INDUSTRIAL ASSESSMENT CENTER

ENERGY EFFICIENCY, POLLUTION PREVENTION, AND PRODUCTIVITY IMPROVEMENT
ASSISTANCE FOR INDUSTRY
A U.S. DEPARTMENT OF ENERGY SPONSORED PROGRAM

INDUSTRIAL ASSESSMENT REPORT FOR ENERGY EFFICIENCY, POLLUTION PREVENTION, AND PRODUCTIVITY IMPROVEMENT

No. CO0999

ASSESSMENT DATE:	February 29, 2000
LOCATION:	______, Colorado
PRINCIPAL PRODUCTS:	Injection molded plastic parts
S.I.C. NUMBER:	3079
REPORT DATE:	April 10, 2000

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SAMPLE REPORT

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PREFACE

The work described in this report was performed under the direction of the Industrial Assessment Center (IAC) at Colorado State University. The IAC program is managed by the University City Science Center under agreement with the U.S. Department of Energy, which financially supports the program.

The objective of the IAC is to identify, evaluate, and recommend - through analyses of industrial plants' operations - the most significant opportunities to conserve energy, prevent pollution, and increase productivity, thereby reducing associated costs and increasing profits. Our recommendations are based upon observation and measurement we make in your plant; because our time was limited, we do not claim to have complete detail on every aspect of the plant's operations. At all times we try to offer specific and quantitative recommendation of cost savings, energy efficiency, pollution prevention, and productivity improvement to the plants we serve. But we do not attempt to prepare engineering designs or otherwise perform services that you would expect from an engineering firm, a vendor, or a manufacturer's representative. When the need for that kind of assistance arises, we urge you to consult them directly.

The opportunities presented in this report identify economic benefits for energy efficiency, pollution prevention, and productivity improvement. Other recommendations that may not provide economic incentives are also presented; consideration of these recommendations is strongly encouraged. Note that the interrelationships between energy, wastes, and production are also explored and presented. Other possible benefits, such as improved workplace conditions, reduced liability exposure, improved public image, and reduced environmental damage should also be considered. The recommendations are not intended to deal with the issue of compliance with applicable hazardous materials regulations. Questions regarding compliance should be addressed to either a reputable consulting engineering firm experienced with hazardous waste regulations or to the appropriate regulatory agency. Clients are encouraged to develop positive working relationships with regulators within which matters pertaining to compliance can be addressed and resolved.

The assumptions and equations used to calculate the savings for each recommendation are given in the report. The assumptions represent conservative engineering practice. If the client does not agree with the assumptions, the assumptions may be adjusted. New values for the savings for each opportunity may then be determined using the same equations.

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Please feel free to contact the CSU IAC if there are any questions or comments related to this report. The IAC staff can be contacted as follows:

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

Report No.: CO0999
Principal Products: Injection molded plastic parts
Annual Production: 6 million plastic parts
S.I.C. Code: 3079
Estimated cost to the plant for the assessment: 5 hours, $600

Location: ______, Colorado
Number of Employees: 75
Annual Sales: $10 million
Visit Date: February 29, 2000

CURRENT ENERGY USAGE AND WASTE GENERATION

Energy consumption and the corresponding energy costs at this plant for the twelve-month period from February 1999 through January 2000 consisted of the following:

Energy Type	Usage	Cost
Electrical Usage	1,237,920 kWh 4,225.0 MMBtu	$21,041
Electrical Demand	3,564.8 kW 297.1 kW/mo. (avg.)	$46,544
Misc. Electric Costs	N/A	$192
Natural Gas Usage	76,992 ccf 71,548 therms 7,154.8 MMBtu	$30,266
TOTALS	**11,379.8 MMBtu**	**$98,043**

Waste generation and management costs for the streams of concern during the twelve-month period from January 1999 through December 1999, are summarized in the following table:

Waste Type	Liquid	Solid	Air Emissions
Hazardous Waste Generation	440 gals	0 pounds	Not considered
Waste Water Generation	4,089,000 gallons		
Other Nonhazardous Waste Generation	730 gals	117,985 pounds	
Waste Management Costs			**TOTALS**
Applicable Raw Material Costs	Not considered		$0
Water Purchase Costs	$8,512		$8,512
Hazardous Waste Disposal	$1,285	$0	$1,285
Waste Water Disposal	$8,537		$8,537
Other Nonhazardous Waste Generation	$2,415	$6,431	$8,846
TOTAL			**$27,180**

RECOMMENDATIONS AND RESULTS

The assessment recommendations (ARs) presented in this report would:

- reduce electric energy consumption by 62,926 kilowatt-hours per year
- reduce peak electric demand by 1,468 kilowatts per year (122.3 kW/month)
- reduce natural gas energy consumption by 93 million Btus per year
- reduce solid hazardous waste generation by 77 pounds per year
- reduce waste water generation by 11,037,600 gallons per year.

The total cost savings for the ideas presented are $206,800 per year. The total implementation cost is $88,300. Thus, the simple payback period is about 0.4 year. The recommendations are listed in the table below, and are presented in detail in Sections 4, 5, and 6.

AR No.	Assessment Recommendation	Resource Savings *per year*	Cost Savings	Implement Cost	Payback *years*
		ENERGY EFFICIENCY RECOMMENDATIONS			
1	Improve Power Factor By Installing Capacitors	890 kW peak demand	$6,420	$15,880	2.5
2	Reduce Peak Electric Demand	0 kWh electricity 384 kW peak demand	$2,940	$7,500	2.6
3	Reduce Compressed Air Leaks	82,298 kWh electricity 0 MMBtu natural gas	$2,750	$2,070	0.8
4	Install Energy Efficient Lamps and Ballasts as Existing Lamps Burn Out	17,944 kWh electricity 72 kW peak demand	$660	$0	N/A
5	Reset Thermostats in Offices	5,900 kWh electricity 93 MMBtu natural gas	$530	$750	1.4
		POLLUTION PREVENTION RECOMMENDATIONS			
6	Install Cooling Tower To Reduce Water Usage	11,037,600 gal waste water 10,437,600 gal water savings	$19,000	$21,600	1.1
7	Recycle Used Fluorescent Lamps And Replace With Low Mercury Lamps	77 lbs hazardous solid	$200	$0	0.0
		PRODUCTIVITY IMPROVEMENT RECOMMENDATIONS			
8	Reduce Material Shortages and Material Handling	Reduced labor costs	$166,400	$40,000	0.2
9	Reduce Natural Gas Purchase Costs	Gas commodity savings only	$7,900	$500	0.1
	TOTALS		**$206,800**	**$88,300**	**0.4**

Note that the savings for AR No. 4 are the totals after two years of incremental implementation. Also note that the savings given reflect those achievable when implementing each opportunity independently. A more detailed total cost analysis for applicable ideas is provided in Section 7.

2. CURRENT FACILITY OPERATIONS

2.1 Facility Description

The plant considered in this report produces injection molded plastic parts. About 75 employees are involved in processing about 6 million lbs of parts per year for an annual sales figure of about $10 million. The plant operates 7 days per week, 52 weeks per year. Current operating and lighting hours for the various plant areas in this report are given in the table below.

Operating and Lighting Hours

AREA	Production	Warehouse	Office
Shift Start	11:00 PM	7:00 AM	8:00 AM
Shift End	11:00 PM	5:00 PM	5:00 PM
Daily Hours	24	10	9
Days	Sun - Fri	Mon - Fri	Mon - Fri
Weekly Shift Days	5	5	5
Weekly Shift Hours	120	50	45
Annual Months	12	12	12
Annual Shift Days	260	260	260
Annual Shift Hours	6,240	2,600	2,340

The facility consists of a single enclosure building with a total area of 39,714 ft^2. A simple layout of the facility, including the numbered injection machines, is given as Figure 1 on the next page.

One building houses four areas with shared walls or sections of walls. Walls are constructed of metal, brick, concrete block and prestressed concrete, with the majority constructed of metal. The roof over most of the facility is sheet metal, with a layer of blanket insulation on the inside surface. Sections of the office roof are of the built up type; rubber membrane over a wood deck with gravel on top. A steel superstructure supports the walls and ceilings in the facility.

Gas-fired unit heaters supply space heating throughout the production areas of the facility, with the exception of the painting area, which is heated with a large (4,675,000 Btu/h) gas fired makeup air unit. A significant amount of internal gain is generated by the waste heat from the molding machines, and space heating in the Tool Room (supplied by gas fired unit heaters) is supplemented by heat ducted from the ceiling of the molding area. Space heating in the office areas is supplied by a small (164,000 Btu/h) boiler system via coils and ductwork located in the office ceiling. Space cooling is supplied to the office areas by evaporative cooling units (swamp coolers). Thermostats in all areas of the facility are maintained at about 70°F during the heating system, with the exception of the warehouse/storage area, which is maintained at about 60°F in some sections, and is unheated in other sections.

Lighting in this facility is provided energy efficient four-foot and eight-foot fluorescent lamps and electronic ballasts, with mercury vapor and metal halide lamps in the production area. The installed capacity is 74.3 kW.

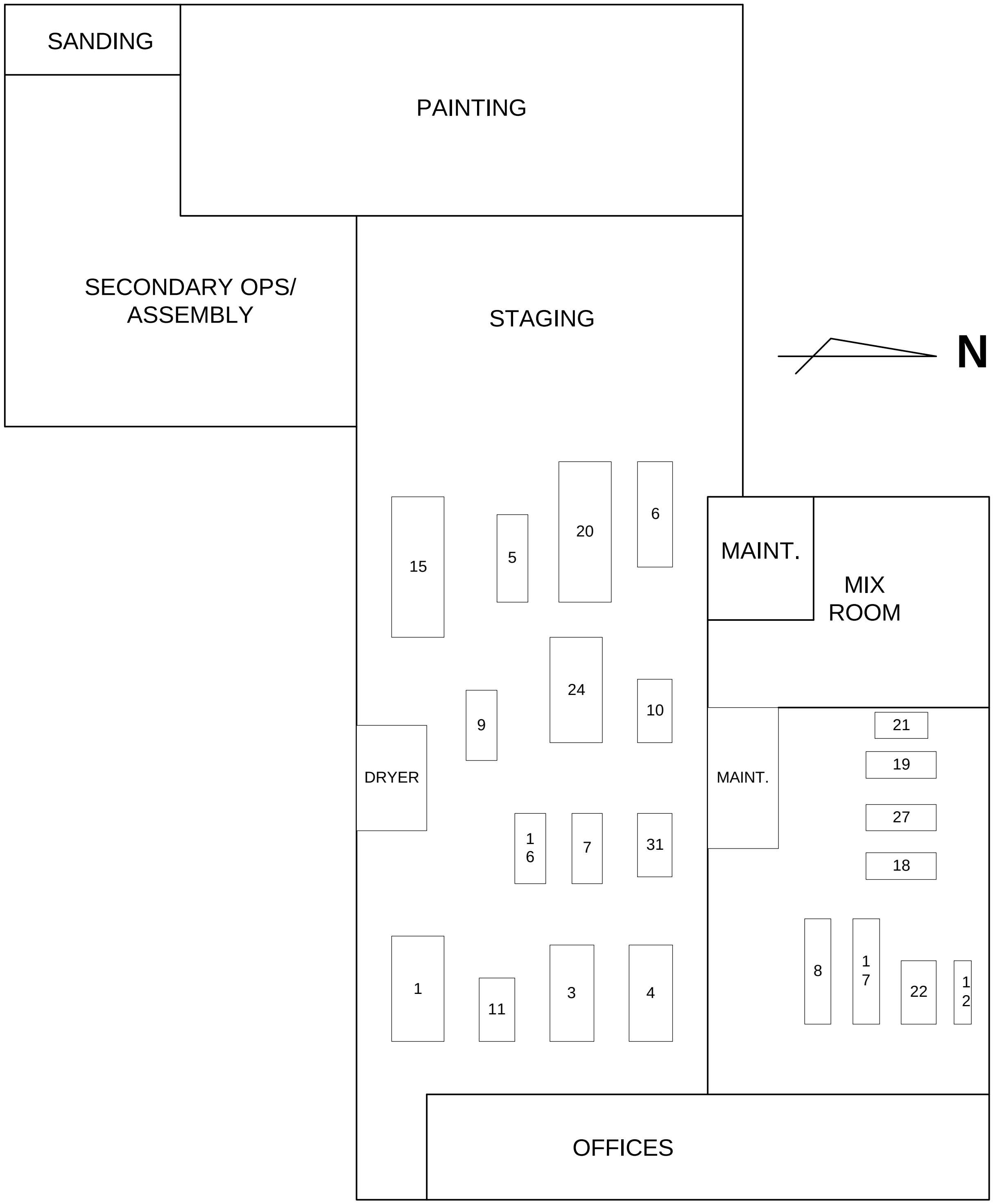


Figure 1: Simple Facility Layout

2.2 General Process Description

A simplified description of the manufacturing processes performed at this facility is given in this section. The description is intended to provide general information on the manufacturing processes at this plant, with an emphasis on energy use and waste generation. The general manufacturing processes at this facility is illustrated in Figure 2 on the following page.

The products manufactured are injection molded plastic parts. The material used in the fabrication of finished products include the following:

- Plastic pellets
- Paint

The manufacturing operations include the following:

- Pellet drying
- Molding
- Painting

Production processes at this facility are all related either directly or indirectly to manufacturing of injection molded parts. The facility is a job shop, as opposed to a proprietary shop, and therefore, the types of parts produced vary significantly throughout the year; at times, they may vary throughout a given day.

Raw material for the molding process, in the form of plastic pellets, are received at docks on the north end of the facility, and are stored either in the storage/warehouse area or in one of two large storage silos. The raw material is transported to the individual molding machines by a central pneumatic material handling system, located in the molding area. Small drying bins at the machine sites store and dry the plastic pellets. Drying is required to prevent contamination of the molding process; moisture in the plastic can cause surface streaking and thereby render the molded product unacceptable to the customer. Parts are injection molded in one of several machines, ranging in size from 55 tons to 1,500 tons.

Heating and cooling of the molds is provided by several electric water heaters and by a central process chiller and cooling tower. Small electrical chillers located at the molding sites assist cooling. Heating is required more often than cooling for the molded parts produced at this particular facility. Water is heated to temperatures from about 70°F up to about 180°F.

Many of the parts are painted in the paint area. Parts are transported on a monorail conveyor system through spray booths where they are primed and then surface painted. After they are painted, most of the parts are conveyed into one of two bake ovens for drying or heat treatment. A total of nine painting booths are used to paint the various parts produced. Once painted, the parts are inspected and packaged, then sent to the warehouse area to await shipping.

2.3 Energy Forms and Use in the Plant

Electrical energy is used for lighting, compressing plant air, and operation of various process equipment in the facility. Natural gas is used in the paint drying equipment as well as to provide heating and domestic hot water needs for the facility.

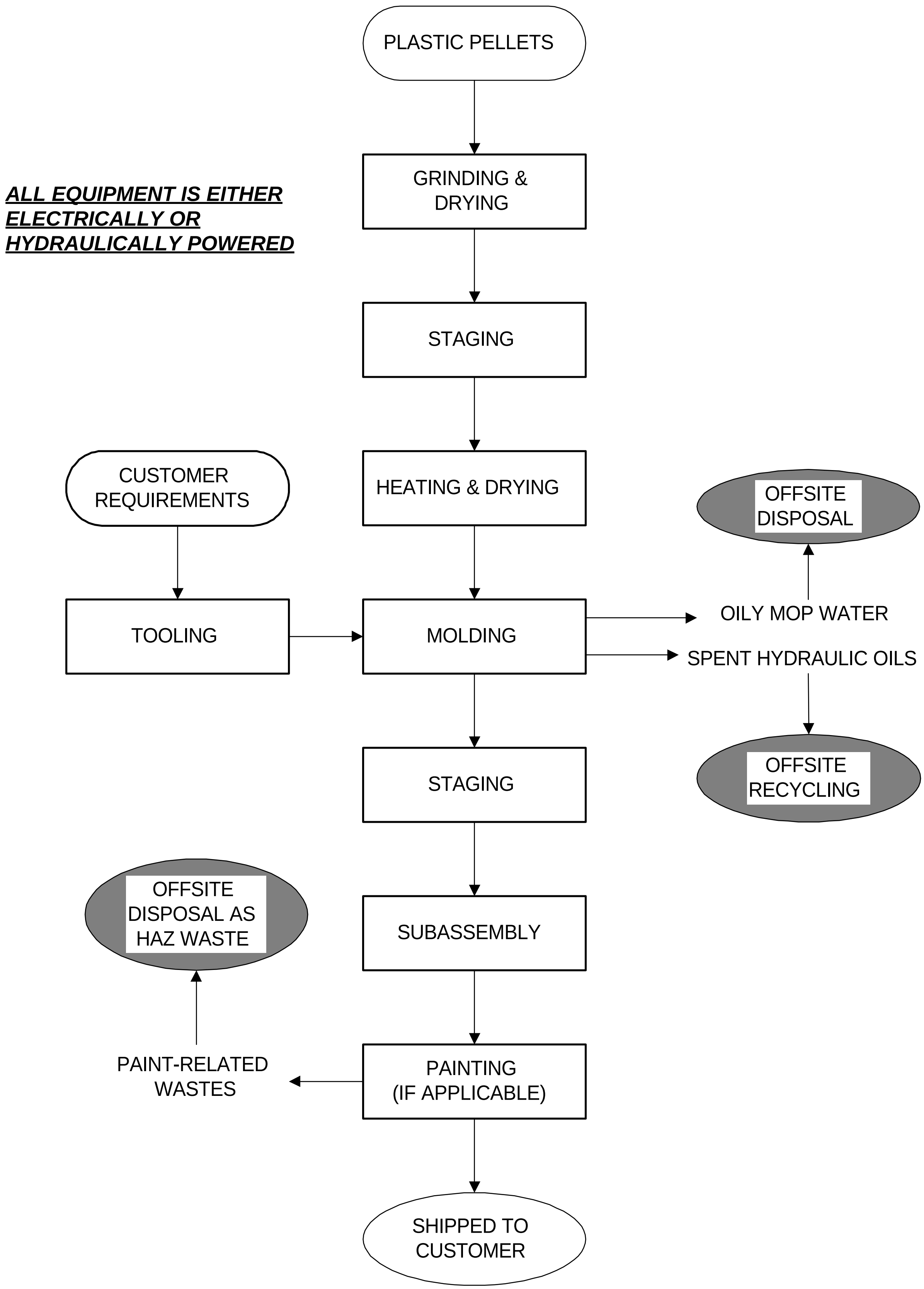


Figure 2: Production Processes and Energy Use for Plastic Injection Molded Parts

2.4 Material Use and Waste Production in the Plant

Waste generation was not considered significant at this plant. Trash and waste water are the only other streams of concern. Since no recommendations were developed to reduce trash generation, the trash bills were not collected for analysis.

Spent fluorescent lamps are the only hazardous wastes considered. Most fluorescent and high intensity discharge (HID) lamps are considered hazardous due to a small quantity of mercury found in the lamps. This hazardous waste can be potentially harmful to human health and the environment and is therefore regulated under federal law as part of the EPA's Resource Conservation and Recovery Act (RCA). The four-foot 34 W and eight-foot 60 W fluorescent lamps are not currently being disposed of as hazardous solid waste. As may be seen in *AR No. 7 - Recycle Used Fluorescent Lamps and Replace with Low Mercury Lamps*, it is estimated that 95 four-foot lamps and 21 eight-foot lamps burn out and disposed of as trash annually. This results in about 548-ft of fluorescent lamps totaling 77 lbs annually. The proper hazardous solid waste disposal of these lamps would cost about $0.58 per foot, or about $320 annually. Recycling the same number of lamps would cost about $100/yr.

2.5 Current Energy Efficiency Practices

The following energy efficiency practices have been implemented:

- Major plant equipment is turned off overnight and on weekends
-
- Evaporative coolers provide cooling in the production area during summer months
- Strip doors are installed to prevent humidity losses from the paint department
- Several ovens and dryers utilized in the plant are fired by natural gas

The following pollution prevention practices have been implemented:

- A silver recovery unit is utilized
- Silkscreens are reclaimed with pressure washer whenever possible.

2.6 Other Assessment Services Offered and Performed

No other energy efficiency or productivity improvement assessments have been offered or performed at this plant.

2.7 Major Plant Equipment

The following list is an approximate summary of the major equipment at this facility.

ELECTRICAL EQUIPMENT

Air Compressors

One 50-hp screw compressor (main)

Heating, Ventilation and Air Conditioning

One paint booth exhaust fan, 5-hp

Seven paint booth exhaust fans, 3-hp each

Major Process Related Equipment

22 injection molders, varying in size from 55 tons to 1,500 tons, 1,376.1 kW total

Plastic dyer loader, 11 kVA

Plastic dryer dehumidifier, 64 kVA

Process chiller, 25-hp

Cooling tower fan, 30 hp

Molder barrel heaters, 22 at 10 kW each

Molder chiller/heaters, 22 at 7 kW each

Lighting

74.3 kW installed capacity

NATURAL GAS-FIRED EQUIPMENT

Heating, Ventilation and Air Conditioning

One boiler (space heater) for the offices, 164,000 Btu/h

One makeup air heating unit for the painting area, 4,675,000 Btu/h

Major Process Related Equipment

- Two bake ovens, about 1.0 MMBtu/h each

3. ENERGY AND WASTE ACCOUNTING

3.1 Energy Management

An essential component of any energy management program is a continuing account of energy use and its cost. Keeping up-to-date records of monthly energy consumption and associated costs can help develop this. When utility bills are received, the energy use and costs should be recorded as soon as possible. A separate record will be required for each type of energy used, i.e., gas, electric, oil, etc. A single energy unit should be used to express the heating values of the various fuel sources so that a meaningful comparison of fuel types and fuel combinations can be made.

The primary electric energy unit used in this report is kilowatt-hours per year (kWh/yr); electric demand savings are reported in kilowatts per year (kW/yr). The primary gas energy unit used in this section is therms (thm) of natural gas. Both electric energy and gas energy savings are also reported in a common unit of British thermal units per year (Btu/yr), or million Btus per year (MMBtu/yr). Some conversion factors for energy and other units are listed below.

UNIT	EQUIVALENT VALUE
GENERAL	
1 MMBtu	1,000,000 Btu
1 gallon of water	8.33 lbs
ELECTRICITY	
1 kWh	3,413 Btu or 0.003413 MMBtu
1 MMBtu	293.0 kWh
1 hp-h (electric)	2,545 Btu or 0.002545 MMBtu
1 hp (electric)	0.746 kW
1 kW	1.341 hp (electric)
NATURAL GAS	
1 therm (thm)	100,000 Btu
1 decatherm (Dth)	10 therms = 1,000,000 Btu = 1 MMBtu
100 cu. ft. natural gas (ccf)	See Section 3.3
1 hp h (boiler)	33,500 Btu
OTHER	
1 gallon No. 2 oil (diesel)	140,000 Btu*
1 gallon gasoline	130,000 Btu*
1 gallon propane	92,000 Btu*
1 ton coal	20,000,000 Btu*

* Varies with supplier

In addition to tracking the monthly energy consumption and cost, it is also desirable to consider the ratio of monthly energy consumption to monthly production. A measure of production consistent with the company's production record-keeping procedures should be used. Examples of appropriate measures are gross sales, number of units produced or processed, or pounds of raw material used. It is important that the same period should be used for energy consumption and production.

3.2 Electric Bill Sample Calculation

The electric energy and peak electric demand are billed monthly using the following secondary general rate:

- Monthly service charge: $15.30/month.
- Electric energy consumption: $0.01645/kWh.
- Incentive Cost Adjustment (ICA): ($0.0005)/kWh as of October 1, 1999. Prior to that, this adjustment was $0.00004/kWh.
- General rate schedule adjustment (GRSA): varied over the past twelve months from 3.61% to 4.79% of consumption, demand and meter fees. As of October 1, 1999, the rate is 4.14%.
- Electric demand (highest 15-minute energy usage during the billing period): $12.55/kW.
- Sales tax: None.

The following is an example of the determination of the electrical charges for January 2000 (from December 27, 1999 through January 25, 2000):

- Electric consumption: 94,880 kWh
- Electric demand: 246.4 kW

Net Electric Usage Cost = 79,040 kWh × [$0.01645/kWh × (1 + 4.14% GRSA) - $0.00005/kWh] = $1,315

Net Electric Demand Cost = 246.4 kW × $12.55/kW × (1 + 4.14% GRSA) = $3,220

Net Service Charge = $15.30 × (1 + 4.14% GRSA) = $16

Net Total Electric Charge = $4,551.

3.3 Gas Bill Sample Calculation

Gas consumption is billed monthly using the commercial gas rate schedule below:

- Monthly service and facility charge: $11.00/month.
- Gas commodity charge: $0.3695/therm
- General rate schedule adjustment: As of July 1, 1999, the GRSA rate is 5.89% of consumption and meter fees. Prior to then, the rate was 3.46%
- Gas cost adjustment: As of October 1, 1999, the rate is $0.04390/thm. Prior to then, the rate was $0.0255/therm.
- Therm billing is based on a factor that includes the elevation, the gas temperature, and the gas energy. The therm factor can vary slightly each month but over the last twelve months, the therm factor averaged 0.9313 therm/ccf.
- Sales tax: None.

The following is an example of the determination of the gas charges for January 2000 (from December 27, 1999 through January 25, 2000):

- Consumption: 10,246 ccf
- Therm factor: 0.9202 therm/ccf

Therms = 10,246 ccf × 0.9202 therm/ccf = 9,428 therms = 942.8 Dth = 942.8 MMBtu

Net Gas Usage Cost = 9,428 therms × [$0.3695/therm × (1 + 5.89% GRSA) + $0.0439/therm] ×
= $4,103

Net Customer Charge = $11 × (1 + 5.89% GRSA) = $12

Net Total Gas Charge = $4,115.

3.4 Avoided Cost of Electrical Energy
The avoided cost of electrical energy consumption for the rate schedule for this plant is composed of the electric energy charge adjusted for ECA and the current GRSA, as follows:

- Avoided cost of electric energy = [$0.01645/kWh × (1 + 4.14% GRSA) - $0.0005/kWh]
= <u>$0.01663/kWh</u>

This avoided cost of electricity is used to determine the electric energy cost savings in this report.

3.5 Avoided Cost of Electrical Demand
The avoided cost of electrical demand for the rate schedule at this plant is composed of the electric demand charge adjusted for the current GRSA, as follows:

- Avoided cost of electric demand = $12.55/kW × (1 + 4.14% GRSA) = <u>$13.07/kW</u>

This avoided cost of electrical demand is used to determine the demand cost savings in this report.

3.6 Avoided Cost of Natural Gas
The avoided cost of natural gas is composed of the current gas commodity charge adjusted for the most recent GRSA, GCA, and taxes, as follows:

- Avoided cost of gas = [$0.3695/therm× (1 + 5.89% GRSA) + $0.0439/therm] = <u>$0.4352/therm</u>

= $0.4352/therm × 10 therm/MMBtu = <u>$4.352/MMBtu</u>

This avoided cost of natural gas is used to determine the gas energy cost savings in this report.

3.7 Summary of Energy Usage and Costs
Table 1 lists the monthly energy consumption and costs by energy for the twelve-month period from February 1999 through January 2000. The energy usage and cost per plant area are also provided. Total annual energy consumption and costs are shown in Figures 3 and 4, and the components of the total electrical costs are shown in Figure 5. From these figures, trends and irregularities in energy consumption and costs can be detected, and the relative merits of energy conservation and load management can be assessed.

Table 1: Facility Energy Summary

Period Considered: February 1999 through January 2000

OVERALL ENERGY & COST SUMMARY

Electric Usage	1,237,920	kWh or	4,225.0	MMBtu	Electric Usage Cost	$21,041
Electric Demand	3,564.8	kW or avg.	297.1	kW/mo.	Electric Demand Cost	$46,544
					Misc. Electric Costs	$192
Gas Usage	71,548	therms or	7,154.8	MMBtu	Gas Cost	$30,266
TOTALS			**11,379.8**	**MMBtu**		**$98,043**

ELECTRICAL SUMMARY

Month	Energy Usage *kWh*	Energy Usage *MMBtu*	Net Usage Cost	Peak Demand *kW*	Net Demand Cost	Avg. Load Factor	Net Other Costs	Total Cost
Jan-00	79,040	269.8	$1,315	246.4	$3,220	46.1%	$16	$4,551
Feb-99	110,880	378.4	$1,894	265.6	$3,454	58.0%	$16	$5,364
Mar-99	92,320	315.1	$1,577	251.2	$3,266	54.7%	$16	$4,859
Apr-99	95,520	326.0	$1,632	292.8	$3,807	42.5%	$16	$5,455
May-99	92,960	317.3	$1,588	308.8	$4,015	43.3%	$16	$5,619
Jun-99	108,160	369.2	$1,848	329.6	$4,286	42.7%	$16	$6,150
Jul-99	117,120	399.7	$2,016	328.0	$4,297	55.1%	$16	$6,329
Aug-99	136,000	464.2	$2,346	334.4	$4,390	49.8%	$16	$6,752
Sep-99	111,040	379.0	$1,915	324.8	$4,264	44.5%	$16	$6,195
Oct-99	97,280	332.0	$1,624	324.8	$4,247	44.6%	$16	$5,887
Nov-99	94,880	323.8	$1,578	307.2	$4,015	46.0%	$16	$5,609
Dec-99	102,720	350.6	$1,708	251.2	$3,283	48.7%	$16	$5,007
TOTALS	**1,237,920**	**4,225.1**	**$21,041**	**3,564.8**	**$46,544**	**48.0%**	**$192**	**$67,777**

NATURAL GAS SUMMARY

Month	Gas Usage *ccf*	Gas Usage *therms*	Gas Usage *MMBtu*	Net Usage Cost	Net Other Costs	Total Cost
Jan-00	10,246	9,428	942.8	$4,103	$12	$4,115
Feb-99	10,798	10,054	1,005.4	$4,100	$11	$4,111
Mar-99	7,402	6,892	689.2	$2,810	$11	$2,821
Apr-99	7,257	6,767	676.7	$2,759	$11	$2,770
May-99	4,845	4,518	451.8	$1,842	$11	$1,853
Jun-99	3,061	2,855	285.5	$1,164	$11	$1,175
Jul-99	2,388	2,225	222.5	$917	$12	$929
Aug-99	2,305	2,146	214.6	$894	$12	$906
Sep-99	2,985	2,779	277.9	$1,158	$12	$1,170
Oct-99	5,919	5,501	550.1	$2,380	$12	$2,392
Nov-99	6,556	6,091	609.1	$2,651	$12	$2,663
Dec-99	13,230	12,292	1,229.2	$5,349	$12	$5,361
TOTALS	**76,992**	**71,548**	**7,154.8**	**$30,127**	**$139**	**$30,266**

ANNUAL ENERGY USAGE BY BUILDING SIZE

Facility Size:	80,000	sq. ft.			
Electric Usage	52,813	Btu/sq. ft./yr	Electric Cost	$0.85	/sq. ft./yr
Gas Usage	89,435	Btu/sq. ft./yr	Gas Cost	$0.38	/sq. ft./yr
Total Energy Usage	142,248	Btu/sq. ft./yr	Total Energy Cost	$1.23	/sq. ft./yr

FIGURE 3: ENERGY USAGE

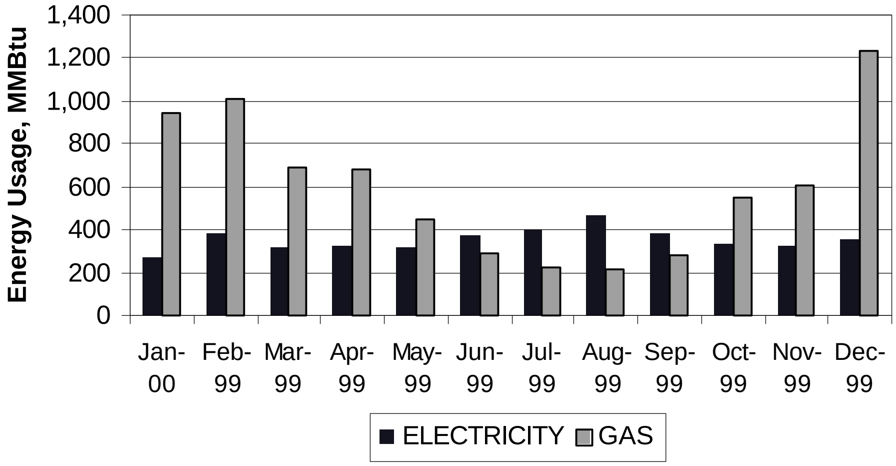


FIGURE 4: ENERGY COSTS

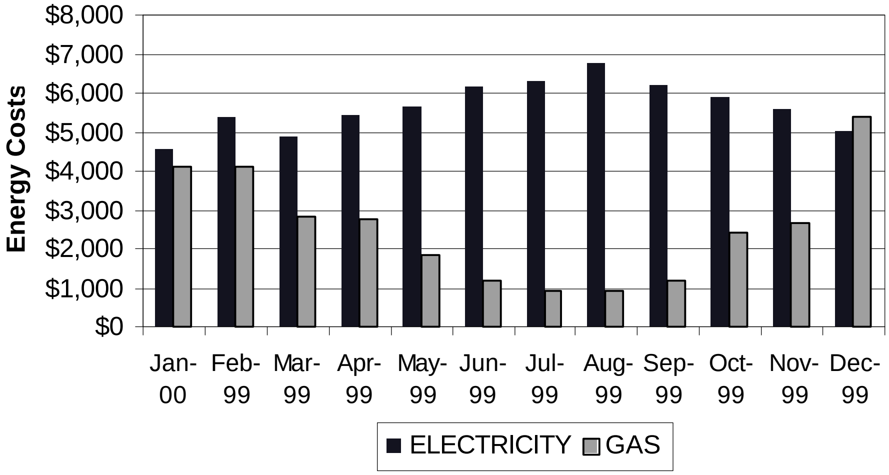
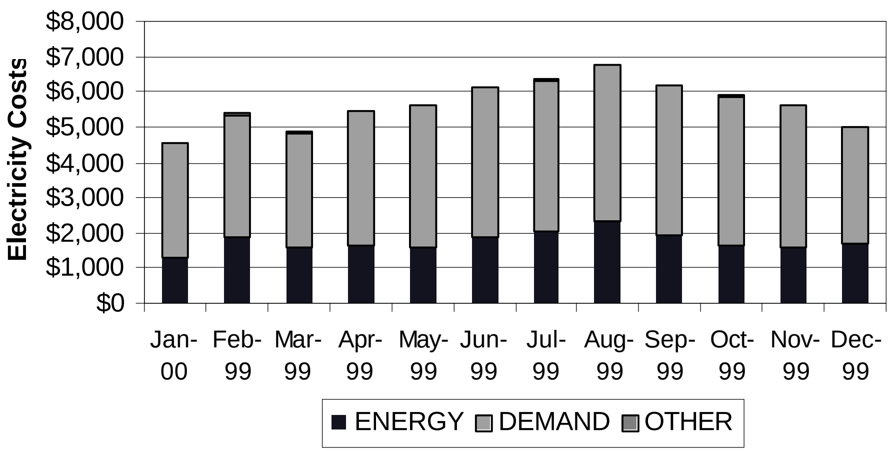


FIGURE 5: ELECTRICITY COSTS



3.8 Water & Sewer Bill Sample Calculation

Two water meters serve this facility. A larger meter serves production and the offices. A smaller meter serves the recent addition. The table below compares the bills for these meters:

Area Served	Water Consump. *gallons*	Fraction of Total	Waste Water *gallons*	Fraction of Total	Total Cost *per year*	Fraction of Total
Main Building	3,810,000	93.2%	3,810,000	93.2%	$15,361	90.1%
Addition	279,000	6.8%	279,000	6.8%	$1,688	9.9%
TOTALS	4,089,000	100.0%	4,089,000	100.0%	$17,049	100.0%

Water consumption through these meters is billed monthly based on the following rate schedule:

- Minimum charge: $11.80 per month for the large meter, $22.17/month for the small meter
- Fire protection: $10 per month on the large meter only
- Water usage: $1.40 per 1,000 gallons for all consumption over 4,000 gallons
- Water surcharge: $0.67 per 1,000 gallons for all consumption on the large meter only

The following is an example of the determination of the water charges for December 1999 (from December 7, 1999 through January 7, 2000):

Production and Offices
Water usage: 481,000 gallons

Monthly Charge = $12 + $10 = $22

Water Usage Cost = (481 – 4 kgals) × $1.40/kgal + 441 kgals × $0.67/kgal = $990

Total Water Cost = $1,012.

Building Addition
Water usage: 6,000 gallons

Monthly Charge = $22

Water Usage Cost = (6 – 4 kgals) × $1.40/kgal = $3

Total Water Cost = $25.

3.9 Water & Sewer Bill Sample Calculation

The waste water discharged to the sewer is billed monthly based on the following rate schedule:

- Minimum charge: $21.50 per month for the large meter (was $20.45/month prior to January 1, 2000); $62.45/month for the small meter (was $63.25/month prior to January 1, 2000 and $51.85/month prior to October 1, 1999)
- Sewer Charge: $2.00 per 1,000 gallons of water consumption over 4,000 gallons, was $1.90 per 1,000 gallons of water consumption prior to January 1, 2000.

The following is an example of the determination of the sewer charges for December 1999 (from December 7, 1999 through January 7, 2000):

Production and Offices
Water usage: 481,000 gallons

Monthly Charge = $22

Waste Water Cost = (481 – 4 kgals) × $2.00/kgal = $954

Total Waste Water Cost = $976.

Building Addition
Water usage: 6,000 gallons

Monthly Charge = $62

Waste Water Cost = (6 – 4 kgals) × $2.00/kgal = $4

Total Waste Water Cost = $66.

3.10 Avoided Cost of Water
The avoided cost of water consists of the most recent usage cost and applicable surcharge for each meter, as follows:

Production and Offices
- Avoided cost of water = $1.40/kgal + $0.67/kgal = $2.07/1,000 gallons

Building Addition
- Avoided cost of water = $1.40/1,000 gallons

3.11 Avoided Cost of Waste Water
The avoided cost of waste water consists of the sewer cost based on water usage as follows:

- Avoided cost of water = $2.00/1,000 gallons

3.12 Summary of Water, Waste Water, and Costs
Table 2 below lists the water consumption, water charges, and sewer charges for the twelve-month period from November 1998 through October 1999.

Table 2: Facility Water and Waste Water Summary
Period Considered: November 1998 through October 1999

Read Date	Water Consump. *gallons*	Water Consump. Cost	Water Meter Fees	Waste Water *gallons*	Waste Water Cost	Sewer Meter Fees	Total Cost
Jan-99	195,000	$384	$44	195,000	$355	$72	$855
Feb-99	192,000	$375	$44	192,000	$350	$72	$841
Mar-99	235,000	$463	$44	235,000	$432	$72	$1,011
Apr-99	195,000	$386	$44	195,000	$356	$74	$860
May-99	256,000	$503	$44	256,000	$471	$72	$1,090
Jun-99	374,000	$735	$44	374,000	$695	$72	$1,546
Jul-99	397,000	$772	$44	397,000	$740	$72	$1,628
Aug-99	379,000	$738	$44	379,000	$705	$72	$1,559
Sep-99	419,000	$838	$44	419,000	$781	$72	$1,735
Oct-99	445,000	$907	$44	445,000	$830	$83	$1,864
Nov-99	515,000	$890	$44	515,000	$964	$83	$1,981
Dec-99	487,000	$993	$44	487,000	$958	$84	$2,079
TOTALS	**4,089,000**	**$7,984**	**$528**	**4,089,000**	**$7,637**	**$900**	**$17,049**

3.13 Summary of Waste Generation and Costs

Hazardous wastes from painting constitute the largest and costliest waste streams at this plant. During the period from May 1998 through January 1999, 26 drums of pumpable waste paint were shipped offsite for fuel recovery and disposal. The fuel cost was $120/drum (including transportation), but generally there were significant fractions of solid waste and aqueous waste in each shipment so that the total disposal cost was $10,346. This averages to $398/drum. In addition, 15 drums of paint solids in sludge form were shipped offsite for fuel recovery and/or incineration at a total cost of $6,030. The disposal cost alternated between $202/drum and $577/drum, so the average cost is $402/drum.

A small amount of nonhazardous liquid waste is also generated at this plant. Oily waste water is generated from floor cleaning; no floor dry is used in the plant. The water is collected in drums that are periodically pumped out by a vacuum truck for recycling. During the period considered, 1,734 gallons of oily waste were shipped offsite at a rate of $0.72/gallon for a total cost of $1,248. The same recycler collects used oil at a cost of $0.20/gallon. During the same period, 695 gallons of used oil were generated and collected for recycling.

Hazardous waste shipments are usually made every three months. At the time of the initial site visit, the most recent shipment occurred on January 5, 1999. Thus, Table 3 below lists the estimated waste disposal volumes and costs for each waste stream from February 1998 through January 1999.

Table 3: Major Waste Streams and Waste Management Costs

Period Considered: February 1998 through January 1999

Waste Stream	Waste Stream Notes	Amount of Waste Generated		Waste Disposal Cost *per year*	Current Waste Disposal Unit Cost	
SOLVENT AIR EMISSIONS						
Base coat	51.75 gals/wk x 3.5 lbs/gal	9,419	lbs	$0	N/A	
Shielding	29.75 gals/wk x 3.5 lbs/gal	5,415	lbs	$0	N/A	
Primer	12.75 gals/wk x 3.5 lbs/gal	2,321	lbs	$0	N/A	
Thinner	27.5 gals/wk x 3.5 lbs/gal	9,295	lbs	$0	N/A	
NONHAZARDOUS LIQUID WASTE						
Oily waste water	Shipped offsite for recycling	1,734	gals	$1,248	$0.72	/gal
Used oil	Shipped offsite for recycling	695	gals	$139	$0.20	/gal
HAZARDOUS LIQUID WASTE						
Waste paint (pumpable)	Includes sludge, water charges	1,430	gals	$10,346	$120	/drum
Waste paint solids/sludge	From painting	825	gals	$6,030	$202	/drum
TOTALS				**$17,763**		

4. ENERGY EFFICIENCY ASSESSMENT RECOMMENDATIONS

AR No. 1 - Improve Power Factor By Installing Capacitors

Estimated Electric On-Peak Demand Savings = 867.03 kW/yr
Estimated Electric Off-Peak Demand Savings = 21.67 kW/yr
Estimated Electric Total Demand Savings = 890.00 kW/yr
Estimated Electric On-Peak Demand Cost Savings = $6,300/yr
Estimated Electric Off-Peak Demand Cost Savings = $120/yr
Estimated Electric Total Demand Cost Savings = $6,420/yr
Estimated Implementation Cost = $15,880
Simple Payback = 2.5 years

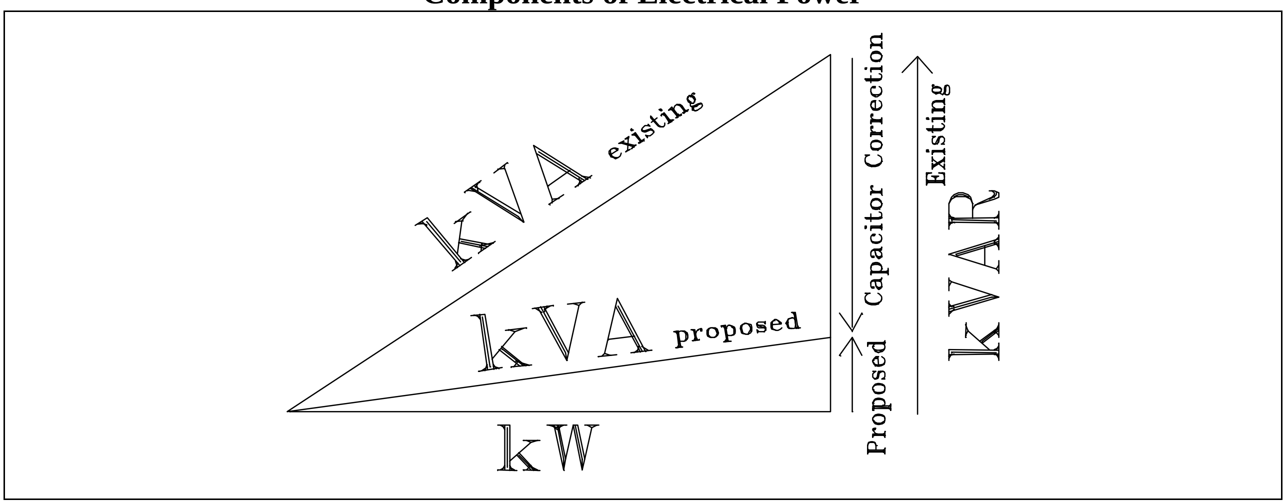
Recommended Action

Capacitors should be installed to correct for low power factor caused by the inductive loads of the motors and lamp ballasts. Savings will result in the form of decreased demand and demand costs.

Background

Power factor is a way of quantifying the reaction of alternating current (AC) electricity to various types of electrical loads. Inductive loads, such as motors and fluorescent lamp ballasts, cause the voltage and current to shift out of phase. The utility company must supply additional power, measured in kilovolt-amps (kVA), to make up for the phase shift. The total power requirement of the load is made up of two components, the resistive, or real, component and the reactive component. The resistive component, measured in kilowatts (kW) by a watt meter, does the useful work. The reactive component, measured in reactive kilovolt-amps (kVAR), represents the current needed to produce the magnetic field for the operation of a motor or other inductive device. This component does no useful work, is not registered on a power meter, but contributes to the heating of generators, transformers and transmission lines, constituting a loss for the utility company.

Components of Electrical Power



The ratio of real, useable power (kW) to apparent power (kVA) is known as the power factor. To reduce reactive losses, the user should increase the power factor to a value as close to unity (1.0) as is practical for the entire manufacturing plant. The utility supplying electricity to the facility assesses a power factor charge when the power factor falls below a specified level because more apparent power must be supplied as the user's power factor decreases.

For example, assume that a manufacturing plant has an average annual power factor of 0.78. Power factor of 0.78 means that for every 78 kW of usable power that the plant requires the utility must supply 78 kW/PF or 100 kVA. If the plant's power factor is changed from 0.78 to 0.95, then for every 78 kW demanded by the plant, the utility need only supply 78 kW/0.95 or 82 kVA. Note for this facility, the electric utility states the power factor as a percentage below 95%. For example, during the month of January 1999, the billing power factor was 11.89%. Thus, the power factor would be 95% minus 11.89% or 83.11%.

The utility supplying electricity to this facility requires the power factor to be as near unity as possible at all times, and assesses a power factor charge when the power factor is below 95%. This charge is accomplished by increasing the billing demand (kW) by 1% for each 1% by which the power factor is less than 95% for on-peak periods. During off-peak times power factor is assess is the same manor, but the facility is only billed for the demand in excess of the peak at the off-peak rate. The table below summarizes demand and power factor information extracted from the bills.

Demand Billing Summary

READ DATE	Number of Billing Days	On-Peak Demand *kW*	On-Peak Power Factor *no units*	On-Peak Billing Demand *kW*	Off-Peak Demand *kW*	Off-Peak Power Factor *no units*	Off-Peak Billing Demand *kW*	Excess Off-Peak Billing Demand *kW*
01/15/99	31	656.98	11.89%	735.09	712.76	10.64%	788.60	53.51
02/17/99	33	697.16	9.86%	765.90	781.18	7.67%	841.10	75.20
03/18/99	29	792.60	9.35%	866.71	787.20	8.93%	857.50	0.00
04/16/99	29	747.00	9.59%	818.64	745.80	8.08%	806.06	0.00
05/14/99	28	763.80	9.87%	839.19	766.80	10.17%	844.78	5.59
06/15/99	32	758.40	8.98%	826.50	771.60	10.06%	849.22	22.72
07/15/99	30	789.60	9.76%	866.66	799.20	10.40%	882.32	15.66
08/13/99	29	765.60	9.94%	841.70	739.80	11.10%	821.92	0.00
09/14/99	32	778.20	8.43%	843.80	793.20	8.82%	863.16	19.36
10/13/99	29	778.20	8.77%	846.45	772.20	9.72%	847.26	0.81
11/12/99	30	736.20	9.43%	805.62	775.80	10.26%	855.40	49.78
12/15/99	33	724.80	10.28%	799.31	778.80	9.47%	852.55	53.24
		8,988.54		9,855.57	9,224.34			295.87

Capacitor banks can be installed to decrease the reactive power (kVAR) and thus the apparent power. Capacitors draw current that leads the voltage, while inductive loads draw current that lags the voltage. The net result is that the current in the supply line is brought more closely in phase with the supply voltage. A power factor of 1.0 indicates that the current and the voltage are exactly in phase.

Capacitors can be installed at any point in the electrical system and will improve the power factor between the point of application and the power source. Capacitors can be added at each piece of equipment, ahead of groups of small motors, or at main services. The advantages and disadvantages of each type of installation are highlighted in the table below.

Types Of Capacitor Installation

Type of Capacitor Installation[1]	Advantages	Disadvantages
Individual Equipment	Increased load capabilities of distribution system	Smaller capacitors cost more per kVAR than larger units
	Better voltage regulation	
Grouped Equipment	Increased load capabilities of the service	Switching means may be required to control the amount of capacitance used
Main Service	Low installation costs	Switching means will usually be required to control the amount of capacitance used
		Does not improve load capabilities of distribution system

Attaining a power factor of exactly unity is very difficult in practice. Installation of too many capacitors in an attempt to obtain a power factor of unity may result in overcompensation for the inductive load caused by motors. The overcompensation results in a situation, where instead of the current lagging the voltage, it leads the voltage. In both cases, the power factor is reduced. Therefore, it is recommended that sufficient capacitors be installed to increase the minimum monthly power factor to 0.95, the power factor at which no charge is billed. Months with higher power factors should experience a correction which results in a power factor greater than 0.95, but not greater than unity since the range of monthly power factors is not large.

Anticipated Savings

The annual cost savings can be estimated by multiplying the demand cost by the increased demand due to low power factor for each month and summing the monthly results, as follows:

$$CS = \sum_{i=1}^{12} (D_{ONPF,i} \times ONDR + D_{OFFPF,i} \times OFFDR) \times BD_i$$

where

$D_{ONPF,i}$ = on-peak billing demand savings for a given month *i*, kW

$ONDR$ = on-peak demand rate, \$/kW/day

$D_{OFFPF,i}$ = excess off-peak billing demand savings for a given month *i*, kW

$OFFDR$ = off-peak demand rate, \$/kW/day

BD_i = number of billing days per billing period for a given month *i*, days

[1] Energy Management, Ottaviano, pg. 2.2-8.

The on-peak and off-peak billing demand savings for a given month *i* are estimated as follows:

$$D_{ONPF,i} = D_{onp,i} \times (PF_{onp,i} - PF_p)$$

$$D_{OFFPF,i} = D_{offp,i} \times (PF_{offp,i} - PF_p) - D_{ONPF,i}$$

where

$D_{onp,i}$	=	on-peak measured peak demand for a given month *i*, kW
$PF_{onp,i}$	=	current on-peak power factor for a given month *i*, no units
PF_p	=	minimum power factor necessary to avoid power factor charges, no units
$D_{offp,i}$	=	off-peak measured peak demand for a given month *i*, kW
$PF_{offp,i}$	=	current off-peak power factor for a given month *i*, no units

In all calculations, a proposed billed power factor term is included. Although the proposed billed power factor is 0.0% for each month, the included variable allows for the calculation of the billing demand savings for a proposed billed power factor of more than 0.0%. Some manufacturers of power factor correction units state that with a target power factor of 95% (or 0.0% billed power factor), the resulting power factor may range anywhere from 92.0% to 98.0%. As an example, the billing demand and cost savings for January 1999 are calculated as follows:

$$D_{ONPF,1} = (656.98\ kW)(11.89\% - 0\%) = 78.11\ kW$$

$$CS_1 = (578.11\ kW)(\$0.2391/kW/day)(31\ days) = \$579$$

$$D_{ONPF,1} = (712.76\ kW)(10.64\% - 0\%) - 78.11\ kW = -2.27\ kW$$

$$CS_1 = (-2.27\ kW)(\$0.1968/kW/day)(31\ days) = (\ \$14)$$

The table on the following page details the potential cost savings over all months.

Summary Of Cost Savings

READ DATE	On-Peak Billing Demand Savings kW	On-Peak Cost Savings	Off-Peak Billing Demand Savings kW	Off-Peak Cost Savings	Total Billing Demand Savings kW	Total Cost Savings
15-Jan-99	78.11	$579	-2.27	($14)	76.00	$565
17-Feb-99	68.74	$542	-8.82	($58)	60.00	$484
18-Mar-99	74.11	$514	0.00	$0	74.00	$514
16-Apr-99	71.64	$496	0.00	$0	72.00	$496
14-May-99	75.39	$505	2.59	$14	78.00	$519
15-Jun-99	68.10	$521	9.52	$60	78.00	$581
15-Jul-99	77.06	$553	6.06	$35	83.00	$588
13-Aug-99	76.10	$527	0.00	$0	76.00	$527
14-Sep-99	65.60	$502	4.36	$28	70.00	$530
13-Oct-99	68.25	$473	0.81	$5	69.00	$478
12-Nov-99	69.42	$498	10.18	$60	80.00	$558
15-Dec-99	74.51	$588	-0.76	($5)	74.00	$583
TOTALS	867.03	$6,298	21.67	$125	890.00	$6,423

Assuming this data is similar each year, the total estimated demand savings are about 867.03 kW/yr on-peak and 21.67 kW/yr off-peak and the total estimated cost savings are about $6,420/yr.

<u>Implementation Cost</u>

The reactance of the capacitors needed to adjust the power factor per kW of electrical power can be determined using the geometric relationships between kW, kVA, and kVAR. This capacitance factor, *CAP*, in units of kVAR/kW, can be estimated as follows:

$$CAP = tan[arccos(PF_c)] - tan[arccos(PF_p)]$$

where

tan	=	tangent function
arccos	=	inverse cosine function, (cosine^{-1})
PF_p	=	projected power factor, kW/kVA

From the utility bills, the minimum power factor during the period considered was in January 1999 when the billed off-peak power factor was 11.89%, resulting in a power factor of 95%-11.89% = 0.831. The power factor below which the utility penalizes customers is 0.95. Thus, the kVAR/KW of capacitors needed to reduce power factor charges can be computed as follows:

$$CAP = tan[arccos(0.79)] - tan[arccos(0.95)] = 0.340\ kVAR/kW$$

The table on the following page, generated from the equation above, provides the capacitance factors that can be used to determine the amount of capacitance required to correct from an existing to a desired power factor.

Capacitance Factor Values

	Corrected Power Factor					
Existing Power Factor	1.00	0.95	0.9	0.85	0.8	0.75
0.66	1.138	0.810	0.654	0.519	0.388	0.256
0.68	1.078	0.750	0.594	0.459	0.328	0.196
0.70	1.020	0.692	0.536	0.400	0.270	0.138
0.72	0.964	0.635	0.480	0.344	0.214	0.082
0.74	0.909	0.580	0.425	0.289	0.159	0.027
0.76	0.855	0.526	0.371	0.235	0.105	
0.78	0.802	0.474	0.318	0.183	0.052	
0.80	0.750	0.421	0.266	0.130		
0.82	0.698	0.369	0.214	0.078		
0.84	0.646	0.317	0.162	0.026		
0.86	0.593	0.265	0.109			
0.88	0.540	0.211	0.055			
0.90	0.484	0.156				
0.92	0.426	0.097				
0.94	0.363	0.034				
0.96	0.292					
0.98	0.203					
0.99	0.142					

The rated installation of capacitors needed to attain the desired power factor, *kVAR*, can be determined as follows:

$$kVAR = D_a \times COR$$

where

D_a = maximum annual demand, kW

COR = correction factor, as calculated above or read from table, kVAR/kW

The maximum monthly demand load during the previous year was 478.86 kW in October 1999. Thus,

$$kVAR = (799.2\ kWmax)(0.340\ kVAR/kW) = 272\ kVAR$$

Thus, a minimum capacitance of 272 kVAR would be required to correct for low power factor. The installation of these capacitors should increase the power factor to the desired level of 95% or 0.0% billed power factor. With this improved power factor there would be no power factor charge.

There are three options available for improving the power factor for the facility, an automatic power factor correction unit, a fixed capacitance unit and a combination of the two. The combination of an automatic power factor correction unit and a fixed capacitance unit allows for more flexibility in power factor management plus meeting the need of the facility. The automatic unit is able to vary its capacitance as the power factor changes, thus accounting for a varying demand usage in the facility. The fixed capacitance unit on the other hand will supply the same amount of capacitance regardless of the facility demand requirements. If the plant demand and power factor are sporadic with time, the automatic unit will supply the best power factor correction. If the power factor and demand are constant with time, then fixed capacitance units will meet the plant's needs at a much lower cost. Although since this facility has a minimally fluctuating demand usage and power factor from month to month, the combination of units would offer the best solution to improving power factor. From a similar analysis from another Colorado Springs IAC client, it is estimated that a fixed capacitor unit rated at 132 KVAR used in conjunction with a 167 KVAR automatic unit would meet the facilities needs plus accounting for varying power factor requirements. The following table itemizes the major items need for implementation.

Implementation Summary

Item	Hardware Cost	Labor Costs	Total
167 KVAR Auto. Unit	$6,800	$3,400	$10,200
132 KVAR Fixed Unit	$1,316	$658	$1,974
Enclosed Breaker	$1,965	$983	$2,948
Fixed Capacitor Switch	$502	$251	$753
Totals	$10,583	$5,292	$15,875

Thus, the estimated implementation cost is $15,880. The annual cost savings of $6,420yr would pay for the implementation cost in about 2.5 years.

To determine the exact optimum power correction factor and the specification of the capacitors require engineering work beyond the scope of this report. Additional professional advice should be obtained from a capacitor supplier or an engineering firm.

AR No. 2 - Reduce Peak Electric Demand

Estimated Electric Demand Savings = 384 kW/yr
Estimated Electric Demand Cost Savings = $2,940/yr
Estimated Implementation Cost = $7,500
Simple Payback = 2.6 years

Recommended Action
An overall energy management system for this facility should be determined and implemented. This would reduce the electrical demand of the facility, thus reducing the overall cost of electrical bills. One suggested strategy is to interlock major process related equipment in order to prevent an overabundant amount of equipment from operating concurrently.

Background
Electric demand is the average rate at which electric energy (measured in kWh) is used during a specific metered period. This period is called the demand interval and is normally 15 minutes in length. Demand is defined as the average energy used during the interval, as follows:

$$kW\ DEMAND = \frac{kWh}{DEMAND\ INTERVAL}$$

The peak demand is the highest average load (measured in kW) reached over all of the demand intervals within a given billing period. A high demand charge therefore results from a large usage of power during any demand interval of the billing period.

High demand charges can result from a high rate of energy usage for short periods during production hours. This problem may have one or more solutions. Plant production schedules and the economics of each situation should be considered in assessing the options. One possible solution may be to distribute the facility's electrical usage over alternate shifts. Thus, if high peak demand occurs during one shift while several equipment stations with heavy electrical usage are used, it may be possible to move usage of one or more stations to a shift with less peak usage resulting in lower overall peak usage.

An alternate solution is to interlock specific pieces of equipment, thereby preventing them from consuming power at their peak rates at the same time. This is not always feasible when the natural operating interval of the equipment is much shorter than the demand interval, or when the machines must be in continuous operation to maximize production. Controlling electrical resistance heaters and other heating and ventilating equipment during periods when process requirements are peaking is another demand control strategy. This is sometimes referred to as duty-cycling or load shedding. This concept is feasible if the thermal storage capacity of the facility is large enough or if slight temperature changes can be tolerated. Often load shedding is accomplished by installing a demand controller.

Demand controllers are devices that can be connected to an electric meter in order to monitor electric demand through the meter. Different warning levels can be selected so that when the peak reaches specified levels, an alarm sounds and displays the level of demand that would need to be shed to remain below a desired level. Depending on the complexity of the demand controller and the equipment being controlled, demand controller may also be able to automatically turn off unnecessary equipment to shed some of the electrical load if necessary. A demand controller is much more reliable than manual control and is often used to ensure the overall reliability of equipment scheduling.

Another possibility is to schedule the operation of high consumption electrical equipment to specific times and to stagger the scheduled employee breaks. Coordinating these times could reduce the amount of equipment operating at one time, thus decreasing the demand. As was mentioned earlier, some equipment must operate continuously to achieve maximum production, thus no rescheduling of that equipment could be done.

<u>Possible Demand Control Strategies</u>

The determination of an overall energy management system that would be best for this facility requires engineering analysis that is beyond the scope of this report. Additional advice should be obtained from a reputable controls supplier or engineering firm if a more detailed study is required. However, here are some suggestions garnered from the experience at other IAC clients:

- Contact the customer service representative at the local utility and discuss the facility's electricity usage in order to gain some insight as to the times when the peak demand occurs each month. By matching this information with production records, patterns may emerge that would indicate strategies for control. For example, if the peak demand is consistently set at a given time that corresponds to running a particular piece of equipment, some rescheduling may be in order.

- Consider the impact that the time of day has on the peak. In many plants the peak demand is set during one of the following periods: 1) in the morning when some of the equipment is first turned on; 2) just before or just after breaks or lunch; 3) during summer afternoons due to cooling; and 4) just before or after shift changeovers. If the peak occurs during these periods, observe the equipment and operations to identify opportunities to reduce unnecessary equipment loading.

- Consider staggering employee breaks. Employees returning from a break period will use process-related equipment that has been idle or turned off. Initial use of idle equipment often increases demand usage for a short period of time.

- Consider moving some operations that occur during the typical peak period to the off-peak period. For example, if an operation can be shifted past office hours, when the office lights are typically off, then the load during the peak demand period will be reduced. Some process equipment may also be moved to a swing shift in order to reduce peak demand. **At this site, every kilowatt reduction in the peak demand from the main building's meter translates into $7.656/month, correlating to about $90/yr savings.**

- Consider staggering the start-up of equipment. For example, motors typically experience an in-rush current, which is much higher than their rated current, when they are first energized. This in-rush current varies depending on the starting torque of the motor, but is at least 5 times as great as the rated current. This higher in-rush current doesn't last long (perhaps 20 seconds), but averaged over 15 minutes with a lot of equipment, this additional load could be significant. For example, a 100 hp motor (74.6 kW) with a 500% inrush current over a 20 second period would result in a demand of 81.2 kW (when averaged over 15 minutes). This power requirement is about 9% higher than the level load of 74.6 kW, which is expected for this motor.

- Develop a strategy to turn off or reduce the load on select equipment when the demand starts to rise. Identify which equipment is critical to the production process first and then consider ways to reduce the load from other equipment.

- Install equipment to monitor demand onsite in real time. Demand managers and controllers are available to monitor and/or automatically turn off equipment (or "shed" equipment) as the demand rises. This will be more instructive than the utility's demand plots, which are good for understanding when the peak *occurred*, but not if it is *occurring*. This equipment will also make it easier to match which equipment is on when the peak demand is set.

- Consider interlocking equipment. Interlocking similar equipment prevents several units from turning on and consuming power at the same time. For example, consider a building cooled by two roof top units (RTUs) with air conditioning compressors that are rated 2.5 ton and one 5 ton whose compressors are rated to draw 3 and 8 kW, respectively. If the two units ran at the same time, the combined load would be 11 kW, which is 3 kW higher than either unit individually. Although it may not be likely that both units would run simultaneously during the same interval of time coinciding with the demand period for each of the cooling months, it may occur during the summer months or about four months per year. Therefore, interlocking the two RTUs would result in an estimated 12 kW per year demand savings.

- Involve production personnel. While equipment causes the peak electric demand, facility personnel typically turn the equipment on. Enlist the support and assistance of production personnel to help identify necessary and unnecessary equipment when the peak occurs. These same people will also have a role in implementing the demand control strategy, so it is important that they understand what peak demand is and how much it costs.

- Be vigilant! Demand control requires daily monitoring. It only takes one motor or one set of equipment to be on for 15 minutes to set an excessive peak for the month.

Anticipated Savings

Proper rescheduling or interlocking of equipment can reduce the monthly peak electrical demand. The cost savings associated with this analysis are dependent on the amount of equipment that can be rescheduled or interlocked. The table on the following page shows some of the rated electric characteristics of equipment used in the facility.

Installed Equipment Loads

Equipment	Rated Power			Number at Facility	Total Power Consumption, *kW*
	hp/unit	*kW/unit*	*tons/unit*		
LIGHTING					
Installed lighting	N/A	N/A		N/A	31.6
AIR COMPRESSORS					
25 hp screw compressor	25.0	21.1		1	21.1
HEATING, VENTILATION, AND AIR CONDITIONING EQUIPMENT					
Trane YCC0606F3MOBF		14.3	4.1	4	57.2
Trane 48DL003		17.6	5.0	1	17.6
York DCVC-FO36N1003		8.4	2.4	1	8.4
Generic RTU		10.6	3.0	1	10.6
Reznor RBL CAB AVA-0826		2.2	0.0	1	2.2
Reznor RBL CAB		0.8	0.0	2	1.5
Swamp cooler		0.8	0.0	2	1.5
Installed Fans & Blowers	N/A	N/A	N/A	N/A	40.3
Sub Total					*139.3*
MAJOR PROCESS EQUIPMENT					
Annealing Ovens		34.3		32	1,097.4
Coffin Oven		102.9		1	102.9
Sub Total					*1,200.3*
TOTAL					**1,392.3**

As can be seen from the table, the estimated installed capacity at this plant is 1,392.3 kW. Typically, the peak electrical demand that occurs during operational hours would be much less then the maximum peak, due to the fact that not all of the equipment is operating at one time. As is seen by studying electrical energy bills from January 1999 through December 1999, an average of about 281 kW of *on-peak electric demand* and about 305 kW of *off-peak electric demand* was recorded for the facility. This suggests that plant personnel are already doing a good job of reducing peak demand. Yet there is still potential for demand savings. The bills also indicate that of the total electric cost of about $56,700 in 1999, on-peak and off-peak demand accounted for about $27,400 or about 48% of the total electric costs.

The equipment summarized in the table on the following page describes the equipment at this facility that operates at all times during the on-peak demand period. The total power consumption of this equipment, 93.0 kW, represents the baseline demand level.

Baseline Demand Level

Equipment	Rated Power		Number at Facility	Total Power Consumption, *kW*
	hp/unit	*kW/unit*		
Installed lighting	N/A	N/A	N/A	31.6
25 hp screw compressor	25.0	21.1	1	21.1
Installed Fans & Blowers	N/A	N/A	N/A	40.3
TOTAL				93.0

Even though demand plots were not available for this facility, experience from other IAC clientele suggests that a reasonable goal for this plant would be a reduction of approximately 10% of the actual electrical demand from the facility. This 10% reduction in demand represents the load of about one annealing oven and suggests that a possible demand strategy might be to limit the number of annealing ovens that are one at any time.

Using a basis of one annealing oven or 32 kW/month of on-peak demand reduction, the yearly demand and demand cost savings, *DS* and *DCS*, that can be expected interlocking specific pieces of equipment and rescheduling certain production operations can be estimated as follows:

$$DS = MDR \times C_1$$

$$DCS = DS \times \text{avoided cost of on-peak electric demand}$$

where

MDR	=	monthly demand reduction, 32 kW/month
C_1	=	conversion constant, 12 months/yr

The demand and associated cost savings are thus estimated as follows:

$$DS = (32)(12) = 384 \text{ kW/yr}$$

$$DCS = (384 \text{ kW/yr})(\$7.656/\text{kW}) = \$2{,}940/\text{yr}$$

Implementation Cost

If the energy management strategy were implemented on a manual basis negligible implementation costs would occur. However, with manual control, the possibility of equipment start-up during a peak period could still raise the monthly demand to an undesirable level. The result of manual implementation and control could reduce demand savings. Installation of equipment to monitor and/or automatically turn off equipment could be purchased to solve this problem. Based on experience at other IAC clients, installation of a demand monitor would cost about $7,500. Consequently, the cost savings of $2,940/yr would pay for the implementation in approximately 2.6 years.

AR No. 3 - Reduce Compressed Air Leaks

Estimated Electric Energy Savings = 82,298 kWh/yr; 280.8 MMBtu/yr
Estimated Electric Energy Cost Savings = $2,530/yr
Estimated Electric Demand Savings = 122.2 kW/yr
Estimated Electric Demand Cost Savings = $900/yr
Estimated Labor Costs = $780/yr
Estimated Total Cost Savings = $2,750/yr
Estimated Implementation Cost = $2,070
Simple Payback = 0.8 year

Recommended Action

Leaks in compressed air lines should be repaired on a regular basis. Savings will result from reduced electrical consumption and electrical demand charges since less power will be required to operate the compressed air system.

Background

The compressed air system at this facility consists of an air line system supplied by one 150 hp compressor running at 127 psig. The line pressure is generally 120 psig. This compressor is in good condition (only three years old), and it supplies air to a system that had several leaks in the valves, fittings, joints, and other pneumatic equipment.

Air leaks within the compressed air system are creating additional operating costs for the company. These additional expenses are the costs associated with the energy required to compress the air that is lost through leaks in the compressed air system. Thus, by fixing the air leaks, the percentage of time the compressor is loaded will decline and the costs associated with supplying compressed air to the facility will decrease in the form of reduced electrical consumption and demand charges. It is noted that maintenance personnel should also implement a preventive maintenance program to continuously check for and repair air leaks. The cost of such a program will subtract from the potential savings. The only one-time implementation cost is the cost associated with the parts and labor required to repair the leaks.

Anticipated Savings

The amount of lost air depends on several factors: the line pressure, the compressed air temperature at the point of the leak, the air temperature at the compressor inlet, and the estimated area of the leak. This leak area, one of the most important factors when calculating air and energy losses, is estimated by listening and feeling the airflow from the leak. It is usually recorded as an equivalent circle diameter (in inches) according to the following scale: 1/64, very small hole; 1/32, small hole; 1/16, medium size hole; 1/8, large hole; and ¼, enormous hole. Values for all factors affecting the cost of compressed air leaks were determined during the site visit, and are listed in the table on the following page. Because of long equipment runs, the compressed air temperature is estimated to be the same as room temperature.

Condition of Pneumatic System at Time of Site Visit

Variable	
Air temperature at compressor inlet, F	85
Atmospheric pressure, psia	11.76
Compressor operating pressure, psig	127
Air temperature at the leak, F	80
Line pressure at the leak, psig	120
Compressor motor size, hp	150
Compressor motor efficiency	93.5%
Compressor type	Rotary screw
Number of stages	1
Compressor operating hours, per year	8,112
Coincidence factor, per month	1.0
Demand usage factor	1.0

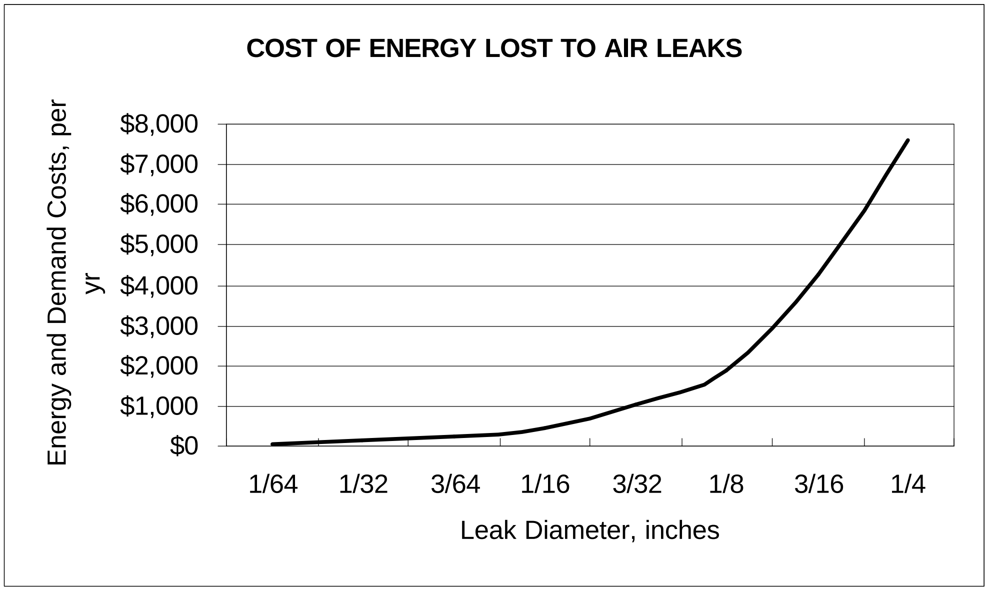
Note that since the air compressor runs the same hours as the machine shop, that the avoided cost of electricity should be that of the machine shop or $0.03213/kWh.

Using these values, the volumetric flow rate, power lost due to leaks, energy lost and cost for leaks of various sizes were calculated specifically for the conditions at this plant. Detailed equations which outline these calculations are included at the end of this analysis. The following table shows the results given that the pressure at the leak is 120 psig. These results are functions of the pressure at the leak and thus the results will vary in cases where the leak is found on a piece of equipment regulated to a different pressure.

Potential Cost of Compressed Air Leaks At This Plant

Leak Diameter	Flow Rate *cfm*	Power Loss *hp*	Demand Savings *kW/yr*	Demand Cost Savings *per year*	Energy Lost *kWh/yr*	Energy Cost Savings *per year*	Total Cost Savings *per year*
1/64	0.5	0.1	0.9	$7	605	$19	$26
1/32	1.9	0.5	4.5	$33	3,026	$97	$130
3/64	4.3	1.0	9.0	$65	6,052	$194	$259
1/16	7.6	1.8	16.1	$117	10,893	$350	$467
3/32	17.2	4.1	36.7	$267	24,811	$797	$1,064
1/8	30.5	7.3	65.3	$475	44,176	$1,419	$1,894
3/16	68.6	16.5	147.7	$1,074	99,851	$3,208	$4,282
1/4	122.0	29.3	262.3	$1,908	177,310	$5,697	$7,605

As the table shows, the cost of compressed air leaks increases exponentially as the size of the leak increases. This can be seen even more clearly in the accompanying graph. As part of a continuing program to find and repair compressed air leaks, the table or graph can be referenced to estimate the cost of any leaks that might be found.



The estimated energy savings and corresponding cost savings for the air leaks found during the site visit are listed in the following table.

Summary of Savings

Location	Leak Diameter	Pressure at Leak *psig*	Flow Rate *cfm*	Power Loss *hp*	Demand Savings *kW/yr*	Demand Cost Savings *per year*	Energy Lost *kWh/yr*	Energy Cost Savings *per year*	Total Cost Savings *per year*
Overhead Pipe, 2" coupling	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
"	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
"	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
Quick Connect	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
PVC Fitting	1/64	60.0	0.3	0.1	0.9	$7	605	$19	$26
Quick Connect	1/64	60.0	0.3	0.1	0.9	$7	605	$19	$26
Quick Connect	1/32	60.0	1.0	0.2	1.8	$13	1,210	$39	$52
Fitting	1/64	50.0	0.2	0.0	0.0	$0	0	$0	$0
Quick Connect	1/64	50.0	0.2	0.0	0.0	$0	0	$0	$0
Fitting	1/64	50.0	0.2	0.0	0.0	$0	0	$0	$0
Valve	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
3/4" Elbow	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
Overhead Pipe, 2" coupling	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
"	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Pressure Gage	1/32	80.0	1.3	0.3	2.7	$20	1,815	$58	$78
Tube Clamp	1/16	120.0	7.6	1.8	16.1	$117	10,893	$350	$467
Fitting	1/64	105.0	0.4	0.1	0.9	$7	605	$19	$26
Tube Clamp	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
1/2" T fitting	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Regulator on Robot	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Fitting	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Electric Valve	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Fitting	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Fitting on Robot	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Hole in Hose	1/16	50.0	3.6	0.9	8.1	$59	5,446	$175	$234
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Robot Wrist	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
Tube Clamp	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Hole in Hose	1/16	120.0	7.6	1.8	16.1	$117	10,893	$350	$467
Tube Clamp	1/32	120.0	1.9	0.5	4.5	$33	3,026	$97	$130
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
1/2" T fitting	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Fitting	1/64	90.0	0.4	0.1	0.9	$7	605	$19	$26
Quick Connect	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Quick Connect	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Filter	1/32	80.0	1.3	0.3	2.7	$20	1,815	$58	$78
Tube Clamp	1/64	120.0	0.5	0.1	0.9	$7	605	$19	$26
Hole in Hose	1/64	15.0	0.1	0.0	0.0	$0	0	$0	$0
Button	1/64	70.0	0.3	0.1	0.9	$7	605	$19	$26
T-Fitting	1/64	95.0	0.4	0.1	0.9	$7	605	$19	$26
Hole in Hose	1/64	95.0	0.4	0.1	0.9	$7	605	$19	$26
TOTALS				13.6	122.2	$905	82,298	$2,629	$3,534

From the table above, the total power loss is seen to be 13.6 hp. It is believed that this result is very conservative since conservative estimates for the leak diameter were recorded. It is possible that the total power loss due to air leaks be as much as 20% of the total compressor power (20% of 150 hp, or 30 hp in this case). In any event, as the table shows, the total estimated energy savings are 82,298 kWh/yr with a corresponding cost savings of about $2,630/yr. The demand savings are 122.2 kW/yr with a corresponding cost savings of about $900/yr.

<u>Annual Operating Costs</u>
After the initial repairs are completed, a preventive maintenance program could be implemented by having someone spend approximately one hour every other week checking for and repairing air leaks. Based on IAC staff discussions with the maintenance supervisor, the estimated cost of maintenance labor is $30/h. Thus, the annual operating costs for such a program are about $780/yr.

<u>Total Annual Savings</u>
The total annual cost savings are the annual electric energy and demand cost savings less the annual operating costs or $3,530/yr less $780/yr = $2,750/yr.

<u>Implementation Cost</u>
In general, implementation involves any or all of the following:

1) replacement of couplings and/or hoses
2) replacement of seals around filters
3) shutting off air flow during lunch or break periods
4) repairing breaks in lines, etc.

Estimations of the specific repairs needed for the leaks found during the site visit are given in the table on the following page, along with the associated implementation costs. The recommended repairs are based on the preliminary analysis of the leaks made by IAC personnel during the site visit. Prices for replacement equipment were obtained from the 1998-1999 Grainger catalog. Maintenance personnel should perform a thorough examination to obtain a more accurate cost assessment. In some cases, the repair cost has been estimated high in order to provide a picture of the worst case scenario.

Implementation Costs

Location	Repair Needed	Parts	Labor	Total Cost
Overhead Pipe, 2" coupling	seal/replace	$100	$100	$200
"	seal/replace	$100	$100	$200
"	seal/replace	$100	$100	$200
Quick Connect	replace	$10	$10	$20
PVC Fitting	glue	$5	$5	$10
Quick Connect	replace	$10	$10	$20
Quick Connect	replace	$10	$10	$20
Fitting	replace	$10	$10	$20
Quick Connect	replace	$10	$10	$20
Fitting	replace	$10	$10	$20
Valve	replace	$10	$10	$20
3/4" Elbow	tighten	$0	$10	$10
Overhead Pipe, 2" coupling	seal/replace	$100	$100	$200
"	seal/replace	$100	$100	$200
Pressure Gage	replace	$15	$10	$25
Tube Clamp	trim hose & reattach	$0	$10	$10
Fitting	replace	$10	$10	$20
Tube Clamp	trim hose & reattach	$0	$10	$10
1/2" T fitting	tighten	$0	$10	$10
Regulator on Robot	replace	$75	$20	$95
Fitting	replace	$10	$10	$20
Electric Valve	replace	$45	$30	$75
Fitting	replace	$10	$10	$20
Tube Clamp	trim hose & reattach	$0	$10	$10
Fitting on Robot	replace	$50	$10	$60
Tube Clamp	trim hose & reattach	$0	$10	$10
Tube Clamp	trim hose & reattach	$0	$10	$10
Hole in Hose	replace hose	$5	$10	$15
Tube Clamp	trim hose & reattach	$0	$10	$10
Tube Clamp	trim hose & reattach	$0	$10	$10
Robot Wrist	??	$100	$100	$200
Tube Clamp	trim hose & reattach	$0	$10	$10
Tube Clamp	trim hose & reattach	$0	$10	$10
Tube Clamp	trim hose & reattach	$0	$10	$10
Tube Clamp	trim hose & reattach	$0	$10	$10
Hole in Hose	replace hose	$5	$10	$15
Tube Clamp	trim hose & reattach	$0	$10	$10
Tube Clamp	trim hose & reattach	$0	$10	$10
1/2" T fitting	tighten	$0	$10	$10
Fitting	replace	$10	$10	$20
Quick Connect	replace	$10	$10	$20
Quick Connect	replace	$10	$10	$20
Tube Clamp	trim hose & reattach	$0	$10	$10
Filter	replace	$30	$20	$50
Tube Clamp	trim hose & reattach	$0	$10	$10
Hole in Hose	replace hose	$5	$10	$15
Button	replace	$35	$10	$45
T-Fitting	tighten	$0	$10	$10
Hole in Hose	trim hose & reattach	$0	$10	$10
TOTALS		$1,000	$1,065	$2,065

Assuming that this work can be done by facility maintenance personnel, these leaks can be eliminated for approximately $2,070. Thus, the cost savings of $2,750/yr would pay for the implementation cost of $2,070 in about 0.8 year.

Equations for Air Flow, Power Loss, and Energy Savings

The volumetric flow rate of free air exiting the hole is dependent upon whether the flow is choked. When the ratio of atmospheric pressure to line pressure is less than 0.5283, the flow is said to be choked (i.e., travelling at the speed of sound). The ratio of 12.2 psia atmospheric pressure to 132.2 psia line pressure (120 psig) is 0.0923. Thus, the flow is choked. The volumetric flow rate of free air, V_f, exiting the leak under choked flow conditions is calculated as follows:

$$V_f = \frac{NL \times (T_i + 460) \times \frac{P_1}{P_i} \times C_1 \times C_2 \times C_d \times \frac{\text{ð} D^2}{4}}{C_3 \times \sqrt{T_1 + 460}}$$

where

V_f	=	volumetric flow rate of free air, cubic feet per minute
NL	=	number of air leaks, no units
T_i	=	temperature of the air at the compressor inlet, °F
P_l	=	line pressure at leak in question, psia
P_i	=	inlet (atmospheric) pressure, psia
C_1	=	isentropic sonic volumetric flow constant, 28.37 ft/sec-°$R^{0.5}$
C_2	=	conversion constant, 60 sec/min
C_d	=	coefficient of discharge for square edged orifice[2], 0.8 no units
	=	pythagorean constant, 3.1416
D	=	leak diameter, inches (estimated from observations)
C_3	=	conversion constant, 144 in^2/ft^2
T_l	=	average line temperature, °F

The power loss from leaks is estimated as the power required to compress the volume of air lost from atmospheric pressure, P_i, to the compressor discharge pressure, P_o, as follows[3]:

$$L = \frac{P_i \times C_3 \times V_f \times \frac{k}{k-1} \times N \times C_4 \times \left[\left(\frac{P_0}{P_i} \right)^{\frac{k-1}{K \times N}} - 1 \right]}{E_a \times E_m}$$

where

L	=	power loss due to air leak, hp
k	=	specific heat ratio of air, 1.4, no units
N	=	number of stages, no units
C_4	=	conversion constant, 3.03 x 10^{-5} hp-min/ft-lb
P_o	=	compressor operating pressure, psia

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2 A.H. Shapiro, **The Dynamics and Thermodynamics of Compressible Fluid Flow**, Vol 1, Ronald Press, N.Y. 1953, p. 100.

3 Chapters 10 and 11, **Compressed Air and Gas Handbook, Fifth Edition**, Compressed Air and Gas Institute, New Jersey, 1989.

E_a = air compressor isentropic (adiabatic) efficiency, no units
E_a = 0.88 for single stage reciprocating compressors
E_a = 0.75 for multi-stage reciprocating compressors
E_a = 0.82 for rotary screw compressors
E_a = 0.72 for sliding vane compressors
E_a = 0.80 for single stage centrifugal compressors
E_a = 0.70 for multi-stage centrifugal compressors
E_a = 0.70 for turbo blowers
E_a = 0.62 for Roots blowers[4]
E_m = compressor motor efficiency, no units

The annual energy savings, *ES*, are estimated as follows:

$$ES = L \times H \times C_5$$

where
H = annual time during which leak occurs, h/yr
C_5 = conversion factor, 0.746 kW/hp

The annual cost savings, *ECS*, can be calculated as follows:

$$ECS = ES \times \text{avoided cost of electricity}$$

The demand savings, *DS*, and demand cost savings, *DCS*, can be estimated as follows:

$$DS = L \times C_5 \times C_6 \times CF \times DUF$$

$$DCS = DS \times \text{avoided cost of electric demand}$$

where
CF = coincidence factor - probability that the equipment contributes to the facility peak demand, per month
DUF = fraction of the year equipment contributes to peak demand, no units
C_6 = conversion constant, 12 months/yr

[4] From Table 1, p. 49, **Pneumatic Handbook, 7th ed.**, Anthony Barber, Trade and Technical Press, 1989.

AR No. 4 - Install Energy Efficient Lamps and Ballasts As Existing Lamps Burn Out

Estimated Electric Energy Savings (after two years) = 17,944 kWh/yr; 61.2 MMBtu/yr
Estimated Electric Energy Cost Savings (after two years) = $380/yr
Estimated Electric Demand Savings (after two years) = 71.5 kW/yr
Estimated Electric Demand Cost Savings (after two years) = $1,120/yr
Estimated Lamp and Ballast Costs (after two years) = $600/yr
Estimated Ballast Installation Labor Costs (after two years) = $240/yr
Estimated Total Cost Savings (after two years) = $660/yr
Estimated Implementation Cost = None
Simple Payback Period = Not Applicable

Recommended Action

The existing fluorescent lamps and magnetic ballasts should be replaced with energy efficient lamps and electronic ballasts as the existing lamps burn out. In addition, incandescent light bulbs should be replaced with energy efficient compact fluorescent bulbs. Energy efficient lamps use less energy than standard lamps with comparable light output. Savings will result in the form of reduced electrical consumption and demand charges.

Background

The facility is designed in such a way, so that it has a unique and inviting feel. As a result, the lighting is supplied by an amalgamation of many different types of lamps and fixtures. The main lighting for the office areas comes from 50-watt halogen track lighting. Several tracks, each with multiple movable lights, are suspended from the ceilings. Additional light is supplied to the office areas by 300-watt halogens, 100-watt incandescent lamps, and 32-watt fluorescent lights (both of straight and U tube designs). In the remainder of the facility, such as the test, production, and assembly areas, the lighting is primarily provided by fluorescent lamps. The bulk of this lighting is 40 and 32-watt fixtures. There is also a limited amount of 34-watt fluorescent lamp and 60-watt incandescent lamp fixtures. When compiling this recommendation, the original aesthetics of the building were considered and assiduous efforts were made not to compromise the facility’s overall appeal.

The production area, which includes the assembly and test areas, operates in two shifts for a total of 4,108 hours per year. Generally, the rest of the building operates from seven in the morning to four at night, five days a week, for a total of 2,340 hours per year. The exception to this is the office areas. Plant personnel determined that, on average, the shifts in the office areas require the lights to be left on for about 12 hours a day, 5 days a week (about 3,120 h/yr).

Facility personnel also informed the IAC team that the principle lighting in the offices (halogen lamps) and the production area (fluorescent lamps) are occasionally left on during weeknights and weekends accidentally. The halogens in the office area are left on overnight (12 hours) about three days per week (about 1,872 h/yr). The fluorescent lamps in the main production area are left on over the weekend (about 55 hours) once a month (about 660 h/yr). These additional lighting hours add to the hours mentioned above.

A common practice for many facilities is to re-lamp on a spot basis as the existing lamps burn out or group re-lamp a fraction of the fixtures in an area of the plant at periodic time intervals depending upon the rated life of the lamps and the lamp’s annual usage hours. These methods of re-lamping spread the total implementation cost over several years, as lamps are replaced only as the existing lamps burn out. Differential costs are used for the lamps in this case and labor costs are not included for fixtures requiring only lamp replacement, as there is no additional labor cost associated with installing energy efficient lamps in place of conventional lamps. *For the purpose of this analysis, only replacement upon burn-out is considered. Further, for reporting purposes, the energy, demand and cost savings are given for the second year of implementation. For recommendations that are implemented incrementally, most of the savings are assumed to occur after two years of implementation.*

The common replacements for the lamps currently used at this facility are as follows:

- ENERGY EFFICIENT FLUORESCENT LAMPS AND ELECTRONIC BALLASTS
  Several options are available for replacing 40 W fluorescent lamps. The most common replacement is 34 W lamps. A more costly replacement is a combination of 32 W T-8 lamps[5] and electronic ballasts that are required to operate these lamps. This combination provides higher quality light while using less energy than the existing magnetic ballasts and 40/34 W T-12 fluorescent lamps. The triphosphor type T-8 lamps provide light that renders color nearly as well as sunlight, thus providing excellent lighting for office and production. A 32 W T-8 lamp provides 5% more light than a 40 W T-12 lamp and 15% more light than a 34 W T-12 lamp. An added benefit to electronic ballasts is the high frequency at which they operate, eliminating the flicker often associated with standard fluorescent lighting.

- COMPACT FLUORESCENT LAMPS
  Compact fluorescent lamps are the recommended replacement for conventional incandescent lamps. These energy efficient lamps provide more lumens than their equivalent incandescent lamps, have a lamp life ten times that of incandescent lamps, and reduce power consumption by about 75%. Compact fluorescent lamps have a Color Rendering Index (CRI)[6] between 80-85, while incandescent lamps have a CRI of about 100.

This analysis considers replacing all of the four-foot, two, three or four-lamp fixtures with four-foot T-8 lamps and one electronic ballast per fixture. It also considers replacing the existing incandescent lights with comparable compact fluorescent lights.

<u>Anticipated Savings</u>
For convenience to the reader, lighting fixture identity codes, specifications, and costs are given in the table on the following page. For reference, all costs are taken from the Grainger 1999-2000 catalog and discounted by 10%.

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5 The T rating refers to lamp tube diameter in 1/8ths of an inch.

6 CRI is a scale from 0-100 on how well a given lamp renders color. A lamp with a CRI of 100 will make objects appear as they do in sunlight.

Lighting Fixture Codes and Specifications

FLUORESCENT LIGHTING											
Lamp/Ballast Description	Fixture Power *W*	Fixture Lumen Output	*CRI*	Lamp Life *hours*	Total Lamp Cost	Ballast Cost	Indiv. Lamp Cost	Indiv. Lamp Lumens	Grainger Catalog Number	Indiv. Ballast Cost	Grainger Catalog Number
4 ft, 4 x 40W T-12 FL fix; 2 mag ballasts	174	12,800	73	20,000	$12.20	$0.00	$3.39	3,200	3V526	$16.25	6X922
4 ft, 3 x 40W T-12 FL fix; 2 mag ballasts	131	9,600	73	20,000	$9.15	$0.00	$3.39	3,200	3V526	$16.25	6X922
4 ft, 2 x 40W T-12 FL fix; 1 mag ballast	87	6,400	73	20,000	$6.10	$0.00	$3.39	3,200	3V526	$16.25	6X922
4 ft, 4 x 34W T-12 FL fix; 2 mag ballasts	144	10,600	62	20,000	$4.28	$0.00	$1.19	2,650	3V477	$16.25	6X922
4 ft, 3 x 34W T-12 FL fix; 2 mag ballasts	108	7,950	62	20,000	$3.21	$0.00	$1.19	2,650	3V477	$16.25	6X922
4 ft, 2 x 34W T-12 FL fix; 1 mag ballast	72	5,300	62	20,000	$2.14	$0.00	$1.19	2,650	3V477	$16.25	6X922
4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	99	11,400	78	20,000	$6.80	$35.06	$1.89	2,850	6VR65	$38.95	3G805
4 ft, 3 x 32W T-8 FL fix; 1 elec ballast	75	8,550	78	20,000	$5.10	$32.99	$1.89	2,850	6VR65	$36.65	3G801
4 ft, 2 x 32W T-8 FL fix; 1 elec ballast	50	5,700	78	20,000	$3.40	$30.51	$1.89	2,850	6VR65	$33.90	3G789
4 ft, 4 x 32W T-8 low Hg FL fix; 1 elec ballast	99	11,400	78	20,000	$7.49	$35.06	$2.08	2,850	4PL15	$38.95	3G805
4 ft, 3 x 32W T-8 low Hg FL fix; 1 elec ballast	75	8,550	78	20,000	$5.62	$32.99	$2.08	2,850	4PL15	$36.65	3G801
4 ft, 2 x 32W T-8 low Hg FL fix; 1 elec ballast	50	5,700	78	20,000	$3.74	$30.51	$2.08	2,850	4PL15	$33.90	3G789
U-lamp, 2 x 40W T-12 FL fix; 1 mag ballast	87	5,600	70	18,000	$12.22	$0.00	$6.79	2,800	3JK12	$16.25	6X922
U-lamp, 2 x 35W T-12 FL; 1 mag ballast	74	4,800	62	18,000	$9.88	$0.00	$5.49	2,400	3V528	$16.25	6X922
U-lamp, 2 x 32W T-8 FL fix; 1 elec ballast	50	5,400	75	20,000	$21.83	$30.51	$12.13	2,700	3V979	$33.90	3G789
8 ft, 2 x 75W T-12 FL fix; 1 mag ballast	165	13,000	73	12,000	$14.38	$0.00	$7.99	6,500	4V468	$27.25	6X923
8 ft, 2 x 75W T-12 FL fix; 1 elec ballast	132	13,000	73	12,000	$14.38	$39.78	$7.99	6,500	4V468	$44.20	3V600
8 ft, 2 x 60W T-12 FL fix; 1 mag ballast	130	11,000	62	12,000	$6.46	$0.00	$3.59	5,500	3V480	$27.25	6X923
8 ft, 2 x 60W T-12 FL fix; 1 elec ballast	107	11,000	62	12,000	$6.46	$39.78	$3.59	5,500	3V480	$44.20	3V600
8 ft, 2 x 60W T-12 low Hg FL fix; 1 mag ballast	130	11,000	62	12,000	$7.11	$0.00	$3.95	5,500	4PL17	$27.25	6X923
8 ft, 2 x 60W T-12 low Hg FL fix; 1 elec ballast	107	11,000	62	12,000	$7.11	$39.78	$3.95	5,500	4PL17	$44.20	3V600
8 ft, 2 x 59W T-8 FL fix; 1 elec ballast	110	11,600	75	15,000	$14.02	$48.87	$7.79	5,800	2D049	$54.30	3G791
8 ft, 2 x 110W HO T-12 FL fix; 1 mag ballast	237	13,500	75	12,000	$23.38	$0.00	$12.99	6,750	3V540	$58.60	3X961
8 ft, 2 x 110W HO T-12 FL fix; 1 elec ballast	205	13,500	75	12,000	$23.38	$53.69	$12.99	6,750	3V540	$59.65	3V967
8 ft, 2 x 95W HO T-12 FL fix; 1 mag ballast	203	16,000	73	12,000	$9.88	$0.00	$5.49	8,000	3V351	$58.60	3X961
8 ft, 2 x 95W HO T-12 FL fix; 1 elec ballast	170	16,000	73	12,000	$9.88	$53.69	$5.49	8,000	3V351	$59.65	3V967
8 ft, 2 x 86W HO T-8 FL fix; 1 elec ballast	160	16,000	75	18,000	$31.77	$80.37	$17.65	8,000	2F962	$89.30	3JN64

INCANDESCENT/HALOGEN/COMPACT FLUORESCENT LIGHTING											
Lamp/Ballast Description	Fixture Power *W*	Lumen Output	*CRI*	Lamp Life *hours*	Total Lamp Cost	Ballast Cost	Indiv. Lamp Cost	Indiv. Lamp Lumens	Grainger Catalog Number	Indiv. Ballast Cost	Grainger Catalog Number
1 x 40W incand. lamp	40	505	100	1,000	$0.44	$0.00	$0.49	505	5V597		
1 x 34W incand. lamp	34	380	100	2,000	$0.89	$0.00	$0.99	380	4V552		
1 x 9W CF lamp w/ballast	9	600	80	10,000	$4.00	$0.00	$4.44	600	2V834		
1 x 50W halogen lamp	46	610	100	2,000	$0.40	$0.00	$0.44	865	5V598		
1 x 60W incand. lamp	60	865	100	1,000	$0.40	$0.00	$0.44	865	5V598		
1 x 52W incand. lamp	52	730	100	1,330	$0.77	$0.00	$0.85	730	4V553		
1 x 13W CF lamp w/ballast	13	825	80	10,000	$4.31	$0.00	$4.79	825	2V835		
1 x 75W incand. lamp	75	1,190	100	750	$0.40	$0.00	$0.44	1,190	5V599		
1 x 67W incand. lamp	67	1,030	100	1,000	$0.77	$0.00	$0.85	1,030	4V555		
1 x 18W CF lamp w/ballast	18	1,150	80	10,000	$16.69	$0.00	$18.54	1,150	6V069		
1 x 100W incand. lamp	100	1,710	100	750	$0.40	$0.00	$0.44	1,710	5V600		
1 x 90W incand. lamp	90	1,465	100	1,000	$0.77	$0.00	$0.85	1,465	4V557		
1 x 26W CF lamp w/ballast	26	1,710	80	10,000	$14.45	$0.00	$16.05	1,710	6V070		
1 x 150W incand. lamp	150	2,850	100	750	$1.59	$0.00	$1.77	2,850	2V286		
1 x 135W incand. lamp	135	2,380	100	1,000	$1.57	$0.00	$1.74	2,380	4V559		
1 x 32W CF lamp w/ballast	32	2,200	82	10,000	$21.81	$0.00	$24.23	2,200	1E635		
1 x 200W incand. lamp	200	3,920	100	750	$2.48	$0.00	$2.76	3,920	2V287		
1 x 300W halogen lamp	300	5,950	100	2,000	$0.40	$0.00	$0.44	865	5V598		2V529

The table below provides the existing lighting as determined from a survey conducted during the facility visit.

Existing Lamp/Ballast Combinations

Building Area	Existing Lamp/Ballast Description	Number of Fixtures	Fixture Power *W*	Total Power *W*	Average Demand *kW/yr*	Usage Time *h/yr*	Energy Usage *kWh/yr*	Lamp Life *hours*	Annual Replcmnt Fraction
Test Area	4 ft, 4 x 40W T-12 FL fix; 2 mag ballasts	20	174	3,480	41.8	4,108	14,296	20,000	20.5%
Conference Room	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	11	99	1,089	13.1	2,340	2,548	20,000	11.7%
Conference Room	1 x 100W incand. lamp	17	100	1,700	20.4	2,340	3,978	750	100.0%
Dining Room	1 x 100W incand. lamp	17	100	1,700	20.4	2,340	3,978	750	100.0%
Lobby	1 x 300W halogen lamp	8	300	2,400	28.8	2,340	5,616	2,000	100.0%
Office Area	1 x 50W halogen lamp	151	46	6,946	83.4	4,992	34,674	2,000	100.0%
Office Area	1 x 300W halogen lamp	24	300	7,200	86.4	4,992	35,942	2,000	100.0%
Office Area	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	28	99	2,772	33.3	3,120	8,649	20,000	15.6%
Office Area	1 x 100W incand. lamp	15	100	1,500	18.0	3,120	4,680	750	100.0%
Stairs	4 ft, 2 x 32W T-8 FL fix; 1 elec ballast	12	50	600	7.2	4,108	2,465	20,000	20.5%
Fourth Floor	1 x 60W incand. lamp	2	60	120	1.4	2,340	281	1,000	100.0%
Fourth Floor Offices	U-lamp, 2 x 32W T-8 FL fix; 1 elec ballast	3	50	150	1.8	3,120	468	20,000	15.6%
Kitchen	4 ft, 4 x 40W T-12 FL fix; 2 mag ballasts	6	174	1,044	12.5	2,340	2,443	20,000	11.7%
Test Cells	4 ft, 4 x 40W T-12 FL fix; 2 mag ballasts	27	174	4,698	56.4	4,108	19,299	20,000	20.5%
Shipping/Receiving	4 ft, 4 x 40W T-12 FL fix; 2 mag ballasts	21	174	3,654	43.8	2,340	8,550	20,000	11.7%
Metrology	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	6	99	594	7.1	4,108	2,440	20,000	20.5%
Assembly	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	12	99	1,188	14.3	4,108	4,880	20,000	20.5%
Bathrooms	4 ft, 2 x 32W T-8 FL fix; 1 elec ballast	50	50	2,500	30.0	4,108	10,270	20,000	20.5%
Production Area	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	105	99	10,395	124.7	4,768	49,563	20,000	23.8%
Production Offices	4 ft, 2 x 34W T-12 FL fix; 1 mag ballast	2	72	144	1.7	4,108	592	20,000	20.5%
Production Task Lighting	4 ft, 2 x 40W T-12 FL fix; 1 mag ballast	5	87	435	5.2	4,108	1,787	20,000	20.5%
Production Task Lighting	4 ft, 3 x 40W T-12 FL fix; 2 mag ballasts	10	131	1,310	15.7	4,108	5,381	20,000	20.5%
TOTALS		552		55,619	667.4		222,780		

The table on the following page provides the proposed recommended changes to lighting.

Proposed Lamp/Ballast Combinations

Building Area	Proposed Lamp/Ballast Description	Percent Existing Lumen Output	No. of Fixtures	Fixture Power *W*	Total Power *W*	Total Energy Usage *kWh/yr*	Annual Average Demand *kW/yr*
Test Area	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	89%	20	99	1,980	8,134	23.8
Conference Room	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	100%	11	99	1,089	2,548	13.1
Conference Room	1 x 26W CF lamp w/ballast	100%	17	26	442	1,034	5.3
Dining Room	1 x 26W CF lamp w/ballast	100%	17	26	442	1,034	5.3
Lobby	1 x 300W halogen lamp	100%	8	300	2,400	5,616	28.8
Office Area	1 x 50W halogen lamp	100%	151	46	6,946	34,674	83.4
Office Area	1 x 300W halogen lamp	100%	24	300	7,200	35,942	86.4
Office Area	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	100%	28	99	2,772	8,649	33.3
Office Area	1 x 26W CF lamp w/ballast	100%	15	26	390	1,217	4.7
Stairs	4 ft, 2 x 32W T-8 FL fix; 1 elec ballast	100%	12	50	600	2,465	7.2
Fourth Floor	1 x 13W CF lamp w/ballast	95%	2	13	26	61	0.3
Fourth Floor Offices	U-lamp, 2 x 32W T-8 FL fix; 1 elec ballast	100%	3	50	150	468	1.8
Kitchen	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	89%	6	99	594	1,390	7.1
Test Cells	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	89%	27	99	2,673	10,981	32.1
Shipping/Receiving	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	89%	21	99	2,079	4,865	24.9
Metrology	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	100%	6	99	594	2,440	7.1
Assembly	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	100%	12	99	1,188	4,880	14.3
Bathrooms	4 ft, 2 x 32W T-8 FL fix; 1 elec ballast	100%	50	50	2,500	10,270	30.0
Production Area	4 ft, 4 x 32W T-8 FL fix; 1 elec ballast	100%	105	99	10,395	49,563	124.7
Production Offices	4 ft, 2 x 32W T-8 FL fix; 1 elec ballast	108%	2	50	100	411	1.2
Production Task Lighting	4 ft, 2 x 32W T-8 FL fix; 1 elec ballast	89%	5	50	250	1,027	3.0
Production Task Lighting	4 ft, 3 x 32W T-8 FL fix; 1 elec ballast	89%	10	75	750	3,081	9.0
TOTALS			552		45,560	190,750	546.8

The annual savings due to replacing burned out conventional lamps with energy efficient lamps (and magnetic ballasts with electronic ballasts for the fluorescent fixture cases) will depend on the life of the old lamps. Assuming an even distribution of lamp life throughout the areas considered, the current annual lamp replacement fraction in a given plant area *i*, f_i, is estimated as follows:

$$f_i = \frac{H_i}{CLL_i}$$

where H_i is the number of hours that the lamps in area *i* operate per year and CLL_i is the lamp life in hours for the lamps in area *i*. As an example, the lamp replacement fraction for the Dyno Test Area, $f_{Test\ Area}$, that operates for 4,108 h/yr with lamps that have an average life of 20,000 hours, is calculated as follows:

$$f_{Test\ Area} = \frac{4{,}108\ h/yr}{20{,}000\ h} = 0.205/yr$$

This value can be used to estimate the number of lamps of a specific type that will burn out each year. All lamps in a fixture are assumed to be of equal age, thus the lamp replacement fraction also represents the fixture replacement fraction for each area of the facility. The energy savings for an area after the first year would be the fraction of fixtures that burn out in that area in a given year multiplied by the difference in the total projected and total current electrical energy usage for all fixtures in that area. Each succeeding year more of the original lamps and ballasts are replaced with energy efficient lamps and electronic ballasts Thus, the energy savings, $ES_{i,n}$, and energy cost savings, $ECS_{i,n}$, in the n^{th} year for a given plant area i, can be estimated as follows:

$$ES_{i,n} = \frac{n \times f_i \times N_i \times (CFW_i - PFW_i) \times H_i}{C_1}$$

$$ECS_{i,n} = ES_{i,n} \times avoided\ cost\ of\ electricity$$

where

N_i	=	number of fixtures in area i, no units
CFW_i	=	power rating of current fixtures in area i, W
PFW_i	=	power rating of proposed fixtures in area i, W
H_i	=	operating hours of fixtures in area i, h
C_1	=	conversion constant, 1,000 W/kW

The savings in a given year cannot be greater than the total savings when all the lamps and ballasts have been replaced (i.e., if $f \times n > 1$, then $f \times n = 1$). As an example, the energy savings, $ES_{Test\ Area,1}$, and energy cost savings, $ECS_{Test\ Area,2}$, that can be realized in the second year ($n = 2$) for the fixtures in the Test Area are calculated as follows:

$$ES_{Test\ Area,2} = \frac{(2)(0.205)(20)(174-99)(4{,}108)}{1{,}000} = 2{,}526\ kWh/yr$$

$$ECS_{Test\ Area,2} = (2{,}526\ kWh/yr)(\$0.04584/kWh) = \$116/yr$$

where the avoided electricity cost for the Dyno meter is used ($0.04584/kWh) since the Testing Area is located in the Dyno building. The demand savings, $DS_{i,n}$, and the demand cost savings, $DCS_{i,n}$, in the n^{th} year for a given plant area i, are given by the following relations:

$$DS_{i,n} = \frac{n \times f_i \times N_i \times (CFW_i - PFW_i) \times CF_i \times DUF_i \times C_2}{C_1}$$

$$DCS_{i,n} = DS_{i,n} \times avoided\ cost\ of\ electric\ demand$$

where

CF_i	=	coincidence factor for fixtures in area i - probability that the equipment contributes to the facility peak demand, per month
DUF_i	=	fraction of the year that fixtures in area i contribute to peak demand, no units
C_2	=	conversion constant, 12 months

Continuing the Test Area example for the first year, since the lights will likely be operating at their rated power when the peak demand is set each month $CF_{Test\ Area}$ is set at 1.0/month. The lamps operate continuously throughout the year, so $DUF_{Test\ Area}$ is set at 100%. *These values for CF and*

DUF are assumed for all fixtures in the plant for both the existing and proposed fixtures. Thus, the demand savings, $DS_{Test\ Area,2}$, and demand cost savings, $DCS_{Test\ Area,2}$, that can be realized in the second year for the fixtures in the Test Area are calculated as follows:

$$DS_{Test\ Area,2} = \frac{(2)(0.205)(20)(174 - 99)(1.0)(1.0)(12)}{1{,}000} = 7.4\ kW/yr$$

$$DCS_{Test\ Area,2} = (7.4\ kW/yr)(\$7.124/kW) = \$52/yr$$

where the avoided demand cost for the Dyno meter ($7.124/kW) is used. The table below provides the annual energy, demand, and cost savings for all of the areas in the plant where lighting retrofits are recommended for the first two years of implementation. Note that the avoided cost of electricity and demand for the Dyno building ($0.04584/kWh and $7.124/kW) are used to calculate the cost savings in the test area. All other areas are located in the main building.

Annual Energy and Demand Savings and Cost Savings

	1st Year					2nd Year				
Building Area	Energy Savings *kWh*	Demand Savings *kW*	Energy Cost Savings	Demand Cost Savings	Total Cost Savings	Energy Savings *kWh*	Demand Savings *kW*	Energy Cost Savings	Demand Cost Savings	Total Cost Savings
Test Area	1,263	3.7	$22	$62	$84	2,526	7.4	$43	$123	$166
Conference Room	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Conference Room	2,944	15.1	$51	$253	$304	2,944	15.1	$51	$253	$304
Dinning Room	2,944	15.1	$51	$253	$304	2,944	15.1	$51	$253	$304
Lobby	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Office Area	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Office Area	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Office Area	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Office Area	3,463	13.3	$60	$222	$282	3,463	13.3	$60	$222	$282
Stairs	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Fourth Floor	220	1.1	$4	$18	$22	220	1.1	$4	$18	$22
Fourth Floor Offices	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Kitchen	123	0.6	$2	$11	$13	246	1.3	$4	$21	$25
Test Cells	1,705	5.0	$29	$83	$112	3,410	10.0	$59	$166	$225
Shipping/Receiving	431	2.2	$7	$37	$44	862	4.4	$15	$74	$89
Metrology	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Assembly	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Bathrooms	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Production Area	0	0.0	$0	$0	$0	0	0.0	$0	$0	$0
Production Offices	37	0.1	$1	$2	$3	74	0.2	$1	$3	$4
Production Task Lighting	156	0.5	$3	$8	$11	312	0.9	$5	$15	$20
Production Task Lighting	472	1.4	$8	$23	$31	943	2.7	$16	$46	$62
TOTALS	13,758	58.1	$238	$972	$1,210	17,944	71.5	$309	$1,194	$1,503

<u>Annual Operating Cost</u>

The annual operating cost for a given fixture in a given area is equal to the fraction of fixtures in that area requiring replacement in a given year multiplied by the sum of the differential lamp costs, electronic ballast costs for that area (if needed) and labor costs (if electronic ballasts are being installed). If no electronic ballasts are being installed the additional labor cost would be zero because the fixture would be serviced anyway when the existing lamp burns out. For a given fixture type in a given area, each year will have the same fraction of fixture replacement and thus equal annual costs. The final year will usually have a smaller fraction of fixtures to replace and thus lower ballast and associated labor operating costs in the last year. After the final year of full implementation, the operating costs will not be zero, but will equal the costs associated with the difference in the lamp costs of the new fixtures relative to the previous fixtures. Consequently, the annual operating cost in the n^{th} year for a given plant area i, $AOC_{i,n}$, can be calculated as follows:

$$\textit{For years before full implementation: } AOC_{i,n} = f_i \times N_i \times \left[\begin{matrix} differential \\ lamp\ cost \end{matrix} + \begin{matrix} electronic \\ ballast\ cost \end{matrix} + \begin{matrix} ballast \\ labor\ cost \end{matrix} \right]$$

and

$$\textit{For the final year of implementation: } AOC_{i,n} = f_i \times N_i \times \left[\begin{matrix} differential \\ lamp\ cost \end{matrix} \right] +$$

$$[1-((n-1)\times f)] \times N_i \times \left[\begin{matrix} electronic \\ ballast\ cost \end{matrix} + \begin{matrix} ballast \\ labor\ cost \end{matrix} \right]$$

and

$$\textit{For the following years: } AOC_{i,n} = f_i \times N_i \times \left[\begin{matrix} differential \\ lamp\ cost \end{matrix} \right]$$

Thus, the annual operating cost for the fixtures in the Test Area for the second year, $AOC_{Test\ Area,2}$, are estimated as follows:

$$AOC_{Test\ Area,2} = (0.205/yr)(20\ fixtures) \left[\begin{matrix} (\$6.80/fixture - \$12.20/fixture) + \\ (\$35.06/fixture\ ballast\ cost) + \\ (\$15.00/fixture\ ballast\ labor\ cost) \end{matrix} \right] = \$184/yr$$

The table below provides the annual operating costs for all of the areas in the plant where lighting retrofits are recommended for the first two years of implementation.

Annual Operating Costs

Building Area	Current Lamp Cost *per fixture*	Proposed Lamp Cost *per fixture*	Proposed Ballast Cost *per fixture*	Current Ballast Labor Cost *per fixture*	1st Year Lamp Cost	1st Year Ballast Cost	1st Yr Ballast Labor Cost	1st Year Annual Cost	2nd Year Lamp Cost	2nd Year Ballast Cost	2nd Yr Ballast Labor Cost	2nd Year Annual. Cost
Test Area	$12.20	$6.80	$35.06	$15.00	-$22	$144	$62	$184	-$22	$144	$62	$184
Conference Room	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Conference Room	$0.40	$14.45	$0.00	$0.00	$239	$0	$0	$239	$36	$0	$0	$36
Dining Room	$0.40	$14.45	$0.00	$0.00	$239	$0	$0	$239	$36	$0	$0	$36
Lobby	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Office Area	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Office Area	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Office Area	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Office Area	$0.40	$14.45	$0.00	$0.00	$211	$0	$0	$211	$43	$0	$0	$43
Stairs	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Fourth Floor	$0.40	$4.31	$0.00	$0.00	$8	$0	$0	$8	$0	$0	$0	$0
Fourth Floor Offices	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Kitchen	$12.20	$6.80	$35.06	$15.00	-$4	$25	$11	$32	-$4	$25	$11	$32
Test Cells	$12.20	$6.80	$35.06	$15.00	-$30	$194	$83	$247	-$30	$194	$83	$247
Shipping/Receiving	$12.20	$6.80	$35.06	$15.00	-$13	$86	$37	$110	-$13	$86	$37	$110
Metrology	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Assembly	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Bathrooms	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Production Area	$0.00	$0.00	$0.00	$0.00	$0	$0	$0	$0	$0	$0	$0	$0
Production Offices	$2.14	$3.40	$30.51	$15.00	$1	$13	$6	$20	$1	$13	$6	$20
Production Task Lighting	$6.10	$3.40	$30.51	$15.00	-$3	$31	$15	$43	-$3	$31	$15	$43
Production Task Lighting	$9.15	$5.10	$32.99	$15.00	-$8	$68	$31	$91	-$8	$68	$31	$91
TOTALS					$618	$561	$245	$1,424	$36	$561	$245	$842

The total annual savings in year *n*, TS_n, are equal to the electric cost savings plus the demand cost savings less the annual operating costs for year *n*. Thus, using the savings and costs from the tables above, the total annual savings for the second year, TS_2, are estimated as follows:

$$TS_2 = \$382 + \$1{,}123 - \$842 = \$663$$

The table below provides a year-by-year breakdown of the annual savings and costs for all fixtures in all areas until full replacement. As the table shows, all recommended fixtures should be replaced by the end of Year 9. From Year 9 on, the total cost savings will be about $2,540/yr.

Annual Savings and Costs By Year

Savings At End Of Year	Energy Savings *kWh*	Energy Cost Savings	Demand Savings *kW*	Demand Cost Savings	Costs At End Of Year	Lamp Cost	Ballast Cost	Ballast Labor Cost	Total Operating Cost	Total Cost Savings
1	13,758	$274	58.1	$936	1	$618	$561	$245	$1,424	-$214
2	17,944	$382	71.5	$1,123	2	$36	$561	$245	$842	$663
3	22,133	$490	84.9	$1,315	3	$36	$561	$245	$842	$963
4	26,320	$598	98.3	$1,503	4	$36	$561	$245	$842	$1,259
5	30,064	$695	110.6	$1,675	5	$36	$506	$221	$763	$1,607
6	30,618	$705	113.4	$1,722	6	$36	$111	$48	$195	$2,232
7	31,172	$714	116.2	$1,770	7	$36	$111	$48	$195	$2,289
8	31,727	$724	119.1	$1,817	8	$36	$111	$48	$195	$2,346
9	32,030	$729	120.6	$1,843	9	$36	$61	$26	$123	$2,449
10	32,030	$729	120.6	$1,843	10	$36	$0	$0	$36	$2,536

Implementation Costs

By replacing the lamps and ballasts as the existing lamps burn out, no additional implementation costs are necessary. Since this analysis considers that the lamps be replaced incrementally, it really doesn't make sense to compute a simple payback period. However, by examining the total cost savings from the table above, it may be seen that about $660 of profit will already start to accrue during the second year.

Additional Information

- When removing lamps, the ballast should be disconnected since the ballast draws energy even when there are no lamps in the fixture.

- Lamp life ratings for fluorescent lamps are based on the assumption of 3 hours between lamp start-ups. If the time between starts is reduced to only one hour, lamp life is reduced by 25%.[7]

7 Chapter 8, **1981 Illuminating Engineering Society Handbook Reference Volume.**

AR No. 5 - Reset Thermostats in Offices

Estimated Electric Energy Savings = 5,900 kWh/yr; 20 MMBtu/yr
Estimated Electric Energy Cost Savings = $140/yr
Estimated Electric Demand Savings = None
Estimated Electric Demand Cost Savings = $0/yr
Estimated Gas Energy Savings = 93 MMBtu/yr
Estimated Gas Cost Savings = $390/yr
Estimated Total Cost Savings = $530/yr
Estimated Implementation Costs = $750
Simple Payback Period = 1.4 years

Recommended Action

Thermostats in the offices could be reset at night and weekends during both the heating and cooling seasons to reduce the overall energy usage in the facility.

Background

Presently, thermostats in the offices are set to maintain a temperature of about 68°F during the heating season and 70°F during the cooling season. Each of the four rooftop units that serve the offices is equipped with its own thermostat, but none of them are programmed to reset the heating and cooling setpoints during the evenings and weekends when the offices are unoccupied. Electric and gas energy savings would result if programmable thermostats were to be installed and properly programmed and maintained. The winter setpoint temperature could be reduced (set back) by 5°F during unoccupied periods. The cooling system in could be increased (setup) by 5°F during these unoccupied periods as well. Adequate time should be allowed for the heating system to bring the space temperatures back to normal thermostat settings prior to occupancy. In general, the time clocks should be set to allow 2-4 hours for morning preheat or precool.

Anticipated Savings

Savings calculations were performed using a software package called Energy 10, Version 1.3[8]. Energy 10 is a comprehensive set of programs for predicting energy consumption and energy system performance and cost in buildings. The system was a collaborative project between the National Renewable Energy Laboratory (NREL), Lawrence Berkeley National Laboratory (LBNL) and the Berkeley Solar Group (BSG). The program has its own user-oriented input language and is accompanied by a library which contains the properties of the construction materials, wall, roof, and floors listed in the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Handbook of Fundamentals. Energy 10 uses an hourly calculation procedure with construction, occupancy, and equipment data for the building to determine the heating and cooling energy required to maintain a given setpoint temperature. Table 3 below summarizes the heating and cooling set points considered for this recommendation.

[8] Energy 10 Software, version 1.3, Passive Solar Industries Council, November 1999.

Table 3 - Building Heating and Cooling Setpoints

Building Zone	Base Case Setpoints	Base Case Setbacks	Proposed Case Setpoints	Proposed Case Setbacks
Office	68F htg 70F clg	None	68F htg 70F clg	63F htg 75F clg

Building modeling with Energy 10 is composed of three parts, namely the building envelope, building loads, and the HVAC system modeling. For this building, construction materials were chosen from the Energy 10 library that most closely resembled the construction materials observed during the site visit. Building geometry is often simplified in the model with the stipulation that the overall area for each building component be accurate. Table 4 below summarizes the components used to construct the building envelope portion of this Energy 10 model.

Table 4 - Building Envelope Components

Components	Area	Materials
Roof	6,600 ft^2	R19: 1" plaster 2.7" polyiso foam 3/8" gypboard
Floor	6,600 ft^2	R-4: 6" earth 4" concrete 1/2" carpet
Walls	1,430 ft^2 - south 1,890 ft^2 - east 1,890 ft^2 - west	R2.2: 8" concrete block 0.5" gypboard
Windows	10 on south 5 on east 5 on west	R2.1: Double-pane, alum. 36" wide x 48" high
UA	2,086.0 Btu/h-F	
Avg. U	0.129 Btu/h-ft^2-F	

Building loads consist of people, lighting, and electric equipment. The assumed loads and schedules are shown in Table 5.

Table 5 - Building Loads for Reference Building

Type	Peak Values	Approx. Schedule
People	8 people	0800-1700 hrs M-F
Lights	0.96 W/ft^2	0800-1700 hrs M-F
Other Equip.	1.52 W/ft^2	0800-1700 hrs M-F

The building was modeled as a one-zone, single-story office space that is heated and cooled with packaged rooftop units equipped with direct expansion cooling units and gas-fired heaters. The base model uses constant heating and cooling with no setback or setup. The weather data file used for the simulation is for Colorado Springs. The file provides hourly weather information such as ambient temperature and solar radiation.

Using this information, a reference case was constructed to simulate the annual energy usage for the offices. Since there are <u>not</u> separate gas and electric meters for the production and office spaces, there is no way to check if this projected energy usage matches the actual usage for the offices. However, some reasonable assumptions were made in the construction of the reference case, as follows:

- The walls were assumed to be constructed of concrete block throughout, with no insulation. This seems to match the actual construction of the walls.

- The office is exposed on just three sides, with the north side joined to the production area. To simulate this, the area of the wall was assumed to be zero. This simulates the case where there is no heat transfer across the wall, which is a likely scenario for this building.

- The roof is assumed to have an R-value of 19, which results from about 2.7" of polyiso foam insulation. This probably overestimates the R-value of the roof and results in lower energy savings.

- The windows were assumed to be double-pane, aluminum frame windows measuring three feet wide and four feet high. Ten windows were assumed on the south-facing front of the building, and five windows were assumed on each of the east and west walls of the office.

- The thermostats were assumed to be set at 68°F during the heating season and 70°F during the cooling season. The heating setpoint is likely lower than the actual setpoint, which would underestimate the gas usage and thereby result in lower energy savings. The cooling setpoint seems reasonable given the IAC experience with other clients.

Allowing that the model provides a reasonable simulation of the office energy use, a low energy model was developed from this base model by adjusting the schedule and temperatures during the unoccupied hours as shown in Table 3. Table 6 below provides the results of this proposed case as compared to the base case:

Table 6 – Comparison of Proposed Case To The Base Case

ELECTRIC BILL COMPARISON							GAS BILL COMPARISON		
MONTH	Simulated Usage *kWh*	Projected Usage *kWh*	Simulated Less Projected *kWh*	Simulated Capacity *kW*	Projected Capacity *kW*	Simulated Less Projected *kW*	Simulated Usage *MMBtu*	Projected *MMBtu*	Simulated Less Projected *MMBtu*
Jan	7,797	7,537	260	27.4	27.0	0.4	76.4	60.3	16.1
Feb	7,027	6,788	239	26.2	25.9	0.3	53.7	41.3	12.4
Mar	7,862	7,594	268	27.5	27.3	0.2	51.8	39.1	12.7
Apr	8,190	7,761	429	31.9	31.9	0.0	29.9	21.3	8.6
May	9,090	8,412	678	33.9	34.2	-0.3	11.9	6.8	5.1
Jun	10,735	9,921	814	40.1	40.4	-0.3	5.0	2.9	2.1
Jul	11,868	11,110	758	39.2	39.7	-0.5	2.3	2.3	0.0
Aug	11,214	10,447	767	35.9	36.4	-0.5	2.3	2.3	0.0
Sep	9,158	8,500	658	35.2	35.8	-0.6	6.6	3.2	3.4
Oct	8,988	8,456	532	35.0	35.3	-0.3	17.1	10.7	6.4
Nov	7,440	7,208	232	29.2	28.9	0.3	43.0	30.9	12.1
Dec	7,725	7,486	239	25.9	25.5	0.4	63.9	49.9	14.0
TOTAL	107,094	101,220	5,874	387.4	388.3	-0.9	363.9	271.0	92.9
	Percent Savings		5%	Percent Savings		0%	Percent Savings		26%

As would be expected, resetting the thermostats will have the greatest impact on gas usage during the winter months. The electric savings are due to reductions in fan usage throughout the year and air conditioning in the summer. Note that the changes in the electric demand are so slight that they are disregarded for this analysis.

Based on these results, the electric energy cost savings, *ECS*, and the gas energy cost savings, *GCS*, can be estimated as follows:

$$ECS = ES \times avoided\ cost\ of\ electricity$$

$$GCS = GS \times avoided\ cost\ of\ gas$$

where

ES = estimated electric energy savings (compared to base model), kWh/yr (from Table 6)
GS = estimated gas energy savings (compared to base model), MMBtu/yr (from Table 6)

Note that for this analysis, the avoided cost of electricity for the off-peak period is used since the savings will likely occur during the off-peak period throughout the year. Thus,

$$ECS = (5{,}900\ kWh/yr)(\$0.02367/kWh) = \$140/yr$$

$$GCS = (93\ MMBtu/yr)(\$4.216/MMBtu) = \$390/yr$$

Thus, the total cost savings are $530/yr.

<u>Implementation Cost</u>
Implementation of this measure will require the purchase of programmable thermostats. Costs for the thermostats are estimated from the Grainger 1999-2000 catalog, (page 3315), as follows:

Estimated Implementation Cost

Grainger Stock #	Description	Grainger List	Est. Discount	Est. Cost	Est. Labor	Total Incl. O & P	No. Req'd	Total Cost
4CZ55	Honeywell Chronotherm, 2 stage heat, 2 stage cool	$174	10%	$157	$30	$187	4	$748
Totals								$748

Note that a 10% discount is considered above the list price and that one hour of labor at $30/h is estimated to install each thermostat. Thus, the total estimated implementation cost is $750. The total cost savings of $530 per year will pay for the implementation cost in about 1.4 years.

Implementation will likely be improved by thorough evaluation of the current thermostats and developing a programming protocol. This may include deciding on the unoccupied and occupied time periods, the setpoints during these time periods, the purchase of lockboxes, or staff training to illustrate the reasons behind resetting the thermostats and the consequences of incorrectly setting these thermostats.

Energy savings due to thermostat setbacks can be achieved without installing programmable thermostats. Facility personnel could set the temperatures up and back manually. This solution would eliminate the implementation costs, but would have its own problems. One problem is that energy and cost savings are dependent upon personnel remembering to set back the thermostats in the evening. The other problem is that morning reheat would not occur until someone turned the thermostats back up to the heating setpoint.

Additional Information: Energy 10 Input and Output

For reference, the input/output page created by Energy 10 for this simulation is provided below.

IAC 460		
Energy-10 Summary Page		Weather file: Colospgs.et1
Variant: Office Thermostat Reset		
Comments:		
Description:	Reference Case	Low Energy Case
Floor Area, ft²	6600	6600
Surface Area, ft²	16190	16190
Volume, ft³	85800	85800
Surface Area Ratio	1.39	1.39
Total Conduction UA, Btu/h-F	2086	2086
Average U-value, Btu/hr-ft²-F	0.129	0.129
Wall Construction	8in cmu, R=2.2	8in cmu, R=2.2
Roof Construction	flat, r-19, R=19.0	flat, r-19, R=19.0
Floor type, insulation	Slab on Grade, Reff=21.6	Slab on Grade, Reff=21.6
Window Construction	3040 double, alum, U=0.78	3040 double, alum, U=0.78
Window Shading	None	None
Wall total gross area, ft²	2990	2990
Roof total gross area, ft²	6600	6600
Ground total gross area, ft²	6600	6600
Window total gross area, ft²	240	240
Window s (N/E/S/W:Roof)	0/5/10/5:0	0/5/10/5:0
Glazing name	double, U=0.49	double, U=0.49
Operating parameters for zone 1		
HVAC system	DX Cooling w ith Gas Furnace	DX Cooling w ith Gas Furnace
Rated Output (Heat/SCool/TCool),kBtuh	263/157/210	263/157/210
Rated Air Flow /MOOA,cfm	9847/990	9847/990
Heating thermostat	68.0 °F, no setback	68.0 °F, setback to 63.0 °F
Cooling thermostat	70.0 °F, no setup	70.0 °F, setup to 75.0 °F
Heat/cool performance	eff=80,EER=8.9	eff=80,EER=8.9
Economizer?/type	no/NA	no/NA
Duct leaks/conduction losses, total %	3/0	3/0
Peak Gains; IL,EL,HW,OT; W/ft²	0.96/0.00/0.26/1.52	0.96/0.00/0.26/1.52
Added mass?	none	none
Daylighting?	no	no
Infiltration, in²	ELA=587.9	ELA=587.9
Results:	(Energy cost: 0.422 $/Therm, 0.024 $/kWh, 7.656 $/kW)	
Simulation dates	01-Jan to 31-Dec	01-Jan to 31-Dec
Simulation status, Thermal/DL	valid/NA	valid/NA
Energy use, kBtu	729400	616500
Energy cost, $	7040	6516
Saved by daylighting, kWh	NA	NA
Total Electric, kWh	107117	101242
Internal/External lights, kWh	19241/0	19241/0
Heating/Cooling/Fan, kWh	0/20303/14430	0/16460/12398
Hot w ater/Other, kWh	0/53144	0/53144
Peak Electric, kW	40.1	40.4
Fuel, hw /heat/total, kBtu	26718/337167/363885	26718/244313/271031
Emissions, CO2/SO2/NOx, lbs	186940/886/486	168078/830/450

5. POLLUTION PREVENTION ASSESSMENT RECOMMENDATIONS

AR No. 6 - Install Cooling Tower To Reduce Water Usage

Estimated Wastewater Reduction = 11,037,600 gal/yr
Estimated Water Cost Savings = $11,040/yr
Estimated Waste Water Cost Savings = $9,900/yr
Estimated Electric Energy Increase = 43,216 kWh/yr; 147.5 MMBtu/yr
Estimated Electric Energy Cost Increase = $790/yr
Estimated Electric Demand Increase = 83.1 kW/yr
Estimated Electric Demand Cost Increase = $1,150/yr
Estimated Total Cost Savings = $19,000/yr
Estimated Implementation Cost = $21,600
Simple Payback = 1.1 years

Recommended Action

A cooling tower should be installed to reduce water usage. Currently, the water that cools the seven diecast machines is sent directly to the wastewater pretreatment system. The water usage would be significantly reduced if these machines were cooled by a cooling tower.

Anticipated Savings

Currently seven diecast machines run 24 hours per day throughout the year. Each machine uses approximately three gallons per minute of water resulting in 11,037,600 gallons/yr of total water usage. Estimates of usage were obtained from data given by plant personnel and from measurements taken during the site visit.

The annual water cost savings, *WCS*, associated with cooling these machines by using a cooling tower can be estimated as follows:

$$WCS = CWU \times ACW + (CWU - PWU) \times ACS$$

where

CWU	=	total current annual water usage, in 1,000 gals/yr
PWU	=	proposed water usage (for evaporation losses from tower), in 1,000 gals/yr
ACW	=	avoided cost of water, $1.00/1,000 gals
ACS	=	avoided cost of waste water, $0.9488/1,000 gals

Based on data from local cooling tower manufacturers, the total evaporation, drift and blowdown losses from a typical 80-ton tower, operated for 6,240 hours/yr, would be approximately 600,000 gallons/yr. Thus,

$$WCS = (11{,}037{,}600 \text{ gals/yr})(\$1.00/\text{kgal}) + (11{,}037{,}600 - 600{,}000 \text{ gals/yr})(\$0.9488/\text{kgal}) = \$20{,}940/\text{yr}$$

Due to the use of the pump and fan on the proposed tower, energy usage will increase slightly. This increase in energy usage, *EU,* and energy cost increase, *ECI,* can be estimated as follows:

$$EU = \frac{HPT \times LF \times C_1 \times H}{EFF}$$

$$ECI = EU \times avoided\ cost\ of\ electricity$$

where

HPT	=	total power of proposed fan and pump, hp
LF	=	average estimated load factor on pump and fan, no units
C_1	=	conversion factor, 0.746 kW/hp
H	=	operating hours of proposed tower, h/yr
EFF	=	average efficiency of fan and pump motor, no units

A local manufacturer estimated the fan and pump horsepower for an 80 ton cooling tower to be 7.5 hp and 3 hp respectively. It will be assumed that the load factor of both motors is 0.75. The average efficiencies for 7.5 hp and 3 hp motors are assumed to be 0.861 and 0.818 respectively. Thus, the increased energy usage is estimated as follows:

$$EU = \frac{(7.5)(0.75)(0.746)(6{,}240)}{0.861} + \frac{(3)(0.75)(0.746)(6{,}240)}{0.818} = 43{,}216\ kWh/yr$$

$$ECI = (43{,}216\ kWh/yr)(\$0.01821/kWh) = \$790/yr$$

The demand increase, *DI*, and demand cost increase, *DCI*, can be estimated as follows:

$$DI = \frac{EU}{H} \times C_2 \times CF \times DUF$$

$$DCI = DI \times avoided\ cost\ of\ electric\ demand$$

where

CF	=	fraction of rated power contributing to the facility peak demand, per month
DUF	=	fraction of the year equipment contributes to peak demand, no units
C_2	=	conversion constant, 12 months/yr

To reflect conservative engineering practice, the cooling tower fans and pumps are assumed to be operating when the peak demand is set each month, so CF = 1.00/month. The cooling tower would need to operate year-round, so DUF = 100%. Thus, the demand increase and the demand cost increase are calculated as follows:

$$DI = \left(\frac{43{,}216}{6{,}240} \right)(12)(1.0)(1.0) = 83.1\ kW/yr$$

$$DCI = (83.1\ kW/yr)(\$13.86/kW) = \$1{,}150/yr$$

The total annual cost savings, *TCS*, are estimated as follows:

$$TCS = WCS - ECI - DI$$

$$TCS = \$20{,}940/yr - \$790/yr - \$1{,}150/yr = \$19{,}000/yr$$

Implementation Cost

Implementation involves installing a new cooling tower to supply the cooling load required by the foundry equipment. From previous experience with similar cooling applications, a cooling tower rated at about 80 tons will be required to handle the total cooling load. An equipment cost estimate of $7,200 was obtained from a reputable dealer in the area. Installation cost was estimated as approximately three times equipment cost as recommended by a local manufacturer. Thus, the total implementation cost is estimated as $21,600. The cost savings of $19,000/yr will pay for the implementation cost within about 1.1 years.

AR No. 7 - Recycle Used Fluorescent Lamps and Replace with Low Mercury Lamps

Estimated Hazardous Solid Waste Reduction (each year) = 77 lbs/yr
Estimated Hazardous Waste Disposal Savings (each year) = $320/yr
Estimated Lamp Recycling Cost (after two years) = $100/yr
Estimated Low Mercury Lamp Cost (each year) = $20/yr
Estimated Total Cost Savings (after two years) =$200/yr
Estimated Implementation Cost = None
Simple Payback Period = Immediate

Recommended Action
All spent fluorescent lamps should be shipped to a recycling facility. This would lessen the potential regulatory exposure that results from disposing these mercury-containing lamps in the local municipal landfill.

Background
Most fluorescent lamps are considered hazardous due to a small quantity of mercury found in the lamps. This hazardous waste can be potentially harmful to human health and the environment and is therefore regulated under federal law as part of the EPA's Resource Conservation and Recovery Act (RCRA). Responsible action in disposal of these lamps is essential to prevent environmental contamination. All lamps containing more than 0.2 mg of mercury, as determined by the Toxic Characteristic Leaching Procedure, must be either recycled by a licensed recycling company, or disposed of as hazardous waste. However, as a means of reducing harmful mercury exposure to the environment, all mercury content lamps should be recycled.

It is suggested that *all fluorescent lamps should be sent to a recycling facility.* Fluorescent lamps can be 100% recycled by a licensed lamp recycler. The practice of recycling fluorescent lamps is currently about $0.40 per four-foot lamp with an additional $0.08 per foot shipping, packaging and profile fee. Currently, the closest lamp recycling centers are found in Arizona, California, and Minnesota. *For the purpose of this analysis, only replacement upon burn-out is considered. Further, for reporting purposes, the energy, demand and cost savings are given for the second year of implementation. For recommendations that are implemented incrementally, most of the savings are assumed to occur after two years of implementation.*

Spent fluorescent lamps can be disposed of as hazardous waste. However this method is much more expensive than recycling, with an average cost of about $2.00 per four-foot lamp, plus an additional $0.08 per foot shipping, packaging and profile fee. Additionally, a landfill may require payment for testing prior to disposal. One disposal option not explored in this analysis is shipment to a hazardous waste landfill for high temperature incineration. Hazardous lamp waste should <u>not</u> be incinerated, as most landfills lack the controls necessary to remove mercury from the flue gas.

Spent lamps should be considered hazardous waste from a regulatory perspective. This will require attention to handling and shipping. As of October 1, 1996, the following EPA and Department of Transportation (DOT) regulations must be followed if the lamps are considered hazardous.

- The appropriate shipping description for discarded fluorescent lamps containing trace amounts of mercury is "Hazardous waste, solid, n.o.s. (D009), 9, NA 3007, PG III."

- Large quantity generators (those that dispose of over 3,600 4-ft. lamps per month) can store hazardous waste up to 90 days. Small quantity generators (those that dispose of fewer than 3,600 4-ft. lamps per month) can store hazardous waste up to 180 days.

Fluorescent lamps can be tested for toxicity through the Toxicity Characteristic Leaching Procedure. This test should be performed on more than one lamp of a given type. The cost to test one lamp is approximately $140, and most lamps fail this test. *To avoid this cost, the generator can assume that all used lamps are hazardous waste and manage them as hazardous waste.*

Anticipated Hazardous Waste Reduction

The fluorescent lighting fixtures for this facility (including lamp type and operation hours) are summarized in the table below.

Existing Light Fixtures and Operating Conditions

Building Area	Existing Lamp/Ballast Description	Number of Fixtures	Fixture Power *W*	Total Power *W*	Annual Average Demand *kW/yr*	Usage Time *h/yr*	Total Energy Usage *kWh/yr*	Rated Lamp Life *hours*	Annual Replcmnt Fraction
Offices	4 ft, 4 x 34W T-12 FL fix; 2 mag ballasts	44	144	6,336	76.0	2,340	14,826	20,000	11.7%
Exit Signs	Plastic exit sign w/ 2 x 15W incand lamps	8	30	240	2.9	8,760	2,102	2,000	100.0%
Halls	4 ft, 4 x 34W T-12 FL fix; 2 mag ballasts	20	144	2,880	34.6	2,704	7,788	20,000	13.5%
Halls	8 ft, 2 x 60W T-12 FL fix; 1 mag ballast	3	130	390	4.7	2,704	1,055	12,000	22.5%
Breakroom	4 ft, 4 x 34W T-12 FL fix; 2 mag ballasts	12	144	1,728	20.7	2,340	4,044	20,000	11.7%
Welding/Prodt'n	4 ft, 4 x 34W T-12 FL fix; 2 mag ballasts	57	144	8,208	98.5	2,704	22,194	20,000	13.5%
Ovens	8 ft, 2 x 60W T-12 FL fix; 1 mag ballast	11	130	1,430	17.2	2,704	3,867	12,000	22.5%
Lathe Room	8 ft, 2 x 60W T-12 FL fix; 1 mag ballast	11	130	1,430	17.2	2,496	3,569	12,000	20.8%
Quality Control	4 ft, 4 x 34W T-12 FL fix; 2 mag ballasts	11	144	1,584	19.0	2,288	3,624	20,000	11.4%
Grinder	4 ft, 4 x 34W T-12 FL fix; 2 mag ballasts	5	144	720	8.6	2,704	1,947	20,000	13.5%
Grinder	4 ft, 2 x 34W T-12 FL fix; 1 mag ballast	2	72	144	1.7	2,704	389	20,000	13.5%
Receiving	4 ft, 4 x 34W T-12 FL fix; 2 mag ballasts	20	144	2,880	34.6	3,328	9,585	20,000	16.6%
Receiving	8 ft, 2 x 60W T-12 FL fix; 1 mag ballast	14	130	1,820	21.8	3,328	6,057	12,000	27.7%
Maintenance	8 ft, 2 x 60W T-12 FL fix; 1 mag ballast	5	130	650	7.8	2,704	1,758	12,000	22.5%
Storage	4 ft, 4 x 34W T-12 FL fix; 2 mag ballasts	8	144	1,152	13.8	2,704	3,115	20,000	13.5%
TOTALS		231		31,592	379.1		85,920		

Using this information, the total length of fluorescent lamps currently being disposed of can be estimated. The annual replacement fraction, RF_i, of burnt out lamps in an area i can be calculated for each fixture as shown below:

$$RF_i = \frac{H_i}{RL_i}$$

where

H_i = annual lamp usage for area i, h/yr

RL_i = rated life for lamps in area i, h

As an example, there are 44 fixtures in the office area that each contain four, four-foot 34W fluorescent lamps with a rated life of 20,000 hours. These lights are being used for about 2,340 hours per year. Using these values, the annual replacement fraction for the fixtures in the office area, *RFp*, can be estimated as follows:

$$RFp = \frac{2{,}340\ h/yr}{20{,}000\ h} = 0.117/yr$$

Using the replacement fraction, the number of fluorescent lamps being disposed of annually, *FD*, for area *i* can then be calculated as follows:

$$FD_i = N_i \times RF_i$$

where

N_i = number of lamps in area *i*

Continuing with the example from above, there are 44 four-lamp fixtures or 176 four-foot lamps in the office area. Using this data, the number of four-foot fluorescent lamps being disposed of annually from this area can be estimated as follows:

$$FDp = (176\ lamps)(0.117) = 21\ \ lamps/yr$$

Using this method, the total number of lamps being disposed of each year can be found for each area of the plant, as shown in the following table.

Estimated Annual Fluorescent Lamp Disposal

Building Area	Annual Usage Time *h/yr*	Rated Lamp Life *hours*	Annual Replacement Fraction	Four-Ft Lamps *per fixture*	Eight-Ft Lamps *per fixture*	Total Four-Ft Lamps	Total Eight-Ft Lamps	Four-Foot Lamps Replaced *per year*	Eight-Foot Lamps Replaced *per year*
Offices	2,340	20,000	11.7%	4	0	176	0	21	0
Exit Signs	8,760	2,000	100.0%	0	0	0	0	0	0
Halls	2,704	20,000	13.5%	4	0	80	0	11	0
Halls	2,704	12,000	22.5%	0	2	0	6	0	1
Breakroom	2,340	20,000	11.7%	4	0	48	0	6	0
Welding/Prodt'n	2,704	20,000	13.5%	4	0	228	0	31	0
Ovens	2,704	12,000	22.5%	0	2	0	22	0	5
Lathe Room	2,496	12,000	20.8%	0	2	0	22	0	5
Quality Control	2,288	20,000	11.4%	4	0	44	0	5	0
Grinder	2,704	20,000	13.5%	4	0	20	0	3	0
Grinder	2,704	20,000	13.5%	2	0	4	0	1	0
Receiving	3,328	20,000	16.6%	4	0	80	0	13	0
Receiving	3,328	12,000	27.7%	0	2	0	28	0	8
Maintenance	2,704	12,000	22.5%	0	2	0	10	0	2
Storage	2,704	20,000	13.5%	4	0	32	0	4	0
TOTALS						712	88	95	21

Thus, a projected 95 four-foot lamps and 21 eight-foot lamps are generated and disposed of each year. By recycling these lamps, the estimated hazardous waste reduction, *RHW*, is as follows:

$$RHW = FL \times WF$$

where

FL = amount of fluorescent lamps disposed of per year for the plant, ft/yr

WF = weight of one foot of lamp, 0.14 lbs/ft

The total length of lamps disposed of would be: 95 four-foot lamps $\times$ 4 feet + 21 eight-foot lamps $\times$ 8 feet = 548 feet total length. A quantity of 400 four-foot lamps weighs approximately 220 lbs, which is about 0.14 lbs/ft. Therefore, the anticipated reduction in hazardous waste is as follows:

$$RHW = (548 \text{ ft of lamps/yr})(0.14 \text{ lbs/ft}) = 77 \text{ lbs/yr}$$

<u>Anticipated Cost Savings</u>

Hazardous Waste Disposal

Since the plant is currently not disposing of the lamps as hazardous waste, a projected hazardous waste disposal cost is required for comparison purposes. The lowest cost method to dispose of spent fluorescent lamps is to crush the lamps onsite. However, the only savings for this method are reduced trucking costs; labor costs would not decrease and no savings in recycling charges would result. Onsite crushing requires the purchase of a small crushing machine, which consists of a 30-gallon drum, a crushing device, a charcoal filter, and a polysleeve enveloping the entire assembly. For disposal, a burnt out lamp is placed into the drum and crushed. The charcoal filter collects all contaminated discharge from the crushing procedure. The polysleeve is provided to reduce the risk of exposure to any damaging fumes. *Due to the potential of exposing plant personnel to mercury fumes, this technique is not recommended.*

This analysis assumes that the plant will have to hire a hazardous waste disposal company to transport the waste to the drop off facility in Denver. Assuming a crushing machine is used to dispose of lamps in drums, the hazardous waste disposal savings, *HWS*, can be estimated as follows:

$$HWS = FL \times DLC$$

where

DLC = per foot cost of disposing lamp as hazardous waste, \$0.58/ft

Thus, the savings in hazardous lamp disposal are calculated as follows:

$$HWS = (548 \text{ ft})(\$0.58/\text{ft}) = \$318$$

This value stays constant over time since the same amount of spent lamps should be generated each year and could be considered for hazardous waste disposal.

TCLP Testing

If the spent lamps are to be disposed of as hazardous waste, a TCLP test should be performed to ensure proper waste characterization and handling. The cost of a single TCLP test is about \$140. By recycling the lamps, the cost of this initial testing will be saved. The cost for a TCLP test is not considered after the first year because it's assumed that further testing would not be required after the initial characterization in the first year. *Thus, the costs for TCLP tests are not considered in calculating the costs at the end of Year 2.*

Annual Operating Costs

Lamp Recycling

Instead of disposing of the spent lamps in the trash or as hazardous waste, the lamps can be shipped offsite for recycling. If the plant can store their spent fluorescent lamps for one year in their facility at no additional cost, then a load of 548 linear feet will need to be recycled. The annual cost of lamp recycling is about $0.18/ft. Thus, the lamp recycling cost, *RC*, is calculated as follows:

$$RC = (548\ ft)(\$0.18/ft) = \$99$$

This cost will lessen over time as more lamps are replaced with low mercury lamps.

Low Mercury Lamp Costs

To avoid the generation of hazardous waste from spent lamps, new low mercury content lamps are recommended to replace the existing lamps as they burn out. Since the facility will be replacing burnt out lamps with low mercury lamps that are below the EPA's threshold for mercury content, reductions in the amount of hazardous waste produced are expected to be seen in time.

At present, low mercury lamps are commonly available for four-foot, 34W T12 lamps, four-foot 32W T8 lamps and eight-foot 60W T12 lamps. From the 1999-2000 Grainger catalog, a GE F40T12/CW/RS/WM four-foot, cool white, 34 W lamp costs $1.19 each and a GE F40T12/CW/RS/WM/ECO four-foot, cool white, 34 W reduced mercury lamp costs $1.31 each. Allowing for a 10% discount, the four-foot reduced mercury lamps cost about $0.11 more. Similarly, a GE F96T12/CW/RS/WM eight-foot, cool white, 60 W lamp costs $3.59 each and a GE F96T12/CW/RS/WM/ECO eight-foot, cool white, 60 W reduced mercury lamp costs $3.95 each. Allowing for a 10% discount, the eight-foot reduced mercury lamps cost about $0.33 more. Thus, for the first year when a projected 95 four-foot and 21 eight-foot lamps are to be replaced, the total incremental cost for low mercury lamps is $17. *Given that the same number of fluorescent lamps as assumed to burn out each year, this incremental cost is considered to be constant over time.*

Total Cost Savings

The total cost savings gained by recycling spent lamps instead of having them disposed of as hazardous waste in a given year *n*, TS_n, can be estimated as follows:

$$TS_n = HWS + TS - RC_n - LWLC_n$$

where

RC_n	=	lamp recycling cost in year *n*, $
$LWLC_n$	=	low mercury lamp cost in year *n*, $

Thus, the total cost savings for Year 2 are estimated as follows:

$$TS_2 = \$318 - \$99 - \$17 = \$202$$

The table on the following page shows a year-by-year breakdown of anticipated savings and costs until all of the lamps have been either recycled or disposed. As the table shows, all lamps should be replaced by the end of Year 9.

Anticipated Annual Savings and Costs for Fluorescent Lamp Recycling

Year	Four-Foot Haz Lamp Recycled	Eight-Foot Haz Lamp Recycled	Length of Haz Lamps Recycled	Weight of Haz Lamps Recycled	Projected Hazardous Waste Cost	Projected Waste Profiling Fee	Projected Recycling Cost	Low Mercury Lamp Cost	Total Savings
1	95	21	548	77	$318	$140	$99	$17	$342
2	95	21	548	77	$318	$0	$99	$17	$202
3	95	21	548	77	$318	$0	$99	$17	$202
4	95	18	524	73	$318	$0	$94	$17	$207
5	95	8	441	62	$318	$0	$79	$17	$222
6	95	0	380	53	$318	$0	$68	$17	$233
7	82	0	329	46	$318	$0	$59	$17	$242
8	52	0	209	29	$318	$0	$38	$17	$263
9	19	0	75	10	$318	$0	$13	$17	$288
10	0	0	0	0	$318	$0	$0	$17	$301

Implementation Costs

In order to implement a fluorescent lamp recycling program at the facility, no additional implementation costs are necessary. Lamps can be re-packed into original lamp packaging for transporting. Therefore, payback on this recommendation is expected to be immediate.

6. PRODUCTIVITY IMPROVEMENT ASSESSMENT RECOMMENDATIONS

AR No. 8 - Reduce Material Shortages and Material Handling

Estimated Labor Cost Reduction = $166,400/yr
Estimated Implementation Cost = $40,000
Simple Payback = 0.2 year

Recommended Action

An overall material handling system should be developed and utilized in order to prevent material shortages, late deliveries, and "catch-up" work. Reductions in labor costs will cause savings as product throughput will be done in more timely fashion.

Background

IAC personnel investigated several opportunities to improve productivity at this plant. Investigation by the team discovered that production throughput at the plant is likely constrained by internal material handling procedures. Facility personnel mentioned several example problems that are common at this facility. For instance, there are concerns that the layout of the facility necessitates excess material handling time; time that is non-value added. There are also concerns that there is an insufficient prioritizing schedule for quality control (QC) inspections. Many times, a product that is due out quickly is checked by QC after products that are due at a latter time. Also, the four-axis, computer programmed laser, which is currently the only cutting tool utilized by the facility to cut, scribe, and edge the raw material quartzware plates into the desired shapes and textures, is generally known to deliver parts late and is the facility's primary constraint. The late deliveries are caused from laser downtime and the production of parts with incorrect dimensions. Since laser operations are one of the first steps in the manufacturing process, material shortages resulting from the laser propagate down the manufacturing stream. The machine shop is also known to deliver late parts. As another example, miscommunication between warehouse personnel and the welders leads to cases where common welding supplies, which are stored and utilized at the welder's workstations, are not replenished. When this happens, welder's time is wasted trying to gather the much-needed supplies. Finally, miscommunication between the purchasing department and outside vendors leads to instances where supplies are not delivered to the plant at the appropriate time.

Although each of these problems by themselves may seem insignificant when compared to the challenges associated with running a manufacturing plant, the culmination of all of the problems together takes place at a tremendous expense to the facility. The calculations performed under *Anticipated Savings*, are provided to illustrate the effect these material handling problems have on the bottom line. By taking a systems approach to the material handling issues, plant personnel should be able to identify the specific steps needed to assure that these negative impacts are lessened or eliminated. It is recommended that a consultant, skilled in the concepts of the Theory of Constraints (TOC), be hired to help employees develop a systems approach to the material handling problems. Such training would be specific to the plant operations, yet flexible, to allow the employees to adapt these principles to changing conditions. Hopefully, these skills will also help generate opportunities for additional business that might be generated from improved distribution and quicker delivery times. In any event, the costs involved with implementing this recommendation are the costs associated with hiring such a consultant. Employee training may result in additional implementation costs.

Possible Strategies for Material Shortage and Material Handling Reduction

The determination of an overall material handling system that would be best for this facility requires engineering analysis that is beyond the scope of this report. Additional advice should be obtained from a consultant skilled in the TOC concepts. However, the following list of questions and suggestions summarizes important material handling concepts garnered from experience at other IAC clientele[9].

REDUCE EXCESS MATERIAL HANDLING TIME:

- Is excessive double handling of goods due to a convoluted floor layout or improper shipment scheduling? If yes, could the floor layout be modified or equipment be relocated to reduce internal material handling?

- Consider laying-out the factory floor into a more product-oriented, rather than process-oriented, fashion. Currently, the major process related equipment is grouped in terms of their function (process). That is, the ovens are grouped together and located in one corner of the facility, the welding stations are grouped together and located in another corner, etc. Instead, grouping major process related equipment in a product-oriented fashion has several advantages. When process related equipment is grouped in a product-oriented fashion, the processes a particular material must transverse are linked much more closely and the distance materials have to travel to complete the total production sequence is considerably shorter. There is also less confusion about where a particular material must travel next in the sequence of processes.

REDUCE MATERIAL SHORTAGES FROM INTERNAL PRODUCTION BOTTLENECKS:

- Since the laser is known to have downtime that affects production throughput, is there an effective preventive maintenance (PM) program in place that will minimize unscheduled work stoppages of the laser? If not, will a preventive maintenance program prevent laser downtime? May such a program be implemented? The costs associated with such a program will certainly be minimal when compared to the savings that will result.

- Are the best and most reliable employees working at the laser, so that the numbers of parts produced with incorrect dimensions are minimized? Do these workers receive appropriate incentives for producing quality work and high production rates?

- Is it possible to have a QC inspection take place on the parts leaving the laser area? This will ensure time is not wasted downstream, welding defective parts.

- Consider purchasing an abrasive waterjet to ease the strain on the laser. See *AR No. 9 - Purchase Abrasive Waterjet*, for more information on this recommendation.

- Plant personnel suggested that the equipment in the machining department is sufficient to produce parts on time. Will employee training yield better throughput time?

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[9] Some of these suggestions are taken from: Kiyoshi Suzaki, **The New Manufacturing Challenge**, The Free Press, N.Y. 1987.

REDUCE MATERIAL SHORTAGES FROM OUTSIDE VENDORS:

- Are raw material and purchased part deliveries based on production needs or supplier convenience?

- Are there certain items of raw material that commonly produce material shortages? If so, can inventory levels of these items be increased?

- May the purchasing department be employed to confirm material delivery dates? This will help minimize the chance of undelivered supplies.

OTHER GENERAL GUIDELINES FOR MATERIAL HANDLING PROBLEMS:

- Can a prioritizing schedule be made for QC inspections? This should be done to ensure that the products that must be completed first are in fact completed first.

- Can a computerized data handling system be purchased or developed?

- Can production volumes be leveled on a monthly, bi-monthly, or weekly basis? By leveling the schedule, production personnel can focus their attention on production activities without having to worry much about sudden schedule changes or expediting work. Leveled scheduling can vastly improve line performance and reduce parts shortage problems. In order to make leveled production work, both sales and production people need to decide on the fixed level of production volume and its duration. Whether a company is marketing-driven or manufacturing-driven, both sides need to understand each other very well in order to arrive at the best solution for the company. At the same time, both sides need to do their best to help each other. For example, production might improve flexibility and lead time, while sales and marketing could improve the accuracy of their forecast and reduce the information lead-time for order taking.

- Are production problems, such as low productivity and necessary overtime due to lost worker time? If yes, could these problems be addressed by implementing employee training or cross-training?

<u>Anticipated Savings</u>

Plant personnel estimated that about 10 to 15 % of the entire facility-wide payroll is used to pay for material shortage "catch-up" activities caused by material handling problems. Since this figure is given as a percentage of the total facility-wide payroll, the annual labor cost savings, *LCS*, associated with this recommendation may be estimated as follows:

$$LCS = \%PR \times PR$$

where

$\%PR$	=	percentage of the facility-wide payroll associated with material shortage "catch-up" activities, no units
PR	=	facility-wide payroll, \$/yr

Currently, the facility-wide payroll is between \$30,000 and \$34,000 per week (about \$1,664,000/yr) as explained by plant managers. Conservatively using the lowest estimated percentage of *%PR*, the annual labor cost savings may be estimated as follows:

$$LCS = (0.10)(\$1{,}664{,}000/yr) = \$166{,}400/yr$$

It is noted that these savings represent, and are meant to illustrate, the non-value added labor costs associated with the production process. The savings garnered from this recommendation will not result from the reduction of employee headcount however. Instead, the savings associated with this recommendation will result from either or both of following reasons. First, savings will result in the form of reduced overtime activities, as less “catch-up” time will be spent trying to meet production deadlines. The reduction in this non-value added “catch-up” time would in effect increase the company’s profit margin. Secondly, although not considered in this recommendation, in all likelihood, savings will result in the form of increased production and associated profits since the extra customer satisfaction garnered from on-time deliveries may spawn additional sales opportunities.

Implementation Cost

The implementation costs associated with making the necessary changes to material handling systems are difficult to quantify. Generally, no significant equipment purchases are required, only changes to procedures. However, since it is recommended that a consultant, trained in the TOC, be hired to help employees develop a systems approach to material handling, it is possible to make some estimates on possible implementation costs associated with this recommendation. A suitable consultant should be able to be hired for about $20,000. Employee training is another action with monetary consequences. The cost for employee training depends on the complexity and sophistication of the training required, but a reasonable estimate is also $20,000. Consequently, the annual total cost savings of $166,400 will pay for the estimated total implementation cost of $40,000, in about 0.2 years.

AR No. 9 - Reduce Natural Gas Purchase Costs

Estimated Gas Cost Savings = $7,900/yr
Estimated Implementation Cost = $500
Simple Payback = less than one month

<u>Recommended Action</u>
The cost for natural gas supplied to this facility could be reduced by purchasing gas on a firm basis directly from a gas supplier or gas marketer in the area, such as HS Energy.

<u>Background</u>
Due to a 1986 ruling by the Federal Energy Regulatory Commission (*FERC*, order 436), facilities can purchase natural gas from a number of suppliers and transporters in Colorado and throughout the U.S. The potential exists for purchasing contract natural gas from a local transporter, or from a gatherer/transporter in the Denver area. The current natural gas supplier (Public Service Company of Colorado or PSCo) is an open access carrier as defined under the *FERC* order 436, and thus is required to allow carriage of gas from other suppliers through their system. Some clients have been able to reduce gas costs by up to 20% through such purchases. The amount saved is dependent upon the volume of gas purchased, summer gas usage, availability of alternative fuel sources, peak gas usage rates and transportation costs (dependent on location).

There are several gas suppliers that can provide contract gas. HS Energy in Denver is one such supplier *(Note: this does not imply endorsement of HS Energy by the U.S. DOE or Colorado State University).* HS Energy has an established gas service program that could provide gas savings for this facility. A comparison of the PSCo CG rate currently in place at this site and the projected wellhead gas scenario are presented below.

Note that this idea will not result in a reduction in energy consumption but will only lower the natural gas costs. Since this will lower the costs of production, this recommendation is considered as a productivity improvement action.

CURRENT SERVICE
Firm gas is currently purchased from PSCo. During the twelve-month period considered, 123,060 therm or 12,306 Dth of gas were purchased. As shown in section 3.6, the avoided cost of natural gas is currently $4.539/Dtm. The monthly service cost is $11.00/month. Adjusting this cost to allow for 5.89% GRSA and 4.3% sales tax, the estimated annual cost under the current system, *CGC*, can be estimated as follows:

$$CGC = (12{,}306\ Dth/yr)(\$4.539/Dth) + (\$11.00/mo)(12)(1+5.89\%)(1+4.3\%) = \$56{,}000/yr$$

PROPOSED SERVICE
Firm gas could be purchased through a gas supplier, with transport gas as a source, and transportation and delivery provided by PSCo. Either the supplier or PSCo could supply firm backup, *but it is assumed to be included in the commodity cost for this analysis*. All costs are estimated based on contracts with HS Energy and PSCo rate data for transport service (updated: October 1999) as follows:

- $2.608/Dth – HS Energy commodity charge. *Note: this number is based on market rates as of February 8, 2000. A specific contract price would need to be determined from the supplier*.
- $0.358/Dth - PSCo standard commodity (transport) fee. Note that this charge is subject to a 14.1% GRSA for transport gas service.
- $185/month for the first meter - PSCo service and facility charge. This charge too is subject to a 14.1% GRSA
- $3.30/Dth (peak) - PSCo firm capacity charge. The peak usage is estimated to be the average daily gas usage divided by a load factor of 35%. This charge too is subject to a 14.1% GRSA.

Natural gas usage for the last 12 months was 12,306 Dth, leading to an average daily usage of about 33.7 Dth/day. Dividing by a load factor of 35%, the peak daily usage is 96.3 Dth/day.

In addition to the peak capacity, the losses in distribution must also be considered. PSCo usually considers gas losses of about 3.7% so that additional amount must be purchased from the contract supplier. Using these costs and projected gas usage, the projected annual gas cost using contract gas from a wellhead supplier and delivered by PSCo, *WGC*, is estimated as follows:

$$WGC = (12{,}306\ Dth/yr)(1+3.7\%)(\$2.608/Dth)(1+4.3\%)+$$

$$\begin{bmatrix} (12{,}306\ Dth/yr)(\$0.358/Dth)+ \\ (96.3\ Dth/mo)(12\ mo/yr)(\$3.30/Dth)+(\$185/mo)(12\ mo/yr) \end{bmatrix} \times (1+14.1\%)(1+4.3\%)$$

$$WCG = \$48{,}100/yr$$

The table below shows the cost comparison on a monthly basis.

Monthly Comparison of Commercial Gas and Contract Gas Costs

Month	Gas Usage *ccf*	Gas Usage *therms*	Gas Usage *MMBtu*	Est. Utility Gas Cost	Est. Contract Gas Cost	Total Cost Savings
Jan-99	21,738	20,925	2,092.5	$9,509	$7,555	$1,954
Feb-99	31,069	29,877	2,987.7	$13,572	$10,531	$3,041
Mar-99	17,286	16,623	1,662.3	$7,557	$6,125	$1,432
Apr-98	15,530	14,961	1,496.1	$6,802	$5,572	$1,230
May-98	12,025	11,585	1,158.5	$5,270	$4,450	$820
Jun-98	1,986	1,913	191.3	$880	$1,234	-$354
Jul-98	1,253	1,205	120.5	$559	$999	-$440
Aug-98	1,627	1,565	156.5	$722	$1,118	-$396
Sep-98	1,850	1,776	177.6	$818	$1,189	-$371
Oct-98	1,111	1,072	107.2	$499	$955	-$456
Nov-98	4,168	4,015	401.5	$1,834	$1,933	-$99
Dec-98	18,224	17,543	1,754.3	$7,974	$6,431	$1,543
TOTALS	**127,867**	**123,060**	**12,306.0**	**$55,996**	**$48,092**	**$7,904**

Thus, the annual cost savings are about $7,900/yr. The actual cost savings will be determined based on contracts negotiated with local wellhead gas supplier and transporter representatives.

<u>Implementation Cost</u>

The only cost associated with changing gas suppliers is the cost in contracting with a supplier. Allowing five hours of administrative time at $60/h, the total cost is about $500. The cost savings of $7,900/yr will pay for the implementation cost in less than one month.

7. TOTAL COST ACCOUNTING

When making investment decisions, many people base their decisions on calculations of simple payback periods. If the simple payback period is greater than two years, the decision often is not to invest capital. However, it is often preferable to take a long-term view and base decisions on a total cost accounting analysis, taking into account the time value of money.

The total cost savings that would be realized by a capital improvement, such as a new boiler, would depend on several factors, such as the discount rate, the energy cost inflation rate, the interest rate on any borrowed capital, and the period of economic analysis.

The U. S. Department of Energy's Eco-Efficiency Financial Analysis and Cost Evaluation System (E2/FINANCE) software package version 1.1 was used to consider the total cost allocation for each of the applicable ARs in this report. E2/FINANCE is a tool designed to assist businesses in evaluating the profitability of recommendations for energy efficiency, pollution prevention, productivity improvement, and other types of investments. Some standard economic variables are used in an E2/FINANCE analysis. For the recommendations in this report, the following variables and values were used:

- Discount rate = 12.0%
- Economic analysis period = 5 years
- Equipment life = 15 years
- General inflation rate = 3.0%
- Electricity costs inflation rate = 2.0%
- Natural gas costs inflation rate = 2.0%
- Federal corporate income tax rate = 39.0%
- State (Colorado) corporate income tax rate = 5.0%
- Effective income tax rate = 42.05%
- Depreciation method = 200% double declining balance depreciated over 7 years
- Fractional salvage value of equipment at end of economic life = $0 in all cases

Using these values, E2/FINANCE was used to determine the following for each applicable AR:

- Net present value (NPV) of the savings after five years, based on a discount rate of 12%
- Internal rate-of-return at the end of five years, based on a discount rate of 12%
- The discounted payback period, the point at which the NPV of the investment is zero.

One of the important components of total cost analysis is the use of multiple financial indicators in measuring profitability. E2/FINANCE offers three indicators: Net Present Value, Internal Rate of Return, and Discounted Payback. Each indicator has specific strengths and weaknesses. By considering all three indicators you can minimize these limitations and gain a deeper understanding of the project's profitability.

Net Present Value (NPV)
Net Present Value (NPV) is the sum of the discounted cash flows. A project with an NPV of zero provides a return equal to your discount rate. Therefore, any project with a negative NPV is unprofitable (i.e., provides a return below your discount rate), and any project with a positive

NPV is profitable. If you are considering only one project, it is financially justifiable if the NPV is positive. If you are looking at a number of projects and must prioritize among them, you should choose the one with the highest NPV, i.e., the most profitable one.

NPV is a very useful indicator because it is a direct measure of the project's profitability in dollars and therefore most directly relates to the company's interests (i.e., higher cash flows). It does, however, depend significantly on the value of the discount rate. If you are not comfortable with your chosen discount rate, you can perform a sensitivity analysis by trying different discount rates and comparing the results. In general, NPV is the strongest of the three indicators because it has few limitations and can be used in all types of analyses.

Internal Rate of Return (IRR)

IRR is the discount rate that makes the Net Present Value (NPV) of the discounted cash flows equal to zero. The IRR can thus be compared to the company's discount rate or to the IRR calculated for other projects. If the IRR is higher than the company's discount rate, then the project is profitable. When comparing multiple investments, the one with the highest IRR is the most profitable.

IRR is a useful indicator because it is easy to interpret and considers equally all of the cash flows of the investment. However, IRR does have its limitations. For example, if you are performing a complex analysis (e.g., capital costs in multiple years or widely fluctuating operating costs and revenues), you should avoid using this indicator. E2/FINANCE does not calculate IRR if the analysis is too complex, instead reporting "N/A". (Complex analyses contain more than one change in the mathematical sign of the cash flow, allowing for multiple IRR values).

In addition, IRR can be misleading because it does not directly measure the magnitude of the cash flow or investment but instead measures the return on the investment. Suppose you are interested in two investments; A requires an initial outlay of $50,000 and B requires only $500. Even if investment B has a higher IRR than investment A, this does not necessarily indicate that B is more profitable for the company in absolute terms. In fact, B can have an IRR of 173% and A an IRR of 85% over the first five years and A would generate more than four times as much revenue. Therefore, when you are comparing investments with significantly different magnitudes of costs and revenues, you should use NPV because it is a direct measure of the dollars the investment will generate.

Discounted Payback

Discounted Payback is one of several payback calculations, which, in general, measure the time it takes for a company to break even on an investment. Payback calculations typically do not incorporate the time value of money through discounting. However, E2/FINANCE calculates Discounted Payback, a method that includes inflation, escalation, and discounting. A project's Discounted Payback is the time at which the Net Present Value of the investment equals zero, i.e., when you have recovered your investment costs.

Many companies base their investment decisions on payback because it is easy to understand and use. Knowing that payback for a one motor is 2 years while payback for another motor is 3 years can help guide decision-making. However, you should be aware of certain limitations of this indicator before using it.

One limitation is that payback does not account for all of the cash flows of a project. It considers the cash flows before the investment is paid back, but ignores all cash flows after this threshold. Ignoring these later cash flows can mislead you as to the true profitability of the investment.

As an example, suppose you are considering two investments, A and B, and each requires an initial investment of $50,000. Investment A generates $25,000 in revenues for the next three years, whereas investment B generates $20,000 in revenues for the next 20 years. Using payback principles, investment A is more profitable than investment B because you recover the initial capital costs earlier with investment A. However, investment A generates revenues for only three years, whereas B continues to earn revenues for 20 years. This example illustrates that an investment's payback does not necessarily reflect its overall profitability because payback only measures the time it takes to reach the break-even point of an investment. For E2, P2, and other process improvement projects, this is an especially significant limitation because many operating cost savings and revenues occur several years after the initial capital expenditure.

A second limitation exists because there can be multiple paybacks in complex scenarios (e.g., when operating costs and revenues vary significantly from year to year or when there are investments in multiple years). E2/FINANCE does not calculate a discounted payback when there is the possibility of multiple paybacks (i.e., when the mathematical sign of the cash flow changes more than once). Instead it reports "N/A" when payback cannot be calculated.

The table below provides a summary of the results total cost analysis for the ARs in this report.

Total Cost Savings – Results

AR No.	Description	Cost Savings *per year*	Impl. Cost	Simple Payback Period *years*	NPV After 5 Yrs At 12% Disc. Rate	IRR After 5 Yrs At 12% Disc. Rate	Discounted Payback Period *years*
ENERGY EFFICIENCY RECOMMENDATIONS							
1	Improve Power Factor By Installing Capacitors	$6,420	$15,880	2.5	$2,150	17%	4.2
2	Reduce Peak Electric Demand	$2,940	$7,500	2.6	$810	16%	4.3
3	Reduce Compressed Air Leaks	$2,750	$2,070	0.8	$4,460	83%	1.3
4	Install Energy Efficient Lamps and Ballasts as Existing Lamps Burn Out	$660	$0	N/A	$1,660	325%	N/A
5	Reset Thermostats in Offices	$530	$750	1.4	$600	41%	2.4
POLLUTION PREVENTION RECOMMENDATIONS							
6	Install Cooling Tower To Reduce Water Usage	$19,000	$21,600	1.1	$26,750	54%	1.9
7	Recycle Used Fluorescent Lamps And Replace With Low Mercury Lamps	$200	$0	0.0	$540	N/A	N/A
PRODUCTIVITY IMPROVEMENT RECOMMENDATIONS							
8	Reduce Material Shortages and Material Handling	$166,400	$40,000	0.2	$353,000	282%	0.4
9	Reduce Natural Gas Purchase Costs	$7,900	$500	0.1	$17,130	N/A	0.1
TOTALS		**$206,800**	**$88,300**	**0.4**	**$407,100**	**N/A**	**N/A**

From the table, the following point emerges:

- *AR No. 8 – Reduce Material Shortages and Material Handling*
  This recommendation has the highest NPV of all ARs. Given these results, *this recommendation should be considered for implementation first.* Other recommendations that merit consideration for immediate implementation include AR No. 6 - "Install Cooling Tower to Reduce Water Use" and AR No. 9 - “Reduce Natural Gas Purchase Costs.”

8. SECONDARY EFFECTS OF ENERGY EFFICIENCY ON AIR POLLUTION

Reductions in air pollution are projected due to the proposed energy efficiency opportunities. In general the electrical energy savings will decrease carbon dioxide (CO_2), carbon (C), sulfur dioxide (SO_2), and oxides of nitrogen (NO_x) emissions at the utility's power generating station. Natural gas savings will decrease mainly CO_2 emissions at the plant. The emission reductions are products of the energy reductions and the following emissions factors:

For Electric Energy Savings:
- CO_2 reductions of 2.2 lbs/kWh[10]
- SO_2 reductions of 3.3 g/kWh
- NO_x reductions of 3.2 g/kWh

For Natural Gas Energy Savings:
- CO_2 reductions of 113 lbs/MMBtu[11]

The emission factors for electrical power generating plants are aggregates for EPA Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming). The mix of generation modes for the local utility (i.e., hydroelectric power plants, coal-burning power plants, etc.) should be used to determine the specific emission factors, but these average factors provide a suitable starting point.

For the total electrical energy savings of 62,926 kWh/yr and the total gas energy savings of 93 MMBtu presented in this report, the increase emissions and emission reductions are estimated as follows:

$$62{,}926\ kWh/yr \times 2.2\ lbs\ of\ CO_2/kWh = 138{,}400\ lbs\ (69.2\ tons)\ of\ CO_2/yr$$

$$62{,}926\ kWh/yr \times 3.3\ g\ of\ SO_2/kWh = 210\ kg\ of\ SO_2/yr$$

$$62{,}926\ kWh/yr \times 3.2\ g\ of\ NO_x/kWh = 200\ kg\ of\ NO_x/yr$$

$$93\ MMBtu/yr \times 113\ lbs\ of\ CO_2/MMBtu = 10{,}500\ lbs\ (5.3\ tons)\ of\ CO_2/yr$$

[10] U.S. EPA, "Green Lights Update." EPA 430-N-94-006, U. S. Environmental Protection Agency, Air and Radiation Division: Washington D.C. June 1994, page 14.

[11] Based on stoichiometric combustion (0% excess air).