each of the major energy systems in the plant. Each system is designated either as process (P), process support (PS), or facility (F). The steam system uses the most energy; however, it is not the most costly since electricity costs on an equivalent unit basis is 60% higher than natural gas. Until the last few years, electricity on an equivalent unit basis was 2 to 3 times more expensive.

Figure 3.5 is a one-page fact sheet that summarizes the most important facts that an energy manager should have committed to memory.

FACILITY UTILITY SUMMARY REPORT

Main Plant

MONTH	DAYS	ELECTRICITY USE (KWH)	ELECTRICITY COST ($)	FOSSIL FUEL USE (MMBTU)	FOSSIL FUEL COST ($)	WATER USE (KGAL)	WATER COST ($)	TOTAL ENERGY (MMBTU)	TOTAL UTILITY COST($)	AVG. COST ($/MMBTU)
JAN 2004	29	10,784,997	$434,406	15,056	$105,040	2,251	$25,651	51,854	$565,097	$10.40
FEB 2004	31	10,145,851	$409,980	13,655	$99,605	1,276	$22,651	48,273	$532,236	$9.83
MAR 2004	29	11,151,479	$412,600	14,838	$91,773	4,177	$31,342	52,887	$535,714	$9.73
APR 2004	25	10,939,572	$400,391	14,125	$96,865	1,517	$17,462	51,451	$514,718	$9.59
MAY 2004	28	11,852,729	$460,899	15,029	$112,066	1,092	$19,097	55,471	$592,061	$11.05
JUN 2004	31	11,670,184	$498,781	14,726	$121,445	1,923	$28,101	54,545	$648,326	$11.96
JUL 2004	32	12,153,485	$528,816	15,175	$116,339	2,444	$29,391	56,643	$674,545	$12.44
AUG 2004	30	12,156,708	$538,735	15,131	$114,489	2,524	$44,019	56,610	$697,243	$12.60
SEP 2004	30	11,542,064	$522,071	14,048	$91,562	6,330	$39,293	53,430	$652,927	$11.83
OCT 2004	30	11,840,188	$501,505	14,777	$107,383	6,042	$37,365	55,176	$646,254	$11.74
NOV 2004	30	11,112,093	$462,872	14,915	$140,302	6,561	$40,667	52,829	$643,841	$11.63
DEC 2004	32	11,191,334	$461,372	15,067	$148,208	919	$15,569	53,252	$625,149	$11.76
TOTALS	356	136,540,684	$5,632,427	176,542	$1,345,077	37,056	$350,608	642,419	$7,328,112	$10.86

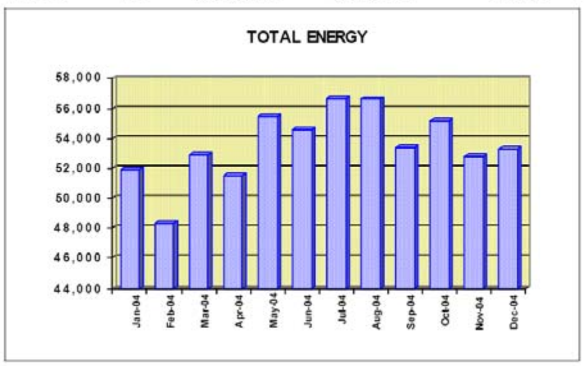


Figure 3.1 – Annual Utility Consumption and Cost (2004)

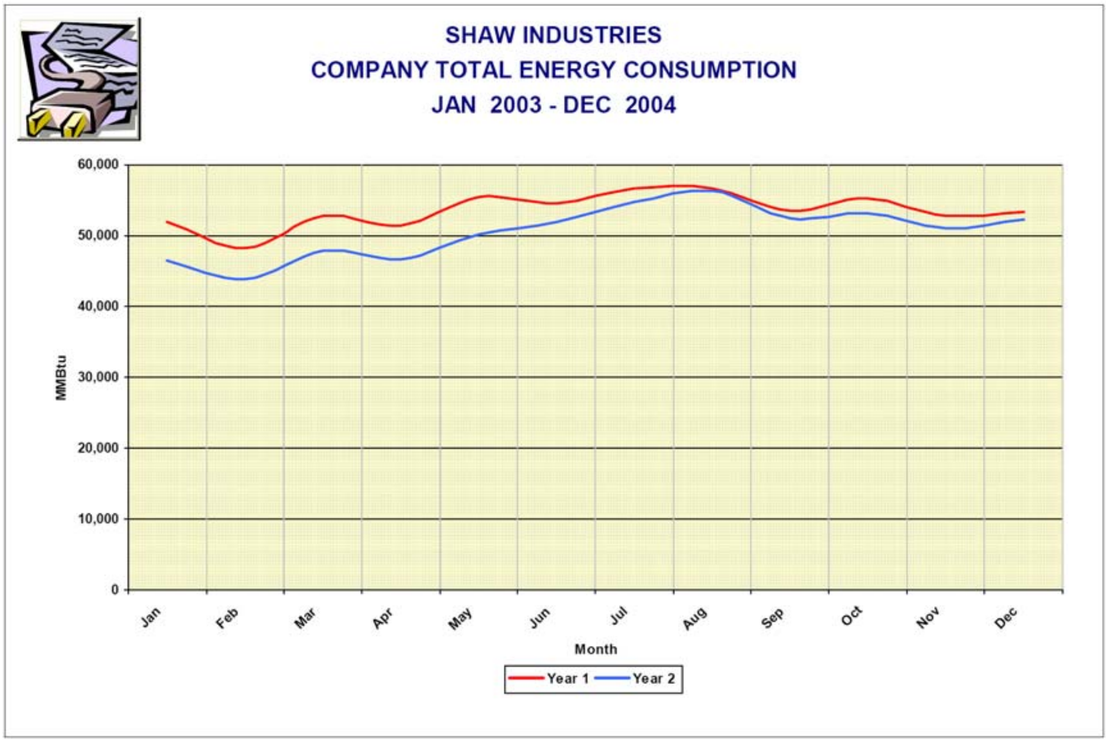


Figure 3.2: Total Energy Consumption trends for 2003 – 2004

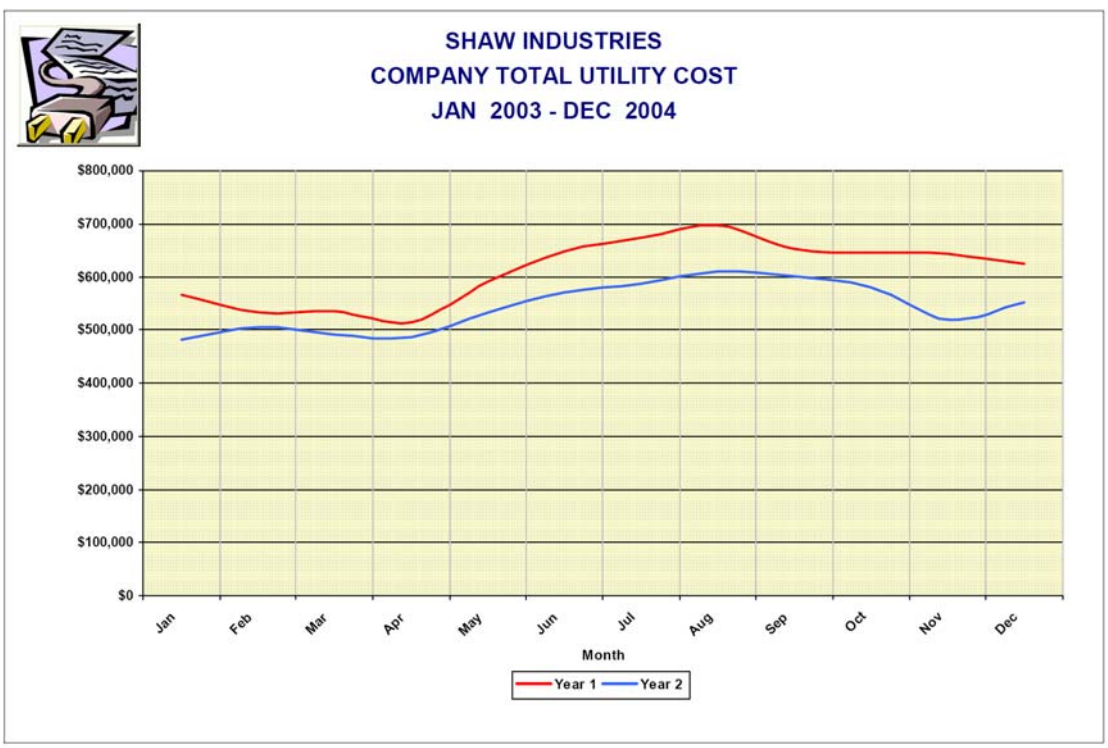


Figure 3.3: Total Energy Cost trends for 2003-2004

ENERGY BALANCE REPORT

Main Plant

SYSTEM	ELECTRICITY MMBTU		FOSSIL FUEL MMBTU		TOTAL MMBTU	
PS-CHW System	36,170	7.8%	0	0.0%	36,170	5.6%
PS-Compressed A	104,896	22.5%	0	0.0%	104,896	16.3%
F-HVAC	54,216	11.6%	0	0.0%	54,216	8.4%
F-Lighting	8,190	1.8%	0	0.0%	8,190	1.3%
PS-Steam System	279	0.1%	175,966	99.7%	176,244	27.4%
P-Polymerization	34,293	7.4%	0	0.0%	34,293	5.3%
P-Extrusion	79,246	17.0%	0	0.0%	79,246	12.3%
P -Twisting	78,932	16.9%	0	0.0%	78,932	12.3%
Other	69,655	15.0%	576	0.3%	70,231	10.9%
TOTAL	465,877		176,542		642,419	

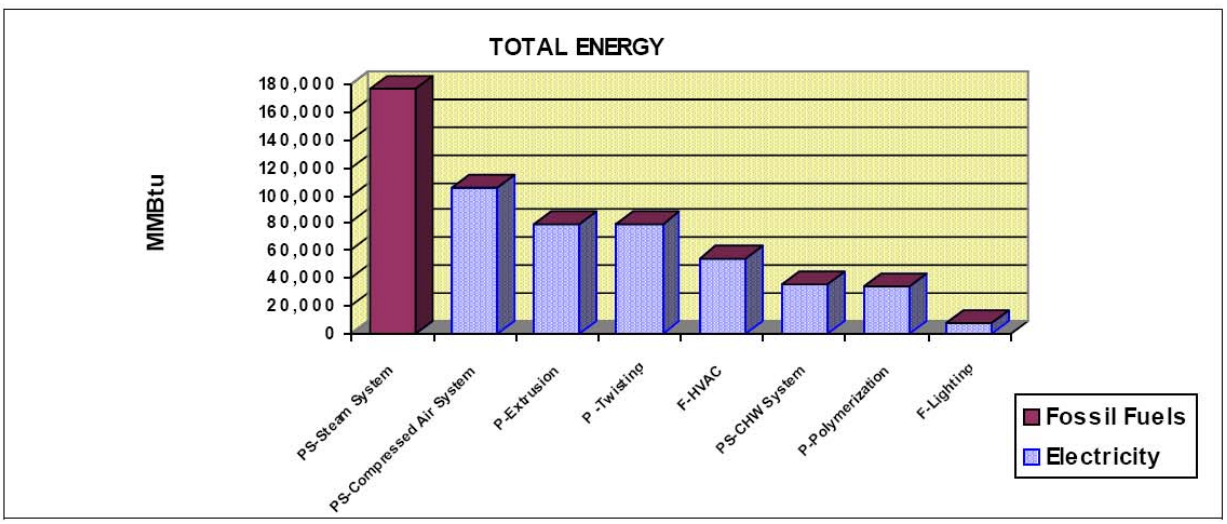


Figure 3.4: Energy Balance Report

COMPANY UTILITY FACT SHEET

ELECTRICITY		
kWh	136,540,684	
Peak Demand	34,267.74	kW/Month
Cost	$5,632,427	
Avg. Cost	$0.0413	$/kWh
Cost / Square Foot	$11.73	/Ft^2
kWh / Square Foot:	284	kWh/Ft^2
Load Factor	46.6%	

WATER AND SEWER		
Water Use	37,056	KGal/yr
Peak Use	6,561	KGal/month
Cost	$350,608	
Avg. Water Cost	$0.01	/KGal
Avg. Sewer Cost	$0.02	/KGal
Cost / Squre Foot	$0.73	/Ft^2
KGal / Square Foot	0	KGal/Ft^2

FOSSIL FUEL		
Fossil Fuel Use	176,542	MMBtu/yr
Peak Use	15,175	MMBtu/Month
Cost	$1,345,077	
Avg. Cost	$7.62	/MMBtu
Cost / Square Foot	$2.80	/Ft^2
MMBtu / Square Foot	0	MMBtu/Ft^2

UTILITY SUMMARY		
Total Energy	642,419	MMBTU
Total Cost	$7,328,112	
MMBtu / Square Foot	1	MMBtu/Ft^2
Cost / Square Foot	$15.27	/Ft^2
Cost / MMBtu	$11.41	/MMBTU

FINANCIAL INFORMATION	3/28/2005
Sales	
Gross Margin	
Raw Material Cost	
Labor Cost	
Total Cost of Manufacturin	
Total Utility Cos	$7,328,112
Utility Cost / COM	0.0%
Utility Cost / (COM - Mat.)	0.0%
Utility Cost / (COM - Mat. and Lab	0.0%

KPI SUMMARY		
Yarn Production	245,431.96	1000lbs
	3	MMBTU/1000lbs
	$30	$/1000lbs
KPI 3	0.00	
	0	
	$0	

Figure 3.5: Utility fact sheet

Utility Costs

Table 3.1 shows the utility resource costs used in the evaluation of ESOs included in this report. Following this table is a discussion of how each of these numbers was derived.

Table 3.1. Utility Costs Used in Evaluation of ESOs.

Resource	Energy Rates*	
Electricity	$0.0270	per kWh Energy
	$10.38	per kW-month Demand
Natural Gas	$7.62	per MMBtu

Electricity

Rate structures for electricity are often the most difficult to understand. However, a basic understanding of these rate structures is necessary in order to properly evaluate potential measures geared to reducing energy costs. This is because using a simple average electricity cost to evaluate measures will either overstate or understate the benefits.

There are primarily two components to electricity costs: energy and demand. The first component, energy, is measured in kWh. This is equivalent to the electricity required to power a light bulb for a fixed period of time. The second component, demand, is measured in kW. This component is equivalent to the instantaneous power consumed by a light bulb, or the rating of that light bulb.

Figure 3.6 graph shows the incremental demand for this facility for all of 1/1/04 through 12/31/04. This graph shows a very flat demand profile. Some demand increase is evident in the summer months which can be accounted for in increased demand being made upon air compressors and air washer demands.

In the case of utility charges for this facility, demand is based on the peak demand occurring during the period of coincident peak for the Aiken Cooperative electrical system. During the summer months, the period of system coincident peak tends to occur between 4PM and 6PM. During the non-summer months, the coincident peak tends to occur during the morning hours between 6AM and 8AM.

Average electricity costs are not sufficient to evaluate energy measures, therefore marginal costs were determined for both energy and demand cost components. These marginal costs reflect the dollar cost for the last incremental kWh or kW. The use of marginal costs is a more accurate way to project the savings impact of an electricity conservation project or measure. For this plant the marginal costs for energy (kWh) and demand (kW) were calculated. The plant is billed under the IL-4, industrial rate schedule. The marginal cost for electricity at the plant is $0.027/kWh and the cost of demand is $10.38/kW. Additional information on utility rate structures and a sample of how an electric bill is calculated is included in Appendix A.

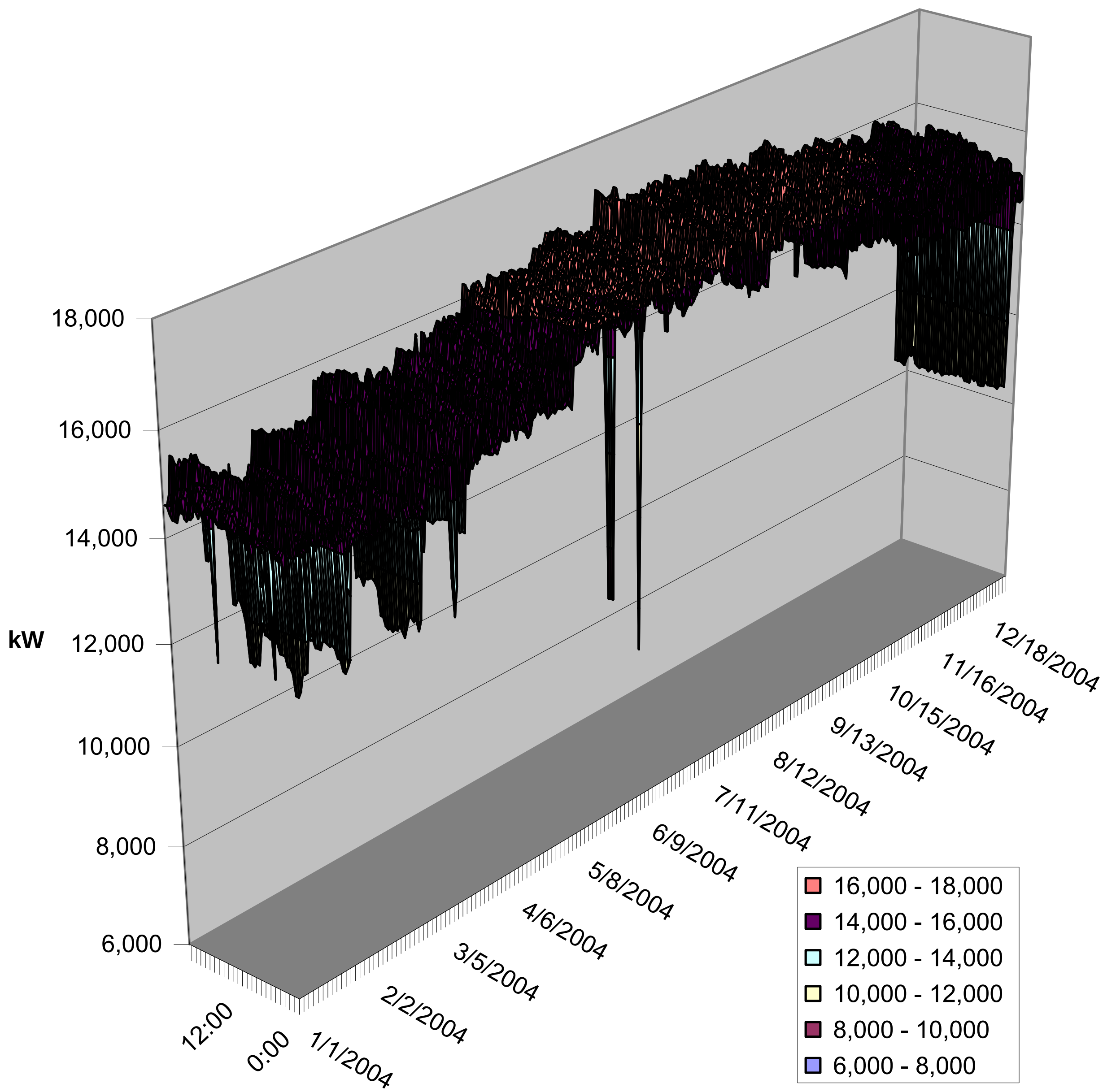


Figure 3.6. Incremental electrical demand for Shaw Plant 78.

Natural Gas

Natural gas costs have varied significantly over time. Table 3.2 shows how both average cost for this plant and NYMEX natural gas cost have varied over time. Therefore, using average historic cost may not be a good indicator of future costs of natural gas. However, failing to have a better method for projecting future costs, historic average costs were used for the analysis in this study. During the calendar year of 2004, the average cost for natural gas was $7.62 per million Btu. A million Btu of natural gas is roughly equivalent to 1,000 cubic feet.

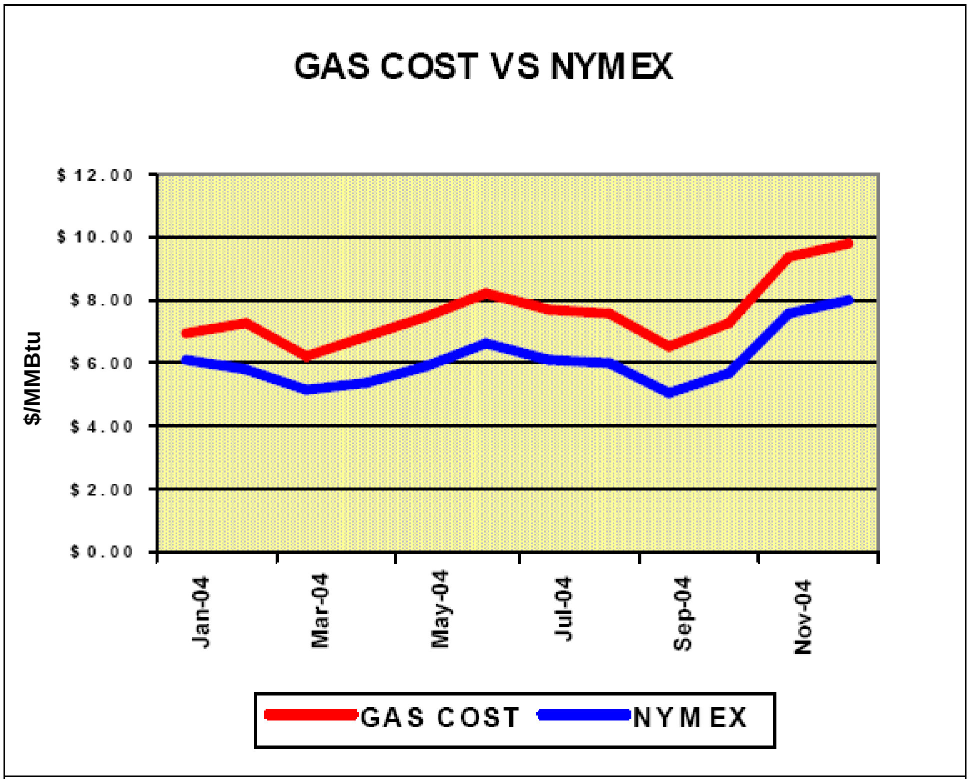


Table 3.2. Average natural cost versus NYMEX.

Historic Utility Consumption

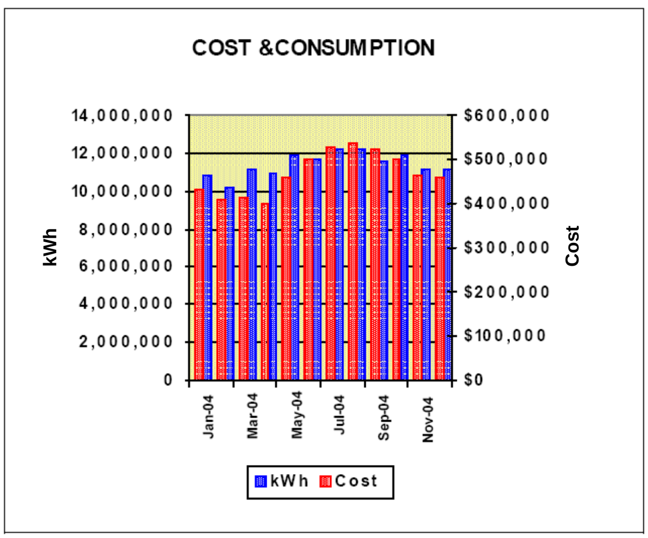
The tables and graphs on the following pages are provided to give a better picture of the different utility usages and costs at the facility. These graphical tools summarize each utility account during calendar year 2004. Average electricity costs during the 2004 calendar year were $0.0412/kWh and natural gas costs were $7.62/MMBtu.

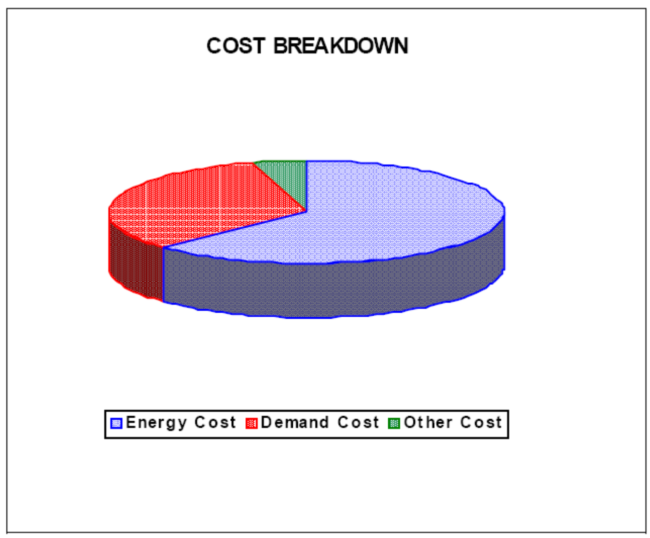
The monthly consumption and cost of each utility account at your facility can be found in the tables on pages 22 through 27. Following each of these tables is a bar chart, which graphically displays this data. These bar charts are included to give visual indications of any unusual patterns of usage in the plant.

ELECTRICITY ACCOUNT REPORT

EL - 8817601

MONTH	DAYS	TOTAL KWH	ACTUAL DEMAND	BILLING DEMAND	TOTAL COST	¢/KWH	COST PER DAY
JAN 2004	30	10,769,896	15,753.00	14,678.00	$433,268	4.023	$14,442
FEB 2004	28	10,133,961	15,521.00	14,502.00	$409,080	4.037	$14,610
MAR 2004	30	11,142,305	16,122.00	14,525.00	$411,909	3.697	$13,730
APR 2004	29	10,932,571	16,112.00	15,854.00	$399,864	3.658	$13,788
MAY 2004	30	11,847,087	16,916.00	16,306.00	$460,450	3.887	$15,348
JUN 2004	29	11,665,096	16,869.00	16,458.00	$498,428	4.273	$17,187
JUL 2004	30	12,150,029	17,221.00	16,810.00	$528,566	4.350	$17,619
AUG 2004	30	12,153,540	17,119.00	16,463.00	$538,503	4.431	$17,950
SEP 2004	29	11,538,992	16,870.00	16,532.00	$521,845	4.522	$17,995
OCT 2004	30	11,837,500	16,639.00	16,449.00	$501,303	4.235	$16,710
NOV 2004	29	11,108,925	16,408.00	14,364.00	$462,640	4.165	$15,953
DEC 2004	30	11,187,110	16,192.00	14,807.00	$461,057	4.121	$15,369
TOTALS	354	136,467,012			$5,626,913	4.123	$15,895



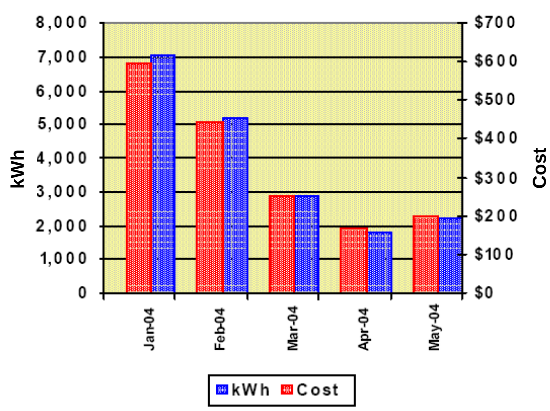


ELECTRICITY ACCOUNT REPORT

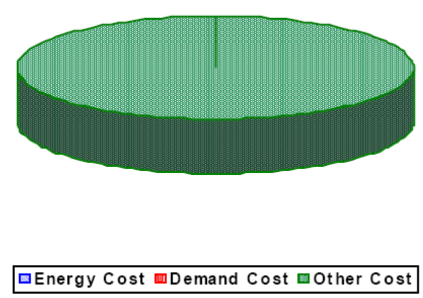
EL - 8817602

MONTH	DAYS	TOTAL KWH	ACTUAL DEMAND	BILLING DEMAND	TOTAL COST	¢/KWH	COST PER DAY
JAN 2004	29	7,037	0.00	0.00	$598	8.497	$21
FEB 2004	30	5,170	0.00	0.00	$444	8.589	$15
MAR 2004	32	2,838	0.00	0.00	$252	8.889	$8
APR 2004	29	1,817	0.00	0.00	$168	9.237	$6
MAY 2004	30	2,186	0.00	0.00	$198	9.069	$7
TOTALS	150	19,048			$1,660	8.717	$11

COST &CONSUMPTION



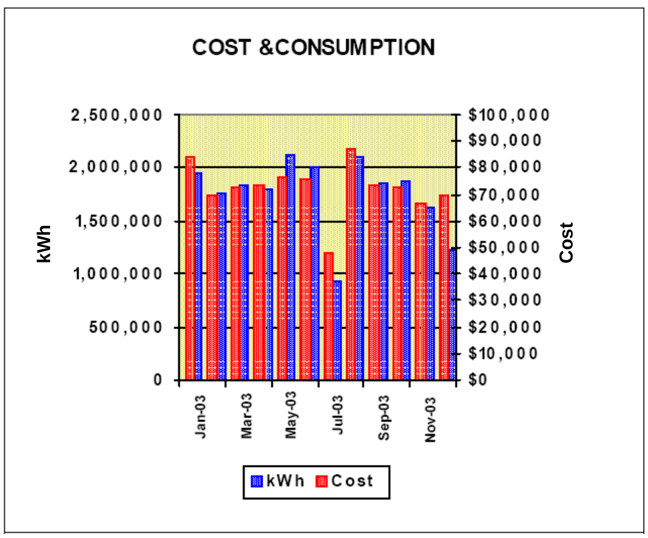
COST BREAKDOWN

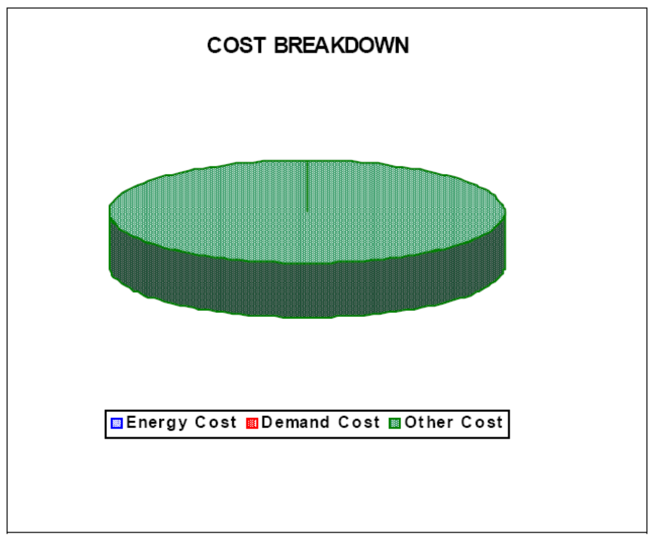


ELECTRICITY ACCOUNT REPORT

EL - 8817603

MONTH	DAYS	TOTAL KWH	ACTUAL DEMAND	BILLING DEMAND	TOTAL COST	¢/KWH	COST PER DAY
JAN 2004	29	8,064	122.70	122.70	$540	6.702	$19
FEB 2004	30	6,720	124.70	124.70	$456	6.782	$15
MAR 2004	32	6,336	82.40	82.40	$439	6.925	$14
APR 2004	29	5,184	75.17	75.17	$359	6.927	$12
MAY 2004	30	3,456	74.40	74.40	$250	7.239	$8
JUN 2004	32	5,088	82.37	82.37	$353	6.938	$11
JUL 2004	32	3,456	118.37	118.37	$250	7.239	$8
AUG 2004	30	3,168	118.37	118.37	$232	7.324	$8
SEP 2004	31	3,072	101.95	101.95	$226	7.356	$7
OCT 2004	30	2,688	84.77	84.77	$202	7.507	$7
NOV 2004	29	3,168	64.90	64.90	$232	7.324	$8
DEC 2004	32	4,224	100.13	100.13	$315	7.455	$10
TOTALS	366	54,624			$3,854	7.056	$11

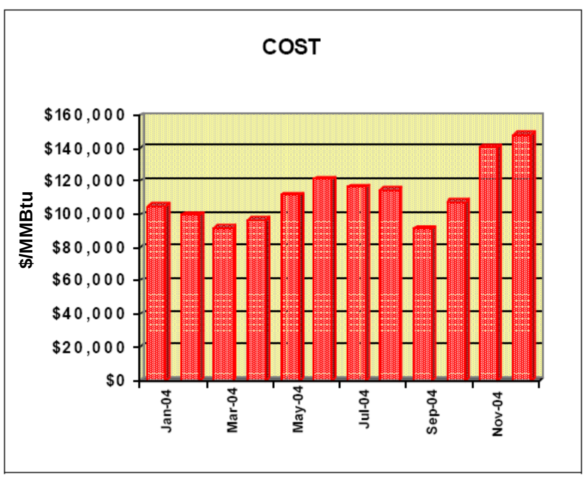


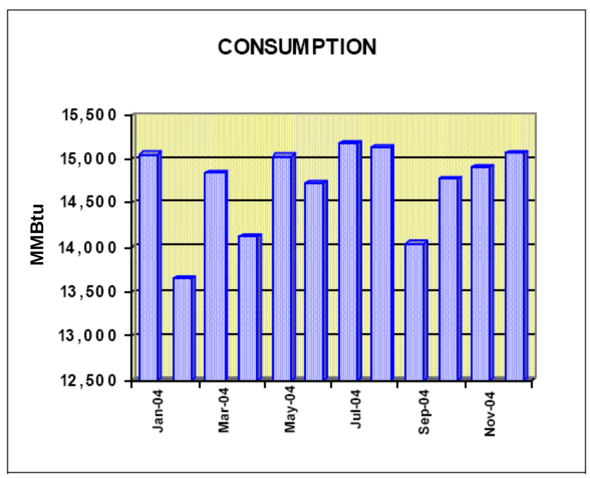


NATURAL GAS ACCOUNT REPORT

NG -2-1512-0001-1216

MONTH	DAYS	TOTAL MMBTU	TOTAL COST	$ / MMBtu	NYMEX $/MMBTU
JAN 2004	30	15,056	$105,040	$6.98	$6.150
FEB 2004	28	13,655	$99,605	$7.29	$5.775
MAR 2004	30	14,838	$91,773	$6.18	$5.150
APR 2004	29	14,125	$96,865	$6.86	$5.370
MAY 2004	30	15,029	$112,066	$7.46	$5.940
JUN 2004	29	14,726	$121,445	$8.25	$6.680
JUL 2004	30	15,175	$116,339	$7.67	$6.140
AUG 2004	30	15,131	$114,489	$7.57	$6.050
SEP 2004	29	14,048	$91,562	$6.52	$5.080
OCT 2004	30	14,777	$107,383	$7.27	$5.720
NOV 2004	29	14,915	$140,302	$9.41	$7.630
DEC 2004	30	15,067	$148,208	$9.84	$7.980
TOTALS	354	176,542	$1,345,077	$7.62	

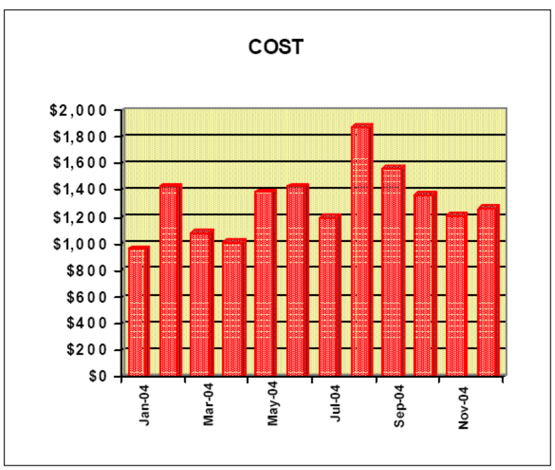


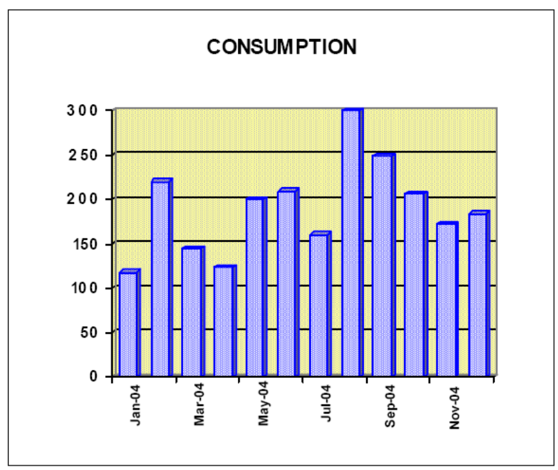


WATER ACCOUNT REPORT

WA - 67293-3496

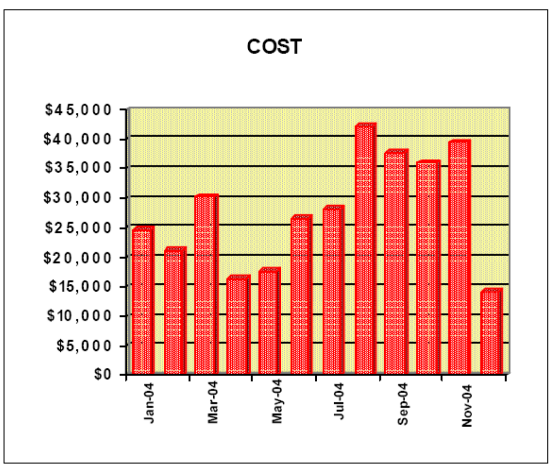
MONTH	DAYS	TOTAL CCF	WATER COST	WATER $ / KGAL	SEWER COST	SEWER $ / KGAL	TOTAL COST	$ / KGAL	COST PER DAY
JAN 2004	26	118	$0.00	$0.00	$0.00	$0.00	$961	$10.89	$36.98
FEB 2004	37	220	$0.00	$0.00	$0.00	$0.00	$1,433	$8.71	$38.72
MAR 2004	25	145	$0.00	$0.00	$0.00	$0.00	$1,086	$10.01	$43.45
APR 2004	14	123	$0.00	$0.00	$0.00	$0.00	$1,013	$11.02	$72.39
MAY 2004	28	200	$0.00	$0.00	$0.00	$0.00	$1,388	$9.28	$49.56
JUN 2004	30	209	$0.00	$0.00	$0.00	$0.00	$1,431	$9.16	$47.71
JUL 2004	31	161	$0.00	$0.00	$0.00	$0.00	$1,198	$9.95	$38.65
AUG 2004	30	300	$0.00	$0.00	$0.00	$0.00	$1,873	$8.35	$62.43
SEP 2004	30	248	$0.00	$0.00	$0.00	$0.00	$1,562	$8.42	$52.07
OCT 2004	31	206	$0.00	$0.00	$0.00	$0.00	$1,368	$8.88	$44.13
NOV 2004	30	172	$0.00	$0.00	$0.00	$0.00	$1,211	$9.41	$40.36
DEC 2004	33	184	$471.96	$3.43	$794.40	$5.77	$1,266	$9.20	$38.37
TOTALS	345	2,286	$472	$0.28	$794	$0.46	$15,791	$9.24	$45.77

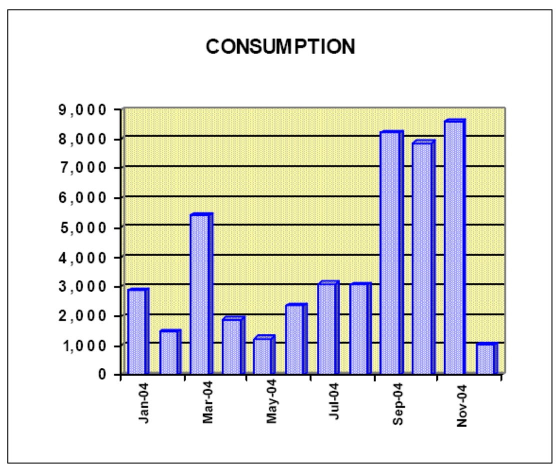




WATER ACCOUNT REPORT
WA - 67293-3498

MONTH	DAYS	TOTAL CCF	WATER COST	WATER $ / KGAL	SEWER COST	SEWER $ / KGAL	TOTAL COST	$ / KGAL	COST PER DAY
JAN 2004	28	2,892	$0.00	$0.00	$0.00	$0.00	$24,690	$11.41	$881.78
FEB 2004	35	1,486	$0.00	$0.00	$0.00	$0.00	$21,218	$19.09	$606.24
MAR 2004	25	5,439	$0.00	$0.00	$0.00	$0.00	$30,255	$7.44	$1,210.22
APR 2004	21	1,905	$0.00	$0.00	$0.00	$0.00	$16,448	$11.54	$783.24
MAY 2004	22	1,260	$0.00	$0.00	$0.00	$0.00	$17,709	$18.79	$804.96
JUN 2004	34	2,362	$0.00	$0.00	$0.00	$0.00	$26,669	$15.09	$784.39
JUL 2004	35	3,106	$0.00	$0.00	$0.00	$0.00	$28,193	$12.13	$805.50
AUG 2004	28	3,074	$0.00	$0.00	$0.00	$0.00	$42,146	$18.33	$1,505.21
SEP 2004	29	8,214	$0.00	$0.00	$0.00	$0.00	$37,731	$6.14	$1,301.08
OCT 2004	30	7,872	$0.00	$0.00	$0.00	$0.00	$35,997	$6.11	$1,199.92
NOV 2004	31	8,599	$0.00	$0.00	$0.00	$0.00	$39,456	$6.13	$1,272.77
DEC 2004	35	1,045	$0.00	$0.00	$0.00	$0.00	$14,303	$18.30	$408.66
TOTALS	353	47,254	$0	$0.00	$0	$0.00	$334,817	$9.47	$948.49





4. ENERGY PRICE SENSITIVITY

When evaluating energy projects, the effect of future energy prices can be a concern for some project economics. In general, it can be assumed that future energy prices will be higher, and higher energy prices will typically improve energy project economics. However, in some cases higher energy prices can hurt projects; specifically this can be the case when fuel switching is involved.

To evaluate the effect of higher energy prices in this study, different combinations of electricity and natural gas price increases of 30% were considered. These higher energy prices were evaluated to determine the effect on ESO economics. Only ESOs with a payback greater than two years are shown here. This is because those with less than a two year payback were only negligibly impacted by changes in energy prices, and in all cases positively impacted. The results of this evaluation are shown in Figure 4.1. The numerical data for this figure is shown in Table 4.1 and 4.2.

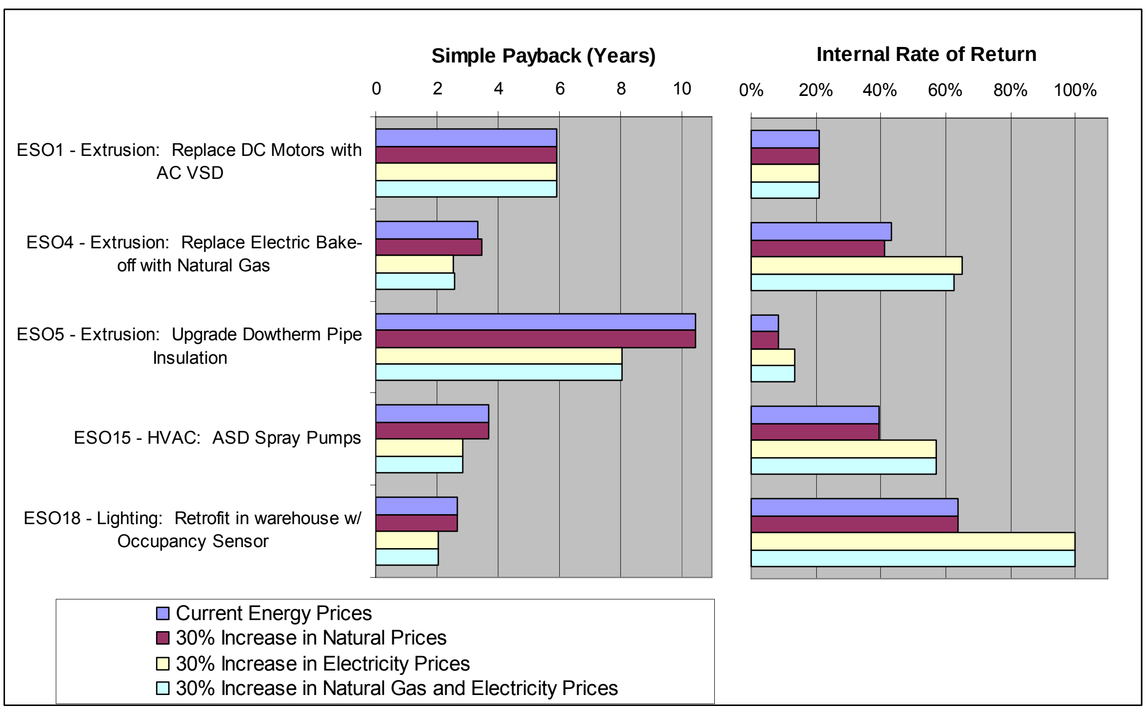


Figure 4.1. Project Sensitivity to Energy Prices.

As can be noted in Figure 4.1, ESO1 was not impacted by any assumed increase in energy prices. This is because the evaluation of ESO1 had no associated energy savings. ESO4 showed a weakening in economics when natural prices increase and an improvement when electricity prices increase. This is because this recommendation proposes a fuel switch replacing an electric application with natural gas. ESO5, ESO15, and ESO18 are independent of natural price increases, because the systems considered only consume electricity. Therefore, any increase in electricity prices only improves the economics of these recommendations.

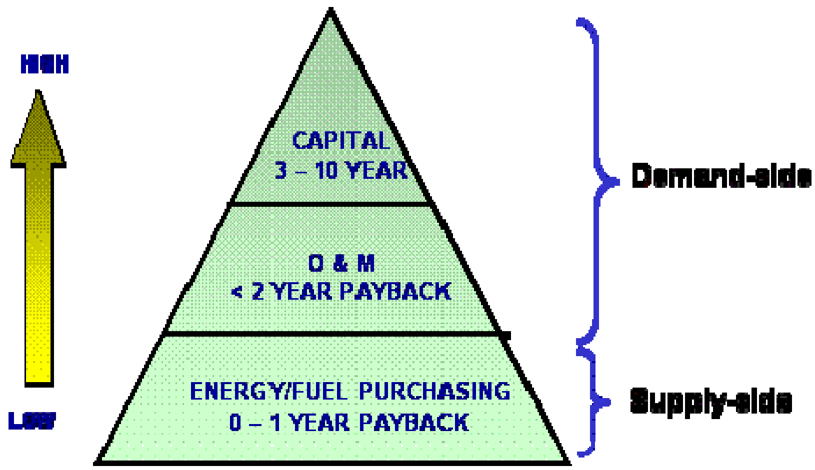
Table 4.1. Table of Project Simple Paybacks' Sensitivity to Energy Prices.

ESO #		ESO	Simple Payback (years)			
			Current Energy Prices	30% Increase in Natural Prices	30% Increase in Electricity Prices	30% Increase in Natural Gas and Electricity Prices
1	ESO1	Extrusion: Replace DC Motors with AC VSD	5.9	5.9	5.9	5.9
4	ESO4	Extrusion: Replace Electric Bake-off with Natural Gas	3.4	3.5	2.5	2.6
5	ESO5	Extrusion: Upgrade Dowtherm Pipe Insulation	10.5	10.5	8.0	8.0
15	ESO15	HVAC: ASD Spray Pumps	3.7	3.7	2.9	2.9
18	ESO18	Lighting: Retrofit in warehouse w/ Occupancy Sensor	2.7	2.7	2.0	2.0

Table 4.2. Table of Project Internal Rate of Returns' Sensitivity to Energy Prices.

ESO #		ESO	Internal Rate of Return (IRR)			
			Current Energy Prices	30% Increase in Natural Prices	30% Increase in Electricity Prices	30% Increase in Natural Gas and Electricity Prices
1	ESO1	Extrusion: Replace DC Motors with AC VSD	21%	21%	21%	21%
4	ESO4	Extrusion: Replace Electric Bake-off with Natural Gas	43%	41%	65%	63%
5	ESO5	Extrusion: Upgrade Dowtherm Pipe Insulation	9%	9%	14%	14%
15	ESO15	HVAC: ASD Spray Pumps	39%	39%	57%	57%
18	ESO18	Lighting: Retrofit in warehouse w/ Occupancy Sensor	64%	64%	100%	100%

5. ENERGY SAVINGS OPPORTUNITY



Move up the opportunity hierarchy

This section of the report contains detailed descriptions of the Energy Savings Opportunities or ESOs. Energy savings recommendations loosely fall into three categories: purchasing, operation & maintenance, and capital. The pyramid shown above arranges these opportunities into a hierarchy. Those ESOs at the bottom of the pyramid have the lowest cost to benefit ratio. This implies that the cost savings can be achieved with little or no implementation cost. As you move up the pyramid, the implementation cost increases relative to the cost savings. This yields longer periods of simple payback. It is important to consider this categorization when evaluating recommendations, since moving from the bottom to the top of this pyramid will prioritize savings opportunities in the order of the best rate of return.

The ESOs that typically yield the best investment are those that are related to purchasing. One such purchasing opportunity may be changing to a different electric tariff for example. While some limited cost may be involved in investigating this measure or negotiating with utility representative, this cost is normally very small relative to the potential benefit which may be significantly reduced electricity costs. Unfortunately, no energy purchasing opportunities were discovered during this assessment.

The next best investments are normally operation and maintenance opportunities. These ESOs are typically considered corrective measures which present opportunities to operate equipment more efficiently. When compared to capital measures, these ESOs have a smaller savings, but also require little investment. An example of such an opportunity might be to begin a compressed air leak detection and repair program. While this maintenance measure may seem minor, plants typically lose 10% to 30% of the energy consumed by air compressors to air leaks.

The final ESOs that should be considered are capital projects. An example of this type of opportunity might be the purchase of more efficient equipment or significantly changing an existing system design. While these projects might generate significant savings, they will typically have longer paybacks and therefore present greater risk.

It is important to prioritize savings opportunities, and the best “bang for the buck” is not always the latest and greatest technology that is expensive and promises a lot. Managing energy well means taking care of the regular activities such as purchasing, operation, and maintenance. When those areas are controlled, then new, high-tech opportunities should be investigated.

ESO1 – Extrusion: Replace DC Motors with AC VSD

Recommended Action

The extruders are driven by fan cooled, SCR-controlled DC motors. Replacing these motors with efficient, adjustable speed drive AC induction motors will reduce extruder maintenance costs and make the drives easier to operate.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
0	0	0	$ 43,200	$43,200	$256,000	5.9	$139,000	21.1%

Background

Adjustable speed drive (ASD) AC motors offer several advantages over traditional brush-type DC motors. ASD motors provide accurate speed regulation and reduced maintenance requirements since there are no brushes or commutators to replace. Although AC and DC motor efficiencies are approximately equal, the maintenance and operating simplicity of AC drives make them a preferred choice over DC motors.

Most adjustable speed drives (ASD) use inverter-based speed control. The inverter converts standard 60 cycle AC power into variable cycle power (Figure 5.1.2). In the first stage of the inverter, the input AC power is converted to DC using a solid-state rectifier. The DC link which carries the DC power from the first to the second stage includes a filter to smooth the electrical waveform.

In the second stage, the inverter uses the DC input power to synthesize an adjustable-frequency, adjustable-voltage AC waveform by releasing short steps or pulses of power. The speed of the motor will change in proportion to the frequency. Most inverters are pulse-width modulators (PWM). In pulse-width modulation, a pulse-width modulated waveform is created.

Another advantage of ASD induction motors when compared to DC motors is reduced maintenance costs. The only maintenance activity required is regular greasing of the bearings and replacing them when necessary. Traditional brush-type DC motors require brush replacement, field rewinding, and commutator maintenance at regular intervals.

Because there is not a significant difference in energy consumption between AC and DC extruder drives, the justification for replacement is based on maintenance savings. If all 17 of the large and 1 small extruder motors are replaced, the cost savings from reduced maintenance would be $2,400/yr-motor. The extruders are assumed to operate continuously except for 360 hours per year when maintenance and repair is performed. The net operating hours are 8,400 hours/year.

Because there is essentially no energy savings from replacing DC drives with adjustable speed AC drives, replacement of the existing extruder drives should be initiated at the time a DC motor must be replaced due to failure or age. The calculations used to determine the savings for variable speed AC motors are shown below. The annual cost savings from reduced maintenance is $43,200/yr.

Anticipated Savings

The following information is useful in determining the annual energy and cost savings.

Number of Large Extruders	- 17
Extruder Motor Horsepower	- 165 kW (220 hp)
Number of Small Extruders	- 1
Extruder Horsepower	- 90 kW (121 hp)
DC Motor Efficiency	- 93%
Variable Speed AC Motor Consumption	- 100% of DC
Extruder Operating Hours,	- 8,400 hours
Electricity Cost	- $0.027/kWh
Demand Cost	- $10.38/kW-mo
Maintenance Cost, Brush Replacement DC Motors	- $2,400/year

Measurements of power consumption for DC and AC extruder drives were conducted at a sister extrusion plant (Thompson). The extruders were processing the same material (PET) and the same throughput of material. The results of the two tests are summarized in the table below. The measurements indicate that the power consumption for a variable speed AC motor and a DC motor were essentially the same within experimental error. The only savings is from reduced maintenance cost. Operators prefer the ASD motor because it is easier to use.

Extruder Tests 200 hp Drive-Thomason Plant

Test Number	DC motor: Power Input	AC motor: Power Input	Power Savings	AC/DC Power
2	126.9 kW	127.4 kW	-0.4 kW	1.004

The measured load on the extruders at Plant #78 was 60%. The measured amp loading on an extruder is shown in Figure 5.1.1.

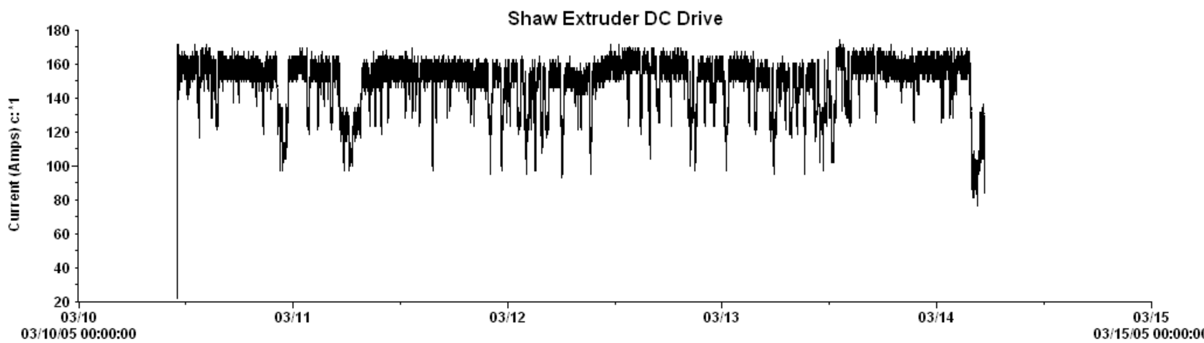


Figure 5.1.1 DC Extruder Current Draw During 3½ Day Period, Spring, 2005

Estimated Motor Load:

Average Current Draw (from graph)	- 149 A
Motor Voltage	- 460 V
Estimated Power Factor	- 0.9

Motor Power Draw:
$= \sqrt{3} \times V \times A \times PF / 1000$
$= 1.732 \times 460 \times 149 \times 0.9 / 1000$
= 107 kW (143 hp)

Motor Load:
= Electrical Input / (Rated Motor Output / Motor Efficiency)
= 143 hp / (220 hp / 0.93)
= 0.60

DC Motor Demand:
= (No. Motors x Rated Power x Average Load Factor)/ Motor Efficiency
= [(17 motors x 165 kW x 0.60) + (1 motor x 90 kW x 0.60)]/.93
= 1,868 kW

Variable Speed AC Motor Demand:
= DC Demand x Measured DC to AC Demand Ratio
= 1,868 kW x 1.004
= 1,875 kW

Demand Savings:
= DC Motor Demand – AC Motor Demand
= 1,868 kW – 1,875 kW
= 0 kW (Total)

Energy Savings:

= Demand Saved x Annual Operating Hours
= 0 kW x 8,400 hr/yr
= 0 kWh/yr

Energy Cost Savings:
= [(Electricity Saved x Electricity Cost) + (Demand Saved x Demand Cost x Demand Factor)]
= [(0 kWh/yr x $0.027/kWh) + (0 kW x $10.38/kW-mo x 12 mo)]
= $0/yr

Maintenance Cost Savings:
On an annual basis, the brushes must be replaced in each DC drive. The brush cost for each motor is $1,600. The labor to install the brushes requires 2 men for 10 hours each or 20 total hours. At an average labor cost of $40/hr, the total labor is $800. The net maintenance cost is $2,400.

Cost Savings:
= No. of Motors x Maintenance Savings per Motor
= 18 motors x $2,400/motor
= $43,200

Combined Savings:
= Energy Savings + Maintenance Savings
= $0/yr + $43,200
= $43,200/yr

Implementation Cost

The investment cost to retrofit the extruders with adjustable speed drive (ASD) AC motors includes the cost of the motor and controller for each extruder. The plant contains 17 large, 165 kW, and one small extruder rated at 90 kW total. The small extruder is composed of three-30 kW (40 hp) DC motors.

The estimated investment costs are presented in Table 5.1.1. The controller costs are for an electronic speed control based on an inverter. AC power is inverted to DC and the DC is converted to an adjustable frequency AC by the controller. A schematic of a typical electronic speed controller for AC motors is presented in Figure 5.1.2. The AC motor prices were taken from the MotorMaster International version. The motor used is a 460 volt, 1800 rpm, TEFC design from Toshiba. Because the motor costs contained in the program are from 2002, they were escalated by 6% or 2% per year for three years.

The final cost included is the labor to install the motor and controller. The installation is assumed to require one electrician. The labor time to install the motor is three hours, and the time to install the controller is six hours. The estimated labor cost is $900 or 12 labor hours at $75/hr.

The investment for all 17-165 kW motors is $511,700. The investment cost for the 3-30 kW adjustable speed AC motors is $25,770 and $534,770 for all motors and controllers in the project. From the cost of the AC drive, the salvage value of the DC drive must be subtracted. With a new cost of $40,000 for a 165 kW DC motor and controller, the salvage value of a functioning DC drive would be $16,000 or 40% of the new cost. The salvage value of a 30 kW drive is assumed to be $3,000.

Total Investment:

= Cost for 165 kW motors + Cost for 30 kW motors – Salvage Value of DC Drives
= $511,700 + $25,770 – (17 Drives x $16,000) – (3 drives x $3,000)
= $534,470 - $281,000
= $256,470

Simple Payback

= Investment / Savings
= $ 256,470 / $43,200/yr
= 5.9 years

Table 5.1.1. Extruder ASD Investment Costs.

Extruder Size (kW)	Equivalent English	Controller Cost	Motor Cost	Labor Cost	Total Per Motor	Number of Motors	Total
165	220 hp	$15,000	$14,200	$900	$30,100	17	$511,700
30	40 hp	$5,160	$2,530	$900	$8,590	3	$25,770
Total							$534,470

The incremental payback is based on the cost difference between the existing and the proposed equipment. The cost to replace a 165 kW DC motor is $23,000. Because the cost of a replacement DC motor exceeds the cost of an adjustable speed AC replacement, the incremental payback is immediate.

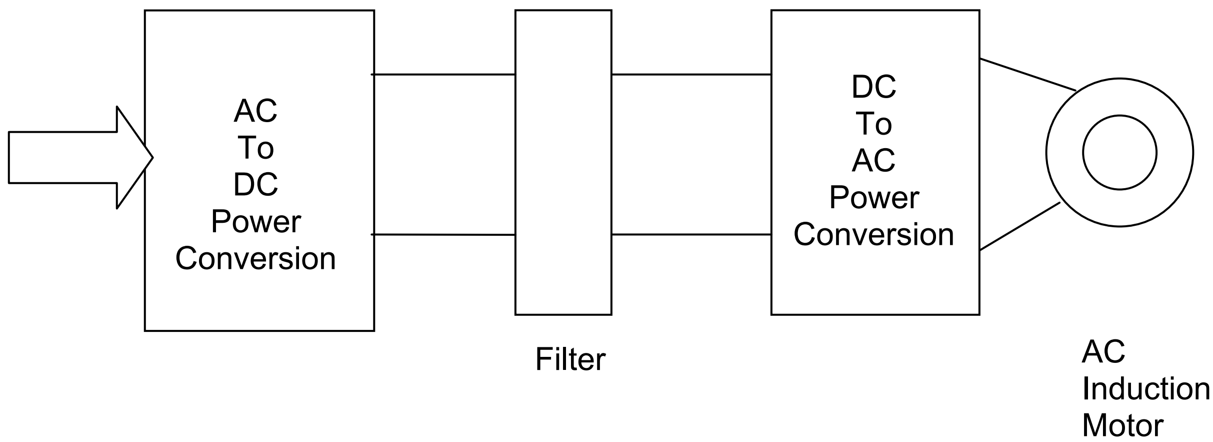


Figure 5.1.2. Inverter to provide variable frequency AC power output.

ESO2 – Extrusion: Upgrade Belts to Cogged V-belts

Recommended Action

The standard V-belts on the extruder drive motors should be replaced with cogged V-belts.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
367,000	43.7	0	$ -	$15,400	$7,280	0.5	$133,000	NA

Background

The use of more efficient drive belts in common power transmission applications, cogged V-belts or high torque drive (HTD) belts, have been demonstrated to provide energy savings over standard V-belts. Flexing losses are caused by the bending and unbending of the belt material when the belt enters and leaves the pulley. HTD belts have lower flexing losses, due to their modified cross section. This reduction in flexing losses contributes to a 2% increase in efficiency over standard V-belts. Further, HTD belts are used with notched drive pulleys. The drive pulleys mate with the notches on the HTD belt to eliminate slippage losses. Eliminate of belt slippage adds an additional 2% increase in drive efficiency. Switching from standard V-belts to HTD drive belts will yield an increase in drive efficiency of 5% (see table below). Because the investment to install HTD belts is much more because the belts and pulleys must be replaced, replacing the standard V-belts with cogged V-belts was considered for this application.

Replacing standard V-belts with cogged V-belts will yield an average efficiency improvement of 2.5% from 93% to 95.5% and will cost much less than HTD belt retrofit.

Belt Type	Power Transfer Efficiency
Standard V-belts	93%
Cogged V-belts	95-96%
HTD Belts	98%

Anticipated Savings

The following given values are needed to determine the energy and cost savings for the 220 hp extruder drives.

Motor Size	- 220 hp
Number of Motors	- 16
Annual Full Load Hours of Operation	- 8,400 hrs/yr
Motor Efficiency	- 93%
Motor Load	- 60%
Electricity Cost	- $0.027kWh
Demand Cost	- $10.38/kW-mo
Present Drive Efficiency with V-Belt	- 93%
Proposed Drive Efficiency with Cogged V-Belt	- 95.5%

Demand Savings:
= No. of Motors x Hp Rating x Load Factor x 0.746 kW/Hp x [(1 / Present Eff.) - (1 / Proposed Eff)] / Motor Eff.
= 16 Motors x 220 hp x 0.60 x 0.746 kW/Hp x [(1 / .93) - (1/ .955)] / 0.93
= 47.7 kW

Energy Savings:
= Demand Savings x Hours of Operation
= 47.7 kW x 8,400 hrs/yr
= 400,680 kWh/yr

Cost Savings:
= (kWh Saved x Electricity Cost) + (Demand Saved x Demand Cost x Ratchet Factor)
= [(400,680 kWh/yr x $0.027/kWh) + (47.7 kW x $10.38/kW-mo x 12 mo)]
= $16,760yr

Implementation Cost

The cost for a cogged V-belt is $75.80 versus $49.20 for a standard V-belt. Because each motor uses 6 belts, the replacement cost per motor is $455. An additional benefit of cogged belts is longer life because they run cooler. The cost for all 16 motors is $7,280.

Simple Payback:
= Implementation Cost / Cost Savings
= $7,280 / $16,760/yr
= 0.4 years

If the belts are replaced incrementally at failure, the required investment is the difference between cogged and standard belts. The incremental cost of cogged belts is $27/belt or $162 per motor with 6 belts. The incremental investment for all 16 motors is $2,592.

Incremental Payback:

= Incremental Investment / Cost Savings

= $2,592 / $16,760

= 0.15 years

ESO3 – Extrusion: Use Synthetic Oil in Gear Box

Recommended Action

Synthetic lubricants yield reduced frictional losses in numerous process applications.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
368,000	43.8	0	$ -	$15,100	$1,280	0.1	$137,000	NA

Background

Synthetic lubricants are literally "space age" products. For a given viscosity, they are much more "slippery" than conventional petroleum lubricants. They are also much less susceptible to oxidation, and thus may last 4-8 times longer than conventional lubricants. The energy savings from their increased "slipperiness" is an added bonus.

Evaluations in textile mills have shown minimum savings of 5% in air compressor cylinder lubrication and 3% in gear-box applications.

Although synthetic lubricants and greases should be considered throughout the plant, use in the extruder gear drives would save $17,850 annually. The gear drives are directly connected to the extruder screw and are turned by a belt that connects the motor and gear system. The increased cost of synthetic lubricants is somewhat offset by an extension in effective life. The implementation cost of this measure based on a purchase cost of $40/gallon for synthetic lubricant is $1,280. This cost yields a payback of 0.1 years or 1 month.

Anticipated Savings

The following calculation estimates the savings from converting the extruder gear drives to synthetic lubricants.

Size of Extruder Drive Motor	- 220 hp (165 kW)
No. of Extruders	- 16
Average Load Factor	- 60%

Average Motor Efficiency	- 93%
Expected Savings	- 3%
Annual Hours of Operation	- 8,400 hr/yr
Electrical Energy Cost	- $0.027/kWh
Demand Cost	- $10.38/kW-mo

Demand Savings:

= (No. of Extruders x Extruder HP) x Load Factor x 1/Motor Efficiency x Conversion Factor x Synthetic Lubricant Savings
= (16 x 220 hp) x 0.60 x 1/0.93 x 0.746 kW/hp x 0.03
= 50.8 kW

Energy Savings:

= Demand Reduction x Annual Hours
= 50.8 kW x 8,400 hr/yr
= 426,720 kWh/yr

Cost Savings:

= (Electricity Saved x Marginal Energy Cost) + (Demand Saved x Demand Cost x Demand Factor)
= (426,720 kWh/yr x $0.027/kWh) + (50.8 kW x $10.38/kW-mo x 12 mo/yr)
= $17,850/yr

Implementation Cost

The cost of commonly available 85W-140 synthetic gear oil is $40/gallon. Conventional petroleum gear oil can be purchased for approximately $10/gallon. Although synthetic lubricants cost considerably more than conventional lubricants, they also last considerably longer so the increase in operating cost is reduced somewhat.

The capacity of each extruder gear drive is assumed to be 2 gallons. The lubricant life expectancy for synthetic oil is 4 years and 2 years for petroleum oil.

Investment:

= No. Machines x Oil Capacity x Oil Cost
= 16 machines x 2 gal/machine x $40/gal
= $1,280

Maintenance Cost:

= Oil Replacement Cost / Oil Life
= $1,280 / 4 years
= $320/yr

Simple Payback

= Implementation Cost / Cost Savings
= $1,280 / ($17,850 - $320) per year
= 0.07 years

ESO4 – Extrusion: Replace Electric Bake-off with Natural Gas

Recommended Action

Replace the two electric bakeoff ovens used in extrusion with a single, more economical gas-fired oven.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
154,000	53.3	-140	$ -	$9,690	$32,600	3.4	$55,100	43.2%

Background

Electric bakeoff ovens are used to clean the extrusion dies of polymer buildup. The plant has two Beringer ovens, a model 2448 and a model JCP 3648. The ovens remove plastic buildup from metal parts by heating them in a high-vacuum chamber. By replacing the electrically heated ovens with a natural gas fired oven, the energy cost of parts cleaning will be reduced.

Savings are generated with natural gas cleaning because gas costs less than electricity. Furthermore because the electric ovens have limited chamber volume, a single gas oven can replace both electric ovens. The electric ovens use energy for heating and operating a vacuum pump. The gas oven does not operate at a vacuum but instead uses a high temperature afterburner to destroy the polymers burned off.

In addition to the energy cost savings with natural gas, the gas oven has a larger chamber volume which will reduce the number of times the gas oven is used. The chamber volume for each of the ovens is shown in Table 5.4.1. The gas oven volume is over five times larger than the two electric ovens combined. Because of the greater oven volume, the gas oven will only need to operate one-fifth as many cycles as the electric. Replacing the 2 electric bakeoff ovens with a single natural gas-fired oven will reduce plant energy costs by $9,690.

The estimated equipment cost for a gas-fired bakeoff oven with afterburner is $30,850. This oven has a heating chamber capacity of 94.5 ft^3 so few cleaning cycles would be required each year. The expected cost included installation and gas piping less the salvage value of the existing electric ovens is $32,550.

Table 5.4.1. Bakeoff Oven Chamber Volume.

Oven Type	Chamber Volume (ft^3)
Beringer 2448 Electric	7.0
Beringer JCP 3648 Electric	10.7
TOTAL VOLUME, ELECTRIC	17.7
Natural Gas Oven	94.0

Anticipated Savings

The following data is used to calculate the savings for this measure.

Small Electric Oven Average Demand	- 18.1 kW
Small Electric Oven Peak Demand	- 27.6 kW
Small Electric Oven Cycle Time	- 6.26 hours
Small Electric Oven Daily Cycles	- 1.15 per day
Large Electric Oven Average Demand	- 20.6 kW
Large Electric Oven Peak Demand	- 31.6 kW
Small Electric Oven Cycle Time	- 14.13 hours
Small Electric Oven Daily Cycles	- 1.0 per day
Operating Days	- 365 day/yr
Natural Gas Oven Input	- 493,000 Btu/hr
Natural Gas Oven Cycle Time	- 4 hours
Natural Gas Oven Cycles	- 20% of electric
Electrical Cost ($/kWh)	- $0.027/kWh
Demand Cost ($/kW)	- $10.38/kW-mo
Demand Factor (mo/yr)	- 12 mo
Average Natural Gas Cost	- $7.62/MMBtu

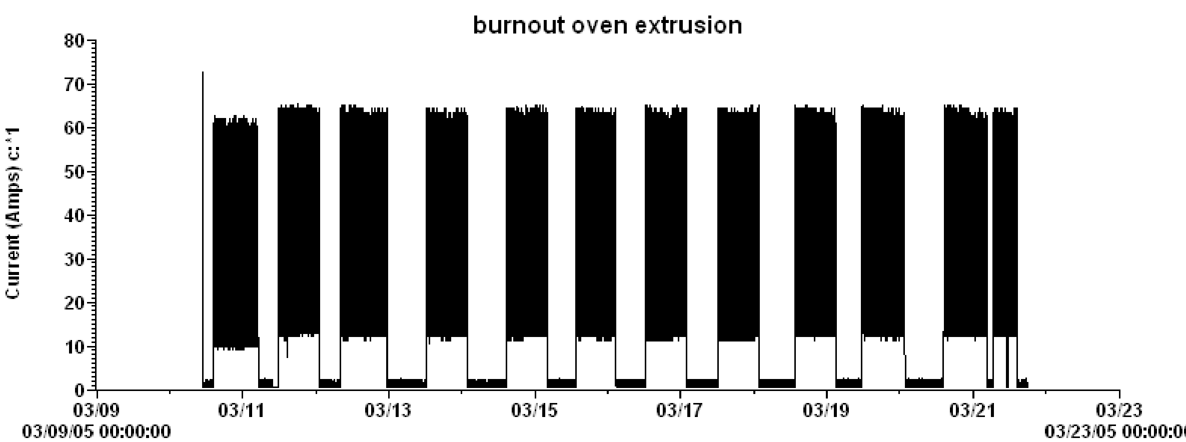


Figure 5.4.1 Large Bakeoff Oven Operating Cycle, 3/10 – 3/21/05

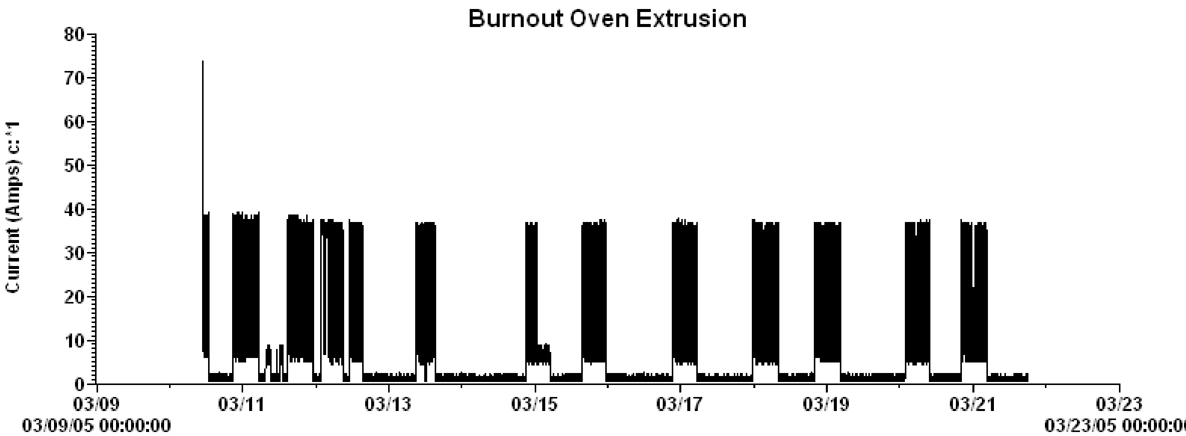


Figure 5.4.2. Small Bakeoff Oven Operating Cycle, 3/10- 3/21/05.

The Figures above, 5.4.1 and 5.4.2, show the bakeoff ovens operating cycle and current reading for a continuous 10 day period in March, 2005. From an analysis of the data, the following average trends were found:

Small Bakeoff Oven:
Average cycles per day: 1.15
Average cycle time: 6.68 hr
Average electrical load: 18.1 kW

Large Bakeoff Oven
Average cycles per day: 1.0
Average cycle time: 14.13 hr
Average electrical load: 20.6 kW

Based on these usage numbers, the operating costs of the electric ovens can be estimated.

Operating costs for electric ovens:
Small Electrical Oven Consumption:
= Heater Demand x hours per Cycle x Cycles/day x Days/year
= 18.1 kW x 6.26 hr/cycle x 1.15 cycle/day x 365 day/yr
= 47,560 kWh/yr

Large Electrical Oven Consumption:
= Heater Demand x hours per Cycle x Cycles/day x Days/year
= 20.6 kW x 14.13 hr/cycle x 1.0 cycle/day x 365 day/yr
= 106,240 kWh/yr

Total Oven Electrical Consumption:
= Small Oven Consumption + Large Oven Consumption
= 47,560 kWh/yr + 106,240 kWh/yr

= 153,800 kWh/yr

Electrical Energy Demand:
= Oven Demand x Diversity Factor
= (27.6 + 31.6) kW x 0.9
= 53.3 kW

Electric Oven Operating Cost:
= [(Heater Demand x Demand Cost x Demand Factor) + (Heater Consumption x Electric Cost)]
= [(53.3 kW x $10.38/kW-mo x 12 mo/yr) + (153,800 kWh/yr x $0.027/kWh)]
= $10,790

Natural Gas Oven Usage:
= Hourly Usage x Cycle Time x Cycles/day x Annual Operating Days x Percentage Electric Oven Cycles
= 0.493 MMBtu/hr x 4 hr/cycle x 1 cycle/day x 365 day/yr x 0.2
= 144 MMBtu/yr

Annual Gas Cost:
= 144 MMBtu/yr x $7.62/MMBtu
= $1,097/yr

Operating Cost Savings:
= Electric Oven Cost – Gas Oven Cost
= $10,790 – $1,100
= $9,690/yr

Implementation Cost

The cost for a gas-fired bakeoff oven with primary burner and afterburner of adequate chamber volume is estimated to be $30,850. The installation cost includes flue piping, electrical wiring, and fuel piping. Installation is estimated to cost $3,000. The costs are for a model 456-BA-P gas oven manufactured by Steelman Industries of Kilgore, TX. This model oven or an equivalent would be appropriate. Any oven selected must have accurate temperature control and an after-burner section capable of achieving 1,500°F to destroy all vapors produced.

The two existing electric ovens are usable and can be sold for salvage. The estimated salvage value of these units is $5,000 for both. The income generated from selling the existing ovens will off-set the required investment for a gas oven.

Because there is no natural gas supply to this area of the plant, a gas line must be added. Since natural gas will also be needed for the hot oil heaters in extrusion and the poly-tower, the cost for a gas header can be split between these applications.

According to Means CostWorks estimating guide, 4-inch steel gas line that can serve as a gas header can be installed for $20.70 per linear foot. As branch piping to individual pieces of equipment, a 2-inch steel pipe can be installed for $10.85 per linear foot.

The estimated length of 4-inch header piping is 200 linear feet. The branch pipe serving the bakeoff heater will require an addition 150 linear feet of 2-inch piping. If the cost for the gas header is split equally between the bakeoff ovens and oil heaters, the cost of gas piping for this application is $3,700.

Piping cost:

= ½ x Cost of 4” Header + Cost of 2” Branch Line
= ½ x 200 lf x $20.70 + 150 lf x $10.85
= $3,700

Implementation Cost:

= Oven Cost + Installation + Gas Piping – Electric Oven Salvage Value
= $30,850 + $3,000 + $3,700 - $5,000
= $32,550

Simple Payback

= Implementation Cost/ Cost Savings
= $32,550 / $9,690/yr
= 3.4 years

ESO5 – Extrusion: Upgrade Dowtherm Pipe Insulation

Recommended Action

Replace the existing calcium silicate insulation on the Extrusion Dowtherm with cellular glass insulation. This recommendation has a long payback when only energy savings is considered as was done here. However, this recommendation was included because there may also be financial benefits because of risk levels the insurance company currently associates with the use of calcium silicate insulation on Dowtherm systems. This benefit of reduced risk to the insurance company was not quantified here.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
146,000	16.7	0	$ -	$6,020	$63,000	10.5	-$7,900	8.5%

Background

Calcium silicate is a common insulation material used in many applications. However, there are risks with using this material on systems with working fluids that are combustible, as is the case with Dowtherm oils. This is because calcium silicate is a very absorbent material. This can be a problem if leaks form in the insulated pipe. These small leaks can result in saturation of the insulation, creating a fire hazard that may not even be obvious by quick inspection of the incased insulation. According to plant personnel, the current insurance company has noted this inherent risk in the current extrusion operation. Although not estimated, it has been assumed that there is some risk premium being charged by the insurance company that can be recovered if this recommendation is implemented.

In addition to the risk associated with the current operation, it was also noted that the current surface temperature of the existing insulation was high, on the order of 120°F to 150°F. It is recommended that the surface temperature should be below 110°F. This lower surface temperature would provide an increased level of safety from incidental contact as well as increased energy savings.

As a replacement for the calcium silicate insulation, cellular glass is proposed. This material is comparable in performance in heat containment to that calcium silicate; however, this material would not absorb the Dowtherm oil if a leak occurred. To achieve the surface temperature below 110°F, an increase in the thickness of insulation would be required.

Anticipated Savings

Plant personnel had indicated that the current pipe diameter was 4.5 inches. The following calculations are based upon that assumption. The dimensions and surface temperatures were collected during the plant visit. Using this information, the current level of heat loss was determined using 3E Plus Version 4 (software made available at no cost by the North American Insulation Manufacturers Association). Table 5.5.1 summarizes this information. This table also shows the values for the proposed new insulation.

Table 5.5.1. Dimensions, surface temperatures, and heat loss for one machine.

	Existing									Proposed	
Description	**#**	**Surface Temp (F)**	**Circum. (in)**	**Dia. (in)**	**Length (in)**	**V or H**	**Pipe Dia. (in)**	**Insulation Thickness**	**Heat Loss**	**Insul. Thickness**	**Heat Loss**
3 Horizontal Pipes	3	120	41	13.1	38	H	4.5	4.3	135.8 Btu/hr-ft	6.0	101.2 Btu/hr-ft
2 Horizontal Pipes	2	135	41	13.1	41	H	4.5	4.3	164.7 Btu/hr-ft	6.0	101.2 Btu/hr-ft
1 Horizontal Pipe	1	155	48	15.3	24	H	4.5	5.4	245.5 Btu/hr-ft	6.0	101.2 Btu/hr-ft
1 Horizontal Pipe	1	135	48	15.3	31	H	4.5	5.4	195.9 Btu/hr-ft	6.0	101.2 Btu/hr-ft
1 Vertical Pipe Section	1	130	48	15.3	30	V	4.5	5.4	194.9 Btu/hr-ft	6.0	101.0 Btu/hr-ft
Tank Horizontal Length	1	135	91	29.0	81	H	24	24	288.5 Btu/hr-ft	8.0	191.0 Btu/hr-ft
Tank End		135				V			46.6 Btu/hr-ft^2	8.0	28.7 Btu/hr-ft^2
Total Heat Loss									6,703 Btu/hr		4,185 Btu/hr
									1.96 kW		1.23 Kw

Demand Savings, DS:

= (Current Heat Loss per Hour - Proposed Heat Loss per Hour)
= (6,703 Btu/hr - 4,185 Btu/hr)
= 2,517 Btu/hr per Dowtherm machine
= 0.738 kW per machine

HVAC Demand Savings, HVACDS:

= DS x (1 ton / 12000 Btu/hr) x HVAC Efficiency
= 2,517 Btu/hr x (1 ton / 12,000 Btu/hr) x 0.9 kW/Ton
= 0.189 kW per machine

Total Demand Savings, TDS:

= DS + HVACDS
= 0.738 kW + 0.189 kW
= 0.927 kW per machine

Energy Savings, ES:

= TDS x Operational Hours
= 0.927 x 8,760 hrs
= 8,117 per machine

Cost Savings, CS:
= (TDS x Demand Cost x 12 months + ES x Energy Cost) x # of Machines
= (0.927 kW x $10.38/kW x 12 months + 8,117 KWh x $0.27/kWh) x 18 Mach.
= $6,020 per year for all machines

Implementation Cost

The estimate for installation of cellular glass insulation was based upon conversation with insulation installers. The estimated cost is $3,500 installed per machine, or $63,000 for all machines. This cost estimate is roughly split 50/50 for materials and labor. It may be possible to achieve better pricing since the work would be essentially the same from machine to machine, and therefore some efficiency for labor may be possible for this project may be possible.

Simple Payback, SPB:
= Project Cost / Cost Savings per Year
= $63,000 / $6,020/year
= 10.5 years

ESO6 – Steam: Repair/replace Traps / Add Drip Legs to Poly-tower Steam Supply Header

Recommended Action

Adding steam trapping to the steam header serving the poly-tower will improve steam quality at the tower and allow increased condensate recovery and return to the boiler.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
0	0	7,500	$ 46,800	$104,000	$10,100	0.1	$926,000	NA

Background

The poly-tower is located across the plant from the boiler area. Transporting saturated steam over 300 feet across the plant results in the delivery of poor quality, wet steam to the polymer process. Operating personnel have indicated that the steam moisture content at the poly-tower is so high, the steam traps are incapable of handling it. In order to operate the process, the poly-tower steam traps are by-passed and the condensate is lost.

To improve poly-tower condensate recovery, condensate drip-legs need to be added whenever the pipe has a change in elevation and at the end of the steam header. Because of the length of piping run, there will be some amount of condensate formation that must be removed by trapping to assure a supply of dry steam at the process. Installing multiple drip-legs and steam traps on the poly-tower steam supply header will result in energy savings of 7,230 MMBtu, waste water savings of 4,945 thousand gallons, and cost savings of $101,870. Installation of eight condensate drip legs at an estimated cost of $800/leg, two condensate receivers at $850 each and $1,000 each to tie both receivers into the existing condensate return line or $10,100 will solve the problem and yield a 0.10 year simple payback.

The amount of condensate return is determined by testing the condensate, makeup and feedwater for chlorides. The results of the chlorides test for boiler water from this plant are presented below. Based on this test, the estimated amount of condensate returned is 33%.

Water	Measured Chlorides (ppm)
Condensate	25
Makeup	100
Feedwater	75
Calculated Condensate Return	33%

Anticipated Savings

The following information is needed to calculate the potential water and energy savings from adding a drip-leg in the poly-tower and increasing condensate return to the boiler.

Average Steam Flow to Process	- 12,400 lb/hr
Average Steam Flow to Polymer Process	- 8,800 lb/hr
Measured Condensate Return	- 33%
Approximate Condensate Return from Poly-tower	- 3,600 lb/hr
Temperature of Condensate	- 210 ^oF
Enthalpy of Condensate	- 178 Btu/lb
Feed water Temperature	- 70 ^oF
Enthalpy of Feed water	- 36 Btu/lb
Water/Sewer Cost	- $9.46/kgal
Average Natural Gas Cost, 2004	- $7.62/MMBtu
Water Density	- 8.34 lb/ gal
Boiler Efficiency (after tune-up)	- 81%
Operating Hours	- 8,760 hr/yr

Calculated Condensate Return:
= Process Flow x Percent Return
= 12,400 lb/hr x 0.33
= 4,092 lb/hr

Increase in Condensate Return:
= Steam to Poly-tower – Calculated Condensate Return
= 8,800 lb/hr – 4,092 lb/hr
= 4,708 lb/hr

Next, the energy lost by discharging this condensate to the sewer can be calculated.

Annual Energy Savings, ES:
= Mass of Condensate Recovered x (Enthalpy of Condensate – Enthalpy of Make-up Water) x Annual Operating Hours / Boiler Efficiency

= 4,708 lb/hr x (178 Btu/lb – 36 Btu/lb) x 8,760 hr/yr / 0.81
= 7,230 MMBtu/year

Annual Water Savings, WS:
= Condensate Recovered x Operating Hours / Conversion Factor
= 4,708 lb/hr x 8,760 hr/yr / 8.34 lb/gal x 1000 gal/k gal
= 4,945 k gal/year

Annual Cost Savings, CS:
= (ES x Cost of Natural Gas) + (WS x Cost of Water/Sewer)
= (7,230 MMBtu/hr x $7.62/MMBtu) + (4,945 kgal/yr x $9.46/kgal)
= $57,150/yr + $46,780/yr
= $101,870 per year

Implementation Cost

The cost for implementing this recommendation includes condensate piping and fittings, insulation, and a steam trap. It is proposed that eight drip-legs be installed to collect condensate from the steam header and return it to the poly-tower condensate receiver. Because condensate tends to collect at the lowest point of the piping when there is a change in elevation, an estimate of eight elevation changes was used for this analysis. A steam system consultant revealed that drip legs had to be added at a new automotive assembly plant, and the net installation cost per drip leg station was only $500. For this measure, a cost of $800 per station is used. The cost is based on 1-inch diameter, carbon steel condensate pipe, float and thermostatic (F&T) type steam traps, jacketed calcium silicate thermal insulation and the necessary fittings and hangers as required. The cost of condensate recovery piping and trapping for eight drip-legs is estimated to be $6,400.

To capture the condensate, we propose the addition of two condensate receiver tanks at intermediate locations between the boiler and the poly-tower receiver tank. Of the eight drip legs, two will be piped to the existing condensate receiver at the poly-tower and three traps each will drain into the two new receiver tanks. The proposed receivers are 6 gallon capacity cast iron tanks with a single ⅓ hp condensate pump. To collect the condensate, the receivers must be connected to the existing condensate return line from the poly-tower receiver.

Drip legs, including trap and condensate piping, 8 @ $800 each	$6,400
Condensate receiver, 6 gallon w/ ⅓-hp pump, 2 @ $850 each	$1,700
Connect new receivers to existing piping, $1,000 each	+ $2,000
Total cost of condensate upgrade	$10,100

Simple Payback, SP:

= Investment / Savings

= $10,100 / $101,870/year

= 0.10 years (5.2 weeks)

ESO7 – Steam: Evaluate Savings of RO Water Treatment

Recommended Action

Substitution of reverse osmosis (RO) treated water for softened water as boiler makeup will allow an increase in the cycles of concentration and reduction in boiler blowdown.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
0	0	856	$ 5,350	$11,900	$2,250	0.2	$104,000	NA

Background

The automatic blowdown control on boilers #1 and #2 controls the total dissolved solids in the boiler water based on conductivity. Boiler blowdown rate is regulated based on silica content of the makeup water. Presently, the boilers are supposed to operate with 30 to 40 cycles of concentration. Measurement of chloride content in the boiler and feed water revealed actual operation at 20 cycles. This is equivalent to a blowdown rate of 5 percent (1/20).

If reverse osmosis treated water is used for makeup, the silica content of the water will be reduced and a higher cycle of concentration will be allowed. It is estimated that RO makeup water would allow the boiler to operate safely with 60 cycles of concentration. Since the blowdown rate is the inverse of the cycles of concentration, RO makeup will permit the blowdown to be reduced from the present 5% (20 cycles) to 1.67% (60 cycles).

Energy savings are achieved because less hot boiler water is blown down. Make-up water, which has a temperature of 65°F, must be added to compensate for the loss of boiler water during blowdown. The estimated energy savings is 856 million Btu, 566,000 gallons of water and $11,870 in utility cost. Since a reverse osmosis water treatment unit is being installed in the plant for other applications, the only investment is the piping from the unit to the boiler. The estimated piping cost is $2,250 yielding a 0.19 year payback.

Table 5.7.1

Current Cycles of Concentration, Average	Current Blowdown Rate	Reduced Cycles of Concentration w/RO Makeup	Improved Blowdown Rate
20	5.0%	60	1.67%

Anticipated Savings

The following information is needed to determine the annual savings for this energy conservation measure.

Average Boiler Steaming Rate (600 HP)	- 14,400 lb/hr
Present Average Blowdown Rate	- 5.0%
Proposed Average Blowdown Rate	- 1.67%
Makeup Water Enthalpy (65F)	- 31 Btu/lb
Boiler Water Enthlapy (165 psig. Saturated)	- 196 Btu/lb
Average Boiler Efficiency	- 81%
Annual Operating Hours	- 8,760 hrs/yr
Water Cost	- $9.46/kgal
Natural Gas Cost	- $7.62/MMBtu

Blowdown Reduction:
= (Current BD – Reduced BD) x Steam Rate
= (0.05 – 0.0167) x 14,400 lb/hr
= 480 lb/hr

Energy Saved:
= Blowdown Reduction x (Boiler Water Enthalpy – Makeup Water Enthalpy) x Annual Operating Hours / Boiler Efficiency
= 480 lb/hr x (196 Btu/lb – 31 Btu/lb) x 8,760 hr/yr / 0.81
= 856 MMBtu/yr

Water Saved:
= Lbs. Blowdown / 7.43 lb/gal @ 350°F Saturated Liquid x Annual Hrs.
= 480 lb/hr / 7.43 lb/gal x 8,760 hr/yr
= 566 kgal/yr

Annual Cost Savings:
= (Energy Savings x Energy Cost) + (Water Savings x Water Cost)
= (856 MMBtu/yr x $7.62/MMBtu) + (566 kgal/yr x $9.46/kgal)
= $6,520/yr + $5,350/yr
= $11,870/yr

Implementation Cost

The investment is the cost to install a reverse osmosis water treatment system to handle the boiler makeup water. If the blowdown remains 5% and the condensate return remains 33%, the RO system will have to handle 21 pgm. If the blowdown is reduced to 1.67% and the condensate return increased to 67%, the RO system will have to treat 10 gpm.

A complete 15,000 gpd (10 gpm) reverse osmosis system can be purchased for $36,000. The system contains 5 filtration elements, stainless steel frame for membranes, electronic controls for continuous TDS monitoring, level controls, (on/off) flow meters, pressure regulator valves, high pressure tank, pressure gauges for inlet and concentrate, and automatic fast rinse flush. Installation involves supply and discharge piping connections and 110V power supply to operate the controls. The system is skid mounted and comes complete with a 300 gallon storage tank. The simple payback period is 3.1 years on the $36,540 investment.

Investment:

Water Treatment Supply WH RO-15000 Reverse Osmosis Unit	$36,000
100 linear feet of 1" diameter water pipe @ $5/lf	$500
Electrical connection, 1 hr. labor @ $40/hr	$40
Total Cost	$36,540

However, the plant is installing an RO system for other applications and 10 gpm of boiler makeup can be provided from this unit. The only required investment is then the piping from the RO unit to the boiler and a surge tank for storing additional water. If tanks on the existing softener are used for storage, the cost for piping is estimated to be $2,250.

Piping - 2" carbon steel, installed with valves and hangers @ $15/lf x 150 linear feet equal to $2,250.

Simple Payback:

= Investment / Savings
= $2,250 / $11,870/yr
= 0.19 years

ESO8 – Steam: Verify Proper Operation of O2 Sensor

Recommended Action

Adjust the boiler O2 trim system to reduce the excess oxygen level of the steam boilers from their present level to 2.0 percent. Annual cleaning and calibration of the oxygen sensors is recommended to maintain proper operation.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
0	0	3,490	$ -	$25,900	$0	0.0	$237,000	NA

Background

Proper maintenance and adjustment of boilers can make a substantial difference in fuel consumption. Combustion efficiency deserves special attention if a boiler is to deliver peak performance.

A computer analysis was performed using data and measurements collected for the two 600 boiler horsepower (20,100 lb/hr steam) Cleaver-Brooks steam boilers. These calculations used the present excess oxygen levels of 4.8 percent for boiler #1 and 6.9 percent for boiler #2 to determine existing combustion efficiencies of 81.5 percent for boiler #1 and 81.96 percent for boiler #2. If the excess oxygen level of the boilers is lowered to 2.0 percent in boiler #1 and 2.0 percent in boiler #2 at the same stack temperature, the improved efficiency would be 82.76 percent and 84.0 percent respectively. The associated energy and cost savings would be 3,490 MMBtu and $26,590 annually. It is assumed that the O_2 trim systems can be adjusted to the recommended excess oxygen level for an annual cost of $340 each or $680 total. The net savings will be $25,910. If simple adjustment cannot rectify the problem, the oxygen sensors could be faulty and need replacement. This would increase the tune-up expense.

Combustion efficiency is a measure of how effectively the heat content of a fuel is being transferred in the combustion process. Factors such as fuel atomization, air flow and combustion temperature affect combustion efficiency. The primary objective of a boiler tune-up is to achieve efficient combustion with a controlled amount of excess air (as indicated by measurement of excess oxygen). Maintaining the lowest practical excess air level minimizes the quantity of air that must be heated to stack temperature, thereby reducing fuel consumption.

When lowering the excess air level, it is important to keep the excess air level sufficiently high to prevent the loss of unburned fuel out of the stack. One technique to properly set the excess air level is to lower the excess air level until combustibles are detected in the exhaust. The excess air level is then increased slightly, thus eliminating unburned fuel in the exhaust, and providing adequate air for complete combustion.

Fuel type and boiler design have the greatest effects on recommended excess air levels. Most forced-draft boilers use today can be adjusted to 5 - 10 percent excess air (1 - 2 percent excess oxygen) for gaseous fuels, 10 - 20 percent excess air (2 - 3.5 percent excess oxygen) for fuel oils and 15 - 40 percent excess air (3 - 6 percent excess oxygen) for pulverized coal. For natural draft boilers, the excess air level is intentionally kept high to prevent partially burned fuel emissions which compromise boiler safety. Excess oxygen of 7 to 8 percent is acceptable for this type of boiler.

Once the boilers' oxygen trim systems are adjusted, they need to be monitored to insure they are operating properly. You should take measurements of the boiler flue gas at regular intervals to verify that the oxygen trim systems are properly calibrated and maintaining stack oxygen at the correct level. If the trim systems are no longer capable of maintaining the stack oxygen at the desired level, the oxygen sensors may need replacement.

Anticipated Savings

The following information is useful in calculating the energy and cost savings for this energy conservation opportunity.

Boiler Fuel Usage, 2004	- 176,542 MMBtu/yr
Fuel Usage Split Between #1 and #2	- 50/50
Boiler #1 Stack Oxygen	- 4.8%
Boiler #1 Stack Temperature (50% Load)	- 427^{o}F
Boiler #2 Stack Oxygen	- 6.9%
Boiler #2 Stack Temperature (10% Load)	- 365 ^{o}F
Ambient Temperature	- 70^{o}F
Average Natural Gas Cost, 2004	- $7.62/MMBtu

Boiler Efficiency:
The current efficiency for boiler #1 is easily arrived at from Table 5.8.1. Boiler #1 has 4.8 percent oxygen in the stack (27 percent excess air) and a 357^{o}F differential flue gas temperature, which gives a present combustion efficiency of 81.5 percent. Reducing the excess oxygen to 2 percent, at the same stack temperature will increase the combustion efficiency to 82.76 percent.

The current efficiency for boiler #2 is also arrived at from Table 5.8.1. Boiler #2 has 6.9 percent oxygen in the stack (43.9 percent excess air) and a 295°F differential flue gas temperature, which gives a present combustion efficiency of 81.96 percent. Reducing the excess oxygen to 2 percent, at the same stack temperature will increase the combustion efficiency to 84.0 percent. Although 3 percent excess oxygen in the stack is the suggested level for normal operation, oxygen trim may be able to reduce stack oxygen level to 2% even at this low load condition.

Boiler Energy Consumption:
- = Fractional Split x Fuel Consumption
- = ½ x 176,542 MMBtu/yr
- = 88,271 MMBtu/boiler-yr

Energy Savings:
- = Boiler Consumption x [1 - (Old Efficiency / New Efficiency)]
- = 88,271 MMBtu/yr x [1 - (81.5 / 82.76)] + 88,271 MMBtu/yr x [1 - (81.96 / 84.0)]
- = 3,490 MMBtu/yr

Annual Energy Cost Savings:
- = Energy Savings x Boiler Fuel Cost
- = 3,490 MMBtu/yr x $7.62/MMBtu
- = $26,590/yr

Implementation Cost

To maintain optimum control, the stack oxygen sensor must be regularly cleaned and calibrated. The cost to have a boiler technician perform the necessary oxygen trim system maintenance is $340 per unit. This cost is based on 4 hours of technician labor at $85/hr. The annual cost for both boilers is $680. If the technician determines that the oxygen sensors need replacement, additional cost would be incurred.

Net Cost Savings:
- = Energy Cost Savings - Tune-up Cost
- = $26,590/yr - $680/yr
- = $25,910/yr

Table 5.8.1. Combustion Efficiency for Natural Gas Fuel Type.

Exess Air	CO_2	O_2	Differential Stack Temperature, T_{ex} - Ta: 300	310	320	330	340	350	360	370	380	390	400
0.0%	11.7%	0.0	0.845	0.843	0.841	0.839	0.837	0.835	0.834	0.832	0.830	0.828	0.826
2.2%	11.5%	0.5%	0.843	0.842	0.840	0.838	0.836	0.834	0.832	0.830	0.828	0.826	0.824
4.5%	11.2%	1.0%	0.842	0.840	0.838	0.836	0.834	0.832	0.830	0.828	0.826	0.825	0.823
6.9%	10.9%	1.5%	0.841	0.839	0.837	0.835	0.833	0.831	0.829	0.827	0.825	0.823	0.821
9.4%	10.6%	2.0%	0.839	0.837	0.835	0.833	0.831	0.829	0.827	0.825	0.823	0.821	0.819
12.1%	10.3%	2.5%	0.837	0.835	0.833	0.831	0.829	0.827	0.825	0.823	0.821	0.819	0.816
14.9%	10.1%	3.0%	0.836	0.834	0.831	0.829	0.827	0.825	0.823	0.821	0.819	0.816	0.814
17.9%	9.8%	3.5%	0.834	0.832	0.830	0.827	0.825	0.823	0.821	0.818	0.816	0.814	0.812
21.1%	9.5%	4.0%	0.832	0.830	0.828	0.825	0.823	0.821	0.818	0.816	0.814	0.812	0.809
24.4%	9.2%	4.5%	0.830	0.828	0.825	0.823	0.821	0.818	0.816	0.814	0.811	0.809	0.807
28.0%	8.9%	5.0%	0.828	0.825	0.823	0.821	0.818	0.816	0.813	0.811	0.809	0.806	0.804
31.8%	8.7%	5.5%	0.826	0.823	0.821	0.818	0.816	0.813	0.811	0.808	0.806	0.803	0.801
35.8%	8.4%	6.0%	0.823	0.821	0.818	0.815	0.813	0.810	0.808	0.805	0.803	0.800	0.797
40.1%	8.1%	6.5%	0.821	0.818	0.815	0.813	0.810	0.807	0.805	0.802	0.799	0.797	0.794
44.8%	7.8%	7.0%	0.818	0.815	0.812	0.809	0.807	0.804	0.801	0.798	0.796	0.793	0.790
49.7%	7.5%	7.5%	0.815	0.812	0.809	0.806	0.803	0.800	0.797	0.795	0.792	0.789	0.786
55.1%	7.3%	8.0%	0.811	0.808	0.805	0.802	0.799	0.797	0.794	0.791	0.788	0.785	0.782
60.9%	7.0%	8.5%	0.808	0.805	0.802	0.799	0.795	0.792	0.789	0.786	0.783	0.780	0.777
67.1%	6.7%	9.0%	0.804	0.801	0.798	0.794	0.791	0.788	0.785	0.781	0.778	0.775	0.772
73.9%	6.4%	9.5%	0.800	0.796	0.793	0.790	0.786	0.783	0.780	0.776	0.773	0.770	0.766
81.4%	6.1%	10.0%	0.795	0.792	0.788	0.785	0.781	0.778	0.774	0.771	0.767	0.764	0.760
89.5%	5.9%	10.5%	0.790	0.786	0.783	0.779	0.775	0.772	0.768	0.764	0.761	0.757	0.753
98.5%	5.6%	11.0%	0.784	0.781	0.777	0.773	0.769	0.765	0.761	0.757	0.754	0.750	0.746
108.3%	5.3%	11.5%	0.778	0.774	0.770	0.766	0.762	0.758	0.754	0.750	0.746	0.742	0.738
119.3%	5.0%	12.0%	0.771	0.767	0.763	0.758	0.754	0.750	0.746	0.741	0.737	0.733	0.728
131.6%	4.7%	12.5%	0.764	0.759	0.754	0.750	0.745	0.741	0.736	0.732	0.727	0.722	0.718
145.4%	4.5%	13.0%	0.755	0.750	0.745	0.740	0.735	0.730	0.726	0.721	0.716	0.711	0.706
161.1%	4.2%	13.5%	0.745	0.740	0.734	0.729	0.724	0.719	0.714	0.708	0.703	0.698	0.693
179.0%	3.9%	14.0%	0.733	0.728	0.722	0.716	0.711	0.705	0.700	0.694	0.688	0.683	0.677

ESO9 – Reduce Flash Losses from Condensate Tank

Recommended Action

Condensate in the polytower receiver is currently being lost as the pressure is reduced to atmospheric and it flashes through the exhaust stack. The flash can be eliminated and makeup water heated by installing a heat exchanger in the condensate receiver vent stack.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
0	0	12,100	$ -	$92,400	$9,920	0.1	$835,000	NA

Background

Condensate develops in steam systems after the steam has given off its latent heat energy. The condensate is still more valuable than makeup since it contains more thermal energy and has fewer solids. Condensate is typically recovered and collected in a receiver tank before it is sent back to the boiler.

Depending on how far the condensate tank is from the steam trap and the friction loss through the steam trap, the pressure of the condensate will be slightly lower than the steam pressure prior to the steam trap. When the steam trap opens and condensate is forced into the condensate tank, some of the condensate will flash into steam due to the decrease pressure because receiver tanks must be maintained at atmospheric pressure. Flash steam resulting from this reduction in condensate pressure exits the receiver tank through a vent stack. Energy contained in flash steam is lost to the environment. The percentage of water that flashes into steam can be found by using steam tables or a pressure-enthalpy chart for water as the one shown on the following page.

It is recommended that a heat exchanger be installed in the exhaust stack of the condensate receiver tank to prevent the flash steam from escaping the steam system and being lost. A heat exchanger would remove heat from the steam causing it to condense. The cold fluid in the heat exchanger would be the makeup water to the boiler. Therefore, the heat normally lost by flashing would be returned to the boiler.

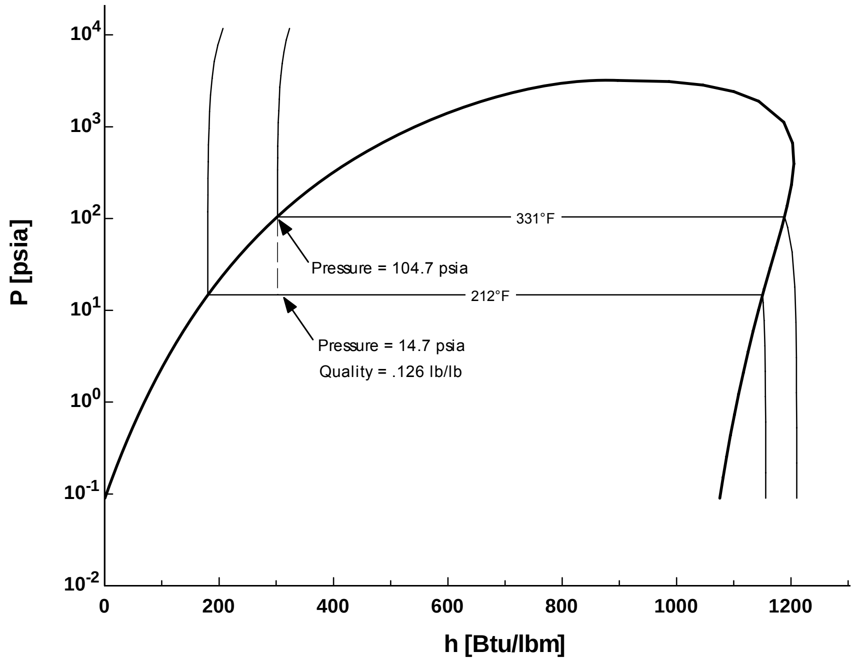


Figure 5.9.1. P-h chart for water.

There are two types of heat exchangers that can be used in this process, a direct contact heat exchanger and an indirect contact heat exchanger. A direct contact heat exchanger mixes the hot and cold fluids to transfer the heat from the hot stream to the cold stream. An example of this kind of heat exchanger is an air washer. Direct contact heat exchangers have the advantage of overall high heat transfer between the two fluids, and minimum equipment costs. However, since the streams mix, if one stream is contaminated, it will contaminate the other stream as well. An indirect contact heat exchanger separates the streams via a barrier and uses conduction through the barrier to transmit heat from one stream to another. This method is less effective in transferring heat between the two streams.

A direct contact heat exchanger is chosen for this application since both streams should have a low solid content. The envisioned heat exchanger would have a packed bed of ceramic media that is located in the exhaust stack of the condensate tank. This bed of ceramic media will slow down the exhaust rate of the flash steam passing through the exhaust stack. Above the media bed, treated makeup water would be sprayed into the media so that is can absorb heat from the rising flash and the ceramic media. In doing so, the flash will condense into water and fall back into the tank and the makeup water will be heated before falling into the tank. A simple diagram is shown on the following page to demonstrate the system. Care must be taken to prevent the pressure in the condensate tank from reaching a point at which condensate from the steam system can not be forced into the condensate tank. However, as long as the exhaust stack is not sealed, this shouldn't be an issue. If the pressure in the tank is too high, the ceramic media should not be installed in the exhaust stack. Removing the media will decrease the amount flash steam that is condensed in the exhaust stack but it will decrease the pressure in the tank.

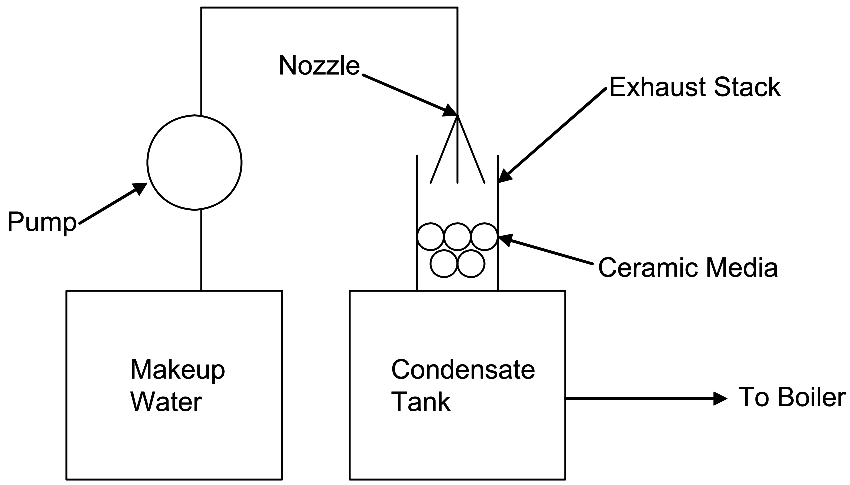


Figure 5.9.2 : Flash steam recovery diagram

Anticipated Savings

The following data was used to determine the cost savings for this recommendation. It is assumed that recommendation ESO6 is completed prior to implementing this recommendation. Therefore, all of the steam that enters the polytower is assumed to eventually pass through the condensate return tank.

Steam Flow Rate to the Polytower	- 8,000 lb/hr
Condensate Pressure	- 90 psig
Quality of Flash	- 0.126 lb/lb
Enthalpy of Flash	- 1,150 Btu/lb
Enthalpy of Makeup Water at 70 ^{o}F	- 38.1 Btu/lb
Boiler Efficiency	- 81 Percent
Annual Operating Hours	- 8,760 hrs/yr
Average Cost of Fuel	- $7.62/MMBtu

Flash Loss Quantity:

= Steam Flow Rate x Quality of Flash
= 8,000 lb/hr x 0.126 lb/lb
= 1,008 lb/hr

Energy Savings:

= Flash Loss Quantity x (Enthalpy of Flash – Enthalpy of Makeup Water) x Operating Hours / Boiler Efficiency
= 1,008 lb/hr x (1,150 Btu/lb – 38.1 Btu/lb) x 8,760 hrs/yr x (1MMBtu / 1,000,000 Btu) / 0.81

= 12,121 MMBtu/yr

Energy Cost Savings:
= Energy Savings x Marginal Cost
= 12,121 MMBtu/yr x $7.62/MMBtu
= $92,400/yr

Implementation Cost

To implement this recommendation, a pump is needed to spray the water from the makeup tank over the ceramic media. Furthermore, ceramic media is needed to reduce the flow rate of the flash passing through the exhaust duct. Pipes are needed to transport the water from the makeup tank to the condensate tank, and a spray nozzle is needed to spray the water onto the media. It is assumed that the installation cost is half of the equipment cost.

Investment:

Ceramic Media	- $2,000
Pump	- $3,500
Piping and Fittings	- $400
Spray Nozzle	- $15
Installation, Assume 2 man crew, $50/hr, 80 hours total	- $4,000
TOTAL	- $9,915

Simple Payback Period:
= Investment / Cost Savings
= $9,915 / $92,400/yr
= 0.1 years

ESO10 – Compressed Air: Repair Air Leaks

Recommended Action

Repair compressed air leaks throughout the plant. An air balance indicates that approximately 30% of the compressed air supplied to the plant is lost through leaks. A dedicated leak repair program should be able to reduce and maintain a leakage rate of 10%.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
4,550,000	519	0	$ -	$187,000	$25,000	0.1	$1,640,000	NA

Background

The leakage of compressed air from storage vessels, piping and equipment represents a costly and unnecessary waste of energy. An air balance prepared for the plant indicates that approximately 31 percent of the compressed air supplied to the plant is lost through air leaks. Air leaks were identified in the piping supplying texturizers, the plastic tubing supplying air cylinders in winding and numerous other locations. Calculations reveal that these compressed air leaks result in an increased energy consumption of 4.5 million kWh/yr and increased operating cost of $187,400 each year. These leaks can be corrected for approximately $100 each, eliminating the loss entirely. Based on an estimated 250 air leaks of substantial size plant-wide, the cost to repair the leaks would be $25,000. This would yield a simple payback of 0.13 years (1.6 months).

The magnitude of compressed air leakage was determined by subtracting the calculated process air usage from measured plant air usage. The estimated leakage rate was found to be slightly over 30%. The number of leaks and estimated leak size was determined using an ultrasonic probe. By adjusting the sensitivity on the probe until the ultrasonic noise is mid-range, the approximate leakage rate can be determined from a calibration sheet. Because of the high cost of air leaks in the plant, the ultrasonic detection program is justified and should be continued.

Anticipated Savings

The following given values are useful in determining the energy and cost savings for repairing compressed air leaks in the plant.

Average Compressed Air Flow	- 12,300 cfm
Identified Process Air Usage	- 8,490 cfm
Air Pressure (at leak)	- 110 psig
Compressor Energy Draw (per 100 ft^3 air/min)	- 23.5 Brake hp
Specific Volume of Air	- 13.2 ft^3/lb
Annual Operating Hours	- 8,760 hrs/yr
Electrical Cost	- $0.027/kWh
Demand Cost	- $10.38/kW-mo

Process Usage of Compressed Air
The compressed air consuming processes were analyzed to develop an estimate of air usage. By subtracting the air used in plant processes from the air supplied to the plant, an approximate leakage rate can be determined. The air usage by processes with an orifice opening is determined by the same approach as leakage losses. Usage by contained processes like air cylinders is found from equipment specifications. The air flow through orifices is determined with the equation below.

Shaw Pt. #78
Process Compressed Air Usage

Airflow (cfm)		$M = 0.53 \times C_d \times P_L \times A / (T_L)^{1/2}$
Line Temp	530	Rankin
Air Volume	13.2	Ft^3/lb
Pt. Airflow	13,140	cfm

Application	Opening	Area	No. Openings	Pressure		Airflow	% of Pt.
	mm	sq in		bar	Psig	Cfm	Airflow
Aspirator	2	0.0049	4.167	8	116	25.7	0.002
Texturize	oval	0.0103	208	8	116	2,718.6	0.221
Entangle	oval	0.0133	208	8	116	3,515.1	0.286
Winder	5.7	cfm/wind	88	6	87	500.0	0.041
Counter	5.5	0.2165	1	5	72.5	29.2	0.002
Twister	10	cfm/twist	59	6.6	95.7	590.0	0.048
Heat Set Tunnel	15	Cfm/tunnel	16	7.6	110	240.0	0.020
Poly-tower		Control air				100.0	0.008
Misc	10%					772.0	0.063
Total						8,490.5	0.691

Air Mass Flow Rate for Orifices:

$= 0.53 \times C_d \times P_L \times A / (T_L)^{1/2}$

where:

C_d - Discharge Coefficient (0.60)

P_L - Line Pressure, in psia

T_L - Line Temperature, 70^oF, (530^oR)

Process Usage:

= Texturizer + Entangle + Twister + Aspirator + Heat Set + Winders + Poly-tower + Misc.

= (2,719 + 3,515 + 590 + 55 + 240 + 500 + 100 + 772) cfm

= 8,491 cfm

Leak Volume:

= Compressed Air Flow to Plant – Process Usage

= 12,300 cfm – 8,491 cfm

= 3,809 cfm

Leak Percentage:

= Calculated Leakage Rate / Average Plant Air Flow

= 3,809cfm / 12,300 cfm

= 31%

Reduced Leakage:

A leakage rate of 10 percent should be maintained in the plant.

= Plant Usage x 10%

= 8,491 cfm x 0.1

= 849 cfm

Leakage Savings:

= Current Leakage – Proposed Leakage

= 3,809cfm – 849 cfm

= 2,906 cfm

Reduction in Annual Leakage Volume:

= Leakage Rate x Time Conversion x Annual Hours

= 2,906 cfm x 60 min/hr x 8,760 hr/yr

$= 1{,}556 \times 10^6 \text{ ft}^3/\text{yr}$

Energy Savings:

= Leak Volume x Compressor Energy Draw

$= 1{,}556 \times 10^6 \text{ ft}^3/\text{yr} \times 23.5 \text{ Hp-min}/100 \text{ ft}^3 \times 0.746 \text{ kW/Hp} \times 1 \text{ hr}/60 \text{ min}$

= 4,546,400 kWh/yr

Demand Savings:

= Energy Saved / Annual Hours
= 4,546,400 kWh/yr / 8,760 hr/yr
= 519 kW

Cost Savings:

= Energy Saved x Electricity Cost
= (4,546,400 kWh/yr x $0.027/kWh) + (519 kW x $10.38/kW-mo x 12 mo/yr)
= $187,400/yr

Implementation Cost

Leaks can occur in a number of locations, for example valve stems, regulators, connectors, fittings, etc. The cost to repair a leak depends on where it occurs and how difficult it is to access. For this location, we will use an average cost of $100/leak for detection and repair. Included in the cost is the labor to detect the leak ultrasonically, purchase the required replacement item and the maintenance labor to complete the repair. The plant already has an air leak repair program underway and extrapolating the area already surveyed to include the entire facility, we estimate the presence of approximately 250 leaks of substantial size are present in the plant.

Investment:

= Number of Leaks x Cost to Repair Leaks
= 250 Leaks x $100/leak
= $25,000

Simple Payback Period:

= Investment / Savings
= $25,000 / $187,400/yr
= 0.13 years (1.6 months)

ESO11 – Compressed Air: Evaluate Primary Air Storage

Recommended Action

The plant operates a 1000 hp centrifugal compressor to satisfy demand fluctuations. Adding additional primary storage and a 220 hp screw compressor will satisfy variations in air demand. Coupled with an aggressive air leak repair program, these changes will solve concerns about compressed air capacity.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
2,040,000	466	0	$ -	$113,000	$39,900	0.4	$995,000	NA

Background

The compressed air demand in the plant is met by two base-loaded 1,750 hp centrifugal compressors and a 1,000 hp centrifugal compressor for trim. The base-loaded compressors run fully loaded most of the time. The swing load compressor also has a high load factor, but most of the compressor output blows off to atmosphere. Because centrifugal compressors cannot cycle quickly, the trim compressor must operate a large portion of the time even though most of the air is wasted. This indicates that there is a periodic event demanding air for short periods of time. Many periodic, short term events can be met by using compressed air storage.

Compressed air storage is sized according to the quantity of air needed to meet the demand of a certain event. The tank size required in conjunction with a 200 hp screw compressor to meet fluctuations of 1,000 cfm is 6,000 gallons. A screw compressor can be used because the system pressure is assumed to be 125 psig instead of the present 145 psig. Using a smaller screw compressor coupled with a storage tank eliminates the need for the large centrifugal compressor for the air system.

The average air flow is 12,300 cfm which can be satisfied by the plant's 2-1750 hp centrifugal compressors. The 1000 hp centrifugal is operated to satisfy variations in compressed air demand that exceed 12,300 cfm. Because the 1,000 hp compressor produces 3,200 cfm, most of the air from this compressor must be blown off to the atmosphere to maintain the correct system pressure. Replacing the 1,000 hp centrifugal compressor with a 220 hp screw will save energy and more closely match the plant air demand. ESO10, Repair Air Leaks, will reduce plant air requirements by over 3,000 cfm which will further decrease the need for the 1,000 hp compressor. Thus, the 220 hp screw coupled with additional storage will provide all the reserve compressed air capacity necessary.

This recommendation is based on an analysis of instantaneous compressed air demand from plant air flow charts.

Anticipated Savings

The proposed compressed air system changes are based on the following operating data.

Average Demand 1,000 hp Compressor (905 amps)	- 616 kW
220 hp Screw Compressor Rated Capacity @ 125 psig	- 940 CFM
220 hp Screw Compressor Electrical Demand	- 176 kW
Screw Compressor Load Factor	- 85%
Operating Hours	- 4,380 hr/yr
Demand Cost	- $10.38/kW-mo
Electricity Cost	- $0.027/kWh

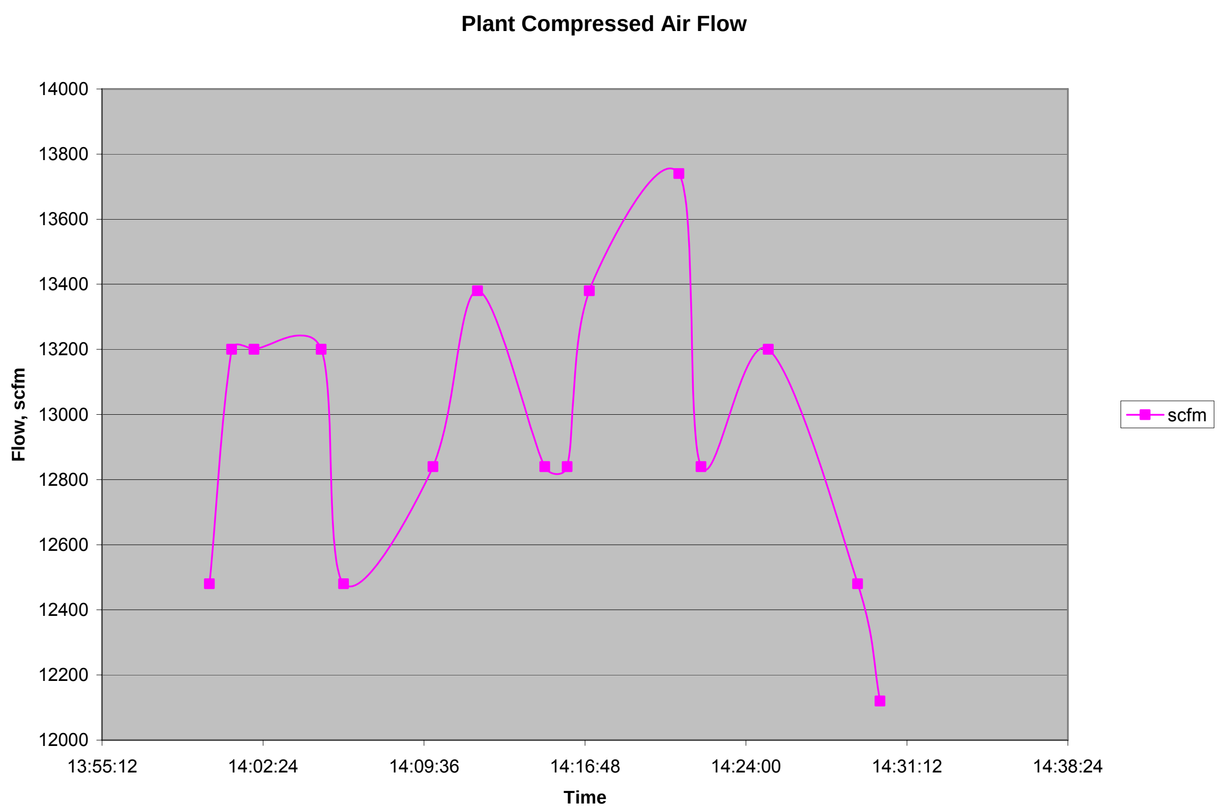


Figure 5.11.1

First, the amount of compressed air needed to satisfy the air system event is calculated.

Compressed Air Needed to Satisfy Periodic Event:
= Maximum Variation in Air Flow
= 13,800 CFM – 12,800 CFM
= 1,000 CFM

Next, the storage tank size is calculated based on a storage pressure of 125 psig. Assume that the air pressure required by the equipment is 115 psig.

Compressed Air Storage:
= Compressed Air Needed - (Compressor Pressure / Process Pressure) x Capacity of 220 hp Compressor (at 125 psig) x Event length
= 1,000 CFM - (139.7 psia / 129.7 psia) x 940 CFM x (10 sec/60 sec)
= 835 ft^3 (at 125 psig)

Compressed Air Storage Tank Size (at 115 psig):
= Compressed Air Storage x (Process Pressure + ΔP) / (Compressor Pressure) x Conversion Factor
= 835 ft^3 x (129.7 psia + 5 psig) / (139.7 psia) x 7.5 gal/ft^3
= 6,000 gallons

The energy savings results from substituting a 200 hp rotary screw compressor for the current 1,000 hp centrifugal. In the present operations, much of the air generated by the 1,000 hp compressor is wasted by blowing to atmosphere. By increasing the storage and adding a smaller screw compressor, the compressed air system will be able to respond to load variations without having the compressor air held in reserve blown off to the atmosphere.

Screw Compressor Full-Load Demand:
= Rated HP / Motor Eff.
= 220 hp x 0.746 kW/hr / 0.93
= 176 kW

Screw Compressor Demand:
= Rated Power x load Factor
= 176 kW x 0.85
= 150 kW

Demand Saved:
= Centrifugal Compressor Demand – Screw Compressor Demand
= 616 kW – 150 kW
= 466 kW

The energy saved is a function of the number of hours the small compressor must operate. Because the compressed air demand events that require an additional compressor are cyclic, the third compressor need not operate continuously. For purposes of analysis, it is assumed the trim compressor (small) will operate approximately half the time the plant operates or 4,380 hours per year.

Electricity Saved:
= Demand Saved x Operating Hours
= 466 kW x 4,380 hr/yr
= 2,041,000 kWh/yr

Cost Saved:
= (Electricity Saved x Marginal Electricity Cost + (Demand Saved x Demand Cost x 12 mo/yr)
= (2,041,000 kWh/yr x $0.027/kWh) + (466 kW x $10.38/kW-mo x 12 mo/yr)
= $113,100/yr

Implementation Cost

Implementation of this recommendation will require installation of a storage tank and a smaller screw compressor to satisfy periodic cyclical events. A base-mounted 200 hp rotary screw air compressor can be purchased for $56,750. The cost includes a standard rotary screw air compressor in a self contained package with v-belt drive, cooling fan and controls.

The 6,000 gallon air storage tank is constructed of carbon steel, is pressured rated to 120 psig and has an ASME pressure vessel stamp. The tank is 10' diameter and 12¾' tall. The tank cost is $23,100.

Equipment Cost:

200 hp screw compressor	$56,750
6,000 gallon storage tank	+ $23,100
Sub-total	+ $79,850
Salvage value 1,000 hp centrifugal	- $40,000
Net Investment	$39,850

Simple Payback:
= Investment / Savings
= $39,850 / $113,100/yr
= 0.35 yr

Figure 5.11.2. 200 hp Rotary Screw Air Compressor.

ESO12 – Compressed Air: Lower Plant Pressure with the Use of Demand-side Storage

Recommended Action

Reduce the air pressure control setting on the plant air compressors from 145 psig to 125 psig to decrease the energy consumption. Compressing the air to the current pressure requires about 10% more energy than is necessary to compress the air to the suggested pressure.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
2,480,000	284	0	$ -	$102,000	$51,400	0.5	$885,000	NA

Background

Currently, the centrifugal compressors' pressure setting for air delivered to the plant is 145 psig. The required pressure for the plant equipment varies from 109 psig (7.5 bar) at entangling to 95 psig (6.6 bar) at twisting. To achieve the required pressure at the equipment, the plant compressors operate at 145 psig to compensate for losses in undersized piping, excessive leakage and insufficient storage. Lowering the air compressor discharge to 125 psig will produce savings and still maintain adequate pressure for the equipment if the air distribution system in the facility is corrected.

To achieve the lower operating pressure, secondary storage tanks must be added at texturizing, heat set winding and twisting. The proposed tank volumes are 5,000 gallons at texturing and 2,500 gallons at both winding and twisting. The estimated investment for these changes is $51,400. A simple payback of 0.5 years (6 months) is achieved.

Anticipated Savings

The demand savings and the total annual energy savings can be estimated from the following relationships:

Demand Savings:
= (1 – Ratio of Proposed Power Consumption to Current Power Consumption Based on Operating Pressure) x Combined Electrical Load of Compressors

The following equation can be used to estimate the horsepower reduction factor, based on current and proposed operating pressures[1].

Horsepower Reduction Factor:

$$= \frac{\left(\frac{\text{Proposed Discharge Pressure}}{\text{Inlet Pressure}}\right)^{\frac{N(k-1)}{k}}}{\left(\frac{\text{Current Discharge Pressure}}{\text{Inlet Pressure}}\right)^{\frac{N(k-1)}{k}}}$$

where

N is the compression factor based on type of compressor considered
K is the ratio of specific heat for air (k=1.4)
N = 1 for single stage compressor
N = 2 for two-stage compressor
N = 3 for three-stage compressor
N = 1.25 for screw comp., assuming a polytropic efficiency of 80%

Energy Savings:
= Demand Savings x Operating Hours

For this facility,
Horsepower Reduction Factor:

$$= \frac{\left(\frac{139.7\text{ psia}}{14.7\text{ psia}}\right)^{\frac{2(1.4-1)}{1.4}}}{\left(\frac{159.7\text{ psia}}{14.7\text{ psia}}\right)^{\frac{2(1.4-1)}{1.4}}}$$

= 0.90

Demand Savings:
= (1 – 0.90) x 2,835 kW
= 283.5 kW

Energy Savings:
= 283.5 kW x 8,760 hrs/yr
= 2,483,500 kWh/yr

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1 Compressed Air and Gas Handbook, Compressed Air and Gas Handbook, New York, New York, Third Edition, 1961.

Annual Cost Savings:

= Demand Savings x Demand Cost x Demand Ratchet + Energy Savings x Consumption Cost

= (283.5 kW/month x \$10.38/kW-mo x 12 month/yr) + (2,483,500 kWh/yr x \$0.027/kWh)

= \$102,400/yr

Implementation Cost

In order for the plant air pressure to be reduced and still have the equipment operate properly, changes to the distribution system are required. The following changes are suggested:

Add three compressed air storage vessels at major use points: 5,000 gallons @ texturizing, 2,500 gallons @ heat set winding, and 2,500 gallons @ twisting.

The cost of the stage tanks is based on an estimate provided by Niles Steel Tank Co. of Niles Michigan. The tanks are ASME rated to 120 psig.

1-5,000 gallon tank @ \$4.50/gallon	\$21,400
2-2,500 gallon tanks @ \$6.00/gallon	\$30,000
TOTAL	\$51,400

Simple Payback:

= Investment / Savings

= \$51,400 / \$102,400/yr

= 0.5 yr

ESO13 – Compressed Air: Install Compressor Controller

Recommended Action

Install integrated sequence controls on the air compressors to improve compression efficiency. The controller generates savings by turning off unneeded units and optimizing the load on part-load units.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
4,540,000	518	0	$ -	$187,000	$20,000	0.1	$1,690,000	NA

Background

An air compressor sequencer controls multiple air compressor installations such that a minimum number of air compressors are used to produce a desired amount of compressed air. Usually compressed air sequencers control how many air compressors operate at a given time based on the system air pressure. As the demand for air increases, the sequencer turns on more compressors to supply the air. The most efficient compressors are loaded first. When the demand drops, the sequencer shuts off compressors in order of least efficient to most efficient. In doing so, the most efficient air compressors are loaded for the majority of the time.

Three centrifugal air compressors are used to provide compressed air to the facility. An air compressor sequencer was installed during the time of the energy assessment. With the compressor sequencer installed, readings of compressor amp loading were conducted with the sequencer activated and de-activated. The resulting savings are presented in the attached calculations.

According to facility personnel, all three air compressors operate all year.

Anticipated Savings

The following recorded values are useful in determining the energy and cost savings from improved air compressor control.

Air Compressor Amps, Sequencer Off	- 530 amps
Air Compressor Amps, Sequencer On	- 450 amps
Air Compressor Voltage	- 4160 volts

Estimated Compressor Power Factor	- 0.9
Annual Operating Hours	- 8,760 hrs/yr
Electrical Cost	- $0.027/kWh
Demand Cost	- $10.38/kW-mo

Demand Savings:

= (Amps on Compressor w/o sequencer x Voltage X 1.732 x Power Factor/1000) – (Load on Compressor w/ sequencer x Voltage x 1.732 x Power Factor/1000)
= (530 x 4160 x 1.732 x 0.9/1000) – (450 x 4160 x 1.732 x 0.9/1000) kW
= 3,436 kW – 2,918 kW
= 518 kW

Energy Savings:

= Demand Savings x Annual Operating Hours
= (518 kW x 8,760 hr/yr)
= 4,537,680 kWh/yr

Cost Savings:

= (kWh Saved x Marginal Cost of Electricity) + (Demand Saved x Demand Cost x Effective Months)
= (4,537,680 kWh/yr x $0.027/kWh) + (518 kW x $10.38/kW-mo x 12 mo)
= $187,000/yr

Implementation Cost

The implementation of this measure requires the purchase of an electronic compressor controller. For the purpose of cost analysis, an Ingersoll-Rand Intellisys Controller (ISC) is used. The purchase price is $15,000 with upper range modulation control and energy management options. Installation and set-up is estimated to cost $5,000. This yields a total investment of $20,000.

Simple Payback Period:

= Investment / Savings
= $20,000 / $187,000/yr
= 0.11 years (1.3 months)

Georgia Institute of Technology

ESO14 – Replace Heat Set Compressed Air Supply with Dedicated Low Pressure Compressed Air Supply

Recommended Action

Replace high pressure compressed air use in the heat set tunnels with a dedicated compressor supplying lower pressure air. Low pressure compressed air takes less energy to produce and will reduce heat set operating cost.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
231,000	26.4	0	$ -	$9,530	$14,500	1.5	$72,700	197%

Background

High pressure compressed air is used in the Superba heat set tunnels to fluff and bulk yarn. The 125 psig compressed air is reduced to 29 psig (2 Bar) by an air regulator. Instead of using high pressure compressed air, low pressure air from a dedicated compressor can be used and energy will be saved. The compressed air usage by each Superba heat set tunnel is 15 cfm or 240 cfm for all 16 tunnels in this plant. Other plants have reported Superba air usage as high as 45 cfm. If the Superbas use more than 15 cfm of compressed air, the energy savings from converting to a smaller compressor would be even greater. To supply the required 240 cfm, a small, 30 hp rotary screw compressor would be adequate. Converting from high pressure compressed air to low pressure air on the Suprbas will lead to a reduction in monthly electrical demand of 25.8 kW, energy savings of 226,000 kWh/yr and cost savings of $9,315, annually.

A 30 hp rotary screw compressor for low pressure operation can be purchased and installed for $14,529. The calculations below show how the savings were obtained for this measure.

Anticipated Savings

The following data was used to determine energy and cost savings:

Superba Compressed Air Usage	- 240 cfm
Superba Compressed Air Pressure	- 2 Bar, 29 psig

Compressor Demand @ 120 psig Discharge	- 24 hp/100 cfm
Low Pressure Compressor Discharge Pressure	- 29 psig
Superba Operating Hours	- 8,760 hr/yr
Electrical Energy Cost	- $0.027/kWh
Electrical Demand Cost	- $10.38/kW-mo

The demand savings and the total annual energy savings can be estimated from the following relationships:

Demand Savings:

= (1 – Ratio of Proposed Power Consumption to Current Power Consumption Based on Operating Pressure) x Combined Electrical Load of Compressors for 240 cfm

The following equation can be used to estimate the horsepower reduction factor, based on current and proposed operating pressures.

Horsepower Reduction Factor:

$$= \frac{\left(\frac{\text{Proposed Discharge Pressure}}{\text{Inlet Pressure}}\right)^{\frac{N(k-1)}{k}}}{\left(\frac{\text{Current Discharge Pressure}}{\text{Inlet Pressure}}\right)^{\frac{N(k-1)}{k}}}$$

where

N is the compression factor based on type of compressor considered
K is the ratio of specific heat for air (k=1.4)
N = 1 for single stage compressor
N = 2 for two-stage compressor
N = 3 for three-stage compressor
N = 1.25 for screw comp., assuming a polytropic efficiency of 80%

Energy Savings:

= Demand Savings x Operating Hours

For this facility,
Horsepower Reduction Factor:

$$= \frac{\left(\frac{43.7\text{ psia}}{14.7\text{ psia}}\right)^{\frac{1.25(1.4-1)}{1.4}}}{\left(\frac{139.7\text{ psia}}{14.7\text{ psia}}\right)^{\frac{1.25(1.4-1)}{1.4}}}$$

= 0.385

Demand Savings:

= (1 – 0.385) x 24hp/100 cfm x 240 cfm x 0.746 kW/hp
= 26.4 kW

Energy Savings:

= 26.4 kW x 8,760 hrs/yr
= 231,300 kWh/yr

Annual Cost Savings:

= Demand Savings x Demand Cost x Demand Ratchet + Energy Savings x Consumption Cost
= (26.4 kW/month x $10.38/kW-mo x 12 month/yr) + (231,300 kWh/yr x $0.027/kWh)
= $9,530/yr

Implementation Cost

A small rotary screw compressor installed in the heat set area will be able to replace the compressed air currently used. A 30 hp blower that supplies 125 cfm A 100 psig should be able to supply all of the low pressure air demanded by the Superbas. Grainger lists 30 hp Ingersol-Rand rotary screw compressor for @ $11,629. Assume that the compressor can be installed for 25% of the investment cost or $2,900. The investment cost includes the labor, electrical wiring and connection piping needed to complete the installation. This yields a total capital cost of $14,529.

Simple Payback:

= (Capital cost) / (Cost Savings)
= ($14,529) / $9,530 per year
= 1.5 years

ESO15 – HVAC: ASD Spray Pumps

Recommended Action

Install a variable frequency drive on each spray pump in the air washers. The variable speed drive will eliminate the need for throttling the water flow resulting in energy savings.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
363,000	0	0	$ -	$9,800	$36,400	3.7	$53,300	39.3%

Background

Each air washer has a pump to spray water onto the incoming air stream. The pumps use throttling valves to control the flow rate of the water sprayed. As the throttling valves close, the head on the pumps increase and the flow rate decreases. The intersection of the system head curve and the pump head curve at maximum speed determines the operating point of the pump. As the valve closes, this effectively moves the system curve to the left (see system curves A & B in Figure 5.15.1) resulting in higher head. If variable speed control were utilitized, the head developed by the pump would follow the system curve resulting in power, energy and cost savings.

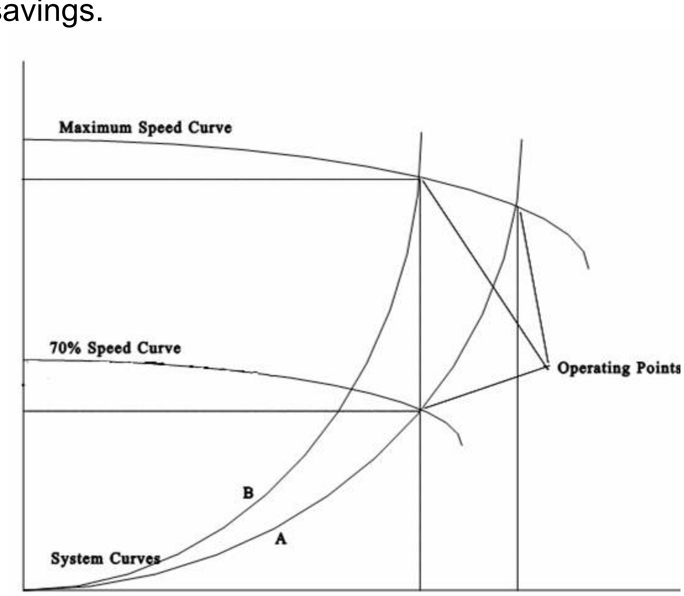

Figure 5.15.1 Example Head Flow Curve for Spray Tree Pump

Through the use of electronic variable speed drives (VSD's), the water flow rate would be controlled by adjusting the speed of the pump motors. The flow rate and the pump head is lowered when the speed of the motor is reduced. In fact, the pump head would follow the system head curve similar to the one shown in Figure 5.15.1. The power savings would be proportional to the difference in head developed with throttling verses speed reduction. Because full flow is needed when the ambient temperature is at or near its peak, there are no demand savings since the electrical demand peak occurs in conjunction with the summertime peak temperature.

A variable speed drive was installed on an air washer spray pump to see how much of a reduction in electrical energy a VFD could achieve. According to facility personnel, the load dropped from 32 amps to 25 amps when the discharge pressure was 20 psi. This pressure corresponds to the flow rate of cooling water needed durring the summer months. Furthermore, it was estimated by the plant engineer that the exit pressure could be dropped to 15 psi during times outside of the peak summer months causing the load to drop to 21 amps. Using these values, the total energy and cost savings for installing VSD on the spray pumps were calculated. These are shown in the following section.

Anticipated Savings

Data needed to estimate potential savings:

Current Draw, Throttled Discharge Flow	- 32 Amps
Current Draw, Variable Speed Drive Summer Months	- 25 Amps
Current Draw, Variable Speed Drive Non Summer Months	- 21 Amps
Estimated Non Summer Operating Hours	- 5,832 hrs/hr
Estimated Summer Operating Hours	- 2,928 hrs/hr
Pump Motor Voltage	- 480 V
Pump Motor Power Factor	- 86%
Electrical Energy Cost	- $0.027/kWh

Energy Savings:

= √3 x Voltage x Power Factor x [(Throttled Current Draw – VFD Current Draw Non Summer) x Non Summer Operating Hours + (Throttled Current Draw – VFD Current Draw Summer) x Summer Operating Hours] x Number of Pumps / 1,000 Watts/kW

= √3 x 480 V x 0.86 x [(32 Amps – 21 Amps) x 5,832 hrs/yr + (32 Amps – 25 Amps) x 2,928 hrs/yr] x 6 pumps / 1,000 Watts/kW

= 363,135 kWh/yr

Cost Savings:
= Energy Savings x Marginal Energy Cost
= 363,135 kWh/yr x $0.027/kWh
= $9,800/yr

Implementation Cost

A variable speed drive for a 40 horsepower pump was found to cost $5,160. It will take approximately 12 hours for an electrician to install a VFD.

Investment:
= Number of VFD x (Cost Per VFD + Time to Install x Labor Cost)
= 6 x ($5,160/VFD + 12 hrs/VFD x $75/hr)
= $36,360

Simple Payback:
= Investment / Annual Savings
= $36,360/ $9,800/yr
= 3.7 yrs

ESO16 – HVAC: Enthalpy Controls on Airwashers

Recommended Action

Install enthalpy controls on air washers 1 through 6 such that outdoor air is used whenever the internal energy of the outdoor air is lower than the internal energy of the return air.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
2,760,000	0	0	$ -	$74,500	$94,100	1.3	$587,000	390%

Background

There are eight air washers that provide cooling and humidity control for the facility. Due to the large amount of heat generated at the facility, these air washers operate all year. All of the air washers are equipped with outdoor dampers which allow outdoor air to be used whenever it is desirable. Of these eight air washers, only the last two, air washer 7 and 8, utilize the outdoor dampers. Air washers 1 through 6 do not have controls installed on the dampers. Therefore outdoor air is not used by these air washers whenever the outdoor air has less energy than the return air. Since the additional energy in the return air must be removed by the chiller, not using outdoor air under certain conditions causes an increase in electrical load on the chiller.

According to historical weather data, there are approximately 6,986 hours in a typical year when the outdoor air has less internal energy than the return air. During these times, outdoor air should be used by the air washers instead of return air from the facility. This will cause a reduction in electrical load on the chiller providing chilled water to the air washers. Furthermore, of the 6,986 hours there are approximately 5,437 hours when the outdoor air has less internal energy than the supply air provided to the facility by the air washers. In this case, using outdoor air would allow the chiller to turn off.

A plot showing the enthalpy of the return air, the supply air and the outdoor air at different external temperatures is shown in Figure 5.16.1. From this plot, one can see the large number of external conditions at which outdoor air can be used.

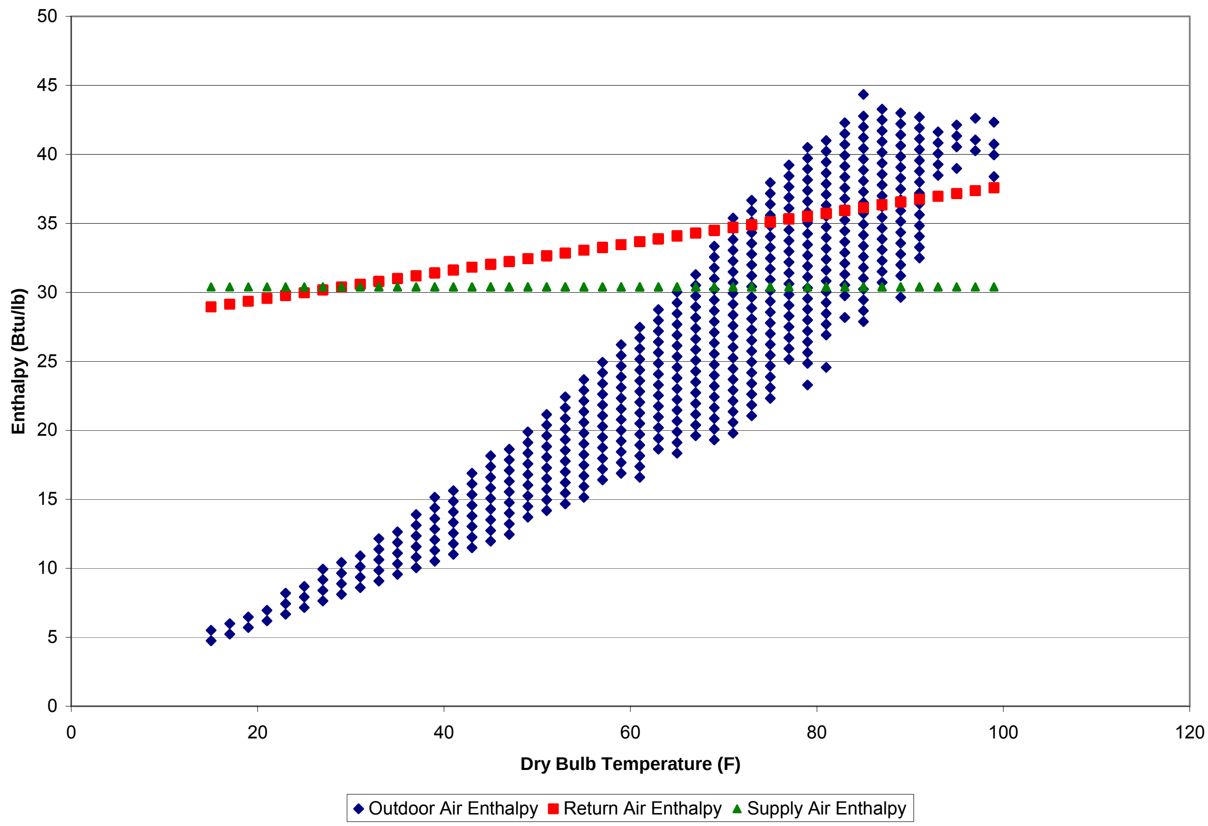

Figure 5.16.1. Outdoor, return, and supply air enthalpy at given external conditions.

It is assumed that the design temperature for the air washers is 95ºF. This is the external temperature at which all of the available cooling capacity from the chiller is used by the air washers. Therefore, at 95ºF, the chiller will draw the rated amps. A measurement of the current draw from the chiller was obtained during the site visit on December 8, 2005. From this measurement, the power draw of the chiller is calculated when the outdoor temperature is 48ºF.

An equation for the chiller power draw at a given external temperature is derived from these values. This equation is used to determine the balance temperature for the building as well as the current energy use of the chillers. The balance temperature is the external temperature at which the heat generated by the building is dissipated to the atmosphere by the building. Therefore, no cooling is needed by the building.

Using all of the information above as well as the supply air enthalpy and the chiller efficiency, the annual energy savings for using outdoor air is calculated. The details of the calculations are shown in the following section.

Anticipated Savings

Data needed to estimate potential savings:

Power Draw from Chiller When Outdoor T=95°F	- 1,061 kW
Current Draw from Chiller When Outdoor T=48°F	- 412 Amps
Chiller Voltage	- 478 Volts
Power Factor	- 0.89
Enthalpy of Supply Air	- 30.4 Btu/lb
Density of Supply Air	- 0.07407 lb/ft^3
Supply Air Flow Rate for Air Washers 1-4	- 99,000ft^3/min
Supply Air Flow Rate for Air Washers 5-6	- 155,000ft^3/min
Electrical Energy Cost	- $0.027/kWh
Electrical Demand Cost	- $10.38/kW

Power Draw at 48°F

= √3 x Voltage x Current x Power Factor / 1000 W/kW

= √3 x 478 V x 412 A x .89 / 1000 W/kW

= 304 kW

Slope of Equation for Chiller Power Draw Versus Outdoor Temperature

= (Power Draw at 95°F - Power Draw at 48°F) / (95°F - 48°F)

= (1,061 kW – 304 kW) / (95°F - 48°F)

= 16.1 kW/°F

Y Intercept of Equation for Chiller Power Draw Versus Outdoor Temperature

= Power Draw at 48°F – Slope of Equation x 48°F

= -470 kW

Balance Temperature:

= -Y Intercept of Equation / Slope of Equation

= 470 kW / 16.1 kW/°F

= 29°F

Using the formula that was derived, the balance temperature was found to be 29°F. Therefore, whenever the external temperature is below 29°F, the air washers are not performing any cooling. A plot of the equation is shown in Figure 5.16.2.

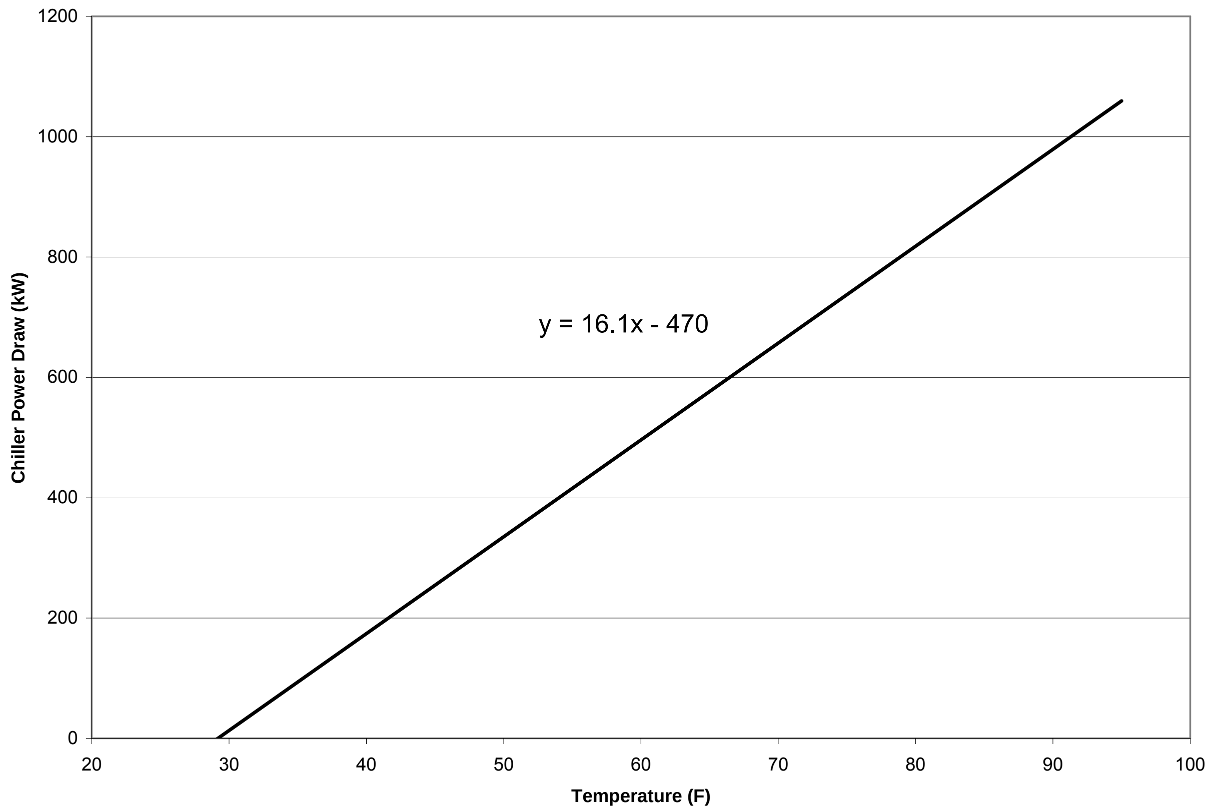

Figure 5.16.2 Plot of chiller power draw versus outdoor temperature

The excel table was used to calculate energy and cost savings for each external condition for this recommendation. This table was too large to include, but is available electronically upon request. Sample calculation for a case when the external air has less energy than the supply air, and a case when the outdoor air has less energy than the return air but more energy than the supply air is shown below to demonstrate how the savings were calculated.

Case 1: Outdoor Air Has Less Energy Than Supply Air:
Energy Savings:

= Chiller Power Draw at 53°F x Hours per Year at Given External Conditions
= 384 kW x 49 hrs/yr
= 18,826 kWh/yr
= (2,245,632 kWh for all External Conditions under Case 1)

Cost Savings:

= Energy Savings x Marginal Energy Cost
= 18,826 kWh/yr x $0.027/kWh
=$508/yr
= ($60,632/yr for all External Conditions under Case 1)

Case 2 : Outdoor Air Has Less Energy Than Return Air:
Return Air Enthalpy at Given External Temperature:

= [Chiller Power Draw at 67°F / (Density of Supply Air x Supply Air Flow Rate x Chiller Performance)] + Enthalpy of Supply Air

= [610 kW / (0.07407 lb/ft^3 x (99,000 ft^3/min x 4 + 155,000 ft^3/min x 2) x 60 min/hr x 1 ton / 12,000 Btu/hr x 0.6 kW/ton)] + 30.4 Btu/lb

= 34.3 Btu/lb

Energy Savings for Case When Outdoor Air Has Less Energy Than Return Air:

= (Return Air Enthalpy – Outdoor Air Enthalpy) x Density of Supply Air x Supply Air Flow Rate x Chiller Performance x Hours per Year

= (34.3 Btu/lb – 31.29 Btu/lb) x 0.07407 lb/ft^3 x (99,000 ft^3/min x 4 + 155,000 ft^3/min x 2) x 60 min/hr x 1 ton / 12,000 Btu/hr x 0.6 kW/ton x 15 hrs/yr

= 14,580 kWh/yr

= (512,146 kWh for all External Conditions under Case 2)

Cost Savings:

= Energy Savings x Marginal Energy Cost

= 14,580 kWh/yr x $0.027/kWh

= $394/yr

= ($13,828/yr for all External Conditions under Case 2)]

Implementation Cost

Since the actuators and dampers that were originally installed on the air washers have become dysfunctional over time, the implementation cost for this recommendation includes new dampers and actuators for all 6 air washers. Furthermore, STAEFA controls should be installed to operate the dampers based on the outdoor conditions. The controls should also be set up to exercise the dampers once a week to prevent them from rusting shut again. Cost data for the dampers, actuators, installation and controls was obtained from the facility personnel. Between the time the report was written and submitted to the facility, the facility has replaced all of the actuators and dampers on the air washers and has fixed the controls on air washers 5 and 6.

Investment:

= Dampers, Actuators, and Installation + STAEFA Controls

= $64,056 + $30,000

= $94,056

Simple Payback:

= Investment / Annual Savings

= $94,056 / $74,460/yr

= 1.3 yr

ESO17 – HVAC: Cover Entrance for AGV

Recommended Action

Install a plastic curtain or an automatic roll-up door in the AGV passageway between the warehouse and the main facility. This barrier will reduce the infiltration losses due to the opening.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
24,500	0	0	$ -	$663	$517	0.8	$5,540	NA

Background

An AGV is used to transport material from the warehouse area to the main production area. It travels through an opening in the wall between the two spaces. Currently the opening is not covered when the AGV is not in use. Since the air in the main production area is conditioned whereas the air in the warehouse is not, infiltration of unconditioned air from the warehouse area is constantly introduced into the main production area through the opening. This unconditioned air adds an additional cooling load to the air washers.

During the site visit, air flow measurements through the passageway were obtained using a velometer. With this information, as well as the external temperature conditions, the savings for installing a barrier to reduce the infiltration losses was calculated. It is assumed that the conditioned space is maintained at 72ºF during the year.

Anticipated Savings

The following information is needed to calculate the savings:

Main Production Area Temperature	- 72ºF
Average Air Velocity Through Opening	- 450 ft/min
Width of Opening	- 7.5 ft
Height of Opening	- 7.25 ft
Specific Heat of Air	- 0.24 Btu/lb-ºF
Density of Air	- 0.072 lb/ft^3
Chiller Performance	- 0.6 kW/ton
Electrical Energy Cost	- $0.027/kWh

% Reduction in Air Flow, Plastic Curtain - 90%

Since the warehouse is not conditioned, it is assumed that the air temperature in the warehouse is similar to the outdoor temperature. Typical weather data for Aiken was used to calculate the savings for this recommendation over the course of a year. A sample calculation for a given external temperature is shown to demonstrate how the savings were calculated.

Heat Gain Through Infiltration When Outdoor Temperature = 81ºF:

= Density of Air x Air Velocity Through Opening x Width of Opening x Height of Opening x Specific Heat of Air x (Warehouse Temperature – Production Temperature)

= 0.072 lb/ft^3 x 450 ft/min x 7.5 ft x 7.25 ft x 0.24 Btu/lb-ºF x (81ºF - 72ºF) x 60 min/hr

= 228,323 Btu/hr

Heat Gain Reduction Using a Plastic Curtain:

= Heat Gain x % Reduction Using a Plastic Curtain

= 228,323 Btu/hr x 90%

= 205,491 Btu/hr

Energy Savings:

= Heat Gain Reduction x Chiller Performance x Annual Hours When Outdoor Temperature is 90ºF

= (205,491 Btu/hr / 12,000 Btu/hr-ton) x 0.6 kW/ton x 240 hrs/yr

= 2,466 kWh/yr

(24,545 kWh/yr for all temperature bins)

Energy Cost Savings:

= Energy Savings x Marginal Energy Cost

= 2,466 kWh/yr x $0.027/kWh

= $67/yr

($663 for all temperature bins)

Outdoor Temperature (F)	Hours Per Year (hrs/yr)	Heat Gain Through Infiltration (Btu/hr)	Heat Gain Reduction (Btu/hr)	Energy Savings (kWh)	Energy Cost Savings ($)
99	5	684,968	616,472	154	$4
97	6	634,230	570,807	171	$5
95	9	583,492	525,142	236	$7
93	23	532,753	479,478	551	$15
91	147	482,015	433,813	3,189	$89
89	147	431,276	388,149	2,853	$80
87	197	380,538	342,484	3,373	$94
85	219	329,800	296,820	3,250	$91
83	251	279,061	251,155	3,152	$88
81	240	228,323	205,491	2,466	$69
79	265	177,584	159,826	2,118	$59
77	205	126,846	114,161	1,170	$33
75	334	76,108	68,497	1,144	$32
73	628	25,369	22,832	717	$20

Implementation Cost

A 8 ft x 8 ft plastic curtain door costs $337.25 on Grainger. It is assumed it takes 4 hours to install the curtain.

Investment:

= Cost of Plastic Curtain + (Labor Cost x Time to Install)
= $337.25 + ($45/hr x 4 hrs)
= $517

Simple Payback:

= Investment / Annual Savings
= $517 / $663/yr
= 0.8 yrs

ESO18 – Lighting: Retrofit in warehouse w/ Occupancy Sensor

Recommended Action

Install 6-lamp T5 fixtures in the warehouse. These fixtures should come with occupancy sensors installed.

Electric Energy (kWh)	Electric Demand (kW)	Natural Gas (MMBtu)	Other Savings ($)	Cost Savings ($/year)	Imp. Cost ($)	Simple Payback (years)	Net Present Value (NPV)	Internal Rate of Return (IRR)
422,000	15.0	0	$ -	$13,300	$35,200	2.7	$86,100	63.7%

Background

Light energy consumption can be reduced by almost 40% in the warehouse with the use of energy-efficient lamps and electronic ballasts. Six lamp T5 High Output fixtures are recommended for installation in these areas. These fixtures come with occupancy sensors installed resulting in better savings.

These fixtures are designed specifically for industrial applications where light control and an instant start are required. When the area is unoccupied, only 2 of the 6 lamps in the fixture stay on while the others go off. All the lamps turn on instantly as soon as any motion is detected. The calculations for energy and cost savings are summarized in the following sections.

Anticipated Savings

The following information is needed to calculate the savings for this recommendation. Installing 190 6 lamp T-5 fixtures should be enough to replace the light that is currently provided by the 200 Watt Metal Halide fixtures. Also, it was estimated that these areas were unoccupied for 70% of the time.

Number of 200 Watt Fixtures	- 384
Proposed Number of 6 x 4’ T-5 Replacement Fixtures	- 192
Connected Load of 200 Watt Fixture	- 0.219 kW
Connected Load of 4' Fixture (6 T-5 Lamps on, Elec Balast)	- 0.351 kW
Connected Load of 4' Fixture (2 T-5 Lamps on, Elec Balast)	- 0.117 kW
Hours of Operation	- 8,760 hrs/yr
Electrical Energy Cost	- $0.0342/kWh
Electrical Demand Cost	- $15.20/kW

Demand Savings:

= (Number of Fixtures x Connected Load with Original Fixture) – (Number of Fixtures x Connected Load with New Fixture)

= (384 Fixtures x 0.219 kW/Fixture) – (192 Fixtures x 0.351 kW/Fixture)

= 16.7 kW

Energy Savings (Space Occupied):

= Demand Savings x Operating Hours x Percent Time Occupied

= 16.7 kW x 8,760 hrs/yr x 0.3

= 43,898 kWh/yr

Energy Savings (Space Unoccupied):

= (Number of Fixtures x Connected Load with Original Fixture) – (Number of Fixtures x Connected Load with New Fixture and 4 Lights off) x Operating Hours x Percent Time Unoccupied

= (384 Fixtures x 0.219 kW/Fixture) – (192 Fixtures x 0.117 kW/Fixture) x 8,760 hrs/yr x 0.7

= 377,927 kWh/yr

Cost Savings:

= (Energy Saved Space Occupied + Energy Saved Space Unoccupied) x Energy Cost + (Demand Savings x Demand Cost)

= (43,898 kWh/yr + 377,927 kWh/yr) x $0.027/kWh + (15 kW x $10.38/kW x 12 mths)

= $13,260/yr

The cost savings can be reduced further if all 6 lamps are turned off by the occupancy sensor for as many fixtures as possible.

Implementation Cost

One 6 lamp T5 fixture with occupancy sensors installed costs approximately $185.00. This includes installation cost if the fixtures are purchased in bulk.

Investment:

= Number of Fixtures x Cost per Fixture

= 190 x $185.00

= $35,150

Simple Payback:

= Investment / Savings

= $35,150/ $13,260/yr

= 2.7 years

6. ESO's WITH UNFAVORABLE ECONOMICS

Compressed Air: Reverse Aftercooler

During the first facility visit, it was noted that the flow of the cooling water through the aftercoolers is in parallel with the compressed air. The hottest air and the coolest water entered at the same ends of the heat exchangers. If the flows of the cooling water are reversed such that the coolest water enters on the opposite side of the heat exchanger from the hottest air, a reduction in air temperature leaving the aftercoolers would occur. Assuming the refrigerated air dryers are cycling dryers, the reduction in temperature would result in electrical energy savings.

There are two types of refrigerated dryers that are used to remove moisture from compressed air systems, cycling and non-cycling. The difference between the two types of dryers is how the dewpoint temperature is controlled in the dryer. The cycling dryer cycles the compressor motor to match the cooling demand. On the other hand, the non-cycling dryer uses the thermostatic expansion valve and the hot bypass valve to modulate the refrigerant flow. In the non-cycling dryer, the compressor motor is fully loaded at all times no mater how much cooling load is needed by the dryer.

If the facility had cycling dryers, energy saving would result in lowering the air temperature going into the dryers. The cooling load would decrease in the chillers, causing a reduction in compressor load due to the reduction in refrigerant needed. However, the air dryers located at the facility are non-cycling dryers. When the cooling load is reduced, the hot air bypass valve is gradually opened causing some of the refrigerant to bypass the condenser and enter the evaporator. Less heat would be rejected by the condenser, but the load on the compressor motor would not change. Therefore, as long as the inlet temperature of the compressed air to the air dryers is below the maximum operating range, there are no energy or cost savings for reducing the temperature of the compressed air.

Combined Heat and Power and Distributed Generation

Options that include combined heat and power (CHP) and distributed generation (DG) were considered in this study. CHP possibilities considered were to generate power on site, and to use the waste heat to generate steam for the plant use. The possibility of having DG onsite was also considered. These options are vary comparable, except the DG option does not allow for the recovery of waste heat, and therefore this system requires a lower capital cost.

The economics for both CHP and DG options turned out to be unfavorable, and therefore were not included as recommendations in this report. The evaluation of CHP yielded a simple payback in excess of 20 years. The evaluation of a DG resulted in an annual loss.

The unfavorable economics of these options is the result of the energy prices that this plant is subject too. Sometimes referred to as the "spark spread", the difference between the cost of electricity and natural gas needed to generate the equivalent amount of electricity is unfavorable. In other words, electricity is priced too low when compared to natural gas to make these recommendations favorable. This is a challenge normally seen in the south east, and is a function of the large amount of electricity generated from both coal and nuclear generation. The economics of both CHP and DG can be more favorable in this region if alternative fuels, i.e. not natural gas, are available at a facility. Normally these alternate fuels are byproducts of production.

Install Backpressure Turbine to Reduce Steam Pressure at Heatset

The plant boilers operate at 165 psig while the steam pressure required by the Superbas is only approximately 29 psig. Currently, steam pressure from the header is reduced through a throttling valve at heat set. An alternative approach to reduce the steam pressure prior to entering the Superba would use a steam turbine. A properly sized steam turbine would provide the necessary reduction in pressure while simultaneously generating electricity or shaft power.

The evaluation of this ESO turned out to be unfavorable because of the high initial capital cost of such a project. The initial capital cost was high, because the range of turbine generator considered, about 50 kW to 70kW, was small relative to what is typically available. In addition, because of this small size of this potential system, the benefits of scale that may be available in a larger system are not present.

It was determined that this system would cost around $150,000 to $200,000 for a steam turbine with synchronous generator installed. In addition to this capital cost, there would also be annual maintenance cost. This cost would likely be around $10,000 per year. The actual savings determine for this project was approximately $25,000 per year, or $15,000 after the maintenance cost is deducted. This would yield a simple payback in excess of 10 years at a minimum. Therefore, it was determined that this project to be economically unfeasible.

Isolate Heat Set Area with Curtains

Because heat set is a thermal process and the area is hot, the idea of using plastic strip curtains or some other suitable means of isolation was examined. The area surrounding heat set is conditioned, thus keeping the heat lost during the heat set process out of the adjacent cooled space will save energy by reducing the cooling load.

While there is some merit to this idea, the implementation is not simple. To isolate the area, strip curtains must be hung from the ceiling. However to maintain material flow to the area and provide some comfort to employees, the curtains can not extend to the floor. The concept considered had the curtains ending at the 8 foot level above the floor.

Preliminary calculations showed a small amount of savings, but the difficulty of isolating the area resulted in the idea being rejected.

Use Nitrogen Evaporation for Useful Cooling

Currently, as is typically done at most industrial plants, the liquid nitrogen is evaporated across a heat exchanger to create the nitrogen gas needed by the plant. While this is the norm, is does waste potential useful cooling available in the nitrogen liquid to has phase change. The value of this unused cooling was considered in this study.

It was determined that the value of this unused cooling of the nitrogen evaporation is approximately equivalent to 14 tons of cooling. This is comparable annual dollar amount of $4,000. While this savings is not insignificant, this option was not recommended because of capital cost.

The capital cost was expected to be high for two reasons. First, because there is no cooling needs immediately near the current nitrogen receiver tank, significant piping would be required to implement project, or the current nitrogen receiver station would have to be moved. Secondly, because of the low temperatures of evaporating nitrogen, designing a cooling system that can make use of this cooling while avoiding undesired freezing in the system would require complicated controls and equipment. For these two reasons, it was believed that the capital cost for any such project would require implementation cost well above the anticipated savings.

Recover Condensate from Heat Set

Another idea that appeared to have merit was the recovery of condensate from the heat set area. Presently, the condensate from all the steam used in heat set is lost. Some is used to bulk the yarn and is not recoverable, but some that is used for heating could be reclaimed.

Because condensate from the heat set steam traps mixes with contaminated water in the drain pipe, the condensate cannot be separated from contaminated water and cannot be returned to the boiler. However if the condensate retains some heat, it could be piped into a heat exchanger and used to heat makeup water.

To estimate the energy savings potential, measurements of wastewater flow and temperature were made in the heat set drain pipe. The measured flow rate was 24 gallons per hour and the temperature was 84°F. Due to the low flowrate and low temperature, heat recovery from this condensate was deemed unfeasible.

Belt Drives

A potential recommendation was to replace the v-belts on the twisters with cogged or HTD belts to improve drive efficiency. When a twister was opened and inspected, it was discovered that the twister was already equipped with a flat belt drive. Flat belts have a high contact force with the drive and driven shafts so there is effectively no belt slippage. Furthermore, their rectangular cross section makes then easier to bend than V-belts so flexing losses are low. Because efficient flat belts are used to transmit power on the twisters, there is no incentive to install cogged V-belts on these machines.

Shutoff Second Boiler

Although the load on the primary boiler is only approximately 60 percent, the secondary boiler is maintained on hot standby. The stated reason is to prevent product quality problems should the primary boiler have an outage. Although the boiler is necessary to properly operate heat set, keeping a backup boiler heated seems like an expensive solution to the problem.

As an alternative solution, other methods of keeping a standby boiler at operating temperature were studied. Unfortunately no alternative heating method was found that saved any energy. The only loss for a boiler on hot standby is the convective heat transfer loss from the exposed surfaces. Our energy balance indicated that the standby losses were less than 2 percent of the rated boiler capacity. While there are some losses from the standby boiler, it is a loss that must be tolerated because there is no more efficient alternative method of keeping the boiler hot.

Install VFD on Twister Motors

The plant has a total of 59 twisters each driven by two 60 hp AC motors. In numerous AC motor applications, most frequently pumps and fans, adding speed control to a constant speed motor will yield significant energy savings. Because yarn twisters are often required to change speed in order to vary the characteristics of the yarn, adding variable speed control to the existing constant speed motor was analyzed for energy savings.

Tests on a twister with a variable frequency drive (VFD) controller were conducted to quantify the energy savings potential for such a conversion. The tests were made at Shaw Plant WL in Valdosta. In normal constant speed operation, the driven pulley is changed to provide the output shaft speed needed to generate the specified yarn twist. Every time the twister speed is changed, the machine must be stopped, the drive belt loosened and removed, the driven pulley changed, the pulley reinstalled and tightened and the motor restarted. The process requires a commitment of maintenance labor and a loss of production when the twister is shutdown.

For the VFD test, a drive pulley capable of supplying the maximum twist required at a reduced motor speed was selected. With this pulley in place, if less twist is required the motor can be slowed further using the VFD controller. In this arrangement, the machine does not have to be stopped to change yarn twist ratio.

Measurements of twister motor power input were made at several speeds while keeping the output shaft speed constant. The test revealed that the twister motor has an optimum speed that yields the lowest power input. If the twister is operated at the speed that consumes the least amount of power, energy savings of approximately 7 percent were found. The estimated energy cost savings is around $2,400 per year. With a required investment of $15,000 to install VFD controllers on both twister motors, the simple payback on energy savings is over 6 years.

As stated earlier, VFDs generate savings through productivity increases and maintenance cost savings by simplifying changes in yarn twist ratio. The savings from eliminating twister shutdown to change yarn twist depend on the frequency of changes, the value of production, changeover time and labor costs. If changes in yarn twist occur frequently, for example every 2 weeks or less, the productivity savings will exceed the energy savings.

Because the twisters at Plant #78 do not change yarn twist ratio very often, converting the twisters to VFD is not recommended. However if production changes and different yarn twists are frequently rum, VFD control might become feasible. The analysis of energy and productivity savings for VFD control on twisters is presented in Appendix D.

Convert Dowtherm Heaters in Poly-tower and Extrusion to Natural Gas

Dowtherm heat transfer fluid is used in the poly-tower and extrusion processes to supply heat at temperatures in excess of those provided by steam. There are ten heat transfer fluid (HTF) heaters in the poly-tower and seventeen HTF heaters in extrusion, and all of them are fired with electricity. Because electricity is more expensive per Btu than natural gas, generally it reduces energy cost to convert heaters, boilers and vaporizers although no real energy is saved. The lower cost of natural gas is sufficient to counteract losses in thermal efficiency when changing from electricity.

Because converting to natural gas requires a much more complex heater than is required with electricity, there will always be some significant investment in equipment to accomplish the conversion. A gas boiler has a burner, stack, combustion air fan, fuel and air controls and substantial safety equipment which are not present on electric boilers. To reduce the cost of the conversion at Plant #78, one large natural gas heater is used to replace the seventeen small electric heaters in extrusion. This requires the Inclusion of THF supply and return manifold piping and a pump to circulate the fluid. Similarly in the poly-tower, separate heaters with similar THF outlet conditions were combined. Eight electric heaters in the poly-tower can be replaced with just two gas-fired heaters. The remaining two heaters have such a low load that replacement was not considered.

The feasibility of converting from electricity to natural gas as a fuel source for boilers and heaters is dependent exclusively on the differential energy cost per Btu between the two fuels. In most instances, the cost for electricity is sufficiently greater than natural gas to cover the cost of equipment changes needed. However at the present time, constraints in natural gas supply have elevated its cost while the price of electricity has remained stable. Therefore, the change from electricity to natural gas for the Dowtherm heaters in the poly-tower and extrusion is not justified at the present time. As energy prices change, it might be worth considering at some future time.

The complete analysis of changing the Dowtherm heater fuel from electricity to natural gas is included in Appendix D.

7. PLANT INFORMATION

The plant-wide assessment was prepared for Shaw Plant #78 located in Aiken, SC. The Aiken plant is one of the corporation's five fiber extrusion plants. Plant #78 has annual energy costs of approximately $7 million. The energy cost is divided between electricity which constitutes 80 percent of the total and natural gas the remaining 20 percent.

Plant #78 is an integrated yarn preparation plant that includes nylon formation, extrusion of filament, yarn twisting and heat set. The facility was initially constructed in 1994 by Beaulieu Carpets. The facility was expanded in 1996 when a second polymer formation line was added. The facility contains 480,000 square feet with 240,000 square feet devoted to warehouse space. Employment at this location is approximately 600 on staff.

Due to the continuous nature of the polymer formation process, the plant operates continuously 24 hours per day, 7 days per week.

Process Description

The plant consists of four main process operations: polymer formation, filament extrusion, yarn twisting and heat setting. Polymer formation, the creation of nylon 6, is conducted in the two polymer towers. The raw material for this process is caprolactum. Raw caprolactum monomer is feed into the top of the reactor and mixed with de-ionized water. By controlling temperature and residence time, a reaction that converts caprolactum monomer to nylon 6 polymer is allowed to occur. Acetic acid is added to the reactor to terminate the polymer chain reaction.

Following the polymer formation reaction, the reactant solids are washed with water and centrifuged. Washing recovers unreacted caprolactum. The nylon 6 exiting the reactor is dried with nitrogen gas and ground into chips for processing. Production of nylon from the two polymerization units is approximately XX million pounds per week.

The next step in the process is extrusion where nylon chips are converted into fiber filament. The plant operates 18 extruders, 17 large 165 kW and 1 small 90 kW units. In the extruder, the nylon chips are heated by a combination of shear force from the screw and thermal energy from the electrical resistance elements in the barrel. Melted nylon polymer is forced through the small holes in a spinnerette head to yield a filament of the desired thickness or linear density.

The finished filament is cooled using a closed loop air wash system to solidify the fiber. The final step in extrusion is drawing. In the draw box, fiber is pulled over heated rollers and textured with compressed air. Also known as crimping or bulking, texturizing imparts texture/fullness to the fiber or yarn during production. Bulking is done to increase the coverage and bloom the fiber will have in the finished carpet face as well as adding to the resiliency ("spring back") of the fiber. Texturizing is the largest application of compressed air in the process.

The next step in the process is twisting where individual nylon filaments are combined to yield carpet yarn. The plant has a total of 59 Volkman twisters. Each twister has 2-60 hp drive motors that operate a total of 160 spindle positions. In addition to twisting individual filaments together, the twister inserts a specified twist ratio to the yarn.

The final step in yarn formation conducted at this plant is heat setting. Heat setting is performed to permanently set twist and texture in the yarn. The plant has 16 Superba heat set machines. Direct application of low pressure steam is applied to the yarn for bulking. Steam supplied to a heat exchanger is used to provide dry heat to the yarn. Yarn exiting heat set is wound onto spools on a winder.

Because Plant #78 does not have sufficient twisting and extruder capacity to process all of the nylon produced, excess polymer is shipped to other plants. The through-put of each of the processes is presented in Table 7.1.

Table 7.1. Plant #78 Process Through-Put.

Process	Output (lb/wk)
Polymerization	Removed
Extrusion	for public
Twisting	distribution.
Heat-Set	

Process Support Equipment

To operate the manufacturing process, Plant #78 is equipped with a large in-house utility system to provide the necessary heating, cooling and compressed air. The most energy intensive process support system is compressed air. The plant has 3-1750 hp and 1-1000 hp Ingersol-Rand centrifugal compressors that supply approximately 12,500 cfm to the plant. Compressed air is used in each of the four processing steps, but texturizing and entangling in extrusion are the largest users. Plant air pressure is set at 145 psig.

Steam is used in polymerization and heat setting. The plant has 2-600 hp Burnham firetube boilers that supply process steam. The steam pressure is 165 psig. Only one boiler is used at any one time with the second boiler running low-fire as hot standby. The lead boiler is alternated weekly.

The plant is equipped with five Trane centrifugal chillers. There are 3 CVHF-1280 units with a rated capacity of 1280 tons, 1 CVHF 770 with a capacity of 770 tons and 1 CVHF 1150 with a rated capacity of 1150 tons for a plant total of 5760 tons. The units use HCFC-123 refrigerant. The chillers supply chilled water to air washers for plant cooling and for process cooling. The allocation of chillers to different applications is present in Table 7.2.

Table 7.2. Chiller Applications.

Chiller Number	Size (tons)	Application
1	1280	Process cooling
2	1280	Air washer 1-6
3	1280	Process cooling
4	770	Swaps with #3 when demand is low
5	1150	Air washer 7-8

Chilled water is used for plant cooling by means of eight air washers. Air washers 5 and 6 have been renovated and the dampers, actuators and economizer controls repaired and restored. Air washers 1-4 have had their outside air dampers and actuators repaired but new controls have not been completed. Air washers 7 and 8 are the newest units and have not had any upgrades to their economizers.

The three process chillers, #1, #3, and #4, are on a closed loop system where chilled water from different chillers is not mixed. Chillers #2 and #5 are on an open loop chilled water system where the air washers dump their discharge water into a common sump that the chillers draw from. The air washer ratings are presented in Table 7.3.

Table 7.3. Air Washer Capacities.

Air Washer Number	Supply Air Fan (HP)	Total Rated Flow (cfm)
1-4	1-75	99,000
5-6	2-100	155,000
7-8	3-75	330,600

The plant has 6 cooling towers, one for each chiller and one for all the air compressors.

Major Plant Equipment

Removed for public distribution. Equipment related to energy conservation recommendations is described in each energy saving opportunity.

8. APPENDIX

Appendix A – Supplemental Energy Rate Structure Information

Electricity Costs

Electricity charges are primarily based upon two components: (1) Electrical Energy (measured in kWh) which is the quantity of electricity used by a customer and (2) Electrical Demand (measured in kW) which is the peak usage of a customer. These two components are used to determine electrical charges because they account for two components of the service that the utility is providing to its customers. Charges for electrical energy cost represents the cost associated with delivering incremental quantity of electricity. Electrical demand charges are often less understood. This charge is reflective of the utilities need to have and maintain the infrastructure necessary to not only deliver electricity to its customer most of the year, but also to deliver a customer electricity during peak system conditions. Although these peak system conditions may only occur for a small number of days during a year, typically during the hottest days of the summer season, the system must be designed and maintained to accommodate these infrequent peak conditions. The net result to the utility customer is that these two components equate to nearly a 50/50 split for demand/energy charges on the electricity bill. This split varies depending on a customer's electricity usage profile.

To add complexity of understanding electricity costs, the energy and demand components are not always obvious on utility invoices or in the rate structures. However, these components must always be in the utility's rate structure if the resulting charges are to send price appropriate signals to the customer that reflects the utility's true costs. These price signals can be built into rate structures in various ways in different rate structures. Some of these various rate structures may include:

- Flat energy and demand charge rates ($/kWh and $/kW, respectively)
- Energy charges that vary depending on the season and time of day ($/kWh - TOU and RTP)
- Energy charges that vary depending on the customer's pattern of use ($/kWh - HUD)

To aid in explaining how bills are calculated by the utility for this facility, a sample bill for December 2004 is shown in Figure 8.1. As shown in the first circled section of the bill, the coincident system peak demand occurred during the hour ending at 8AM on 12/20/06. At this point in time, this facility had a coincident peak (CP) demand of 14,678 kW. Note that this CP demand is different from the facilities actual peak demand. This is because the facility's peak demand did not occur at the same time the electrical system wide peak occurred. The CP demand, the billing demand for this rate structure, is used to calculate the demand cost. The energy portion of the bill, or the charge based on the kWh's consumed, is a simple flat rate calculation based on total consumption.

1428 Shaw Industries
Rate Schedule - IL4

Aiken Electric Cooperative, Inc.
January 2004 Wholesale Power Bill
Rundate: 02FEB04:11:38 Pgm = BLP50

Combined System Peak: Wednesday, Jan 21, 2004 Hour Ending 7

SUBSTATION BILLING DETERMINANTS

	Metered		Transformation Losses		Delivered
Energy	10,719,132	+	50,764	=	10,769,896 kWh
CP Demand	14,608	+	70	=	14,678 kW
CP Reactive					4,205 kVAr
CP Power Factor (14608 / Sqrt(14608^2 + 4205^2)) =					96.10 % Lagging
Substation Peak 30 Minute Demand					15,753 kW
Contract Demand (Based on NCP)					17,910 kW
Minimum Billing Demand @50% of Contract Demand				=	8,955 kW
Billing kW Based on Contribution to System Peak					14,678 kW

WHOLESALE BILLING CHARGES

Demand Charges	kW	$/kW		Charges	Avg Cost mills/kWh
Total Billing Demand	14,678				
Base Demand	14,678	x 11.250	=	$165,127.50	
Demand Adjuster	14,678	x -1.364	=	-20,020.79	
Energy Charges	**kWh**	**mills/kWh**			
Total Billing Energy	10,769,896				
Base Energy	10,769,896	x 21.900	=	235,860.72	
Wholesale Power Cost Adjustments					
Current Energy	10,769,896	x 1.822	=	19,622.75	
Previous Energy	10,814,362	x 0.645	=	6,975.27	
Station Charge			=	350.00	
Total Base Wholesale Power Billing Charges				407,915.45	37.876

WHOLESALE SUPPLY SYSTEM ADJUSTMENTS

TOTAL WHOLESALE POWER CHARGES $407,915.45 37.876

Notes:
Previous Month: 14,388 kW 10,814,362 kWh $391,969.65 36.245

Figure 8.1. Page two of January 2004 electrical bill.

Natural Gas Costs

There are three, primary components to natural gas costs:

Commodity Cost - Sometimes called the “molecule cost.” It is the cost of the natural gas purchased from the commodity supplier, which may be a local utility or other third party.

Transportation Cost - Represents the cost of pumping, line losses, and handling to move the natural gas from the wellhead to the local city gate or reception point.

LDC Cost - The local distribution cost. Represents the cost for the local utility to deliver gas to your facility, read the meter, and upkeep their pipeline.

Appendix B – DOE Plant Wide Assessment Summary Form Table

Summary Table: Projects Identified During the Plant-wide Energy Assessment

		Annual Projected Economic Impact						
Project Planned to be Implemented?	Project Title/Number	Fuel (10^6 Btu) (e.g. gas, oil, coal)	Electricity (kWh)	Emissions CO2	Annual Savings ($)	%savings from energy reduction	Capital Cost ($)	Payback Period (yr)
	ESO1	-	-		$ 43,200	0.6%	$ 256,470	5.94
	ESO2	-	400,680		$ 16,760	0.2%	$ 7,280	0.43
	ESO3	-	426,720		$ 17,529	0.3%	$ 1,280	0.07
	ESO4	(144)	153,800		$ 9,694	0.1%	$ 32,550	3.36
	ESO5	-	146,000		$ 6,022	0.1%	$ 63,000	10.46
	ESO6	7,230	-		$ 101,472	1.5%	$ 10,100	0.10
	ESO7	856	-		$ 11,877	0.2%	$ 2,250	0.19
	ESO8	3,490	-		$ 25,914	0.4%	$ -	0.00
	ESO9	12,121	-		$ 92,362	1.3%	$ 9,915	0.11
	ESO10	-	4,546,400		$ 187,399	2.7%	$ 25,000	0.13
	ESO11	-	2,041,000		$ 113,152	1.6%	$ 39,850	0.35
	ESO12	-	2,483,500		$ 102,367	1.5%	$ 51,400	0.50
	ESO13	-	4,537,680		$ 187,039	2.7%	$ 20,000	0.11
	ESO14	-	231,300		$ 9,533	0.1%	$ 14,529	1.52
	ESO15	-	363,135		$ 9,805	0.1%	$ 36,360	3.71
	ESO16	-	2,757,779		$ 74,460	1.1%	$ 94,056	1.26
	ESO17	-	24,545		$ 663	0.0%	$ 517	0.78
	ESO18	-	421,825		$ 13,258	0.2%	$ 35,150	2.65

Appendix C – Performance Scorecard Survey

Removed for public distribution.

Appendix D – Supplemental Analysis of Two Rejected ESO Measures

<u>1. Convert Dowtherm Heaters in Poly-tower and Extrusion to Natural Gas</u>

Background

The hot Dowtherm produced by the 17-45 kW oil heaters in extrusion and 10 Dowtherm heaters in polymerization could be generated more economically by gas-fired oil heaters. Replacing the electric heaters will lower the electricity demand, usage, and overall energy costs. Although the electric heaters are more efficient on a Btu basis, the fuel cost is much more expensive because electricity costs more than natural gas. Because the hot oil boilers located at Polymerization E07 have an extremely low load factor, their replacement does not yield sufficient savings to justify replacement. Replacing the remaining, 21 electric hot oil heaters and 4 oil vaporizers in the plant with 3 large capacity natural gas heaters will reduce plant energy costs by $91,365.

The existing hot oil heaters process location, oil output conditions and electrical input are presented in Table 1 below.

Table 8.D.1. Plant Hot Oil Heater Inventory.

Heater Location	No. of Units	Rated Input (kW)	Hot Oil Output	Average Heater Load
Extrusion	17	45	240°C liquid	28%
Polymerization (E03)	2	525	280°C, vapor	70%
Polymerization (E04)	2	59.1	265°C, vapor	60%
Polymerization (E05)	2	33	240°C, liquid	90%
Polymerization (E06)	2	33	240°C, liquid	50%
Polymerization (E07)	2	87.6	260°C, liquid	1%

Anticipated Savings

The following data is used to calculate the savings for this measure.

Electric Heater Capacity	- Table 8.D.1
Electric Heater Load	- Table 8.D.1
Operating Hours	- 8,760 hr/yr
Natural Gas Heater Efficiency	- 80%
Electric boiler Efficiency	- 98%
Electrical Cost ($/kWh)	- $0.027
Demand Cost ($/kW)	- $10.38
Demand Factor (mo/yr)	- 12
Gas Cost ($/MMBtu)	- $7.62

Savings calculation for hot oil heaters in extrusion:

Electrical Demand:

kW = (No. Heaters x Rated Capacity x Average Load Factor)
= (17 Heaters x 45 kW x 0.28)
= 214.2 kW

Electrical Energy Consumption:

kWh = Oil Heater Demand x Annual Operating Hours
= 214.2 kW x 8,760 hr/yr
= 1,876,400 kWh/yr

Hot Oil Heater Operating Cost:

$$ = [(Heater Demand x Demand Cost x Demand Factor) + (Heater Consumption x Electric Cost)] x (1 + Sales Tax Rate)
= [(214.2 kW x $10.38/kW-mo x 12 mo/yr) + (1,876,400 kWh/yr x $0.027/kWh)]
= $77,340

Natural Gas Heater Input:

Btu = (Electrical Demand x Btu Conversion x Elect. Heater Eff.)/ Gas Heater Efficiency
= (214.2 kW x 3,412 Btu/kWh x .98)/0.80
= 895,300 Btu/hr

Annual Gas Usage:

Btu = Hourly Usage x Annual Operating Hours
= 0.8953 MMBtu/hr x 8,760 hr/yr
= 7,843 MMBtu/yr

Annual Gas Cost

$$ = 7,843 MMBtu/yr x $7.62/MMBtu
= $59,760/yr

Operating Cost Savings:

$ Saved = Electric Heater Cost – Gas Heater Cost
= $77,340 – $59,760
= $17,580/yr

Savings calculation for hot oil vaporizers at poly-tower:

Electrical Demand:

kW = (No. Heaters x Rated Capacity x Average Load Factor)
= (2 Heaters x 525 kW x 0.7) + (2 Heaters x 59 kW x 0.6)
= 805.8 kW

Electrical Energy Consumption:

kWh = Oil Heater Demand x Annual Operating Hours
= 805.8 kW x 8,760 hr/yr
= 7,058,800 kWh/yr

Hot Oil Vaporizer Operating Cost:

$$ = [(Heater Demand x Demand Cost x Demand Factor) + (Heater Consumption x Electric Cost)]
= [(805.8 kW x $10.38/kW-mo x 12 mo/yr) + (7,058,800 kWh/yr x $0.027/kWh)]
= $291,000

Natural Gas Heater Input:

Btu = (Electrical Demand x Btu Conversion x Elect. Heater Eff.)/Gas Heater Efficiency
= (805.8 kW x 3,412 Btu/kWh x 0.98)/0.80
= 3,368,000 Btu/hr

Annual Gas Usage:

Btu = Hourly Usage x Annual Operating Hours
= 3.368 MMBtu/hr x 8,760 hr/yr
= 29,500 MMBtu/yr

Annual Gas Cost

$$ = 29,500 MMBtu/yr x $7.62/MMBtu
= $224,800/yr

Operating Cost Savings:

\$ Saved	=	Electric Heater Cost – Gas Heater Cost
	=	\$291,000 – \$224,800
	=	\$66,200/yr

The estimated savings for converting all the oil heaters and vaporizers to natural gas is \$91,365. Because the thermal load on the Poly-07 heat is so low, there is not sufficient cost savings from natural gas firing to justify the conversion.

Table 8.D.2

Unit	Electrical Cost	Natural Gas Cost	Cost Savings
Extrusion	77,340	59,760	17,580
Poly-03	265,400	205,000	60,400
Poly-04	25,600	19,800	5,800
Poly-05	21,450	16,575	4,875
Poly-06	11,915	9,205	2,710
Poly-07	590	450	140
Total	431,020	328,590	91,365

Implementation Cost

The cost for a gas fired oil heater depends on the size (heating capacity) and whether or not the liquid is vaporized (boiler or heater). Converting the designated heaters to natural gas will require installation of 2 oil heaters and 1 vaporizer. To reduce installation costs, redundant heaters were combined wherever possible. Thus in extrusion where 17 electric heaters are used was replaced with a single, large capacity gas-fired heater. The installation cost includes flue piping, electrical wiring, and fuel piping. Installation is estimated to cost $3,000 per unit.

Table 8.D.3. Electric Heater Replacement Schedule.

<table>
<tr><th>Location</th><th>No. Electric Heaters</th><th>Electric Heater Capacity</th><th>No. Replacement Gas Heaters</th><th>Gas Heater Capacity</th><th>Gas Heater Capital Cost</th></tr>
<tr><td>Extrusion</td><td>17</td><td>765 kW</td><td>1</td><td>4,000,000 Btu/hr</td><td>$71,500</td></tr>
<tr><td>Poly-03</td><td>2</td><td>1050 kW</td><td rowspan="2">1</td><td rowspan="2">6,000,000 Btu/hr</td><td rowspan="2">$160,000</td></tr>
<tr><td>Poly-04</td><td>2</td><td>118.2 kW</td></tr>
<tr><td>Poly-05</td><td>2</td><td>66 kW</td><td rowspan="2">1</td><td rowspan="2">693,000 Btu/hr</td><td rowspan="2">$39,000</td></tr>
<tr><td>Poly-06</td><td>2</td><td>66 kW</td></tr>
<tr><td>Poly-07</td><td>2</td><td>175.2 kW</td><td colspan="3">Heater not replaced</td></tr>
</table>

A gas fired vaporizing oil heater is recommended to replace the 4 electric vaporizing heaters located at Poly-03 and Poly-04. Vaporizing heater- vertical, serpentine vaporizer with 6,000,000 Btu/hr natural gas burner. Package includes heater, vapor drum, centrifugal oil pump and electrical control panel. Base cost is $160,000 with additional $40,000 for installation and accessories. The total price for a gas-fire vaporizing heater is $200,000.

To replace the 17 electric oil heaters in extrusion, a single 4,000,000 Btu/hr natural gas fired, horizontal coil oil heater is recommended. Included in the price is the heater, 250 gpm centrifugal pump, and standard control package. The base price for a skid mounted assembly is $71,500. Installation is estimated to be an additional $18,000 giving an installed equipment cost of $89,500.

In addition, a piping loop for the oil must be provided. The existing heaters are natural convection, but the replacement heater will use forced convection with oil circulated by a pump. To accomplish this change, a supply and return piping loop to convey hot oil from the boiler to each heater box must by provided. Also, connecting piping from the oil header to the heater box must be supplied. The hot oil header will be 8-inch diameter, schedule 40 steel pipe. The connection piping will be 6-inch steel pipe. The piping will be insulated with 2" thick cellular glass, closed cell composition covered with an all service jacket. According to Means CostWorks estimating guide, insulated 8-inch diameter steel can be installed for $99/linear foot. Six inch steel pipe can be installed for $77/lf.

To access all the heater boxes, the piping loop must include two separate headers, one for supply and one for return. Assuming the distance for the piping loop is 160 feet, 80 feet down and 80 feet back, the length of 8 inch pipe required is 320. If six feet of connecting piping is needed to access each header box connection, a total of 12 linear feet per header or 204 feet is required.

Extrusion Heater Piping Cost:	
320 lf of 8-inch steel pipe for header x $99/lf	$31,680
204 lf of 6-inch steel pipe for connections x $77/lf	$15,700
TOTAL	$47,380

This yields a total price for replacing the extrusion heaters of $136,880 ($89,500 + $47,380).

To replace the four-33 kW electric oil heaters located at Poly-05 and Poly-06, a 690,000 Btu/hr vertical, gas fired heater is suggested. The equipment package includes the boiler, 132 gallon capacity deaerator, 125 gpm centrifugal circulation pump and standard control package. The base price for a skid mounted boiler is $39,000. Installation is expected to be an additional $10,000 for an installed cost of $49,000.

In addition to the mechanical equipment installation, a gas line must be extended from the utility room to the extrusion and poly-tower area. According to Means CostWorks estimating guide, 4-inch steel gas line can be installed for $20.70 per linear foot. As branch piping to individual pieces of equipment, a 2-inch steel pipe can be installed for $10.85 per linear foot. Because the bake-off ovens require natural gas also, the cost of the gas header piping can be split between the two areas.

The estimated length of 4-inch header piping is 200 linear feet. The branch pipe serving the heater for extrusion will require an addition 100 linear feet of 2-inch piping. Additionally, the two oil heaters in the poly-tower will require 200 linear feet of branch piping. If the cost for the gas header is split equally between the bakeoff ovens and oil heaters, the cost of gas piping for this application is $5,325

Piping cost:

Pipe = ½ x Cost of 4" Header + Cost of 2" Branch Line
= ½ x 200 lf x \$20.70 + (100 + 200) lf x \$10.85
= \$5,325

The discarded electrical heaters will retain some value when salvaged. As an estimate, a value of \$20,000 is assumed for the large 525 kW heaters and \$1,000 for the smaller 59, 45 and 33 kW heaters. The total salvage value of all heaters is \$41,000. This yields a net investment cost when all is included of

Net Installed Cost:

Heater and boiler = Vaporizer + Extrusion + Poly-tower Heater + Gas Piping – Salvage Value
= \$200,000 + \$136,880 + 49,000 + \$5,325 - \$41,000
= \$350,205

Simple Payback = Implementation Cost/ Cost Savings
= \$350,205 / \$91,365/yr
= 3.8 years

2. Install VFD on Twister Motors

Background

Variable Speed Drive (VSD) technology on twisters can save energy by regulating the output power to the power required and allowing changes in twist ratio (turns per inch) without requiring a change of pulley sheaves. Replacing the constant-speed motors with adjustable speed drives will provide accurate speed adjustment to match processing requirements while saving energy. Adjustable speed drives will also reduce production time losses from changing motor drive pulleys.

Equipment manufacturers that have replaced constant speed drives with variable speed electric motors technology estimate that adjustable speed drive motors reduce twister energy consumption by 2-10% because motor internal losses decrease with output speed. Adjustable speed controls will simultaneously eliminating the requirement to shut the machine off and change the drive pulleys in order to adjust the yarn twist ratio (turns per inch). Power measurements conducted on twisters at plant WL with and without speed adjustment revealed an almost linear reduction in power consumption with speed reduction.

Savings are based on measured power consumption for constant speed and adjustable speed twister drives. The data was obtained from monitoring the power draw of a twister drive motor at different speeds is shown in Figure 8.D.1. With a motor speed reduction of 6 per cent from 60 Hertz to 56.4 Hertz, a power savings of 5.9% was measured.

However as the speed is reduced further, the power draw slowly increases. This relation is not unusual. Since the twister is operating at a fixed speed, the motor is slowed down by reducing the effective voltage. To develop the required torque, the motor begins to draw increased voltage at lower speeds and the power input begins to increase. The VFD has an optimum speed for this application that is approximately 56 Hertz.

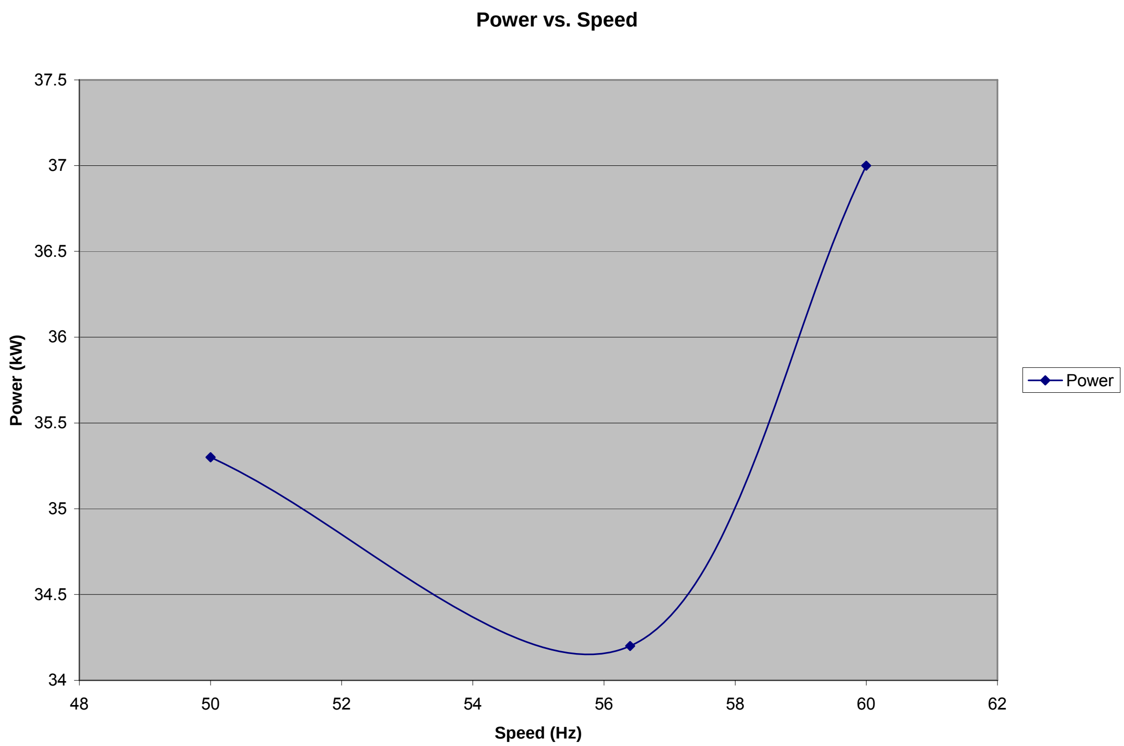

Figure 8.D.1 Power versus Speed Relation for Twister (Twister speed constant and motor speed variable)

Anticipated Savings

Power measurements were conducted on a 60-hp twister motor to estimate the savings from converting to adjustable speed drive operation. The twister was operated first at a drive frequency of 60 Hz corresponding to 1800 rpm. Next, the drive pulleys were changed and the drive frequency reduced to 56.4 Hz or a motor speed of 1692 rpm. At the lower speed, the pulleys were sized to provide the same twister shaft speed as the original condition. The results of the test are presented in the table below. Because the twister power draw is a function on the number of spindles operating, only the fully loaded condition was considered.

Twister drive speed-rpm	1800	1692
VFD Frequency-Hz	60	56.4
Measured Power-kW	37	34.2
Power Savings	-	7.6%

According to the measurements comparing constant speed and adjustable speed twister drives, a power savings of 5.9% was found when a VSD is installed and twister motor speed is reduced 6%. However as speed is reduced further there is a gain in power. Thus, a parabolic relationship between twister power and speed was found.

The following given values are useful in determining the energy and cost savings for the implementation of VSD motors in all the twister drives throughout the plant. Because the motor speed will vary depending on the characteristics of the yarn being processed, an average speed reduction and corresponding power savings of 7.6 percent is assumed.

Range of motor input frequency w/ASD - 53.5 to 56.5 Hz
Average operating frequency - 55 Hz

Expected Savings = (Std. Freq. – Reduced Freq.)/ Std. Freq.
= (37 – 34.2) / 37
= 7.6%

Annual Hours of Operation	8,760 hrs
Electrical Energy Cost	\$0.027/kWh
Demand Cost	\$10.38/kW
Number of Twisters	59
No. of Motors per Twister	2
Twister Motor Size	60 hp
AC Motor Load	63%
Motor Efficiency	92%
ASD Motor Operating Speed Percentage	93.3%
ASD Energy Savings	7.6%
Twister Duty Factor	94%

The following is a calculation for the energy cost savings on the 60-hp twister.
Average Motor Load, Constant Speed Twister:

= (Measured Load) / ((60 hp/Motor Eff.) x 0.746 kW/hp)
= (30.855 kW) / ((60 hp/0.92) x 0.746 kW/hp))

= 30.855 kW / 48.6 kW
= ~ 63% Load

Electrical Demand Savings Per Twister:
= No. Motors x Rated Power x Load Factor x Estimated Savings
= 2 motors x (60 hp/0.92) x 0.746 kW/hp x 63% load x 7.6%
= 4.66 kW/twister

Electrical Demand Savings all Twisters:
= (Demand Savings per Twister) x No. of Twisters
= (4.66 kW/twister) x (59 twisters)
= 275 kW

Electrical Energy Savings:
= (Demand Savings) x Annual Hours of Operation x Duty Factor
= (275 kW) x (8,760 hr/yr) x .94
= 2,264,500 kWh

Annual Energy Cost Savings:
= (Electrical Energy Savings x Electrical Energy Rate) + (Demand Savings x Demand Cost x Demand Factor)
= (2,264,500 kWh x $0.027/kWh) + (275 kW x $10.38/kW-mo x 12 mo/yr)
= $95,400

Productivity Savings

An added advantage of ASD drives is the elimination of down time when replacing the pulleys to change the motor output speed. The ASD allows changing of the output speed by simply altering the setting on a dial. The ASD will eliminate the maintenance labor used to change the pulleys and increase the yarn produced by the twisters by eliminating the down time for pulley change-out.

Average number of speed changes	0.5/wk-twister
Time to change pulleys and restart	35 minutes (0.58 hr)
Twister Production Rate	156 lb/hr
Maintenance Labor cost	$40/hr
Yarn Twisting Value Added	$0.50/lb
Twister Motor Size	60 hp

Maintenance Savings:
= (Changes/wk) x wk/yr x time/change x no. twisters x labor cost
= (0.5 wk/twister) x 52 wk/yr x 0.58 hr/change x 59 twisters x $40/hr

= $35,600/yr

Productivity Savings:

(Production Rate) x changes/wk x wk/yr x time/change x no. twisters x
= yarn value added
(156 lb/hr) x 0.5/wk-twister x 52 wk/yr x 0.58 hr/change x 59 twisters x
= $0.50/lb
= $69,400/yr

Total Productivity Savings:

= Maintenance Savings + Production Savings
= $35,600/yr + $69,400/yr
= $105,000/yr

Total Cost Savings:

The total cost savings from conversion to ASDs on the twisters is the combination of the energy and productivity cost savings>

Total Productivity Savings:

= Energy Savings + Productivity Savings
= $95,400/yr + $105,000/yr
= $200,400/yr

Implementation Cost

Prices for AC motor electronic speed controllers were found from several vendors. An average price for these units was used. Because this project involves such a large number of controllers, 118, there may be an opportunity for a quantity discount. Installation is assumed to require one electrician for 9 hours at $75/hour or $675/motor. The total investment for all 118 twister motors is $905,650. Below is a tabulated list of total implementation cost for all motors.

	# of	Package Price	
Motor Size	**units**	**Unit**	**Total**
60-hp	118	$7,000	$826,000
Installation (9 hr at labor costs of $75/hr) or $675/motor			$79,650
Total			**$905,650**

Simple Payback

Simple Payback on 60-Hp Twisters

= Total Investment / Total Savings

= $905,650 / $200,400
= 4.5 years

Appendix E – Financial Analysis of Each ESO

ESO1 - Extrusion: Replace DC Motors with AC VSD

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	-	kWh	$ -	
Electricity - Demand	-	kW	$ -	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
Maintenance			$ 43,200	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	537,470
Salvage (Existing Equipment)	281,000
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	**5.9**
Net Present Value (NPV)	**$ 138,609**
Internal Rate of Return (IRR)	**21.1%**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (256,470)	$ -	$ 43,200	$ (213,270)	$ (213,270)	$ (213,270)
1		$ -	$ 44,064	$ 44,064	$ 39,697	$ 36,391
2		$ -	$ 44,945	$ 44,945	$ 36,479	$ 30,656
3		$ -	$ 45,844	$ 45,844	$ 33,521	$ 25,824
4		$ -	$ 46,761	$ 46,761	$ 30,803	$ 21,754
5		$ -	$ 47,696	$ 47,696	$ 28,305	$ 18,325
6		$ -	$ 48,650	$ 48,650	$ 26,010	$ 15,437
7		$ -	$ 49,623	$ 49,623	$ 23,901	$ 13,004
8		$ -	$ 50,616	$ 50,616	$ 21,963	$ 10,954
9		$ -	$ 51,628	$ 51,628	$ 20,183	$ 9,228
10		$ -	$ 52,661	$ 52,661	$ 18,546	$ 7,773
11		$ -	$ 53,714	$ 53,714	$ 17,042	$ 6,548
12		$ -	$ 54,788	$ 54,788	$ 15,661	$ 5,516
13		$ -	$ 55,884	$ 55,884	$ 14,391	$ 4,647
14		$ -	$ 57,001	$ 57,001	$ 13,224	$ 3,914
15		$ -	$ 58,142	$ 58,142	$ 12,152	$ 3,297
					$ 138,609	$ (0)

ESO2 - Extrusion: Upgrade Belts to Cogged V-belts

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	400,680	kWh	$ 10,818	
Electricity - Demand	48	kW	$ 5,942	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ 7,280
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	**0.4**
Net Present Value (NPV)	**$ 145,995**
Internal Rate of Return (IRR)	**#DIV/0!**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (7,280)	$ -	$ 16,760	$ 9,480	$ 9,480	#DIV/0!
1		$ -	$ 17,095	$ 17,095	$ 15,401	#DIV/0!
2		$ -	$ 17,437	$ 17,437	$ 14,152	#DIV/0!
3		$ -	$ 17,786	$ 17,786	$ 13,005	#DIV/0!
4		$ -	$ 18,141	$ 18,141	$ 11,950	#DIV/0!
5		$ -	$ 18,504	$ 18,504	$ 10,981	#DIV/0!
6		$ -	$ 18,874	$ 18,874	$ 10,091	#DIV/0!
7		$ -	$ 19,252	$ 19,252	$ 9,273	#DIV/0!
8		$ -	$ 19,637	$ 19,637	$ 8,521	#DIV/0!
9		$ -	$ 20,030	$ 20,030	$ 7,830	#DIV/0!
10		$ -	$ 20,430	$ 20,430	$ 7,195	#DIV/0!
11		$ -	$ 20,839	$ 20,839	$ 6,612	#DIV/0!
12		$ -	$ 21,256	$ 21,256	$ 6,076	#DIV/0!
13		$ -	$ 21,681	$ 21,681	$ 5,583	#DIV/0!
14		$ -	$ 22,114	$ 22,114	$ 5,130	#DIV/0!
15		$ -	$ 22,557	$ 22,557	$ 4,714	#DIV/0!
					$ 145,995	#DIV/0!

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ESO3 - Extrusion: Use Synthetic Oil in Gear Box

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	426,720	kWh	$ 11,521	
Electricity - Demand	51	kW	$ 6,328	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ (320)	2.0%

Implementation Data

CapEx / Initial Cost	$ 1,280
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	**0.1**
Net Present Value (NPV)	**$ 159,030**
Internal Rate of Return (IRR)	**#DIV/0!**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (1,280)	$ (320)	$ 17,849	$ 16,249	$ 16,249	#DIV/0!
1		$ (326)	$ 18,206	$ 17,880	$ 16,108	#DIV/0!
2		$ (333)	$ 18,570	$ 18,237	$ 14,802	#DIV/0!
3		$ (340)	$ 18,942	$ 18,602	$ 13,602	#DIV/0!
4		$ (346)	$ 19,320	$ 18,974	$ 12,499	#DIV/0!
5		$ (353)	$ 19,707	$ 19,354	$ 11,485	#DIV/0!
6		$ (360)	$ 20,101	$ 19,741	$ 10,554	#DIV/0!
7		$ (368)	$ 20,503	$ 20,135	$ 9,698	#DIV/0!
8		$ (375)	$ 20,913	$ 20,538	$ 8,912	#DIV/0!
9		$ (382)	$ 21,331	$ 20,949	$ 8,189	#DIV/0!
10		$ (390)	$ 21,758	$ 21,368	$ 7,525	#DIV/0!
11		$ (398)	$ 22,193	$ 21,795	$ 6,915	#DIV/0!
12		$ (406)	$ 22,637	$ 22,231	$ 6,355	#DIV/0!
13		$ (414)	$ 23,090	$ 22,676	$ 5,839	#DIV/0!
14		$ (422)	$ 23,551	$ 23,129	$ 5,366	#DIV/0!
15		$ (431)	$ 24,023	$ 23,592	$ 4,931	#DIV/0!
					$ 159,030	#DIV/0!

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ESO4 - Extrusion: Replace Electric Bake-off with Natural Gas

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)	Annual Savings	Escalation
Electricity - Energy	153,800 kWh	$ 4,153	
Electricity - Demand	53 kW	$ 6,639	
Natural Gas	(144) MMBtu	$ (1,097)	
Water	- kGal	$ -	
0		$ -	2.0%
Annual O&M Cost		$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ 37,550
Salvage (Existing Equipment)	$ 5,000
Project Implementation Time (% of 1 year)	10%

Financial Measures

Simple Payback (years)	**3.4**
Net Present Value (NPV)	**$ 55,139**
Internal Rate of Return (IRR)	**43.2%**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (32,550)	$ -	$ 8,725	$ (23,825)	$ (23,825)	$ (23,825)
1		$ -	$ 9,888	$ 9,888	$ 8,908	$ 6,903
2		$ -	$ 10,086	$ 10,086	$ 8,186	$ 4,915
3		$ -	$ 10,288	$ 10,288	$ 7,522	$ 3,500
4		$ -	$ 10,493	$ 10,493	$ 6,912	$ 2,492
5		$ -	$ 10,703	$ 10,703	$ 6,352	$ 1,774
6		$ -	$ 10,917	$ 10,917	$ 5,837	$ 1,263
7		$ -	$ 11,136	$ 11,136	$ 5,364	$ 900
8		$ -	$ 11,358	$ 11,358	$ 4,929	$ 641
9		$ -	$ 11,586	$ 11,586	$ 4,529	$ 456
10		$ -	$ 11,817	$ 11,817	$ 4,162	$ 325
11		$ -	$ 12,054	$ 12,054	$ 3,824	$ 231
12		$ -	$ 12,295	$ 12,295	$ 3,514	$ 165
13		$ -	$ 12,541	$ 12,541	$ 3,229	$ 117
14		$ -	$ 12,792	$ 12,792	$ 2,968	$ 83
15		$ -	$ 13,047	$ 13,047	$ 2,727	$ 59
					$ 55,139	$ 0

ESO5 - Extrusion: Replace Electric Dowtherm with Gas

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	-	kWh	$ -	
Electricity - Demand	-	kW	$ -	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ -
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	#DIV/0!
Net Present Value (NPV)	$ -
Internal Rate of Return (IRR)	#NUM!

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ -	$ -	$ -	$ -	$ -	#NUM!
1		$ -	$ -	$ -	$ -	#NUM!
2		$ -	$ -	$ -	$ -	#NUM!
3		$ -	$ -	$ -	$ -	#NUM!
4		$ -	$ -	$ -	$ -	#NUM!
5		$ -	$ -	$ -	$ -	#NUM!
6		$ -	$ -	$ -	$ -	#NUM!
7		$ -	$ -	$ -	$ -	#NUM!
8		$ -	$ -	$ -	$ -	#NUM!
9		$ -	$ -	$ -	$ -	#NUM!
10		$ -	$ -	$ -	$ -	#NUM!
11		$ -	$ -	$ -	$ -	#NUM!
12		$ -	$ -	$ -	$ -	#NUM!
13		$ -	$ -	$ -	$ -	#NUM!
14		$ -	$ -	$ -	$ -	#NUM!
15		$ -	$ -	$ -	$ -	#NUM!
					$ -	#NUM!

ESO5 - Extrusion: Upgrade Dowtherm Pipe Insulation

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	146,000	kWh	$ 3,942	
Electricity - Demand	17	kW	$ 2,080	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ 63,000
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	**10.5**
Net Present Value (NPV)	**$ (7,925)**
Internal Rate of Return (IRR)	**8.5%**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (63,000)	$ -	$ 6,022	$ (56,978)	$ (56,978)	$ (56,978)
1		$ -	$ 6,143	$ 6,143	$ 5,534	$ 5,660
2		$ -	$ 6,265	$ 6,265	$ 5,085	$ 5,319
3		$ -	$ 6,391	$ 6,391	$ 4,673	$ 4,999
4		$ -	$ 6,519	$ 6,519	$ 4,294	$ 4,698
5		$ -	$ 6,649	$ 6,649	$ 3,946	$ 4,415
6		$ -	$ 6,782	$ 6,782	$ 3,626	$ 4,150
7		$ -	$ 6,918	$ 6,918	$ 3,332	$ 3,900
8		$ -	$ 7,056	$ 7,056	$ 3,062	$ 3,665
9		$ -	$ 7,197	$ 7,197	$ 2,813	$ 3,445
10		$ -	$ 7,341	$ 7,341	$ 2,585	$ 3,237
11		$ -	$ 7,488	$ 7,488	$ 2,376	$ 3,043
12		$ -	$ 7,638	$ 7,638	$ 2,183	$ 2,860
13		$ -	$ 7,790	$ 7,790	$ 2,006	$ 2,687
14		$ -	$ 7,946	$ 7,946	$ 1,843	$ 2,526
15		$ -	$ 8,105	$ 8,105	$ 1,694	$ 2,374
					$ (7,925)	$ (0)

ESO6 - Steam: Repair/replace Traps / Add Drip Legs to Poly-tower Steam Supply Header

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	-	kWh	$ -	
Electricity - Demand	-	kW	$ -	
Natural Gas	7,230	MMBtu	$ 55,093	
Water	4,945	kGal	$ 46,780	
0			$ -	2.0%
Annual O&M Cost			$ (400)	2.0%

Implementation Data

CapEx / Initial Cost	$ 10,100
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	10%

Financial Measures

Simple Payback (years)	**0.1**
Net Present Value (NPV)	**$ 907,753**
Internal Rate of Return (IRR)	**#DIV/0!**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (10,100)	$ (360)	$ 91,685	$ 81,225	$ 81,225	#DIV/0!
1		$ (408)	$ 103,910	$ 103,502	$ 93,245	#DIV/0!
2		$ (416)	$ 105,988	$ 105,572	$ 85,684	#DIV/0!
3		$ (424)	$ 108,108	$ 107,683	$ 78,737	#DIV/0!
4		$ (433)	$ 110,270	$ 109,837	$ 72,353	#DIV/0!
5		$ (442)	$ 112,475	$ 112,034	$ 66,486	#DIV/0!
6		$ (450)	$ 114,725	$ 114,274	$ 61,096	#DIV/0!
7		$ (459)	$ 117,019	$ 116,560	$ 56,142	#DIV/0!
8		$ (469)	$ 119,360	$ 118,891	$ 51,590	#DIV/0!
9		$ (478)	$ 121,747	$ 121,269	$ 47,407	#DIV/0!
10		$ (488)	$ 124,182	$ 123,694	$ 43,563	#DIV/0!
11		$ (497)	$ 126,665	$ 126,168	$ 40,031	#DIV/0!
12		$ (507)	$ 129,199	$ 128,691	$ 36,785	#DIV/0!
13		$ (517)	$ 131,783	$ 131,265	$ 33,803	#DIV/0!
14		$ (528)	$ 134,418	$ 133,891	$ 31,062	#DIV/0!
15		$ (538)	$ 137,107	$ 136,568	$ 28,543	#DIV/0!
					$ 907,753	#DIV/0!

ESO7 - Steam: Evaluate Savings of RO Water Treatment

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings		Escalation
Electricity - Energy	-	kWh	$	-	
Electricity - Demand	-	kW	$	-	
Natural Gas	856	MMBtu	$	6,523	
Water	566	kGal	$	5,354	
0			$	-	2.0%
Annual O&M Cost			$	-	2.0%

Implementation Data

CapEx / Initial Cost	$	2,250
Salvage (Existing Equipment)	$	-
Project Implementation Time (% of 1 year)		20%

Financial Measures

Simple Payback (years)		**0.2**
Net Present Value (NPV)	**$**	**103,995**
Internal Rate of Return (IRR)		**#DIV/0!**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (2,250)	$ -	$ 9,502	$ 7,252	$ 7,252	#DIV/0!
1		$ -	$ 12,115	$ 12,115	$ 10,914	#DIV/0!
2		$ -	$ 12,357	$ 12,357	$ 10,029	#DIV/0!
3		$ -	$ 12,604	$ 12,604	$ 9,216	#DIV/0!
4		$ -	$ 12,856	$ 12,856	$ 8,469	#DIV/0!
5		$ -	$ 13,113	$ 13,113	$ 7,782	#DIV/0!
6		$ -	$ 13,376	$ 13,376	$ 7,151	#DIV/0!
7		$ -	$ 13,643	$ 13,643	$ 6,571	#DIV/0!
8		$ -	$ 13,916	$ 13,916	$ 6,038	#DIV/0!
9		$ -	$ 14,194	$ 14,194	$ 5,549	#DIV/0!
10		$ -	$ 14,478	$ 14,478	$ 5,099	#DIV/0!
11		$ -	$ 14,768	$ 14,768	$ 4,686	#DIV/0!
12		$ -	$ 15,063	$ 15,063	$ 4,306	#DIV/0!
13		$ -	$ 15,364	$ 15,364	$ 3,957	#DIV/0!
14		$ -	$ 15,672	$ 15,672	$ 3,636	#DIV/0!
15		$ -	$ 15,985	$ 15,985	$ 3,341	#DIV/0!
					$ 103,995	#DIV/0!

ESO8 - Steam: Verify Proper Operation of O2 Sensor

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings		Escalation
Electricity - Energy	-	kWh	$	-	
Electricity - Demand	-	kW	$	-	
Natural Gas	3,490	MMBtu	$	26,594	
Water	-	kGal	$	-	
0			$	-	2.0%
Annual O&M Cost			$	(680)	2.0%

Implementation Data

CapEx / Initial Cost	$	-
Salvage (Existing Equipment)	$	-
Project Implementation Time (% of 1 year)		0%

Financial Measures

Simple Payback (years)		**-**
Net Present Value (NPV)	**$**	**236,991**
Internal Rate of Return (IRR)		**#DIV/0!**

Year	CapEx		O&M		Resources		Cash Flow		PV(WACC)	PV(IRR)
0	$ -	$	(680)	$	26,594	$	25,914	$	25,914	#DIV/0!
1		$	(694)	$	27,126	$	26,432	$	23,813	#DIV/0!
2		$	(707)	$	27,668	$	26,961	$	21,882	#DIV/0!
3		$	(722)	$	28,222	$	27,500	$	20,108	#DIV/0!
4		$	(736)	$	28,786	$	28,050	$	18,477	#DIV/0!
5		$	(751)	$	29,362	$	28,611	$	16,979	#DIV/0!
6		$	(766)	$	29,949	$	29,183	$	15,603	#DIV/0!
7		$	(781)	$	30,548	$	29,767	$	14,337	#DIV/0!
8		$	(797)	$	31,159	$	30,362	$	13,175	#DIV/0!
9		$	(813)	$	31,782	$	30,969	$	12,107	#DIV/0!
10		$	(829)	$	32,418	$	31,589	$	11,125	#DIV/0!
11		$	(845)	$	33,066	$	32,221	$	10,223	#DIV/0!
12		$	(862)	$	33,727	$	32,865	$	9,394	#DIV/0!
13		$	(880)	$	34,402	$	33,522	$	8,632	#DIV/0!
14		$	(897)	$	35,090	$	34,193	$	7,933	#DIV/0!
15		$	(915)	$	35,792	$	34,877	$	7,289	#DIV/0!
								$	236,991	#DIV/0!

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ESO9 - Reduce Flash Losses from Condensate Tank

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings		Escalation
Electricity - Energy	-	kWh	$	-	
Electricity - Demand	-	kW	$	-	
Natural Gas	12,121	MMBtu	$	92,362	
Water	-	kGal	$	-	
0			$	-	2.0%
Annual O&M Cost			$	-	2.0%

Implementation Data

CapEx / Initial Cost	$	9,915
Salvage (Existing Equipment)	$	-
Project Implementation Time (% of 1 year)		0%

Financial Measures

Simple Payback (years)		**0.1**
Net Present Value (NPV)	**$**	**834,768**
Internal Rate of Return (IRR)		**#DIV/0!**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (9,915)	$ -	$ 92,362	$ 82,447	$ 82,447	#DIV/0!
1		$ -	$ 94,209	$ 94,209	$ 84,873	#DIV/0!
2		$ -	$ 96,093	$ 96,093	$ 77,992	#DIV/0!
3		$ -	$ 98,015	$ 98,015	$ 71,668	#DIV/0!
4		$ -	$ 99,976	$ 99,976	$ 65,857	#DIV/0!
5		$ -	$ 101,975	$ 101,975	$ 60,517	#DIV/0!
6		$ -	$ 104,015	$ 104,015	$ 55,610	#DIV/0!
7		$ -	$ 106,095	$ 106,095	$ 51,102	#DIV/0!
8		$ -	$ 108,217	$ 108,217	$ 46,958	#DIV/0!
9		$ -	$ 110,381	$ 110,381	$ 43,151	#DIV/0!
10		$ -	$ 112,589	$ 112,589	$ 39,652	#DIV/0!
11		$ -	$ 114,841	$ 114,841	$ 36,437	#DIV/0!
12		$ -	$ 117,137	$ 117,137	$ 33,483	#DIV/0!
13		$ -	$ 119,480	$ 119,480	$ 30,768	#DIV/0!
14		$ -	$ 121,870	$ 121,870	$ 28,273	#DIV/0!
15		$ -	$ 124,307	$ 124,307	$ 25,981	#DIV/0!
					$ 834,768	#DIV/0!

ESO10 - Compressed Air: Repair Air Leaks

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	4,546,400	kWh	$ 122,753	
Electricity - Demand	519	kW	$ 64,647	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ 25,000
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	25%

Financial Measures

Simple Payback (years)	**0.1**
Net Present Value (NPV)	**$ 1,641,984**
Internal Rate of Return (IRR)	**#DIV/0!**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (25,000)	$ -	$ 140,550	$ 115,550	$ 115,550	#DIV/0!
1		$ -	$ 191,147	$ 191,147	$ 172,205	#DIV/0!
2		$ -	$ 194,970	$ 194,970	$ 158,242	#DIV/0!
3		$ -	$ 198,870	$ 198,870	$ 145,412	#DIV/0!
4		$ -	$ 202,847	$ 202,847	$ 133,622	#DIV/0!
5		$ -	$ 206,904	$ 206,904	$ 122,788	#DIV/0!
6		$ -	$ 211,042	$ 211,042	$ 112,832	#DIV/0!
7		$ -	$ 215,263	$ 215,263	$ 103,683	#DIV/0!
8		$ -	$ 219,568	$ 219,568	$ 95,277	#DIV/0!
9		$ -	$ 223,960	$ 223,960	$ 87,551	#DIV/0!
10		$ -	$ 228,439	$ 228,439	$ 80,453	#DIV/0!
11		$ -	$ 233,008	$ 233,008	$ 73,929	#DIV/0!
12		$ -	$ 237,668	$ 237,668	$ 67,935	#DIV/0!
13		$ -	$ 242,421	$ 242,421	$ 62,427	#DIV/0!
14		$ -	$ 247,270	$ 247,270	$ 57,365	#DIV/0!
15		$ -	$ 252,215	$ 252,215	$ 52,714	#DIV/0!
					$ 1,641,984	#DIV/0!

ESO11 - Compressed Air: Evaluate Primary Air Storage

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	2,041,000	kWh	$ 55,107	
Electricity - Demand	466	kW	$ 58,045	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ 79,850
Salvage (Existing Equipment)	$ 40,000
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	**0.4**
Net Present Value (NPV)	**$ 994,965**
Internal Rate of Return (IRR)	**#DIV/0!**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (39,850)	$ -	$ 113,152	$ 73,302	$ 73,302	#DIV/0!
1		$ -	$ 115,415	$ 115,415	$ 103,977	#DIV/0!
2		$ -	$ 117,723	$ 117,723	$ 95,547	#DIV/0!
3		$ -	$ 120,078	$ 120,078	$ 87,800	#DIV/0!
4		$ -	$ 122,479	$ 122,479	$ 80,681	#DIV/0!
5		$ -	$ 124,929	$ 124,929	$ 74,139	#DIV/0!
6		$ -	$ 127,427	$ 127,427	$ 68,128	#DIV/0!
7		$ -	$ 129,976	$ 129,976	$ 62,604	#DIV/0!
8		$ -	$ 132,576	$ 132,576	$ 57,528	#DIV/0!
9		$ -	$ 135,227	$ 135,227	$ 52,864	#DIV/0!
10		$ -	$ 137,932	$ 137,932	$ 48,577	#DIV/0!
11		$ -	$ 140,690	$ 140,690	$ 44,639	#DIV/0!
12		$ -	$ 143,504	$ 143,504	$ 41,019	#DIV/0!
13		$ -	$ 146,374	$ 146,374	$ 37,693	#DIV/0!
14		$ -	$ 149,302	$ 149,302	$ 34,637	#DIV/0!
15		$ -	$ 152,288	$ 152,288	$ 31,829	#DIV/0!
					$ 994,965	#DIV/0!

ESO12 - Compressed Air: Lower Plant Pressure with the Use of Demand-side Storage

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	2,483,500	kWh	$ 67,055	
Electricity - Demand	284	kW	$ 35,313	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ 51,400
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	**0.5**
Net Present Value (NPV)	**$ 884,785**
Internal Rate of Return (IRR)	**#DIV/0!**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (51,400)	$ -	$ 102,367	$ 50,967	$ 50,967	#DIV/0!
1		$ -	$ 104,415	$ 104,415	$ 94,067	#DIV/0!
2		$ -	$ 106,503	$ 106,503	$ 86,440	#DIV/0!
3		$ -	$ 108,633	$ 108,633	$ 79,431	#DIV/0!
4		$ -	$ 110,806	$ 110,806	$ 72,991	#DIV/0!
5		$ -	$ 113,022	$ 113,022	$ 67,073	#DIV/0!
6		$ -	$ 115,282	$ 115,282	$ 61,635	#DIV/0!
7		$ -	$ 117,588	$ 117,588	$ 56,637	#DIV/0!
8		$ -	$ 119,940	$ 119,940	$ 52,045	#DIV/0!
9		$ -	$ 122,338	$ 122,338	$ 47,825	#DIV/0!
10		$ -	$ 124,785	$ 124,785	$ 43,947	#DIV/0!
11		$ -	$ 127,281	$ 127,281	$ 40,384	#DIV/0!
12		$ -	$ 129,826	$ 129,826	$ 37,110	#DIV/0!
13		$ -	$ 132,423	$ 132,423	$ 34,101	#DIV/0!
14		$ -	$ 135,071	$ 135,071	$ 31,336	#DIV/0!
15		$ -	$ 137,773	$ 137,773	$ 28,795	#DIV/0!
					$ 884,785	#DIV/0!

ESO13 - Compressed Air: Install Compressor Controller

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings		Escalation
Electricity - Energy	4,537,680	kWh	$	122,517	
Electricity - Demand	518	kW	$	64,522	
Natural Gas	-	MMBtu	$	-	
Water	-	kGal	$	-	
0			$	-	2.0%
Annual O&M Cost			$	-	2.0%

Implementation Data

CapEx / Initial Cost	$	20,000
Salvage (Existing Equipment)	$	-
Project Implementation Time (% of 1 year)		0%

Financial Measures

Simple Payback (years)	**0.1**
Net Present Value (NPV)	**$ 1,690,542**
Internal Rate of Return (IRR)	**#DIV/0!**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (20,000)	$ -	$ 187,039	$ 167,039	$ 167,039	#DIV/0!
1		$ -	$ 190,780	$ 190,780	$ 171,874	#DIV/0!
2		$ -	$ 194,596	$ 194,596	$ 157,938	#DIV/0!
3		$ -	$ 198,488	$ 198,488	$ 145,133	#DIV/0!
4		$ -	$ 202,458	$ 202,458	$ 133,365	#DIV/0!
5		$ -	$ 206,507	$ 206,507	$ 122,552	#DIV/0!
6		$ -	$ 210,637	$ 210,637	$ 112,615	#DIV/0!
7		$ -	$ 214,850	$ 214,850	$ 103,484	#DIV/0!
8		$ -	$ 219,147	$ 219,147	$ 95,093	#DIV/0!
9		$ -	$ 223,529	$ 223,529	$ 87,383	#DIV/0!
10		$ -	$ 228,000	$ 228,000	$ 80,298	#DIV/0!
11		$ -	$ 232,560	$ 232,560	$ 73,787	#DIV/0!
12		$ -	$ 237,211	$ 237,211	$ 67,805	#DIV/0!
13		$ -	$ 241,955	$ 241,955	$ 62,307	#DIV/0!
14		$ -	$ 246,795	$ 246,795	$ 57,255	#DIV/0!
15		$ -	$ 251,730	$ 251,730	$ 52,613	#DIV/0!
					$ 1,690,542	#DIV/0!

ESO14 - Replace Heat Set Compressed Air Supply with Dedicated Low Pressure Compressed Air Supply

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	231,300	kWh	$ 6,245	
Electricity - Demand	26	kW	$ 3,288	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ 14,529
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	1.5
Net Present Value (NPV)	$ 72,658
Internal Rate of Return (IRR)	196.7%

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (14,529)	$ -	$ 9,533	$ (4,996)	$ (4,996)	$ (4,996)
1		$ -	$ 9,724	$ 9,724	$ 8,760	$ 3,278
2		$ -	$ 9,919	$ 9,919	$ 8,050	$ 1,127
3		$ -	$ 10,117	$ 10,117	$ 7,397	$ 388
4		$ -	$ 10,319	$ 10,319	$ 6,798	$ 133
5		$ -	$ 10,526	$ 10,526	$ 6,247	$ 46
6		$ -	$ 10,736	$ 10,736	$ 5,740	$ 16
7		$ -	$ 10,951	$ 10,951	$ 5,275	$ 5
8		$ -	$ 11,170	$ 11,170	$ 4,847	$ 2
9		$ -	$ 11,393	$ 11,393	$ 4,454	$ 1
10		$ -	$ 11,621	$ 11,621	$ 4,093	$ 0
11		$ -	$ 11,854	$ 11,854	$ 3,761	$ 0
12		$ -	$ 12,091	$ 12,091	$ 3,456	$ 0
13		$ -	$ 12,333	$ 12,333	$ 3,176	$ 0
14		$ -	$ 12,579	$ 12,579	$ 2,918	$ 0
15		$ -	$ 12,831	$ 12,831	$ 2,682	$ 0
					$ 72,658	$ (0)

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ESO15 - HVAC: ASD Spray Pumps

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings		Escalation
Electricity - Energy	363,135	kWh	$	9,805	
Electricity - Demand	-	kW	$	-	
Natural Gas	-	MMBtu	$	-	
Water	-	kGal	$	-	
0			$	-	2.0%
Annual O&M Cost			$	-	2.0%

Implementation Data

CapEx / Initial Cost	$	36,360
Salvage (Existing Equipment)	$	-
Project Implementation Time (% of 1 year)		0%

Financial Measures

Simple Payback (years)		**3.7**
Net Present Value (NPV)	**$**	**53,307**
Internal Rate of Return (IRR)		**39.3%**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (36,360)	$ -	$ 9,805	$ (26,555)	$ (26,555)	$ (26,555)
1		$ -	$ 10,001	$ 10,001	$ 9,010	$ 7,179
2		$ -	$ 10,201	$ 10,201	$ 8,279	$ 5,256
3		$ -	$ 10,405	$ 10,405	$ 7,608	$ 3,849
4		$ -	$ 10,613	$ 10,613	$ 6,991	$ 2,818
5		$ -	$ 10,825	$ 10,825	$ 6,424	$ 2,063
6		$ -	$ 11,042	$ 11,042	$ 5,903	$ 1,511
7		$ -	$ 11,262	$ 11,262	$ 5,425	$ 1,106
8		$ -	$ 11,488	$ 11,488	$ 4,985	$ 810
9		$ -	$ 11,717	$ 11,717	$ 4,581	$ 593
10		$ -	$ 11,952	$ 11,952	$ 4,209	$ 434
11		$ -	$ 12,191	$ 12,191	$ 3,868	$ 318
12		$ -	$ 12,435	$ 12,435	$ 3,554	$ 233
13		$ -	$ 12,683	$ 12,683	$ 3,266	$ 170
14		$ -	$ 12,937	$ 12,937	$ 3,001	$ 125
15		$ -	$ 13,196	$ 13,196	$ 2,758	$ 91
					$ 53,307	$ 0

ESO16 - HVAC: Enthalpy Controls on Airwashers

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	2,757,779	kWh	$ 74,460	
Electricity - Demand	-	kW	$ -	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ 94,056
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	**1.3**
Net Present Value (NPV)	**$ 586,907**
Internal Rate of Return (IRR)	**389.6%**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (94,056)	$ -	$ 74,460	$ (19,596)	$ (19,596)	$ (19,596)
1		$ -	$ 75,949	$ 75,949	$ 68,423	$ 15,513
2		$ -	$ 77,468	$ 77,468	$ 62,875	$ 3,232
3		$ -	$ 79,018	$ 79,018	$ 57,777	$ 673
4		$ -	$ 80,598	$ 80,598	$ 53,092	$ 140
5		$ -	$ 82,210	$ 82,210	$ 48,788	$ 29
6		$ -	$ 83,854	$ 83,854	$ 44,832	$ 6
7		$ -	$ 85,531	$ 85,531	$ 41,197	$ 1
8		$ -	$ 87,242	$ 87,242	$ 37,857	$ 0
9		$ -	$ 88,987	$ 88,987	$ 34,787	$ 0
10		$ -	$ 90,766	$ 90,766	$ 31,967	$ 0
11		$ -	$ 92,582	$ 92,582	$ 29,375	$ 0
12		$ -	$ 94,433	$ 94,433	$ 26,993	$ 0
13		$ -	$ 96,322	$ 96,322	$ 24,804	$ 0
14		$ -	$ 98,248	$ 98,248	$ 22,793	$ 0
15		$ -	$ 100,213	$ 100,213	$ 20,945	$ 0
					$ 586,907	$ 0

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ESO17 - HVAC: Cover Entrance for AGV

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings		Escalation
Electricity - Energy	24,545	kWh	$	663	
Electricity - Demand	-	kW	$	-	
Natural Gas	-	MMBtu	$	-	
Water	-	kGal	$	-	
0			$	-	2.0%
Annual O&M Cost			$	-	2.0%

Implementation Data

CapEx / Initial Cost	$	517
Salvage (Existing Equipment)	$	-
Project Implementation Time (% of 1 year)		0%

Financial Measures

Simple Payback (years)		**0.8**
Net Present Value (NPV)	**$**	**5,544**
Internal Rate of Return (IRR)		**#DIV/0!**

Year	CapEx		O&M		Resources		Cash Flow		PV(WACC)	PV(IRR)
0	$	(517)	$	-	$	663	$	146	$ 146	#DIV/0!
1			$	-	$	676	$	676	$ 609	#DIV/0!
2			$	-	$	689	$	689	$ 560	#DIV/0!
3			$	-	$	703	$	703	$ 514	#DIV/0!
4			$	-	$	717	$	717	$ 473	#DIV/0!
5			$	-	$	732	$	732	$ 434	#DIV/0!
6			$	-	$	746	$	746	$ 399	#DIV/0!
7			$	-	$	761	$	761	$ 367	#DIV/0!
8			$	-	$	776	$	776	$ 337	#DIV/0!
9			$	-	$	792	$	792	$ 310	#DIV/0!
10			$	-	$	808	$	808	$ 285	#DIV/0!
11			$	-	$	824	$	824	$ 261	#DIV/0!
12			$	-	$	840	$	840	$ 240	#DIV/0!
13			$	-	$	857	$	857	$ 221	#DIV/0!
14			$	-	$	874	$	874	$ 203	#DIV/0!
15			$	-	$	892	$	892	$ 186	#DIV/0!
									$ 5,544	#DIV/0!

ESO18 - Lighting: Retrofit in warehouse w/ Occupancy Sensor

Resource Saved (+) or Expended (-)

Resource	Quantity (+ or -)		Annual Savings	Escalation
Electricity - Energy	421,825	kWh	$ 11,389	
Electricity - Demand	15	kW	$ 1,868	
Natural Gas	-	MMBtu	$ -	
Water	-	kGal	$ -	
0			$ -	2.0%
Annual O&M Cost			$ -	2.0%

Implementation Data

CapEx / Initial Cost	$ 35,150
Salvage (Existing Equipment)	$ -
Project Implementation Time (% of 1 year)	0%

Financial Measures

Simple Payback (years)	**2.7**
Net Present Value (NPV)	**$ 86,096**
Internal Rate of Return (IRR)	**63.7%**

Year	CapEx	O&M	Resources	Cash Flow	PV(WACC)	PV(IRR)
0	$ (35,150)	$ -	$ 13,258	$ (21,892)	$ (21,892)	$ (21,892)
1		$ -	$ 13,523	$ 13,523	$ 12,183	$ 8,260
2		$ -	$ 13,793	$ 13,793	$ 11,195	$ 5,146
3		$ -	$ 14,069	$ 14,069	$ 10,287	$ 3,206
4		$ -	$ 14,351	$ 14,351	$ 9,453	$ 1,997
5		$ -	$ 14,638	$ 14,638	$ 8,687	$ 1,244
6		$ -	$ 14,930	$ 14,930	$ 7,982	$ 775
7		$ -	$ 15,229	$ 15,229	$ 7,335	$ 483
8		$ -	$ 15,533	$ 15,533	$ 6,740	$ 301
9		$ -	$ 15,844	$ 15,844	$ 6,194	$ 187
10		$ -	$ 16,161	$ 16,161	$ 5,692	$ 117
11		$ -	$ 16,484	$ 16,484	$ 5,230	$ 73
12		$ -	$ 16,814	$ 16,814	$ 4,806	$ 45
13		$ -	$ 17,150	$ 17,150	$ 4,416	$ 28
14		$ -	$ 17,493	$ 17,493	$ 4,058	$ 18
15		$ -	$ 17,843	$ 17,843	$ 3,729	$ 11
					$ 86,096	$ 0