Save Energy Now
Assessment Report
For

Hatfield Marine Science Center

2030 SE Marine Science Drive

Newport, OR 97365

Energy/Efficiency Center

OREGON STATE UNIVERSITY
Energy/Efficiency Center

Sponsored by
Bonneville Power Administration

Assessment Report No. 2002

March 16, 2009

Joseph F. Junker, Director E/EC ______________________

Elsie Deland, Lead Analyst ______________________

Assessment Participants

Cosmo Prindle	Energy Analyst
Michael Koch	Energy Analyst
Bryan Kilgore	Energy Analyst and Safety Officer
Peter Hanslits	Energy Analyst
David McIntosh	Energy Analyst

Dr. George Wheeler
IAC Director
Batcheller Hall 341
Corvallis, OR
97331-2405
(541) 737-2515

Joseph F. Junker
EEC Director
Batcheller Hall 344
Corvallis, OR
97331-2405
(541) 737-5034

OSU
Oregon State
UNIVERSITY

PREFACE

The work described in this report is a service of the Oregon State University Energy/Efficiency Center (E/EC). The project is funded by the Bonneville Power Administration (BPA).

The primary objective of the E/EC is to identify and evaluate opportunities for energy conservation, waste minimization, and productivity improvements through visits to industrial, agricultural and Oregon University System facilities. Data is gathered during a one-day site visit and assessment recommendations (ARs) are identified. Some ARs may require additional engineering design and capital investment. When engineering services are not available in-house, we recommend that a consulting engineering firm be engaged to provide design assistance as needed. In addition, since the site visits by E/EC personnel are brief, they are necessarily limited in scope and a consulting engineering firm could be more thorough.

We believe this report to be a reasonably accurate representation of energy use, waste generation, and production practices, and opportunities in your facility. However, because of the limited scope of our visit, the Bonneville Power Administration and the Oregon State University Energy/Efficiency Center cannot guarantee the accuracy, completeness, or usefulness of the information contained in this report, nor assumes any liability for damages resulting from the use of any information, equipment, method or process disclosed in this report.

Pollution prevention recommendations are not intended to deal with the issue of compliance with applicable environmental regulations. Questions regarding compliance should be addressed to either a reputable consulting engineering firm experienced with environmental regulations or to the appropriate regulatory agency. Clients are encouraged to develop positive working relationships with regulators so that compliance issues can be addressed and resolved.

The assumptions and equations used to arrive at energy, waste, productivity, and cost savings for the recommended ARs are given in the report. We believe the assumptions to be conservative. If you do not agree with our assumptions you may follow the calculation methodologies presented with revised assumptions to develop your own estimates of energy, waste, productivity, and cost savings.

Please feel welcome to contact the E/EC if you would like to discuss the content of this report or if you have another question about energy use or pollution prevention. The E/EC staff that visited your plant and prepared this report is listed on the preceding page.

TABLE OF CONTENTS

APPENDIX

1. INTRODUCTION

This report describes how energy is used in your facility, and includes our recommendations on cost effective steps you can take to reduce your energy and waste costs. The contents are based on our recent visit to your plant. The report is divided into 5 major sections and 3 appendices:

1. **Introduction.** The purpose, contents and organization of the report are described.

2. **Executive Summary.** Your energy use and waste generation costs, productivity, energy, and waste savings, and our recommendations are summarized here with details in the following sections.

3. **Assessment Recommendations.** This section contains our Assessment Recommendations (AR), briefly highlights the current and proposed systems and summarizing the cost savings available upon implementation. Some of our recommendations will require a significant investment to implement, while others will cost little or nothing.

4. **Other Measures Considered.** These measures were considered but not recommended because: (1) they are alternatives to measures that were recommended; (2) the payback period is too long; (3) we were unable to obtain the information necessary to estimate savings or cost accurately; or (4) the measure would adversely affect production. Some measures are included in response to specific questions you raised during the plant visit, but which do not appear to be feasible.

5. **Calculation Methodologies.** This section includes the detailed calculations for the Assessment Recommendations (AR). It includes any data that was collected during the audit, assumptions we use to estimate savings, our estimate of the implementation cost, and the simple payback of implementation. We have grouped the calculations in the same order as the AR's in section 3.

Appendix A: Utilities. Your utility bills and energy use by process are summarized and plotted in detail. Due to the changes in rate schedules and adjustments our calculations are an approximation and may not be exactly consistent with your bills. When available, we also include water and solid waste bills.

Appendix B: Motors. Motors are typically a large energy user. This section contains your motor information including: nameplate information, and area of the facility where the motor is located.

Appendix C: General Background. This appendix describes your facility, including a description of operations at your facility, best practices identified during the visit, and a facilities map.

2. EXECUTIVE SUMMARY

This section includes a summary of energy use and waste generation in your facility, our recommendations, and total productivity, energy, waste, and cost savings of all recommendations if implemented.

Recommendation Summary The following is a brief explanation of each of the recommendations made in this report. If all 5 recommendations are implemented, the total cost savings will be $25,220 and will pay for costs in 1.0 years.

AR No. 1, Pump House VFD: Install a Variable Frequency Drive (VFD) to operate two 50 hp sea water pumps at half speed for 4 hours per cycle, twice per day. VFDs allow motors to operate at a lower speed, allowing the pumps to operate at a significantly lower energy cost. Running the pumps in overflow conditions at the end of the tide cycle will also be avoided. Total pump operating cost will be reduced by 84%.

AR No. 2, Chiller Waste Heat Reclamation: Install insulated ductwork to capture heat produced by chiller motors and chiller condensers for the HVAC system and install controls to reduce space heating costs. Total heating costs will be reduced by 39%.

AR No. 3, Dock Water Meter: Install a "landscape" water meter at the dock for visiting vessel use. Because there are reduced sewer treatment costs associated with landscape water meters, the incremental cost per gallon of water consumed using a landscape meter is 27% less than water from a standard meter. The ability to accurately measure the amount of water each vessel uses for washing and ballast will also allow you to charge vessels for their water usage to defray water costs.

AR No. 4, Visitor Center Lighting: Replace halogen bulbs in the visitor center with compact fluorescent bulbs as the halogen bulbs expire. Replacing all bulbs will reduce lighting electrical energy usage by 70%.

AR No. 5, Premium Efficiency Motors: Replace 63 selected standard motors with premium efficiency electric motors rather than rewinding your motors or purchasing new or used non-premium motors. 7% of your total electrical energy used by motors will be saved.

Our recommendations are summarized in the following table.

Assessment Recommendation Summary					
AR#	Description	Energy (MMBtu)	Cost Savings	Implementation Cost	Payback (Years)
1	Pump House VFD	386	$8,940	$3,900*	0.4
2	Chiller Waste Heat Reclamation	474	$6,790	$2,930*	0.4
3	Dock Water Meter	0	$1,800	$15,000	8.3
4	Visitor Center Lighting	75	$1,940	$360*	0.2
5	Premium Efficiency Motors	367	$5,750	$2,470*	0.4
Totals		**1,302**	**$25,220**	**$24,660**	**1.0**

**Implementation Cost includes estimated incentives*

Total savings are sum of savings for each recommendation. Some of the recommendations may interact. Therefore, actual savings may be less than the total indicated above. In our calculations we indicate where we have assumed that other recommendations will be implemented in order to provide a realistic estimate of actual savings. When either one or another recommendation can be implemented, but not both, we have included the recommendation we recommend in this table and the alternate recommendation in a later section, Other Measures Considered. Total savings, including interactions among recommendations, can be better estimated after you select a package of recommendations.

Savings Summary. Total cost savings are summarized by energy cost savings. We then normalize savings as a percentage of annual plant costs. For example, Energy Cost% is energy cost savings divided by the total energy cost from the Utility Summary. Savings% is cost savings for each category (energy, waste or productivity) divided by total cost savings.

Savings Summary					
Source	Qty.	Units	Cost Savings	Cost %	Savings %
Energy	1,302	MMBtu	$13,650	16.0%	54.1%
Demand	193	kW	$9,400	15.3%	37.3%
Maintenance			$370		1.5%
Water			$1,800		7.1%
Totals			**$25,220**	**31.3%**	**100.0%**

Energy Use Summary. We used your utility bills to determine annual energy use for all fuels. From these bills we summarized annual energy consumption at your facility in the following table.

Energy costs and calculated savings are based on the incremental cost of each energy source. The incremental rate is the energy charge first affected by an energy use reduction and is taken from your utility rate schedules. For example, electrical use and savings include energy (kWh), demand (kW), reactive power charges (KVARh or power factor), and other fees such as basic charges, transformer rental, and taxes. However, if a recommendation does not affect your electrical demand, such as turning off equipment at night, then we use the cost of electrical energy alone. The fuel costs we used can be found in the Energy Accounting Summary in Appendix A.

Existing Energy Use Summary

Source	Qty.	Units	MMBtu	Use %	Cost	Cost %
Electric Energy	2,473,093	kWh	8,433	100.0%	$85,171	57.7%
Demand	7,952	kW			$61,473	41.6%
Miscellaneous Charges					$1,092	0.7%
Totals			8,433	100.0%	$147,736	100.0%

3. ASSESSMENT RECOMMENDATIONS

AR No. 1

Pump House VFD

Recommended Action

Install a Variable Frequency Drive (VFD) to operate two 50 hp sea water pumps at half speed for 4 hours per cycle, twice per day. VFDs allow motors to operate at a lower speed, allowing the pumps to operate at a significantly lower energy cost. Running the pumps in overflow conditions at the end of the tide cycle will also be avoided. Total pump operating cost will be reduced by 84%.

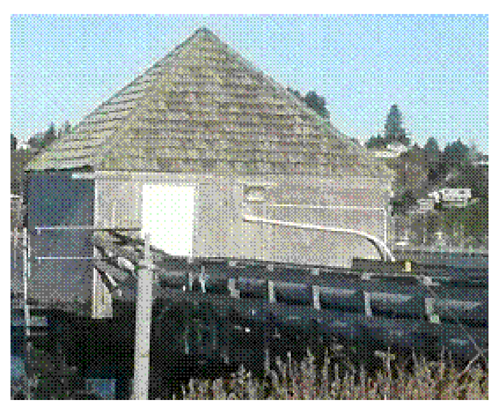
Assessment Recommendation Summary					
Energy (MMBtu)	Power (kW)	Energy (kWh)*	Cost Savings	Implementation Cost**	Payback (years)
385.5	54	113,040	$8,940	$3,900	0.4

** 1kWh = 3,410 Btu 1,000,000 Btu = 1 MMBtu*
***Note: Implementation Cost includes incentives.*

Background

The sea water pump system supplies all of the HMSC laboratory sea water. Allowing the pump motors to be operated at a lower speed will result in a lower input electrical power. An efficient way to reduce pump speed is to install a variable frequency drive (VFD). Because only two pumps are utilized at a time, a VFD unit capable of operating at an output power of 100 hp is required. Electrical switching gear can be utilized to operate the alternate motor pair.

Proposal



Install a VFD unit and electrical switch gear to operate two of the four sea water pump motors at a time. Installing a VFD will result in energy savings by operating at a slower pump speed with reduced line losses. It will also remove the need to run the pumps in overflow conditions at the end of the tide cycle This yields cost savings of $8,940, representing a savings of 84% of pumping costs.

As detailed in the Pump House VFD Calculation Methodology, there is a 0.4 year payback with a $3,900 implementation cost after incentives.

AR No. 2

Chiller Waste Heat Reclamation

Recommended Action

Install insulated ductwork to capture heat produced by chiller motors and chiller condensers for the HVAC system and install controls to reduce space heating costs. Total heating costs will be reduced by 39%.

Assessment Recommendation Summary					
Energy (MMBtu)	Power (kW)	Energy (kWh)*	Cost Savings	Implementation Cost**	Payback (years)
473.9	29.5	150,920	$7,040	$2,930	0.4

** 1 kWh = 3,410 Btu. 1,000,000 Btu = 1 MMBtu*

*** Implementation Cost includes incentives*

Background

Chillers produce waste heat in two ways. The first is through inefficiencies inherent to motors. The second is through the nature of a chilling system, which removes heat from the load and exhausts that heat somewhere away from the load. By redirecting this waste heat into the HVAC system during appropriate times, space heating costs can be reduced. Control can be achieved through the installation of dampers, ducting and a programmable logic controller.

Proposal

Duct heat produced by chiller motors and chiller condensers 200 feet to the HVAC system and install controls to reduce space heating costs.

As detailed in the Chiller Heat Reclamation Calculation Methodology, there is a 0.4 year payback with $2,930 implementation cost after incentives.

AR No. 3

Dock Water Meter

Recommended Action

Install a "landscape" water meter at the dock for visiting vessel use. Because there are reduced sewer treatment costs associated with landscape water meters, the incremental cost per gallon of water consumed using a landscape meter is 27% less than water from a standard meter. The ability to accurately measure the amount of water each vessel uses for washing and ballast will also allow you to charge vessels for their water usage to defray water costs.

Assessment Recommendation Summary		
Cost Savings	Implementation Cost	Payback (years)
$1,800	$15,000	8.3

Background

Numerous vessels dock at the Hatfield Marine Science Center (HMSC) throughout the year. These vessels use potable, city water for cleaning and filling ballast tanks. Although this water never returns to the Newport sewer treatment plant, the gallons of water used are still assessed a sewage charge. "Landscape" water meters are not assessed this sewage charge and therefore are assessed a lower cost per gallon.

Proposal

Contract with the City of Newport Public Works Department to install a new 3 inch meter to supply water to the dock allowing HMSC to accurately charge visiting vessels for the water they consume. Charge visiting vessels $0.04 per gallon for the use of this water.

As detailed in the Dock Water Meter Calculation Methodology, there is an 8.3 year payback with a $15,000 implementation cost.

AR No. 4

Visitor Center Lighting

Recommended Action

Replace halogen bulbs in the visitor center with compact fluorescent bulbs as the halogen bulbs burn out. Replacing all bulbs will reduce lighting electrical energy usage by 70%.

Assessment Recommendation Summary					
Energy (MMBtu)	Power (kW)	Energy (kWh)*	Cost Savings	Implementation Cost**	Payback (years)
75	8.8	22,026	$1,943	$360	0.2

** 1 kWh = 3,410 Btu. 1,000,000 Btu = 1 MMBtu*

*** Implementation Cost includes incentives*

Background

169 halogen screw bulb lights are being used in the visitor center. Halogen lights convert most input energy to heat. Compact fluorescents yield the same light as halogens with less heat and are therefore more energy efficient.

Proposal

Replace all 75 watt halogen bulbs with 23 watt compact fluorescent bulbs in the Visitor Center, as the halogen bulbs burn out, resulting in a savings of $1,943 per year.

As detailed in the Halogen Lights - Calculation Methodology, there is a 0.2 year payback with $752 implementation cost after incentives.

Courtesy of www.grainger.com

AR No. 5

Premium Efficiency Motors

Recommendation

Replace 63 selected standard motors with premium efficiency electric motors rather than rewinding your motors or purchasing new or used non-premium motors. 7% of your total electrical energy used by motors will be saved.

Assessment Recommendation Summary				
Energy (MMBtu)	Energy (kWh)*	Cost Savings	Implementation Cost**	Payback (years)
376.2	110,320	$5,750	$2,470	0.4

**1 kWh = 3,410 Btu 1,000,000 Btu = 1 MMBtu*

***Note: Implementation Cost includes incentives.*

Background

Depending on horsepower, premium efficiency motors operate from 1 to 10 percent more efficiently than standard motors and those called "high efficiency" or "energy efficient." The savings are larger for motors that operate for long periods and small motors which currently exhibit low efficiency. We recommend replacing only those motors for which the size and operating conditions yield favorable payback periods. Premium efficiency motors must meet or exceed NEMA minimum efficiency standards to be classified as such. A policy of purchasing premium efficiency motors when motor replacement or rewinding is considered will reduce motor electrical energy costs.

We also performed a rewind analysis to consider the incremental cost between rewinding a failed motor and purchasing a new premium efficiency motor. Since we assume that the replacement occurs when the motor fails and is removed for repair, no additional installation costs are incurred.

Proposal

Install premium efficiency motors to replace your current motors as they fail. The implementation cost and savings above is for replacing 63 selected motors. Assuming the implementation cost is incurred uniformly over a 12-year motor life, the annual implementation cost will be approximately $690. Appendix B.9 is a detailed list of the selected motors to be replaced.

Courtesy of: ge.ecomagination.com

As detailed in the Premium Efficiency Motors -Calculation Methodology, there is a 0.4 year payback with $2,470 implementation cost after incentives.

4. OTHER MEASURES CONSIDERED

These measures were considered but not recommended because: (1) they are alternatives to measures that were recommended; (2) the payback period is too long; (3) we were unable to obtain the information necessary to estimate savings or cost accurately; or (4) the measure would adversely affect production. Some measures are included in response to specific questions you raised during the plant visit, but which do not appear to be feasible at the present time. However, these measures may become feasible in the future as conditions change.

1. Cover Drain Troughs. We observed open drain troughs throughout the facility designed to carry waste sea water out of the facility. These troughs are covered only by removable wooden grates to allow for the removal of accumulated material. This flowing water cools the surrounding area and increases the heating load for the building. We recommend covering these troughs to lower their cooling effect. Rubber mats on top or plastic sheeting wrapped under the wooden grates would be a low-cost method of coving the troughs. This does not appear as a full recommendation because we were unable to quantify the cooling effect of the troughs and we were therefore unable to calculate a cost associated with the cooling.

2. Pre-Chilled Water in Elephant Barn. Water is chilled in order to reproduce natural conditions present in Alaska. We measured chilled water flowing out of the "Elephant Barn" through open drain troughs at 44.8°F. We estimate the average incoming temperature of water before chilling to be 59°F. This water represents a portion of the chilling load provided by the glycol chillers. Because the energy used by the chillers is proportional to the difference between the incoming sea water and the target chilled temperature, the colder the incoming water is the less energy is required by the chillers. We considered the installation of a rudimentary heat exchanger that would cool incoming water by passing it beside outgoing chilled water in the drain trough. This could be achieved by simply directing the incoming water through a pipe submerged in the chilled outgoing water trough. This does not appear as a full recommendation because we believe the temperature difference of 14.2°F between the two streams is not a big enough temperature for much heat exchange to occur. Adding a simple heat exchange loop as described above would pre-chill the incoming water to some degree, resulting in some chiller energy savings, but not a great deal.

3. Electric to Natural Gas Heating. Currently, building 900 is heated with electric resistance coils. Nationally, natural gas tends to be a more cost effective method of heating than electricity since natural gas is generally cheaper than electricity. Local costs of natural gas and electricity as well as the relative price stability are factors when considering electrical or natural gas heating. The maximum cost of natural gas required to allow for savings over electricity is determined below:

$$
\begin{aligned}
GC &= \text{Natural gas cost} \\
&= EC \times CF \times EF \\
&= \$0.03444\ /\text{kWh} \times 31.85\ \text{kWh}/\text{therm} \times 0.8 \\
&= \$0.8776\ /\text{therm}
\end{aligned}
$$

Where,

EC	=	Incremental energy cost
	=	\$0.03444 /kWh
CF	=	Conversion factor
	=	31.85 kWh/therm
EF	=	Natural gas furnace thermal efficiency
	=	80%

If natural gas can be found for less than \$0.8776 /therm then it will be cheaper to use natural gas heating. Additionally, demand savings may also be achieved. Careful consideration of installation costs and minimum charges will assist in determining the full cost of natural gas heating. This does not appear as a full recommendation because we are unable to estimate the full cost of converting from electric to natural gas heating and do not know how much electricity is used for heating.

4. EPA Pump. Two 15 hp pumps, termed "EPA Pump" are heavily throttled via a partially closed valve. These pumps operate in an alternating fashion to pump sea water from the sea water reservoir through a sand filter to the facility. Throttling modifies the pumps' operating point away from the best efficiency design point. Facility staff estimated a current flow rate of 20 GPM and further estimated that the pumps are designed to operate at 200 GPM. Pressure gauges were not installed at the pump discharge, and thus accurate savings analysis is not possible. The pumps are likely oversized for the application and it is recommended that they be replaced with a single 5 hp pump depending on actual flow rates and head. Replacing the EPA Pump with an appropriately sized pump will save approximately \$500-\$1,000 annually in electrical energy and demand costs. A 5 hp sea water pump will cost approximately \$1,000 resulting in a payback period of between 1 and 2 years. This does not appear as a full recommendation because we were unable to obtain a head pressure and thus are unable to determine the horse power pump needed to replace the current pump.

5. Fume Hood. Install variable air volume exhaust fans (VAVs) as well as sash stops to the existing fume hoods. The VAVs will decrease the amount of conditioned air that is exhausted by the fume hoods, therefore decreasing the load on the exhaust fan and furnace delivering warm make-up air. Also, the sash stops will ensure that the sash is not lifted above 50% open, limiting the amount of air that is exhausted and reducing the load on the exhaust fan.

This does not appear as a full recommendation because actual cost savings at this point will be too high to implement as a facility-wide project since all the fume hoods are not running at the industry-standard 24 hours/day, 365 days/year. Since the fume hoods do not run constantly, as new fume hoods are installed it should be required that the most energy efficient models are installed with features such as sash stops.

6. Insulate Ductwork. Building 900 is currently heated by an electric forced air system. The air is supplied to the building through ducts which run in the attic. The ductwork is currently insulated with 1 inch thick fiberglass insulation which is degrading. The insulation is no longer able to insulate the ductwork properly since it is falling off the ductwork allowing heat to escape from the air being carried in the ductwork. Facilities personnel estimate that there is 400 feet of 6 in by 12 in ductwork that would need to be insulated throughout the attic. Insulating the ductwork would result in a savings of $112 /year based on the temperature of the air inside the duct, the temperature of the air outside the duct and the heat transfer coefficients of bare metal and of insulation. The cost of materials and labor to reinsulate this ductwork would be $3,200. This does not appear as a full recommendation because the payback period is too great.

5. CALCULATION METHODOLOGY

AR No. 1

Pump House VFD
Calculation Methodology

Recommended Action

Install a Variable Frequency Drive (VFD) to operate two 50 hp sea water pumps at half speed for 4 hours per cycle, twice per day. VFDs allow motors to operate at a lower speed, allowing the pumps to operate at a significantly lower energy cost. Running the pumps in overflow conditions at the end of the tide cycle will also be avoided. Total pump operating cost will be reduced by 84%.

Assessment Recommendation Summary					
Energy (MMBtu)	Power (kW)	Energy (kWh)*	Cost Savings	Implementation Cost**	Payback (years)
385.5	54	113,040	$8,940	$3,900	0.4

** 1kWh = 3,410 Btu 1,000,000 Btu = 1 MMBtu*
***Note: Implementation Cost includes incentives.*

Data Collected Summary

- Four 50 hp pumps operating in pairs
- Alternate pairs are operated in 6 week cycles to limit sea life accumulation
- Pump cycles follow the tide schedule (two per day)
- Pump cycle runs for 3 hrs, with 1 hr per cycle in overflow condition (overflow returns to the bay).
- Incremental energy cost from power bills is $0.0344 /kWh
- Incremental demand cost from power bills is $7.73 /kW
- According to a vendor the VFD has an efficiency of 0.95

During our visit, two pumps were running with on-site naming ‘Yellow’ and ‘Red’. The data below was collected from the name plates, gauges, ammeter readings, and a non-contact flow meter for the two pumps in operation.

Live Motor/Pump Data					
	Voltage (Volts)	Current (Amps)	Power (kW)	Power Factor	Flow (GPM)
Yellow	481	43.5	30.9	0.85	1,590
Red	481	45.6	31.7	0.83	1,630

Savings Analysis

Savings are achieved by installing a VFD and slowing the pumps to reduce electrical power required to operate the pumps and eliminate overflow operation of the pumps. An installed VFD will also allow you to operate the pumps at an even slower speed and longer duration when tidal conditions permit, yielding even greater savings. In rare instances of a shorter tidal window you will also be able to run the pumps at a higher speed to ensure a full reservoir, but at greater operating cost.

Power required to operate a pump at less than full load reduces cubically with shaft speed. For a variable torque load, pump speed can be correlated with power as follows to calculate proposed motor load factor:

Power is proportional to the cube of shaft speed which is represented by the following equation in which P stands for power and ω stands for shaft speed:

$$\frac{P_2}{P_1} = \left(\frac{\omega_2}{\omega_1}\right)^3 .$$

The proceeding analysis is for a proposed reduction of the shaft speed by 50%.

TS = Total Savings
= ES + DS
= \$3,890 + \$5,050
= \$8,940

Where,

ES	=	Energy Cost Savings
	=	AE – BE
	=	\$4,720 /yr – \$830 /yr
	=	\$3,890 /yr
DS	=	Demand Cost Savings
	=	MD – ND
	=	\$5,810 /yr – \$760 /yr
	=	\$5,050 /yr

Where,

AE	=	Current Energy Cost
	=	CE x IE
	=	137,090 kWh /yr x \$0.03444 /kWh
	=	\$4,720 /yr
BE	=	Proposed Energy Cost
	=	PE x IE
	=	24,050 kWh /yr x \$0.03444 /kWh
	=	\$830 /yr
MD	=	Current Demand Cost
	=	CD x ID x MY
	=	62.6 kW x \$7.73 /kW-month x 12 months /yr
	=	\$5,810 /yr
ND	=	Proposed Demand Cost
	=	PD x ID x MY
	=	8.24 kW x \$7.73 /kW-month x 12 months /yr
	=	\$760 /yr

Where,

CE	=	Current Energy Use
	=	CD x CH
	=	62.6 kW x 2,190 hrs
	=	137,090 kWh
IE	=	Incremental Energy Cost
	=	\$0.03444 /kWh
PE	=	Proposed Energy Use
	=	PD x PH
	=	8,240 kW x 2,920 hrs
	=	24,050 kWh /yr

CD = Current Demand
= 62.6 kW

ID = Incremental Demand Cost
= $7.73 /kW-month

MY = Months per Year
= 12 months /yr

PD = Proposed Demand
= LF x CD ÷ VE
= $(0.50)^3$ x 62.6 kW ÷ 0.95
= 8.24 kW

Where,

CH = Current Operating Hours
= CQ x CW x DY
= 2 cycles /day x 3hrs /cycle x 365 days /yr
= 2,190 hrs /yr

PH = Proposed Operating Hours
= CQ x PW x DY
= 2 cycles /day x 4 hrs /cycle x 365 days /yr
= 2,920 hrs /yr

LF = Proposed Load Factor
= $(SR)^3$
= $(0.5)^3$
= 0.125

VE = VFD Efficiency
= 0.95

Where,

CQ = Pump Cycles per Day
= 2 cycles /day

CW = Current Hours per Pump Cycle
= 3 hours /cycle

DY = Days per Year
= 365 days /yr

PW = Pump Cycle Hours
= 4 hours /cycle

SR	=	Shaft Speed Reduction
	=	0.5

Total annual cost savings are summarized in the following Savings Summary table:

Saving Summary				
Source	Quantity	Units	Energy (MMBtu)	Cost Savings
Demand	54	kW		$5,050
Energy Use	113,040	kWh	385.5	$3,890
Total				**$8,940**

Cost Analysis

A single VFD unit rated for 100 hp output can be utilized to run pump pairs. Since independent frequency control is not necessary for each pump, a single unit presents the most cost effective option. Switchgear can be utilized to electronically switch the VFD output to the alternate pair of pump motors. A vendor supplied us with guidelines for estimating implementation costs as follows:

Implementation Cost				
Source	Quantity	Units	$/Unit	Cost
100 hp VFD	1	VFD	$11,000	$11,000
Electrical Switchgear	1	Switchgear	$1,000	$1,000
Labor	1	Installation	$1,000	$1,000
Total				**$13,000**

Note that exact implementation costs may vary according to application details, vendors, and controls (automation) requirements. Please contact a vendor for a site-specific quote.

Savings will pay for implementation in 1.5 years before incentives.

Incentive Summary

Bonneville Power Administration (BPA) offers cash incentives through your utility that are available to help pay for implementation of energy saving measures. These savings are equal to either $0.17 /kWh saved in the first year or 70% of total project cost. The incentive given for a project will be the lesser of these two, which is calculated as follows.

CI	=	BPA Cash Incentives			
	=	Minimum of	ES x $0.17 /kWh	or	0.70 x TC
	=	Minimum of	113,040 kWh x $0.17 /kWh	or	0.70 x $13,000
	=	Minimum of	$19,220	or	$9,100
	=	$9,100			

Where,

ES	=	Energy Savings
	=	113,040 kWh
TC	=	Total Implementation Cost
	=	$13,000

The following table summarizes implementation costs before and after incentives.

Incentive Summary	
Description	Cost
Pre-incentive Cost	**$13,000**
BPA Cash Incentive	($9,100)
Total after Incentives	**$3,900**

Savings will pay for implementation costs in 0.4 years after incentives.

Note: To alleviate concerns related to VFD reliability and remoteness of your facility, consider installing the VFD with an option to bypass it for direct full speed operation of the pump.

AR No. 2

Chiller Waste Heat Reclamation
Calculation Methodology

Recommended Action

Install insulated ductwork to capture heat produced by chiller motors and chiller condensers for the HVAC system and install controls to reduce space heating costs. Total heating costs will be reduced by 39%.

Assessment Recommendation Summary					
Energy (MMBtu)	Power (kW)	Energy (kWh)*	Cost Savings	Implementation Cost**	Payback (years)
473.9	30.6	150,920	$7,040	$2,930	0.4

** 1 kWh = 3,410 Btu. 1,000,000 Btu = 1 MMBtu*

*** Implementation Cost includes incentives*

Data Collected Summary

From bills, observations and facility personnel

- Alaska Chillers coefficient of performance is 2.5. The coefficient of performance is the ratio of the electrical energy required to remove heat from the system to the heat removed from the system.
- Incremental energy cost from power bills is $0.0344 /kWh
- Incremental demand cost from power bills is $7.73 /kW

Chiller Summary					
Location	Quantity	Horsepower (Hp)	Use Factor	Annual Energy Consumption (kWh)	Condenser Type
Alaska Chillers	2	120	40%	500,000	Dry
RSF Attic	1	10	100%	25,000	Dry
RSF Attic	1	15	100%	37,000	Dry
RSF Attic	6	5	100%	47,000	Dry
RSF Attic	1	30	100%	76,000	Dry

Assumptions

- Compressor motors are 90% efficient, with the additional 10% heating the surrounding air
- Annual space heating energy consumption is 400,000 kWh. This is based on the total annual energy consumption compared to our estimate of total motor and lighting energy consumption

- The facility is heated seven months out of the year
- Based on the location of the chillers and the amount of air to be moved, eight 1/6 hp fans will be needed to transport heated air into the duct system

Savings Analysis

Annual cost savings are calculated by finding the value of the heat to be transferred to HVAC before including annual cost increases.

CS	=	Annual Cost Savings Before Yearly Costs
	=	AE + AD
	=	\$5,390 + \$1,650
	=	\$7,040

Where,

AE	=	Annual Energy Cost Savings
	=	EC x ES
	=	\$0.03444/kWh x 156,540 kWh
	=	\$5,390
AD	=	Annual Demand Cost Savings
	=	DS x ID x OM
	=	30.6 kW x \$7.73/kW-month x 7 months /year
	=	\$1,650

Where,

EC	=	Incremental Energy Cost			
	=	\$0.03444/kWh			
ES	=	Energy Savings			
	=	Minimum of	EA	or	HE
	=	Minimum of	156,540 kWh	or	400,000 kWh
	=	156,540 kWh			
DS	=	Demand Savings			
	=	ES ÷ OH			
	=	156,540 kWh ÷ 5,112 hours			
	=	30.6 kW			
ID	=	Incremental Demand Cost			
	=	\$7.73/kW-month			
OM	=	Operating Months			
	=	7 months /year			

Where,

EA	=	Energy Available
	=	(CH + AH + RH) x YU
	=	(200,000 kWh + 50,000 kWh + 18,500 kWh) x 0.583
	=	156,540 kWh
HE	=	Current Space Heating Energy Usage
	=	400,000 kWh
OH	=	Operating Hours for Heating
	=	7 months x 1 year /12 months x 365 days /year x 24 hours /day
	=	5,112 hours

Where,

CH	=	Alaska Condenser Waste Heat Energy
	=	AC ÷ CP
	=	500,000 kWh ÷ 2.5
	=	200,000 kWh
AH	=	Alaska Compressor Waste Heat Energy
	=	AC x (100% - ME)
	=	500,000 kWh x (100% - 90%)
	=	50,000 kWh
RH	=	RSF Total Attic Compressor Waste Heat Energy
	=	RE x (100% - ME)
	=	185,000 kWh x (100% - 90%)
	=	18,500 kWh
YU	=	Fraction of Year heated
	=	OM ÷ MY
	=	7 months /year ÷ 12 months /year
	=	0.583

Where,

AC	=	Alaska Compressor Energy Usage
	=	500,000 kWh
CP	=	Alaska Chillers Coefficient of Performance
	=	2.5
ME	=	Assumed Motor Efficiency
	=	90%

RE = RSF Attic Compressor Energy
= $C_{10} + C_{15} + C_5 + C_{30}$
= 25,000 kWh + 37,000 kWh + 47,000 kWh + 76,000 kWh
= 185,000 kWh

MY = Months per Year
= 12 months /year

Where,

C_{10} = 10 Horsepower Compressor Energy from RFC Attic
= 25,000 kWh

C_{15} = 15 Horsepower Compressor Energy from RFC Attic
= 37,000 kWh

C_5 = 5 Horsepower Compressor Energy from RFC Attic
= 47,000 kWh

C_{30} = 30 Horsepower Compressor Energy from RFC Attic
= 76,000 kWh

The following are annual costs that arise from additional fans that will have to be installed to incorporate waste heat into the HVAC system.

YC = Yearly Fan Costs
= FE + FD
= $190 + $60
= $250

Where,

FE = Annual Fan Energy Cost
= EC x EU
= $0.03444 /kWh x 5,620 kWh
= $190

FD = Annual Fan Demand Cost
= TK x ID x OM
= 1.1 kW x $7.73 /kW-month x 7 months
= $60

Where,

EC = Incremental Energy Cost
= $0.03444/kWh

EU	=	Fan Energy Usage
	=	TK x OH
	=	1.1 kW x 5,112 hours
	=	5,620 kWh
ID	=	Incremental Demand Cost
	=	$7.73/kW-month
OM	=	Operating Months
	=	7 months

Where,

TK	=	Total Fan Power in Kilowatts
	=	CF x TH
	=	0.746 kW/Hp x 1.4 Hp
	=	1.1 kW
OH	=	Operation Hours
	=	8,760 hours

Where,

CF	=	Horsepower to Kilowatts Conversion Factor
	=	0.746 kW/Hp
TH	=	Total Fan Power in Horsepower
	=	QF x FP
	=	8 fans x 1/6 Hp/fan
	=	1.4 Hp

Where,

QF	=	Quantity of Fans
	=	8 fans
FP	=	Fan Power
	=	1/6 Hp/fan

Annual cost savings are summarized in the following Savings Summary table:

Savings Summary				
Source	Quantity	Units	Energy (MMBtu)	Cost Savings
Space Heating Energy Reduction	156,540	kWh	491.5	$5,390
Space Heating Demand Reduction	30.6	kW		$1,650
Annual Energy Consumption Increase	(5,620)	kWh	(17.6)	($190)
Annual Demand Increase	(1.1)	kW		($60)
Total			**473.9**	**$6,790**

Cost Analysis

Implementation costs include ducting, controls, fans, insulation, and labor associated with this recommendation. The following prices were supplied by RSMeans Mechanical Cost Data 2006.

IC	=	Implementation Cost
	=	CI + DC + DL + FC + FL + CM + LC + PL
	=	\$900 + \$2,000 + \$300 + \$4,000 + \$230 + \$1,200 + \$150 + \$1,000
	=	\$9,780

Where,

CI	=	Cost of Insulation
	=	IM x QD
	=	\$4.50/L.F. x 200 L.F.
	=	\$900
DC	=	Ducting Material Cost
	=	QD x CD
	=	200 L.F. x \$10/L.F.
	=	\$2,000
DL	=	Ductwork Labor Cost
	=	DT x CL
	=	20 hours x \$15/hour
	=	\$300
FC	=	Fan Cost
	=	QF x CF
	=	8 fans x \$500/fan
	=	\$4,000
FL	=	Fan Installation Labor Costs
	=	FT x CL
	=	15 hours x \$15/hour
	=	\$230
CM	=	Control Material Cost
	=	QC x CC
	=	8 dampers x \$150/damper
	=	\$1,200
LC	=	Cost of Labor for Controls
	=	CT x CL
	=	10 hours x \$15/hour
	=	\$150

PL	=	Programmable Logic Controller Cost
	=	\$1,000

Where,

IM	=	Insulation Material Cost
	=	\$4.50 /L.F.
QD	=	Quantity of Ductwork
	=	200 L.F.
CD	=	Cost per Linear Foot of Ductwork
	=	\$10 /L.F.
DT	=	Ductwork Installation Time
	=	20 hours
CL	=	Cost of Labor
	=	\$15 /hour
QF	=	Quantity of Fans
	=	8 fans
CF	=	Cost per Fan
	=	\$500 /fan
FT	=	Fan Installation Time
	=	15 hours
QC	=	Quantity of Control Dampers
	=	8 dampers
CC	=	Cost per Control Damper
	=	\$150 /damper
CT	=	Control Damper Installation Time
	=	10 hours

Total implementation costs are summarized in the following Implementation Summary table:

Implementation Summary	
Source	Initial Cost
Insulation Cost (2” thick Air Cell, Corrugated Felt with Cover)	$900
Ductwork Material Cost (24” diameter galvanized steel)	$2,000
Fan Cost	$4,000
Controls Cost	$1,200
PLC Cost	$1,000
Ductwork Labor	$300
Fan Labor	$230
Controls Labor	$150
Total	**$9,780**

Before incentives, savings will pay for implementation in 1.4 years.

Incentive Analysis

Bonneville Power Administration offers cash incentives through your utility that are available to help pay for implementation of energy saving measures. These savings are equal to either $0.17/kWh saved in the first year or 70% of total project cost. The incentive given for a project will be the lesser of these two, which is calculated as follows.

BP	=	Bonneville Power Administration Incentives			
	=	Minimum of	TE x $0.17 /kWh	or	0.70 x TC
	=	Minimum of	150,920 kWh x $0.17/kWh	or	0.70 x $9,780
	=	Minimum of	$25,656	or	$6,850
	=	$6,850			

Where,

TE = Total Energy Savings
= ES - EU
= 156,540 kWh - 5,620 kWh
= 150,920 kWh

TC = Total Implementation Cost
= $9,780

Where,

ES = Energy Savings
= 156,540 kWh

EU = Energy Usage
= 5,620 kWh

The following table summarizes implementation costs before and after incentives.

Incentive Summary	
Description	Cost
Pre-incentive Cost	**$9,780**
Bonneville Power Administration Incentive	($6,850)
Total after Incentives	**$2,930**

Savings will pay for implementation costs in 0.4 years after incentives.

AR No. 3

Dock Water Meter
Calculation Methodology

Recommended Action

Install a "landscape" water meter at the dock for visiting vessel use. Because there are reduced sewer treatment costs associated with landscape water meters, the incremental cost per gallon of water consumed using a landscape meter is 27% less than water from a standard meter. The ability to accurately measure the amount of water each vessel uses for washing and ballast will also allow you to charge vessels for their water usage to defray water costs.

Assessment Recommendation Summary		
Cost Savings	Implementation Cost	Payback (years)
$1,800	$15,000	8.3

Data Collected Summary

The following data was collected from the City of Newport Public Works Department (valid until approximately July 1, 2009 when rates are expected to change):

City of Newport Water Cost Summary		
Meter Size	**3 inch**	**4-6 inch**
Meter Installation Cost	$15,000	$15,000
Base Volume /Mo (gal)	23,000	41,000
Base Charge /Mo	$66.40	$110.25
Infrastructure Charge /Mo	$90.00	$320.00
Flat Sewage Fee /Mo	$13.50	$13.50
Standard Sewage Fee /gal	$3.95	$3.95
$ /1,000 gal. Over Base Vol.	$2.30	$2.30

The following data was collected from Hatfield facilities personnel:

- Currently vessels visiting the Hatfield dock use as much water as they like and there is no metering. The water usage was estimated using the following assumptions:
  - Wecoma research vessel needs to fill its ballast (30,000 gallons) with potable water in December once every three years.
    We average that volume at 10,000 gallons per year
  - Average research vessel water use 2,000 gallons per day
  - Average dredging vessel water use 7,000 gallons per day

The following table summarizes the last three years of visiting vessels. The average yearly usage is found by averaging the number of visits per year over the past three years and multiplying by the research (2,000 gal.) and dredging (7,000 gal.) factors above. The 10,000 gallons for December is the average per year to fill the Wecoma ballasts.

Visiting Vessel Days Summary							
	Research Vessel			**Dredging Vessel**			**Average**
Month	2008	2007	2006	2008	2007	2006	**Usage (gal/year)**
January	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0
March	0	2	0	0	0	0	1,333
April	2	4	0	0	0	2	8,667
May	3	2	6	0	0	0	7,333
June	2	2	2	0	0	2	8,667
July	4	3	2	0	2	0	10,667
August	8	12	9	1	1	0	24,000
September	0	8	0	0	0	1	7,667
October	0	0	0	1	0	1	4,667
November	0	0	0	0	0	0	0
December	0	0	0	0	0	0	10,000
Total	**19**	**33**	**19**	**2**	**3**	**6**	**83,000**

Note: Because we don't know the exact times vessels arrive or depart, we make the conservative assumption that arrival and departure days only count for 0.5 days.

The following assumptions were made:

- Preliminary calculations suggest that a 3 inch water meter can deliver enough water (500 gpm) in a short enough time to supply vessels with the water they require in the time they are at the dock. We assume that a 2 inch water meter would not supply enough water in the timeframe allowable. However, a 2 inch water meter would be significantly less expensive than the 3 inch scenario described here. Further analysis should be conducted to verify these assumptions.

- Extra labor needed to collect revenue from water sales is assumed to be negligible and is not included in this analysis. Extra labor costs may reduce the cost savings per year and lengthen the payback period.

Savings Analysis

Savings are realized by shifting dock water use to an account that would not incur sewer charges. As shown by the Water Cost Summary Table, the base volume for a 3 inch meter is 23,000 gallons. The Visiting Vessel Days Summary Table shows that only during August is there the potential to exceed this monthly base volume. Because usage only exceeds this base amount by 1,000 gallons, the cost is merely $2.30 more than the monthly charge.

Annual cost savings are calculated by finding the associated cost difference between the current and proposed conditions.

CS = Cost Savings
= C$ – P$ + WR
= $520 per year – $2,040 per year + $3,320 per year
= $1,800 per year

Where,

C$ = Current visiting vessel water costs
= G x CC
= 83,000 gallons per year x $0.0063 /gallon
= $520 per year

P$ = Proposed visiting vessel water costs
= PW x 12 months
= $170 /month x 12 months
= $2,040 per year

WR = Water revenue from charging visiting vessels for the water they consume
= G x RC
= 83,000 gallons per year x $0.04 /gallon
= $3,320 per year

Where,

G = Average gallons consumed per year
= 83,000 gallons per year

CC = Current cost of water per gallon
= SC + WC
= $3.95 /1,000 gal + $2.30 /1,000 gal
= $0.0063 /gallon

Because the monthly usage very rarely exceeds the allowed monthly base volume, we make the simplifying assumption that the charges for water used at the dock will be equal to the monthly charges for the new 3 inch meter account:

PW = Proposed monthly water charge for new dock meter account
= Base charge /month + Infrastructure charge /month + Flat sewage fee /month
= \$66.40 /month + \$90.00 /month + \$13.50 /month
= \$170 /month

RC = Rate charged to visiting vessels (see the Payback Summary Table for other cost scenarios)
= \$0.04 /gallon

Where,

SC = Sewage charge per gallon of water consumed
= \$3.95 /1,000 gal

WC = Water charge per gallon of water consumed
= \$2.30 /1,000 gal

Total annual cost savings are summarized in the following Savings Summary table:

Saving Summary				
Source	Quantity	Units	\$ /unit	Cost Savings
Current Cost	83,000	gallons	\$0.0063	\$520
Proposed Cost	12	months	\$170	-\$2,040
Water Revenue	83,000	gallons	\$0.04	\$3,320
Total				**\$1,800**

The following table summarizes the payback per month based on the rate charged per gallon.

Payback Summary Table									
				Rate charged to visiting vessels ($ /gallon)					
Month	**G***	**CC****	**PW*****	**$0.00**	**$0.01**	**$0.02**	**$0.03**	**$0.04**	**$0.05**
January	0	$0	$170	-$107	-$7	$93	$193	$293	$393
February	0	$0	$170	-$170	-$170	-$170	-$170	-$170	-$170
March	1,333	$8	$170	-$162	-$148	-$135	-$122	-$108	-$95
April	8,667	$54	$170	-$116	-$29	$58	$144	$231	$318
May	7,333	$46	$170	-$124	-$51	$23	$96	$169	$243
June	8,667	$54	$170	-$116	-$29	$58	$144	$231	$318
July	10,667	$67	$170	-$103	$3	$110	$217	$323	$430
August	24,000	$150	$170	-$22	$218	$458	$698	$938	$1,178
September	7,667	$48	$170	-$122	-$45	$31	$108	$185	$261
October	4,667	$29	$170	-$141	-$94	-$47	-$1	$46	$93
November	0	$0	$170	-$170	-$170	-$170	-$170	-$170	-$170
December	10,000	$63	$170	-$170	-$170	-$170	-$170	-$170	-$170
Total	**83,000**	**$519**	**$2,040**	**-$1,522**	**-$692**	**$138**	**$968**	**$1,798**	**$2,628**
Payback				**--**	**--**	**109.0**	**15.5**	**8.3**	**5.7**

* G = gallons
** CC = current cost of water per gallon
*** PW = proposed monthly water charge for new dock meter account

Cost Analysis

The only cost associated with this recommendation is the cost of installing a 3 inch water meter at the dock. The City of Newport Public Works Department must install it, and they estimate the cost at $15,000. The work involved to install a new water meter includes tapping into the existing city water main, running a water line beneath the road and pouring a concrete enclosure.

Savings will pay for implementation in 8.3 years. Because there are no energy savings related to this recommendation, no incentives apply.

AR No. 4

Visitor Center Lighting
Calculation Methodology

Recommended Action

Replace halogen bulbs in the Visitor Center with compact fluorescent bulbs, as the halogen bulbs burn out. Replacing all bulbs will reduce lighting electricity usage by 70%.

Assessment Recommendation Summary					
Energy (MMBtu)	Power (kW)	Energy (kWh)*	Cost Savings	Implementation Cost**	Payback (years)
75	8.8	22,000	$1,940	$360	1.3

** 1 kWh = 3,410 Btu. 1,000,000 Btu = 1 MMBtu*

*** Implementation Cost includes incentives*

Data Collected Summary

- 75W PAR30 Halogen lamps: 147
- 75W PAR38 Halogen lamps: 22
- Incremental energy cost: $0.0344/ kWh
- Incremental demand cost $7.73 /kW
- Annual Runtime: 2,503 hours

Savings Analysis

Energy savings are estimated using power, current bulb wattages, proposed bulb wattages, and operating hours. Figures are listed under Lamps, Power and Energy sections of the attachment Visitor Center Lighting I and II, at the end of this recommendation. Visitor Center Lighting I and II compare current bulbs with purposed bulbs.

CS = Total Cost Savings
= ES + DS + LS
= $760 + $810 +$370
= $1,940

Where,

ES = Energy Cost Savings
= PS x EC
= 22,030 kWh x $0.03444 /kWh
= $760

DS	=	Demand Cost Savings
	=	DC x PW x 12 Months
	=	$7.73 /kWh-Month x 8.8 kW x 12 Months
	=	$810
LS	=	Yearly Maintenance Labor Cost Savings from visitor center lighting I and II attachments at the end of the recommendation
	=	$380

Where,

PS	=	Power Saved
	=	CE – PE
	=	31,730 kWh – 9,730 kWh
	=	22,000 kWh
EC	=	Energy Cost
	=	$0.03444 /kWh
DC	=	Demand Cost
	=	$7.73 /kWh-Month
PW	=	Power Saving
	=	8.8 kW

Where,

CE	=	Current Energy Consumption
	=	QT x WC x CF x HR
	=	169 bulbs x 75 watts x 0.001 kW /watt x 2,503 hours
	=	31,730 kWh
PE	=	Proposed Energy Consumption
	=	QT x WP x CF x HR
	=	169 bulbs x 23 watts x 0.001 kW /watt x 2,503 hours
	=	9,730 kWh

Where,

QT	=	Quantity
	=	147 Par 30 bulbs + 22 Par 38 bulbs
	=	169 bulbs
WC	=	Current Watts
	=	75 watts
CF	=	Conversion from watts to kilowatts
	=	0.001 kW /watt

HR = Operating Hours
= 2,503 hours

WP = Proposed Watts
= 23 watts

Installing compact fluorescent bulbs will lead to a decrease in bulb maintenance labor costs by extending the life of lamps. Annual labor savings are $382. However, the increased cost of lamps will increase material costs by $14 annually, totaling $368 of annual decreased maintenance costs. Total annual cost savings are summarized in the following table:

Saving Summary				
Source	Quantity	Units	Energy (MMBtu)	Cost
Demand	8.8	kW		$810
Energy Use	22,000	kWh	75.2	$760
Maintenance Material				($10)
Maintenance Labor				$380
Total	**22,000**		**75.2**	**$1,940**

Cost Analysis

The cost of replacing the halogen bulbs with compact fluorescent bulbs is based on the cost of installation per bulb. There are a total of 169 bulbs that need to be replaced. The compact fluorescents will be installed as the halogen lights burn out so there will be no added labor cost.

The costs are summarized in the table below:

Cost Summary				
Item	Quantity	Units	Cost/Unit	Cost
23W PAR30 CFL	147	Bulbs	$11	$1,620
23W PAR38 CFL	22	Bulbs	$22	$480
Total				**$2,100**

Savings will pay for implementation in 1.3 years before incentives.

Incentive Analysis

Bonneville Power Administration offers cash incentives through your utility that are available to help pay for implementation of energy saving measures. These savings are equal to either \$0.17/kWh saved in the first year or 70% of total project cost. The incentive given for a project will be the lesser of these two, which is calculated as follows.

BP	=	Bonneville Power Administration Incentives			
	=	Minimum of	TE x \$0.17 /kWh	or	0.70 x TC
	=	Minimum of	22,000 kWh x \$0.17/kWh	or	0.70 x \$2,100
	=	Minimum of	\$3,740 or	\$1,470	
	=	\$1,470			

Where,

TE	=	Total Energy Savings
	=	22,000 kWh
TC	=	Total Implementation Cost
	=	\$2,100

The following table summarizes implementation costs before and after incentives.

Incentive Summary	
Description	Cost
Pre-incentive Cost	**\$2,100**
Bonneville Power Administration Incentive	(\$1,470)
Total after Incentives	**\$360**

Savings will pay for implementation costs in 0.2 years after incentives.

Visitor Center Lighting I

PLANT DATA				Report Number:	2002	
Building:	Hatfield MSC 900			Incremental Demand Cost:	7.73	/kW-mo.
Area:	Visitor Center			Incremental Energy Cost:	0.03444	/kWh
Lamp Replacement Time:	1/4	hours		Recommended Foot-candles:		
Ballast Replacement Time:	1/2	hours		Maintenance Labor Rate:	$15.00	/hour
Fixture Replacement Time:	1	hours		Electrician Labor Rate:	$50.00	/hour

FIXTURES	Existing	Proposed	Savings	Units
FIXTURE CODE	75W Par 30	FC23-PAR30		
Description:	75W Par 30	23W PAR30 CFL		
Quantity:	147	147	0	
Operating Hours:	2503	2503	0	hours
Output Factor:	100%	100%	0%	
Lamps per Fixture:	1	1	0	
Ballasts per Fixture:	0	0	0	
Fixture Cost:	$0.00	$0.00	$0.00	
LAMPS				
LAMP CODE	75W Par 30	FC23-PAR30		
Description:	75W Par 30	23W PAR30 CFL		
Quantity:	147	147	0	
Life:	3,000	10,000	(7,000)	hours
Lamp Cost:	$3.39	$10.95	($7.56)	
Watts per Lamp:	75	23	52	watts
Lumens:	1,050	1,050	0	
Replacement Fraction:	83%	25%	1	
Annual Lamp Replacement Cost:	$415.77	$402.90	$12.88	
Annual Maintenance Labor Cost:	$459.93	$137.98	$321.95	
BALLASTS				
BALLAST CODE				
Description:				
Quantity:	0	0	0	
Life:	0	0	0	hours
Ballast Cost:	$0.00	$0.00	$0.00	
Ballast Factor:	0%	0%	0	
Input Watts:	0	0	0	watts
Replacement Fraction:	0%	0%	0	
Annual Ballast Replacement Cost:	$0.00	$0.00	$0.00	
Annual Maintenance Labor Cost:	$0.00	$0.00	$0.00	
POWER AND ENERGY				
Power:	11.0	3.4	7.6	kW
Energy Use:	27,533	8,510	19,023	kWh
LIGHT LEVEL CHECK				
Total Lumens:	154,350	154,350	0	
Foot-candles:	65	65	0	
Lighting Efficiency:				Lum./W
ANNUAL OPERATING COST				
Demand Cost:	$1,020	$315	$705.00	
Energy Cost:	$948	$293	$655.00	
Maintenance Material Cost:	$416	$403	$12.88	
Maintenance Labor Cost:	$460	$138	$321.95	
Total Operating Cost:	$2,844	$1,149	$1,694.83	

IMPLEMENTATION COST		
Materials:	$1,610	
Labor:	$366	
Total Implementation Cost:	$1,976	
SIMPLE PAYBACK	1.2	years

Visitor Center Lighting II					
PLANT DATA			Report Number:	2002	
Building:	Hatfield MSC 900		Incremental Demand Cost:	7.73	/kW-mo.
Area:	Visitor Center		Incremental Energy Cost:	0.03444	/kWh
Lamp Replacement Time:	1/4 hours		Recommended Foot-candles:		
Ballast Replacement Time:	1/2 hours		Maintenance Labor Rate:	$15.00	/hour
Fixture Replacement Time:	1 hours		Electrician Labor Rate:	$50.00	/hour
FIXTURES		Existing	Proposed	Savings	Units
FIXTURE CODE		Par 38 75w	FC23-PAR30		
Description:		Par 38 75w	23W CFL PAR38		
Quantity:		22	22	0	
Operating Hours:		2503	2503	0	hours
Output Factor:		100%	100%	0%	
Lamps per Fixture:		1	1	0	
Ballasts per Fixture:		0	0	0	
Fixture Cost:		$0.00	$0.00	$0.00	
LAMPS					
LAMP CODE		Par 38 75w	FC23-PAR38		
Description:		Par 38 75w	23W CFL PAR38		
Quantity:		22	22	0	
Life:		2,500	8,000	(5,500)	hours
Lamp Cost:		$5.49	$21.50	($16.01)	
Watts per Lamp:		75	23	52	watts
Lumens:		1,100	1,200	(100)	
Replacement Fraction:		100%	31%	1	
Annual Lamp Replacement Cost:		$120.92	$147.99	($27.06)	
Annual Maintenance Labor Cost:		$82.60	$25.81	$56.79	
BALLASTS					
BALLAST CODE					
Description:					
Quantity:		0	0	0	
Life:		0	0	0	hours
Ballast Cost:		$0.00	$0.00	$0.00	
Ballast Factor:		0%	0%	0	
Input Watts:		0	0	0	watts
Replacement Fraction:		0%	0%	0	
Annual Ballast Replacement Cost:		$0.00	$0.00	$0.00	
Annual Maintenance Labor Cost:		$0.00	$0.00	$0.00	
POWER AND ENERGY					
Power:		1.7	0.5	1.2	kW
Energy Use:		4,255	1,252	3,003	kWh
LIGHT LEVEL CHECK					
Total Lumens:		24,200	26,400	(2,200)	
Foot-candles:		65	71	(6)	
Lighting Efficiency:					Lum./W
ANNUAL OPERATING COST					
Demand Cost:		$158	$46	$112.00	
Energy Cost:		$147	$43	$104.00	
Maintenance Material Cost:		$121	$148	($27.06)	
Maintenance Labor Cost:		$83	$26	$56.79	
Total Operating Cost:		$509	$263	$245.72	
IMPLEMENTATION COST					
Materials:				$473	
Labor:				$55	
Total Implementation Cost:				$528	
SIMPLE PAYBACK				2.1	years

Note: There is increased light intensity by changing from 75 Watt par 38 halogens to 23 Watt par 38 compact fluorescents.

AR No. 5

Premium Efficiency Motors
Calculation Methodology

Recommendation

Replace 63 selected standard motors with premium efficiency electric motors rather than rewinding your motors or purchasing new or used non-premium motors. 7% of your total motor electrical energy will be saved.

Assessment Recommendation Summary				
Energy (MMBtu)	Energy (kWh)*	Cost Savings	Implementation Cost**	Payback (years)
376.2	110,320	$5,750	$2,470	0.4

** 1 kWh = 3,410 Btu. 1,000,000 Btu = 1 MMBtu*

*** Implementation Cost includes incentives*

Data Collected Summary

Refer to the end of Appendix B for information on motor data collection. If we did not find nameplate data for a motor, it was assumed to be a 1,800 rpm, totally enclosed fan cooled (TEFC) type.

Savings Analysis

A motor must meet or exceed the NEMA Premium Efficiency Standards to be considered a premium efficient motor. The NEMA Premium Efficiency standards are summarized in the following table.

NEMA Premium Efficiency Standards		
	Full - Load Motor Efficiency (%)	
HP	Energy Efficient Motor	NEMA Premium Efficiency Motor
10	89.5	91.7
25	92.4	93.6
50	93	94.5
100	94.5	95.4
200	95	96.2

A DOE energy efficiency calculator, MotorMaster+, determines energy savings by applying the current load profile on the premium efficiency replacement motor. It calculates efficiency at each load point and then determines energy use, electrical demand, and operating costs. Annual energy savings are determined by summing the savings obtained at each operating point.

We chose the following options in MotorMaster+ to model your motors: simple payback criteria, motor list price discount factor, and number of months that the motor is expected to operate during utility "peak" demand periods. We also indicated that the top three "best available" replacement motors should be selected. The "best available" replacement motor provides the quickest simple payback on investment.

The Premium Motor Efficiency Summary worksheet (at the end of the recommendation and in Appendix B.9) tabulates: energy, demand, total savings, new motor cost, anticipated manufacturer discount, and payback period for replacing your existing motors with premium efficiency motors, rather than rewinding these motors. The worksheet includes all standard (900, 1200, 1800, or 3600 rpm) motors that we found during our site visit with motors rated at 1 hp and up. The worksheet was generated using MotorMaster+, and displays motors for which the incremental payback is 10 years or less.

We assume that all motors experience efficiency degradation from rewinding and include this degradation in the savings calculations. We use a default degradation of 2% for motors under 50 hp, and 1% for motors 50 hp and above.

We include Definitions, Motor Inventory list, Batch Analysis worksheet, and Default Installation and Rewind Costs tables in Appendix B.

We calculate demand savings (DS) from the following equation for each motor at each load point.

DS = Demand Savings

$$= D \times \left[1 - \left(\frac{\eta_0}{\eta_1}\right)\right]$$

Where,

D = Current motor demand (kW), Appendix B.3

η_0 = Estimated efficiency of existing motor

η_1 = Efficiency of proposed premium efficiency motor

We do not include diversity factor in our calculations. Diversity factor accounts for the time a motor operates during peak demand period. Since not all of these motors operate during peak demand periods, demand savings will be less than shown on the worksheet.

We calculate annual energy savings (ES) from the following equation for each motor at each load point.

ES = Energy Savings

$$= E \times \left[1 - \left(\frac{\eta_0}{\eta_1}\right)\right]$$

Where,

E = Annual motor energy consumption (kWh), Appendix B.3

Total demand savings (DS) and energy savings (ES) for the 63 motors, as they need to be replaced, are:

DS = Demand Savings
= 21 kW

ES = Energy Savings
= 110,320 kWh

Demand and energy costs are obtained from your current electricity rate schedule. The annual demand cost savings (DC) are given by:

DC = Demand Cost Savings
= DS x ID x 12 Months
= 21 kW x $7.73 /kW-Month x 12 Months
= $1,950

Where,

ID = Incremental Demand Rate
= $7.73 /kW-Month

Annual energy cost savings (EC) are given by:

EC = Energy Cost Savings
= ES x IE
= 110,320 kWh x $0.03444 /kWh
= $3,800

Where,

IE = Incremental Energy Rate
= $0.03444 /kWh

Total annual cost savings for the 63 motors are summarized in the Savings Summary table below.

Savings Summary				
Source	Quantity	Units	Energy (MMBtu)	Cost
Electric Energy	110,320	kWh	376.2	$3,800
Demand	21	kW		$1,950
Totals			**376.2**	**$5,750**

You may select individual motors from Appendix B.9 that best fit your savings and payback criteria.

The savings would be realized after all standard motors are replaced with premium efficiency motors. Based on Internal Revenue Service depreciation guidelines, the average motor lifetime is 12 years. Therefore, we assume that 1/12 of the motors at this plant will be replaced each year. The implementation cost and savings will materialize over the life of existing motors as they need replacing.

Cost Analysis

The rewind analysis considers the incremental cost between rewinding a failed motor and purchasing a new premium efficiency motor. Since we assume that the replacement occurs when the motor fails and is removed for repair, no additional installation costs are incurred.

MotorMaster+ calculates the implementation cost for each motor (IC) using

IC = Implementation Cost
= $MC \times (1 - MD) - RC$

Where,

MC = Motor cost (list price)

MD = Manufacturer discount, in %, Appendix B.9

RC = Rewind cost, Appendix B.13

MotorMaster+ lists up to three of the “best available” motors in Appendix B.11 that match the selection criteria, and lists them in order of increasing payback. We typically select the replacement motor with the shortest payback as the “best available” and use it in the Premium Motor Efficiency Summary worksheet at the end of the recommendation and in Appendix B.9. However, you can select any motors for replacement.

The implementation cost associated with installing premium motors, as they need replacement, is the difference between the premium motors' net purchase prices and the cost of rewinding the existing motors. The total cost for the 63 motors in Appendix B.9 is summarized in the Implementation Summary table.

Implementation Summary		
Source	Quantity	Total Cost
Motors Replaced with Premium Efficiency Motors	63	$8,190

The combined payback period for replacing all 63 motors is 1.4 years before utility incentives or rebates. For motors that show an "immediate" payback, the cost to purchase a new premium efficiency motor, including the manufacturer discount, is less than the cost to rewind the existing motor. In our calculations of implementation costs, we assigned these a value of zero.

Assuming the implementation cost is incurred uniformly over a 12-year motor life, the annual implementation cost will be approximately $680.

Incentive Analysis

Bonneville Power Administration offers cash incentives through your utility that are available to help pay for implementation of energy saving measures. These savings are equal to either $0.17/kWh saved in the first year or 70% of total project cost. The incentive given for a project will be the lesser of these two, which is calculated as follows.

BP	=	Bonneville Power Administration Incentives			
	=	Minimum of	TE x $0.17 /kWh	or	0.70 x TC
	=	Minimum of	110,320kWh x $0.17/kWh	or	0.70 x $8,190
	=	Minimum of	$18,750	or	$5,730
	=	$5,730			

Where,

TE	=	Total Energy Savings
	=	110,320 kWh
TC	=	Total Implementation Cost
	=	$8,190

The following table summarizes implementation costs before and after incentives.

Incentive Summary	
Description	Cost
Pre-incentive Cost	**$8,190**
Bonneville Power Administration Incentive	($5,730)
Total after Incentives	**$2,460**

Savings will pay for implementation costs in 0.4 years after incentives.

APPENDIX A

UTILITIES

A.1. Energy Definitions

An essential component of any energy management program is tracking energy. When utility bills are received, we record energy use and cost in a spreadsheet and get the appropriate graphs. A separate spreadsheet may be required for each type of energy used, such as oil, gas, or electricity. A combination might be merited when both gas and oils are used interchangeably in a boiler. In such a case we suggest using a common energy unit for a cost-benefit analysis that can represent most fuel options: the Btu.

We have prepared a utility spreadsheet analysis based on the information provided by you or your utility companies. The worksheets are in section A.3, Energy, Waste, and Production Accounting. They show how energy is used and help identify potential energy savings.

We use specific terminology and calculations in analyzing and discussing your energy, water, and waste expenses. Energy related terms and calculations are detailed below followed by those for waste and water.

Electricity Definitions:

Average Energy Cost. The total amount billed for 12 months of energy, divided by the total number of energy units. Each energy type (oil, gas, electricity, propane, etc.) has its own average energy cost. The average cost per energy unit includes the fees, taxes and unit cost.

Average Energy Cost = (Total Billed $) ÷ (Total Energy Units)

Average Load Factor. The ratio of annual electrical energy use divided by the average kilowatts (kW) and the hours in a year.

Average Load Factor = (Total kWh/yr) ÷ (Average kW x 8,760 hrs/yr)

Average Load Factor expresses how well a given electrical system uses power. A higher load factor yields lower average energy cost.

An example of how load factor applies: A large air compressor has high electric demand for small periods of time and is not a large energy user. It will usually have low load factor and relatively high demand charges. A smaller air compressor that runs for longer periods of time at higher part load efficiency will have higher load factor and lower demand charges.

Basic Charge. The fee a utility company can charge each month to cover their administrative, facility, or other fixed costs. Some companies have higher energy or power rates that compensate for no or low basic charge.

Energy. The time-rate of work expressed in kWh for electric energy. The common unit is million Btu. For a more complete description, see Power.

Energy = Work ÷ Time = (Force x Distance) ÷ Time

Incremental Demand Cost. It is the price charged by your utility company for the capacity to meet your power needs at any given time. Peak demand is the highest demand level required over a set period of time and is calculated by continuously monitoring demand levels. Demand is usually billed based on peak power, but charges such as facility charges and other fees billed per kW are also included in the incremental demand cost. If your utility company has stepped demand cost rates, the step with the greatest demand is considered in the incremental demand cost. If your utility company bills one set rate for all power needs, this value is used as the incremental demand cost.

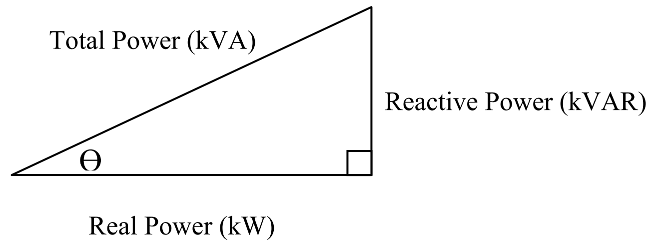
Incremental Energy Cost (Electricity). It is cost of one more unit of energy, from current use. This cost is usually taken from your utility rate schedule. When all large meters are on the same rate schedule, the incremental energy cost is the cost from the highest energy tier, or tail block. To further clarify this method: if a company is charged $0.05/kWh up to 100,000 kWh, and $0.03/kWh over 100,000 kWh and they are consistently buying over 100,000 kWh each month, any energy savings will be calculated using the $0.03/kWh cost.

If your company has multiple meters on different rate schedules or tariffs, the incremental cost is calculated by adding electrical energy costs and dividing by the total electrical energy use.

Incremental Energy Cost = (Total kWh $) ÷ (Total kWh)

Minimum Charge. The least amount billed by a utility at the end of the billing period.

Power (and Energy). The rate at which energy is used, expressed as the amount of energy use per unit time, and commonly measured in units of watts and horsepower. Power is the term used to describe the capacity the utility company must provide to serve its customers. Power is specified three ways: real, reactive and total power. The following triangle gives the relationship between the three.



Real power is the time average of the instantaneous product of voltage and current (watts). Apparent power is the product of rms (root mean square) volts and rms amps (volt-amps).

Demand

The highest electrical power required by the customer, generally averaged over 15 minute cycling intervals for each month. Demand is usually billed by kW unit.

Kilovolt Amperes (kVA)

Kilovolt amperes are a measure of the current available after accounting for power factor. See the triangle on the previous page. Power is sometimes billed by kVA.

Reactive Power

Reactive power is measured in units of kVAR. Reactive power produces magnetic fields in devices such as motors, transformers, and lighting ballasts that allow work to be done and electrical energy to be used. Kilo Volt Amperes Reactive (kVAR) could occur in an electrical circuit where voltage and current flow are not perfectly synchronized. Electric motors and other devices that use coils of wire to produce magnetic fields usually cause this misalignment of three-phase power. Out-of-phase current flow causes more electrical current to flow in the circuit than is required to supply real power. kVAR is a measure of this additional reactive power.

High kVAR can reduce the capacity of lines and transformers to supply kilowatts of real power and therefore cause additional expenses for the electrical service provider. Electric rates may include charges for kVAR that exceed a normal level. These charges allow the supplying utility to recover some of the additional expenses caused by high KVAR conditions, and also encourages customers to correct this problem.

Power Factor

The ratio of real power to total power. Power factor is the cosine of angle θ between total power and real power on the power triangle.

$$PF = \cos\theta = kW \div kVA$$

Disadvantages of Low Power Factor

- Increases costs for suppliers because more current has to be transmitted requiring greater distribution capacity. This higher cost is directly billed to customers who are metered for reactive power.
- Overloads generators, transformers and distribution lines within the plant, resulting in increased voltage drops and power losses. All of which represents waste, inefficiency and wear on electrical equipment.
- Reduces available capacity of transformers, circuit breakers and cables, whose capacity depends on the total current. Available capacity falls linearly as the power factor decreases.

Low Power Factor Charges

Most utilities penalize customers whose power factor is below a set level, typically in the range of 95% - 97%, or kVAR greater than 40% of kW. Improving power factor may reduce both energy and power costs, however these are generally much less than savings from real power penalties enforced by electrical utilities. Energy savings are also difficult to quantify. Therefore in our recommendations, only power factor penalty avoidance savings are included.

Improving Power Factor

The most practical and economical power factor improvement device is the capacitor. All inductive loads produce inductive reactive power current (lags voltage by a phase angle of 90°). Capacitors, on the other hand, produce capacitive reactive power, which is the opposite of inductive reactive power (current leads…). Current peak occurs before voltage by a phase angle of 90°. By careful selection of capacitance required, it is possible to totally cancel out the inductive reactive power, but in practice it is seldom feasible to correct beyond your utilities' penalty level (~95% for kVA meters).

Improving power factor results in:

- Reduced utility penalty charges.
- Improved plant efficiency.
- Additional equipment on the same line.
- Reduced overloading of cables, transformers, and switchgear.
- Improved voltage regulation due to reduced line voltage drops and improved starting torque of motors.

Power Factor Penalty

Utility companies generally calculate monthly power factor two ways. One way is based on meters of reactive energy and real energy.

$$\text{Monthly PF} = \cos\left[\tan^{-1}(\text{kVARh} \div \text{kWh})\right]$$

The second method is based on reactive power and real power.

$$\text{Monthly PF} = \cos\left[\tan^{-1}(\text{kVAR} \div \text{kW})\right]$$

Power Factor is often abbreviated as "PF". Also see the Power Factor definition below.

Cost Calculations

Annual operating expenses include both demand and energy costs. Demand cost (DC) is calculated as the highest peak demand (D) multiplied by your incremental demand charge and the number of operating months per year:

$$DC = D \times \text{demand rate } (\$/\text{kW·mo}) \times 12 \text{ mo/yr}$$

Energy cost (EC) is energy multiplied by your incremental electric rate:

$$EC = E \times \text{energy rate } (\$/\text{kWh})$$

Waste and Water Definitions:

Average Disposal Cost. The average cost per pickup or ton of waste or other scrap material. This cost is calculated using all of the annual expenses to get a representative cost per unit of disposal.

Average Disposal Cost / Ton = (Total Disposal $) ÷ (Total tons removed)

Average Disposal Cost / Pickup = (Total Disposal $) ÷ (Total number of pickups)

BOD Charge. Charge levied by the sewer/water treatment utility to cover extra costs for high strength wastewater. High strength wastewater requires more intensive treatment by the utility and extra processing due to very low oxygen levels. BOD, biochemical oxygen demand, is a measure of how much oxygen will be used to microbiologically degrade the organic matter in the wastewater stream. State agencies such as a Department of Environmental Quality set BOD and other regulations that wastewater treatment facilities must meet to discharge treated water into nearby waterways. Your treatment facility may have ideas that could help lower the strength of your wastewater.

Box Rental Charge. The fee imposed by the waste or recycling utility to cover costs of their receiving containers.

Disposal Cost. Incurred by the waste utility for disposing of your waste in a landfill or other facility. These charges increase when hazardous materials are present in the waste.

Pickup Costs. The cost charged by the waste utility for each pickup of waste or recycling. This charge is usually applied when the utility is working on an "on call" basis. Pickup costs can also be a flat rate for a certain number of pickups per month.

A.2. Energy Conversions

An essential component of any energy management program is a continuing account of energy use and its cost. This can be done best by keeping up-to-date graphs of energy consumption and costs on a monthly basis. When utility bills are received, we recommend that energy use be immediately plotted on a graph. A separate graph will be required for each type of energy used, such as oil, gas, or electricity. A combination will be necessary, for example, when both gas and oil are used interchangeably in a boiler. 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 energy unit used in this report is the Btu, British Thermal Unit, or million Btu's (MMBtu). The Btu conversion factors and other common nomenclature are:

Energy Unit	Energy Equivalent	
1 kWh	3,413	Btu
1 MWh	3,413,000	Btu
1 cubic foot of natural gas	1,030	Btu
1 gallon of No. 2 oil (diesel)	140,000	Btu
1 gallon of No. 6 oil	152,000	Btu
1 gallon of gasoline	128,000	Btu
1 gallon of propane	91,600	Btu
1 pound of dry wood	8,600	Btu
1 bone dry ton of wood (BDT)	17,200,000	Btu
1 unit of wood sawdust (2,244 dry pounds)	19,300,000	Btu
1 unit of wood shavings (1,395 dry pounds)	12,000,000	Btu
1 unit of hogged wood fuel (2,047 dry pounds)	17,600,000	Btu
1 ton of coal	28,000,000	Btu
1 MWh	1,000	kWh
1 therm	100,000	Btu
1 MMBtu	1,000,000	Btu
1 10^6Btu	1,000,000	Btu
1 kilowatt	3,413	Btu/hr
1 horsepower (electric)	2,546	Btu/hr
1 horsepower (boiler)	33,478	Btu/hr
1 ton of refrigeration	12,000	Btu/hr

Unit Equivalent		
1 gallon of water	8.33	pounds
1 cubic foot of water	7.48	gallons
1 kgal	1,000	gallons
1 unit wood fuel	200	ft^3

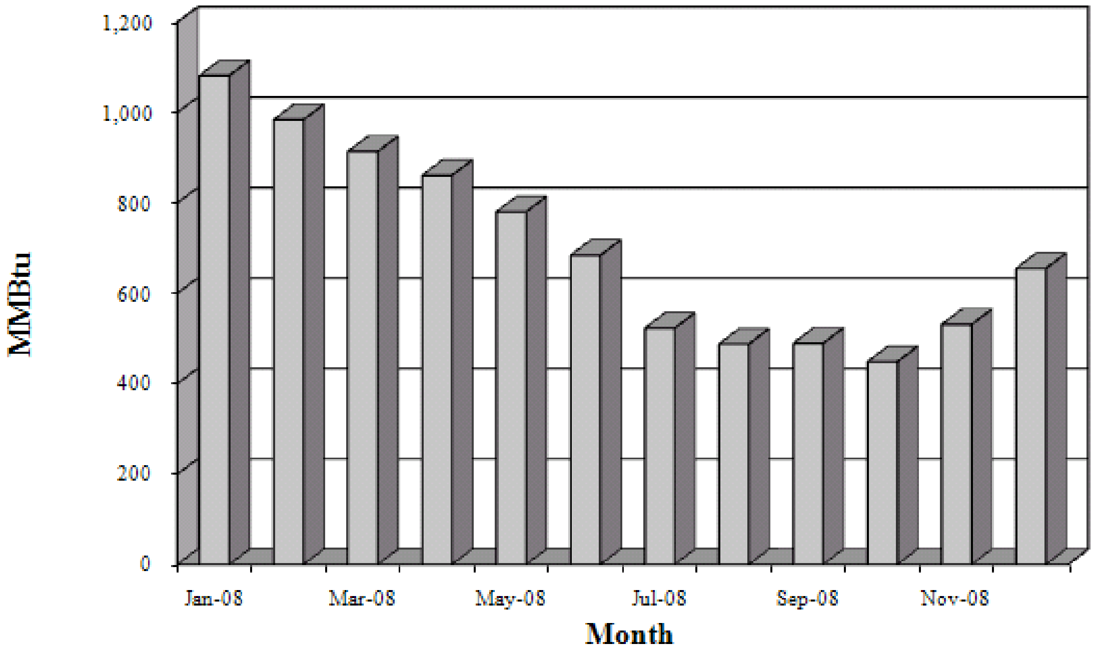
The value of graphs can best be understood by examining those plotted for your company in the Energy Summary. Energy use and costs are presented in the following tables and graphs. From these figures, trends and irregularities in energy usage and costs can be detected and the relative merits of energy conservation can be assessed.

A.3. Energy, Waste, and Production Accounting

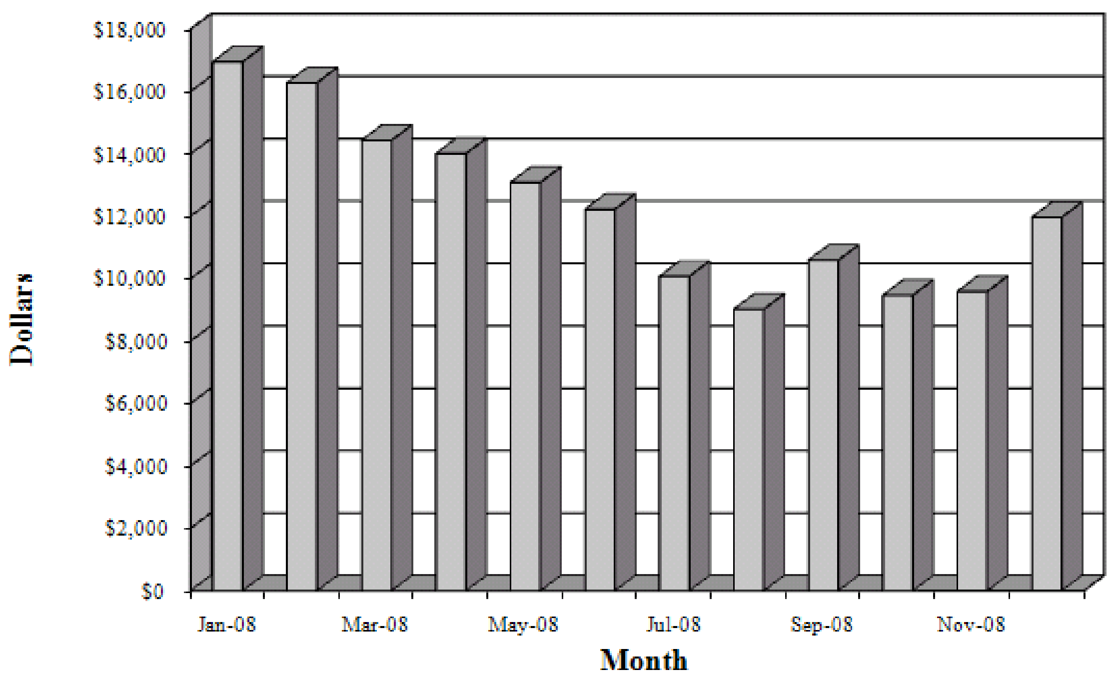
Energy Use Combined Meters / Utilities									
				Water		Sewer		Totals	
Month	kW	kWh	Total $	1000 Gallons	$	1000 Gallons	$	MMBtu	$
Jan-08	770	316,976	$16,957	814	$2,851	814	$2,278	1,082	$22,086
Feb-08	810	288,360	$16,285	565	$2,057	565	$1,637	984	$19,980
Mar-08	663	267,748	$14,435	419	$1,592	419	$1,262	914	$17,289
Apr-08	677	252,243	$14,015	2,285	$7,543	2,285	$6,065	861	$27,622
May-08	663	228,664	$13,090	506	$1,869	506	$1,486	780	$16,444
Jun-08	676	200,512	$12,226	528	$1,939	528	$1,542	684	$15,707
Jul-08	610	153,176	$10,080	519	$1,911	519	$1,519	523	$13,510
Aug-08	518	143,000	$9,023	334	$1,321	334	$1,043	488	$11,386
Sep-08	720	143,408	$10,595	459	$1,719	459	$1,365	489	$13,678
Oct-08	628	131,424	$9,472	343	$1,349	343	$1,066	449	$11,887
Nov-08	536	155,624	$9,591	279	$1,145	279	$901	531	$11,637
Dec-08	682	191,888	$11,968	72	$485	72	$369	655	$12,822
Totals	7,952	2,473,023	$147,736	7,123	$25,780	7123	$20,532	8,440	$194,048
Avg/Mo	663	206,085	$12,311	594	$2,148	594	$1,711	703	$16,171

Combined Utility Summary			
Electricity			
	Rate Schedule	300	
	Incremental Energy Cost	$0.03444	/kWh
	Incremental Demand Cost	$7.73	/kW
	Average Energy Cost	0.05973886	/kWh
	Average Load Factor	43%	
	Taxes/Fees	$91	/Month
Water			
	Incremental Water Cost	$3.19	/1000 Gallons
	Average Water Cost	3.61931022	/1000 Gallons
	Taxes/Fees	$255.33	/Month
Sewer			
	Incremental Sewer Cost	$2.57	/1000 Gallons
	Average Sewer Cost	$2.88	/1000 Gallons
	Taxes/Fees	$183.20	/Month

Total Energy Use



Total Energy Cost



Total Electricity Use

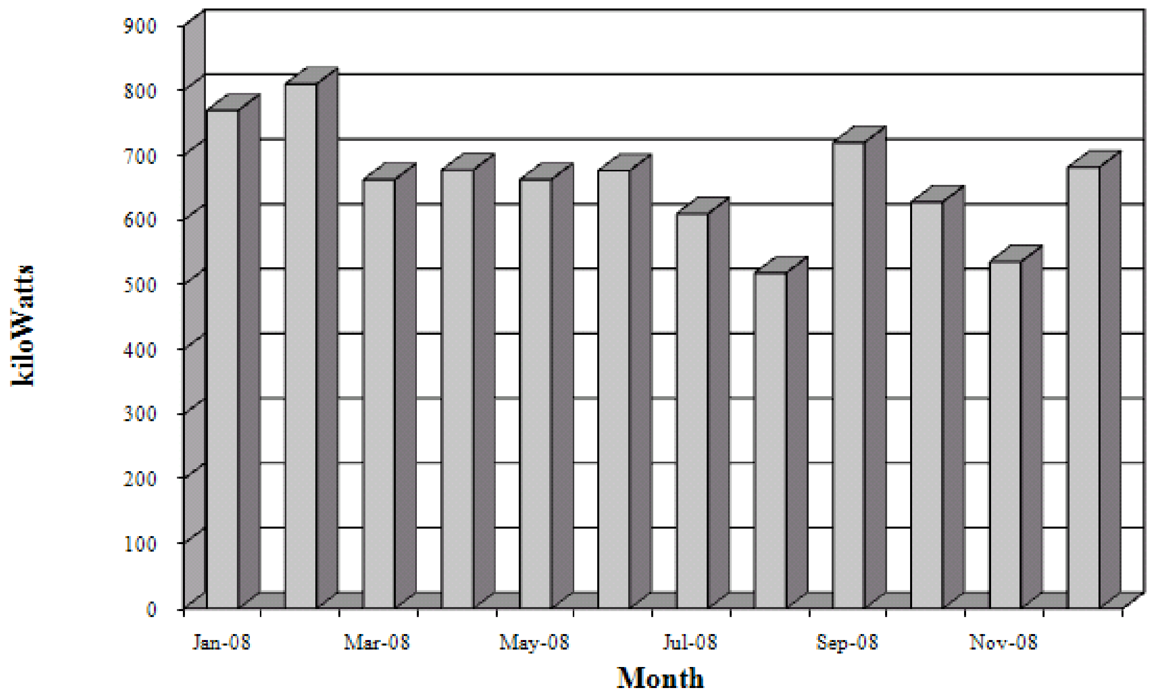
Month	kW	kW$	kWh	kWh$	Taxes/fees	Total $
Jan-08	770	$5,949	316,976	$10,917	$91	$16,957
Feb-08	810	$6,263	288,360	$9,931	$91	$16,285
Mar-08	663	$5,123	267,748	$9,221	$91	$14,435
Apr-08	677	$5,236	252,243	$8,687	$91	$14,015
May-08	663	$5,123	228,664	$7,875	$91	$13,090
Jun-08	676	$5,229	200,512	$6,906	$91	$12,226
Jul-08	610	$4,714	153,176	$5,275	$91	$10,080
Aug-08	518	$4,007	143,000	$4,925	$91	$9,023
Sep-08	720	$5,565	143,408	$4,939	$91	$10,595
Oct-08	628	$4,855	131,424	$4,526	$91	$9,472
Nov-08	536	$4,140	155,624	$5,360	$91	$9,591
Dec-08	682	$5,269	191,888	$6,609	$91	$11,968
Totals	7,952	$61,473	2,473,023	$85,171	$1,092	$147,736
Avg/Mo	663	$5,123	206,085	$7,098	$91	$12,311

Electric Utility Summary

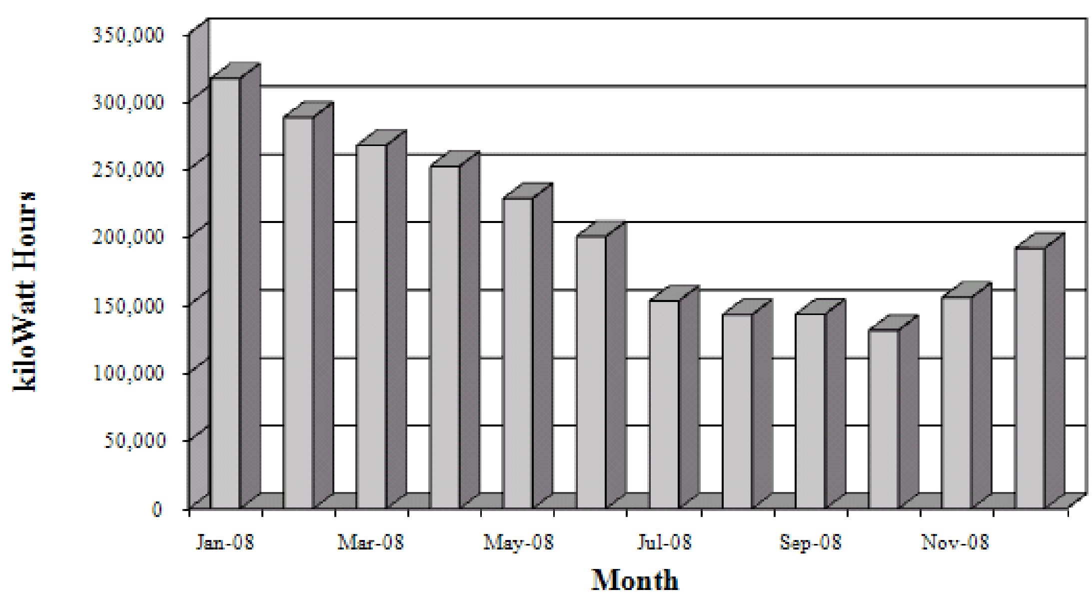
Rate Schedule

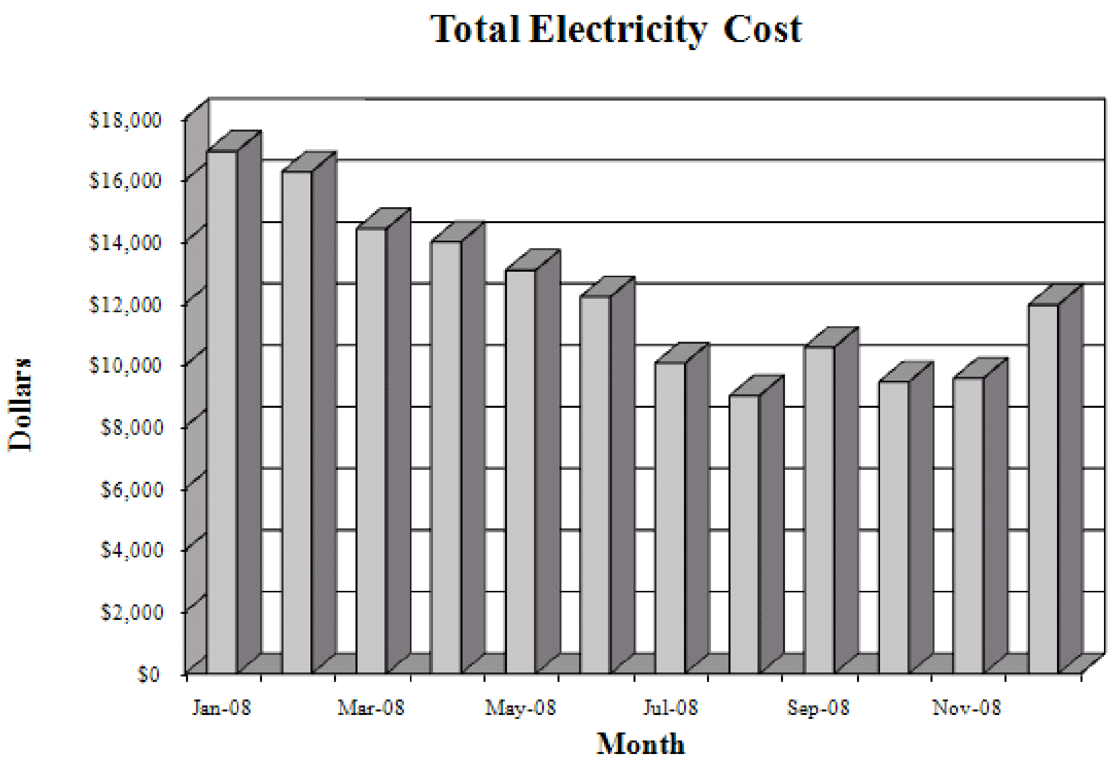
Basic Charge	$91	/month
Energy Cost	$0.03444	/kWh
Demand Cost		
Billed Demand Cost	$7.73	/kW
Average Electricity Cost	$0.05974	/kWh
Average Load Factor	43%	

Electrical Demand



Electrical Energy Use





Total Electricity Cost
Dollars
$18,000
$16,000
$14,000
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$0
Jan-08
Mar-08
May-08
Jul-08
Sep-08
Nov-08
Month

Water Use and Sewage Charges

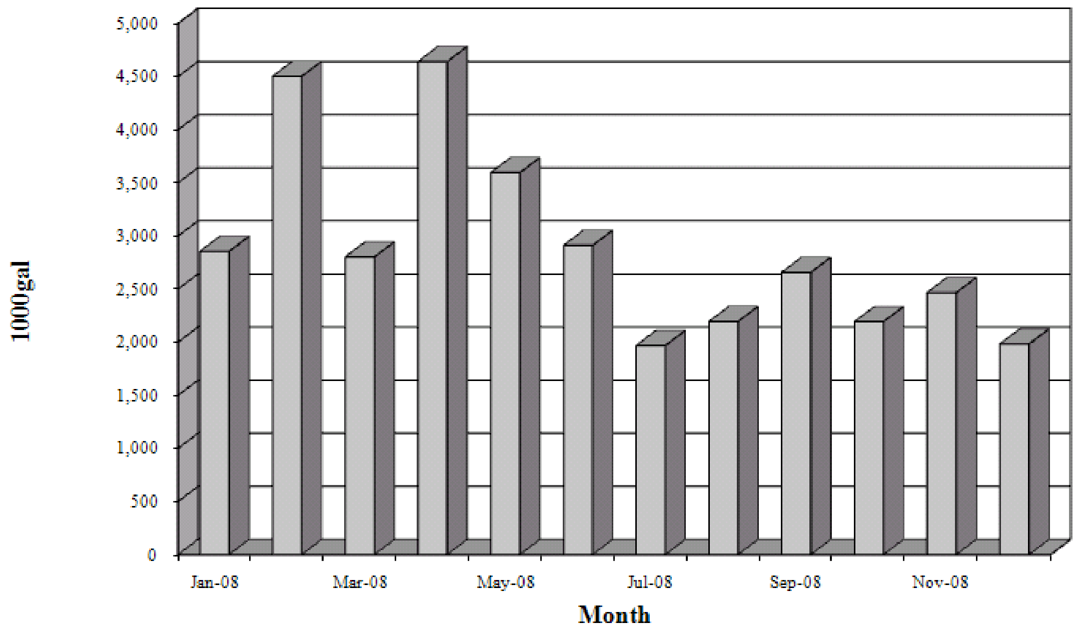
Account No. 160-007651-100 Meter No. 5463393B, 5463393, 98301592

	Water			Sewer			Total
Month	1000gal	$1000gal	fees	1000gal	$1000gal	fees	$
Jan-08	814	$2,596	$255	814	$2,095	$183	$5,130
Feb-08	565	$1,802	$255	565	$1,454	$183	$3,695
Mar-08	419	$1,336	$255	419	$1,078	$183	$2,853
Apr-08	2,285	$7,287	$255	2,285	$5,881	$183	$13,607
May-08	506	$1,614	$255	506	$1,302	$183	$3,355
Jun-08	528	$1,684	$255	528	$1,359	$183	$3,481
Jul-08	519	$1,655	$255	519	$1,336	$183	$3,430
Aug-08	334	$1,065	$255	334	$860	$183	$2,363
Sep-08	459	$1,464	$255	459	$1,181	$183	$3,084
Oct-08	343	$1,094	$255	343	$883	$183	$2,415
Nov-08	279	$890	$255	279	$718	$183	$2,046
Dec-08	72	$230	$255	72	$185	$183	$853
Totals	7,123	$22,716	$3,064	7,123	$18,334	$2,198	$46,312
Avg./Mo	594	$1,893	$255	594	$1,528	$183	$3,859

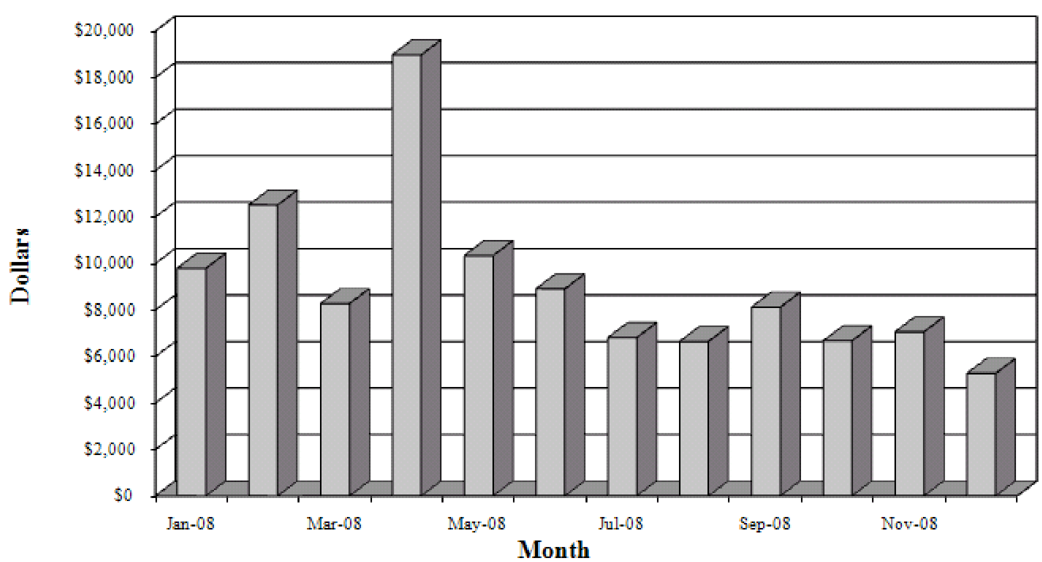
Water / Sewer Utility Summary

Water Basic Customer Charge	$255	/month
Water Use Charges	$3.19	/Tgal
Sewage Basic Customer Charge	$183	/month
Sewer Use Charges	$2.57	/Tgal

Water Use



Water & Sewer Cost



A.4. ENERGY USE SUMMARY & ENERGY ACCOUNTING

END USE SUMMARY

Average Electricity Cost:	$0.05974	/kWh
	$17.52	/MMBtu

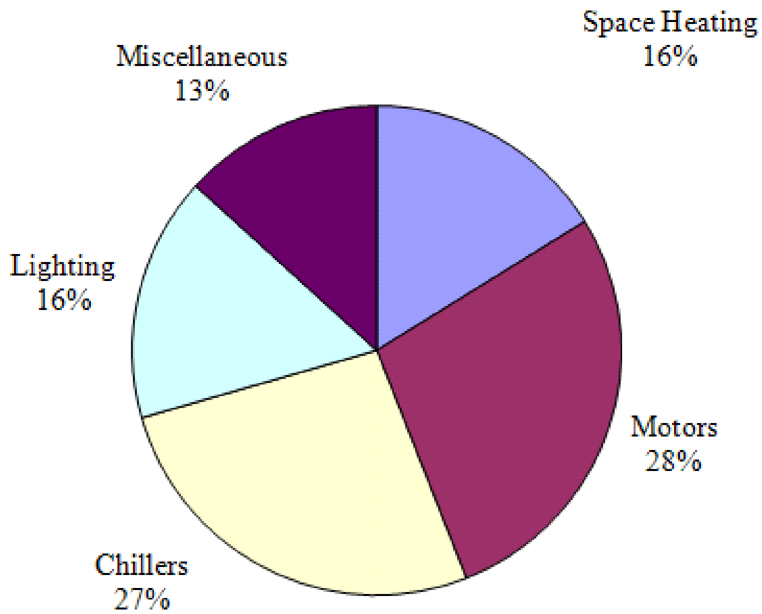
ELECTRICITY

	USE	UNIT	MMBtu	ENERGY %	COST	COST%
Space Heating	400,000	kWh	1,365	16.2%	$23,896	16.2%
Motors	689,000	kWh	2,352	27.9%	$41,160	27.9%
Chillers	656,000	kWh	2,239	26.5%	$39,189	26.5%
Lighting	400,000	kWh	1,365	16.2%	$23,896	16.2%
Miscellaneous	328,023	kWh	1,120	13.3%	$19,596	13.3%
TOTALS	2,473,023	kWh	8,440	100.0%	$147,736	100.0%

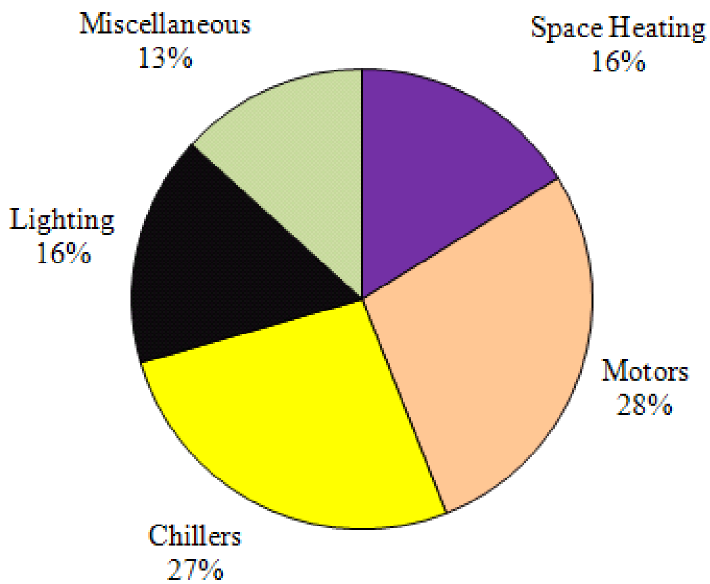
FUEL SUMMARY

	USE	UNIT	MMBtu	COST
ELECTRICITY	2,473,023	kWh	8,440	$147,736

Electricity Use



Energy Cost



APPENDIX B

Motors

B.1. Motor Worksheet Definitions

The motor worksheet uses information obtained during the on-site visit to calculate electric motor energy use, as well as energy and cost savings for efficiency improvements. Motor worksheet information is also used for a variety of AR's, including refrigeration, air compressors, and turning off equipment. In addition, the information contained in the worksheet aids in determining an accurate plant energy breakdown. The worksheet calculation methods and symbols are described as follows:

B.2. Motor Inventory (Nameplate)

The Motor Inventory contains the manufacturer, horsepower, volts, amps and revolutions per minute (rpm), that are read directly from each motor nameplate. Standard NEMA values are used to estimate full load efficiency and power factor.

Identification Number (ID#). An identification number is assigned to each motor.

Manufacturer. The manufacturer of the motor.

Horsepower (Hp). Nameplate horsepower.

Volts. Rated voltage for the motor. If the motor can be wired for more than one voltage, the voltage closest to the operating voltage is entered.

Amps. The rated full-load amperage of the motor corresponding to the voltage listed above.

RPM. Rated full-load RPM.

Power Factor (PF). The motor power factor at full load. Power factor is primarily taken from General Electric publications GEP-500H (11/90) and GEP-1087J (1/92). See section B.9 Motor Performance Table for data and other sources.

Efficiency (EFF). The present motor efficiency at full load. Motor efficiencies for standard and energy-efficient motors are also taken from General Electric publications GEP-500H (11/90) and GEP-1087J (1/92). See section B.9 Motor Performance Table.

Type. The type of motor is described in the table at the bottom of the inventory page. The purpose is to identify standard 900, 1200, 1800, and 3600 rpm motors (Type = 1) that could be replaced with energy-efficient motors.

B.3. Motor Applications (Measured Operating Conditions)

The Motor Applications page contains application-specific information. The same motor may be used in several applications. This information is used to calculate the annual energy consumption of each application.

Application Number (#). A number is assigned to each application described in this section.

Area. A brief description of the location of the motor application.

Identification Number (ID#). The identification number of the motor used in the application. The worksheet looks up the nameplate information for each motor application in section B.2 Motor Inventory.

Use. Each use, such as refrigeration, is given a separate code. This allows the energy use and operating cost for each end use to be summarized in section B.7 Motor Use Summary.

Description. A brief description of the motor application.

Quantity (Qty). The number of motors in each application of the same horsepower and type.

Horsepower (Hp). The horsepower of the motor(s) used in this application is looked up in section B.2 Motor Inventory, based on the motor ID#.

Total Horsepower (Hptot). The total horsepower used in the application is the product of the quantity of motors and the motor horsepower.

Power Factor (PF). For motors with no power factor correction, the operating power factor of the motor is approximated by the following equation to account for part-load conditions:

$$PF = \text{Nameplate PF} \times \{0.728 + [0.4932 / (FLA\%)] - [0.2249 / (FLA\%)^2]\}$$

The power factor correction, enclosed in ({}) brackets, has a minimum allowable value of 0.3 and a maximum value of 1.0 when FLA% is 90% or greater in the worksheet, and is shown as a curve in section B.10. If the motor has been corrected for power factor (PFC = "C"), or the motor is a synchronous type, 0.95 power factor is used.

Power Factor Correction (PFC). If a motor has power factor correction capacitors and the amperage has been measured ahead of the capacitors, a "C" is input.

Drive (DRV). All motors with standard V-belt drives (b) are considered for replacement with High Torque Drive (HTD) belts and sheaves. HTD Replacements are summarized in Section B.5.

Volts. Measured operating voltage.

Amps. Measured operating amperage.

Use Factor (UF). Use Factor is the percentage of the annual operating hours the motor is actually running.

Percent Full Load Amps (FLA%). The measured operating amperage divided by the motor nameplate full load amps.

Efficiency (EFF). Present motor efficiency (η_0) is looked up in section B.2 Motor Inventory, based on the motor ID#.

Demand. The operating power (D) of the motor in kilowatts (kW). If the operating amperage is known, the following equation is used:

$$D = Qty \times Volts \times Amps \times PF \times 1.73 / 1{,}000$$

If operating amperage is not known, the motor load factor (LF) is estimated depending on motor application at your plant. Motor load was either modeled after similar applications at your plant or derived from averaged application specific data of over 160 previous audits. The operating power is found from

$$D = Qty \times LF \times (0.746\ kW/Hp) \times Hp / \eta_0$$

Load Factor (LF). The operating input power divided by the motor nameplate full-load input power, which is found from

$$LF = (D \times \eta_0) / [Hp \times (0.746\ kW/Hp)]$$

Hours. The annual motor operating hours (H) are entered in section B.7 Motor Use Summary for each use.

Energy. The annual energy consumption (E) of the motor in kilowatt-hours (kWh) is calculated by:

$$E = D \times H \times UF$$

B.4. Motor Use Summary

The Motor Use Summary summarizes motor power and energy requirements by end use.

B.5. Economics

The Economics Table summarizes the electrical energy and demand costs, payback criterion, and motor lifetime.

Energy Cost. The electrical energy charge ($/kWh) is taken from your rate schedule. If the energy charge varies seasonally, the average cost is used.

Demand Cost. The demand charge ($/kW-Month) is taken from your rate schedule. If the demand charge varies seasonally, the average cost is used.

Payback Criterion. Standard motors that are candidates for replacement with energy-efficient motors are listed in section B.3 Motor Efficiency. Motors for which the payback is less than this criterion are included in the total at the bottom of the table and included in the Energy Efficient Motors AR.

B.6. Diversity Factor

Diversity Factor (DF). The diversity factor is a tool to estimate the amount of demand a particular motor will contribute to measured peak demand charges. This is a function of average billed demand, found in Section 4; total lighting demand, found in Lighting Inventory Appendix C.2; and the calculated motor demand found in Motor Use Summary Appendix B.4. The diversity factor for your plant is calculated in the diversity factor table. Diversity factor (DF) is calculated from

$$\text{DF} = \text{(Average Billed Power - Total Lighting Power)/ Total Motor Power}$$

The diversity factor accounts for the amount that a particular motor will affect the peak demand, and is a function of billed peak, lighting, and calculated motor demand. The diversity factor is never above 100%.

B.7. Motor Performance Table

The Motor Performance Table contains general motor information used in the worksheet. For each motor horsepower, efficiency, motor cost, and power factor for both standard and efficient motors are listed. Information is primarily taken for totally enclosed fan cooled (TEFC) motors from General Electric publications GEP-500H (11/90) and GEP-1087J (1/92). Larger motors that are not available in TEFC configuration are Open Drip Proof (ODP), and are shown in italics. For motors not found in the General Electric publications, the values for efficiency, motor cost, and power factor were taken as averaged values of several motor manufacturers from Motor Master, a database available from Washington State Energy Office. These sections are indicated by shading.

B.8. Power Factor

Power factor is graphed as a function of operating amperage (FLA%). The curve approximates motor performance data taken from General Electric publication #GEP-500G (3/87). The graph is used to calculate power factor in section B.2 Motor Applications.

B.9. Premium Efficiency Motors

The Premium Efficiency Motor lists every motor that is returned from Motor Master + with a payback of less than ten years.

Identification Number (ID#). An identification number is assigned to each motor.

Motor to Replace. Name of the motor to be replaced.

Quantity (Qty). The number of motors used for a specific purpose.

Horsepower (Hp). Nameplate horsepower.

RPM. Rated full-load RPM.

New Cost. The discounted cost of a new premium efficiency motor to replace a the current standard efficiency motor.

Discount. The percentage discount the buyer receives from the supplier.

Rewind Cost. The cost of rewinding the current standard efficiency motor.

Energy kWh. The amount of kWh saved by a premium efficiency motor.

Demand kW. The amount of kW saved by a premium efficiency motor.

Cost Premium. The additional cost of purchasing a premium efficiency motor over rewinding the existing motor.

Cost Savings. The amount of money that is saved annually by operating premium efficiency motors.

Payback (yrs). The number of years that is required for the cost savings to overcome the cost premium.

B.10. MotorMaster Inventory Query – List

MotorMaster+ compares these motors from your plant with more efficient replacement motors. The MotorMaster+ Energy Savings analysis can be used in several ways. The easiest way to compare the cost of purchasing and powering alternate motors is to compare their simple paybacks. Usually, the shorter the payback period, the more cost-effective the investment. Some industries use a simple payback maximum value of two or three years as a standard by which to make purchasing decisions. If you are considering several energy-efficient motor models, look for the one offering the most rapid payback on investment or shortest simple payback period. Note that once the payback period has passed, your energy cost savings continue.

B.11. MotorMaster Inventory Query – Batch Analysis

The Inventory Query – Batch Analysis worksheet tabulates energy, demand, and total savings, new motor cost, anticipated manufacturer discount, and payback period for replacing existing (900, 1200, 1800, or 3600 rpm) motors with premium efficiency motors, rather than rewinding these motors. This table was generated using the MotorMaster+ program, and displays motors for which the incremental payback is less than 10 years. We assume that all motors experience efficiency degradation from rewinding and include this degradation in the savings calculations. We use a default degradation of 2% for motors under 50 hp, and 1% for motors 50 hp and above.

ID: Matches MotorMaster+ motor to End Use spreadsheet.

Description: Application and motor summary for each motor in the batch analysis

Manufacturer/Model: Motor nameplate information.

Catalog: Additional manufacturer’s catalog number.

Price: Manufacturer’s list price less discount.

Discount: Motor dealers rarely sell motors at the manufacturer's full list price. Customers are offered a list price discount, with standard or energy-efficient motors typically selling for 55 to 85 percent of the manufacturer's stated list price. List price discounts for all manufacturers are originally set at 35 percent.

Installation Cost: Default installation costs are shown in Appendix B.12.

Rebate: MotorMaster+ supports various types of rebate approaches, including Fixed, Price, Efficiency Gain, Two-Tier, and Base Plus Bonus.

Incremental Cost ($): Incremental Cost for each Motor (ICM) is the purchase price of the new motor (MC), less discount (DS) and any available utility rebate (Rebate), minus the rewind cost (RC). Since the replacement is assumed to occur at the time of motor failure and removal for repair, no additional installation costs are incurred. Default rewinding costs are shown in Appendix B.13.

$$ICM = MC \times (1-DS) - Rebate - RC$$

HP: Motor horsepower

Annual Energy Savings (kWh): Energy savings are determined by superimposing the identical load profile on the energy-efficient replacement motor. The efficiency at each load point is computed, and then used to determine energy use, demand, and reductions in operating costs. Annual energy savings are determined by summing the savings obtained at each operating point.

Annual Energy Savings (kWh$): The dollar value of annual kWh savings times the unit cost of energy. The formula is:

kWh (saved) x cost per unit of energy ($/kWh)

Demand Savings (kW): The difference in peak demand for standard and energy-efficient motors.

Demand Savings (kW$): The difference in annual demand charges for standard and energy-efficient motors.

Total Savings ($/yr): The sum of annual energy and demand dollar savings.

Simple Payback (yr): The time it takes to recover the motor price premium from energy and demand cost savings. Calculated by dividing the motor premium by total annual cost savings. "Immediate" payback means that the new motor less discount and rebates costs less than a rewound motor, which occurs more often for smaller motors.

B.12. MotorMaster Default Installation Costs Table.

MotorMaster+ uses this table of default installation costs based on motor size.

B.13. MotorMaster Default Rewind Costs Table.

Default rewind costs depend on motor size, RPM, and enclosure type.

B.2. Motor Inventory (Nameplate)*

#	Manufacturer	Hp	Volts	Amps	RPM	PF%	EFF%	Frame	Type+
1	NA	5	208	5.4	1800	78%	88%		6
2	NA	10	208	8.5	1800	74%	90%		1
3	NA	15	208	16.3	1800	82%	91%		1
4	NA	30	208	35.5	1800	86%	90%		1
89	NA	1	480	2.3	1800	70%	77%		1
90	NA	5	480	6.3	3495	89%	83%		1
91	NA	5	480	12.8	1800	78%	88%		1
92	NA	5	480	12.8	1800	78%	88%		1
93	NA	10	480	13.0	1800	74%	90%		1
94	NA	15	480	18.1	3535	90%	90%		1
95	NA	15	480	20.0	1800	82%	91%		1
96	Reliance	25	480	32.0	1765	86%	92%		1
97	NA	40	480	53.5	1800	83%	93%		1
98	Reliance	50	480	60.0	1170	83%	91%	3651	1
99	NA	50	480	60.0	1185	85%	91%	365TE	1

+ Type Code		
1=Standard Efficiency	TS=Two Speed	HD=Heavy Duty
2=High Efficiency	F=Fractional Horsepower	O=Oversize (>500hp)
C=Composite	G=Gear Motor	SY=Synchronous
DC=Direct Current	H=Hermetic	U=Unknown
V=Standard V-belt	ASD=Adjustable Speed Drive	SP=Single Phase
RPM=Not 900, 1200, 1800, or 3600 RPM		
*Note: Some Nameplate Data May Be Estimated		

B.3. Motor Applications (Measured Operating Conditions)

#	Area	Use	Description	Qty	Hp	Hptot	PF%	DRV	PFC	Volts	Amps	UF%	FLA%	EFF%	Demand kW	LF	Hours	Energy kWh
1	Cold Room	3	Compressor	6	5	30	78.0%					30%		87.5%	17.9	70%	2,628	47,041
90	Reservoir	1	Washdown Pump	2	5	10	81.0%				3.66	50%	58%	83.0%	4.9	55%	4,380	21,462
94	Reservoir	1	EPA Pump	2	15	30	40.4%				6.8	50%	38%	89.5%	4.6	18%	4,380	20,148
96	Reservoir	1	Main Pump	2	25	50	84.8%				24	50%	75%	91.7%	33.8	83%	4,380	148,044
98	Pump House	1	Red/Blue Pump	2	50	100	82.0%				45.6	13%	76%	91.0%	62.1	76%	1,095	68,000
99	Pump House	1	Green/Yellow Pump	2	50	100	83.3%				43.5	13%	73%	91.0%	60.2	73%	1,095	65,919
89	Chillers	2	Chiller Fans	16	1	16	70.0%					40%		77.0%	10.9	70%	3,504	38,194
97	Chillers	2	Chiller Compressor	6	40	240	83.0%					40%		93.0%	134.8	70%	3,504	472,339
91	Various	3	Supply Fans	12	5	60	15.6%				2.7	100%	21%	87.5%	4.2	8%	8,760	36,792
92	Various	3	Return Fans	12	5	60	48.7%				5.36	100%	42%	87.5%	26.0	51%	8,760	227,760
2	Cold Room	3	Compressor	1	10	10	74.0%					50%		89.5%	5.8	70%	4,380	25,404
3	Cold Room	3	Compressor	1	15	15	82.0%					50%		91.0%	8.6	70%	4,380	37,668
4	Cold Room	3	Compressor	1	30	30	86.0%					50%		90.0%	17.4	70%	4,380	76,212
93	Location in Plant	4	Blowers	1	10	10	74.0%					50%		89.5%	5.8	70%	4,380	25,404
95	Location in Plant	4	Blowers	1	15	15	82.0%					50%		91.0%	8.6	70%	4,380	37,668

B.4. Motor Use Summary							
Use	**Area**	**Hours**	**Qty**	**Hp**	**kW**	**kWh**	**kWh%**
1	Pumps	8,760	10	290	165.6	323,573	24.0%
2	Chillers	8,760	22	256	145.7	510,533	37.9%
3	HVAC	8,760	33	205	79.9	450,877	33.4%
4	Miscellaneous	8,760	2	25	14.4	63,072	4.7%
Total			67	776	406	1,348,055	100.0%

B.5. Economics		
Energy Cost:	$0.0344	/kWh
Demand Cost:	$7.73	/kW-month
Average Electricty Cost:	$0.0538	/kWh
Motor Payback Criterion:	10	years
High Torque Drive Payback Criterion:	10	years

B.6. Diversity Factor		
Average Monthly Billed Demand:	308	kW
Lighting Demand:	0	kW
Total Motor Demand:	406	kW
Diversity Factor:	76%	

B.7 Motor Performance Table

900 RPM

Horsepower (HP)	Motor Efficiency Standard	Motor Efficiency Efficient	Motor Efficiency Increase	Motor Cost Standard	Motor Cost Efficient	Motor Cost Increase	Power Factor Standard	Power Factor Efficient
1	**69.4**	75.5	6.1	$283	$359	$76	**62.0**	59.5
1.5	**73.0**	80.0	7.0	$343	$434	$91	**61.7**	62.0
2	**76.4**	85.5	9.1	$459	$581	$122	**61.7**	54.0
3	**79.3**	86.5	7.2	$597	$755	$158	**66.4**	62.5
5	**82.0**	85.5	3.5	$824	$1,043	$219	**67.3**	60.0
7.5	**82.8**	86.5	3.7	$1,049	$1,327	$278	**69.3**	62.0
10	**85.4**	91.0	5.6	$1,243	$1,573	$330	**77.2**	78.0
15	**85.8**	91.0	5.2	$1,633	$2,067	$434	**75.5**	78.0
20	**88.0**	91.7	3.7	$1,968	$2,491	$523	**78.6**	77.5
25	**87.8**	91.7	3.9	$2,331	$2,950	$619	**78.3**	78.0
30	87.5	93.6	6.1	$2,746	$3,475	$729	80.0	76.5
40	89.5	93.0	3.5	$3,401	$4,305	$904	80.0	75.5
50	88.5	93.6	5.1	$4,052	$5,128	$1,076	76.5	84.0
60	91.0	93.6	2.6	$4,699	$5,947	$1,248	80.5	83.5
75	90.2	94.1	3.9	$6,258	$7,920	$1,662	80.0	85.0
100	91.7	94.1	2.4	$7,907	$10,007	$2,100	78.5	84.0
125	92.4	94.5	2.1	$9,193	$11,635	$2,442	78.0	82.5
150	92.4	94.5	2.1	$10,371	$13,126	$2,755	77.5	82.5
200	94.1	95.0	0.9	**13443.0**	**15989.0**	**2546.0**	86.5	87.0
250	94.5	95.0	0.5	**15370.0**	**18213.0**	**2843.0**	86.5	84.0
300	94.5	95.0	0.5	**17411.0**	**20633.0**	**3222.0**	87.0	84.0
350	93.6	95.0	1.4	**10493.0**	**12922.0**	**2429.0**	81.0	80.5
400	93.6	95.0	1.4	**11692.0**	**14251.0**	**2559.0**	81.5	84.0
450	93.6	95.0	1.4	**12622.0**	**15593.0**	**2971.0**	81.0	84.5
500								

1200 RPM

Horsepower (HP)	Motor Efficiency Standard	Motor Efficiency Efficient	Motor Efficiency Increase	Motor Cost Standard	Motor Cost Efficient	Motor Cost Increase	Power Factor Standard	Power Factor Efficient
1	75.5	**82.1**	6.6	$241	$302	$61	60.5	**65.9**
1.5	75.5	87.5	12.0	$193	$253	$60	77.5	72.0
2	80.0	87.5	7.5	$213	$280	$67	74.5	74.0
3	85.5	89.5	4.0	$283	$373	$90	74.5	75.5
5	84.0	89.5	5.5	$407	$548	$141	78.5	76.0
7.5	86.8	91.7	4.9	$550	$740	$190	88.0	72.0
10	87.5	91.7	4.2	$701	$869	$168	84.5	71.5
15	88.5	91.7	3.2	$946	$1,153	$207	82.5	76.5
20	90.2	92.4	2.2	$1,150	$1,403	$253	85.5	76.0
25	**88.5**	92.4	3.9	$1,396	$1,703	$307	**81.0**	83.5
30	89.5	93.0	3.5	$1,704	$1,952	$248	82.5	83.5
40	89.5	93.6	4.1	$2,229	$2,770	$541	83.5	85.5
50	91.0	93.6	2.6	$2,603	$3,232	$629	87.0	85.5
60	91.0	94.1	3.1	$3,008	$3,826	$818	81.0	85.5
75	91.0	95.0	4.0	$3,615	$4,575	$960	79.0	86.0
100	92.4	95.0	2.6	$5,088	$6,405	$1,317	82.5	89.0
125	92.4	95.0	2.6	$6,191	$7,371	$1,180	84.5	88.5
150	93.0	95.8	2.8	$6,818	$8,606	$1,788	87.9	86.0
200	94.1	95.4	1.3	$9,524	$11,733	$2,209	87.8	86.5
250	94.3	95.4	1.1	**12140.0**	**14386.0**	**2246.0**	85.0	89.0
300	95.0	95.4	0.4	**14380.0**	**17042.0**	**2662.0**	88.5	89.5
350	95.0	95.8	0.8	**16692.0**	**19780.0**	**3088.0**	89.0	89.0
400	95.0	95.8	0.8	**18960.0**	**22470.0**	**3510.0**	89.5	87.5
450	94.5	96.2	1.7	**11465.0**	**14119.0**	**2654.0**	87.5	87.0
500	94.5	96.2	1.7	**12626.0**	**15549.0**	**2923.0**	87.0	88.0

1800 RPM

Horsepower (HP)	Motor Efficiency Standard	Motor Efficiency Efficient	Motor Efficiency Increase	Motor Cost Standard	Motor Cost Efficient	Motor Cost Increase	Power Factor Standard	Power Factor Efficient
1	**72.0**	84.3	12.3	$191	$237	$46	**76.0**	72.9
1.5	**77.0**	85.4	8.4	$209	$262	$53	**78.5**	74.2
2	**80.0**	85.2	5.2	$219	$274	$55	**86.5**	78.5
3	82.5	89.5	7.0	$197	$262	$65	79.0	80.0
5	84.0	90.2	6.2	$229	$299	$70	84.0	83.0
7.5	86.5	91.7	5.2	$329	$431	$102	83.0	82.5
10	87.5	91.7	4.2	$409	$520	$111	85.0	81.0
15	87.5	92.4	4.9	$541	$695	$154	83.0	81.5
20	89.5	93.0	3.5	$683	$845	$162	84.5	82.0
25	90.2	93.6	3.4	$820	$1,028	$208	85.0	83.5
30	91.0	93.6	2.6	$996	$1,216	$220	83.0	83.0
40	90.2	94.1	3.9	$1,280	$1,560	$280	80.0	87.5
50	91.7	94.1	2.4	$1,658	$1,921	$263	85.5	86.5
60	91.7	95.0	3.3	$2,489	$2,856	$367	82.5	85.5
75	91.7	95.4	3.7	$3,182	$3,680	$498	83.5	84.5
100	91.7	95.4	3.7	$3,837	$4,517	$680	87.0	85.0
125	92.4	95.4	3.0	$4,950	$6,354	$1,404	84.5	89.0
150	93.0	95.8	2.8	$6,021	$7,415	$1,394	86.5	88.0
200	94.1	95.8	1.7	$7,285	$8,913	$1,628	89.5	90.0
250	93.6	96.2	2.6	$8,157	$11,181	$3,024	88.5	83.0
300	94.1	95.8	1.7	**10084.0**	**12257.0**	**2173.0**	90.0	84.0
350	94.5	95.8	1.3	**11574.0**	**14068.0**	**2494.0**	90.5	90.5
400	94.5	95.8	1.3	**13528.0**	**16113.0**	**2585.0**	91.0	91.0
450	95.0	95.8	0.8	**17016.0**	**19023.0**	**2007.0**	91.0	91.0
500	*94.5*	*95.8*	*1.3*	**10019.0**	**12339.0**	**2320.0**	*89.0*	*90.0*

3600 RPM

Horsepower (HP)	Motor Efficiency Standard	Motor Efficiency Efficient	Motor Efficiency Increase	Motor Cost Standard	Motor Cost Efficient	Motor Cost Increase	Power Factor Standard	Power Factor Efficient
1	**74.0**	**77.4**	3.4	**256.0**	**273.0**	$17	**81.6**	**81.8**
1.5	80.0	**84.0**	4.0	$149	**342.0**	$193	86.0	**82.4**
2	81.5	**85.2**	3.7	$173	**302.0**	$129	87.5	**89.9**
3	82.5	88.5	6.0	$203	$267	$64	81.0	87.0
5	84.0	89.5	5.5	$251	$330	$79	82.0	88.0
7.5	86.5	91.7	5.2	$329	$431	$102	82.0	88.5
10	87.5	91.7	4.2	$395	$509	$114	83.5	88.5
15	87.5	91.7	4.2	$533	$698	$165	83.0	88.5
20	87.5	92.4	4.9	$719	$841	$122	90.0	90.0
25	88.5	92.4	3.9	$883	$1,049	$166	90.5	91.0
30	89.5	92.4	2.9	$974	$1,241	$267	91.5	91.0
40	88.5	93.6	5.1	$1,278	$1,608	$330	85.5	92.0
50	89.5	93.0	3.5	$1,772	$2,070	$298	85.0	92.0
60	89.5	94.1	4.6	$2,594	$2,818	$224	90.0	92.0
75	91.0	94.5	3.5	$3,089	$3,749	$660	91.5	92.0
100	90.2	94.1	3.9	$4,167	$4,743	$576	89.0	91.5
125	91.0	94.5	3.5	$5,809	$6,488	$679	92.5	93.5
150	91.7	94.5	2.8	$6,958	$8,103	$1,145	92.0	93.5
200	93.0	95.0	2.0	$8,695	$10,532	$1,837	93.9	94.0
250	93.0	95.4	2.4	$10,246	$13,283	$3,037	92.5	89.5
300	91.0	95.4	4.4	**13351.0**	**15536.0**	**2185.0**	92.0	93.0
350	91.7	95.4	3.7	**15335.0**	**19973.0**	**4638.0**	93.0	93.0
400	91.7	95.4	3.7	**17948.0**	**20279.0**	**2331.0**	93.0	93.5
450	93.0	95.4	2.4	**18692.0**	**22150.0**	**3458.0**	93.5	93.0
500	*94.1*	*95.4*	*1.3*	**10947.0**	**13482.0**	**2535.0**	*90.0*	*93.0*

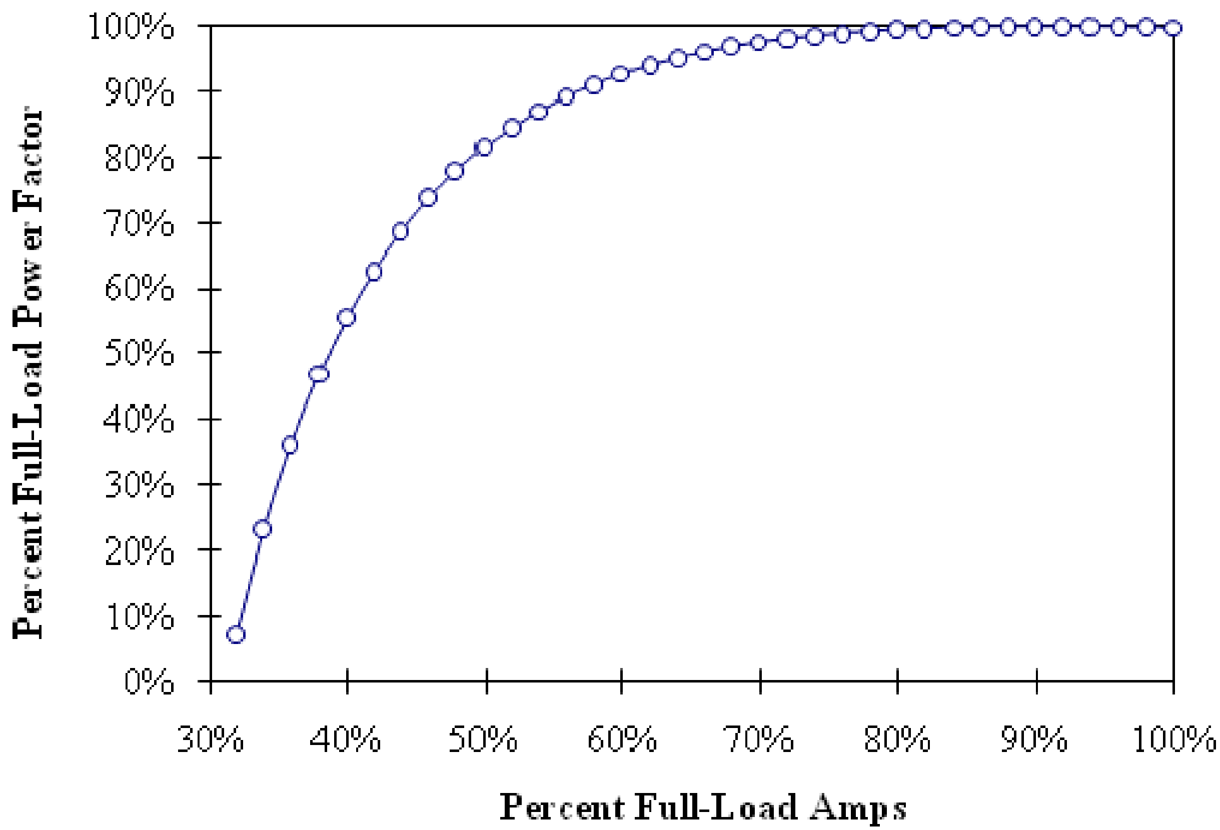
Sources:

Unless otherwise noted, all data is from General publications GEP-500H (11/90), and GEP-1087J (1/92).

Price From Motor Master, Washington State Energy Office.
Efficiency From Motor Master, Washington State Energy Office.
Averaged Data.

Open Drip Proof (ODP)
Totaly Enclosed Fan Cooled (TEFC)

B.8 Power Factor Curve



B.9. Premium Efficiency Motor Summary

					Per Motor			Total Savings				
#	Motor to Replace	Qty	HP	RPM	New Cost	Discount	Rewind Cost	Energy (kWh)	Demand (kW)	Cost Premium	Cost Savings	Payback (yrs)
89	Chiller Fans	16	1	1,800	$195	35%	$220	5,664	1.6	($400)	$343	Immediate
1	Compressor	6	5	1,800	$306	35%	$330	3,906	1.2	($144)	$246	Immediate
91	Supply Fans	12	5	1,800	$280	35%	$330	22,896	2.4	($600)	$1,011	Immediate
92	Return Fans	12	5	1,800	$280	35%	$330	24,480	2.4	($600)	$1,066	Immediate
90	Washdown Pump	2	5	3,600	$338	35%	$330	2,162	0.4	$16	$112	0.1
2	Compressor	1	10	1,800	$521	35%	$500	1,881	0.4	$21	$102	0.2
93	Blowers	1	10	1,800	$521	35%	$500	1,881	0.4	$21	$102	0.2
3	Compressor	1	15	1,800	$697	35%	$550	2,684	0.6	$147	$148	1.0
95	Blowers	1	15	1,800	$697	35%	$550	2,684	0.6	$147	$148	1.0
94	EPA Pump	2	15	3,600	$714	35%	$550	5,126	1.2	$328	$288	1.1
96	Main Pump	2	25	1,800	$1,188	35%	$660	8,088	1.8	$1,056	$446	2.4
4	Compressor	1	30	1,800	$1,483	35%	$760	3,672	0.8	$723	$201	3.6
97	Chiller Compressor	6	40	1,800	$1,835	35%	$880	25,194	7.2	$5,730	$1,536	3.7
Totals		**63**	**-**	**-**	**-**	**-**	**-**	**110,318**	**21.0**	**$8,189**	**$5,749**	**1.4**

B.10. Inventory Query - List

MotorMaster+ 4.0
from US DOE

For :

By :

Page : 1

02-16-2009

Query Parameters

Status: In Service

ID#	Motor ID	Description	Manufacturer	Model	Facility	Department	Process	HP	RPM	Enclosure	Definite Purpose	Volt.	Eff. FL	PF FL	Age	Energy kWh/Yr	Frame Size
15	99	Green/Yellow Pump			HMSC	Pumps	Pumps	50	1200	TEFC		460				32960	365TE
14	98	Red/Blue Pump	Reliance		HMSC	Pumps	Pumps	50	1200	TEFC		460				34055	3651
13	97	Chiller Compressor			HMSC	Chillers	Chillers	40	1800	TEFC		460				78840	0
12	96	Main Pump	Reliance		HMSC	Pumps	Pumps	25	1800	TEFC		460				74022	0
11	95	Blowers			HMSC	Miscellane	Misc	15	1800	TEFC		460				37668	0
10	94	EPA Pump			HMSC	Pumps	Pumps	15	3600	TEFC		460				10074	0
9	93	Blowers			HMSC	Miscellane	Misc	10	1800	TEFC		460				25404	0
8	92	Return Fans			HMSC	HVAC	HVAC	5	1800	TEFC		460				19272	0
7	91	Supply Fans			HMSC	HVAC	HVAC	5	1800	TEFC		460				3504	0
6	90	Washdown Pump			HMSC	Pumps	Pumps	5	3600	TEFC		460				10950	0
5	89	Chiller Fans			HMSC	Chillers	Chillers	1	1800	TEFC		460				2453	0
4	4	Compressor			HMSC	HVAC	HVAC	30	1800	TEFC		208				76212	0
3	3	Compressor			HMSC	HVAC	HVAC	15	1800	TEFC		208				37668	0
2	2	Compressor			HMSC	HVAC	HVAC	10	1800	TEFC		208				25404	0
1	1	Compressor			HMSC	HVAC	HVAC	5	1800	TEFC		208				7884	0

B.11. Inventory Query - Batch Analysis

For :

By :

02-16-2009

Query Parameters

Status: In Service

Batch Parameters

Scenario: Rewind
Load Est Method: kWCalc
Default Load: 70%

Payback: <= 10 yrs
Peak months: 12
AutoDownsize: No

Upgrade option: NEMA Premium only

ID	Description	Manufacturer/Model	Catalog	Price	Disc.	Install	Rebate	HP	Energy		Demand		Total	
									kWh	kWh$	kW	kW$	Savings	Payback
15	**Green/Yellow Pump**		No payback yielded by motors compared.											
14	**Red/Blue Pump**		No payback yielded by motors compared.											
13	**Chiller Compressor**	G.E. E$P-SD	M7924	1835	35	0	0	40	4199	$145	1.2	$111	$256	3.8 yrs
	40 HP, 1800 RPM	G.E. E$P	M7924	1835	35	0	0	40	4199	$145	1.2	$111	$256	3.8 yrs
	TEFC, 460 volts	Siemens 1LA03244ES41	RGZEESD	1945	35	0	0	40	4348	$150	1.2	$115	$265	4.1 yrs
12	**Main Pump**	G.E. E$P	M7892	1188	35	0	0	25	4044	$139	0.9	$86	$225	2.5 yrs
	25 HP, 1800 RPM	G.E. E$P-SD	M7892	1188	35	0	0	25	4044	$139	0.9	$86	$225	2.5 yrs
	TEFC, 460 volts	Siemens 1LA02844ES42	RGZEESD	1258	35	0	0	25	4100	$141	0.9	$87	$228	2.8 yrs
11	**Blowers**	Siemens 1LE21112BB114AA3	GP100A	697	35	0	0	15	2684	$92	0.6	$57	$149	1.6 yrs
	15 HP, 1800 RPM	G.E. E$P-SD	M7871	801	35	0	0	15	2732	$94	0.6	$58	$152	2.2 yrs
	TEFC, 460 volts	G.E. E$P	M7871	801	35	0	0	15	2732	$94	0.6	$58	$152	2.2 yrs
10	**EPA Pump**	Siemens 1LE21112BA114AA3	GP100A	714	35	0	0	15	2563	$88	0.6	$54	$143	1.7 yrs
	15 HP, 3600 RPM	G.E. E$P	M7868	815	35	0	0	15	2709	$93	0.6	$57	$151	2.3 yrs
	TEFC, 460 volts	G.E. E$P-SD	M7868	815	35	0	0	15	2709	$93	0.6	$57	$151	2.3 yrs
9	**Blowers**	Siemens 1LE21112AB214AA3	GP100A	521	35	0	0	10	1881	$65	0.4	$40	$105	1.4 yrs
	10 HP, 1800 RPM	WEG Electric Motors W21		522	35	0	0	10	1710	$59	0.4	$36	$95	1.5 yrs
	TEFC, 460 volts	US Motors AS70	U10P2B	571	35	0	0	10	2068	$71	0.5	$44	$115	1.7 yrs
8	**Return Fans**	G.E. Energy Efficient	S225	280	35	0	0	5	2040	$70	0.2	$22	$92	0.1 yrs
	5 HP, 1800 RPM	Siemens 1LE21111CB314AA3	GP100A	306	35	0	0	5	1895	$65	0.2	$20	$85	0.4 yrs
	TEFC, 460 volts	WEG Electric Motors W21		319	35	0	0	5	1804	$62	0.2	$19	$81	0.6 yrs
7	**Supply Fans**	G.E. Energy Efficient	S225	280	35	0	0	5	1908	$66	0.2	$20	$86	0.1 yrs
	5 HP, 1800 RPM	Siemens 1LE21111CB314AA3	GP100A	306	35	0	0	5	1899	$65	0.2	$20	$85	0.4 yrs
	TEFC, 460 volts	WEG Electric Motors W21		319	35	0	0	5	1899	$65	0.2	$20	$85	0.6 yrs
6	**Washdown Pump**	Siemens 1LE21111CA314AA3	GP100A	338	35	0	0	5	1081	$37	0.2	$23	$60	0.8 yrs
	5 HP, 3600 RPM	Siemens 1LE22111CA314AA3	GP100	402	35	0	0	5	1081	$37	0.2	$23	$60	1.9 yrs
	TEFC, 460 volts	Teco/Westinghouse MAX-	E0052	400	35	0	0	5	1057	$36	0.2	$22	$59	1.9 yrs
5	**Chiller Fans**	Siemens 1LE21111AB214AA3	GP100A	195	35	0	0	1	354	$12	0.1	$9	$22	Immediate
	1 HP, 1800 RPM	WEG Electric Motors W21		212	35	0	0	1	315	$11	0.1	$8	$19	Immediate
	TEFC, 460 volts	Teco/Westinghouse MAX-	E0014	228	35	0	0	1	281	$10	0.1	$7	$17	0.9 yrs
4	**Compressor**	WEG Electric Motors W21		1483	35	0	0	30	3672	$126	0.8	$78	$204	3.7 yrs
	30 HP, 1800 RPM	Teco/Westinghouse MAX-	E0304	1630	35	0	0	30	3688	$127	0.8	$78	$205	4.4 yrs
	TEFC, 208 volts	Baldor SUPER-E, NEMA	EM4104T-8	1926	35	0	0	30	4295	$148	1.0	$91	$239	5.0 yrs
3	**Compressor**	Siemens 1LE21112BB114AA3	GP100A	697	35	0	0	15	2684	$92	0.6	$57	$149	1.6 yrs
	15 HP, 1800 RPM	WEG Electric Motors W21		794	35	0	0	15	2528	$87	0.6	$54	$141	2.3 yrs
	TEFC, 208 volts	Siemens 1LE22112BB114AA3	GP100	831	35	0	0	15	2684	$92	0.6	$57	$149	2.5 yrs

B.11. Inventory Query - Batch Analysis (Cont.)

Query Parameters

Status: In Service

Batch Parameters

Scenario: Rewind
Load Est Method: kWCalc
Default Load: 70%

Payback: <= 10 yrs
Peak months: 12
AutoDownsize: No

Upgrade option: NEMA Premium only

ID	Description	Manufacturer/Model	Catalog	Price	Disc.	Install	Rebate	HP	Energy kWh	Energy kWh$	Demand kW	Demand kW$	Total Savings	Payback
2	**Compressor**	Siemens 1LE21112AB214AA3	GP100A	521	35	0	0	10	1881	$65	0.4	$40	$105	1.4 yrs
	10 HP, 1800 RPM	WEG Electric Motors W21		522	35	0	0	10	1710	$59	0.4	$36	$95	1.5 yrs
	TEFC, 208 volts	Siemens 1LE22112AB214AA3	GP100	620	35	0	0	10	1881	$65	0.4	$40	$105	2.3 yrs
1	**Compressor**	Siemens 1LE21111CB314AA3	GP100A	306	35	0	0	5	651	$22	0.2	$23	$45	0.8 yrs
	5 HP, 1800 RPM	WEG Electric Motors W21		319	35	0	0	5	649	$22	0.2	$23	$45	1.1 yrs
	TEFC, 208 volts	Siemens 1LE22111CB314AA3	GP100	364	35	0	0	5	651	$22	0.2	$23	$45	2.0 yrs
							Totals:		29643	$1021	6.7	$619	$1640	

B.12. Default Installation Costs Table

MotorMaster+ 4.0
from US DOE

For :

By : OSU IAC

Page : 1

08-18-2008

HP	RPM	Encl	Instl$	HP	RPM	Encl	Instl$	HP	RPM	Encl	Instl$	HP	RPM	Encl	Instl$
1	900	ODP	70	15	900	ODP	100	75	900	ODP	275	350	900	ODP	1225
1	900	TEFC	70	15	900	TEFC	100	75	900	TEFC	275	350	900	TEFC	1225
1	1200	ODP	70	15	1200	ODP	100	75	1200	ODP	275	350	1200	ODP	1225
1	1200	TEFC	70	15	1200	TEFC	100	75	1200	TEFC	275	350	1200	TEFC	1225
1	1800	ODP	70	15	1800	ODP	100	75	1800	ODP	275	350	1800	ODP	1225
1	1800	TEFC	70	15	1800	TEFC	100	75	1800	TEFC	275	350	1800	TEFC	1225
1	3600	ODP	70	15	3600	ODP	100	75	3600	ODP	275	350	3600	ODP	1225
1	3600	TEFC	70	15	3600	TEFC	100	75	3600	TEFC	275	350	3600	TEFC	1225
1.5	900	ODP	70	20	900	ODP	125	100	900	ODP	350	400	900	ODP	1400
1.5	900	TEFC	70	20	900	TEFC	125	100	900	TEFC	350	400	900	TEFC	1400
1.5	1200	ODP	70	20	1200	ODP	125	100	1200	ODP	350	400	1200	ODP	1400
1.5	1200	TEFC	70	20	1200	TEFC	125	100	1200	TEFC	350	400	1200	TEFC	1400
1.5	1800	ODP	70	20	1800	ODP	125	100	1800	ODP	350	400	1800	ODP	1400
1.5	1800	TEFC	70	20	1800	TEFC	125	100	1800	TEFC	350	400	1800	TEFC	1400
1.5	3600	ODP	70	20	3600	ODP	125	100	3600	ODP	350	400	3600	ODP	1400
1.5	3600	TEFC	70	20	3600	TEFC	125	100	3600	TEFC	350	400	3600	TEFC	1400
2	900	ODP	75	25	900	ODP	130	125	900	ODP	450	450	900	ODP	1550
2	900	TEFC	75	25	900	TEFC	130	125	900	TEFC	450	450	900	TEFC	1550
2	1200	ODP	75	25	1200	ODP	130	125	1200	ODP	450	450	1200	ODP	1550
2	1200	TEFC	75	25	1200	TEFC	130	125	1200	TEFC	450	450	1200	TEFC	1550
2	1800	ODP	75	25	1800	ODP	130	125	1800	ODP	450	450	1800	ODP	1550
2	1800	TEFC	75	25	1800	TEFC	130	125	1800	TEFC	450	450	1800	TEFC	1550
2	3600	ODP	75	25	3600	ODP	130	125	3600	ODP	450	450	3600	ODP	1550
2	3600	TEFC	75	25	3600	TEFC	130	125	3600	TEFC	450	450	3600	TEFC	1550
3	900	ODP	75	30	900	ODP	135	150	900	ODP	550	500	900	ODP	1750
3	900	TEFC	75	30	900	TEFC	135	150	900	TEFC	550	500	900	TEFC	1750
3	1200	ODP	75	30	1200	ODP	135	150	1200	ODP	550	500	1200	ODP	1750
3	1200	TEFC	75	30	1200	TEFC	135	150	1200	TEFC	550	500	1200	TEFC	1750
3	1800	ODP	75	30	1800	ODP	135	150	1800	ODP	550	500	1800	ODP	1750
3	1800	TEFC	75	30	1800	TEFC	135	150	1800	TEFC	550	500	1800	TEFC	1750
3	3600	ODP	75	30	3600	ODP	135	150	3600	ODP	550	500	3600	ODP	1750
3	3600	TEFC	75	30	3600	TEFC	135	150	3600	TEFC	550	500	3600	TEFC	1750
5	900	ODP	75	40	900	ODP	160	200	900	ODP	650	600	900	ODP	2100
5	900	TEFC	75	40	900	TEFC	160	200	900	TEFC	650	600	900	TEFC	2100
5	1200	ODP	75	40	1200	ODP	160	200	1200	ODP	650	600	1200	ODP	2100
5	1200	TEFC	75	40	1200	TEFC	160	200	1200	TEFC	650	600	1200	TEFC	2100
5	1800	ODP	75	40	1800	ODP	160	200	1800	ODP	650	600	1800	ODP	2100
5	1800	TEFC	75	40	1800	TEFC	160	200	1800	TEFC	650	600	1800	TEFC	2100
5	3600	ODP	75	40	3600	ODP	160	200	3600	ODP	650	600	3600	ODP	2100
5	3600	TEFC	75	40	3600	TEFC	160	200	3600	TEFC	650	600	3600	TEFC	2100
7.5	900	ODP	80	50	900	ODP	200	250	900	ODP	875				
7.5	900	TEFC	80	50	900	TEFC	200	250	900	TEFC	875				
7.5	1200	ODP	80	50	1200	ODP	200	250	1200	ODP	875				
7.5	1200	TEFC	80	50	1200	TEFC	200	250	1200	TEFC	875				
7.5	1800	ODP	80	50	1800	ODP	200	250	1800	ODP	875				
7.5	1800	TEFC	80	50	1800	TEFC	200	250	1800	TEFC	875				
7.5	3600	ODP	80	50	3600	ODP	200	250	3600	ODP	875				
7.5	3600	TEFC	80	50	3600	TEFC	200	250	3600	TEFC	875				
10	900	ODP	85	60	900	ODP	225	300	900	ODP	1050				
10	900	TEFC	85	60	900	TEFC	225	300	900	TEFC	1050				
10	1200	ODP	85	60	1200	ODP	225	300	1200	ODP	1050				
10	1200	TEFC	85	60	1200	TEFC	225	300	1200	TEFC	1050				
10	1800	ODP	85	60	1800	ODP	225	300	1800	ODP	1050				
10	1800	TEFC	85	60	1800	TEFC	225	300	1800	TEFC	1050				
10	3600	ODP	85	60	3600	ODP	225	300	3600	ODP	1050				
10	3600	TEFC	85	60	3600	TEFC	225	300	3600	TEFC	1050				

B.13. Default Rewind Costs Table

MotorMaster+ 4.0
from US DOE

For :

Page : 1

By: OSU IAC

08-18-2008

HP	RPM	Encl	Rwnd$
1	900	ODP	264
1	900	TEFC	317
1	1200	ODP	201
1	1200	TEFC	242
1	1800	ODP	177
1	1800	TEFC	213
1	3600	ODP	180
1	3600	TEFC	215
1.5	900	ODP	284
1.5	900	TEFC	342
1.5	1200	ODP	209
1.5	1200	TEFC	251
1.5	1800	ODP	186
1.5	1800	TEFC	223
1.5	3600	ODP	189
1.5	3600	TEFC	227
2	900	ODP	326
2	900	TEFC	392
2	1200	ODP	220
2	1200	TEFC	264
2	1800	ODP	198
2	1800	TEFC	237
2	3600	ODP	200
2	3600	TEFC	240
3	900	ODP	376
3	900	TEFC	451
3	1200	ODP	255
3	1200	TEFC	306
3	1800	ODP	207
3	1800	TEFC	249
3	3600	ODP	213
3	3600	TEFC	256
5	900	ODP	434
5	900	TEFC	521
5	1200	ODP	306
5	1200	TEFC	367
5	1800	ODP	226
5	1800	TEFC	271
5	3600	ODP	242
5	3600	TEFC	290
7.5	900	ODP	505
7.5	900	TEFC	606
7.5	1200	ODP	365
7.5	1200	TEFC	438
7.5	1800	ODP	265
7.5	1800	TEFC	319
7.5	3600	ODP	271
7.5	3600	TEFC	326
10	900	ODP	576
10	900	TEFC	691
10	1200	ODP	418
10	1200	TEFC	501
10	1800	ODP	314
10	1800	TEFC	377
10	3600	ODP	321
10	3600	TEFC	386
15	900	ODP	675
15	900	TEFC	809
15	1200	ODP	505
15	1200	TEFC	606
15	1800	ODP	386
15	1800	TEFC	463
15	3600	ODP	390
15	3600	TEFC	469
20	900	ODP	778
20	900	TEFC	934
20	1200	ODP	571
20	1200	TEFC	685
20	1800	ODP	446
20	1800	TEFC	536
20	3600	ODP	461
20	3600	TEFC	552
25	900	ODP	898
25	900	TEFC	1078
25	1200	ODP	637
25	1200	TEFC	764
25	1800	ODP	512
25	1800	TEFC	614
25	3600	ODP	534
25	3600	TEFC	641
30	900	ODP	982
30	900	TEFC	1178
30	1200	ODP	708
30	1200	TEFC	850
30	1800	ODP	602
30	1800	TEFC	722
30	3600	ODP	616
30	3600	TEFC	740
40	900	ODP	1178
40	900	TEFC	1414
40	1200	ODP	907
40	1200	TEFC	1088
40	1800	ODP	715
40	1800	TEFC	858
40	3600	ODP	749
40	3600	TEFC	898
50	900	ODP	1344
50	900	TEFC	1612
50	1200	ODP	1051
50	1200	TEFC	1261
50	1800	ODP	860
50	1800	TEFC	1033
50	3600	ODP	873
50	3600	TEFC	1048
60	900	ODP	1543
60	900	TEFC	1852
60	1200	ODP	1221
60	1200	TEFC	1465
60	1800	ODP	976
60	1800	TEFC	1171
60	3600	ODP	1009
60	3600	TEFC	1211
75	900	ODP	1828
75	900	TEFC	2193
75	1200	ODP	1434
75	1200	TEFC	1721
75	1800	ODP	1138
75	1800	TEFC	1365
75	3600	ODP	1236
75	3600	TEFC	1484
100	900	ODP	2200
100	900	TEFC	2641
100	1200	ODP	1796
100	1200	TEFC	2155
100	1800	ODP	1430
100	1800	TEFC	1716
100	3600	ODP	1546
100	3600	TEFC	1855
125	900	ODP	2574
125	900	TEFC	3089
125	1200	ODP	2087
125	1200	TEFC	2505
125	1800	ODP	1690
125	1800	TEFC	2028
125	3600	ODP	1860
125	3600	TEFC	2232
150	900	ODP	2985
150	900	TEFC	3582
150	1200	ODP	2424
150	1200	TEFC	2908
150	1800	ODP	2017
150	1800	TEFC	2420
150	3600	ODP	2192
150	3600	TEFC	2630
200	900	ODP	3540
200	900	TEFC	4248
200	1200	ODP	2974
200	1200	TEFC	3569
200	1800	ODP	2487
200	1800	TEFC	2985
200	3600	ODP	2792
200	3600	TEFC	3350
250	900	ODP	4225
250	900	TEFC	5069
250	1200	ODP	3484
250	1200	TEFC	4182
250	1800	ODP	2976
250	1800	TEFC	3571
250	3600	ODP	3370
250	3600	TEFC	4044
300	900	ODP	4911
300	900	TEFC	5893
300	1200	ODP	4083
300	1200	TEFC	4899
300	1800	ODP	3509
300	1800	TEFC	4211
300	3600	ODP	3933
300	3600	TEFC	4720
350	900	ODP	5448
350	900	TEFC	6538
350	1200	ODP	4659
350	1200	TEFC	5591
350	1800	ODP	3945
350	1800	TEFC	4734
350	3600	ODP	4430
350	3600	TEFC	5317
400	900	ODP	5854
400	900	TEFC	7025
400	1200	ODP	5073
400	1200	TEFC	6088
400	1800	ODP	4307
400	1800	TEFC	5168
400	3600	ODP	4899
400	3600	TEFC	5879
450	900	ODP	6394
450	900	TEFC	7673
450	1200	ODP	5566
450	1200	TEFC	6678
450	1800	ODP	4768
450	1800	TEFC	5722
450	3600	ODP	5409
450	3600	TEFC	6490
500	900	ODP	6750
500	900	TEFC	8099
500	1200	ODP	5856
500	1200	TEFC	7027
500	1800	ODP	5177
500	1800	TEFC	6212
500	3600	ODP	5758
500	3600	TEFC	6910
600	900	ODP	0
600	900	TEFC	0
600	1200	ODP	0
600	1200	TEFC	0
600	1800	ODP	0
600	1800	TEFC	0
600	3600	ODP	0
600	3600	TEFC	0

APPENDIX C

PROCESS DESCRIPTION

C.1 Operations Description

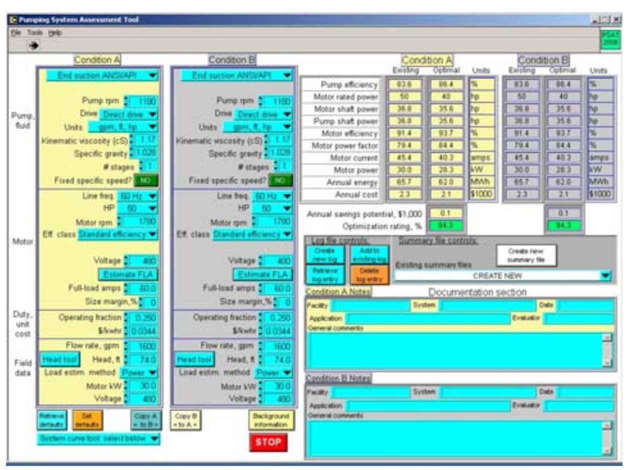
Your facility has two primary energy consumers.

Environmental Controls: This includes space heating, space cooling, space lighting, and any humidity controls. These are used to ensure visitor and employee comfort and safety throughout the facility.

Seawater System: The seawater system begins in the pump house, where high salinity seawater is pumped from the bay to the reservoir. In the reservoir, seawater is filtered through sand filters and stored until it is needed. When seawater is required, it is pumped to the location of use. There, it is conditioned to required standards and used. After use, contaminated seawater is sent to the treatment facility while other seawater is allowed to run back to the bay. In the treatment facility, contaminated seawater is both chlorinated and acidified to kill any contaminants, before being dechlorinated and stabilized and allowed to run off to the bay.

C.2 Best Practices

Pumps. Sea water pumps and motors were evaluated for efficiency utilizing the simulation program Pumping System Assessment Tool (PSAT) pictured below. Based on live data from the motors and pumps and assuming you are utilizing an efficiency end suction stock (standard efficiency ANSI/API) pump we are able to estimate pump efficiency as 83.6% and motor efficiency at 91%.



Chillers. Chillers are used to cool glycol for chiller discharge pressure was evaluated and it was determined that the approach temperature of the condensers was 15 degrees. This suggests that the condensers are appropriately sized and that the condensers are in a clean and unfouled condition.

C.3 Facility Layout