Nebraska Industrial Assessment Center

University of Nebraska–Lincoln (UNL)

Assessment Date:	--------
Client Type:	Wastewater Treatment Facility
Location:	--------
Principle Products:	Treated Wastewater
SIC/NAICS Number:	--------
Report Date:	--------
Report Number:	--------

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Energy Conservation & Waste Management Assistance for Industry. Funded by the US Department of Energy's Advanced Manufacturing Office. Additional funding from the University of Nebraska-Lincoln in support of this effort is gratefully acknowledged.

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DISCLAIMER RELATED TO THIS REPORT:

Client reports are only shared publicly upon receiving permission from the client. This report is a combination of information from a municipal wastewater treatment plant's report, where permission to share the report was given, and two generic recommendations that were stripped of information related to the client. This report does not include a client name since this report is a compilation of materials from several sources, all modified to be representative of actual reports but not using actual client data.

This report is intended to serve as a sample of what an NIAC report might look like, and to provide an example of the depth and detail of an assessment report. Since this report was cobbled together from multiple sources, and site-specific information was removed from many places, the report may not make sense if read as a whole.

It should be noted that ARs are created based on the needs and opportunities of the specific manufacturer. These can vary greatly based on the type of the manufacturer and its processes. The most common ARs are compressed air (leaks, management plan, set point, cool air intakes), conversion to LED lighting, economizers on RTUs, HVLS fans, cogged v-belts, heat recovery, water use reduction and deduct meters.

Typical Disclaimer for an NIAC report

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1.0 Executive Summary

On Feb. XX, XXXX, an NIAC team performed an energy assessment at a wastewater treatment plant located in X, Nebraska. A team of four undergraduate students, one graduate student, an energy engineer, and the Assistant Director of the Nebraska Industrial Assessment Center (NIAC) carried out the assessment.

From April XXXX to March XXXX, the facility spent a total of $354,200 on utilities. The facility pays for electricity, potable water, and natural gas. Electricity was the primary utility cost at $327,618, with usage and demand charges accounting for $182,657 and $143,221 respectively. Water was the second highest annual cost at $17,492. Natural gas accounted for the smallest annual cost at $9,090.

The Assessment of the facility identified 7 specific recommendations the facility could implement to reduce overall operating costs. These assessment recommendations (ARs) are shown in Table 1-1 with the potential savings, implementation costs, and simple payback associated with each AR listed. The facility is willing to accept payback periods in the range of 2 to 3 years and will consider 5 years if there are significant green benefits. Assessment recommendations are listed from the greatest annual cost savings to the least. A summary of each AR is presented after the tables detailing the general observations that were made and the basis of the recommendation. In addition to specific ARs, 2 other measures (OMs) have been identified for the facility. Other measures are classified as such because potential savings are relatively low compared to implementation costs, resulting in a payback period exceeding the facility's desired range. Other measures are shown in Table 1-2 with the same metrics of potential savings, implementation costs, and simple payback period.

Table 1-1: Overall Summary of Assessment Recommendations

Assessment Recommendations (ARs)	**Resource Savings (unit/year)**	**Cost Savings ($/year)**	**Implementation Costs ($)**	**GHG Emission Reduction ($MTCO_2e$)**	**Simple Payback**
Implement New Programming on SBR Blower VFDs	493,452 kWh/year	$44,258/year	$7,000	350	0.2 years
Relocate Dissolved Oxygen Probes in SBR Basins	521,968 kWh/year	$20,357/year	$960	370	< 0.1 years
Reuse Effluent Water in Belt Press	15,705 kWh/year 9,369,805 gallons/year	$17,011/year	$25,884	11.1	1.5 years
Reduce Compressed Air Leaks	105,792 kWh/year	$5,819/year	$5,960	75	1 year
Install a VFD on the Sludge Holding Tank	85,848 kWh/year	$5,339/year	$4,500	60.8	0.8 years

Use Deduct Meter on Cooling Tower	-	$4,237/year	$1,348	-	0.3 years
Upgrade Main Facility Lighting	10,208 kWh/year	$1,608/year	$5,394	7.2	3.4 years
Total		**$98,629/year**	**$51,046**	**847.1**	**0.5 years**
	*Overall payback was calculated by dividing the total sum of implementation costs by the total sum of cost savings				

Table 1-2: Overall Summary of Other Measures Investigated

Other Measures (OMs)	**Resource Savings (unit/year)**	**Cost Savings ($/year)**	**Implementation Costs ($)**	**GHG Emission Reduction ($MTCO_2e$)**	**Simple Payback (years)**
Switch from Class B to Class A Sludge	140,642 kWh/year 1,089 MMBTU	$195,080/year	$3,459,300	99.7	17.7 years
Pre-Air Decommission	326,617 kWh/year	$20,313/year	$716,000	231	35.2 years

Assessment Recommendation Description:

AR No. 1: Implement New Programming on SBR Blower VFDs

It is recommended that the facility implement new programming to control the SBR blower VFDs. The new program will allow VFDs to ramp up and down in accordance with various SCADA metrics and result in direct electricity savings. Implementing this recommendation would result in cost savings of **$44,258 annually** with a simple payback period of **0.2 years**.

AR No. 2: Relocate Dissolved Oxygen Probes in SBR Basins

It is recommended that the facility relocate Dissolved Oxygen (DO) probes out of dead zones. Moving DO probes to more ideal locations will result in more accurate DO concentration readings and hence a reduction electricity usage. Implementing this recommendation could result in cost savings of **$20,357 annually** with a simple payback period of less than **0.1 years**.

AR No. 3: Reuse Effluent Water in Belt Press

It is recommended for the facility to reuse the effluent water that they produce in the belt press. This will eliminate the use of the air compressor they have and cut down on the use of the city water. It will be done by installing a pipeline from where the effluent water comes out to the solids handling building. Implementing this recommendation would result in cost savings of **$17,011 annually** with a simple payback period of **1.5 years**.

AR No. 4: Reduce Compressed Air Leaks

It is recommended that the facility implements a quarterly air leak detection and repair program to minimize air leaks within their air distribution system. In addition to finding the leaks, the identified air leaks should be repaired, and any air leaks discovered in the future should be tagged and repaired as they are found. This recommendation provides savings of 105,792 kWh/year, a cost saving of **$5,819** for an implementation of $5,950 giving a payback of **1 year**.

AR No. 5: Install a VFD on the Sludge Holding Tank

It is recommended that the facility install a variable frequency drive on each blower in the holding tank/pump building. This will allow for the blower to decrease its workload while saving a large amount of money for the company. Implementing this recommendation would result in cost savings of **$5,339 annually** with a simple payback period of **0.8 years**.

AR No. 6: Use Deduct Meter on Cooling Tower

Sewer costs are currently applied based on all water entering the plant instead of directly metering the sewer outfall of the facility. The water evaporated in the cooling tower does not enter the sewer and should not be charged the sewer fee. The facility can implement a deduct meter to find the volume of water evaporated in the cooling tower. It is estimated that the facility can save 6,480 gallons of sewer charges with a savings of **$4,239 annually**. The implementation cost was calculated to be $1,348, resulting in a payback period of **0.3 years**.

AR No. 7: Upgrade Main Facility Lighting

It is recommended that the facility replace their current fluorescent lighting with energy efficient, high-output LED bulbs. There are currently 368 fluorescent that remain within the main operating areas of the facility. By replacing these bulbs with light emitting diode (LED) equivalents, the facility can expect to see cost savings of **$1,608 annually** with a simple payback period of **3.4 years**.

2.0 Introduction

The contents of this report describe how energy is used throughout the plant and include specific recommendations on cost effective changes that could reduce energy usage and improve productivity. A 1-day site visit was conducted on X, in which specific data were collected for analysis of the plant. The following report is divided into seven major sections which are briefly described below.

1. **Executive Summary:** An overall snapshot of the assessment including recommendations and potential cost savings.

2. **Introduction:** Describes the purpose, contents, and overall organization of the report.

3. **Facility Background:** A description of the facility and its main operations, which includes the general process flow, facility layout, some major energy users of plant equipment, and current effective energy practices in place.

4. **Energy Accounting:** Entails the analysis and summary of all energy bills associated with the facility. Costs for electricity usage and demand were determined from the General Service Demand (GSDM) rate structure and used for calculating potential savings. Analysis was also conducted for natural gas provided by Black Hills Energy.

5. **Assessment Recommendations:** Describes the specific, quantified recommendations for the facility to investigate implementing. Each recommendation provides a background description of the specific focus area being investigated, what is being recommended, and what data was collected. The methods for calculating savings and any assumptions are clearly stated. Implementation cost and simple payback were also provided for each recommendation.

6. **Other Measures:** Additional measures that were investigated as potential recommendations but not included in the recommendations section due to the following reasons: the measure was not feasible as presented, data could not be quantified, or implementation would not directly affect energy use or reduce waste.

7. **Appendix:** The appendix includes some pricing information and data used for cost analysis, as well as supplying other material relevant to the assessment.

3.0 Facility Background

3.1 Facility Description

Table 3.1-1: Summary of General Facility Information

SIC Number:	**XXX**	Location:	**XXX**
NAICS Number:	**XXX**	Number of Employees:	**XXX**
Principal Product:	Treated Wastewater	Audit Date:	**XXX**
Annual Sales:	**XXX**	Client Hours:	**XXX**
Annual Production:	**XXX** Gallons	Annual Operation:	**XXX**

The Wastewater Treatment Plant (WWTP) is a municipal wastewater treatment plant which serves the city of XXX, and neighboring communities. According to the plant's superintendent, the WWTP currently treats a range of XXX million gallons per day (MGD) and discharges to the XXX River.

The facility sits on XXX acres of land and buildings and processes occupy approximately XXX square feet of this land. An aerial view of the facility is shown in Figure 3.1-1 with Table 3.1-2 detailing where plant processes occur. The plant consists of grit collectors, pre-aeration basins, primary clarifiers, trickling filters, aeration basins, final clarifiers, sequencing batch reactors (SBRs), and a UV disinfection system. A general process flow is illustrated in Figure 3.2-1 in Section 3.2.

Upon discussion with the plant staff, an acceptable payback period between XXX years was established. However, if there were significant green benefits associated with a recommendation, they would consider a payback period of up to XXX years.

Table 3.1-2: Description of Processes and Area Locations

Number	Description
1	Lift Station
2	Primary Clarifiers
3	Trickling Filters
4	Aeration Basins
5	Final Clarifiers
6	Sequencing Batch Reactors
7	UV Disinfection
8	Solids Handling Building
9	Blower Building
10	Shop
11	Operation's Administration Building
12	Holding Tank Building
13	Trickling Filter Building

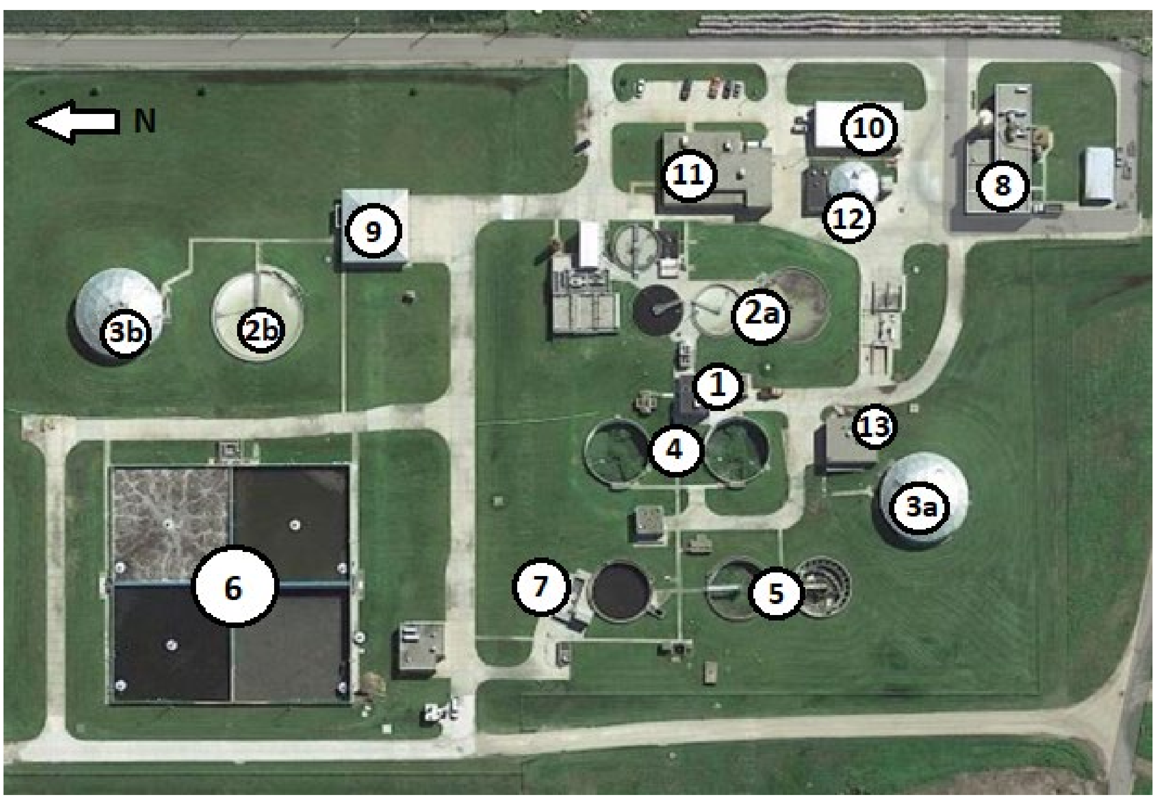

Figure 3.1-1: Aerial View of the Plant

3.2 General Process Description

Figure 3.2-1 shows a process flow diagram which contains the plant's primary treatment processes and material end points. Wastewater first flows through the influent debris screen and then goes to the lift station. The volumetric flow rate of the wastewater is measured by a XX flume and then the wastewater continues to the grit collectors which remove non-treatable inorganic solids.

After the non-treatable solids have been removed by the grit collectors, the wastewater enters the pre-aeration basins. Afterwards, the wastewater is directed to the primary clarifiers and then the trickling filters. The water then enters the activated sludge train which consists of aeration basins, finals clarifiers, and sequencing batch reactors.

After the trickling filters, the wastewater enters one of four sequencing batch reactor (SBR) basins. The first step in the SBR basin is the mix-fill phase which creates an environment for old and young microorganisms to mix and consequently reduces some of the phosphorous. The next step is the react-fill phase during which oxygen is added by blowers which enables organisms present in the water to grow and evolve. After the react-fill phase is the react cycle. During this cycle, the influent wastewater is stopped but the mixing and oxygen addition continues, enabling the water to further be cleaned and reducing pollutants. Next, all action is stopped in the settle phase, resulting in the solids and microorganisms settling in an ideal environment at the bottom of the basin. The last step in the SBR process is the decant phase during which the sludge and cleaned water are separated.

After the SBR process, the treated wastewater then enters the final purification process, ultraviolet disinfection, during which the water passes through chambers containing ultraviolet lamps which kill pathogens upon exposure. Treated wastewater is then discharged into the XXX River.

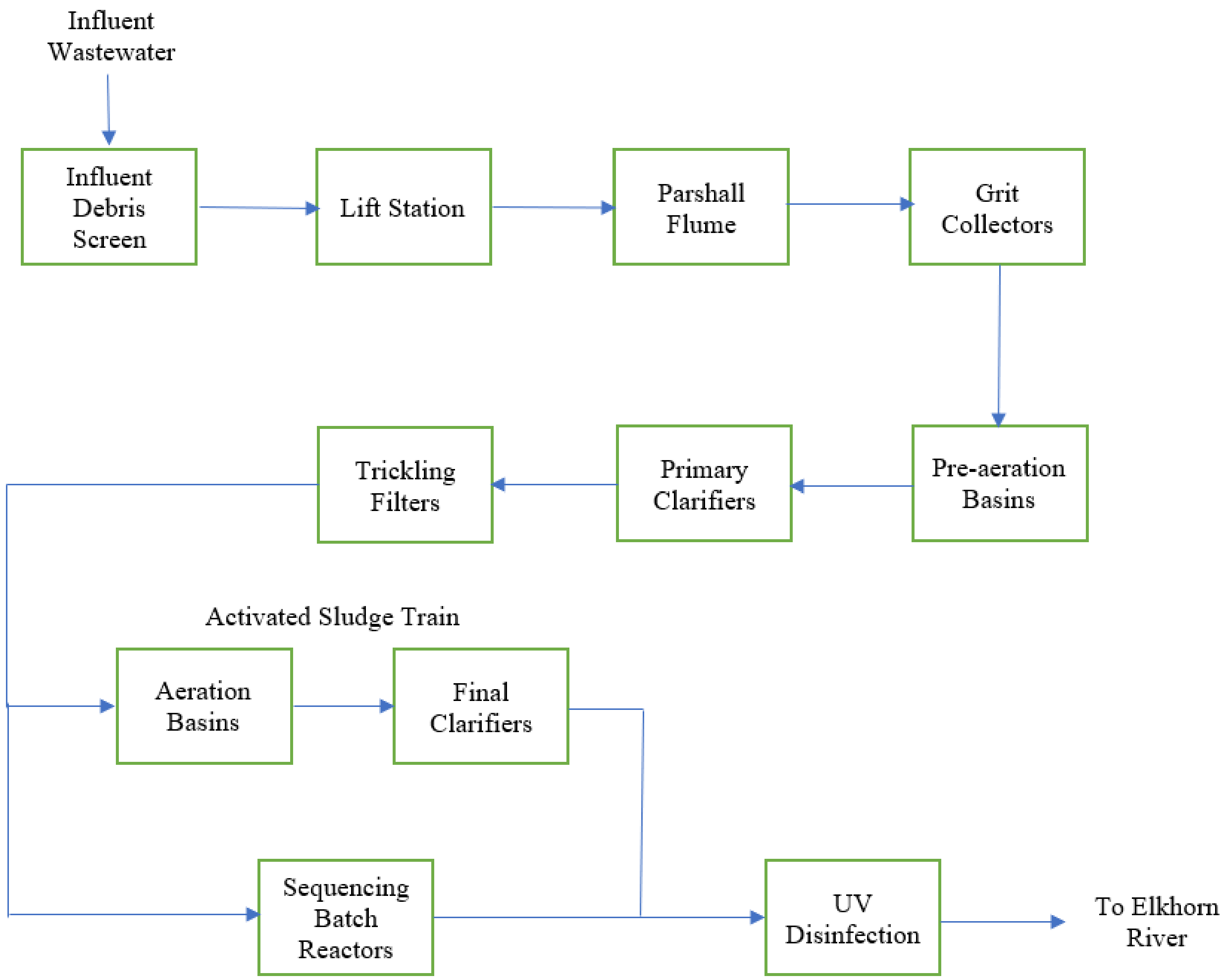

Figure 3.2-1: Plant Process Flow Diagram

3.3 Utility Usage and Applications

The three utilities utilized by the wastewater treatment plant are electricity, natural gas, and water. The WWTP uses electricity for lighting, air conditioning, and to power equipment and machinery. The plant's natural gas is used for space heating. The plant uses water primarily for the belt press and the plant's administrative building.

3.4 Current Energy Efficiency and Waste Management Practices

The wastewater treatment plant currently practices several energy efficiency and waste management measures that minimize the plant's environmental impact. Some of these include:

- Employing a supervisory control and data acquisition (SCADA) system to optimize process control and operation
- Sludge management system which prevents sending the sludge to the landfill and instead applies it to agricultural land as fertilizer
- Variable Frequency Drives (VFDs) installed on the majority of the plant's equipment and machinery
- Dissolved oxygen probe on each of the four sequencing batch reactors to determine appropriate aeration level requirements

3.5 Major Plant Equipment

Table 3.5-1 summarizes the major energy using equipment at the wastewater treatment plant. This list contains most equipment but is not comprehensive, and some smaller pieces of equipment may have been unintentionally excluded.

Table 3.5-1: Summary of Major Facility Equipment

Location	**Description**	**Quantity**	**HP**	**kW**	**Annual Operation Hours**
Main Blower, Pump, and Control Building	SBR Blower	3	300	223.7	8,760
Lift Station	Lift Pump	2	100	74.6	8,760
SBR Basins	Mechanical Mixer	4	75	55.9	1,095
Grit Removal Basin	Pre-Aeration Blower	2	50	37.3	8,760
Sludge Storage Tank	Sludge Blower	2	50	37.3	6,570
Main Blower, Pump, and Control Building	Trickling Filter Pump	3	40	29.8	8,760
Sludge Handling Building	Air Compressor	1	10	7.5	1,251
Main Blower, Pump, and Control Building	Sludge Pump	1	5	3.7	8,760
Main Blower, Pump, and Control Building	Grease Pump	1	5	3.7	8,760
Sludge Handling Building	Press Motor	2	3	2.2	1,251

4.0 Utility Accounting

The three utility streams at the wastewater treatment plant are electricity, natural gas, and water. The overall utility cost for the WWTP during the billing period from XXX to March XXX was **$** XXX. This cost includes all charges, taxes, and fees associated with the electric, natural gas, and water utilities.

Figure 4.1 further summarizes the relative cost of the three utilities. From this figure it is evident that electricity is the largest cost for the facility, accounting for 92% of the annual utility cost. Water accounts for 5% of the utility cost and natural gas accounts for 3% of the total cost. The following sections provide a detailed analysis of each utility.

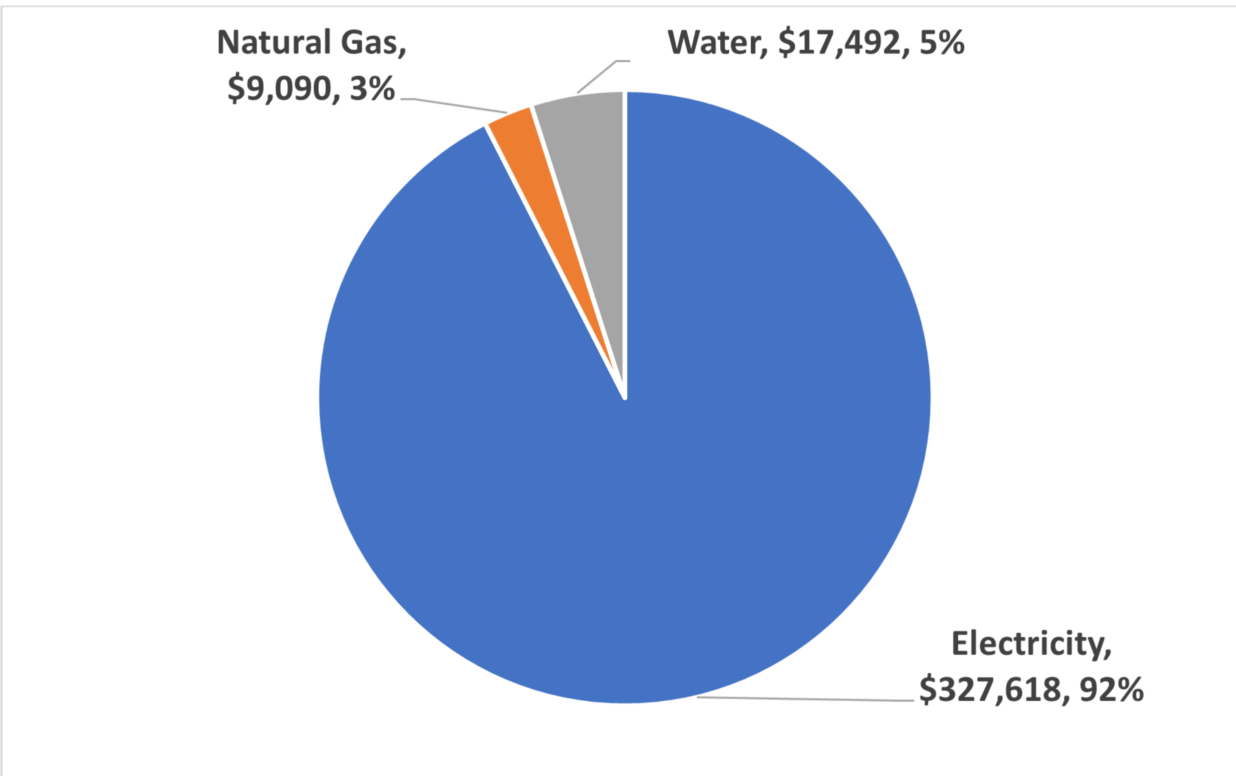

Figure 4.1: Breakdown of Total Utility Costs

4.1 Electricity Analysis

The wastewater treatment plant is provided electricity by XXX. The WWTP uses electricity for lighting, air conditioning, and to power equipment and machinery. Figure 4.1-1 shows the percentage of demand cost compared to the percentage of the usage cost.

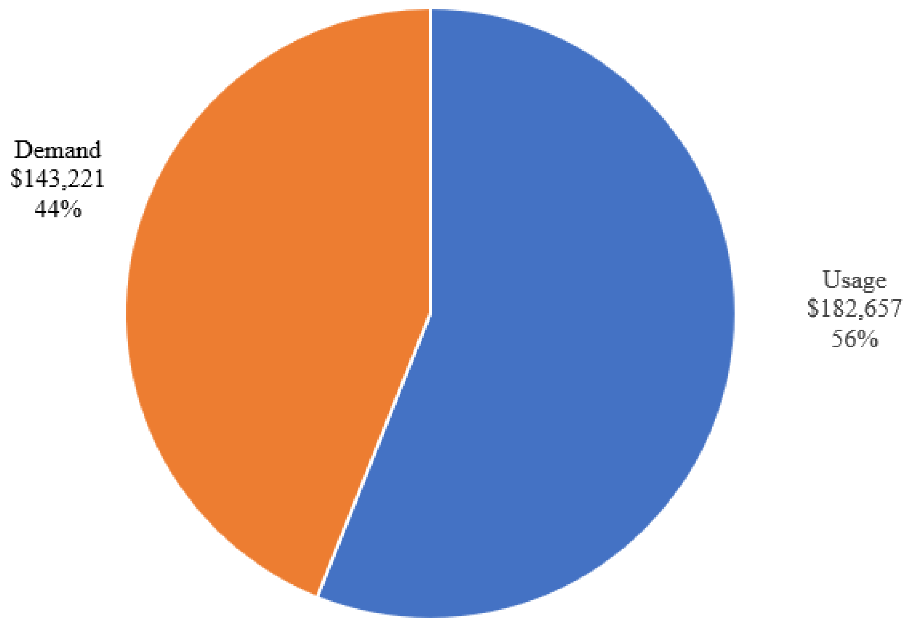

Figure 4.1-1: Electricity Usage and Demand Comparison

Figure 4.1-2 shows the electricity usage in kWh and the electricity demand in kW for each month. As evidenced from the graph, it can be seen that the electricity usage and demand follow similar trends, remaining fairly constant throughout the year but with a slight increase from November to January.

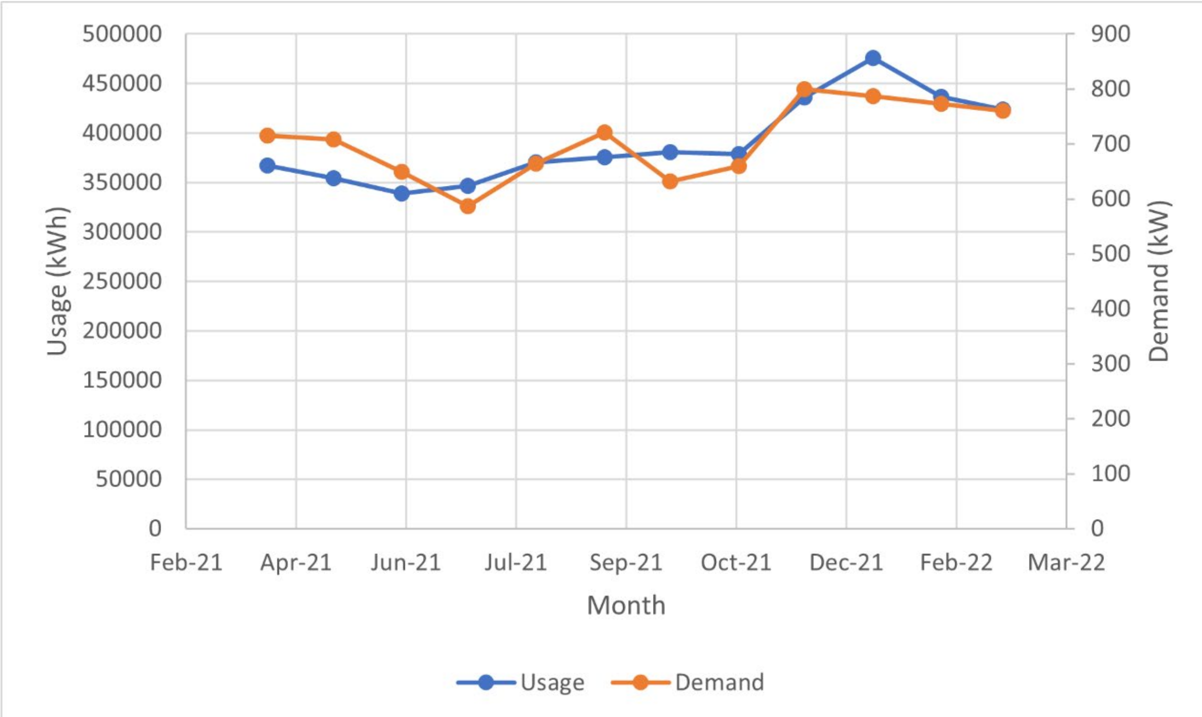

Figure 4.1-2: Electricity Usage and Demand Each Month

The annual electricity usage cost was divided by the total usage to find the electricity usage rate, which was calculated to be **$XX/kWh**. Similarly, the total electricity demand cost and total demand were divided to determine the demand rate, which was found to be **$XX/kW**.

A summary of annual electricity usage and demand as well as the associated costs and rates is provided in Table 4.1-1.

Table 4.1-1: Summary of Annual Electricity Usage and Demand

Annual Electricity Usage	XXX kWh
Annual Electricity Demand	XXX kW
Annual Usage Related Charges	$XXX
Annual Demand Related Charges	$XXX
Annual Customer Charge	$XXX
Electricity Usage Unit Cost	$XXX/kWh
Electricity Demand Unit Cost	$XXX/kW

4.2 Natural Gas Analysis

The wastewater treatment plant is provided natural gas by XXX. From XXX to XXX, the plant used XXX therms of natural gas. Given that the annual natural gas usage cost was $ XXX, the unit cost was determined by averaging the result of dividing each month's natural gas cost by the usage for that month and calculated to be **$ XXX/therm**. A representation of the monthly natural gas usage over the analysis period can be seen in Figure 4.2-1 along with heating degree days (HDD). The highly similar trends between natural gas usage and HDD show a correlation between natural gas usage and heating. This is consistent with the staff's statement that natural gas is used as a space heater at the plant.

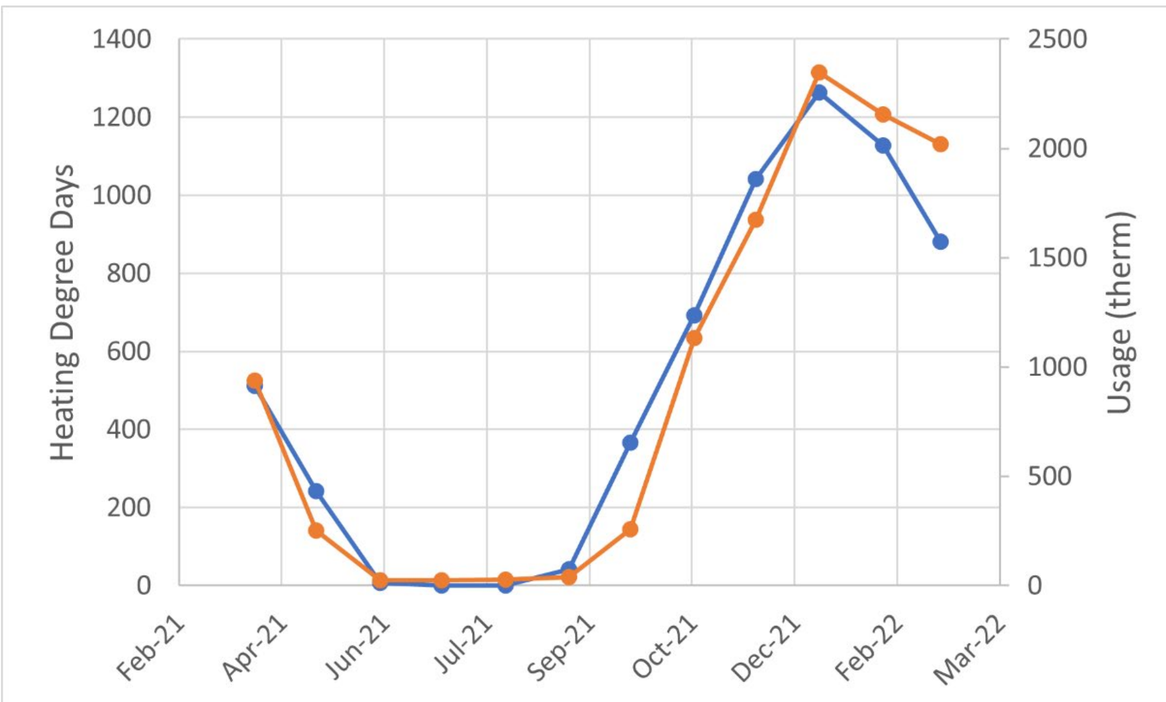

Figure 4.2-1: Monthly Natural Gas Usage and Heating Degree Days

Table 4.2-1 summarizes the annual natural gas usage and cost, as well as the unit cost per therm.

Table 4.2-1: Summary of Annual Natural Gas Usage and Cost

Annual Natural Gas Usage	XXX therms
Annual Natural Gas Usage Cost	$ XXX
Annual Distribution Cost	$ XXX
Customer and Safety Charge	$ XXX
Natural Gas Usage Unit Cost	$ XXX /therm or $ XXX /MMBtu

4.3 Water Analysis

The wastewater treatment plant is provided potable water by the city of XXX and is billed every two months. Over the course of XXX to XXX, the plant used XXX gallons of water. The plant has three water meters within the city limits and their individual usage over the billing months is depicted in Figure 4.3-1. The majority of the water was obtained from the XXX meter within the city limits. It is expected that this water is used for the belt press, which is the primary water user.

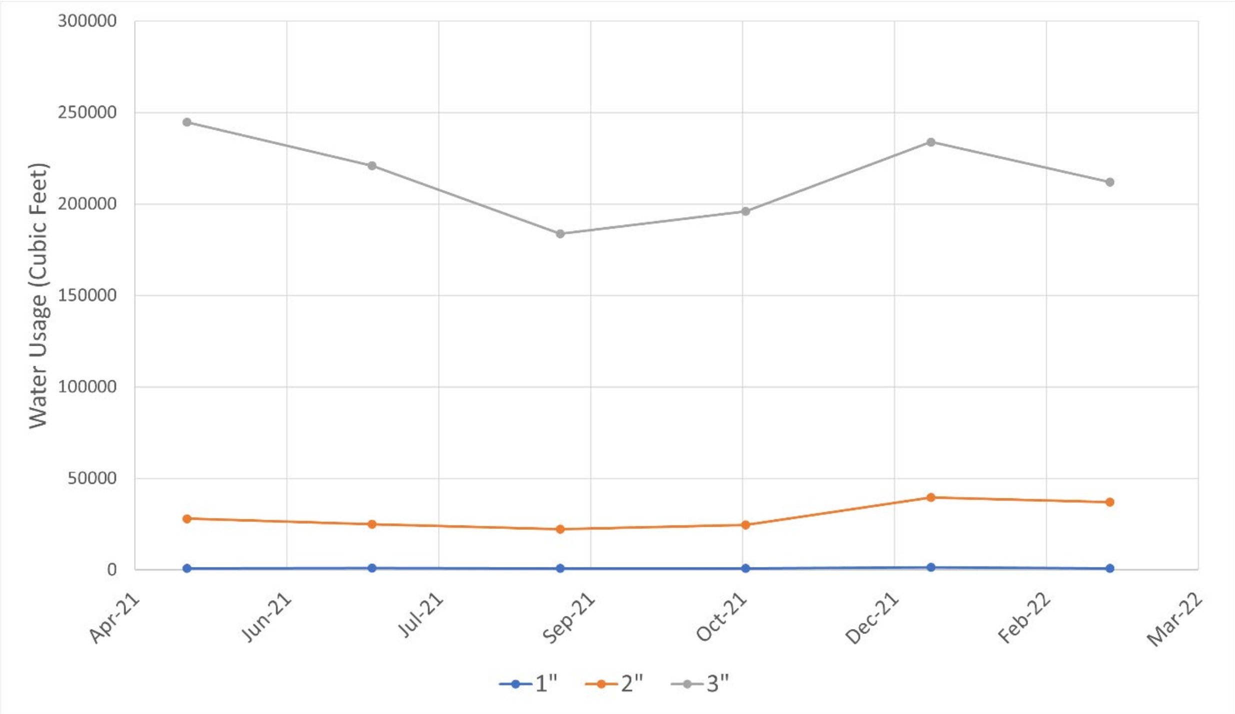

Figure 4.3-1: Annual Water Usage for the Plant's Three Meters

From the utility bill analysis the water usage unit cost was calculated to be **$ XXX/thousand gallons** by dividing the annual water usage cost by the total water usage. As mentioned earlier, the water is used primarily for the belt press, which accounts for XXX % of the annual water usage, and for consumption in the administrative building. Table 4.3-1 shows the relevant data for annual water usage and cost.

Table 4.3-1: Summary of Annual Water Usage and Cost

Annual Water Usage	XXX gallons
Annual Water Usage Cost	$ XXX
Annual COM Stormwater Cost	$ XXX
Water Usage Unit Cost	$ XXX /1000 gallons

5.0 Energy Efficiency Assessment Recommendations

The following section describes the specific assessment recommendations provided for the facility. Each recommendation has some background information describing the recommendation, the estimated savings, implementation cost, and simple payback. The recommendations for the wastewater treatment plant are listed from greatest annual cost savings to least annual cost savings.

5.1 AR No. 1: Implement New Programming on SBR Blower VFDs

Recommended Action

It is recommended that the facility implement new programming to control the SBR blower VFDs. The new program will allow VFDs to ramp up and down in accordance with various SCADA metrics and result in direct electricity savings.

Table 5.1-1: Summary of Reprogramming SBR Blower VFDs

Annual Electricity Savings	Annual Cost Savings	Implementation Costs	Simple Payback
493,452 kWh/year	$44,258/year	$7,000	0.2 years

Background

Currently, the facility operates as a sequenced batch reactor (SBR) wastewater treatment plant. SBRs are employed due to their efficacy in treating pulse inputs of high organic loads that local industries send to the facility daily. Operation of an SBR contains 4 basic stages; Fill, React, Settle, and Decant. The first stage simply involves filling the basin with wastewater. The second phase introduces air, and more importantly the oxygen component of air, to accelerate biological reactions and degrade contaminants. Next, the third phase allows for solids to settle out of the mixed liquor. Finally, aerobically treated wastewater is drained from the basin in the fourth stage.

The “React” stage is most relevant to this recommendation. During this stage, air is introduced to the wastewater via fine bubble diffusers which are fed by large blowers. The facility has a total of three blowers, each blower motor is 300 horsepower. No more than two blowers are allowed to operate at the same time, the third is installed for redundancy purposes. Fortunately, all three blowers already have Variable Frequency Drives (VFDs) installed. However, in discussion with the Wastewater Superintendent it was determined that they are not properly programmed. Currently the VFDs function as soft starts, but do not adjust blower speed based on Supervisory Control and Data Acquisition (SCADA) system parameters as true VFDs should.

Variable frequency drives are typically linked to dissolved oxygen (DO) sensors in a SBR through the SCADA system and programmed to adjust blowers based on oxygen and mixing requirements. When less oxygen is required, the VFD turns down the blower. Operating in this manner results in reduced electricity usage and therefore reduced costs associated with the operation of blowers. It is recommended that the facility set up SBR blower VFDs to operate in a similar manner. To do this, a third party will need to re-program the VFDs so they can ramp up and down based on DO probe measurements.

Anticipated Savings

The following calculations have been performed to assess the possible energy and cost savings encompassed by this recommendation. Three main factors must be considered when identifying the maximum allowable turn down for blowers. First, there must be enough oxygen supplied to the basin for the breakdown of organic matter and inorganic compounds through aerobic digestion to occur unhindered. Second, the air supply must be adequate to mix the contents of the basin and prevent settling that can lead to anoxic conditions. Third, supplied power can only be reduced to a certain extent, beyond that point the blower will not properly function and experience considerable losses in efficiency.

Oxygen Requirements

One purpose of aeration is to supply enough oxygen to meet the carbonaceous biochemical oxygen demands (CBOD) of a thoroughly mixed liquid. This means that enough oxygen must be supplied to aid in the growth of bacteria which help to biodegrade the organic matter in wastewater. Two biproducts of this process are water and carbon dioxide. Additionally, oxygen is necessary for bacteria to oxidize ammonia in the wastewater to produce a final product of nitrate. An analysis based on daily influent nutrient loadings would yield the most accurate results; however, it was not possible to obtain daily data for this facility. Instead, monthly and quarterly averages of required data will be used and assumed representative for the entire associated time period.

The Enforcement and Compliance History Online (ECHO) data base[1] is overseen by the EPA. This database contains detailed reports over a wide range of parameters that facilities are required to track and stay within compliance of. Influent CBOD concentrations for the facility have been obtained from this database. Considering datapoints are only recorded quarterly for CBOD, it is assumed that one datapoint is a representative average for three months of operation. Figure 5.1-1 shows the information as it appears in the database.

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[1] Environmental Protection Agency – Enforcement and Compliance History Online. Web: https://echo.epa.gov

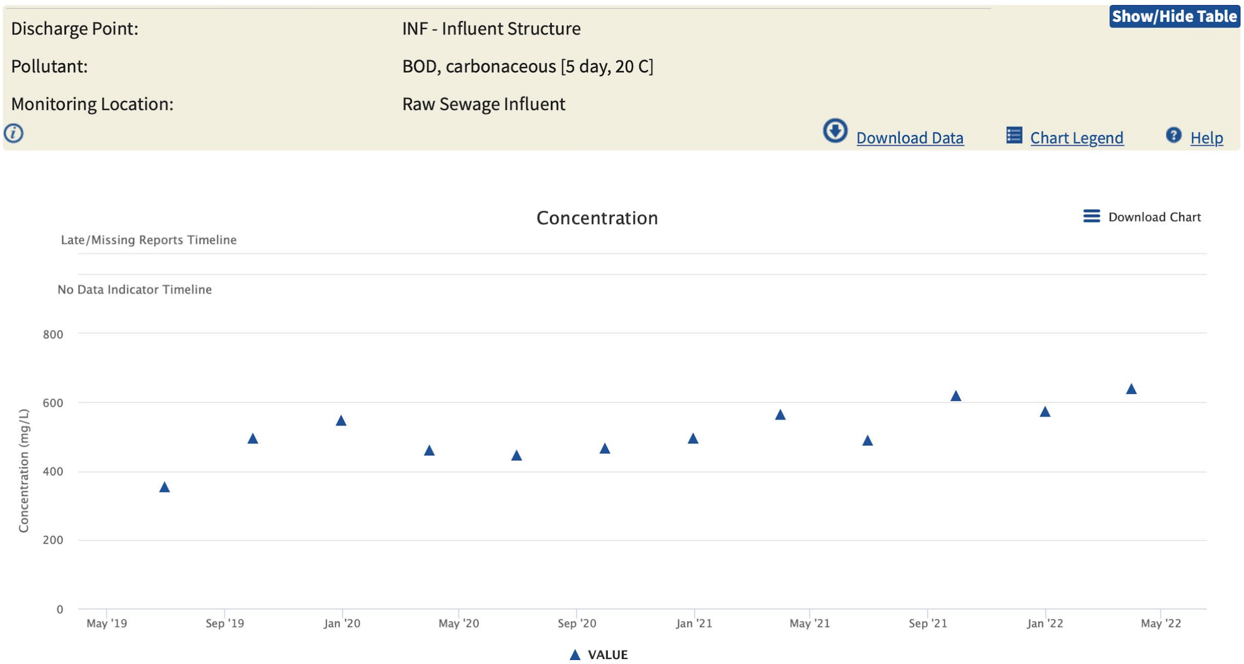


Figure 5.1-1: Quarterly Influent CBOD Concentrations

Unfortunately, influent ammonia (NH_3) concentrations for the facility are not available on the ECHO database. Instead, the Wastewater Superintendent supplied an average influent ammonia concentration of 30 mg/L. This concentration was obtained by looking at several recent lab reports and will be considered representative of annual influent ammonia concentrations for the proposes of this report.

It is necessary to convert the influent concentration of CBOD and NH_3 to mass loading rates. This can be done by multiplying the concentration of contaminant by the wastewater flow rate. Wastewater flow rates were also collected from ECHO. Figure 5.1-2 shows the information as it appears in the database.

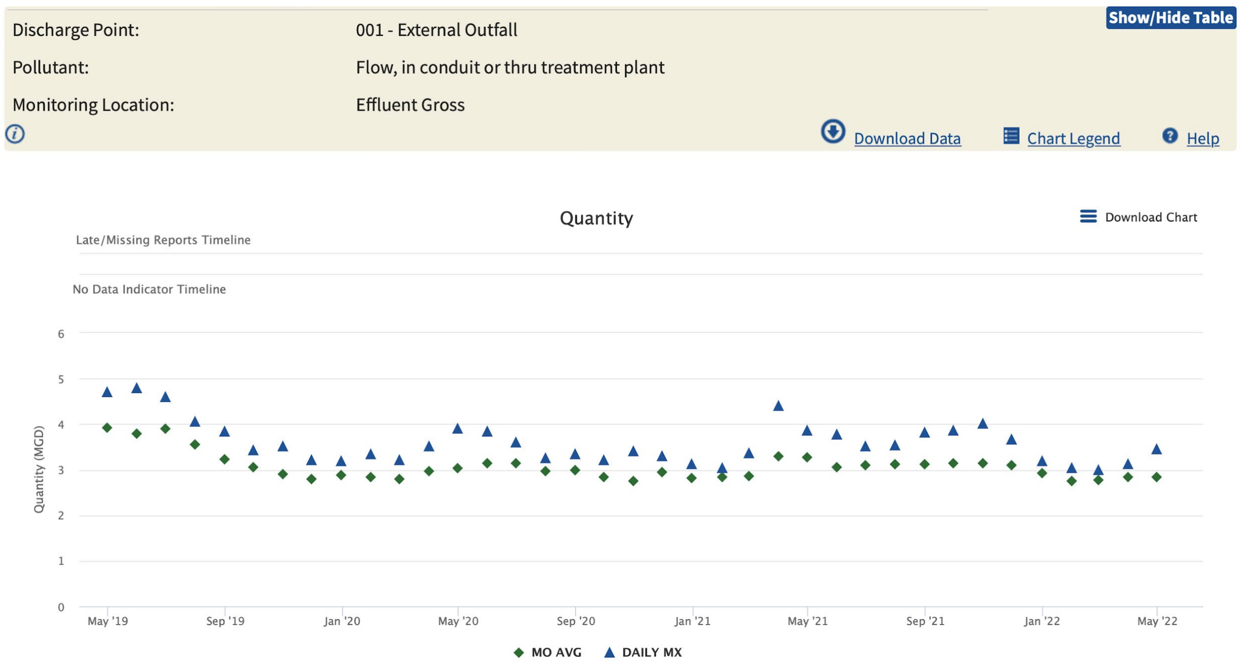


Figure 5.1-2: Monthly Wastewater Flow

Based upon CBOD and ammonia mass loading rates, the required oxygen (RO) can be calculated using the following equation[2].

$$RO = R_{CBOD} * (LCBOD_0 - LCBOD) + R_{NH} * (LNH_0 - LNH)$$

Where,

RO = Required oxygen for CBOD and ammonia removal. $\left(\frac{lbs\ 0_2}{month}\right)$

R_{CBOD} = Oxygen required to break down CBOD. The normal value of 1.1 was obtained by consulting Tchobanoglous et al. (2014). $\left(\frac{lbs\ 0_2}{lbs\ CBOD}\right)$

$LCBOD_0$ = Current CBOD influent loading rate. $\left(\frac{lbs\ CBOD}{month}\right)$

$LCBOD$ = Desired CBOD effluent loading rate. This has been assigned a value of 0. $\left(\frac{lbs\ CBOD}{month}\right)$

R_{NH} = Oxygen required to oxidize ammonia. The normal value of 4.6 was obtained by consulting Tchobanoglous et al. (2014). $\left(\frac{lbs\ O_2}{lbs\ NH}\right)$

LNH_0 = Current ammonia influent loading rate. $\left(\frac{lbs\ NH}{month}\right)$

LNH = Desired ammonia effluent loading rate. This has been assigned a value of 0. $\left(\frac{lbs\ NH}{month}\right)$

The following is a sample calculation for RO in April of XXX.

[2] Tchobanoglous, G., Burton, F., Stensel, H. D., Tsuchihashi, R., Abu-Orf, M., Bowden, G., and Pfrang, W. (2014). *Wastewater Engineering: Treatment and Resource Recover*. McGraw-Hill, New York, NY.

$$RO = 1.1\frac{lbs\ O_2}{lbs\ CBOD} * \left(464{,}561\frac{lbs\ CBOD}{month} - 0\frac{lbs\ CBOD}{month}\right) + 4.6\frac{lbs\ O_2}{lbs\ NH} * \left(24{,}711\frac{lbs\ NH}{month} - 0\frac{lbs\ NH}{month}\right)$$

$$RO = 624{,}686\frac{lbs\ O_2}{month}$$

The same calculation has been repeated for the other months. A summary of all monthly CBOD and NH_4 removal oxygen requirements is shown in Table 5.1-2.

Table 5.1-2: Monthly Oxygen Requirements for CBOD and NH_4 Removal

Date		Required Oxygen ($lbs\ O_2$/month)
XXX	April	624,686
	May	569,116
	June	516,969
	July	539,438
	August	657,984
	September	638,807
	October	662,216
	November	602,064
	December	614,182
XXX	January	580,392
	February	542,323
	March	604,780

The standard oxygen transfer rate (SOTR) must be calculated. Due to inefficiencies in any system the SOTR will always be greater than the previously calculated RO values. This is due to oxygen transfer rate (OTR) efficiency. Oxygen transfer rate is heavily dependent on equipment and design specifications, as well as the configuration of certain equipment. Oxygen transfer rate is set equal to RO in the below equation:

$$OTR = RO = SOTR * \left(\frac{\beta * C_{st} - C_{basin}}{C_{st20}}\right) * \theta^{T-20} * \alpha * FO$$

Rearranging the equation yields the following:

$$SOTR = \frac{OTR}{\left(\frac{(\beta * C_{st}) - C_{basin}}{C_{st20}}\right) * \theta^{T-20} * \alpha * FO}$$

Where,

$SOTR$ = Standard oxygen transfer rate. $\left(\frac{lbs\ 0_2}{month}\right)$

OTR = Oxygen transfer rate, which is equal to the oxygen required by CBOD and ammonia removal for each month shown in Table 5.1-2. $\left(\frac{lbs\ 0_2}{month}\right)$

β = Ratio of oxygen saturation in wastewater to freshwater. The normal value of 0.98 was obtained by consulting Tchobanoglous et al. (2014)

C_{st} = Oxygen concentration of freshwater at field temperature and pressure. The equation used to calculate theses values can be found in Appendix 7.1. $\left(\frac{mg}{L}\right)$

C_{basin} = Desired oxygen concentration in the basin. A value of 3.0 has been assigned. $\left(\frac{mg}{L}\right)$

C_{st20} = Oxygen concentration in freshwater at 20°C, this value is 9.20. $\left(\frac{mg}{L}\right)$

θ = Arrhenius constant for correcting system operating temperature. The normal value of 1.024 was obtained by consulting Tchobanoglous et al. (2014)

T = Temperature of liquid in the basin. Monthly values can be found in Appendix 7.1. (C)

α = Constant depending on the aeration type, in this case fine bubble diffusers. A conservative assumption of 0.40 will be made here.

FO = Fouling factor associated performance reductions of the motor. Based on the good condition of the system, this value is assumed to be 0.90.

A sample calculation for SOTR in April of 2021 is shown here:

$$SOTR = \frac{24{,}686\,\frac{lbs\ O_2}{month}}{\left(\frac{\left(0.98 * 12.4\frac{mg}{}\right) - 3.0\frac{mg}{L}}{9.2\frac{mg}{L}}\right) * 1.024^{(6.1C-20C)} * 0.40 * 0.90}$$

$$SOTR = 2{,}412{,}357\,\frac{lbs\ O_2}{month}$$

The above calculation has been repeated for each month individually. A summary of all SOTR values are shown in Table 5.1-3.

Table 5.1-3: Calculated Monthly SOTR Values

Date		SOTR (lbs O_2/month)
XXX	April	2,412,357
	May	2,530,849
	June	2,947,064
	July	3,601,325
	August	4,392,748
	September	2,965,176
	October	2,751,838
	November	2,456,836
	December	2,309,926
XXX	January	2,229,692
	February	2,063,927
	March	2,428,090

Next, the standard mass flow rate of air (W) required by the SBRs from blowers must be considered for effective treatment. Air is only partially composed of oxygen so the following calculation must adjust the mass flow rate and system inefficiencies to reflect this.

$$W = \frac{SOTR}{CF * SOTE}$$

Where,

W = Standard mass airflow rate required from the blower $\left(\frac{lbs\ air}{month}\right)$

$SOTR$ = Standard oxygen transfer rate for each month, which can be seen in Table 5.1-3 $\left(\frac{lbs\ O_2}{month}\right)$

CF = Mass fraction of oxygen in air, which is 0.23[3]. $\left(\frac{lbs\ O_2}{lbs\ air}\right)$

$SOTE$ = Standard oxygen transfer efficiency of the fine bubble diffuser system. The efficiency of 37.5 % (0.375) was determined by consulting the equipment specification sheet[4] and knowing diffusers are positioned 15 feet below the surface.

A sample calculation for W using values from April of XXX is shown.

$$W = \frac{2{,}412{,}357\ \frac{lbs\ O_2}{month}}{0.23\frac{lbs\ O_2}{lbs\ air} * 0.375}$$

[3] Engineering Tool Box. “Air - Composition and Molecular Weight”. Web: https://www.engineeringtoolbox.com/air-composition-d_212.html

[4] Parkson^{TM} “HiOx Messner aeration panels” Web: https://333330-1023880-raikfcquaxqncofqfm.stackpathdns.com/cdn/ff/v9jvSiqYZpgSFh9rA4L7cmZeXi_9UIniAdYUp_hD4uQ/1571198397/public/documents/document-hiox-messner-aeration-panel-brochure-print-version-1028.pdf

$$W = 27{,}969{,}361 \frac{lbs\ air}{month}$$

A summary of monthly W values is shown in Table 5.1-4.

Table 5.1-4: Calculated Monthly W Values

Date		Standard Mass Flow Rate (lbs air/month)
XXX	April	27,969,361
	May	29,343,171
	June	34,168,859
	July	41,754,493
	August	50,930,408
	September	34,378,849
	October	31,905,369
	November	28,485,056
	December	26,781,754
XXX	January	25,851,501
	February	23,929,588
	March	28,151,769

The operating power requirement (P) of the blower to provide the necessary standard air supply can now be calculated using the following equation. A conversion factor of $5.25 \times 10^{-6}\ \frac{day}{lbs*s}$ is used to balance units.

$$P = \left[\frac{W * R * T_A}{MW_A * m * \eta_B * \eta_{VFD}} * 5.25 \times 10^{-6} \frac{day}{lbs * s}\right] * \left[\left(\frac{p_2}{p_1}\right)^m - 1\right]$$

Where,

P = Operating power requirement of the blower. (kW)
W = Standard mass airflow rate required from the blower. $\left(\frac{lbs\ air}{month}\right)$
R = Universal gas constant[5], which is equal to 8.314. $\left(\frac{J}{mol*K}\right)$
T_A = Inlet air temperature of the blower. Monthly average of historic data from the NOAA[6] can be found in Appendix 7.1. $(Kelvin, or\ K)$
MW_A = Molecular weight of air, which is equal to 28.96[7]. $\left(\frac{g}{mol\ air}\right)$
m = The binomial coefficient, which is equal to 1.395 according to Tchobanoglous et al. (2014).
η_B = Specified blower efficiency, which was found on the nameplate to be 95.4%. (0.954)

[5] Engineering Tool Box. "Universal and Individual Gas Constants". Web: https://www.engineeringtoolbox.com/individual-universal-gas-constant-d_588.html
[6] National Oceanic and Atmospheric Association – The National Weather Service Forecast Office. Web: https://w2.weather.gov/climate/index.php?wfo=oax
[7] Engineering Tool Box. "Air - Composition and Molecular Weight". Web: https://www.engineeringtoolbox.com/air-composition-d_212.html

η_{VFD} = VFD efficiency, which is typically[8] 97% for a 300 HP VFD. (0.97)
p_1 = Absolute inlet pressure, which is assumed to be atmospheric. $(1\ atm)$
p_2 = Absolute outlet pressure, which is the blower outlet pressure added to the atmospheric pressure. The system typically operates at 9 psi. $(1.61\ atm)$

A sample calculation for average daily power requirement in April of XXX is shown.

$$P = \left[\frac{27{,}969{,}361 \frac{lbs\ air}{month} * \frac{month}{30\ days} * 8.314 \frac{J}{mol * K} * 283\ K}{28.96 \frac{g}{mol\ air} * 1.395 * 0.954 * 0.97} * 5.25 \times 10^{-6} \frac{day}{lbs * s}\right] * \left[\left(\frac{1..61\ atm}{1\ atm}\right)^{1.395} - 1\right]$$

$$P = 292\ kW$$

It is important to note that P represents the total power requirement (from both aeration blowers) to treat influent wastewater each day. As previously outlined, this power requirement has been calculated based on influent wastewater quality and considers losses in efficiency within the system. Daily power requirements were assumed to be the same for each day in the given month. This was necessary due to the temporal availability of water quality data. A daily analysis would yield more precise results, but the method utilized in this analysis is still accurate enough to provide significant results. A summary of daily power requirements (per each month) is shown in Table 5.1-5.

Table 5.1-5: Calculated Power Requirements

Date		Daily Power Requirement (kW)
XXX	April	292
	May	302
	June	374
	July	442
	August	449
	September	372
	October	325
	November	293
	December	261
XXX	January	248
	February	255
	March	278

Mixing Requirements

[8] U.S. Department of Energy – Tip Sheets. "Adjustable Speed Drive Part Load Efficiency". Web: https://www.energy.gov/sites/prod/files/2014/04/f15/motor_tip_sheet11.pdf

Another consideration for the "React" phase of SBR operation is complete mixing. There are a total of 4 SBR cells. Each cell is 110 feet wide by 110 feet long, and wastewater is typically added until a depth of 17 feet is reached. This equates to a tank volume of 205,700 ft^3. The SBR system relies on a combination of mechanical and air mixing. One floating mechanical turbine mixer is located at the center of each SBR and fine bubble diffusers line the perimeter.

During the assessment, the Wastewater Superintendent stated that the mixer motors are 75 horsepower. The motors do not have VFDs and therefore run at full speed during the "react" phase. For principal types of mechanical mixing, typical power requirements range from 0.75 to 1.50 hp per 1,000 ft^3 of wastewater[9]. To be conservative, a value of 1 hp per 1,000 ft^3 of wastewater will be used. Using this design value, it can be calculated that the mechanical turbine mixer effectively mixes 75,000 cubic feet of wastewater in a single SBR.

The standard mixing requirement when fine bubble diffusers are deployed is 20 to 30 SCFM per 1,000 ft^3 of wastewater[10]. To be conservative, a value of 30 SCFM per 1,000 ft^3 will be assumed. As previously stated, the total cell volume is 205,700 ft^3 and the mechanical mixer is assumed to completely mix 75,000 ft^3 of wastewater. Therefore, the remaining 130,700 ft^3 must be mixed via aeration. Using the design value of 30 SCFM per 1,000 ft^3 of wastewater it can be determined that 3,921 SCFM of air is required to completely mix the remaining wastewater. The blower cannot be turned down below this point or mixing requirements will not be met for the SBR cell.

The required power draw (P_1) of one 300 horsepower (223.7 kW) blower to provide mixing air can now be calculated using the fan affinity laws[11]. For this calculation two assumptions were made. The first is that the blower speed (rpm) is linearly proportional to the air flow output (SCFM) and motor frequency (Hz). For example, if the air supply is turned down by 50% then both the blower speed and frequency are also reduced by 50%. The second is that the blower speed matches the motor speed. With these assumptions it is possible to calculate the required power for the mixing supply requirements of 3,921 SCFM.

$$\frac{P_1}{P_2} = \left(\frac{N_1}{N_2}\right)^3$$

Where,

P_1 = Power draw associated with required motor speed. (kW)
P_2 = Power draw associated with current motor speed, which is 223.7. (kW)
N_1 = Motor speed associated with required air flow rate, which is 3,921. (SCFM)
N_2 = Current motor speed, which was started by the Wastewater Superintendent to be 5,145. (SCFM)

[9] Tchobanoglous, G., Burton, F., Stensel, H. D., Tsuchihashi, R., Abu-Orf, M., Bowden, G., and Pfrang, W. (2014). *Wastewater Engineering: Treatment and Resource Recover*. McGraw-Hill, New York, NY.
[10] Great Lakes, 2014
[11] The Engineering Toolbox. "Fan Affinity Laws". Web: https://www.engineeringtoolbox.com/fan-affinity-laws-d_196.html

Rearranging the above equation and substituting known values yields the following.

$$P_1 = 223.7 \frac{kW}{blower} * 2\ blowers * \left(\frac{3{,}921\ SCFM}{5{,}145\ SCFM}\right)^3$$

$$P_1 = 198\ kW$$

Blower Turndown Capacity

Variable frequency drives are effective at saving energy but can also have negative effects on efficiency if the motor is turned down too low. Per the Department of Energy[12] motors 200 hp and greater should not be turned below 50% of the original load (speed), or else significant losses in efficiency will occur. The current blower load is 5,145 SCFM. Therefore, the maximum recommended turn down for the aeration blowers is 50% of 5,145 SCFM, or 2,573 SCFM. Turning blowers below this point may cause unnecessary wear on motors and result in a decreased operating efficiency.

Using the fan affinity laws again, minimum allowable power draw can be calculated. Blowers should never be turned down below this point, even if the oxygen or mixing requirements drop below this number.

$$P_1 = 223.7 \frac{kW}{blower} * 2\ blowers * \left(\frac{2{,}573\ SCFM}{5{,}145\ SCFM}\right)^3$$

$$P_1 = 56\ kW$$

Summary of System Requirements

System requirements which restrict the maximum allowable turn down for aeration blowers have been summarized in Table 5.1-6. The power requirements for each section in this table are significant and represent the minimum acceptable values for each factor we consider. If the input power is set below what is needed to supply oxygen for aerobic digestion, organic matter will not be completely broken down. Similarly, insufficient power for mixing requirements will not supply enough air to mix the liquid and cause settling to occur. Lastly, if the supplied power is too low the motor efficiency will be greatly reduced. All parameters considered, the largest required power for each month out of any section must be selected as the minimum allowable power supply for that time period. These values are highlighted in the final column of Table 5.1.6. It should be noted that in this case power requirements tied to oxygen supply rates are the limiting factor for every month.

[12] U.S. Department of Energy – Tip Sheets. "Adjustable Speed Drive Part Load Efficiency". Web: https://www.energy.gov/sites/prod/files/2014/04/f15/motor_tip_sheet11.pdf

Table 5.1-6: Summary of System Power Requirements

Date		Oxygen Power Requirement (kW)	Mixing Power Requirement (kW)	Blower Turndown Capacity (kW)	Minimum Allowable Power Supply (kW)
XXX	April	292	198	56	292
	May	302	198	56	302
	June	374	198	56	374
	July	442	198	56	442
	August	449	198	56	449
	September	372	198	56	372
	October	325	198	56	325
	November	293	198	56	293
	December	261	198	56	261
XXX	January	248	198	56	248
	February	255	198	56	255
	March	278	198	56	278

Electricity and Cost Savings

To calculate monthly electricity savings, we must first know the current usage and demand of the aeration blowers. The current monthly demand is simply equal to the motor size (223.7 kW) for each blower. The current monthly usage is equal to the motor size multiplied by the operational hours. One week of typical blower operational data was obtained from the SCADA system (July 6th, XXX – July 12th, XXX). This sample will be considered representative for the entire analysis period. Sample screenshots of the SCADA information and calculations for average operational hours can be seen in Appendix 7.1. Table 5.1-7 below contains a summary of blower operation hours, demand, calculated usage, and annual usage and demand costs. Usage cost and demand cost are equal to the annual usage and demand multiplied by the appropriate unit rates, which are $0.039/kWh and $16.93/kW, respectively.

Table 5.1-7: Summary of Current Blower Operation

	Annual Operation Hours (hr)	Annual Electricity Demand (kW)	Annual Electricity Usage (kWh)	Annual Demand Cost ($)	Annual Usage Cost ($)
Blower 1	3,885	2,684	869,033	$45,447	$33,892
Blower 2	4,161	2,684	930,857	$45,447	$36,303
SUM	8,046	5,369	1,799,891	$90,894	$70,196

Combining the sum of annual usage cost and annual demand cost will yield the current total annual cost to run the aeration blowers.

$$Current\ Annual\ Cost = \sum Annual\ Demand\ Cost += \sum Annual\ Usage\ Cost$$

$$Current\ Annual\ Cost = \$90{,}894 + \$70{,}196 = \$161{,}090$$

Now, the new annual cost to run aeration blowers which is correlated to the minimum allowable power that still satisfies oxygen requirements, mixing requirements, and turndown capacity must be calculated. The sum of annual operation hours seen in Table 5.1-7 will remain the same as previously stated, but it should be noted that these hours are now split into monthly increments for the following analysis. The new monthly demand is simply equal to the minimum allowable power for each month shown originally in Table 5.1-6. The new monthly usage is equal to the minimum allowable power multiplied by the operational hours for that month. Similar to before, usage cost and demand cost are equal to the new monthly usage and demand multiplied by the appropriate unit rates, which are $0.039/kWh and $16.93/kW. The new monthly values can be seen in Table 5.1-8.

Table 5.1-8: Summary of New Blower Operation

Date		Monthly Operation Hours (hr)	Monthly Electricity Demand (kW)	Monthly Electricity Usage (kWh)	Monthly Demand Cost ($)	Monthly Usage Cost ($)
XXX	April	661	292	96,467	$4,939	$3,762
	May	683	302	103,232	$5,115	$4,026
	June	661	374	123,657	$6,332	$4,823
	July	683	442	151,166	$7,490	$5,895
	August	683	449	153,497	$7,606	$5,986
	September	661	372	122,903	$6,293	$4,793
	October	683	325	111,079	$5,504	$4,332
	November	661	293	96,972	$4,965	$3,782
	December	683	261	89,233	$4,422	$3,480
XXX	January	683	248	84,610	$4,193	$3,300
	February	617	255	78,758	$4,321	$3,072
	March	683	278	94,865	$4,701	$3,700
SUM		8,046	3,891	1,306,439	$65,881	$50,951

Combining the sum of monthly usage and sum of monthly demand costs will yield the new total annual cost to run the aeration blowers.

$$New\ Annual\ Cost = \sum Monthly\ Usage\ Cost + \sum Monthly\ Demand\ Cost$$

$$New\ Annual\ Cost = \$65{,}881 + \$50{,}951 = \$116{,}832$$

Now, annual electricity cost savings can be calculated by finding the difference between current annual cost to run aeration blowers and the new annual cost.

$$Annual\ Savings = Current\ Annual\ Cost - New\ Annual\ Cost$$

$$Annual\ Savings = \$161{,}090 - \$116{,}832 = \$44{,}258$$

Implementation Cost and Simple Payback

As previously mentioned, each blower is already equipped with a variable frequency drive. Therefore. the purchase and installation of drives does not need to be included in the implementation cost. The only cost associated with this recommendation will stem from contracting a third party to write the proper coding and install the program on the current SCADA system. From discussions with the Wastewater Superintendent, it was determined that this will cost approximately $7,000 in total.

A simple payback period can now be calculated using the following equation.

$$Payback\ Period = \frac{Implementation\ Cost}{Annual\ Cost\ Savings}$$

$$Payback\ Period = \frac{\$7{,}000}{\$44{,}258} = 0.2\ years$$

5.2 AR No. 2: Relocate Dissolved Oxygen Probes in SBR Basins

Recommended Action

It is recommended that the facility relocate Dissolved Oxygen (DO) probes out of dead zones. Moving DO probes to more ideal locations will result in more accurate DO concentration readings and hence a reduction electricity usage. A summary of recommendation Impacts are shown in Table 5.2-1.

Table 5.2-1: Summary of Relocating Dissolved Oxygen Probes in SBR Basins

Annual Cost Savings	Annual Electricity Savings	Implementation Costs	Simple Payback
$20,357/year	521,968 kWh/year	$960	< 0.1 years

Background

Currently, the four SBR cells are each equipped with one dissolved oxygen probe. The DO probes are utilized by the SCADA system to monitor and control the biological treatment process in each cell separately. Probes are all located in the corners of SBR cells, as illustrated in Figure 5.2-1. This location is not ideal for accurately measuring a representative DO concentration for the entire basin. Corners of basins are often subject to dead zones and sedimentation[13].

During the assessment, the dissolved oxygen concentration in one basin was measured during the "react" phase with a handheld DO meter. The first measurement was taken directly next to the existing facility DO meter. The second measurement was taken closer to the center of the southern basin wall. Next to the permanent DO probe, the handheld meter measured a concentration of 1.5 mg/L of DO. At the same moment, it was noted that the permanent DO probe measured a concentration of 1.0 ppm (mg/L). At the center of the southern basin wall (about fifty feet away) there was clearly more agitation from aeration. Here, the handheld meter measured a concentration of 4.1 mg/L of DO. Figure 5.2-1 below visually identifies handheld DO measurement locations and the associated values.

[13] Tchobanoglous, G., Burton, F., Stensel, H. D., Tsuchihashi, R., Abu-Orf, M., Bowden, G., and Pfrang, W. (2014). *Wastewater Engineering: Treatment and Resource Recover*. McGraw-Hill, New York, NY.

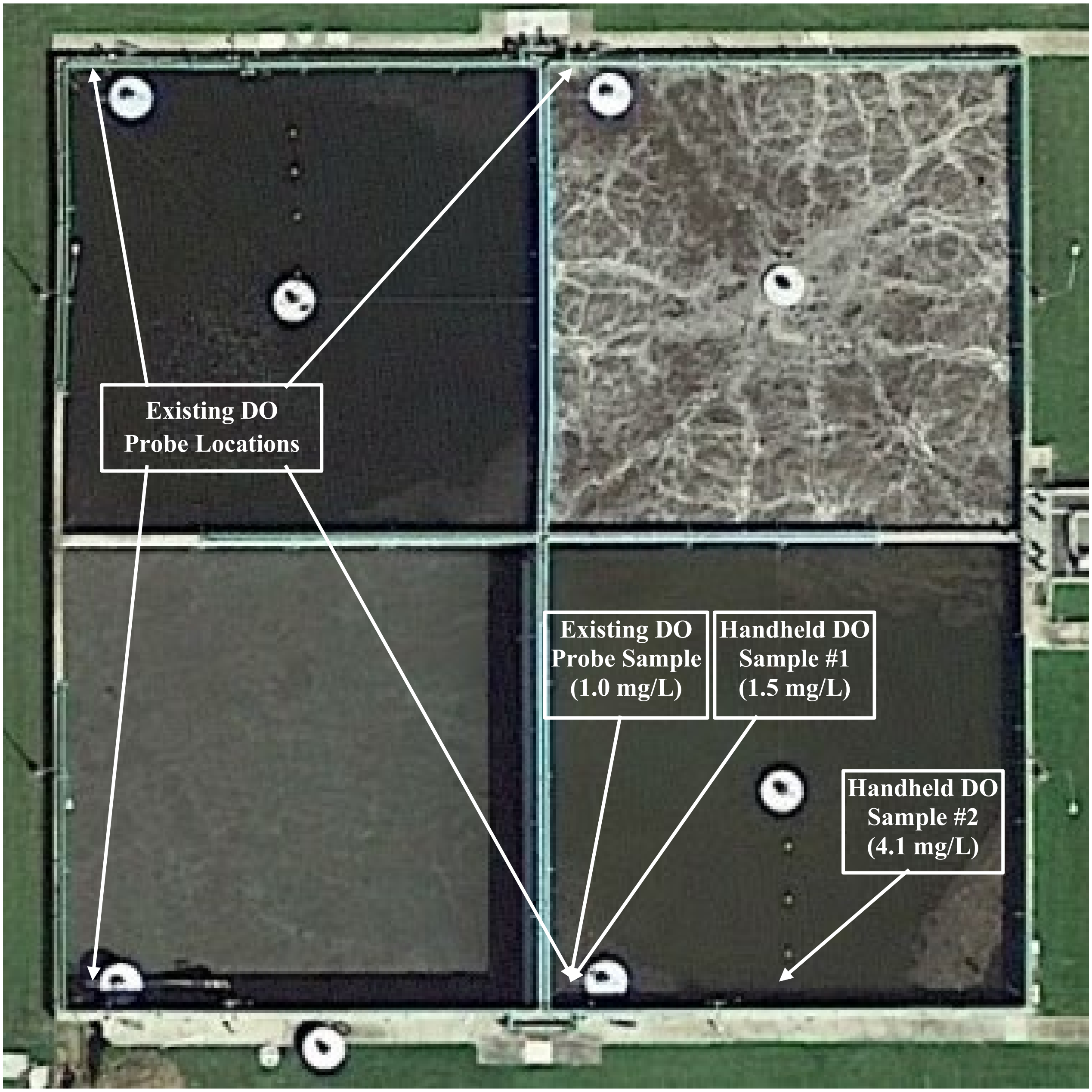


Figure 5.2-1: Existing DO Probe Locations

These measurements clearly indicate that the DO meter is not placed in an ideal location to accurately measure DO concentrations. Each basin augments aerobic mixing with one large impeller type mixer. The mixer is located at the center of each SBR basin; therefore, it is likely that the overall mixing pattern for the basin is in a large circle. This circle will largely exclude basin corners and result in dead zones or at least reduced DO concentrations in basin corners. With DO probes placed in their current location, it is likely that dissolved oxygen concentrations being measured are much lower than the actual average concentration in the basin. This can result in significantly higher aeration than is necessary to properly treat wastewater. Based on this realization, it is recommended that the facility relocate DO probes away from any basin corners. Approximate recommended positions to relocate the probes are shown in Figure 5.2-2 below.

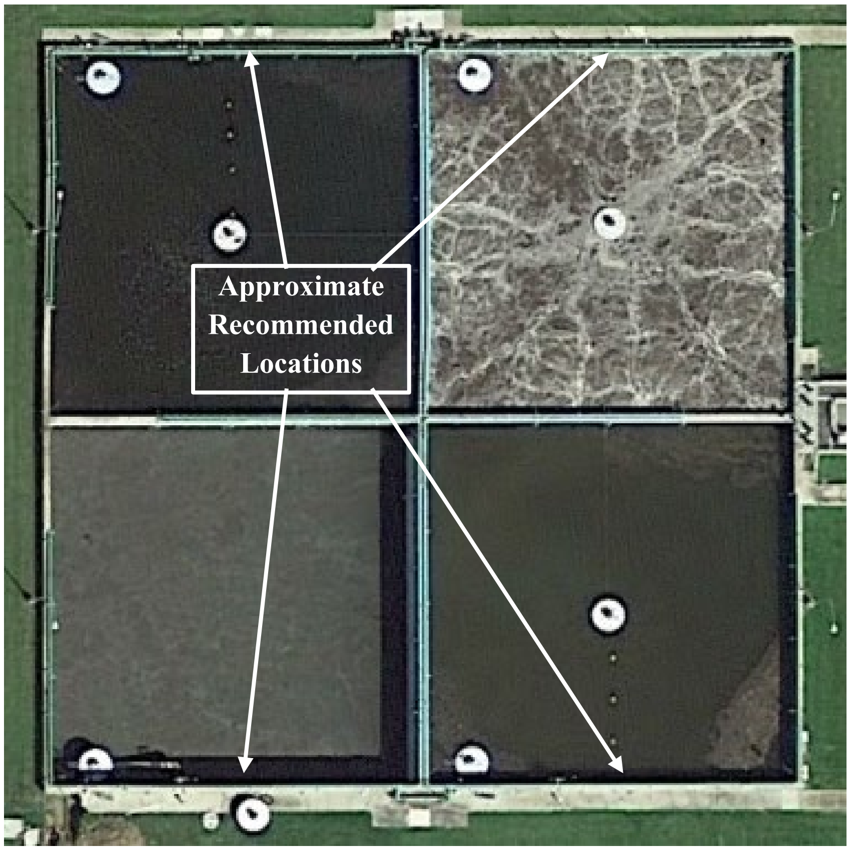


Figure 5.2-2: Proposed DO Probe Locations

Anticipated Savings

Savings would be realized through a reduction in aeration and hence electricity usage. Exact savings for this recommendation are difficult to quantify but a rough estimate can be accomplished. The assumption will be made that moving the DO probe will result in a 2 mg/L drop in the target DO (from 4.1 mg/L to 2.1 mg/L). This is a justifiable assumption considering the current target DO was observed to be 1.0 mg/L at the existing DO meter for sufficient oxygen for the microbial activity to occur; having a higher DO will not improve the microbial activity. Rough oxygen reduction calculations can be accomplished using the following equation.

$$\frac{dC}{dt} = (C_s - C)K_L a$$

Where,

$\frac{dC}{dt}$ = Gas dissolution rate

C_s = Saturation concentration of oxygen in water (mg/L)
C = Observed concentration of oxygen in wastewater (mg/L)
K_L = Mass transfer coefficient
a = Interface Area

The mass transfer coefficient (K_L) and interface area (a) will remain constant since the same equipment will be utilized. Additionally, the saturation concentration (C_s) of oxygen in water will remain constant and is assumed to be the generalized value of 9 mg/L. the term $(C_s - C)$ represents the "driving force" for the aeration process. Knowing this, both current and recommended aeration operation levels can be calculated using the above equation. The K_La value comes from the aeration diffusers, which are the same for both cases.

$$Current\ Aeration = \left(9\frac{mg}{L} - 4.1\frac{mg}{L}\right) K_L a$$

$$Current\ Aeraton = 4.9 K_L a$$

$$Recommended\ Aeration = \left(9\frac{mg}{L} - 2.1\frac{mg}{L}\right) K_L a$$

$$Recommended\ Aeration = 6.9 K_L a$$

Now, a ratio between the two can be determined. This ratio is assumed to be roughly representative of the increase in efficiency of the aeration if the target dissolved oxygen level is lower, due to having a larger "driving force" since relocating DO probes will mean that a lower DO will be measured and maintained.

$$Aeration\ Ratio = \frac{Current\ Aeration}{Recommended\ Aeration}$$

$$Aeration\ Ratio = \frac{4.9 K_L a}{6.9 K_L a}$$

$$Aeration\ Ratio = 0.71 = 71\%$$

The calculation suggests that relocating the DO probes will result in the SBR requiring less aeration (71% of the current) based on more efficient gas transfer. This ratio can first be used to determine expected annual electricity savings. The current annual electricity usage for blowers (1,799,891 kWh) was previously determined in AR No. 1. Annual usage saving can be calculated using the below equation.

$$Annual\ Electric\ Savings = (1 - Aeration\ Ratio) * Annual\ Blower\ Usage$$

$$Annual\ Electric\ Savings = (1 - 0.71) * 1{,}799{,}891\ kWh$$

$$Annual\ Electric\ Savings = 521{,}968\ kWh$$

Additionally, the economic implications of this recommendation can be determined. The annual usage cost associated with operating blowers ($70,196) determined in AR No. 1 will be utilized. Demand savings will not be considered because it is unlikely that reducing blower usage would reduce peak demand on blowers during the react phase of an SBR. Annual saving can be calculated using the following equation.

$$Annual\ Cost\ Savings = (1 - Aeration\ Ratio) * Annual\ Blower\ Cost$$

$$Annual\ Cost\ Savings = (1 - 0.71) * \$70{,}196$$

$$Annual\ Cost\ Savings = \$20{,}357$$

It should be noted that the anticipated savings calculated above are rough and may be an overestimate due to various inefficiencies within the system, and potential other changes that may occur for the aeration system operation. That being said, the savings will certainly be significant enough to heavily consider this recommendation and are expected to be in the 5-digit range. Furthermore, the above calculations are based on current operations. This is noteworthy when considering the possible implementation of AR No. 1. If blowers are re-programmed, it is possible that potential saving realized through relocating DO probes may be reduced. Even in this scenario, savings are still expected to be significant if DO probes are relocated.

Implementation Cost and Simple Payback

The implementation cost for this recommendation would include the labor to relocate DO probe equipment. It is assumed that the existing brackets could be removed from the basin and reused in the new DO probe location. Therefore, only the labor of maintenance staff would contribute to the implementation cost. It is estimated that two maintenance staff members could relocate one DO probe in about 4 hours. With 4 probes to move, the total time to relocate all probe should not exceed 16 hours. Using a burdened hourly wage of $30/hour, the implementation cost can be calculated with the following equation.

$$Implementation\ Cost = N * W * T$$

Where,

N = Number of Employees
W = Burdened Hourly Wage ($30/hour - staff member)
T = Time Required to Complete Task (hour)

$$Implementation\ Cost = 2\ staff\ members * \frac{\$30}{hour - staff\ member} * 16\ hours$$

$$Implementation\ Cost = \$960$$

Knowing the anticipated savings and implementation cost, a simple payback period can now be calculated using the following equation.

$$Payback\ Period = \frac{Implementation\ Cost}{Annual\ Cost\ Savings}$$

$$Payback\ Period = \frac{\$960}{\$20,357}$$

$$Payback\ Period < 0.1\ years$$

5.3 AR No. 3: Reuse Effluent Water in Belt Press

Recommended Action

It is recommended for the facility reuse effluent water to power the belt press. This will eliminate the use of the existing air compressor and reduce use of city water. This will be done by installing a pipeline from where the effluent water comes out to the solids handling building. Table 5.3-1 gives a short summary of resources saved, cost savings and payback period if the recommendation were to be implemented.

Table 5.3-1: Summary of Reusing Effluent Water

Resources Saved	Total Cost Saving	Implementation Cost	Simple Payback
15,705 kWh/year	$17,011/year	$25,884	1.5 years
9,369,805 gallons/year			

Background

Currently the facility uses one 10 horsepower (HP) air compressor and city water in making the belt press filter. According to the facility this air compressor runs fully loaded (100% loading factor) during the operational hours of the belt press which is 2,000 hours a year. It is assumed that the compressor is operating at 95% efficiency. Staff said that 85% of the annual city water usage is directed to the operation of the belt press. Currently, the facility uses 1,473,600 ft^3 which is about 11,023,300 gallons of city water a year.

To be able to use the effluent water there needs to be piping laid from where the effluent water comes out and where the solids handling building is at. The plant's vortex system provides sufficient pumping pressure, so no additional pump system is required. Using a measuring wheel and going from the wet aeration control building to the solids handling building, it was measured that the distance is about 600 feet. To implement this recommendation costs of digging the trench and materials will be considered.

Anticipated Savings

To find the anticipated energy and cost savings for implementing this recommendation, the cost of the entire compressed air system must first be calculated. The cost of running a compressor can be calculated using the following equations[14].

[14] https://energy.gov/sites/prod/files/2014/05/f16/compressed_air1.pdf

$$Energy_{Usage} = \frac{\left(HP * ML * 0.746 \frac{kW}{hp}\right)}{\eta} * T * L$$

$$Cost_{Usage} = Energy_{Usage} * UR$$

$$Demand = \left(HP * ML * 0.746 \frac{kW}{hp}\right) * M/\eta$$

$$Cost_{Demand} = Demand * DR$$

where,

HP = Total Compressor Motor HP
ML = Motor Load
η = Compressor Efficiency
T = Time in Operation
UR = Usage Rate
L = Loading Factor
DR = Demand Rate
M = Months in Operation

The cost for the current compressor system can be calculated by adding the usage cost for the compressor operating at full 100% load factor and the demand cost for the compressor. The peak demand is believed to occur during the daytime when most equipment, including the sludge press, is operating. A summary about the air compressor is provided in the background and cost of energy usage and demand cost are $0.039/kWh and $16.93/kW respectively.

$$Energy_{Loaded} = \frac{\left(10\ HP * 1 * 0.746 \frac{kW}{HP} * 2{,}000 \frac{hours}{year} * 1\right)}{0.95}$$

$$Energy_{Loaded} = 15{,}705.26 \frac{kWh}{year}$$

$$Cost_{Loaded} = Energy_{Loaded} * \frac{\$0.039}{kWh}$$

$$Cost_{Loaded} = \frac{\$612}{year}$$

$$Demand = \frac{\left(10\ HP * 1 * 0.746 \frac{kW}{HP} * 12\ month\right)}{0.95}$$

$$Demand = 94.23 \frac{kW - months}{year}$$

$$Cost_{Demand} = Demand * \frac{\$16.93}{kW - month}$$

$$Cost_{Demand} = \frac{\$1{,}595}{year}$$

The total cost of the compressor use can be found by summing up all costs associated with the use of the compressor:

$$Cost_{Total} = Cost_{Loaded} + Cost_{Demand}$$

Where,

$Cost_{Total}$ – Total Cost of Running the Air Compressor
$Cost_{Loaded}$ – Cost of Running the Air Compressor Loaded
$Cost_{Demand}$ – Cost of Demand charge for using the Air Compressor

$$Cost_{Total} = \frac{\$612}{year} + \frac{\$1{,}595}{year}$$

$$Cost_{Total} = \frac{\$2{,}207}{year}$$

The cost savings associated with using the city water are straightforward. 85% of the water used annually will be saved. Water Usage Rate is $1.58/1000 gallons.

$$WR = WU * P$$

$$WRC = WUR * WR$$

Where,

WUR = Water Usage Rate
WU = Annual Water Usage
P = Percentage saved
WR = Amount of Water Used Reduced
WRC = Annual Water Usage Reduction Cost Saving

$$WR = 11{,}023{,}300 \frac{gallons}{year} * 85\%$$

$$WR = 9{,}369{,}805 \frac{gallons}{year}$$

$$WRC = 9{,}369{,}805 \frac{gallons}{year} * \frac{\$1.58}{1{,}000\ gallons}$$

$$WRC = \frac{\$14{,}804}{year}$$

Implementation Cost and Simple Payback

Implementation of the recommendation will have 3 main costs: digging the trench and materials (labor costs are included for the two). According to the national cost range to dig a trench can cost from $268 to $732 for 50 linear feet[15]. To be conservative, $732 per 50 linear feet will be used. For materials according to RSMeans [16]2-inch PVC piping installation costs $28.50 per foot[17]. Total for each cost of implementation can be seen below:

$$TC = \frac{D_T}{D_S} * TR$$

$$MC = D_T * PR$$

$$Implementation\ Cost = TC + MC$$

Where,

TC = Trench Digging Cost
D_T = Total Distance
D_C = Section Distance
TR = Trench Digging Rate per Section
MC = Material Cost
PR = Piping Rate

$$TC = 600\ feet * \frac{\$732}{50\ feet}$$

$$TC = \$8{,}784$$

$$MC = 600\ feet * \frac{\$28.50}{foot}$$

$$MC = \$17{,}100$$

$$Implementation\ Cost = \$8{,}784 + \$17{,}100$$

$$Implementation\ Cost = \$25{,}884$$

Using the known implementation cost and annual cost savings, a simple payback period can be calculated.

$$Payback\ Period = \frac{Implementation\ Cost}{Annual\ Cost\ Savings}$$

[15] https://porch.com/project-cost/cost-to-dig-a-trench

[16] https://www.rsmeansonline.com/SearchData

[17]

$$Payback\ Period = \frac{\$25{,}884}{\frac{\$2{,}207}{year} + \frac{\$14{,}804}{year}}$$

$$Payback\ Period = 1.5\ years$$

5.4 AR No. 4: Install a VFD on the Sludge Holding Tank

Recommended Action

It is recommended that the facility installs a variable frequency drive on each blower in the holding tank/pump building. This will allow for the blower to decrease its workload while saving money and energy. A summary of this recommendation is shown in Table 5.4-1.

Table 5.4.1: Install Variable Frequency Drive Summary

Energy Savings	Demand Savings	Cost Savings	Implementation Cost	Simple Payback
85,848 kWh/year	117.6 kW-month/year	$5,339/year	$4,500	0.8 years

Background

The facility aerates wastewater to provide necessary oxygen for bacteria and other microbes which naturally treat the water. A proper dissolved oxygen level is the key to rapid and effective wastewater treatment as the oxygen-dependent bacteria promotes microbial growth that forms sludge. The facility currently has a sludge holding tank that gets filled with water of varying heights. The initial height is measured once the water level is one foot above the diffuser and starts to drain once it reaches 14 feet. It takes two days to fill one tank to 14 feet and the tank then drains for the next two days, and the cycle repeats itself. Variable Frequency Drives (VFDs) are often implemented into electric motors to reduce the load on the system in order to promote cost savings. Figure 5.4-1 shows the general sludge flow throughout the plant.

Biosolids are products resulting from the treatment of all commercial, domestic, and industrial wastewater from the City of Norfolk's Water Pollution Control Plant. The treatment process includes screening, grit removal, and aeration in the pre-treatment section and gravity sedimentation in the primary clarifiers. The secondary plant is an activated bio-filter process. The resulting biosolids are pumped to a gravity thickener and then an aerated holding tank. The sludge is dewatered by belt filter presses and then adjusted to a pH of 12.0 by adding lime or kiln dust. It is then held at a pH of 12.0 for 2 hours and 11.5 for an additional 22 hours to satisfy the requirements of federal law 40 CFR 503 pertaining to Class B sludge[18].

[1817] https://www.epa.gov/biosolids/biosolids-laws-and-regulations

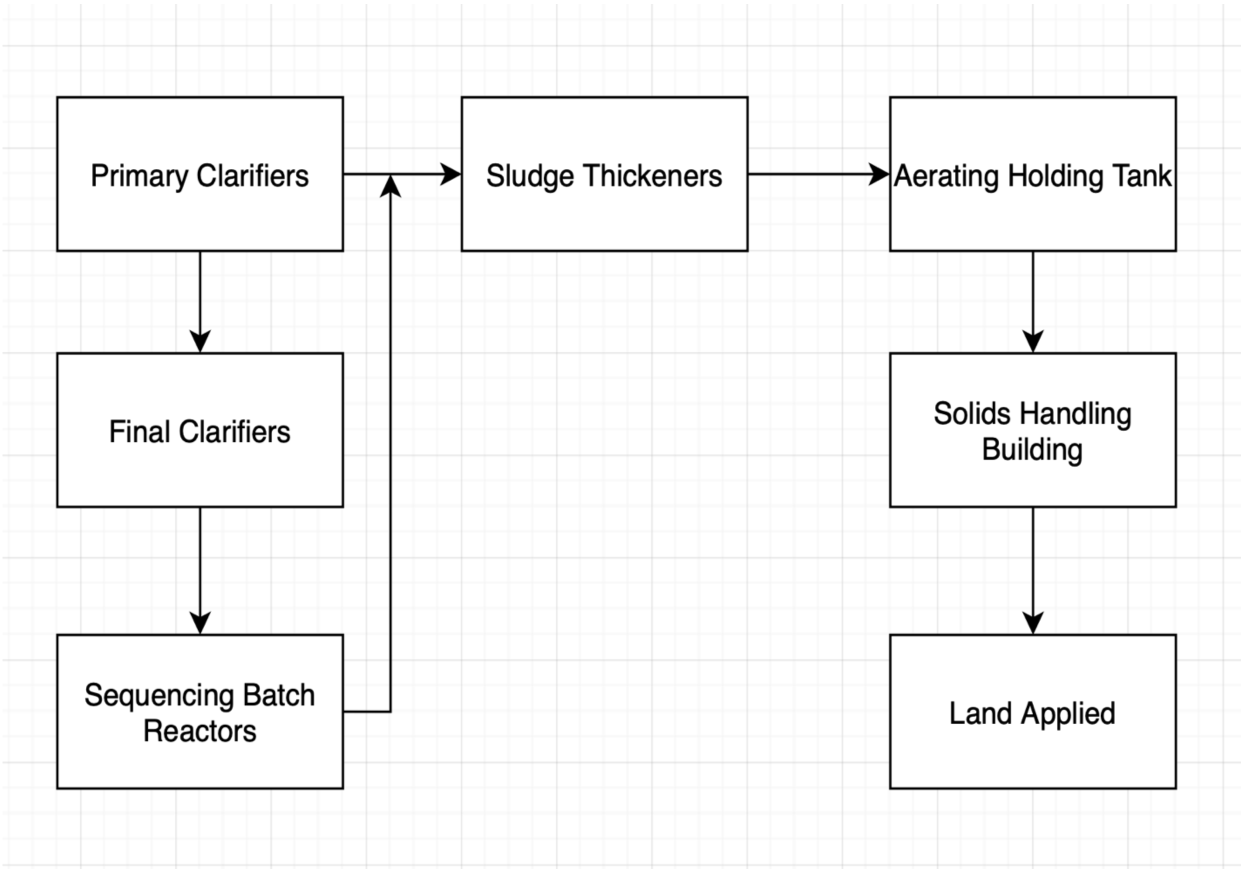


Figure 5.4-1: Sludge Flow Diagram

Anticipated Savings

There are two 30 HP blowers that alternate in operation in the holding tank/pump building. The energy requirement of each blower associated with providing this standard air supply at a specific inlet air temperature, overall blower efficiency, inlet and discharge pressure can be expressed by the following equation. The inlet pressure measurement is just less than standard ambient air pressure due to cool air and the discharge pressure is read from a gauge shown in Appendix 7.2.

$$P_W = \frac{W * R * T_1}{155.7 * e} * [\left(\frac{p2}{p1}\right)^{0.283} - 1]$$

Where,

P_W = operating power of the blower (kW)
W= mass flowrate of air being discharged by the blower (lbs/s)
T_1 = inlet air temperature of the blower (°R)
e = efficiency of the overall blower system (93.6%) in decimal form
R = universal gas constant (53.3 ft-lb/ lb air * °R)
p_2 = absolute outlet pressure (atm)
p_1 = absolute inlet pressure (atm)

$$P_W = \frac{\left(0.7457\frac{kW}{HP}\right) * (1.34\frac{lbs}{s} * 53.3\ \frac{ft-lb}{lb\ air} * (544°R))}{155.7 * 0.936} * [\left(\frac{21.0}{14.5}\right)^{0.283} - 1]$$

$$P_W = 22\ kW$$

The total electricity consumption of the blowers, assuming 100% load, can also be calculated using the operating hours, number of blowers, and power of each blower. The total annual cost can then be calculated using the unit cost of electricity previously calculated.

$$EC = N * T * W$$

$$C = EC * R$$

Where,

EC = Energy Consumption (kWh/year)
N = Number of Blowers in Operation at any given time
T = Time in Operation (hours/year)
W = Number of Kilowatts per Blower (kW)
C = Annual Cost to Run Blowers ($/year)
R = Electricity Rate ($/kWh)

$$EC = 1\ Blower * 8{,}760\frac{hours}{year} * 22\frac{kW}{Blower}$$

$$EC = 192{,}720\frac{kWh}{year}$$

$$C = 192{,}720\frac{kWh}{year} * \frac{\$0.039}{kWh}$$

$$C = \frac{\$7{,}516}{year}$$

An assumption will be made that by implementing a VFD, the average load will be reduced from 100% to 80%. This is because the load will be reduced while the tank volume is low and will increase to maximum power once more water is filled in the tank. The load may vary from 60% while low to 100% while full, thus averaging to 80%, assuming a constant flow rate. Information was provided by the client stating that the water depth would be at a minimum for 40% of the time, the tank would be half-full 40% of the time, and the tank would be full 20% of the time based on one full cycle. Using the pump affinity laws from the US Department of Energy[19], a linear load decrease will result in an exponential amount of demand savings as shown below.

$$kW\ (80\%) = 0.746\frac{kW}{HP} * (H * \frac{(L)^3}{e})$$

[19] https://www.energy.gov/sites/prod/files/2014/04/f15/motor_tip_sheet11.pdf

$$kW\ saved = kW\ old - kW\ new$$

$$CS = kW\ saved * DR$$

Where,

kW (80%) = The Average Percentage of Maximum Power used by the Blower
H = Horsepower of Blower
L = Average Percentage of Load
E = Efficiency of Blower
kW saved = Annual kW saved from Implementing the VFD
kW old = kW Used by Blower Before Implementing the VFD
kW new = kW Used by Blower After Implementing the VFD
CS = Annual Cost Savings After VFD Implementation
DR = Unit Electricity Demand Rate

$$kW\ (80\%) = 0.746\frac{kW}{HP} * \left(30\ HP * \frac{(0.8)^3}{0.936}\right)$$

$$KW\ (80\%) = 12.2\ kW$$

$$kW\ saved = 22\ kW - 12.2\ kW$$

$$kW\ saved = 9.8\ kW = 44.5\%$$

$$CS = 9.8\ \frac{kW}{month} * 12\frac{months}{year} * \frac{\$16.93}{kW}$$

$$CS = \frac{\$1{,}991}{year}$$

The annual cost to run the blowers once the VFD is implemented will decrease as shown in these calculations.

$$EC = N * T * W$$

Where,

EC = Energy Consumption (kWh/year)
N = Number of Blowers in Operation at any given time
T = Time in Operation (hours/year)
W = Number of Kilowatts per Blower (kW)
C_{new} = Annual Cost to Run Blowers

$$EC = 1\ Blower * 8{,}760\frac{hours}{year} * 12.2\frac{kW}{Blower}$$

$$EC = 106{,}872\ \frac{kWh}{year}$$

$$C_{new} = 106{,}872 \frac{kWh}{year} * \frac{\$0.039}{kWh}$$

$$C_{new} = \frac{\$4{,}168}{year}$$

The total annual savings from decreased electricity usage is calculated from the difference between the annual cost to run the blowers before and after the VFD is installed.

$$TCS = (C - C_{new}) + CS$$

Where,

TCS = Total Annual Cost Savings ($/year)
C = Annual Cost to Run Blowers Before VFD Implementation ($/year)
C_{new}= Annual Cost to Run Blowers After VFD Implementation ($/year)
CS = Annual Demand Savings ($/year)

$$TCS = (\$7{,}516 - \$4{,}168) + \$1{,}991$$

$$TCS = \$5{,}339$$

Table 5.4-2 shows a breakdown of all the cost savings calculated in this section.

Table 5.4-2: Summary of Anticipated Savings

	Energy Usage (kWh/year)	**Usage Cost ($/year)**	**Demand (kW/year)**	**Demand Cost ($/year)**	**Total Annual Cost ($/year)**
Current System	192,720	$7,516	22.0	$4,470	$11,986
VFD System	106,872	$4,168	12.2	$2,479	$6,647
Savings	85,848	$3,348	9.8	$1,991	$5,339

Implementation Cost

The price of variable frequency drives can fluctuate from $200-$500/HP. However, with many companies starting to implement the devices, prices have decreased to a more user-friendly range. A 30 HP VFD will cost around $3,000 for the unit, not including labor and installation costs[20,21]. See Appendix 7.3 for an example VFD product. Preventative maintenance can also be performed biannually to reduce wear. The local energy provider offers an incentive for implementing a VFD. For the state of Nebraska, companies can get $30/HP for each blower.

$$Rebate = Number\ of\ Blowers * Blower_{HP} * \frac{\$30}{HP}$$

[20] https://www.zoro.com/schneider-electric-variable-frequency-drive-30-hp-400-480v-altivar-212-ac-drive-atv212hd22n4/i/G1420571/
[21] https://www.grainger.com/product/FUJI-ELECTRIC-Variable-Frequency-Drive-460V-4UAJ8

$$Rebate = 2 * 30\ HP * \frac{\$30}{HP}$$

$$Rebate = \$1{,}800$$

Refer to Appendix 7.4 for a closer look into the VFD Rebates. Table 5.4-3 shows a summary of the implementation costs.

Table 5.4-3: Summary of Implementation Costs

	Number of Units/ Workers	Unit Cost/Rate ($/Unit)	Time (hours)	Cost ($)
VFD	2	$3,000	-	$6,000
Labor	2	$30/hour	4	$240
Maintenance	1	$30/hour	2	$60
Rebates	-	-$30/HP	-	-$1800
Total Cost ($)	**-**	**--**	**-**	**$4,500**

Payback Period

A simple payback period for this recommendation can be calculated by dividing the implementation cost by the annual cost savings.

$$Payback\ Period = \frac{Implementation\ Cost}{Annual\ Savings}$$

$$Payback\ Period = \frac{\$4{,}500}{\$5{,}339}$$

$$Payback\ Period = 0.8\ years$$

5.5 AR No. 5: Upgrade Main Facility Lighting

Recommended Action

It is recommended that the facility replace their current fluorescent lighting with energy efficient, high-output LED bulbs. There are currently 368 fluorescent that remain within the main operating areas of the facility. By replacing these bulbs with light emitting diode (LED) equivalents, the facility can expect to see the savings shown Table 5.5-1. These bulbs will meet or exceed the current lighting quality and will reduce maintenance costs due to longer fixture life.

Table 5.5-1: Upgrade Main Facility Lighting Summary

Energy Savings	Demand Savings	Cost Savings	Implementation Cost	Simple Payback
10,208 kWh/year	71.5 kW-month/year	$1,608/year	$5,394	3.4 years

Background

Light Emitting Diode (LED) lighting solutions have been available since the year 2000 but have only recently become widespread in most applications. This is largely due to the improvement of the technology as well as their drop-in price. Since 2008, LED lighting costs have dropped more than 85%. Many facilities that did not install LEDs due to prohibitive costs as little as 2-3 years ago may be surprised at how competitive LEDs have become compared to more standard fluorescent technology.

LEDs have the benefit of being both an energy efficient technology as well as having superior lighting quality compared to fluorescent or HID technologies. Typical lamp life of LEDs is also considerably longer than other lighting technologies.

Many modern LED lighting solutions are simple to choose and install, often requiring no retrofit. These drop-in solutions are often more inexpensive than getting a new retrofit fixture, however they often do not meet the needs of a company. For best results, it is always suggested that a professional lighting audit be performed to assist you in choosing the best lighting solution for your facility. In this report we use pricing based on competing products found through a web search.[22,23,24] These may not be the best match for your facility, but they are accurate enough to give you a budgetary estimate of replacement cost and energy savings you can expect with a lighting conversion.

[22] https://www.grainger.com/product/PHILIPS-U-Bend-LED-Bulb-T8-53YZ41
[23] https://www.grainger.com/product/PHILIPS-Linear-LED-Bulb-T5-449U96
[24] https://www.homedepot.com/p/Philips-32W-T8-40W-T12-Equivalent-4-ft-Linear-Universal-Fit-Cool-White-LED-Tube-Light-Bulb-4000K-30-Pack-539155/309791571

The facility uses a total of 368 fluorescent bulbs throughout the buildings and grounds. Some of these areas operate at different production hours and use different kinds of lighting. A table of this information can be seen in the next section in Table 5.5-2.

Anticipated Savings

To find the anticipated savings for replacing the current lighting with LED lighting, the current cost of lighting must first be calculated. The energy, demand, and resulting cost of lighting can be calculated using the following equations:

$$E_{Lighting} = \sum N * B * W_{Bulb} * T$$

$$D_{Lighting} = \sum N * B * W_{Bulb}$$

$$C_{Lighting} = (E_{Lighting} * UC) + (D_{Lighting} * DC * M)$$

Where,

$E_{Lighting}$ = Annual Energy Usage (kWh/year)
$D_{Lighting}$ = Electrical Demand (kW)
N = Number of Fixtures
B = Bulbs per Fixture
W_{Bulb} = Wattage of Fixture (kW)
T = Time in Operation (hours/year)
UC = Usage Rate ($/kWh)
DC = Monthly Demand Rate ($/kW-month)
M = Months in Operation (months/year)
$C_{Lighting}$ = Annual Lighting Cost ($/year)

Substituting values for current fluorescent lighting will yield the following results for the T8 bulbs in the solids handling building. The same calculations were performed for all the lights in the plant and the results are summarized in Table 5.5-2.

$$E_{Lighting} = 9\ fixtures * \frac{5\ bulbs}{fixture} * \frac{0.032\ kW}{bulb} * 2{,}000 \frac{hours}{year}$$

$$E_{Lighting} = 2{,}880 \frac{kWh}{year}$$

$$D_{Lighting} = 9\ fixtures * \frac{5\ bulbs}{fixture} * \frac{0.032\ kW}{bulb} * 12\ months$$

$$D_{Lighting} = 17.28 \frac{kW - month}{year}$$

$$C_{Lighting} = \left(2{,}880 \frac{kWh}{year} * \frac{\$0.039}{kWh}\right) + \left(17.28 \frac{kW - month}{year} * \frac{\$16.93}{kW - month}\right)$$

$$C_{Lighting} = \frac{\$404.87}{year}$$

Table 5.5-2: Summary of Current Lighting

Lighting Area	Lighting Bulb Type	Number of Fixtures	Bulbs per Fixture	Annual Hours in Operation	Energy Usage (kWh/year)	Demand (kW/year)	Annual Cost ($/year)
Solids Handling Building	32WT8	9	5	2,000	2,880	17.28	$404.87
Blower Building	32WT8	9	4	500	876	21.02	$390.10
	25WT5	4	6				
Holding Tank/Pump Building	32WT8	5	3	150	72	5.76	$100.33
Service Garage	25WT5	7	4	2,000	1,400	8.40	$196.82
Main Building Conference Room	32WT8	12	4	2,000	3,072	18.43	$431.87
Main Building Hallway	40W U-Tube	12	2	2,000	1,920	11.52	$269.92
	32WT8	38	4	2,000	9,728	58.37	$1,367.57
				Total	**19,948 kWh**	**140.78 kW-month**	**$3,161.44**

Next, the cost of the proposed lighting must be calculated. The same equations can be applied in the same way to find the annual cost of the replacement LED lighting. Each fluorescent bulb will be replaced by one LED tube, (1:1 replacement). The proposed lighting for the solids handling building can be calculated as follows, and the same equations can be applied to all the plant's lights.

$$E_{Lighting} = 9\ fixtures * \frac{5\ bulbs}{fixture} * \frac{0.016\ kW}{bulb} * 2{,}000\frac{hours}{year}$$

$$E_{Lighting} = 1{,}440\frac{kWh}{year}$$

$$D_{Lighting} = 9\ fixtures * \frac{5\ bulbs}{fixture} * \frac{0.016\ kW}{bulb} * 12\ months$$

$$D_{Lighting} = 8.64 \frac{kW - month}{year}$$

$$C_{Lighting} = \left(1440 \frac{kWh}{year} * \frac{\$0.039}{kWh}\right) + \left(8.64 \frac{kW - month}{year} * \frac{\$16.93}{kW - month}\right)$$

$$C_{Lighting} = \frac{\$202.44}{year}$$

A table of the results for each area of your facility as well as totals for energy and cost of the proposed lighting is included in Table 5.5-3.

Table 5.5-3: Summary of Proposed Lighting

Lighting Area	Lighting Bulb Type	Number of Fixtures	Bulbs per Fixture	Annual Hours in Operation	Energy Usage (kWh/year)	Demand (kW/year)	Annual Cost ($/year)
Solids Handling Building	16 W LED	9	5	2,000	1,440	8.64	$202.44
Blower Building	16 W LED	9	4	500	288	6.91	$128.26
	14 W LED	4	6	500	168	4.03	$74.82
Holding Tank/Pump Building:	16 W LED	5	3	150	36	2.88	$50.17
Service Garage	14 W LED	7	4	2,000	784	4.70	$110.22
Main Building Conference Room	16 W LED	12	4	2,000	1,536	9.22	$215.94
Main Building Hallway	13 W LED	12	2	2,000	624	3.74	$87.73
	16 W LED	38	4	2,000	4,864	29.18	$683.79
			Total		**9,740 kWh**	**69.31 kW**	**$1,553.37**

The anticipated savings for implementing the suggested lighting solution is the difference between the current and proposed lighting values. A comparison of the two lighting configurations is shown in Table 5.5-4.

Table 5.5-4: Comparison of Current Lighting and Proposed LED Lighting

	Energy Usage (kWh/year)	**Demand (kW/year)**	**Annual Cost ($/year)**
Current Lighting	19,948	140.784	$3,161.48
LED Lighting	9,740	69.312	$1,553.37
Savings	10,208	71.472	$1,608.11

Implementation Cost

The implementation cost for replacement of the current lighting with LED lighting considers both the cost of the LED bulbs and the labor required to install the LED lighting. Table 5.5-5 shows a breakdown of the cost per LED bulb replacement. See Appendix 7.5 for greater detail on lighting options. It is assumed that the 6 bulbs could be replaced per hour. The labor rate at the facility is $30/hour. A tabulation of implementation cost for all different lights is shown in Table 5.5-5. The electricity provider for the company has rebates in various places for replacing lighting with LED. A $5 rebate is provided to the facility for every new LED bulb installed from 9-22 Watts. See Appendix 7.6 for more information. The facility can save $1,840 this way and can use it to offset the implementation cost. Below is the equation used to find the rebate savings and the implementation cost for each bulb/tube type:

$$R = S * N$$

$$R = \frac{\$5}{bulb} * 368\ bulbs$$

$$R = \$1{,}840$$

$$I = (P * N) + (N * T * L)$$

$$TS = Lighting_{old} - Lighting_{new}$$

Where,

I = Implementation cost
R = Rebate
S = Savings Incentive
P = Price per bulb/tube
T = Time to replace a bulb/tube
N = Number of bulbs/tubes to be replaced
L = Labor Rate
TS = Total Savings from current and proposed lighting
$Lighting_{old}$ = Current lighting cost
$Lighting_{new}$ = Proposed lighting cost

$$I_{LED,T8} = \left(\frac{\$12.80}{bulb} * 296\ tubes\right) + \left(296\ tubes * 10\frac{minutes}{tube} * \frac{1\ hour}{60\ minutes} * \frac{\$30}{hour}\right)$$

$$I_{LED,T8} = \$5{,}269$$

$$I_{LED,T5} = \left(\frac{\$21.93}{tube} * 48\ tubes\right) + \left(48\ tubes * 10\frac{minutes}{tube} * \frac{1\ hour}{60\ minutes} * \frac{\$30}{hour}\right)$$

$$I_{LED,T5} = \$1{,}293$$

$$I_{LED,U-Tube} = \left(\frac{\$22.98}{tube} * 24\ tubes\right) + \left(24\ tubes * 10\frac{minutes}{tube} * \frac{1\ hour}{60\ minutes} * \frac{\$30}{hour}\right)$$

$$I_{LED,U-Tube} = \$672$$

$$TS = \$3{,}173.18 - \$1{,}553.37$$

$$TS = \$1{,}620$$

Table 5.5-5: LED Pricing Summary

Current Bulb	LED Equivalent Cost	Number of Bulbs in Facility	Implementation Cost
4-ft T8	$12.80	296	$5,269
4-ft T5	$21.93	48	$1,293
2-ft U-Tube	$22.98	24	$672
Rebate			($1,840)
Total	-	-	$5,394

Payback Period

Simple payback period can be calculated using the formula below. The annual savings for the lighting is $1,608 per year and the cost of implementation is $5,394. This brings the payback period to 3.4 years as shown.

$$Payback = \frac{Implementation\ Cost}{Annual\ Savings}$$

$$Payback = \frac{\$5{,}394}{\$1{,}608}$$

$$Payback = 3.4\ years$$

5.6 AR No. 1: Reduce Compressed Air Leaks

Recommended Action

It is recommended that the facility implements a quarterly air leak detection and repair program to minimize air leaks within their air distribution system. In addition to finding the leaks, the identified air leaks should be repaired, and any air leaks discovered in the future should be tagged and repaired as they are found. Table 5.6-1 summarizes the potential savings and the implementation cost and payback period associated with this recommendation.

Table 5.6-1: Compressed Air Leak Repair Summary

Annual Energy Savings	GHG Emissions Reduction	Annual Cost Savings	Implementation Cost	Simple Payback
105,792 kWh/year	75 $MTCO_2e$/year	$5,819/year	$5,960	1 year

Background

The facility has two Quincy QGV Series 75 HP compressors. These compressors are run with a VFD at a loading factor of 75%. The two compressors are run for 24 hours a day five days a week for 50 weeks throughout the year. This results in an annual runtime of approximately 6,000 hours. The total capacity of these compressors currently running is 341.2 acfm while their motor efficiency was found to be 94.2%. These data are extracted from the CAGI data sheet of the compressor and the CAGI sheet of the compressor is available in appendix 7.7. This information is summarized in Table 5.6-2.

Table 5.6-2: Current Air Compressor Information

Horsepower (HP)	Capacity (acfm)	Loading Factor	Efficiency (%)	Annual Runtime (hours/year)
75	341.2	0.75	94.2	6,000

The compressors currently in use are set at 110 psi and are rated to supply a total of 576 acfm. According to the facility staff. Since the compressors are not currently operating in their full capacity (341.2 acfm), based on the data available on the CAGI data sheet, the actual capacity for each compressor was considered to be 288 acfm, which is multiplied by 2 for two compressors and the actual capacity will be 576 acfm.

Supplying most of its processes with compressed air costs the facility approximately 28% of its total electricity bill; this equates to $41,168 per year. Every compressed air system will have leaks, but there is a target “acceptable” leakage range for different plant sizes[25].

• For small plants, the leakage should be from 5% to 7%.

• For medium plants, the leakage should be from 7% to 10%.

• For large plants, the leakage should be from 10% to 12%

A realistic goal for the facility would be a leakage rate of 10%.

To improve a plant’s leak performance, a periodic check of the entire compressed air system for leaks using an ultrasonic leak detector is advised to find smaller leaks or leaks further away from employees. Since any compressed air system will degrade over time, new leaks will continually develop. By supporting periodic leak detection and repair, it will be possible for the facility to maintain or surpass its leak rate goal.

The NIAC team performed a leak detection assessment with Fluke acoustic imager during the assessment. The sonic imager was used to locate the leaks and the ultrasonic detector was used to measure the sensitivity of the leaks which was used to find the leak rate in cubic feet per minute. Over approximately one and a half hours, NIAC analysts identified 21 separate leaks when examining approximately 60% of the factory, primarily on the manufacturing floor. There was a significant variation in the size of the leaks. Many leaks were small, and several were large enough to audibly hear and feel, indicating a significant loss of air. A summary of the leaks and locations can be found in Appendix 7.8 and an example of an image taken with the sonic imager is shown in Figure 5.6-1.

[25] http://www.ptonline.com/articles/energy-miser-plug-costly-compressed-air-leaks

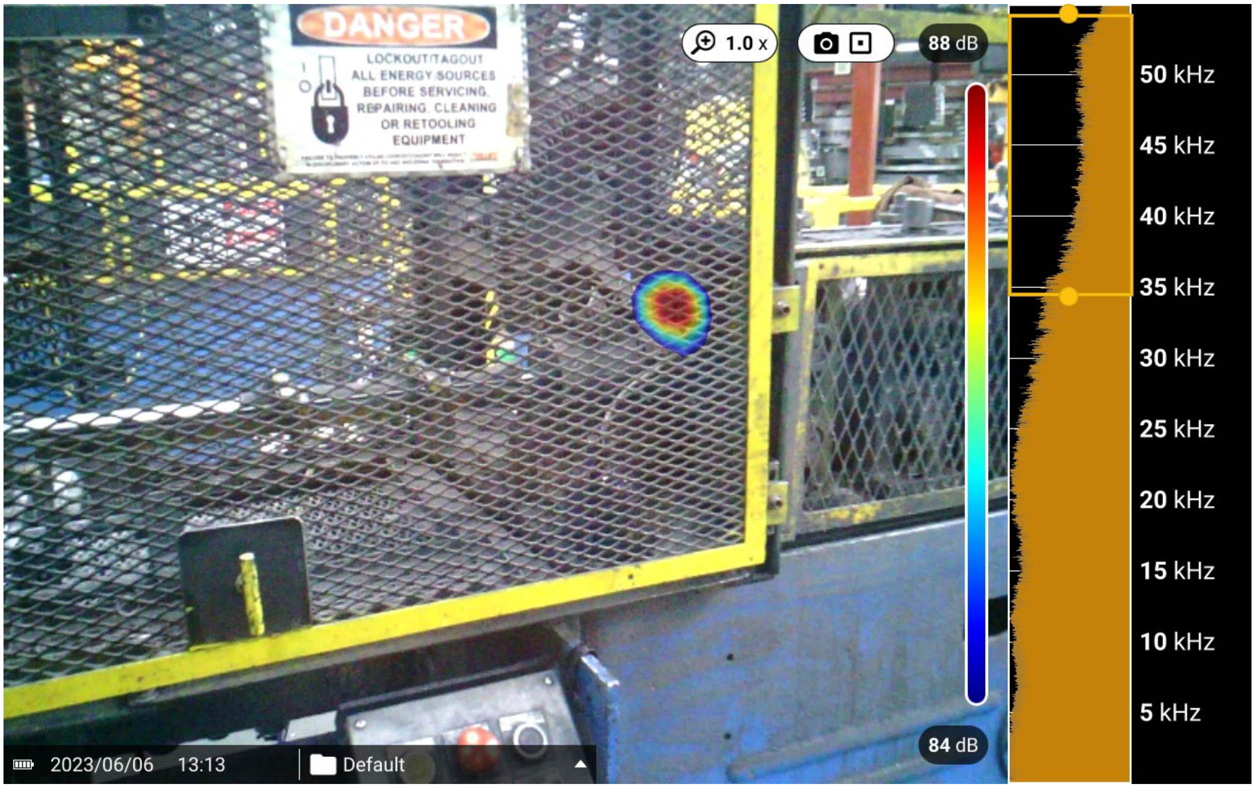


Figure 5.6-1: Air leak detected by Fluke Acoustic Imager Leak Detection

Anticipated Savings

To find the anticipated energy and cost savings for repairing the identified compressed air leaks, the cost of the entire compressed air system must first be calculated. The following equations are used to calculate the energy usage and demand costs associated with running the compressors[26].

$$Energy\ Usage = \left(\frac{HP * ML * 0.746\frac{kW}{hp}}{\eta}\right) * T * L$$

$$Cost_{Usage} = Energy\ Usage * UR$$

$$Energy\ Demand = \frac{HP * ML * 0.746\frac{kW}{hp} * M}{\eta}$$

[26] https://energy.gov/sites/prod/files/2014/05/f16/compressed_air1.pdf

$$Cost_{Demand} = Energy\ Demand * DR$$

Where,

HP = Total Compressor Motor hp

ML = Motor Load

η = Compressor Efficiency

T = Time in Operation (h)

UR = Usage Rate ($/kWh)

L = Loading Factor

DR = Demand Rate ($/kW-month)

M = Months in Operation

The cost for the current compressor system can be calculated by adding the usage cost for the compressors to the demand cost. The calculations for the 75 HP compressor are shown. Table 5.6-3 summarizes the energy and cost values for each compressor.

$$Energy\ Usage = \left(\frac{2 * 75\ hp * 1 * 0.746 \frac{kW}{hp}}{0.942} \right) * 6{,}000 \frac{hours}{year} * 0.75$$

$$Energy\ Usage = 534{,}554 \frac{kWh}{year}$$

$$Cost_{Usage} = 534{,}554 \frac{kWh}{year} * \frac{\$0.062}{kWh}$$

$$Cost_{Usage} = \frac{\$33{,}142}{year}$$

$$Energy\ Demand = \frac{2 * 75\ hp * 1 * 0.746 \frac{kW}{HP} * 12\ months}{0.942}$$

$$Energy\ Demand = 1{,}425 \frac{kW - months}{year}$$

$$Cost_{Demand} = 1{,}425 \frac{kW - months}{year} * \frac{\$5.601}{kW - months}$$

$$Cost_{Demand} = \frac{\$7{,}981}{year}$$

$$Cost_{Total} = \frac{\$33{,}142}{year} + \frac{\$7{,}981}{year} = \frac{\$41{,}123}{year}$$

Table 5.6-3: Current Compressor Cost and Energy

Compressor	Energy Usage (kWh/year)	Usage Cost ($/year)	Demand (kW-months/year)	Demand Cost ($/year)	Total Cost ($/year)
2*75 HP	534,554	$33,142	1,425	$7,981	$41,123

The total energy usage of two 75 HP compressors is 534,554 kWh/year. To determine the impact of air leaks, it is helpful to calculate the unit cost and energy of compressed air. To find the unit energy usage of the air, the energy usage can be divided by the air capacity of the system. This rate can then be multiplied by the energy rate to find the air unit cost.

$$Air_{Energy} = \frac{Energy_{Total}}{Capacity}$$

$$Air_{Energy} = \frac{534{,}554 \frac{kWh}{year}}{576\ cfm}$$

$$Air_{Energy} = \frac{928 \frac{kWh}{year}}{cfm}$$

$$Air_{Cost} = Air_{Energy} * \frac{\$0.062}{kWh}$$

$$Air_{Cost} = \frac{\frac{\$58}{year}}{cfm}$$

The reduction of air leaks within the air distribution system will help minimize air losses, allowing the compressors to operate at a lower load factor and thus have lower power consumption. To quantify approximate cost savings, an estimate of air leakage was made by the UNL team. During the leak detection, the sensitivity meter of the ultrasonic leak detector was tracked. Using a chart supplied by the NIAC that correlates sensitivity readings to approximate airflow, an estimate of each leak was determined which was 114 cfm.

Given this air loss and the cost of air per cfm, the total cost and energy of the identified air leaks can be calculated.

$$Savings_{Energy} = Air\ loss * Air_{Energy}$$

$$Savings_{Energy} = 114\ cfm * \frac{928 \frac{kWh}{year}}{cfm}$$

$$Savings_{Energy} = 105{,}792 \frac{kWh}{year}$$

$$Savings_{Cost} = Savings_{Energy} * UR$$

$$Savings_{Cost} = 105{,}792 \frac{kWh}{year} * \frac{\$0.062}{kWh}$$

$$Savings_{Cost} = \frac{\$6{,}559}{year}$$

This recommendation would only require the time and materials necessary to fix the identified leaks. A simple way to track these leaks is to use an equipment repair tag. Depending on the quality and design desired, these can be purchased for as little as 50 for $10. Most air leaks occur at fittings and joints in pipes which can be tightened or replaced. A good thread sealant will improve the performance of these fittings and can be found at most online stores for prices between $10-$25. Between these incidental costs and replacement fittings, it is assumed that materials for a leak detection program at the facility would cost approximately $100 per year.

Quarterly leak checks should be as thorough as is reasonably possible. Based on the experience of the NIAC team during the assessment, a thorough check of the compressed air system with an ultrasonic leak detector and a thermal imager could be completed in approximately four hours. It is assumed this check would be conducted by maintenance staff at a rate of $40/hour.

The sum of equipment and labor costs required for the program will be the recurring costs of implementing a leak detection program.

$$Cost_{Program} = Equipment + Labor$$

$$Cost_{Program} = \frac{\$100}{year} + \left(\frac{4\ hours}{quarter} * \frac{4\ quarters}{year} * \frac{\$40}{hour}\right)$$

$$Cost_{Program} = \frac{\$740}{year}$$

The overall savings of the program will be the savings due to the reduction of compressed air leaks minus the cost of running the program.

$$Savings = Savings_{Cost} - Cost_{Program}$$

$$Savings = \frac{\$6{,}559}{year} - \frac{\$740}{year}$$

$$Savings = \frac{\$5{,}819}{year}$$

Implementation Cost and Simple Payback

The costs of this recommendation depend on the level of leak detection that is implemented. At a minimum, this recommendation would require no capital investment, only the recurring time and material costs to repair discovered leaks. However, to get the most out of an air leak program, special equipment should be purchased to aid in identifying compressed air leaks. An ultrasonic leak detector is one of the best tools available for locating air leaks. The facility should consider purchasing a leak detector to assist personnel during the quarterly leak checks. The price and functionality of ultrasonic leak detectors vary quite a bit. A simple model can be found for as little as $500, but a model like the one used by the NIAC team during their assessment costs approximately $4,500. Due to the size of the facility, it may be beneficial to spend the additional money on a more expensive ultrasonic leak detector. For the calculation of the payback period, it is assumed that it takes 6 hours to check the whole facility to find the air leaks using the leak detector equipment. Considering the facility's labor rate of $40/hr and the quarterly leak checks, the labor cost will be $960. In addition, for the current case the cost of a high-quality directional detector is $5,000. See Appendix 7.9 for suggested vendors. Including both the directional leak detector and the leak check labor cost, the total implementation cost used for the calculation will be $5,960. Given this implementation cost, a payback period can be calculated.

$$Payback\ Period = \frac{Implementation\ Cost}{Annual\ Savings}$$

$$Payback\ Period = \frac{\$5{,}960}{\frac{\$5{,}819}{year}} = 1.02\ year \sim 1\ year$$

Additional Notes

Using the annual energy savings and the EPA Greenhouse Gas Equivalencies Calculator[27], it was determined that the facility can reduce its GHG emissions by approximately 75 $MTCO_2e$ annually by implementing a compressed air leak detection program. It should be noted that the current values were calculated using Nebraska electricity-based conversion factor.

[27] https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

5.7 AR No. 2: Use Deduct Meter on Cooling Tower

Recommended Action

It is recommended that this facility install a deduct meter on its cooling tower water blowdown line to measure the water evaporation, especially in hot summer months to reduce its annual wastewater cost. The facility is currently being charged sewer fees based on water usage that goes into the plant. A significant portion of the facility's water usage is evaporated in the cooling tower and therefore this amount should not be included in its sewer fees. Table 5.7-1 provides a summary for implementing the deduct meter on the cooling tower.

Table 5.7-1*:* Cooling Tower Deduct Meter Summary

$4,237/year	$1,348	0.3 years

Background

This facility has two charges associated with water billing: a water usage charge and a sewer charge. The input lines to the cooling tower include city water. While in the cooling tower, significant water loss occurs due to evaporation and drift. The loss of water causes increased concentration of multivalent ions measured by increased conductivity.

The output lines from the cooling tower include blowdown and a recirculation line that brings water back to the cooling tower. The blowdown is necessary to prevent scale buildup due to high concentrations of multivalent ions. If the facility tracks the amount of water loss due to evaporation and drift with two new meters, the water loss due to the cooling tower can be deducted from the sewage bill. It is recommended the meters are located on the input (city water line) and the output (blowdown line) of the cooling tower. A process flow diagram can be found in Figure 5.7-1. The amount of water that should be deducted from the water bill is equal to the city water input to the cooling tower minus the amount of blowdown water output from the cooling tower.

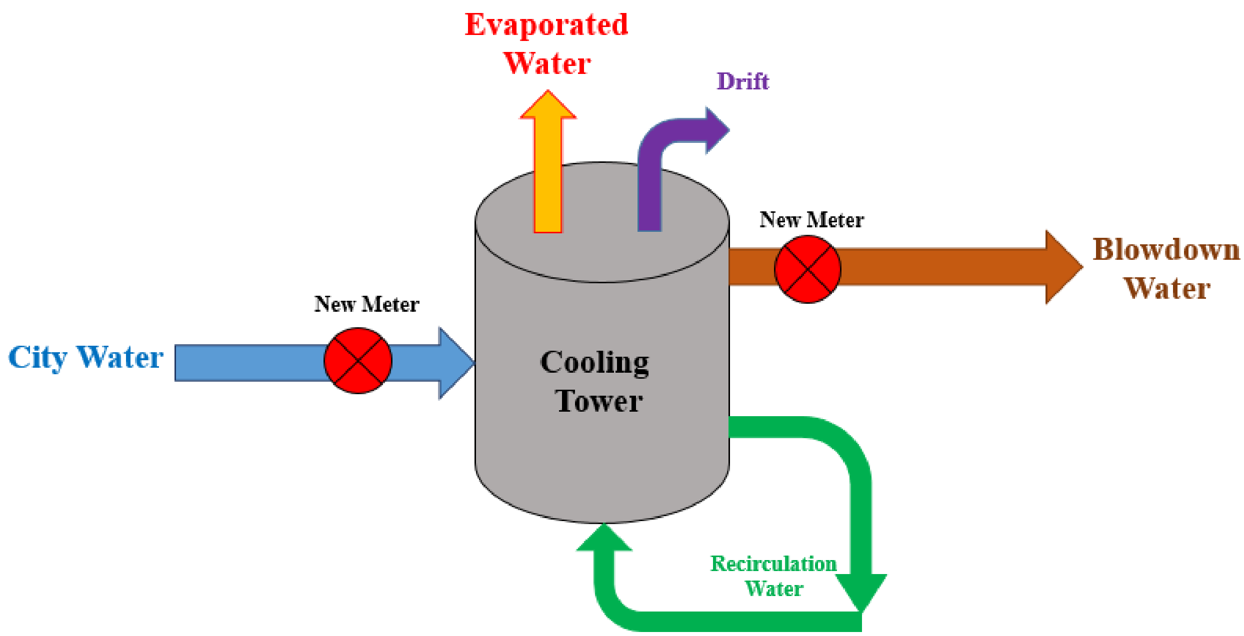


Figure 5.7-1: Cooling Tower Process Flow Diagram

Anticipated Savings

It is assumed the flow rate of makeup water is equal to the sum of evaporation rate, drift rate, and blowdown rate according to the following material balance[28]:

$$R_{makeup} = R_{evap} + R_{drift} + R_{blowdown}$$

Where,

R_{makeup} = Makeup water volume (gal)

R_{evap} = Evaporation rate volume (gal)

R_{drift} = Drift volume (gal)

$R_{blowdown}$ = Blowdown volume (gal)

Based on the data collected from the flowmeter connected to the tower, during a period of 133 days (Feb 13 to June 26), 2.5 million gallons of water flowed into the cooling tower. Since the production rate of the facility is consistent throughout the year, it can be assumed that the total volume of water entering the tower is equal to 6.9 million gallons per year. This is equivalent to 13.05 gallons per minute.

[28] Kuntz (2008). "Environmental Calculations: A Multimedia Approach," 1st Ed., John Wiley & Sons. Web: https://onlinelibrary.wiley.com/doi/pdf/10.1002/9780470925386.app5

The rate of evaporation formula was given by a facility's technical specialist to have a concentration of 3.3 for most of the year. Thus the following formula is used to calculate condenser bleed off.

$$\frac{Condenser\ make-up}{cycles\ of\ concentration} = 3.3$$

The cycle of concentration specifies how often fresh water added into the loop, can be used or pumped around, before the water has to blown down or bleed off from the cooling tower. For example, for a 24-hour condenser make-up volume of 3,000 gallons (cycles of concentration = 3.3):

$$24-hour\ condenser\ bleed\ off\ = \frac{3{,}000\ gallons}{3.3} = 909\ gallons$$

$$24-hour\ condenser\ evaporation = 3{,}000\ gallons - 909\ gallons = 2{,}091\ gallons$$

Since the water flowrate into the tower is 13.05 gal/min, the 24-hr condenser make-up volume is:

$$24-hour\ condenser\ makeup\ volume = 13.05\frac{gallons}{minute} * 60\frac{minute}{hour} * 24\frac{hour}{day} = 18{,}797\ gallons$$

Using the previous formula, the daily volume of 24-hour condenser bleed off is 5,696 gallons while 13,101 gallons of 24-hour condenser evaporates. Figure 5.7-2 shows the annual water usage of the facility. The figure shows that the water usage in five months (June XXX – October XXX) is significantly higher than the other months of the year. Such a difference can be related to water loss in the cooling tower due to evaporation and drift. Therefore, to calculate the evaporated and drift water, 5 months is considered the operation time. The condenser make-up volume for 5 months (150 days) is calculated as follows:

$$Condenser\ makeup\ volume = 18{,}797\ gallons\ * 150\frac{days}{year} = 2{,}819{,}549\frac{gallons}{year}$$

Table 5.7-2 shows the usage of water and wastewater from June 2022 through May2023.

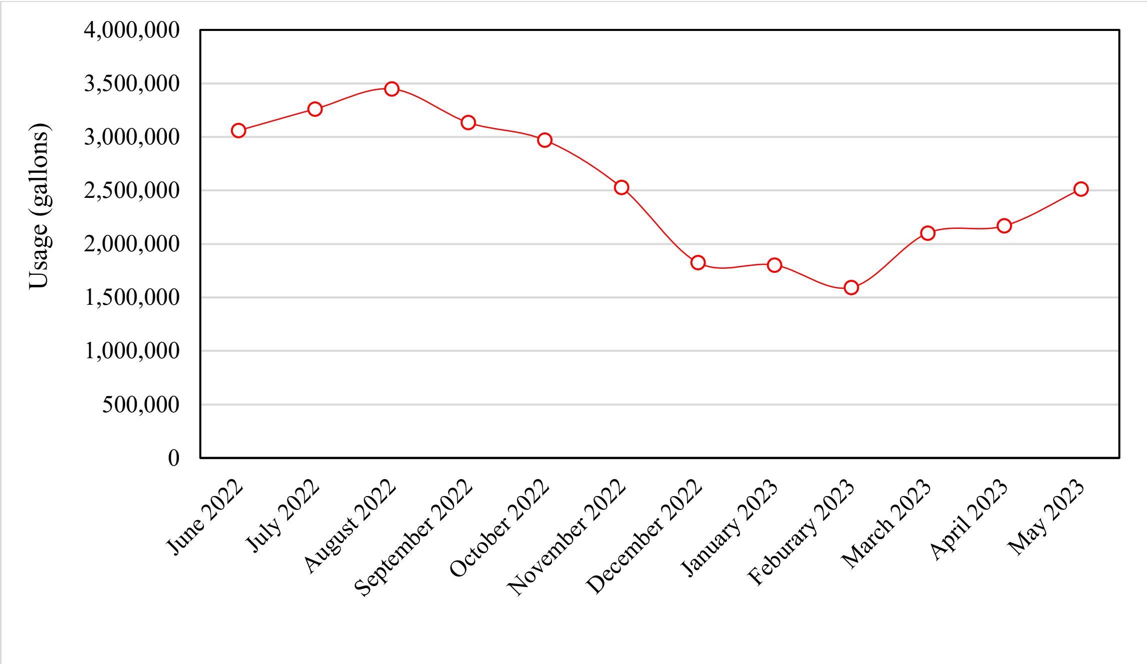


Figure 5.7-2: Annual Water and Wastewater Usage

Based on the data provided by the facility, the average cycle of concentration for the current facility is considered equal to 3.3. The values of condenser bleed off and condenser evaporation in this period of time are calculated as:

$$Volume\ of\ Condenser\ Bleedoff = \frac{2{,}819{,}549\ gallons}{3.3} = 854{,}409\ gallons$$

$$R_{evap} = Volume\ of\ Condenser\ evaporated = 2{,}819{,}549\ gallons - 854{,}409\ gallons = 1{,}965{,}140\ gallons$$

The drift rate is assumed to be 0.2% of the total circulation rate[29]. The drift rate and overall savings can be calculated using the following equations:

$$R_{drift} = 0.002 * F$$

$$S = \left(R_{evap} + R_{drift}\right) * c$$

Where,

F = total circulation flow (gal/min)

S = annual cost savings ($/year)

c = sewage charge ($/1000 gal)

[29] https://www.chemengonline.com/cooling-towers-estimate-evaporation-loss-and-makeup-water-requirements/

$$Rate_{drift} = 0.002 * 13.05\ gallons/min = 0.03\ gallons/min$$

The volume of the water drift in 150 days is:

$$R_{drift} = 0.03 \frac{gallons}{minute} * \frac{60\ minutes}{1\ hour} * \frac{24\ hours}{1\ day} * 150\ days = 6{,}480\ gallons$$

$$S = \left(R_{evap} + R_{drift}\right) * c$$

$$S = (1{,}965{,}140\ gallons\ + 6{,}480\ gallons\ ) * \frac{\$2.15}{1{,}000\ gallons} = \frac{\$4{,}239}{year}$$

Implementation Cost

It is recommended that the facility install two water meters to obtain deduct savings. The meters should be installed on the city water line and the blowdown line. The blowdown water minus the city water is equivalent to the water lost to evaporation and drift. The city of Fremont Utilities Department was contacted to begin deducting water charges as recorded by the new meters. Based on the call to the Fremont Utilities Department, there are no specific requirements for installing deduct meters. The water department of Fremont supplies the deduct meters, the biggest is 2 inches. All facilities within city limits and surrounding neighborhoods must contact the water department of Fremont before making any changes that involve pipies,or building construction/demolition/modifications. If they want to make a change like this, they need to contact the Fremont utility department. The size of the cooling tower's input and output pipelines are 2" and 3/4", respectively. Based on the data received from the Fremont Utilities Department the cost of 2" and 3/4" meters are \$585 and \$413, respectively. The expected implementation cost for each meter is shown in Appendix 7.10, with an expected installation time of two hours per meter. The facility manager also stated that installing the meters requires some minor changes in the piping system. That can be considered an additional 6 hours. The payback period is calculated by dividing the implementation cost by the annual cost savings.

$$Implementation\ Cost = Meter\ Cost + \ Installation\ Cost$$

$$\begin{aligned} Meter\ Cost &= Number\ of\ 2''\ Meter * Cost\ of\ Meter + Number\ of\ ¾''\ Meter * Cost\ of\ Meter \\ &= \$585 + \$413 = \$998 \end{aligned}$$

$$\begin{aligned} &Installation\ Cost \\ &\quad = (required\ time\ fo\ Installing\ 1\ Meter) * Number\ of\ Meters * Labor\ Rate \\ &\quad + Modification\ Time * Labor\ Rate \end{aligned}$$

$$Installation\ Cost = \frac{2\ hours}{meter} * 2\ Flow\ Meters * \frac{\$35}{hour} + \ 6\ hours * \frac{\$35}{hour} = \$350$$

$$Implementation\ Cost = \$998 + \$350 = \$1{,}348$$

$$Payback\ Period = \frac{Implementation\ Cost}{Annual\ Cost\ Savings}$$

$$Payback\ Period = \frac{\$1,348}{\frac{\$4,237}{year}} = 0.3\ years$$

Additional Notes

Although not discussed extensively in this report, it is recommended that the facility consider optimizing the cooling tower process. The cycles of concentration of the system is assumed to be 3.3 for the calculations above. If the cycles of concentration are too low, water is being lost to the sewer unnecessarily. To fully utilize the purchased water, the facility should optimize the cycles of concentration to prevent unnecessary blowdown.

6.0 Other Measures

The following section describes additional actions which could be beneficial to the wastewater treatment plant. These actions were investigated during the assessment but do not qualify as assessment recommendations because of the extended payback periods or other insubstantial data. Each measure contains background information, estimated savings, implementation cost, and simple payback.

6.1 Switch from Class B to Class A Sludge

Recommended Action

The wastewater treatment plant currently produces sludge that has Class B standing. The NIAC considered recommending that the plant switches from Class B to Class A sludge, but the recommendation exceeded the desired payback period. Switching to Class A will eliminate significant costs associated with Class B, as well as enabling the plant to reuse generated biogas and reduce greenhouse gas emissions. The potential annual cost savings, implementation cost, and payback period associated with this recommendation are summarized in Table 6.1-1.

Table 6.1-1: Summary of Impacts from Switching to Class A

Annual Cost Savings	Implementation Cost	Payback Period
$195,080/year	$3,459,300	17.7 years

Background

The wastewater treatment plant is currently a Class B facility with no anaerobic digesters. The plant currently uses two biosolids trucks for sludge transportation with approximately 670 hours of labor associated with using the trucks. The plant also maintains a farm contact which they utilize to spread their sludge. Additionally, there is staff time, soil sampling, and sludge press labor associated with the plant's current Class B status. These costs can be eliminated by shifting to a Class A facility. If the WWTP changes to Class A, anaerobic digestors would need to be installed to produce Class A sludge.

From April XXX to March XXX, the plant used 1,089 MMBTUs of natural gas to heat the facility. The natural gas usage followed a seasonal trend which corresponds to its use as a space heater. Table 6.1-2 summarizes the monthly natural gas usage and cost for the plant.

Table 6.1-2: Summary of Monthly Natural Gas Usage and Cost

Month	Natural Gas Usage (MMBTU)	Natural Gas Cost ($/month)
April, XXX	93.9	$605
May, XXX	25.2	$195
June, XXX	2.3	$57
July, XXX	2.3	$57
August, XXX	2.6	$61
September, XXX	3.9	$76
October, XXX	25.7	$253
November, XXX	113.3	$961
December, XXX	167.4	$1,399
January, XXX	234.9	$1,949
February, XXX	215.6	$1,794
March, XXX	202.0	$1,684
Totals	1,089.1	$9,090

Anticipated Savings

By switching to Class A, the plant can eliminate $168,400 Class B associated costs per year. Currently, the plant utilizes two biosolid spreader trucks with a ten-year life. The cost of the trucks and the labor required to run them accounts for approximately $104,400 annually, including the associated energy and usage costs. Switching to Class A could eliminate the need for the biosolids spreader trucks due to upgrading to Class A sludge. Figure 6.1-1 illustrates estimates of the overall costs that are associated with Class B.

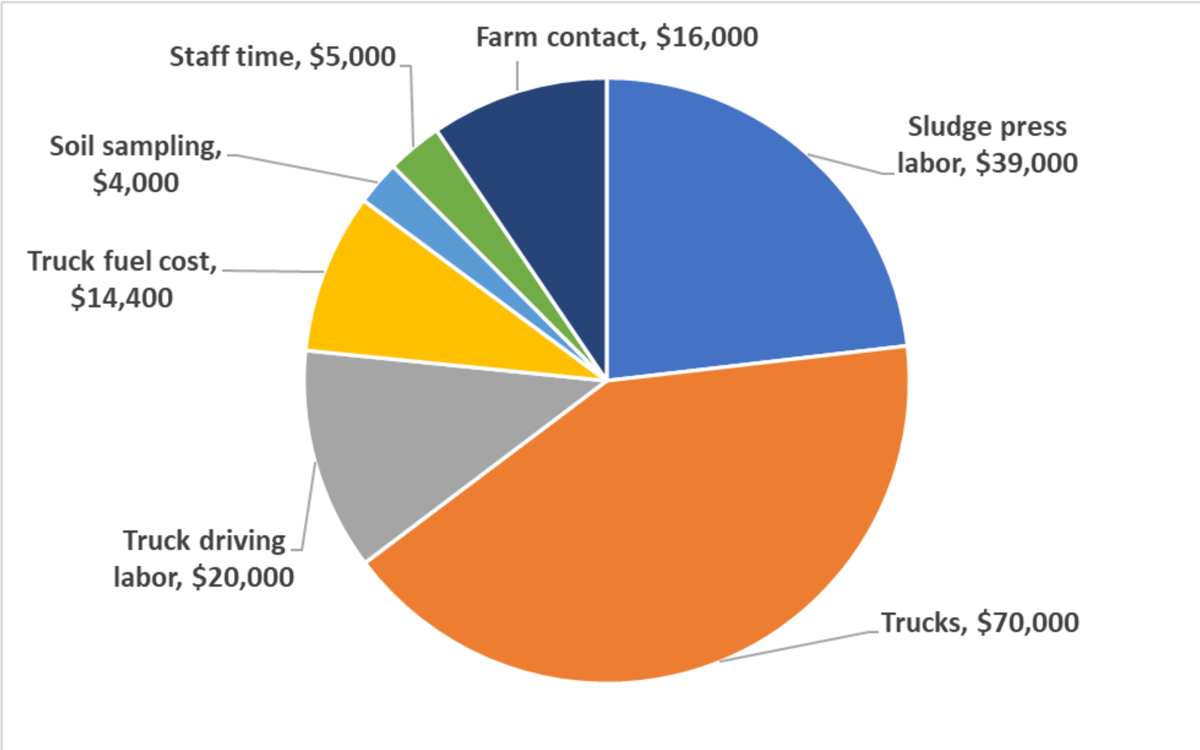


Figure 6.1-1: Annual Costs Associated with Class B Sludge

If the wastewater treatment plant becomes a Class A facility, they could consider reusing the biogas generated by the anaerobic digesters with a microturbine cogeneration system. The WWTP currently receives from 2.5 to 4 million gallons of influent wastewater a day. The methane content of biogas ranges from 50% to 70% with carbon dioxide making up the remainder; a conservative estimate of 50% methane content in the biogas was assumed for this report[30]. The methane content of the biogas represents the natural gas content to be utilized. According to the EPA, roughly 1 cubic foot of biogas is produced for every 100 gallons of influent wastewater to a treatment plant[31]. Furthermore, the thermal energy contained in one cubic foot of methane is 1,037 BTUs[32]. The following equations were used to determine the energy potential of recovered biogas based on the monthly influent wastewater flows to the plant.

$$V_{biogas} = V_{water} * \frac{1\ ft^3\ biogas}{100\ gallons\ of\ water}$$

$$V_{methane} = V_{biogas} * 0.5$$

$$E_{methane} = V_{methane} * \frac{1{,}037\ BTUs}{1\ ft^3\ methane} * \frac{1\ MMBTU}{1{,}000{,}000\ BTU}$$

30 https://www.nrel.gov/docs/fy14osti/60178.pdf
31 https://afdc.energy.gov/fuels/natural_gas_renewable.html
32 https://www.eia.gov/tools/faqs/faq.php?id=45&t=8

Where,

V_{biogas} = Volume of biogas in cubic feet
V_{water} = Volume of influent wastewater
$V_{methane}$ = Volume of methane in cubic feet
$E_{methane}$ = Energy from methane in biogas

Example calculations for April 2021 are provided here. The results for the whole year are summarized in Table 6.1-3.

$$V_{biogas} = 98{,}700{,}000\ gallons\ of\ water * \frac{1\ ft^3\ biogas}{100\ gallons\ of\ water}$$

$$V_{biogas} = 987{,}000\ ft^3$$

$$V_{methane} = 987{,}000\ ft^3 *\ 0.5$$

$$V_{methane} = 493{,}500\ ft^3$$

$$E_{methane} = 493{,}500\ ft^3 * \frac{1{,}037\ BTUs}{1\ ft^3\ methane} * \frac{1\ MMBTU}{1{,}000{,}000\ BTU}$$

$$E_{methane} = 512\ MMBTU * \frac{10\ therms}{1\ MMBTU} = 5{,}120\ therms$$

Table 6.1-3: Summary of the Energy Content of Biogas

	Influent Flow (Million Gallons)	**Biogas Produced (ft^3)**	**Methane Produced (ft^3)**	**Methane Energy (MMBTU)**
April, XXX	98.7	987,000	493,500	512
May, XXX	101.1	1,011,000	505,500	524
June, XXX	91.8	918,000	459,000	476
July, XXX	95.8	958,000	479,500	497
August, XXX	96.4	964,000	482,500	500
September, XXX	93.6	936,000	468,000	485
October, XXX	97.0	970,000	485,000	503
November, XXX	93.9	939,000	469,500	487
December, XXX	95.8	958,000	479,000	497
January, XXX	90.5	905,000	452,500	469
February, XXX	77.3	773,000	386,500	401
March, XXX	86.2	862,000	431,000	447
Totals	1,118.1	11,181,000	5,590,500	5,797

The wastewater treatment plant spends $9,090 on natural gas annually and used 1,089 MMBTUs from April XXX to March XXX. Based on conservative estimates, approximately 5,797 MMBTUs of methane, which represents natural gas, will result from reusing generated biogas. The resulting methane energy will significantly exceed the plant's current natural gas usage, producing more than five times the current natural gas usage. However, this does not factor in the natural gas used by the prospective anaerobic digesters, so additional natural gas usage will need to be considered.

In addition to delivering natural gas savings, the microturbine will provide savings through the electricity it generates. Correct sizing of such systems is important when determining potential power output. The DOE has a CHP Microturbine power tip sheet that makes such estimations straightforward[33]. An overall power rating for an appropriately sized system can be determined from the tip sheet to be 65 kW with an average power efficiency rating of 24.7%. If the turbine operates 24 hours a day and 365 days each year, annual electricity usage and cost savings can be calculated using the following equations.

$$E_{Usage} = S_{Turbine} * H_{Operating} * e$$

$$C_{Usage} = E_{Usage} * UR$$

Where,

E_{Usage} = Electricity usage savings in kWh/year
$S_{Turbine}$ = Turbine size in kW
e = Turbine efficiency
$H_{Operating}$ = Annual operating hours
C_{Usage} = Cost savings due to reduced electric usage
UR = Electricity usage rate

$$E_{Usage} = 65\ kW * \frac{8{,}760\ hours}{year} * 0.247$$

$$E_{Usage} = 140{,}642 \frac{kWh}{year}$$

$$C_{Usage} = 140{,}642 \frac{kWh}{year} * \frac{\$0.039}{kWh}$$

$$C_{Usage} = \frac{\$5{,}485}{year}$$

Additionally, the system will operate during periods of peak demand. This will result in demand reductions and therefore savings. To be conservative, demand savings will only de calculated for 11 months annually. This factors in the possibility that maintenance may not be ideally timed into account. If

[33] https://www.energy.gov/sites/default/files/2016/09/f33/CHP-Microturbines_0.pdf

not planned well, taking the CHP system out of service during a demand peak would eliminate demand savings for the month. Potential savings are calculated as follows.

$$E_{Demand} = S_{Turbine} * M$$

$$C_{Demand} = E_{Demand} * DR$$

Where,

E_{Demand} = Annual electricity demand savings in kW/year
$S_{Turbine}$ = Turbine size in kW
M = Number of months savings are expected
H_{Annual} = Annual operating hours of the system
C_{Demand} = Cost savings due to reduced electric demand
DR = Electricity demand rate

$$E_{Demand} = 65\ kW * 11 \frac{months}{year}$$

$$E_{Demand} = 715 \frac{kW - months}{year}$$

$$C_{Demand} = 715 \frac{kW - months}{year} * \frac{\$16.93}{kW - month}$$

$$C_{Demand} = \frac{\$12{,}105}{year}$$

The total annual savings can be calculated by summing the costs associated with Class B, the annual natural gas cost, and the annual electricity usage and demand cost savings.

$$Annual\ Cost\ Savings = Cost_B + Cost_{gas} + C_{Usage} + C_{Demand}$$

$$Annual\ Cost\ Savings = \frac{\$168{,}400}{year} + \frac{\$9{,}090}{year} + \frac{\$5{,}485}{year} + \frac{\$12{,}105}{year}$$

$$Annual\ Cost\ Savings = \frac{\$195{,}080}{year}$$

Implementation Cost and Simple Payback Period

The capital cost of installing the anaerobic digestors represents the primary implementation cost of this recommendation. This cost was found by inputting the average influent wastewater volume into an EPA cost curve[34]. The cost curve used was in 1980 dollars and consequently adjusted to XXX dollars using Construction Cost Index (CCI) values provided by Engineering News-Record[35]. The estimated capital cost of the anaerobic digesters was found to be $3,250,000. If the facility implements a microturbine

[34] Construction Costs for Municipal Wastewater Treatment Plants (1980): https://nepis.epa.gov/Exe/ZyNET.exe

[35] Construction Cost Index History - Annual Average | Engineering News-Record (enr.com)

cogeneration system, they will likely purchase a 65-kW size turbine at a rate of $3,220/kW[36]. The cost of a microturbine of this size is calculated by the following equation.

$$C_{Microturbine} = 65\ kW * \frac{\$3{,}220}{kW}$$

$$C_{Microturbine} = \$209{,}300$$

Thus, the implementation cost can be calculated as follows:

$$Implementation\ Cost = C_{Digesters} + C_{Microturbine}$$

$$Implementation\ Cost = \$3{,}250{,}000 + \$209{,}300$$

$$Implementation\ Cost = \$3{,}459{,}300$$

The simple payback period for this recommendation can be found by dividing the implementation cost by the annual cost savings and can be calculated using the following formula.

$$Payback\ Period = \frac{Implementation\ Cost}{Annual\ Cost\ Savings}$$

$$Payback\ Period = \frac{\$3{,}459{,}300}{\frac{\$195{,}080}{year}}$$

$$Payback\ Period = 17.7\ years$$

Additional Notes

There may be additional cost savings if the facility sells excess natural gas to a nearby dairy facility. Accurate cost savings were not able to be calculated, so this was left out of the recommendation. It should be noted that some of the excess natural gas would be used to heat the anaerobic digesters.

[36] https://www.energy.gov/sites/default/files/2016/09/f33/CHP-Microturbines_0.pdf.

6.2 Pre-Air Decommission

Recommended Action

The NIAC team investigated implementing a vortex grit removal system that would retire the current system and the blowers that are powering it. As a vortex grit removal system does not require blowers, the facility will see electrical usage and cost savings from decommissioning the current blowers. This was not included with the assessment recommendations as the payback period exceeds the desired range.

Table 6.2-1: Pre-Air Decommission Summary

Energy Savings	Demand Savings	GHG Emissions Reduced	Annual Cost Savings	Implementation Cost	Simple Payback
326,617 kWh/year	447 kW/year	312 $MTCO_2e$/year	$20,313/year	$716,000	35.2 years

Background

At the facility, two identical 50 hp blowers power the water flow of the current aerated grit removal system. Only one blower is running at any time since one 50 hp blower is capable of handling all the water load at once. With a very steady rate of wastewater throughout each day, the facility cannot afford to have a blower not powering their grit removal system. The other blower is integrated into the system for security measures in case the blower would encounter a problem. With one blower always running, the annual operation hours total to 8,760 hours between the two.

Wastewater contains large solids and grit that can interfere with treatment processes or cause mechanical wear and increased maintenance on wastewater treatment equipment. Grit includes sand, gravel, cinder, or other heavy solid materials that are heavier than the organic biodegradable solids in the wastewater. To minimize potential problems, these materials require removal and separate handling from the wastewater. Preliminary treatment, such as grit removal, remove these constituents from the influent wastewater. During this process, grit removal systems increase the head loss through a wastewater treatment plant, which is created from the redirection of the water flow and friction between the walls of the pipe and the fluid. Additional pumping could be required to compensate for this as head loss is problematic for the overall treatment rate and water flow of the facility.

Vortex-type grit chambers consist of cylindrical tanks in while water flows in tangentially creating a vortex water flow. Due to gravity, grit settles into the bottom of the cylindrical tank where it can be removed, while effluent exits at the top of the tank. Vortex-type grit chambers provide wastewater treatment facilities with many more advantages compared to aerated grit chambers. Compared to other grit removal systems, aerated grit chambers require more power, maintenance, and labor from controlling the aeration system. Vortex-type grit chambers can provide advantages including reduced head loss, energy efficiency, less area footprint, no submerged parts requiring maintenance, and consistent grit removal efficiency over a wide flow range. These systems remove a high percentage of fine grit, up to 73 percent of 140-mesh (0.11mm/0.004 in diameter) size. Head loss through a vortex system is minimal, typically 6 mm (0.25 in). These systems are also energy efficient as they rely heavily on gravity compared to equipment requiring energy usage[37].

Anticipated Savings

To find the anticipated savings for replacing the current grit removal system with a vortex-type grit removal system, the current cost of the blowers that power the current system must first be calculated. The cost to run these blowers each year can be calculated as the savings, as the vortex grit system would not require them and only utilize gravity for treatment.

The energy, demand, and resulting cost of the blowers can be calculated using the following equations:

$$W_{Blower} = HP_{Blower} * C$$

$$E_{Blower} = W_{Blower} * T$$

$$D_{Blower} = W_{Blower} * M$$

$$C_{Blower} = (E_{Blower} * UC) + (D_{Blower} * DC)$$

Where,

W_{Blower} = Wattage of Blower (kW)
HP_{Blower} = Horsepower of Blower (hp/blower)
C = Conversion from hp to kW (0.7457 kW/1 hp)
E_{Blower} = Annual Energy Usage (kWh/year)
D_{Blower} = Electrical Demand (kW-months/year)
T = Time in Operation (hours/year)
M = Months in operation per year (month/year)
UC = Usage Rate ($0.039/kWh)
DC = Monthly Demand Rate ($16.93/kW-month)
C_{Blower} = Annual Blower Cost ($/year)

$$W_{Blower} = \frac{50\ hp}{Blower} * \frac{0.7457\ kW}{1hp}$$

$$W_{Blower} = \frac{37.285\ kW}{Blower}$$

$$E_{Blower} = \frac{37.285kW}{Blower} * 8{,}760\frac{hours}{year}$$

$$E_{Blower} = 326{,}617\frac{kWh}{year}$$

[37] https://www3.epa.gov/npdes/pubs/final_sgrit_removal.pdf

$$D_{Blower} = \frac{37.285kW}{Blower} * \frac{12\ months}{year}$$

$$D_{Blower} = 447.42\frac{kW}{year}$$

$$C_{Blower} = \left(326{,}617\ kWh * \frac{\$0.039}{kWh}\right) + \left(447.42\frac{kW}{year} * \frac{\$16.93}{kW}\right)$$

$$C_{Blower} = \frac{\$20{,}313}{year}$$

Table 6.2-2 shows the total potential savings of this project.

Table 6.2-2: Summary of Current Grit System Energy Consumption

Hours in Operation (hours/year)	Energy Usage (kWh/year)	Demand (kW)	Annual Energy Cost ($/year)
8,760	326,317	447	$20,313

Implementation Cost and Simple Payback

The simple payback period of implementing the new vortex grit removal system must be calculated. The implementation cost of installing the vortex grit removal system has been provided by utility staff from a vendor quote totaling to $716,000 for two Vulcan separators and two Vulcan washers.

Given this implementation cost, the simple payback can be calculated using the following equation:

$$Payback\ Period = \frac{Implementation\ Cost}{Annual\ Savings}$$

$$Payback\ Period = \frac{\$716{,}000}{\$20{,}313}$$

$$Payback\ Period = 35.2\ years$$

7.0 Appendices

7.1 SBR VFD Programming

Wastewater Temperature (T)

Wastewater temperature was obtained from the ECHO database. A Screenshot of the data as it appears on the website can be seen below in Figure 7.1-1. The data has also been tabulated in Table 7.1-1.

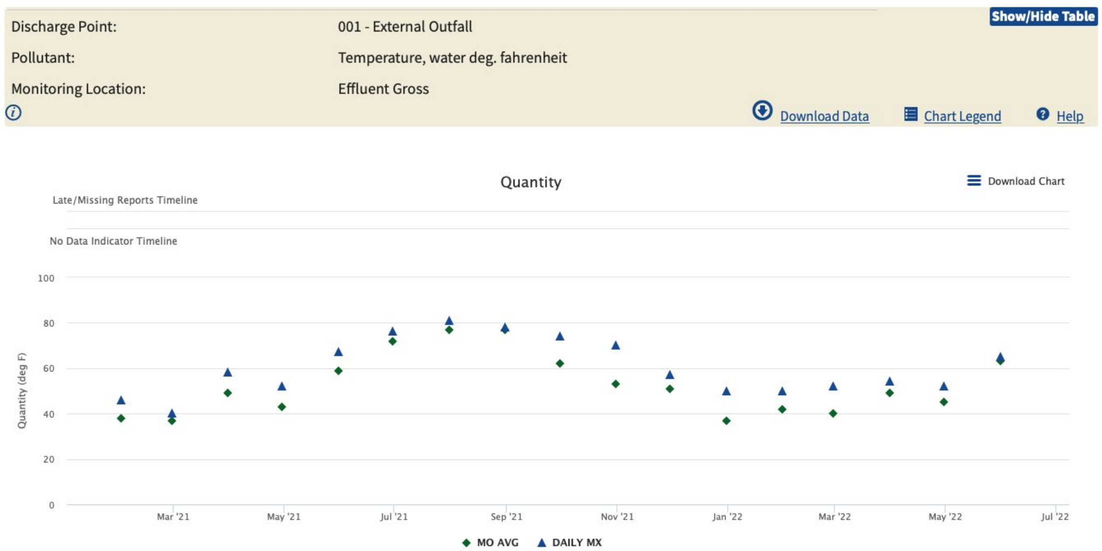


Figure 7.1-1: ECHO Database – Wastewater Temperature

Table 7.1-1: Monthly Wastewater Temperature

		Wastewater Temperature (°C)
XXX	April	6.1
	May	15.0
	June	22.2
	July	25.0
	August	21.7
	September	16.7
	October	11.7
	November	10.6
	December	2.8
XXX	January	5.6
	February	4.4
	March	9.4

Oxygen Concentration in Wastewater (C_{st})

Temperature and concentration data were obtained from Engineering Toolbox (Web: https://www.engineeringtoolbox.com/oxygen-solubility-water-d_841.html). This data was then graphed in excel and an equation for the concentration of oxygen as a function of temperature was established as seen in Figure 7.1-2. Applying this equation to the "Effluent Temperature" column of Table 7.1-2 yields the resulting oxygen concentration as shown in the third column

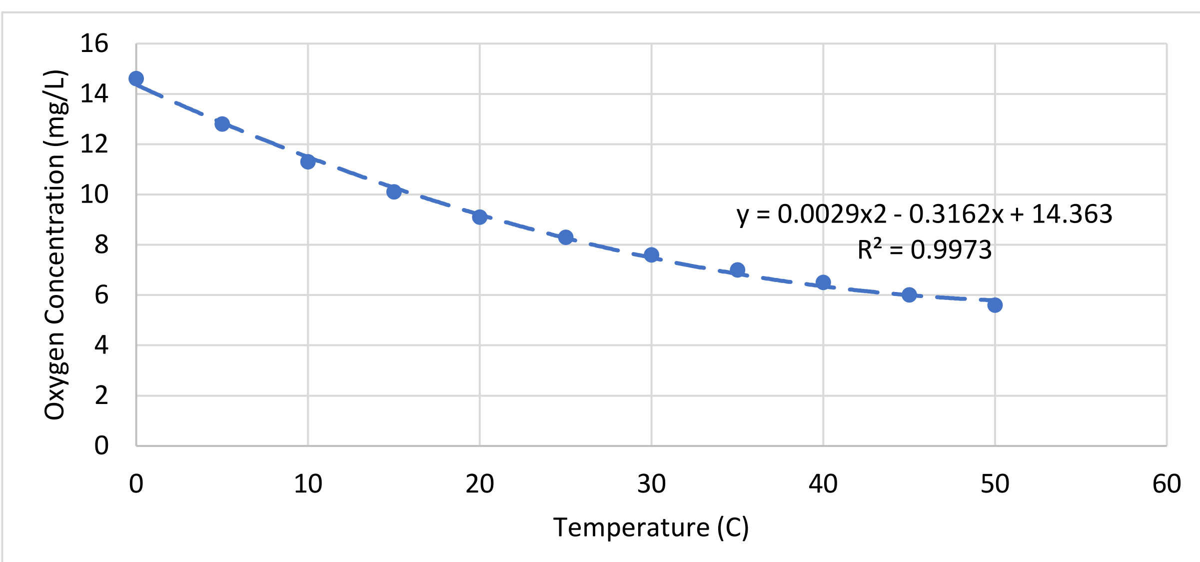


Figure 7.1-2: Concentration of Oxygen in Fresh Water as a Function of Temperature

Table 7.1-2: Summary of Oxygen Concentration

		Wastewater Temperature (°C)	C_{st} (mg/L)
XXX	April	6.1	12.4
	May	15.0	9.7
	June	22.2	7.4
	July	25.0	6.5
	August	21.7	7.6
	September	16.7	9.1
	October	11.7	10.7
	November	10.6	11.1
	December	2.8	13.5
XXX	January	5.6	12.6
	February	4.4	13.0
	March	9.4	11.4

Atmospheric Temperature (T_A)

Average monthly air temperatures for XXX, XXX were obtained from the National Oceanic and Atmospheric Association (NOAA). A summary of the values utilized can be seen in Table 7.1-3 below.

Table 7.1-3: Average Monthly Atmospheric Temperature

Date		Average Atmospheric Temperature (°C)	Average Atmospheric Temperature (K)
XXX	April	10	283
	May	16	289
	June	24	297
	July	24	297
	August	24	297
	September	20	293
	October	13	286
	November	6	279
	December	0	273
XXX	January	(5)	269
	February	(3)	270
	March	3	276

SCADA Data – Annual Blower Operation Hours

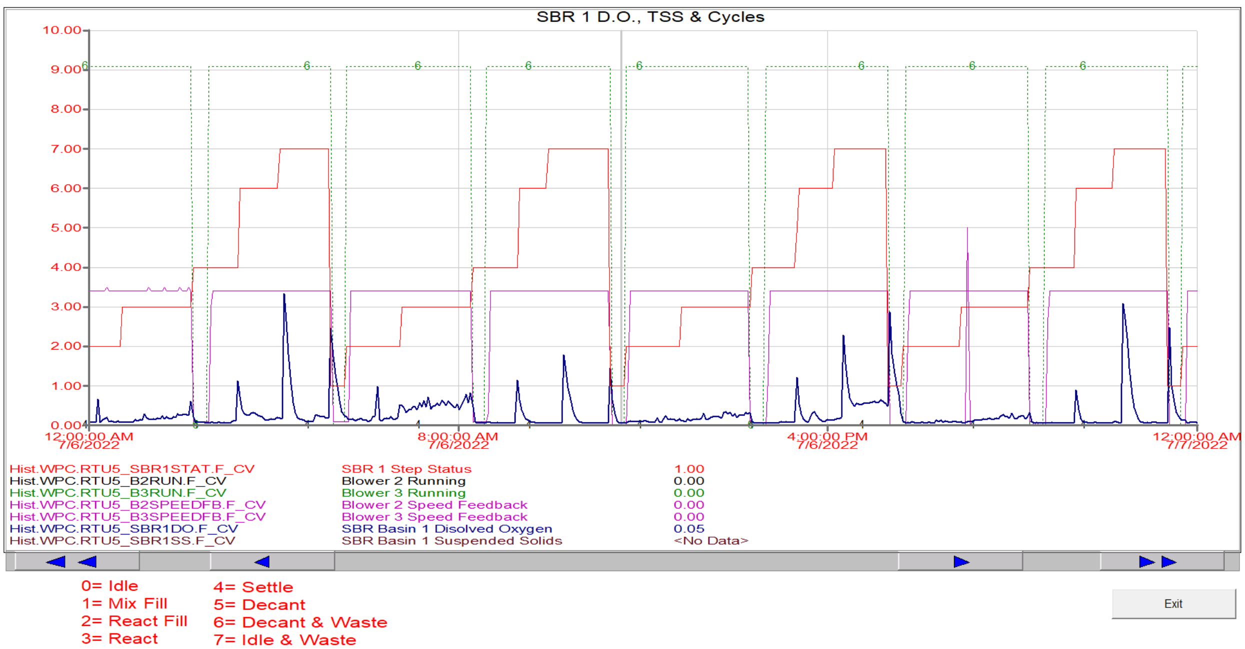


Figure 7.1-3: Screenshot of SCADA Data

SBR 1	
IMAGE #	Total time in "React" Phase (hr)
1	4.8
2	5
3	5
4	5.3
5	5.3
6	5.3
7	5.3
SUM =	36 hr
AVE =	5.14 hr/day

SBR 2	
IMAGE #	Total time in "React" Phase (hr)
1	0
2	5
3	5
4	5.5
5	6
6	6
7	5.5
SUM =	33 hr
AVE =	5.50 hr/day

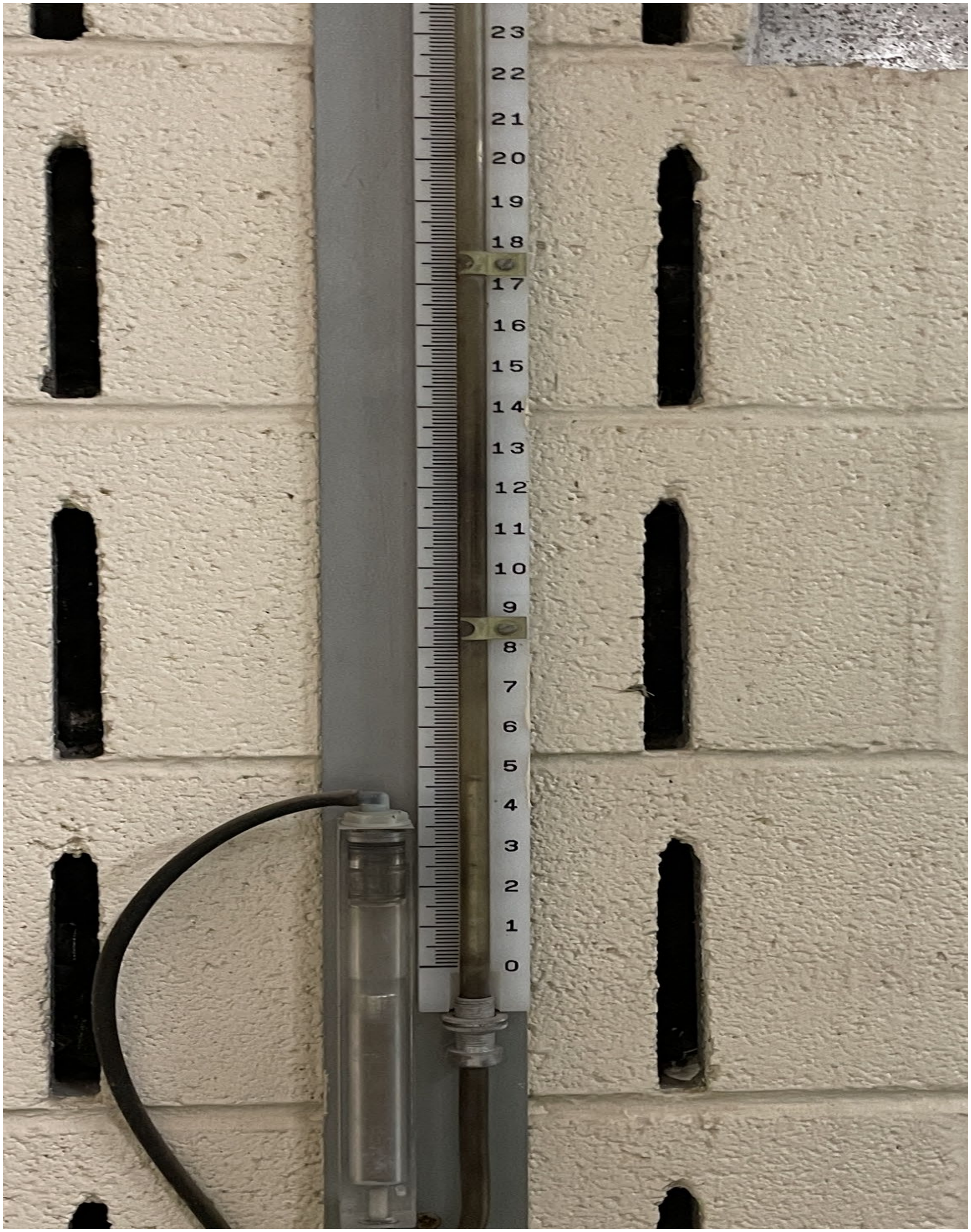
SBR 3	
IMAGE #	Total time in "React" Phase (hr)
1	5.5
2	6
3	5.6
4	5.7
5	5.5
6	5.7
7	6
SUM =	40 hr
AVE =	5.71 hr/day

SBR 4	
IMAGE #	Total time in "React" Phase (hr)
1	5.7
2	5.7
3	5.5
4	5.6
5	6
6	5.6
7	5.7
SUM =	39.8 hr
AVE =	5.69 hr/day

Average Daily Run Time For Blower 1 (SBR 1 + SBR 2) =	10.64	hr/day
Annual Run Time For Blower 1 (SBR 1 + SBR 2) =	3885	hr/year
Average Daily Run Time For Blower 2 (SBR 3 + SBR 4) =	11.40	hr/day
Annual Run Time For Blower 2 (SBR 3 + SBR 4) =	4161	hr/year

Figure 7.1-4: Annual Operational Hour Calculations

7.2 Discharge Pressure Gauge for Sludge Holding Tank Blower



7.3 VFD Information

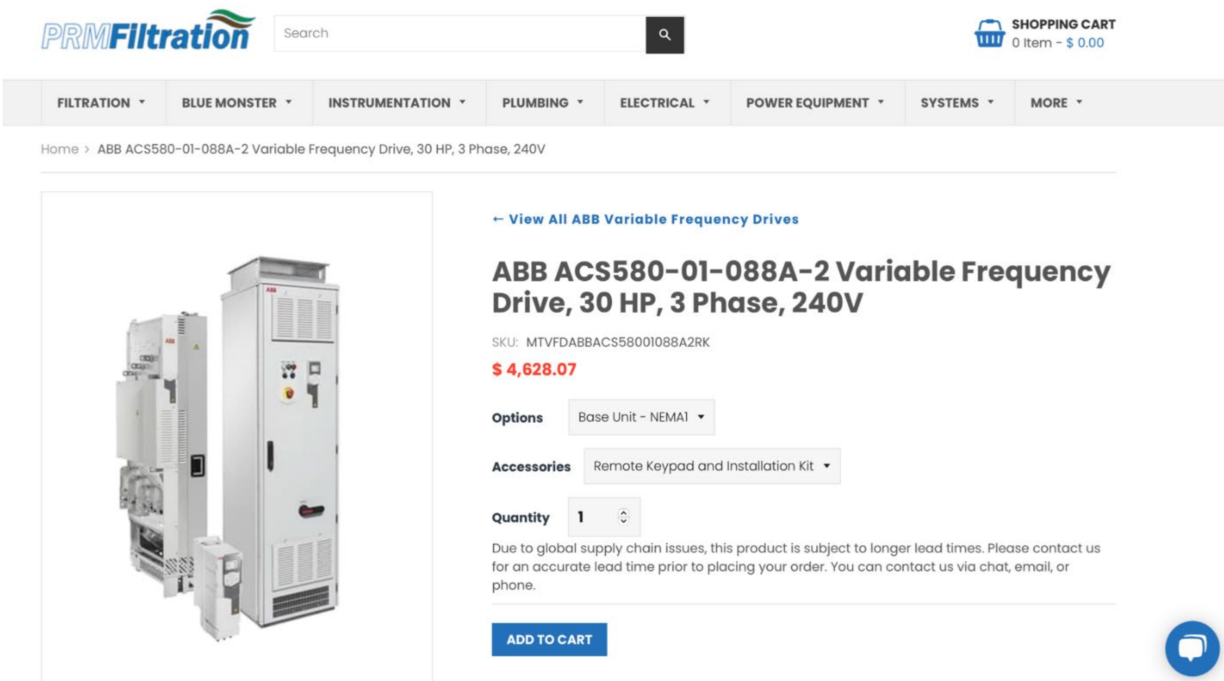


ABB ACS580-01-088A-2 Variable Frequency Drive, 30 HP, 3 Phase, 240V

BRAND: ABB
MPN#: ACS580-01-088A-2
SERIES: ACS580
PRM PART#:MTVFDABBACS58001088A2

SPECS:

- Nominal Input VAC:240 Volts AC
- Input Range VAC: 200 to 240 Volts AC
- Input Phase: 3
- Application: Industrial
- HP (VT): 30 Horsepower
- Amps (VT): 88 Amps
- Max. Frequency: 500 Hertz
- Braking Type: Flux Braking ; Dynamic Braking
- AC Line Regenerative: No
- Closed Loop: No
- Motor Control-Max Level: Open Loop Vector (Sensorless Vector)
- Enclosure Rating: IP21
- Mounting: Panel
- Frame Size: R5
- Height: 28.82 Inches; Width: 7.99 Inches; Depth: 11.61 Inches
- Net Weight: 62 lb 6 oz

ACS580 Technical Catalog

ACS580 Firmware Manual

ABB's new ACS580 drives provide the quality, reliability, and energy savings you expect from ABB drives as well as new features, such as the new primary settings menu and Bluetooth connectivity, that will make it easier to use and safer to maintain.

The ACS580 is simple to install, commission, use, expand, and even upgrade, when the time comes. A compact design makes handling the units easy and with all the essential features built-in, commissioning and setup time is greatly reduced by leveraging the Primary Settings menus and assistants. The assistant control panel, which provides 16 different language options, can be upgraded to and optional Bluetooth control panel to enable wireless commissioning and monitoring.

ACS580 drives are designed for customers who value reliability, high quality, and robustness in their applications. Product features, such as coated boards and compact UL Type 12 (IP55) enclosures, make the ACS580 suitable for harsh conditions.

Additionally, all ACS580 drives and their protective functions are thoroughly tested for performance at maximum temperature with nominal loads.

https://shop.prmfiltration.com/products/abb-acs580-01-088a-2-variable-frequency-drive-30-hp-3-phase-240v?variant=39593632694457

7.4 VFD Rebate Incentive

ENERGYWISE Use less. Spend less. Do more. Nebraska Public Power District Always there when you need us

ABOUT ENERGYWISE ENERGY SAVINGS TIPS TOOLS & RESOURCES CONTACT US

Variable frequency drives (VFDs, also referred to as variable speed drives) can reduce output by controlling the motor rather than having the motor work at a constant, almost full load and adjusting the system to obtain a desired result. Variable speed drives are especially effective at reducing power and energy consumption to centrifugal equipment such as pumps and fans. This is because a reduction in flow is directly proportional to a reduction in speed, while the reduction in power is proportional to the cube of the change in speed.

Potential Savings

For centrifugal loads, small decreases in equipment rotating speed or fluid flow yield significant reductions in energy use. For example, reducing speed (flow) by 20 percent can reduce power requirements by approximately 50 percent. (See Savings Chart, below)

VFD Energy Saving Chart *

Load	Savings
100%	0%
90%	27.1%
80%	48.8%
70%	65.7%
60%	78.4%

Centrifugal loads only. Actual savings will vary based on load and monitor characteristics.

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The latest information on energy grants incentives & programs for residential and business.

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Site Updated:
July 29, 2022

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- Residential Wind Power
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- Renewable & Alternative Energy News
- Solar Hot Water Rebate Information
- Energy Grants For Homeowners
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- Energy Rebates For Insulation
- Energy Rebates For HVAC
- Energy Star Rating System

NE – Nebraska Public Power District – Commercial Energy Efficiency Rebate Programs

Title: Nebraska Public Power District Commercial Energy Efficiency Utility Rebate Program

Details:

The Nebraska Public Power District Commercial Energy Efficiency Utility Rebate Program is a Local Government, State Government, Federal Government, Commercial, Industrial, and Nonprofit program for those who have energy efficient improvements made with the following: Central Air conditioners, Motors, Motor VFDs, Lighting, and Heat pumps. The program offers from $75 for a lighting fixture to $30/hp for a variable frequency drive. For more details use the following links and contact below:

http://www.nppd.com/EnergyWise/business.asp

Contact for more information:

Cory Fuehrer
Nebraska Public Power District
907 West 25th Street
York, NE 68467
Phone: (402) 362-7390
Phone 2: (402) 340-2455
E-Mail: crfuehr@nppd.com
Web Site: http://www.nppd.com/Energy_Efficiency/Energywise/business.asp

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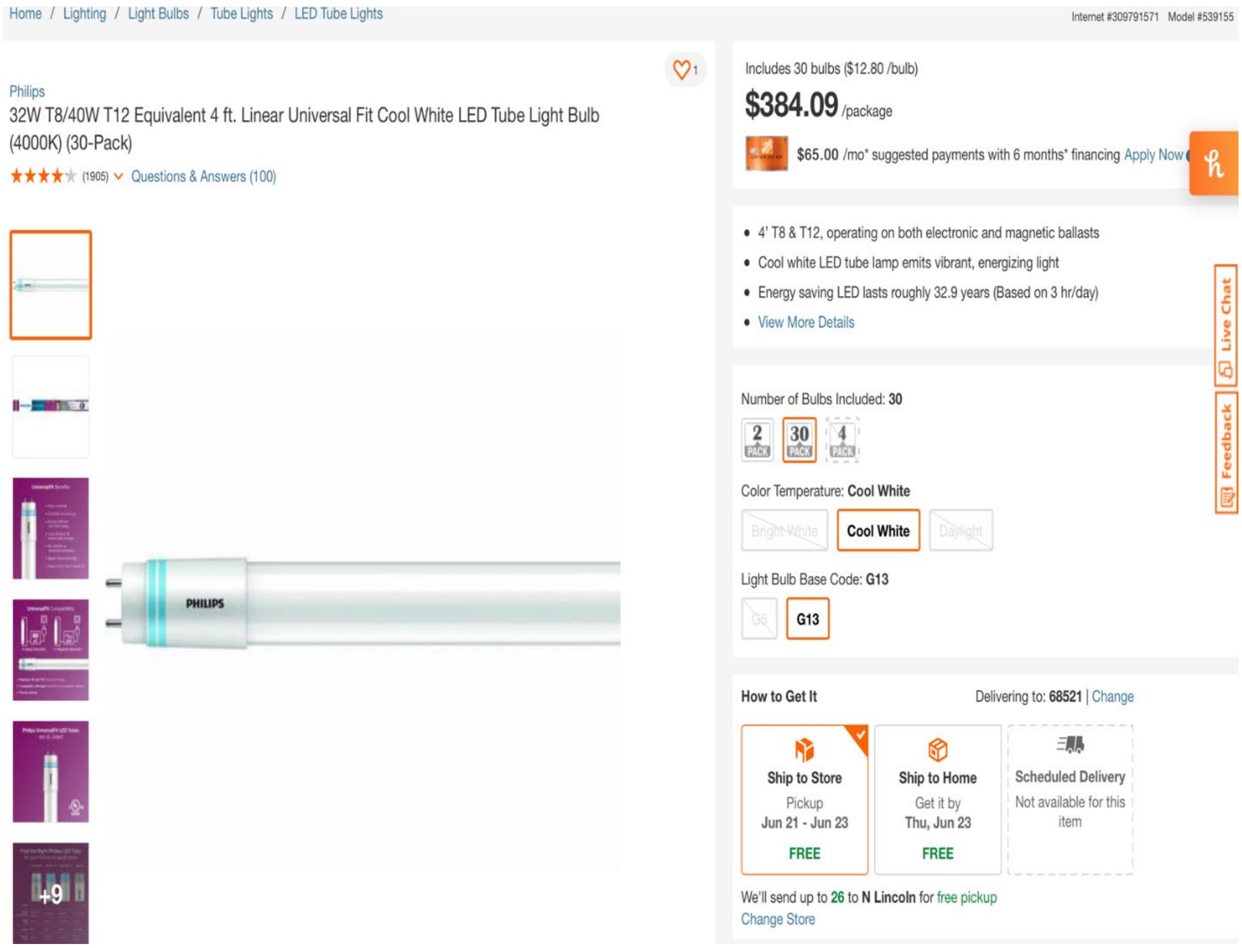
- Iowa
- Kansas

7.5 Lighting Product Information



Product Overview

Philips universal fit LED tubes. The easiest replacement for linear bulbs. Philips universal fit LED tubes (16T8/LED/48-840/UF18/G) replace T8 and T12 linear fluorescent bulbs and can be used with most electronic or magnetic ballasts. Tubes provide bright, energy efficient light in kitchens, laundry rooms, garages and more with up to 40% energy savings (compared to F32T8 electronic instant start systems). These bulbs turn on instantly, contain no mercury, operate in cold temperatures, and have a long life span. LED lifetime means the length of time (in hours) until half of the LED light sources maintain at least 70% of their initial lumen output (B50, L70). Easily replaces T8 or T12 linear fluorescent bulbs with no rewiring; compatible with electronic or magnetic ballasts; turns on instantly and delivers bright, clear light; bright, even light for rooms with frequent on/off switching; 36,000 hour lifespan.

- Brightness: 1800 Lumens
- Estimated yearly energy cost: $2.05 (based on 3-hours per day, 11/kWh, costs depend on rates and use)
- Life: 32.9-year (based on 3-hour/day)
- Light appearance: 4000K (cool white)
- Energy used: 16-Watt (equivalent to a 32-Watt linear fluorescent light bulb)
- Lumens per watt: 112.5
- See every detail when you illuminate your kitchen, garage, workshop, or basement with bright, efficient LED light; ideal for general use or task lighting throughout your home or office, Philips universal fit LED tubes turn on instantly with no flickering or wavering
- Perfect for retail spaces, offices, school, hospitals, and more, Philips universal fit LED tubes are compatible with most electronic and magnetic ballasts and deliver bright, even lighting and up to 40% savings on electricity bills; plus, the long lifespan reduces the hassle of changing burned out fluorescent bulbs in hard to reach areas
- Unsure of tube size or ballast type Philips universal fit LED tubes remove the guesswork because they're designed to

Additional Resources

From the Manufacturer

- Compatibility Chart

You will need Adobe® Acrobat® Reader to view PDF documents. Download a free copy from the Adobe Web site

https://www.homedepot.com/p/Philips-32W-T8-40W-T12-Equivalent-4-ft-Linear-Universal-Fit-Cool-White-LED-Tube-Light-Bulb-4000K-30-Pack-539155/309791571

Product Categories / Lighting / Light Bulbs & Lamps / Linear Light Bulbs & Lamps / General Purpose Linear Light Bulbs / Linear LED Bulb: T5, Miniature Bi-Pin (G5), 4 f...

Email | Pr

Roll over image to zoom.

Product Image Feedback

PHILIPS

Linear LED Bulb: T5, Miniature Bi-Pin (G5), 4 ft Nominal Lg, 28 W LFL, 14 W Watts, 2100 lm

Item # **449U96** Mfr. Model # **476515**
UNSPSC # **39112102** Catalog Page # **481**

Country of Origin China. Country of Origin is subject to change.

Hybrid (UL Type A/C) LED linear light bulbs can be installed in a fluorescent lighting fixture that is powered by a ballast. If the fixture's ballast fails, the fixture can be retrofitted with a compatible LED driver that provides power to the bulb. This spreads out the cost of converting lighting systems from fluorescent tec View More

Compare this product

Web Price
$21.93 / each
Min qty of 10: **$219.30**

Qty 10 | Add to Cart

This product can only be shipped in multiples of 10.

Ship | Pickup

Expected to arrive Fri. Jun 17.
Ship to 68450 | Change

Shipping Weight 0.355 lbs
Ship Availability Terms

Add to List

Technical Specs

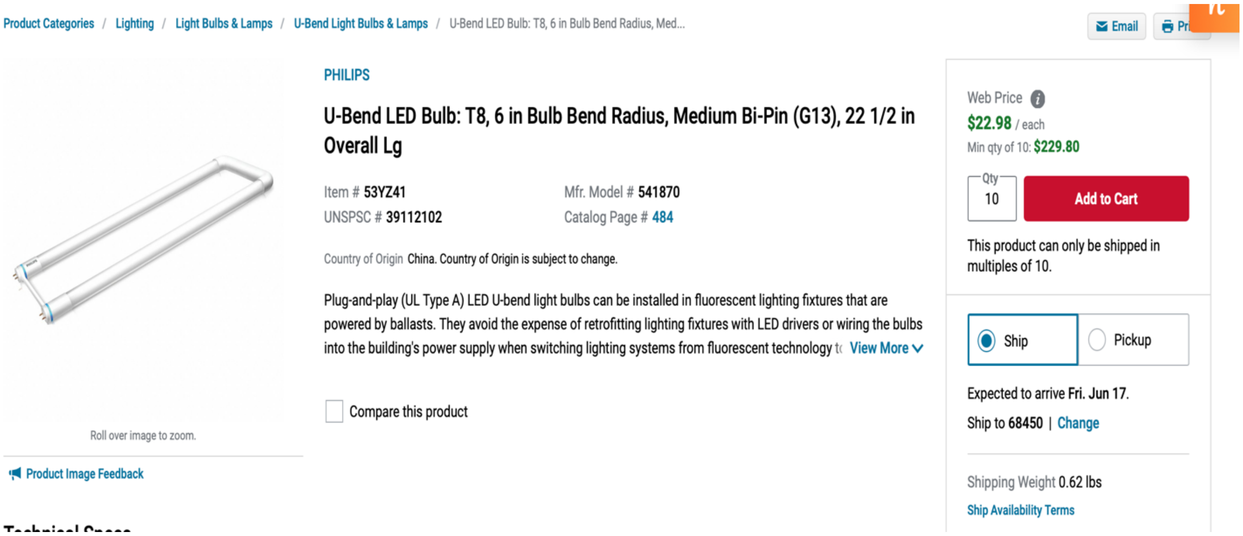
Item	Linear LED Bulb	Rough Service	No

Technical Specs

Item	Linear LED Bulb	Rough Service	No
Bulb UL Type	Type A, Type C	Dimmable	Yes
Nominal Length	4 ft	Color Rendering Index	82
Overall Length	45 3/4 in	Color Tuning	No
Bulb Shape	T5	Bulb Finish	Frosted
Bulb Base Type	Miniature Bi-Pin (G5)	Bulb Housing	Glass
Light Appearance	4000 to 4999K, Cool White	Bulb Minimum Starting Temperature	-4 Degrees F
Color Temperature	4000K	Bulb Operating Temp. Range	-4 Degrees to 113 Degrees F
Light Technology	LED	For Enclosed Fixtures	No
Watts	14 W	Standards	UL, cUL Listed
Wattage Equivalency	28 W LFL	Energy Star Compliant	No
Lumens	2100 lm	Bulb Designation	14T5HE/48-840/IF21/G/DIM 10/1
Voltage	70 to 105 V AC	Bulb Manufacturers Warranty Length	5 yr
Shatter-Resistant	No	Lamp Wiring	Not Applicable
Indoor/Outdoor Usage	Indoor Only	Dimming Type	0-10V
Rated Life	50,000 hr	Dimming Method	Continuous Dimming
Bulb Power Source	Plug and Play	Lighting Certification	DesignLights Consortium (DLC)
Bulb Primary Application	General Purpose	Series	InstantFit
Bulb Dia.	3/4 in	Green Environmental Attribute	Product Contributes To Reducing Energy Consumption

Cu

https://www.grainger.com/product/PHILIPS-Linear-LED-Bulb-T5-449U96


Product Categories / Lighting / Light Bulbs & Lamps / U-Bend Light Bulbs & Lamps / U-Bend LED Bulb: T8, 6 in Bulb Bend Radius, Med...
Email
Roll over image to zoom.
Product Image Feedback
PHILIPS
U-Bend LED Bulb: T8, 6 in Bulb Bend Radius, Medium Bi-Pin (G13), 22 1/2 in Overall Lg
Item # 53YZ41
Mfr. Model # 541870
UNSPSC # 39112102
Catalog Page # 484
Country of Origin China. Country of Origin is subject to change.
Plug-and-play (UL Type A) LED U-bend light bulbs can be installed in fluorescent lighting fixtures that are powered by ballasts. They avoid the expense of retrofitting lighting fixtures with LED drivers or wiring the bulbs into the building's power supply when switching lighting systems from fluorescent technology t
View More
Compare this product
Web Price
$22.98 / each
Min qty of 10: $229.80
Qty
10
Add to Cart
This product can only be shipped in multiples of 10.
Ship
Pickup
Expected to arrive Fri. Jun 17.
Ship to 68450 | Change
Shipping Weight 0.62 lbs
Ship Availability Terms

Technical Specs

Item	U-Bend LED Bulb
Bulb Shape	T8
Bulb Base Type	Medium Bi-Pin (G13)
Overall Length	22 1/2 in
Bulb Bend Radius	6 in
Bulb Dia.	1 1/8 in
Light Technology	LED
Color Temperature	4000K
Light Appearance	4000 to 4999K, Cool White
Lumens	2,100 lm
Dimmable	No
Wattage Equivalency	32W Fluorescent
Watts	13 W
Voltage	120 to 277V AC, 347V AC
Bulb Primary Application	General Purpose
Bulb Type	U-Bend
Bulb Power Source	Plug and Play
Trade Number	13T8/24-4000 IF 10/1
Rated Life	70,000 hr

Shatter-Resistant	Yes
Bulb Finish	Frosted
Bulb Housing	Polycarbonate
Bulb Operating Temp. Range	-4 Degrees to 113 Degrees F
Color Tuning	No
For Enclosed Fixtures	Yes
Indoor/Outdoor Usage	Indoor/Outdoor
Light Distribution	Downward
Bulb Manufacturers Warranty Length	5 yr
Rough Service	No
Energy Star Compliant	No
For Use With	U-Bend Fluorescent Fixtures
High Output	No
Color Rendering Index	80.0
Bulb Minimum Starting Temperature	-4 Degrees F
Includes	No Accessories Included
Standards	CE, RoHS Compliant, UL Listed
Green Environmental Attribute	Product Contributes To Reducing Energy Consumption
Green Certification or Other Recognition	DesignLights Consortium (DLC)(R) Listed

https://www.grainger.com/product/PHILIPS-U-Bend-LED-Bulb-T8-53YZ41

7.6 Lighting Rebate via XXX

ENERGYWISE
Use less. Spend less. Do more.

Nebraska Public Power District
Always there when you need us

ABOUT ENERGYWISE ENERGY SAVINGS TIPS TOOLS & RESOURCES CONTACT US

Follow these easy steps

- Visit with your electrical utility to discuss your project and pick up an application form.
- Obtain a contractor and install any of the energy-efficient lighting products as identified in the chart.
- Complete an application form after installation is complete.
- Submit the signed application, (along with proof of purchase identified in the application's terms & conditions) to your local utility for the incentive within 90 days of installation.

Application		LED Wattage	Incentive
Linear Fluorescent (Replaces fluorescent)	NEW LED Fixture	9 – 22 watts LED	$5
		23 – 45 watts LED	$10
		46 – 68 watts LED	$15
		69 watts or greater LED	$20
	Retrofit Lamp, Tube, Panel or Kit	9 – 22 watts LED	$2
		23 – 45 watts LED	$4
		46 – 68 watts LED	$6
		69 watts LED	$8

https://nppd.energywisenebraska.com/business/

7.7 CAGI data sheet for Quincy Compressor (QGV-75)

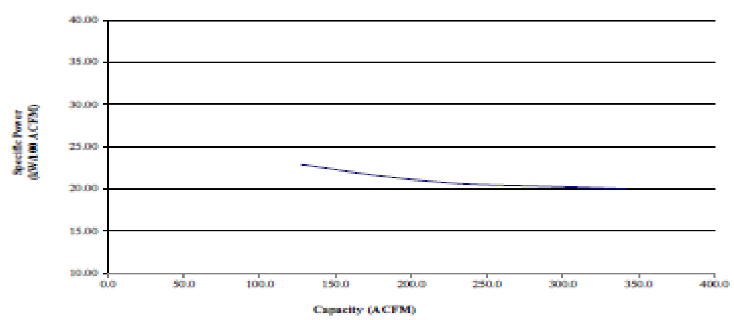
COMPRESSOR DATA SHEET

In Accordance With Federal Uniform Test Method for Certain Lubricated Air Compressors

Rotary Compressor: Variable Frequency Drive

MODEL DATA - FOR COMPRESSED AIR				
1	Manufacturer: **Quincy Compressor**			
2	Model Number: **QGV-75**		Date:	**02/22/21**
	X Air-cooled ☐ Water-cooled		Type:	**Screw**
			# of Stages:	**1**
3*	Full Load Operating Pressure [b]	**125**		psig [b]
4	Drive Motor Nominal Rating	**75**		hp
5	Drive Motor Nominal Efficiency	**94.2**		percent
6	Fan Motor Nominal Rating (if applicable)	**3.75**		hp
7	Fan Motor Nominal Efficiency	**76.0**		percent
8*	Input Power (kW)	Capacity (acfm) [a,d]		Specific Power (kW/100 acfm) [d]
	68.3	**341.2**		**20.00**
	58.4	**287.9**		**20.30**
	48.4	**234.8**		**20.60**
	38.9	**181.2**		**21.50**
	29.3	**127.8**		**22.90**
9*	Total Package Input Power at Zero Flow [c, d]	**0.0**		**kW**
10	Isentropic Efficiency	**71.6**		**%**

11



Note: Graph is only a visual representation of the data in Section 8
Note: Y-Axis Scale, 10 to 35, + 5kW/100acfm increments if necessary above 35
X-Axis Scale, 0 to 25% over maximum capacity

*For models that are tested in the CAGI Performance Verification Program, these items are verified by the third party administrator
Consult CAGI website for a list of participants in the third party verification program: www.cagi.org

NOTES:
a. Measured at the discharge terminal point of the compressor package in accordance with ISO 1217, Annex E; ACFM is actual cubic feet per minute at inlet conditions.
b. The operating pressure at which the Capacity (Item 8) and Electrical Consumption (Item 8) were measured for this data sheet.
c. No Load Power. In accordance with ISO 1217, Annex E, if measurement of no load power equals less than 1%, manufacturer may state "not significant" or "0" on the test report.
d. Tolerance is specified in ISO 1217, Annex E, as shown in table below:
NOTE: The terms "power" and "energy" are synonymous for purposes of this document.

CAGI Compressed Air & Gas Institute Member

Volume Flow Rate at specified conditions		Volume Flow Rate	Specific Energy Consumption	No Load / Zero Flow Power
m^3 / min	ft^3 / min	%	%	%
Below 0.5	Below 17.6	+/- 7	+/- 8	+/- 10%
0.5 to 1.5	17.6 to 53	+/- 6	+/- 7	
1.5 to 15	53 to 529.7	+/- 5	+/- 6	
Above 15	Above 529.7	+/- 4	+/- 5	

ROT 031.1

12/19 Rev 3 This form was developed by the Compressed Air and Gas Institute for the use of its members participating in the PVP. CAGI has not independently verified the reported data.

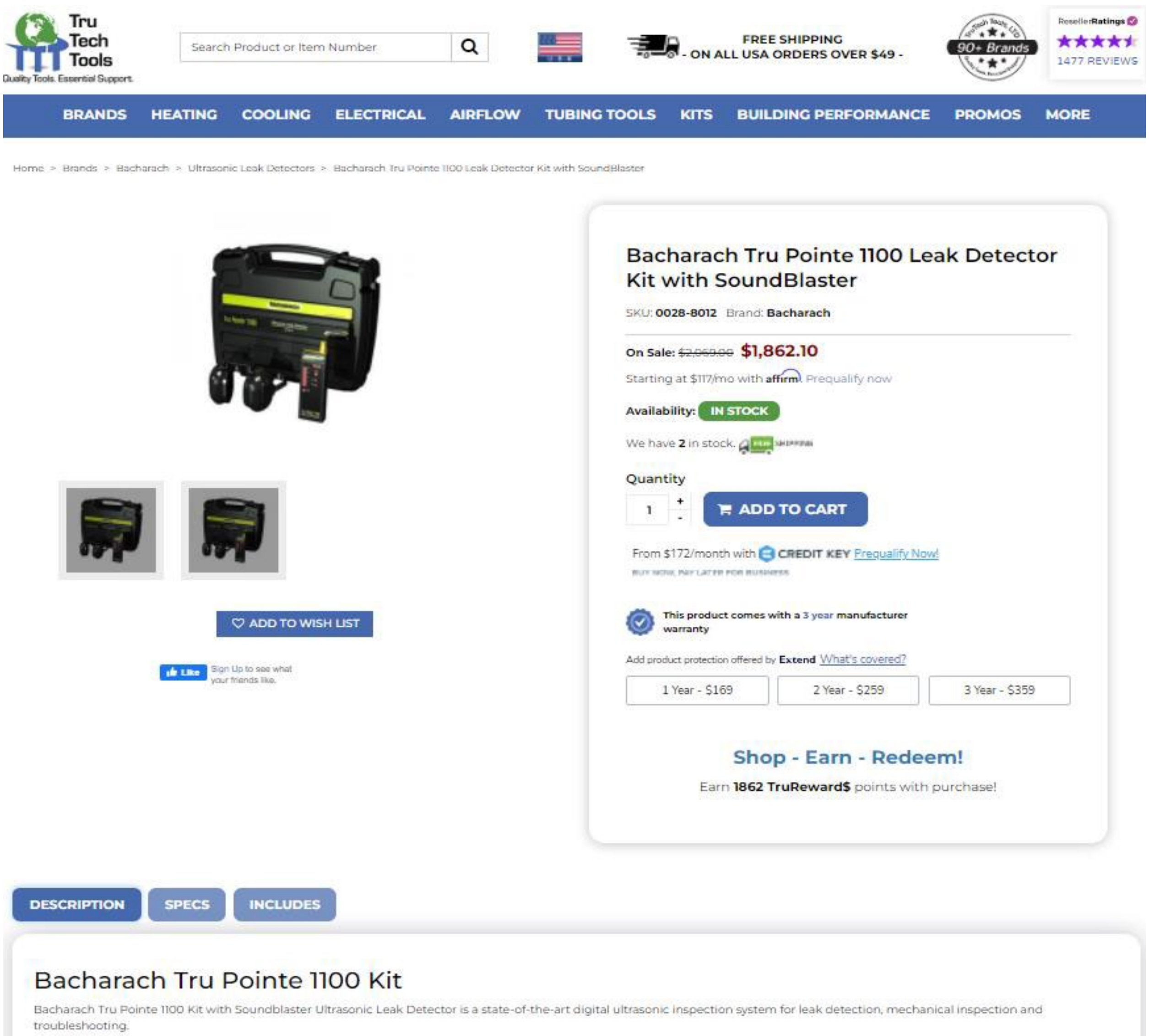
7.8 Leakage Data of the Facility

Table 7.8-1: Summary of Leaks Located During Assessment

Location	Measured Sensitivity Level	Leak Rate (cfm)
Line 3	88	16.47
Line 1	63	1.88
Line 5	83	10.67
Line 7	49	0.56
Line 7	71	3.77
Line 12	61	1.58
Line 6	62	1.73
Line 11	47	0.47
Line 16	55	0.94
Line 18	72	4.11
Line 4	72	4.11
Paint Line	72	4.11
Line 25	47	0.47
Line 25	65	2.24
Line 25	71	3.77
Line 25	51	0.67
Line 28	70	3.46
Line 28	58	1.22
Compressor Room	73	4.49
Compressor Room	57	1.12
Paper Line	48	0.51
Paper Line	88	16.47
Total		**68.37**

7.9 Ultrasonic Leak Detector Vendor Quote Information

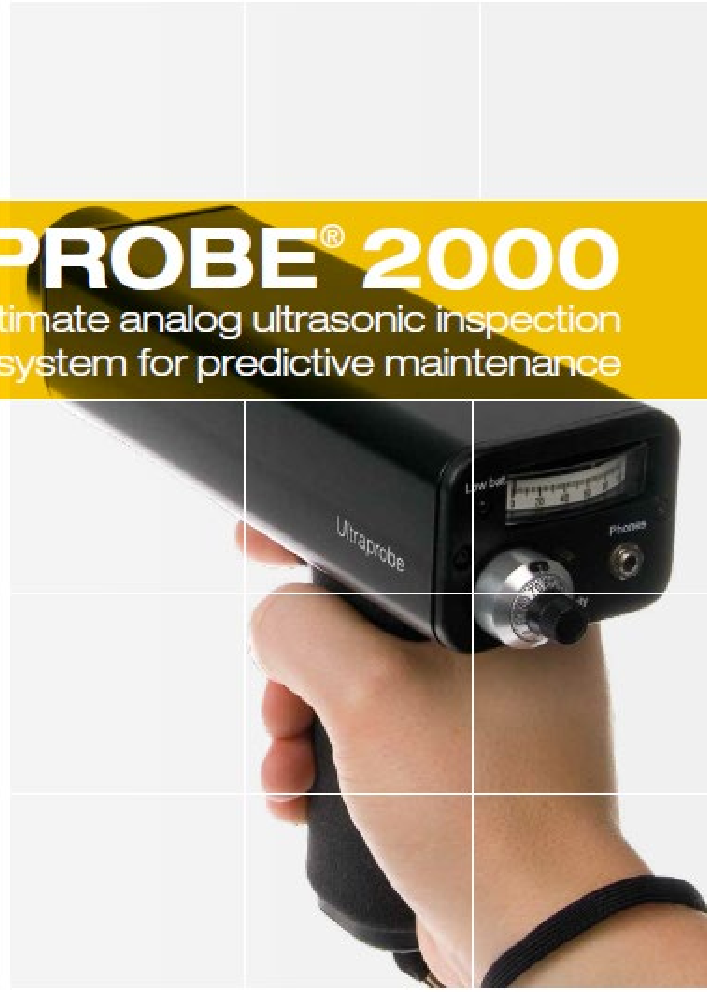
Recommended Product Available from: https://www.trutechtools.com/0028-8012



Other Ultrasonic Leak Detectors:

ULTRAPROBE® 2000

The ultimate analog ultrasonic inspection system for predictive maintenance



The Ultraprobe® 2000 flexibility and adaptability easily adjusts to meet a wide range of testing demands. This intrinsically safe instrument tests for leaks as well as performs mechanical and electrical inspections.

Flexible / Adaptable Recognizing that every test environment is different, our engineers designed the Ultraprobe with many user-friendly features, which can be adapted to approach virtually any inspection requirement.

Frequency Tuning allows the operator to select the specific frequency of a problem sound while reducing interference from competing ultrasonic signals.

Bi-Modal Meter Switch has two meter functions:
1) *Logarithmic Metering* will provide instant 'real time' re-sponse for enhanced leak and fault detection.
2) *Linear Mode* provides a slow, averaging response to stabilize readings for bearing and mechanical monitoring.

A 10-turn Sensitivity Adjust Dial
provides a wide dynamic sensitivity range.

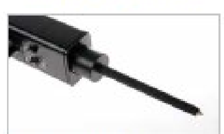
Trisonic™ Scanning Module
a patented transducer, consists of a phased array of three transducers, which provides a level of sensitivity beyond anything previously obtainable.

Acoustic Headphones:
• Noise isolating type for loud environments.

Intrinsically Safe:
• FM, CSA, ATEX rated

Application Selection Chart

APPLICATION	KIT #	UP2000KT	UP2000SC	UP2000C	UP2000S
Pressure & Vacuum Leak Detection		•	•		•
Hydraulic Valve Bypass		•	•	•	
Exhaust System Leaks		•	•		•
Heat Exchangers, Boilers, Condensers		•	•		•
Valve & Steam Trap Inspection		•	•	•	
Bearing Testing		•	•	•	
Gear/Gear Box Inspection		•	•	•	
Cockpit Window/Hatch Leaks		•			
General Mechanical Inspection		•	•	•	
Tanks, Pipes, Leak Testing, etc.		•	•		•
Electrical Inspection		•	•		•


Stethoscope module


Long range module


Close focus module

UE SYSTEMS INC

So advanced, it's simple

Leak Detectors

Ultrasonic Leak Detector
Tru Pointe® Ultra & Tru Pointe® Ultra HD

Bacharach's **Tru Pointe® Ultra** is a compact ultrasonic leak detector that uses patented technology to detect leaks in air conditioning and refrigeration systems. The Tru Pointe® Ultra is the world's first pocket-size electronic instrument that can simultaneously detect the vacuum and high pressure leaks that occur in HVAC/R systems. The Tru Pointe® Ultra guides the user to a leak by quantifying the intensity of the ultrasound and converting it to a sound the user can hear easily through headphones.

Tru Pointe® Ultra's operational principle is based on the detection of inaudible high frequency sounds produced by the flow of gases and liquids in leaks. The leak flow, passing through very narrow spaces (cracks, holes etc.), generates a rich ultrasonic sound spectrum which is easy to detect with the Tru Pointe® Ultra leak detector.

Since the Tru Pointe® Ultra detects airborne ultrasound and is not a particular to gas chemistry it can detect all types of gases including nitrogen and refrigerants rushing in a system under vacuum. An electronic conversion process called heterodyning translates this ultrasound into true audible sound that helps the user distinguish leaks through headphones.

Saves time and money!

The Tru Pointe® Ultra is capable of finding pressure and vacuum leaks in HVAC systems, without being affected by the wind or background refrigerants in confined spaces. It can find a leak as small as 2.5-3oz./yr (84gr/yr).

Available with compact, folding headset (Tru Pointe® Ultra) or high quality stereo headphones (Tru Pointe® Ultra HD), the Tru Pointe® Ultra is an indispensable tool that saves time and money for every HVAC/R technician and contractor.

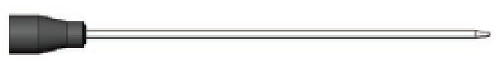
Phone: 1-800-736-4666 | Website: www.MyBacharach.com | E-mail: help@MyBacharach.com

Tru Pointe® Ultra Features & Benefits:

- Not affected by wind or the presence of other gases or high concentrations.
- Ten-step LED Bar Graph shows signal strength.
- On-the-fly Sensitivity Adjustment aids in locating leaks quickly.
- True sound reproduction ensures fast recognition of leaks.

Tru Pointe® Ultra Specifications	
Mechanical:	
Dimensions:	5.5" (14cm) X 2.4" (61mm) X .875 (22.22mm)
Weight:	0.3lb (138gr) Includes Battery
Body Materials:	Durable ABS
Audio Connector:	3.5mm Stereo
Electrical:	
Airborne Sensor Sensitivity:	-80db/V-μbar
Ultrasound Converter Type:	Analog Controlled Heterodyne
Fequency response, Airborne:	34kHz to 42kHz
Heterodyne Filter:	4kHz
Heterodyne Oscillator:	Analog
Controls:	1 Button
Sensitivity Control:	Continually Variable Slide
Output, Audio:	0Hz to 4kHz
Output, Visual:	10 Segment Bar Graph
Battery Type:	9 Volt
Run Time:	80-120 hrs

Touch Probe- Helps convert sounds within valves or solids to airborne sound for the Tru Pointe® Ultra to detect. (Patented).



Headset Options- Choice of compact, foldable headset or high-quality stereo headset; choose Tru Pointe® Ultra or Tru Pointe® Ultra HD.

SoundBlaster® - Ultrasonic Sound Generator. Artificially pressurizes rooms, tanks, enclosures with sound that the Tru Pointe® Ultra can detect thus locating where they leak air, water or other fluids or gases.

Tru Pointe® Ultra & Tru Pointe® Ultra HD	
Ordering Information	
28-8000	Tru Pointe® Ultra Leak Detector Kit w/folding headset
28-8010	Tru Pointe® Ultra Leak Detector Kit w/folding headset & SoundBlaster®
28-8001	Tru Pointe® Ultra HD Leak Detector Kit w/stereo headphones
28-8011	Tru Pointe® Ultra HD Leak Detector Kit w/stereo headphones & SoundBlaster®

Distributed By:

BACHARACH
The Measurable Difference

ISO 9001:2008

Superior® AccuTrak®
Ultrasonic Leak Detectors

Made in USA

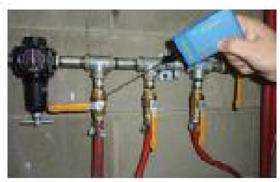
Ultrasonic Leak Detection with Superior *AccuTrak*® VPE

The Patented Superior *AccuTrak*® VPE State-of-the-art Technology for pinpointing leaks in Air Conditioning and Refrigeration Systems

AccuTrak® is extremely sensitive to the ultrasonic sound of a turbulent gas leak. Using a technology called "heterodyning" it translates the sound to a lower frequency which your ear can interpret. *AccuTrak*® maintains the original sound characteristics making it possible to distinguish leaks from other competing background sounds. *AccuTrak*® is so sensitive you can actually hear the blink of an eye, yet most background noise will not interfere with detection accuracy.

Applications:

- Leak Detection: Air, Vacuum, Refrigerants, ANY GAS!
- Diagnose thermal expansion valves in just five minutes!
- Valves: Detect/ Hear internal leakage in any type of valve!
- Bearing Wear: Hear wear & lubrication problems before damage is done!
- Steam Traps: Detect live steam loss in seconds!



Capabilities:

- Works equally well for compressed Air or Nitrogen.
- Not affected by wind or high concentrations of leaked gas or refrigerant.
- Capable of detecting leaks equivalent to 1.5 oz/year of Refrigerant.
- Able to detect a 5 psi leak through a 0.005" (5/1000 inch) hole, from a 20-30 foot distance depending on background noise.
- Easily detects any gas that generates ultrasonic sound during flow including vacuum leaks.

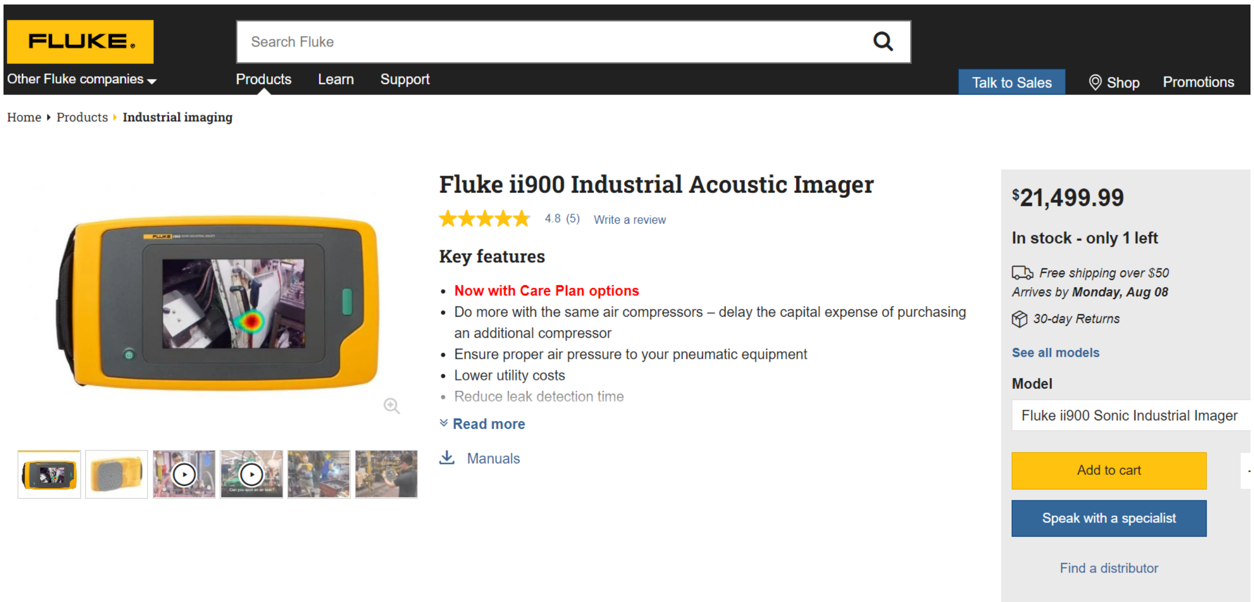
Introducing the NEW VPE-GN Gooseneck
Finds Leaks in Hard to Reach Spaces!

The New 9½" Flexible Gooseneck Makes
Leak Detection Easy in Hard-To-Reach Places!

Superior Signal Company LLC • 1-800-945-TEST • www.SuperiorSignal.com

Fluke Industrial Acoustic Imager Vendor Quote Information

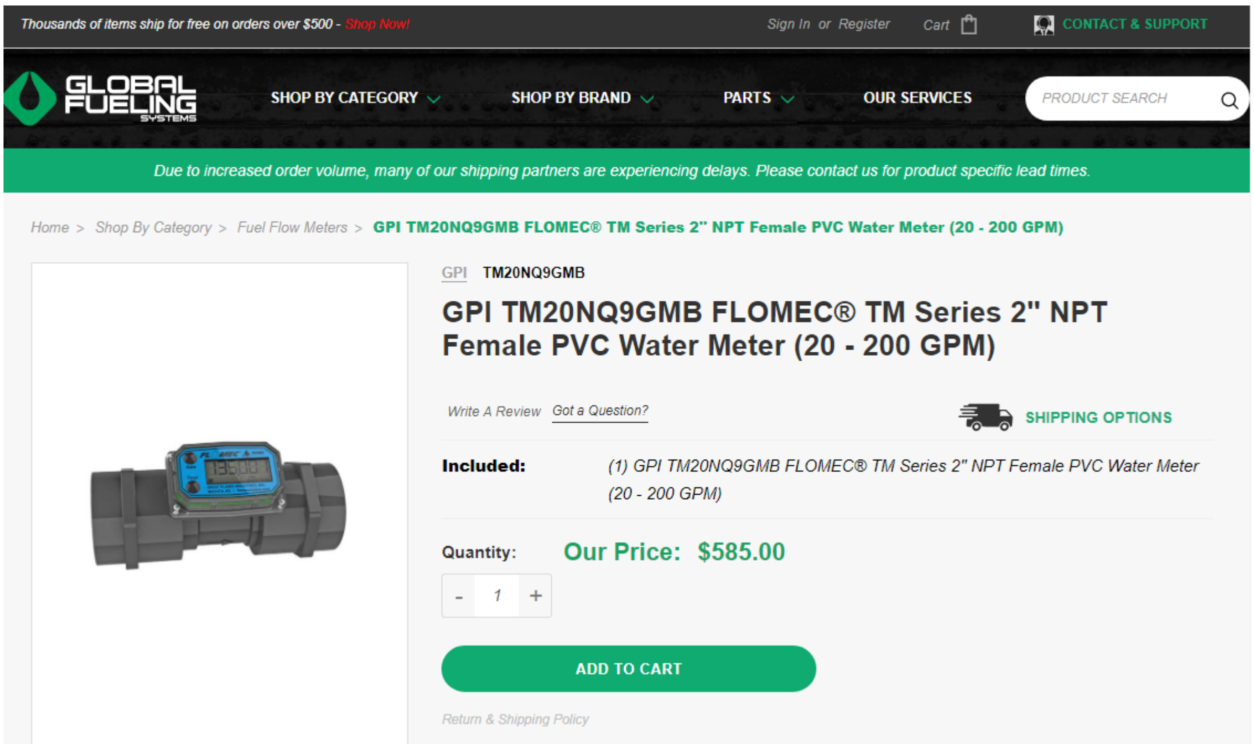
Recommended Product Available from: https://www.fluke.com/en-us/product/industrial-imaging/sonic-industrial-imager-ii900



7.10 Water Flow Meter quotes

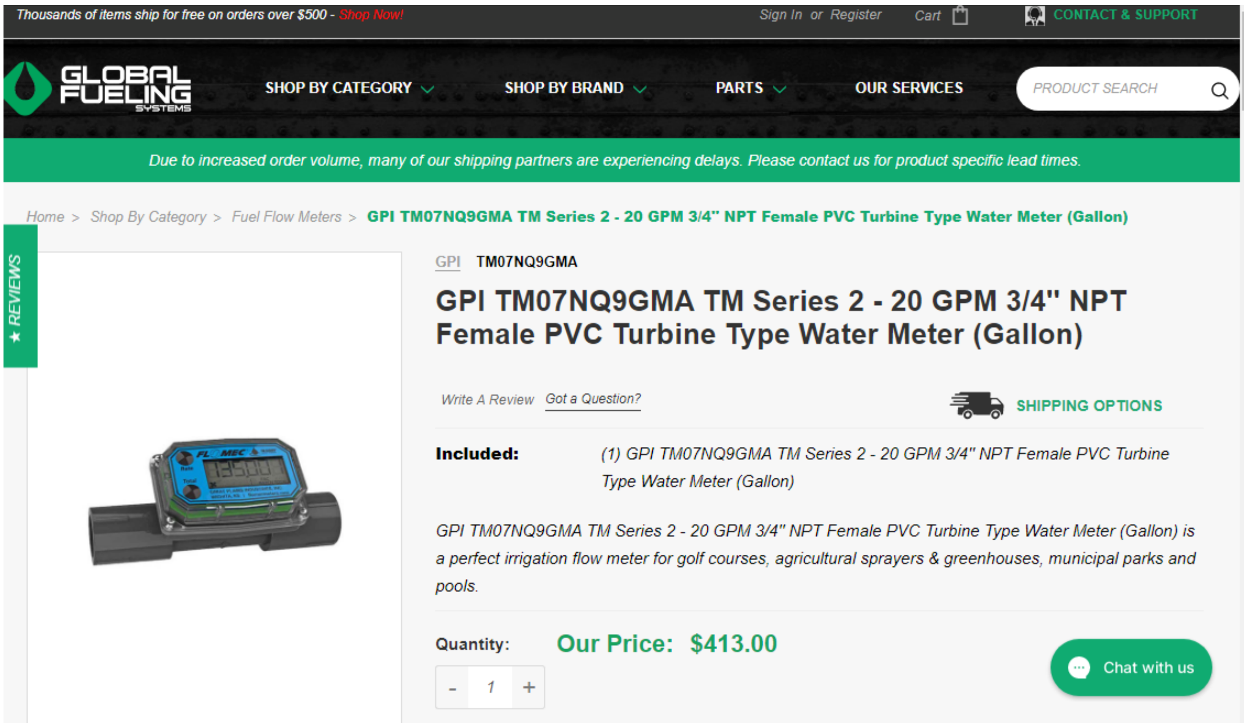
Quote 1

https://globalfuelingsystems.com/gpi-tm20nq9gmb-flomec-2-npt-female-pvc-tm-series-water-meter-20-200-gpm/?setCurrencyId=1&sku=TM20NQ9GMB



Quote 2

https://globalfuelingsystems.com/gpi-tm07nq9gma-tm-series-2-20-gpm-3-4-npt-female-pvc-turbine-type-water-meter-gallon/



Quote 3

https://greatplainsindustries.com/products/1-2-inch-to-2-inch-pvc-water-processing-and-irrigation-flow-meter?currency=USD&variant=44040542060779&utm_medium=cpc&utm_source=google&utm_campaign=Google%20Shopping&gclid=CjwKCAjw5remBhBiEiwAxL2M93Mz7ASpGoqA8QV0kCjKNIw2KXeJt9UYLD3sAJrBtZkmYrbLRiaUNhoCo9kQAvD_BwE