MISSOURI DEPARTMENT OF NATURAL RESOURCES

ENERGIZE MISSOURI

RENEWABLE ENERGY STUDY SUBGRANT

Missouri Department of Natural Resources

Investigating Pump Applications for Pressure Reduction and Electrical Energy Recovery

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MISSOURI AMERICAN WATER

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Preface

The Energize Missouri Renewable Energy Study Subgrant program was created to increase the ability of businesses, governments and organizations to make informed decisions about complex renewable energy systems by understanding and solving information deficiency and technical uncertainties. Program funds are made possible through the American Recovery and Reinvestment Act and the Transform Missouri initiative and administered by the Missouri Department of Natural Resources.

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1.0 PROJECT SUMMARY

The scope of this project was to investigate pump applications for pressure reduction and electrical energy recovery. This project focused on the use of the pumps as turbines (PAT) at an existing pressure reducing station known as Greensbottom, which is owned and operated by Missouri American Water Company. The following are the key findings of this project:

- Centrifugal pumps can be operated in reverse and be used as turbines effectively to produce electricity. The most predominant applications revolve around industrial process applications and municipal water distribution systems.
- Compared to traditional turbines, pumps are available in a wide range of head and flows, have a lower first cost and maintenance operating cost, less complex to operate, replacement equipment and parts are readily available, control of a PAT system is generally less complex, and pumps are readily available in the market place for a variety of operating conditions.
- Turbines use inlet guide vanes and can operate across a large range of flow and pressure and effectively generate electricity, whereas multiple pumps are needed to achieve the same operating diversity. A single pump PAT system operates across a fixed flow and pressure range and generally does not effectively produce electricity below 42% of the total flow range. A multiple PAT system is needed to generate electricity efficiently across a wide range of flows and pressure.
- Analytical formulas and relationships used for pumps can also be used to estimate the performance of a pump operating as a turbine. Mathematical derivations of Flow, Pressure, Efficiency, Specific Speed, Power, and Energy can be used to analyze the performance of a PAT system. Actual PAT performance of pumps is not accurately known and must be established by the pump manufacturers.
- Both three phase and single phase induction motors can be used to generate electricity effectively. When connected to a three phase utility system, the induction system requires no speed governing controls.
- The overall efficiency of the PAT system proposed is approximately 70%. The highest possible efficiency of a single PAT is 82% respectively.
- The facility uses roughly 100,000 kWh of electricity and costs around $6,000 per year to operate ($0.06/ kWh on average). PAT electrical output is expected to outset yearly facility electric use by at least 80%.
- The PAT simulation showed the system could produce between 186,000 and 406,000 kWh per year and provides income between $3,000 and $7,000 per year, with a peak power output between 35 and 140 kW, depending on the number of pumps used.
- Ameren Missouri is expected to pay about $0.0183 per kWh for electricity sold back to the grid for systems with capacities less than 100 kW (two pump system). Rates for systems over 100 kW (three or more pumps) will have to be negotiated and approved by the Missouri Public Service Commission.
- Net-metering may or may not apply to this project. The Missouri Department of Natural Resources (DNR) is responsible for determining if this project can be classified a "renewable energy" project.
- The estimated cost to install the PAT system ranges between $75k and $190k. The simple payback period of the PAT system ranges between 8 and 17 years.
- The single pump installation has the best simple payback performance at 8.3 years, while the two pump installation has the best life cycle cost or lowest present value over a 30 year system life.

2.0 INTRODUCTION

2.1 BACKGROUND

The scope of this project is to investigate pump applications for pressure reduction and electrical energy recovery. This project is focused around an existing domestic water booster pump station known as the Greensbottom Booster Pump Station. More specifically, the use of centrifugal type pumps operating as turbines, otherwise known as PATs, will be investigated for this facility.

Missouri American Water Company (MAWC) presently owns and operates the Greensbottom Booster Pump Station (aka Greensbottom) located in St. Charles County, near the Missouri River. This 15 year old facility was originally designed to boost water pressure supplied to St. Charles County from distribution systems owned by the City of St. Louis. More recently, the water supplied to Greensbottom now comes from other MAWC facilities located in St. Louis County. The MAWC system pressure in St. Louis County is higher than that of the City of St. Louis. Therefore, this station is now required to reduce the pressure to St. Charles County through the use of pressure reducing valves (PRVs). Energy that is used to boost the pressure for St. Louis County is now wasted through the pressure reducing application. The use of a pump as a turbine (PAT) is being considered as a potential strategy to provide pressure reduction, while at the same time recovering the energy lost during the process.

2.2 PROJECT LOCATION

The Greensbottom Booster Pump Station is located in St. Charles County near the Missouri River, at the intersection of Greensbottom Road and Caulks Hill Road, which is situated between St. Peters and Chesterfield, Missouri.

2.3 PROJECT TEAM

The primary members of the project team are as follows:

Project Sponsor

Bob Fuerman, PE, CEM, Missouri American Water, Missouri Production Manager/ Director

Project Manager

Jim Heisserer, PE, LEED AP, Ross & Baruzzini, VP– Senior Project Manager, Electrical Engineer

Engineering Analysis Staff

Ryan Walsh, PE, CEM, LEED AP, Ross & Baruzzini, Mechanical Engineer

Bob Wilson, PE, Ross & Baruzzini, Senior Electrical Engineer

Outside Consultant / Pump Expert

Allan R. Budris, PE, Allan R. Budris – Consulting

Other Contributors

Bill Ebsary, KSB Inc, Application Engineer - Energy & Industrial Division

Loyal Fischer, KSB Inc, USA Regional Manager

3.0 OVERVIEW OF PAT APPLICATIONS

In general, centrifugal pumps can be operated in reverse and be used as turbines to produce electricity. Compared to traditional turbines, most pumps are cost effective, less complex, and are readily available in the market place for a variety of operating conditions, especially small applications where the turbine market is generally oversized. The pump construction itself is simple by comparison and the performance of a pump acting as a turbine can be similar to that of turbines. This makes the PAT application a good alternative for energy recovery applications.

3.1 BENEFITS AND LIMITATIONS OF USING PUMPS AS TURBINES

There are a number of advantages and limitations to using pumps instead of turbines for power generation and pressure reduction. The most predominant advantages include:

- Pumps are available in a wide range of head and flows.
- Pumps have a lower first cost and maintenance operating cost than turbines.
- The operation of pumps is generally better understood than turbines.
- Replacement pumps and parts are readily available.
- The control of a PAT system is generally less complex than a turbine system. This is especially true if multiple generators are needed.

The most predominant limitations include:

- Since true turbines have adjustable inlet guide vanes, in the constant speed mode they can generate power at lower flow rates than a PAT. A typical PAT stops generating power at flow rates around 42% of the PAT best efficiency point. This can be largely mitigated by using multiple pumps in parallel.
- PAT performance of all pumps operated as turbines is not accurately known. Only a few select pump companies have tested/established the true performance of their pumps as PATs.

3.2 TYPICAL PROJECT APPLICATIONS FOR PAT

There are a number of applications for using pumps as turbines, including, but not limited to the following:

- Industrial facilities for pressure reduction applications related to processes.
- Most water pressure reduction applications that rely on pressure reducing valves.
- Small hydropower systems such as vertical down comer applications or dam relief discharge systems.
- Small dams systems that experience high flow rates and low head.
- Chemical and petrochemical processes (e.g., gas scrubbing systems).
- Any application involving the draining of reservoirs or other water storage systems.

4.0 ANALYTICAL FORMULAS AND RELATIONSHIPS

Some analytical formulas and relationships used for pumps can also be used to estimate the performance of a pump operating as a turbine. Mathematical derivations of Flow, Pressure, Efficiency, Specific Speed, Power, and Energy can be used.

4.1 FLOW, PRESSURE, AND EFFICIENCY RELATIONSHIPS TO PUMPS

Similar to a centrifugal pump, a pump acting as a turbine follows similar relationships between flow and pressure. The following relationships can be used to approximate the performance of a pump operating as a turbine (Budris 13.1.1).

$$Q_{Turbine(BEP)} = \frac{Q_{Pump(BEP)}}{\varepsilon_{Pump(BEP)}}$$

$$H_{Turbine(BEP)} = \frac{H_{Pump(BEP)}}{\varepsilon_{Pump(BEP)}}$$

Where:

$Q_{Turbine(BEP)} = Best\ Efficiency\ Flow\ Rate\ as\ a\ Turbine\ (GPM)$

$Q_{Pump(BEP)} = Best\ Efficiency\ Flow\ Rate\ as\ a\ Pump(GPM)$

$H_{Turbine(BEP)} = Best\ Efficiency\ Head\ as\ a\ Turbine\ (Ft\ Head)$

$H_{Pump(BEP)} = Best\ Efficiency\ Head\ as\ a\ Pump\ (Ft\ Head)$

4.2 EFFICIENCY

The overall efficiency of a pump system is driven primarily by hydraulic losses and electrical losses associated with the motor. The same characteristics hold true for a pump acting as a turbine.

The best efficiency point (or BEP) is the point at which the turbine (or pump) operates most efficiently based on flow and pressure (Budris 13.1.1).

$\varepsilon_{Turbine(BEP)} = \varepsilon_{Pump(BEP)}$

$\varepsilon_{Turbine(BEP)} = Best\ Efficiency\ as\ a\ Turbine$

$\varepsilon_{Pump(BEP)} = Best\ Efficiency\ as\ a\ Pump$

The BEP efficiency value of a PAT is normally very close to the BEP efficiency as a pump, being a point or two lower for vertical turbine or diffuser pumps and equal or slightly higher for other pump types.

4.3 POWER

The theoretical (ideal) potential power generated (or work created) for a system that experiences a pressure difference can be calculated using the following hydraulic horsepower equation (Lindeburg 13.2.2):

$$P_{Ideal} = \frac{\Delta P * Q}{1714},$$

Where:

$P_{Ideal} = Power\ (HP), multiplied\ by\ 0.7475\ to\ obtain\ KW$

$Q = Flow\ Rate\ (GPM), \Delta P = Differential\ Pressure\ (PSI)$

The Actual Power generated from a PAT system must be derived from the actual PAT selection curves. However, based on the results of this study and other findings, the overall power output of a PAT system is typically around 70% of the theoretical power, assuming the pump(s) is selected for its best efficiency point (BEP). The maximum efficiency or BEP of any single PAT is around 82%.

4.4 ENERGY

The energy produced from a PAT system can be calculated using the following formula:

$$E_{PAT} = \sum P_{PAT} * t$$

Where:

$$E_{PAT} = Energy\ (kWH), P_{PAT} = Power\ produced\ (KW), t = time\ (Hours)$$

If hour by hour flow and pressure information is readily available (as is the case in Greensbottom), the peak power output can be calculated for each hour and summed for the period. For less accurate calculations, one could use the average flow and pressure drop across a month or some other time period and calculate the energy production that way.

4.5 SPECIFIC SPEED

The capacity and efficiency of a pump is partially governed by the impeller design. For a desired flow rate and head, there will be one optimal impeller design. The specific speed is a dimensionless number that can be used to describe the shape and appropriate pump impeller and configuration that is optimum for a pump or in this case a PAT application. The specific speed of a pump as a turbine can be described at the following (DOI 13.2.1):

$$\mathrm{n_T} = \frac{n(Q_T)^{1/2}}{{H_T}^{3/4}}$$

$$Q_T = Turbine\ Flow\ (GPM)\ at\ BEP, H_T = Turbine\ Head\ (Ft\ Head) at\ BEP$$

Once the specific speed is known, the value can be compared to readily available pump impeller tables in-order to figure out which impeller configuration (ex. Mixed flow, axial flow) is optimal for the design.

5.0 PAT SYSTEM OPERATION

5.1 USING A MOTOR AS A GENERATOR

During PAT system operation, water is sent through the turbine, transferring mechanical work from the pump shaft to the motor windings, which transfers electrical energy back into the electrical system. Using an induction motor as a generator is a cost effective way of generating electrical power with a turbine system. When connected to a three phase utility system, the induction system requires no speed governing controls. The induction motor, instead of consuming energy, is driven at around 50 RPM over its rated speed (DOI 13.2.1), and the motor becomes a generator. Induction generators are much less expensive than other types of generators, but require excitation to operate. This is why they are ideally suited to inter-connected utility applications.

In single phase operations, induction motors can be used as generators by connecting capacitors to the unused legs of the motor. This can result in a very smooth running generator, operating at 100% Power Factor (PF). The extra efficiency is gained by the motor (generator) running balanced on all three legs, which results in less heat (friction) output.

5.2 SINGLE PUMP OPERATION

Figure 1 represents the schematic configuration of a single pump acting as a turbine in a constant pressure control application. A pump and a control valve are installed in parallel with a pressure reducing valve. During normal operation, within the specified flow and pressure, all water flows thru the PAT circuit. Once the pressure or flow exceeds the capability of the PAT, the pressure reducing valve (PRV) opens up and allows flow to bypass the assembly and regulate the discharge of the system.

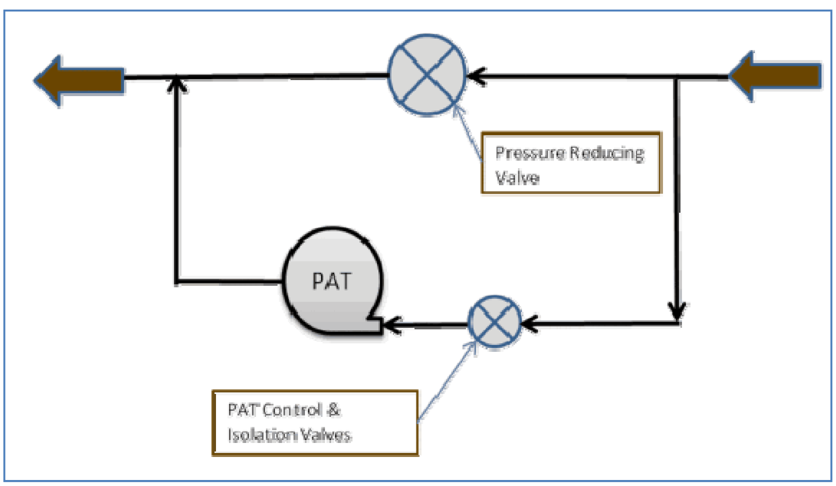


Figure 1 - Single PAT Constant Pressure (Budris 13.1.1)

Figure 2 represents how the PAT performs in a constant head (pressure drop) system, with regard to flow, pressure, and efficiency, using the single PAT configuration. As water flows through the PAT, the impeller spins in the opposite direction compared to operation as a pump. It should be noted that a PAT will always operate on its Head-Capacity (H-Q) curve, meaning that the head (pressure drop) across the PAT will determine the flow rate through the PAT. So in order to achieve a flow rate less than the, PAT flow rate at the full system head, the pressure (head) must be reduced to the PAT, by throttling the "PAT Control Valve". The point at which the PAT H-Q curve and System Head (H-Q) lines intersect represents the point at which the control valve is full open, and the PAT is hopefully operating at its BEP. This is the desired pump selection design point.

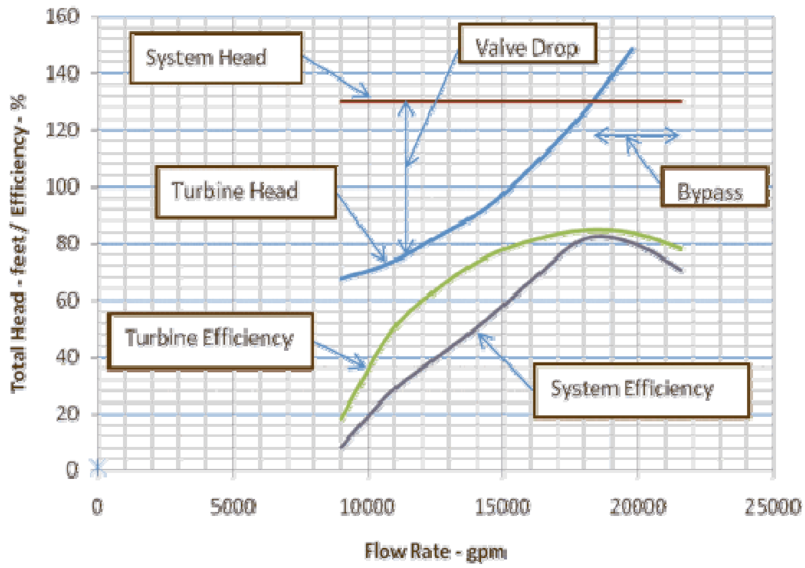


Figure 2 – Single PAT System Operating at Constant Pressure (Budris 13.1.1)

In order to achieve flow rates greater than, the PAT flow rate at the full system head, (in this case to the right of the BEP), the pressure reducing (by-pass) valve must be opened to allow the additional flow to by-pass the PAT. However, no additional power will be generated from this higher flow rate (through the by-pass valve, which converts the pressure drop to heat), thus the overall system efficiency will be lower.

From an efficiency standpoint, you always want to operate as close to the PAT BEP as possible. This should be a consideration when selecting pumps for PAT service, for a wide range of flows and pressures. A single pump sized for peak demand might operate to the left of the BEP, at low flow conditions. Not only might this result in lower efficiency, but below flow rates of about 42% of the PAT BEP, zero or negative energy might be generated by the PAT. It is, therefore, desirable to use multiple pumps/ PAT's operating in parallel, for systems with variable flow and pressure values, to optimize the overall PAT system performance."

5.3 MULTIPLE PUMP OPERATION

Figure 3 represents the schematic configuration for multiple pumps acting as turbines in a constant pressure control application. Multiple pumps and control valves act in parallel to each other and a pressure reducing valve. This system operates similar to the single pump/PAT system, except that now there are multiple PAT/valve sets to handle varying flow and pressure conditions

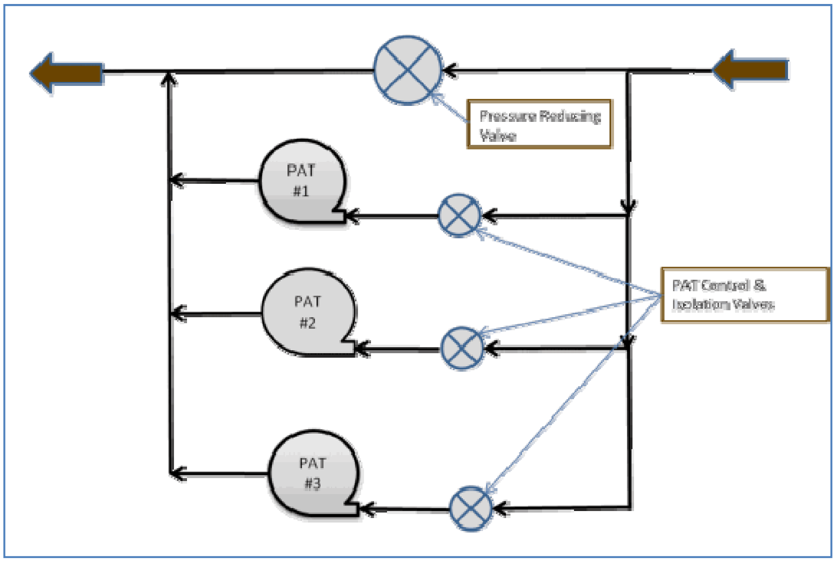


Figure 3 – Multiple PAT Constant Pressure (Budris 13.1.2)

Figure 4 represents how the system performs with regard to flow, pressure (head), and efficiency; using the multiple PAT configurations (three pumps/PAT's operating in parallel, with individual control valves for each, plus a single by-pass pressure reducing valve, as shown). Each PAT is staged on (activated), and its control valve set, plus the by-pass pressure reducing valve adjusted, based on the current system flow rate and pressure drop needed at the time. Power output is maximized by transitioning to the number of PAT units, and control valve setting(s), that will provide the maximum system efficiency, at the required system head and flow rate.

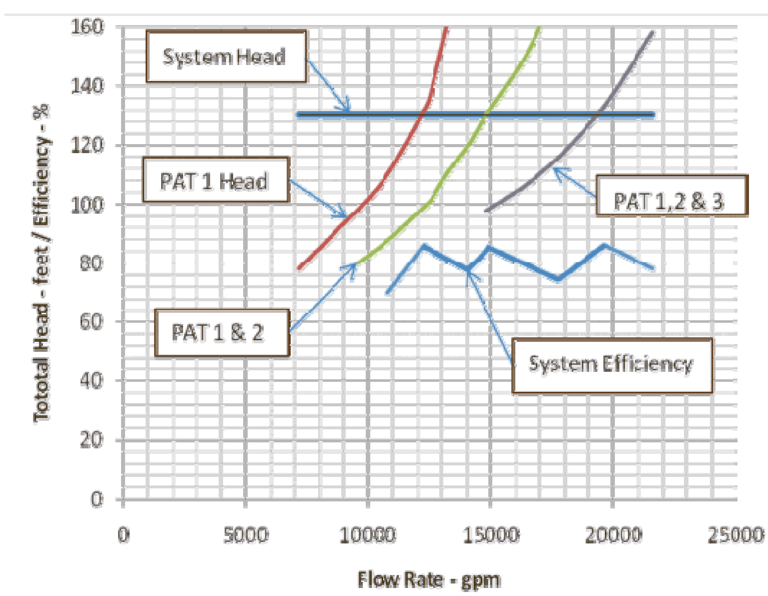


Figure 4 – Multiple PAT System Operating at Constant Pressure (Budris 11.1.2)

5.4 OTHER DESIGN CONSIDERATIONS

Provisions must be taken to ensure that the PAT system operates within the expected range of performance and safety. The following is a list of other design considerations that should be analyzed during the design of any PAT system.

- Pump Stress Analysis – Since a pump is optimally designed to pump water and not act as turbine, the pump operating as a turbine will endure higher stresses than normal. Pump shafts and casings/bowls will be stressed higher when a pump is operated as a PAT, since both the BEP flow rate and head are higher in the reverse flow PAT mode. Most PAT manufacturers should be able to determine the maximum allowable stress of the equipment. General operating conditions should be examined as well as possible conditions of pressure surge or water hammer that may occur.

- Electrical Grid Failure – For installations that are not on island mode, the frequency of the electrical utility grid (field induced onto the motor) ensures the pump system operates at a same speed and frequency. If the case of a power outage, the field (restriction) imposed on the motor from the utility would be lost, and the pump could "accelerate" to a run-away speed, potentially leading to equipment damage or dangerous conditions. Special relaying and controls should be incorporated into the design to handle this possible condition.

- Pump Cavitation – Steam bubbles are formed when the suction side pressure drop on a pump drops below the vapor pressure of the liquid. These bubbles can lead to damage of pump impellers and components. Other factors to consider that will help reduce possible PAT cavitation damage are the addition of a draft tube to the outlet of the PAT, lowering the PAT speed, and the possibility of moving the PAT control valve to after the PAT, instead of before it. Consideration should be given with regard to sizing to avoid potential issues with cavitations.

6.0 PUMP AND TURBINE INDUSTRY

6.1 PUMP AND TURBINE MANUFACTURERS

During the study multiple manufacturers were found to have turbine offerings; however, only two companies found offer turbine products within the flow and pressure ranges of this project – Flowserve and Cornell Pump Company. In general, this application is considered a "medium head pico hydro power" application (pressure ranges between 8 and 50 PSI). Most commercial turbine offerings are oversized for the needs of this project.

The team has researched PAT product availability and been in contact with multiple pump manufacturers including Flowserve, Bell & Gossett (B&G) / Goulds, Peerless, Armstrong, and KSB Pumps. Out of the companies mentioned, Flowserve and KSB pumps appear to have the most experience in PAT field.

6.2 PRODUCT RANGES AVAILIBLE

Flowserve offers power recovery turbine products both with fixed and variable geometric configurations. Their product offering ranges from around 2500 GPM up to around 68000 GPM.

Cornell offers similar power recovery turbine products both with fixed and variable geometry configurations. Their product offerings range from around 100 GPM up to around 8000 GPM, which is well within the range of this project.

For PAT products, KSB Pumps is the only company to date we found that offers pump lines specific to the PAT application. In theory, any pump can be used for a PAT application; however, a detailed stress analysis is needed to insure the pump would not fail operating as a turbine.

KSB offers two primary pump types for this application, axial split case and end suction type. Multiple sizes and configurations are available and can be selected to precisely match our operating conditions.

6.3 EXISTING PAT INSTALLATION – EXAMPLE PROJECTS

Our team found two existing PAT installations, one in Stuttgart, Germany and one in the United States, that are similar in nature to this project. The Greensbottom project falls roughly halfway between these two installations with regard to flow, pressure, and power recovery.

The US installation is located in Baytown, Texas at the Air Products and Chemicals, Inc facility. For this application, pumps where installed (as turbines) on a process cooling water system that needed to reduce pressure from 70 psi down to 15 psi. They used two pumps in parallel to provide for a wide range of flows between 1800 and 3700 GPM. The system recovers around 70 KW of power at peak flow conditions annually.

Figure 5 - PAT Installation at Air Products Facility in Texas

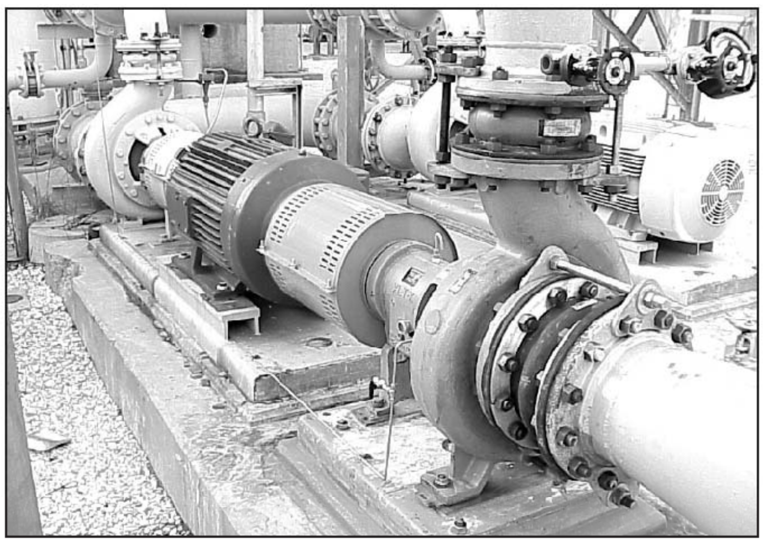


Figure 6 - PAT Installation at Air Products Facility in Texas

The German installation is located in Stuttgart, Germany at the Zweckverband Landeswasserversorgung (aka: LW) water supply plant, which provides water to roughly 250 cities and municipalities in the area. Eight pumps were installed in parallel which operate with flows between 2750 and 17000 GPM and pressure reduction range of 50 to 75 psi. The system recovers around 300 KW of power at peak flow conditions.

Figure 7 – PAT Installation at LW Facility in Stuttgart, Germany

Figure 8 - PAT Assemblies at LW Facility in Stuttgart, Germany

7.0 FACILITY CONDITION AND OPERATIONS

A site survey was performed at the Greensbottom facility in the summer of 2010. The followings systems and operating conditions were observed. Refer to Appendix for the schematic one-line diagrams of existing systems.

7.1 EXISTING MECHANICAL AND ELECTRICAL SYSTEMS

Although originally designed as a pump booster station, this facility now operates as a pressure reducing station. Primary water service at varying flows and pressures enter the building on the southwest corner of the facility, goes through the pressure reduction system, and exits at 115 psi from the northwest corner. Refer to Appendix for the Schematic One-Line Diagrams.

The original pumping and pressure reduction system is still primarily intact from the original design. There are three parallel circuits, two of which are the boosters pump circuits, with the other circuits configured with motorized pressure reduction clay-valves and flow meters. One of the two pumps on the west end has been removed and valved off, with the other pump remaining intact. Additionally, there is an empty concrete pad and pipe stub adjacent to that was planned for a future pump installation.

The original electrical system associated with the systems is also still in place. The electric service from the utility consists of a 12.47 KV primary feed that is transformed down to 480Y/277V through a 1000 kVA utility transformer. The service enters a 3000A motor control center that is designed to serve three booster pumps (2x450 hp, 1x100 hp), two ventilation fans (2x10 hp), a 480/277 volt panel and a transformer to serve a 208/120 volt panel. Additionally, there is an automatic transfer switch that receives standby power from a 600 kW - 480Y/277V diesel engine generator set.

The building is heated using multiple wall mounted electric unit heaters. Ventilation air in the summer is provided by multiple wall mounted exhaust fans and air intake louvers.

7.2 EXISTING CONTROL SYSTEM

The original PLC automatic control system is also still in place. A central main pump control panel houses the entire pump and pressure control systems. A separate telemetry panel is in place to transmit system data from the PLC remotely to the Cottleville office. The controls have been modified to handle the pressure reduction application. The PLC calculates the valve position necessary to provide the desired outlet pressure. Flow and pressures are monitored and recorded by the PLC.

The pressure reducing valves (PRV) are operated using electric solenoid valves as pilot operators to control system water pressure to open or close the valves as needed to respectively reduce or increase the flow restriction and associated pressure drop. These pilot solenoid valves are controlled by signals from the PLC. This pressure reduction system is actually driven by flow rate. Flow meters installed in the system transmit the flow rate into the PLC control system, which then indirectly controls discharge pressure. Currently the pressure reduction system is configured to provide a constant outlet pressure of 115 psi. Some additional hardware would need to be added to the existing PLC along with substantial reprogramming to add control of the PAT system into the existing pressure reduction system.

7.3 FACILITY WATER AND PRESSURE

In general, flow for this facility averages around 8 MGD (Million Gallons per Day) and peaks around 25 MGD during high demand periods. Incoming pressure to this station from the high service main ranges between 120 and 175 psi with an average of about 140 psi. The existing pressure reducing station reduces the pressure down to 115 psi. Figure 9 represents the large range of flows that occurred at this station between 2008 and 2009, which was the most current data available when the study began.

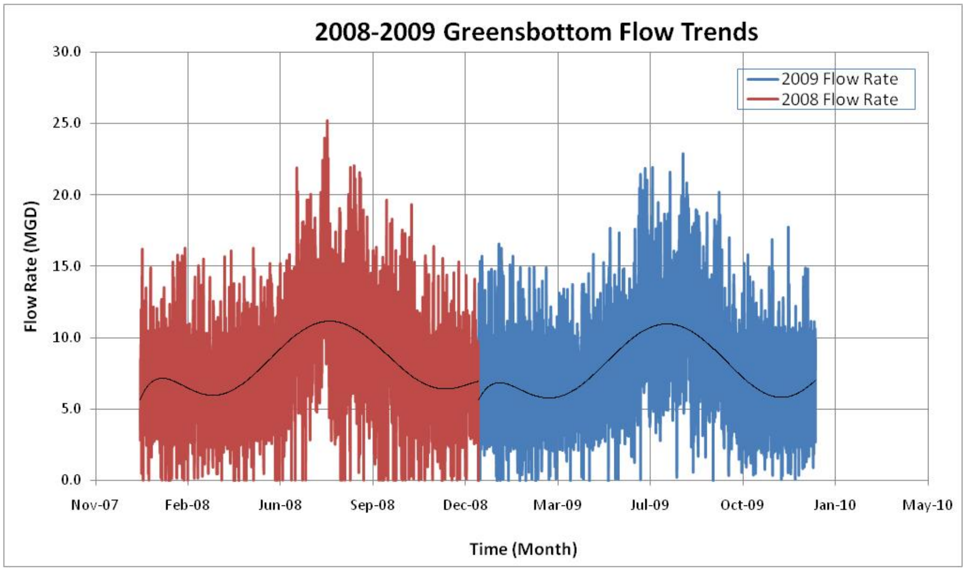


Figure 9 – Historical Flow Trends

As expected, water consumption follows a consistent trend from year to year. During the winter months water use is fairly steady, on average between 6 & 8 MGD. During the summer months water use increases to an average consumption rate between 8 & 10 MGD. Without a significant change in the water system infrastructure, this trend is expected to remain steady in the near future.

Similarly, Figure 10 represents varying amount of differential pressure or pressure reduction achieved by the PRV system at this station between 2008 and 2009.

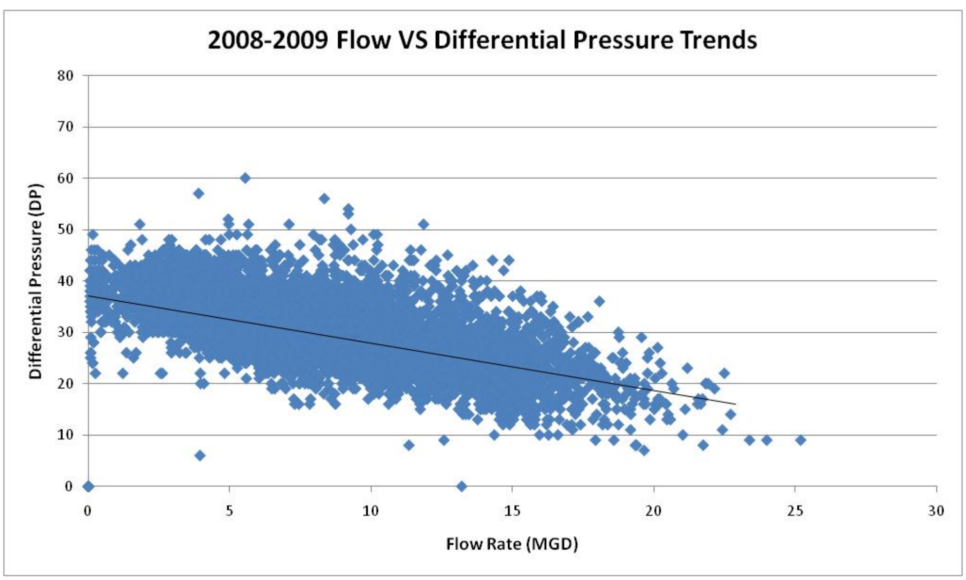


Figure 10 – Historical Pressure Trends

Based on the differential pressure graph it is shown that there is a linear relationship between flow rate of the system and the pressure reduction required on the system. In general, as flow increases the required pressure drop decreases proportionally, a -1% decrease in differential pressure for every 10% increase in flow.

The existing flow and pressure data was also examined to see how many hours in the year certain ranges of flow and pressure were occurring. This was necessary to determinate the target design condition for the P.A.T. system. Figure 11 shows the relative percent operating hours of flow and differential pressure based on historical data. The analysis shows that flow rates higher than 10,000 GPM (14.5 MGD) occur less than 10% of the hours in a year. A similar relationship exists with regard to differential pressures (Delta P) above 40 PSI. This time based analysis can used as a starting point to determine the target design condition for the P.A.T.

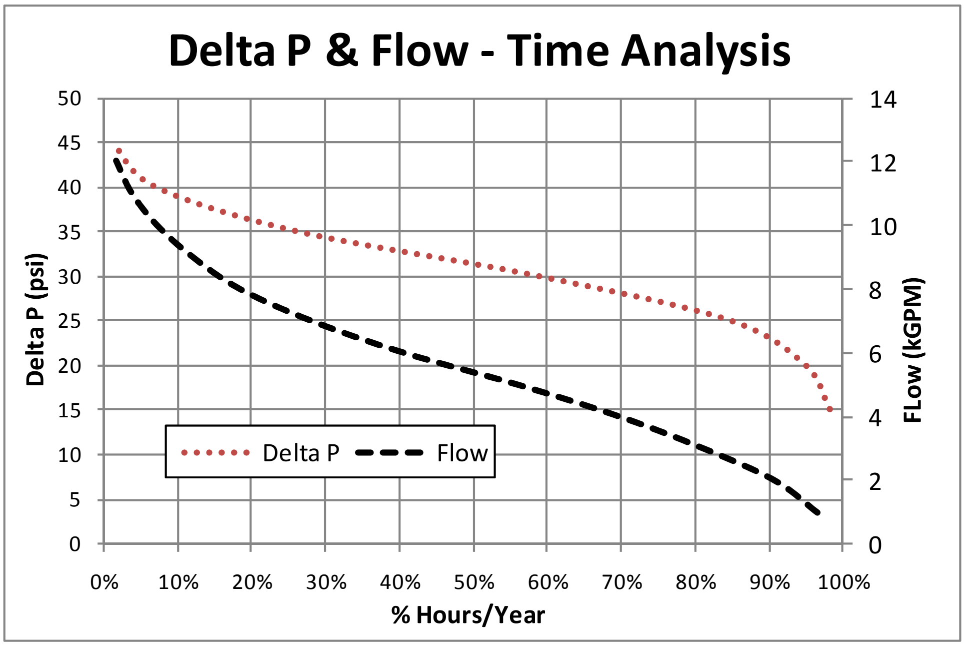


Figure 11 – Time Analysis Curves

7.4 FACILITY ELECTRIC USE

The existing electrical use was examined to see what the facility was using to maintain space conditioning and other building operations. Since this station is no longer used as a pump booster plant, electrical loads are small compared to the original design.

The electrical rate for the facility is a 2M Small General Service - 3 Ph w/Demand. This facility uses roughly 100,000 kWh of electricity and costs around $5,500 per year to operate or roughly $0.055/ kWh on average for the year. A recent rate increase from Ameren Missouri increased the rate to around $0.06/ kWh.

8.0 PAT SYSTEM DESIGN

8.1 PUMP SELECTION AND PERFORMANCE

Based on the analysis of yearly flow and pressure data it was decided that a target design range for this system under peak conditions would be roughly 10,000 GPM at a 40 PSI differential pressure. Since we are considering constant speed pumps it became important to implement as many PATs as possible to maximum overall system efficiency. Therefore, we choose to look at least four PAT to try and match the entire range of flows and pressure.

The pump selected for the project is a Horizontal Split Pump as Turbine, KSB Pump model: Omega 150-290-A-GB-G-F, 1200 rpm, 60 hp, 480 Volt/3PH. Figure 13 below is the performance curve for the pump that was selected for the system.

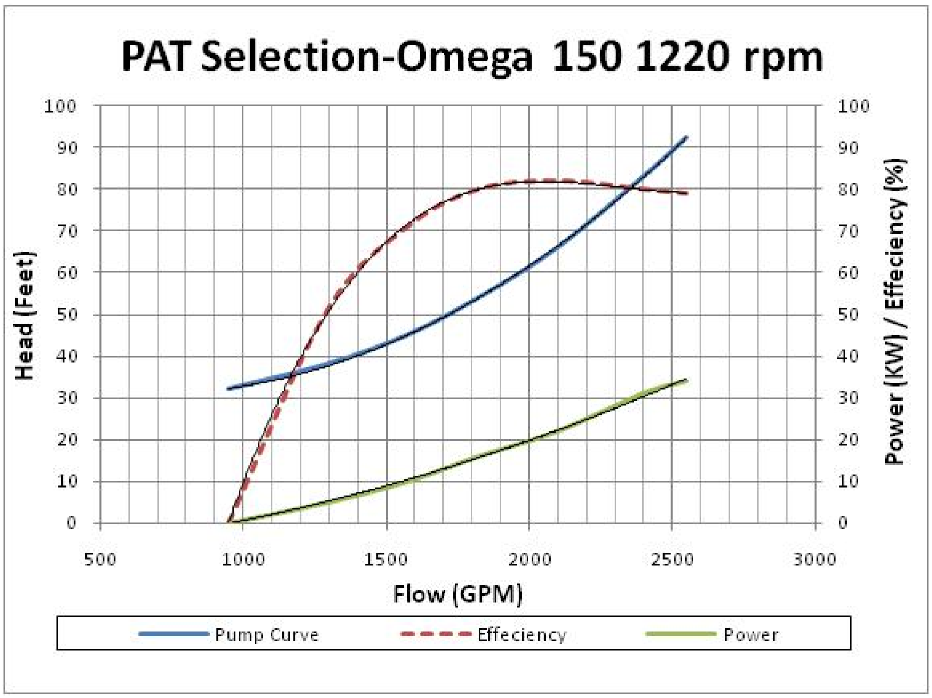


Figure 12 – KSB Pump Selection

The pump was selected for a maximum flow rate of 2500 GPM, which corresponds to 2000 GPM and 62 feet of head at the BEP (~82% efficiency). Based on the previously mentioned flow and pressure relationships (Section 4), the performance as a pump at 82% efficiency would be 1640 GPM at 52 feet of head. With four pumps operating in parallel we are able to achieve the target 10000 GPM peak flow. Another consideration for this selection was the maximum flow range of the pump, which is roughly 2500 GPM. Since the efficiency to the right of the BEP is relatively constant, we are able to flow each pump roughly 20% past the BEP before transitioning to the next pump (stage) with minimum impact to efficiency. This relationship was shown in Section 5.3 – Multiple Pump Operation.

8.2 MULTIPLE PUMP PERFORMANCE

The performance of the single pump was used to develop the combined performance of all four pumps at varying ranges of operation, as shown in Figure 14 below. Since all of the pumps will be the same size and are operating in parallel, it can be assumed that the flow rates of each stage are approximately additive, while the differential pressure remains roughly the same.

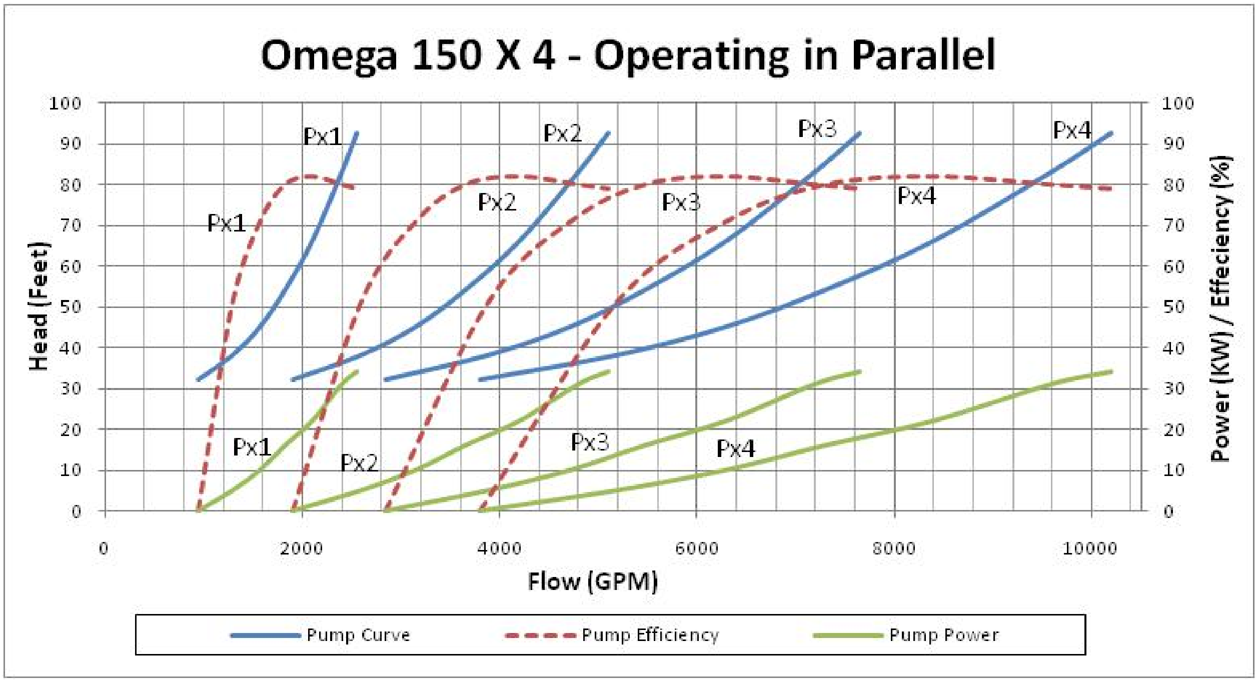


Figure 13 – Parallel Pump Operating Curves

Based on the performance curves it is shown that the most power (KW) is produced at the peak flow rate, therefore it is important to completely load up a pump before transitioning to the next one.

8.3 SYSTEM COMPONENTS AND SEQUENCE OF OPERATIONS

Figure 15 shows a basic system schematic of the PAT system. A more detailed schematic showing the relationship to the existing system is shown in the Appendix.

Four PAT assemblies are shown in parallel with one common bypass. Note that the overall system is installed in a reverse return configuration. This is necessary to keep the pressure and flow balanced between the PAT assemblies. Each PAT assembly circuit (total 4) consists of the following components:

- Manual Isolation Service Valves
- Flow Check Valves
- Modulating Control Valve with differential pressure sensor
- Pump as Turbine with differential pressure sensor, current sensor, and motor (shaft frequency sensor, and power meter.

The remaining PAT system consists of the following primary components:

- System Flow Meter (GPM)
- Incoming and Outgoing pressure sensors
- Modulating bypass valve

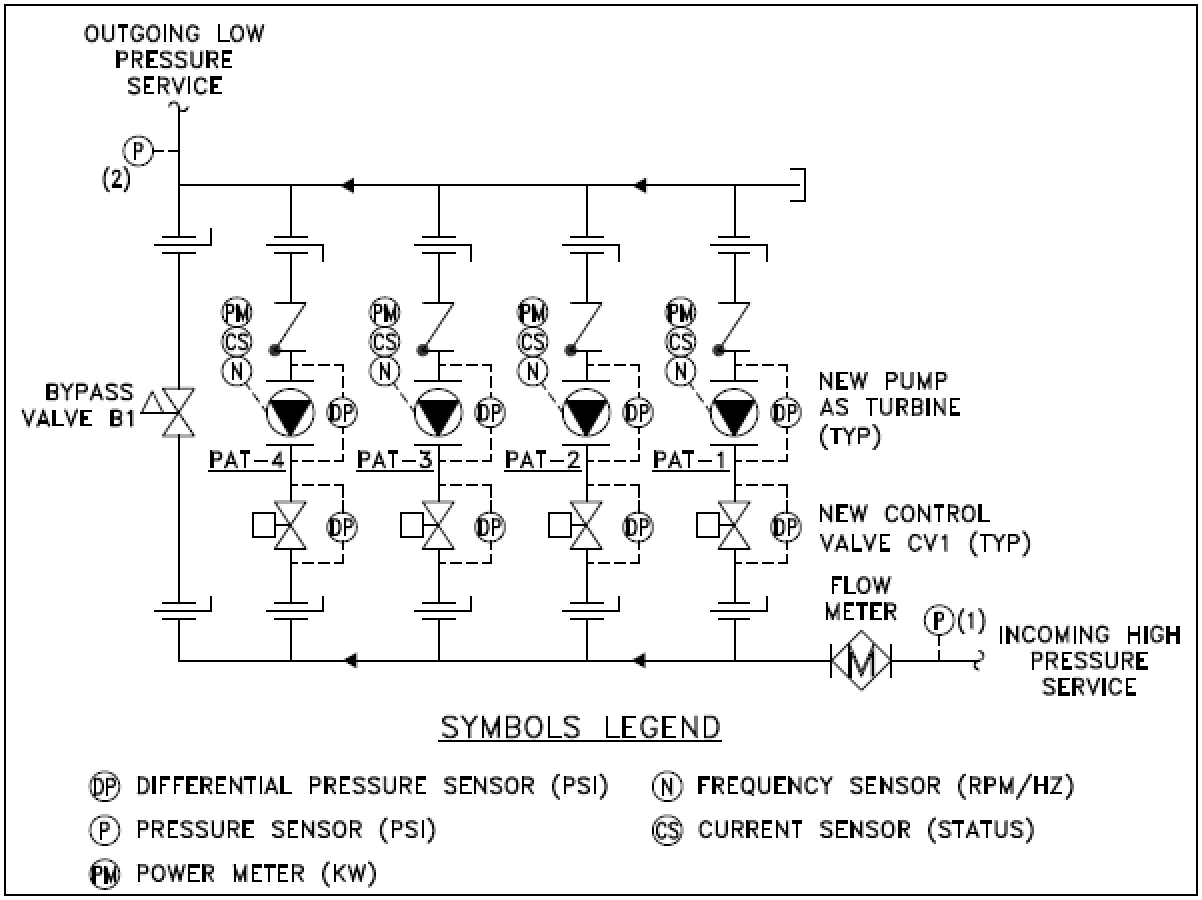


Figure 14 – PAT System Schematic

The following sequence of operations would be used to control pressure reduction for the facility using the PAT system:

<u>Sequence of Operations</u>

- The PAT system is operated to maintain a constant discharge at P2 (~115 PSI).
- At zero differential pressure (P1=P2) & flow (FM=0), all pumps (PAT's) would be off, with all individual control valves (CV1, CV2, CV3 & CV4) and By-Pass valve B1 closed. When P1 > P2, Pumps are enabled (activated) on in stages.
- When P1>P2, the number of pumps (PAT + Control Valve Units) will be enabled (activated), one at a time, and the By-Pass valve set to provide the best, most efficient, match with the total required system flow rate and pressure drop. Pump speed is monitored (RPM/HZ), at approximately 50 RPM (1.1 HZ) above the design frequency (1200 RPM @ 60 Hz), the motor is connected to the grid.
- Pump (PAT) Activation: The PAT CV control valves are adjusted to provide the differential pressure across the PAT's that will permit the desired flow rates for each individual PAT. (Remember, it is the pressure across a PAT that will determine its flow rate, efficiency and output power).
- Flow meter monitors total flow (GPM) and enables pumps based on predetermined minimum and maximum flow ranges of each PAT (Ex. If flow is between 500 to 2500 GPM, one pump is enabled).

- The required system differential pressure (SDP1, not shown) is calculated by the system using P2 – P1. All control valves CV1 thru CV4 are enabled (based on pump status – on/off) and then modulated to maintain the required SDP1 set-point.
- If all pumps are on (CS=all status) and all CVs are full open, and the pressure continues to increase above set-point P2, bypass valve B1 modulates opens to maintain the set-point.
- Power (KW) is calculated and monitored by power meter (PW).

8.4 ELECTRICAL CONNECTION AND METERING REQUIRMENTS

Our team has spoken with the Distribution Operating department at Ameren Missouri to determine what metering and relaying requirements are necessary to implement this project. Reverse power will be allowed, so the facility can sell excess power back to Ameren. The facility will not be permitted to operate in an island mode (generating electricity back to the Ameren's distribution system) if the Ameren's grid is de-energized. This will require adding multi-function relays to disconnect the equipment from the electrical system when the Ameren grid is not available. Because these multi-function relays will be programmable solid state devices, Ameren will require that redundant protection be provided.

9.0 APPLICABLE RULES, REGULATIONS, AND UTILITY RATES

9.1 FEDERAL RULES AND REGULATIONS

Federal rules and regulations were reviewed to determine the requirements for this project. There is one primary regulation that applies to this project:

- Federal Regulation:
  18 C.F.R. PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION

The Federal Regulation 18 C.F.R. PART 292 is used as the basis for determining if the facility is a "Qualified Facility" and is referenced by other applicable state regulations. Excerpts from this section are included in the Appendix. The following is a summary of the major points:

- This facility can be considered a "Small power production facility".
- The "energy" input to the facility is the water pressure.
- The pressure reduction is considered to be a "waste" product that is used to generate electricity.
- This project is not considered to be a "cogeneration" or "renewable energy" for the purposes of the federal regulation.

9.2 STATE RULES AND REGULATIONS

State rules and regulations were reviewed to determine the requirements for this project. There is one primary regulation that applies to this project:

- State Regulation:
  4 CSR 240-20.010 - RULES OF DEPARTMENT OF ECONOMIC DEVELOPMENT, DIVISION 240—PUBLIC SERVICE COMMISSION, CHAPTER 20—ELECTRIC UTILITIES

The State Regulation 4 CSR 240-20.010 describes the rules and regulations set forth by the Missouri Public Service Commission for Electric Utilities. Excerpts from this section are included in the Appendix. The following is a summary of the major points:

- Because this facility is considered to be a "qualified facility" all applicable regulations apply.
- This project is subject to the regulations specified under the "Cogeneration" section even though this project is not classified as "cogeneration" under the Federal regulations.
- The local utility company is required to purchase excess power produced from this facility at rates that are comparable to the utility companies cost for production (avoided cost of production).
- Net-metering may or may not apply to this project. If the "waste" (or excess pressure) used to produce energy is classified to be "renewable energy", than net-metering would apply. The Missouri Department of Natural Resources (DNR) is responsible for determining if this project is classified a "renewable energy" project.
- These regulations apply to systems with a potential power production that is less than 100 KW.

9.3 UTILITY RATE SCHEDULES

Utility company rate schedules and tariffs were reviewed to determine the requirements for this project. There is one primary rate schedule that applies to this project:

- Utility Company Rate Schedule:
  AMEREN MISSOURI RATE SCHEDULE – ELECTRIC POWER PURCHASES FROM QUALIFYING FACILITIES

The Ameren Missouri rate schedule applies to installations with a potential power production of 100 kW or less. Excerpts from this rate schedule are included in the Appendix. The following is a summary of the major points:

- Rates for production over 100 kW will have to be negotiated and approved by the Missouri Public Service Commission.
- This rate would apply if a maximum of two pumps are installed. Each pump has the potential to produce roughly 35 kW of power.
- Rate 1 - The non-time based energy rate would pay the following:
  Summer
  All Periods - 1.98¢ per kWh
  Winter
  All Periods - 1.75¢ per kWh
  (Average - 1.83¢ per kWh)
- Rate 2 - The time based energy rate would pay the following
  Summer
  Weekday (10 AM - 10 PM) 2.58¢ per kWh
  Weekday (10 PM - 10 AM) 1.60¢ per kWh
  Saturday, Sunday, Holiday (1) 1.73¢ per kWh
  Winter
  Weekday (10 AM - 10 PM) 1.89¢ per kWh
  Weekday (10 PM - 10 AM) 1.70¢ per kWh
  Saturday, Sunday, Holiday 1.63¢ per kWh
  (Average - 2.00¢ per kWh)

- If this project is classified as "renewable energy", then net-metering would apply and Rate 1 would be used for purchase of electric power.
- If this project is not classified as "renewable energy", then net-metering would not apply. The project would then be considered a "qualified facility" (Fed 18 C.F.R. PART 292) and Rate 1 or 2 would be used for purchase of electric power.

9.4 QUALIFIED FACILITY VERSUS RENEWABLE ENERGY

The economics of this project are highly dependent on the classification given to the project. It is understood that the Missouri Department of Natural Resources (DNR) would be ultimately responsible for the classification of this project.

If this project is not classified as "renewable energy", then net-metering would not apply. The project would then be considered a "qualified facility" based on Fed 18 C.F.R. PART 292. Under this scenario, all power consumed would be purchased from Ameren Missouri at the current 2M rate, which is roughly \$0.060/kWh. For excess power generation, Ameren Missouri would pay between 1.83¢ and 2.00¢ per kWh, depending on which rate is used (Rate 1 or 2). Since electric power produced and consumed by the facility will occur simultaneously, there will be times where electric consumption will be more than what is produced. It is estimated that 20% of the yearly electric use will not be offset by the PAT system. This is the least favorable scenario from an economic performance standpoint.

If this project is classified as "renewable energy", then net-metering would apply. The amount of electric power consumed by the facility would be subtracted from the overall electric production on a month by month basis. Ameren Missouri would then pay for all excess power production at approximately 1.83¢ per kWh on an annual basis (Rate 1). There would be a 4.17¢ per kWh savings on all electric power consumed by facility, compared to what would be purchased under the "qualified facility" scenario. This is the best case scenario from an economic performance standpoint.

10.0 ENERGY AND PERFORMANCE MODEL

10.1 SIMULATION METHODOLOGY

The basis of the simulation model revolves around testing historical hourly flow and pressure conditions against the performance equations derived from actual PAT product selections. The simulation model was performed using Microsoft Excel. The performance curves can be developed and be used to derive equations for flow, pressure, power, and efficiency as shown in Figure 16 below.

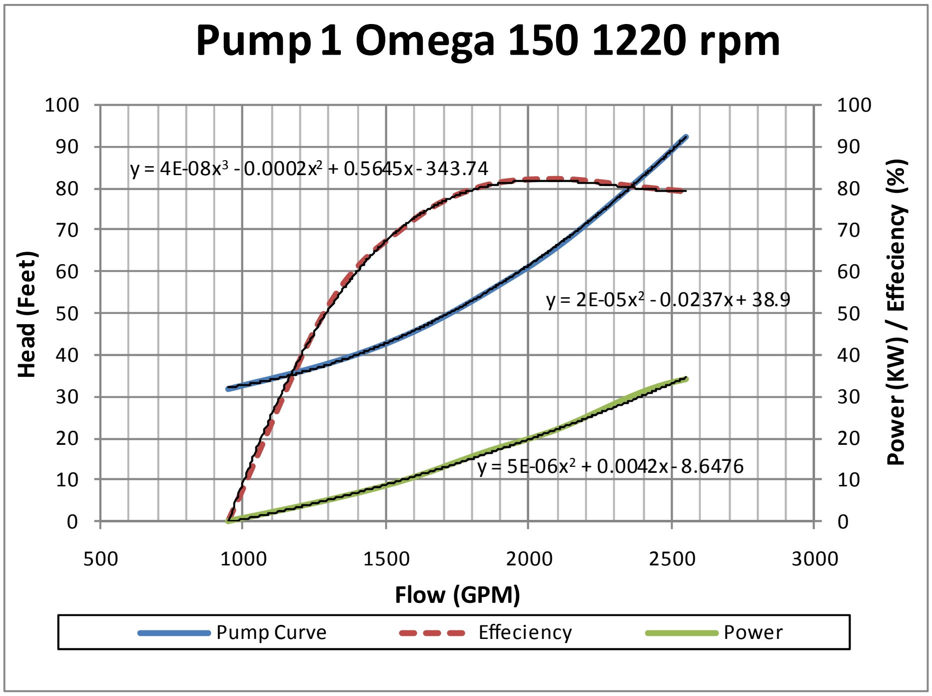


Figure 15 – Pump Selection Performance Equations

The following general methodology was used to simulate the performance of the PAT system.

- Equations of differential pressure, power, and efficiency as they are related to flow rates are derived for the selected pump system (Figure 16).
- Hour by hour flow data is first used to determine how many pumps would be operating, how much flow is sent through each pump, and how much will bypass the system.
- Once the pump and flow distribution is known, the hourly flow and pressure data is tested (plugged into the equations) and results are calculated for hourly power production in KW.
- The hourly power production is then summed on an hourly basis in order to determine the annual energy produced in kWh.
- The annual energy production cost (income) is calculated using the Ameren Missouri sell back rate established.
- The annual facility electrical use and cost is calculated from existing utility bills.
- The difference between the facility electric production and use is calculated to determine the worst case economic performance of the system.
- The theoretical or ideal energy performance of the PAT system is calculated and is used to determine the overall efficiency of the recovery system (Section 4.2.1).

10.2 SIMULATION RESULTS

The following figures 17 & 18 shows the simulated results for electrical production and cost compared to the facility electric consumption. For the purpose of these results, all electrical energy in and out of the facility is shown separately, and generated electricity is not used to offset facility electric use. The simulation showed the system could produce between 188,000 and 406,000 kWh per year, and a peak power output between 35 and 140 kW, depending on the number of pumps used. Values used in the chart are considered to be additive in nature.

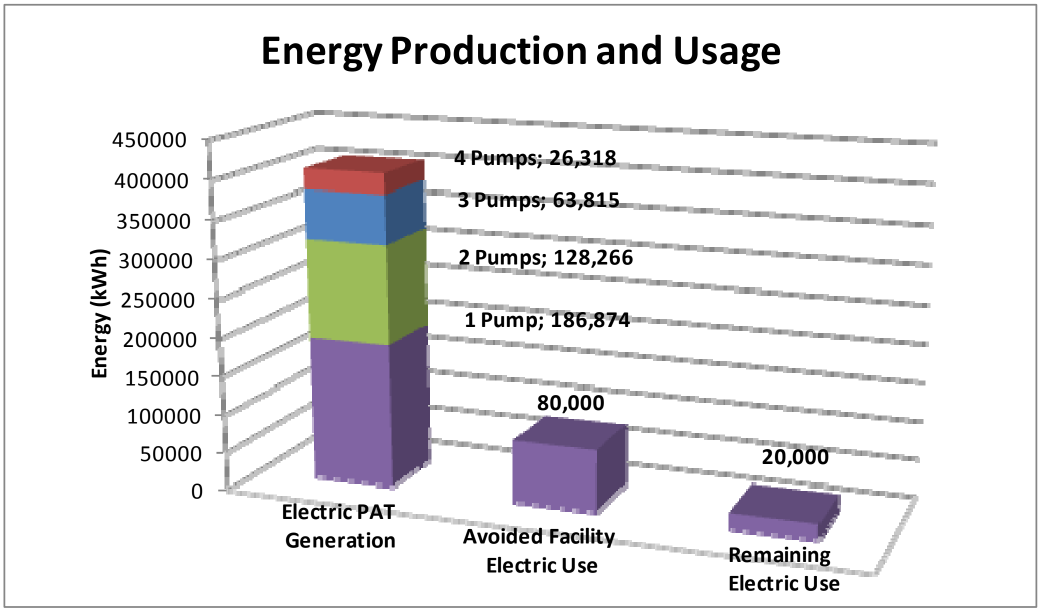


Figure 16 – Energy Production and Usage Chart

Similarly for cost, the simulation showed the system could produce income between $3,000 and $7,000 per year, depending on the number of pumps used. Values used in the chart are additive in nature.

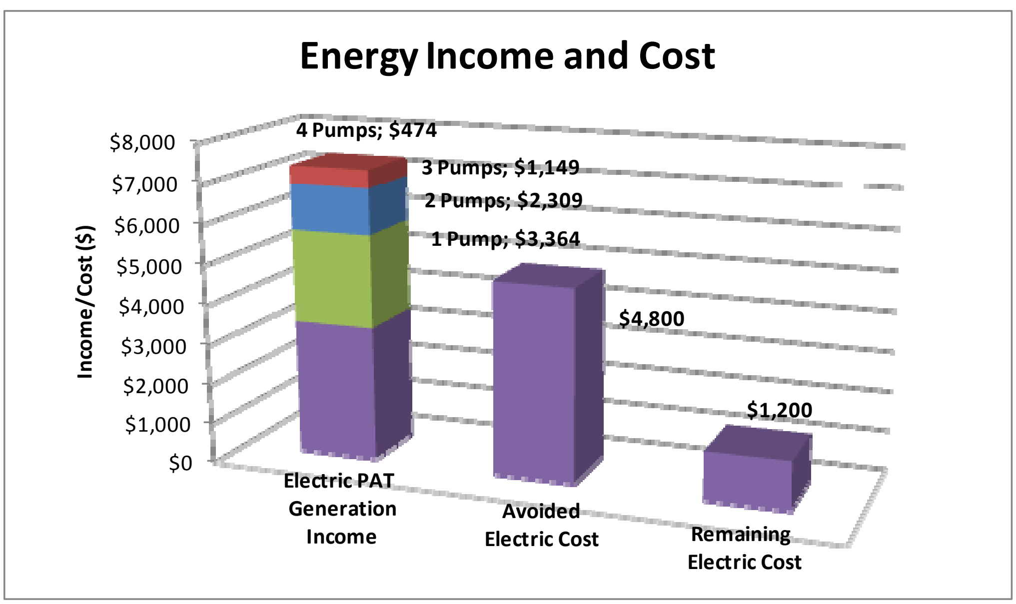


Figure 17 – Energy Income and Cost Chart

Figure 19 shows the electrical energy production for all four pumps combined and the facility energy use on a month by month basis. In all cases, the four pump system produces more electricity than the facility uses.

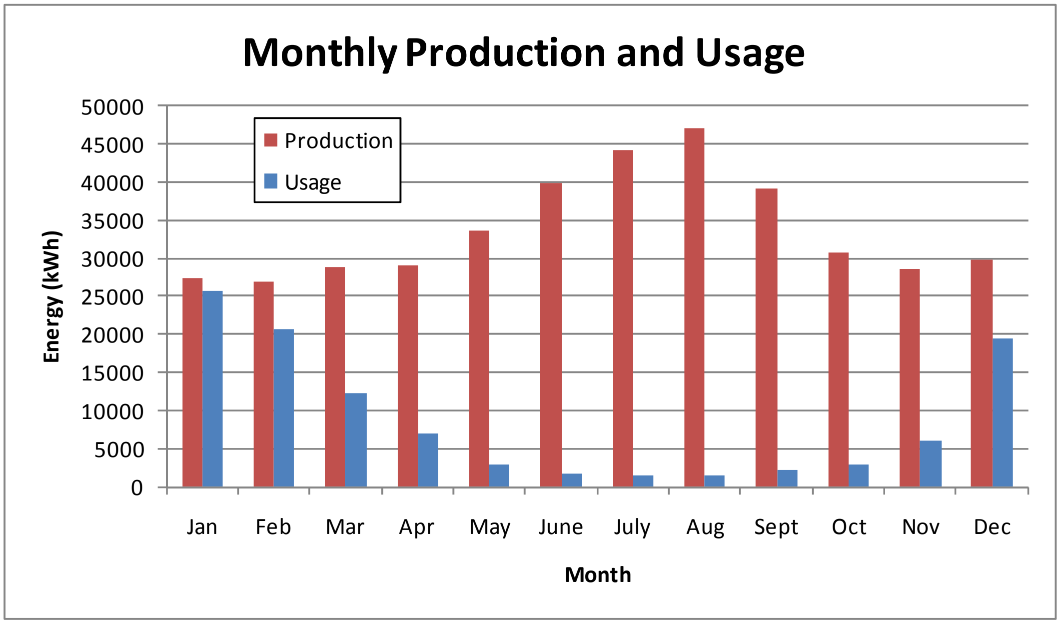


Figure 18 – Monthly PAT Production and Usage Graph

Similarly, Figures 20 shows the same electrical energy production on a pump by pump basis, combined with the facility energy use. It appears even with one pump, PAT production would exceed the facility electric use 80% of year.

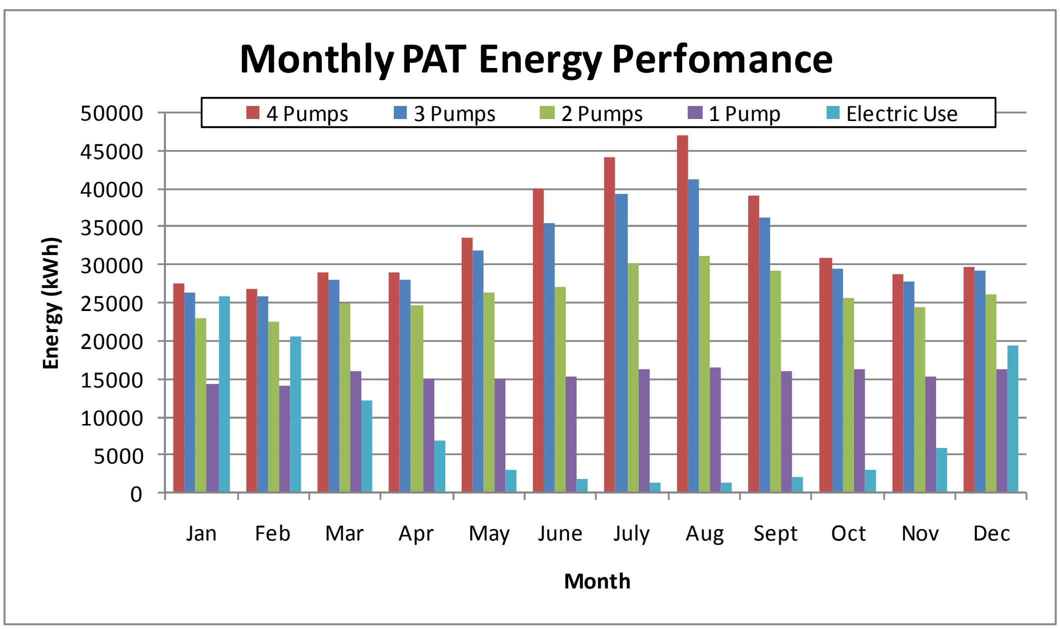


Figure 19 – Monthly PAT Energy Performance Graph

In reality, the energy production and usage grids are interconnected. Any energy produced by the PAT system will first be consumed by the facility if it's needed, before becoming excess back to the grid. Without hour by hour electrical consumption data, it is impossible to know exactly what percentage of the produced energy would actually be used. However, for the purposes of this report it is assumed at least 80% of the electrical consumption will be coincident to the electric produced (created or offset) by the PAT system.

Based on the power equations discussed in Section 4, the ideal energy production of the system is roughly 579,000 kWh per year. Since the simulated peak production was 405,000 kWh, the overall efficiency of the process is 70%. The peak efficiency of any given PAT is roughly 82% efficient.

11.0 ECONOMIC ANALYSIS

An economic cost analysis was performed for the PAT system. Below is a summary of the results.

11.1 IMPLEMENTATION COSTS

Below is a summary of estimated implementation costs associated with the PAT systems. Costs are broke down by number of pumps installed for the system. Economy of scale was considered in the estimate and costs shown are for budgetary purposes only.

Cost Analysis Summary				
Item	One Pump	Two Pump	Three Pump	Four Pump
Equipment and Component Installations	$ 54,000	$ 90,000	$ 116,000	$ 145,000
Construction and Engineering Fees	$ 16,000	$ 22,500	$ 27,000	$ 30,000
Contingency	$ 5,500	$ 9,000	$ 12,000	$ 14,500
Total	**$ 75,500**	**$ 121,500**	**$ 155,000**	**$ 189,500**

Figure 20 – Cost Analysis Summary

11.2 ENERGY COST ANALYSIS

Below is a summary of estimated energy cost performance associated with the PAT system for each of the potential project classifications – qualified facility or renewable energy (net-metering). The summary assumes that 80% of the yearly facility electric use will be offset by the PAT system and that all electricity will be sold back to the utility at $0.0183 per kWh.

Energy Cost Analysis (Annual) - Qualified Facility				
Item	One Pump	Two Pump	Three Pump	Four Pump
PAT Production (kWh)	186874	315140	378956	405274
Facility Electric Use (kWh)	-20000	-20000	-20000	-20000
Electric to Utility (kWh)	166874	295140	358956	385274
Avoided Electric Use (kWh)	80000	80000	80000	80000
Income from Utility ($)	$3,054	$5,401	$6,569	$7,051
Facility Electric Cost ($)	-$1,200	-$1,200	-$1,200	-$1,200
Avoided Utility Cost ($)	$4,800	$4,800	$4,800	$4,800
Total Income ($)	$6,654	$9,001	$10,169	$10,651
Payback (Years)	**11.3**	**13.3**	**15.2**	**17.7**

Figure 21 – Energy Cost Analysis Summary – Qualified Facility

Based on a simple payback analysis, the PAT system under the "qualified facility" classification has a payback period on a range 10.8 to 16.6 years, depending on the number of pumps installed. The single pump installation has the best relative payback at 10.8 years.

Energy Cost Analysis (Annual) - Renewable Energy (Net-Metering)				
Item	One Pump	Two Pump	Three Pump	Four Pump
PAT Production (kWh)	186874	315140	378956	405274
Facility Electric Use (kWh)	-20000	-20000	-20000	-20000
Electric to Utility (kWh)	166874	295140	358956	385274
Income from Utility ($)	$3,054	$5,401	$6,569	$7,051
Avoided Utility Cost ($)	$6,000	$6,000	$6,000	$6,000
Total Income ($)	$9,054	$11,401	$12,569	$13,051
Payback (Years)	**8.3**	**10.7**	**12.3**	**14.5**

Figure 22 - Energy Cost Analysis Summary – Renewable Energy

Based on a simple payback analysis, the PAT system under the "Renewable Energy" classification has a payback period on a range 8.3 to 14.5 years, depending on the number of pumps installed. The single pump installation has the best relative payback at 8.3 years.

11.3 LIFE CYCLE COST ANALYSIS

The following is summary of estimated life cycle costs analysis (LCCA) associated with each of the different alternatives. BLCC Version 5.3 was used to calculate the LCCA. The following assumptions were made to support the analysis.

- The study period is 30 Years and DOE (Department of Energy) escalation rates are included.
- One or more pumps will require replacement in 10 years.
- One of more control system components will require replacement in 5 years.
- System maintenance costs will be approximately $500 per year.
- Costs are presented as positive numbers and payments are presented by negative numbers.
- Financial performance from the "net-metering" scenario was used for this analysis.

Lowest LCC

Comparative Present-Value Costs of Alternatives
(Shown in Ascending Order of Initial Cost, * = Lowest LCC)

Alternative	Initial Cost (PV)	Life Cycle Cost (PV)
Base Case - Do Nothing	$0	$121,576
One Pump PAT System	$75,500	-$33,894
Two Pump PAT System	$121,500	-$35,456 *
Three Pump PAT System	$155,000	-$25,619
Four Pump PAT System	$189,500	-$878

Figure 23 – LCCA Summary

Based on the analysis, the two pump system has the lowest life cycle cost (LLCC) or present value (PV). This implies the two pump system would be the best overall investment. The four pump system has the highest LCC and would be considered the least favorable investment.

12.0 APPENDIX

12.1 BIBLIOGRAPHY OF REFERENCED ARTICLES

12.1.1 "USING PUMPS AS POWER RECOVERY TURBINES" BY ALLAN R. BUDRIS. PUBLISHED IN WATERWORLD MAGAZINE, AUGUST 2009

12.1.2 "MULTIPLE PUMPS AS TURBINE INSTALLATIONS KEEP EFFICIENCY HIGH OVER WIDE FLOW RANGES" BY ALLAN R. BUDRIS. PUBLISHED IN WATERWORLD MAGAZINE, AUGUST 2009

12.2 BIBLIOGRAPHY OF REFERENCED MATERIALS

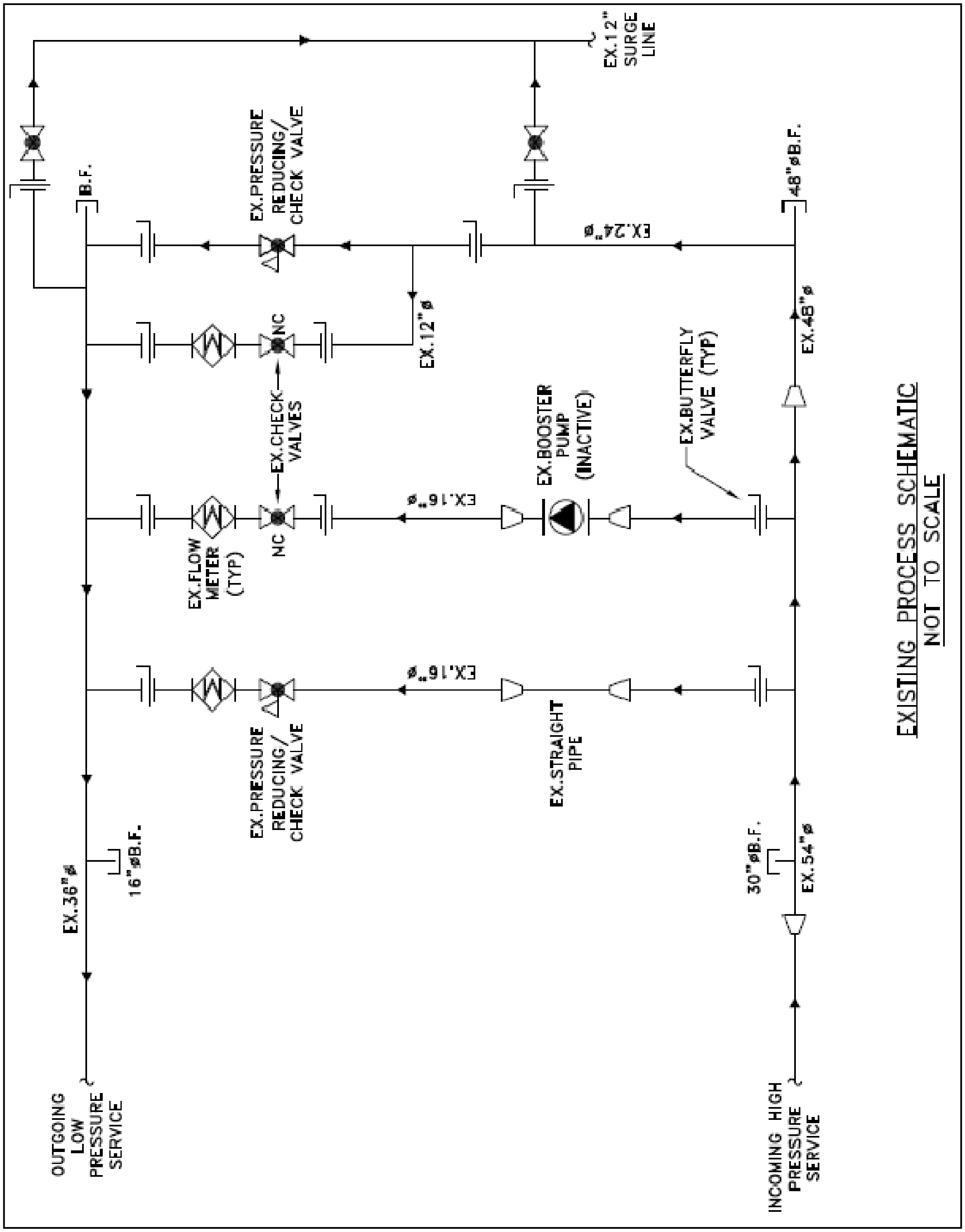
12.2.1 "ESTIMATING REVERSIBLE PUMP-TURBINE CHARACTERISTICS", UNITED STATES DEPARTMENT OF THE INTERIOR - BUREAU OF RECLAMATLON, PUBLISHED 1977.

12.2.2 "MECHANICAL ENGINEERING REFERENCE MANUAL", MICHAEL R. LINDEBURG; PROFESSIONAL PUBLICATIONS, INC, COPYRIGHT2006.

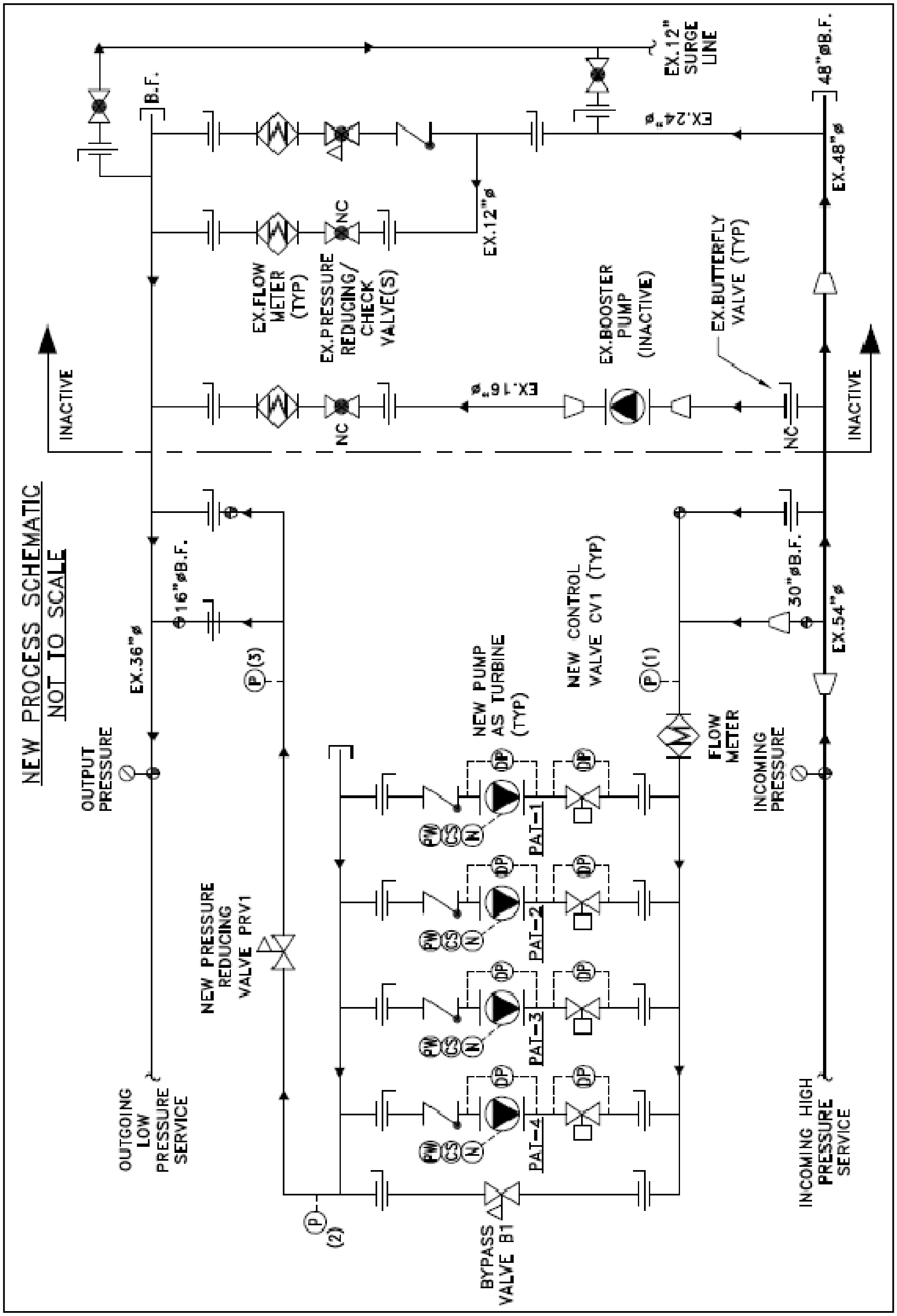
12.3 FACILITY PHOTOGRAPHS

12.4 FACILITY DRAWINGS

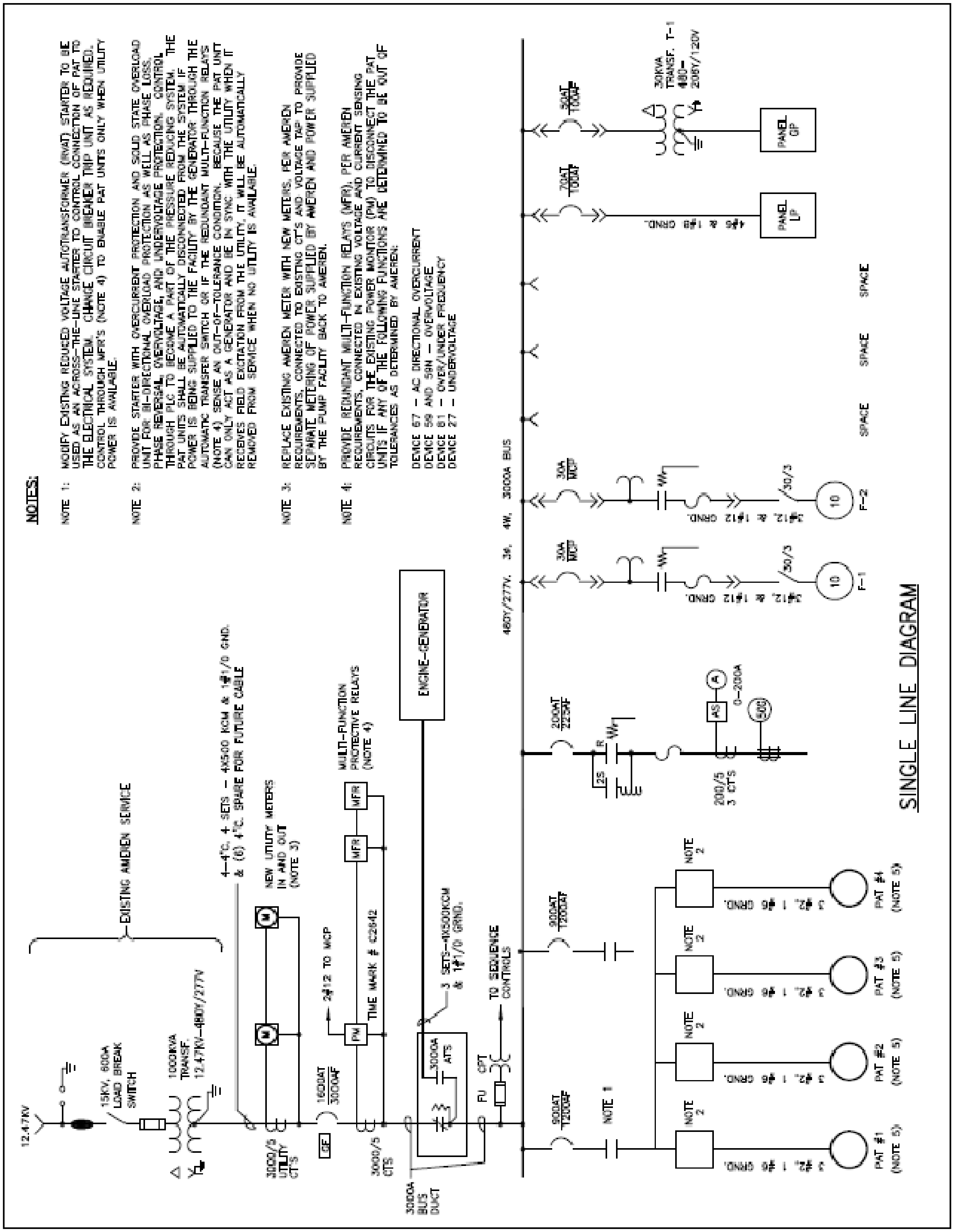
12.4.1 EXISTING GREENSBOTTOM MECHANICAL SCHEMATIC



12.4.2 NEW GREENSBOTTOM MECHANICAL SCHEMATIC

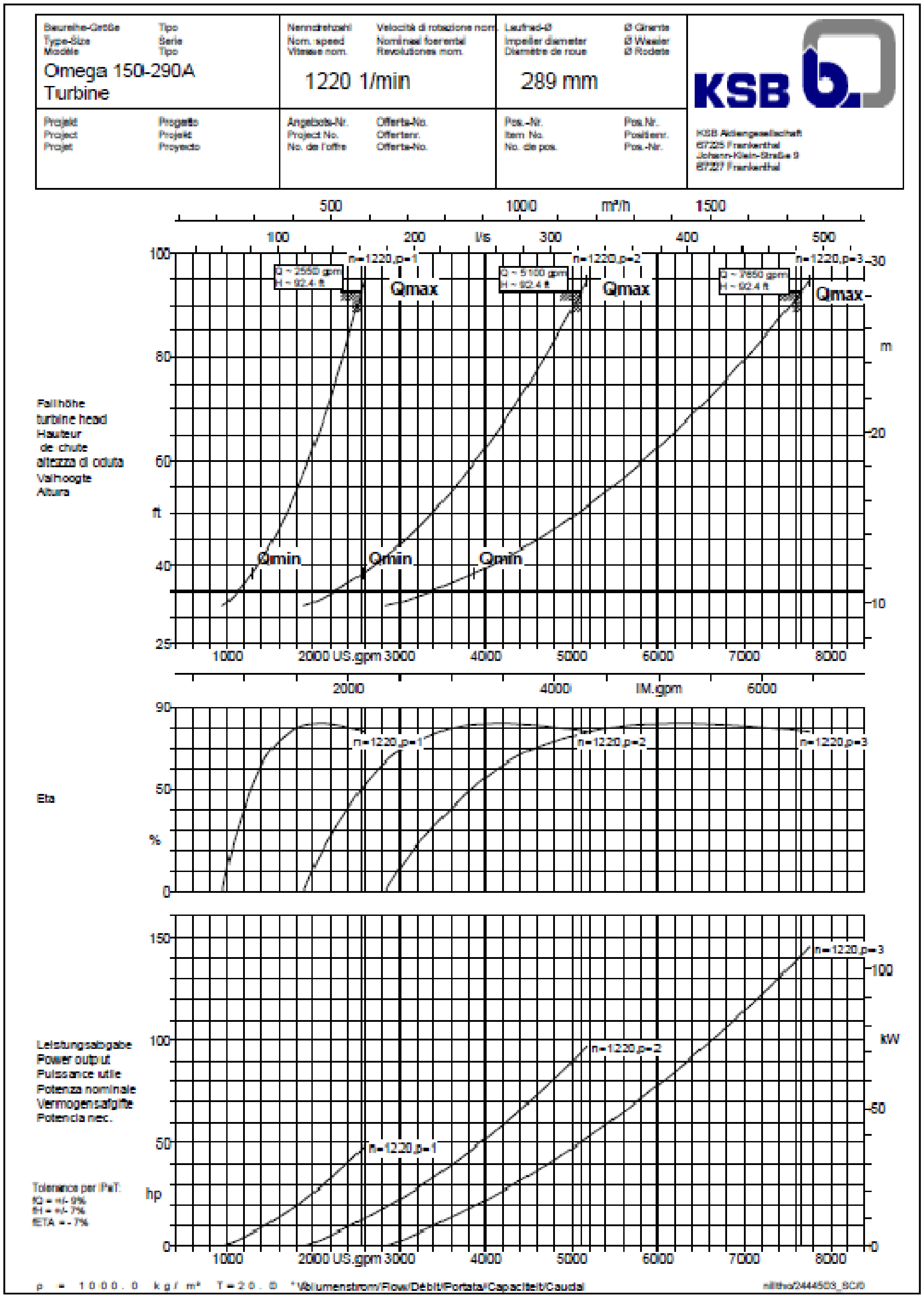


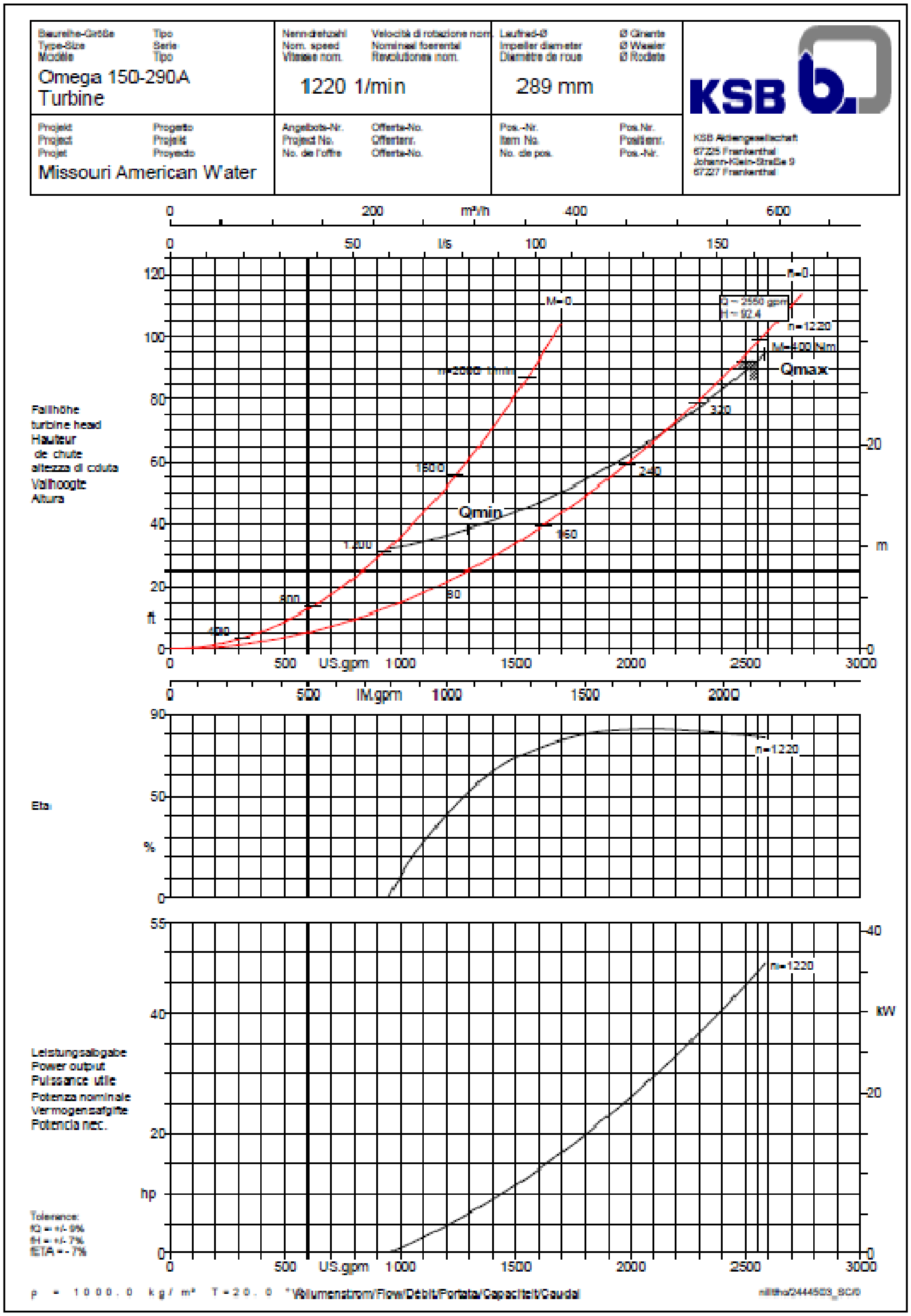
12.4.3 EXISTING/NEW GREENSBOTTOM ELECTRICAL SCHEMATIC



12.5 EQUIPMENT CUTSHEETS AND SELECTIONS

12.5.1 KSB PUMP SELECTION CURVES




Baureihe-Größe Tipo
Type-Size Serie
Modèle Tipo
Omega 150-290A
Turbine
Nenndrehzahl Velocità di rotazione nom.
Nom. speed Nominaal toerental
Vitesse nom. Revoluciones nom.
1220 1/min
Laufrad-Ø Ø Girante
Impeller diameter Ø Waaier
Diamètre de roue Ø Rodete
289 mm
KSB
Projekt Progetto
Project Projekt
Projet Proyecto
Missouri American Water
Angebots-Nr. Offerta-No.
Project No. Offertenr.
No. de l'offre Oferta-No.
Pos.-Nr. Pos.Nr.
Item No. Positienr.
No. de pos. Pos.-Nr.
KSB Aktiengesellschaft
67225 Frankenthal
Johann-Klein-Straße 9
67227 Frankenthal
m³/h
l/s
US.gpm
IM.gpm
Fallhöhe
turbine head
Hauteur
de chute
altezza di caduta
Valhoogte
Altura
ft
m
n=0
M=0
n=1220
M=400 Nm
Qmax
Qmin
Q = 2550 gpm
H = 92.4
Eta
%
Leistungsabgabe
Power output
Puissance utile
Potenza nominale
Vermogensafgifte
Potencia nec.
hp
kW
Tolerance:
fQ = +/- 9%
fH = +/- 7%
fETA = - 7%
ρ = 1000.0 kg/m³ T=20.0 °
Volumenstrom/Flow/Débit/Portata/Capaciteit/Caudal

12.5.2 KSB PUMP SPECIFICATION

KSB Pumps as Turbines

QTY	DESCRIPTION	
3	**KSB Pump model: Omega 150-290 A GB G F** Horizontal Split Pump as Turbine Material of Construction: CI (see KSB data sheets for details) Shaft Seal: Mechanical Seal, Single acting (2) KSB Standard Channel Steel Baseplate: Pump & Motor KSB Standard Coupling: Rexnord Wrapflex KSB Standard Coupling Guard, Steel Fit Motor on Baseplate **Misc.:** KSB Paint: Standard for indoor operation KSB Standard QC & Material Inspections KSB Standard Documentation Package Preparation for Shipment Shipment to Richmond, VA	
3	**Electric Motor / Generator: Siemens, TECO, WEG or equal** 60HP, TEFC, 1200 rpm 460V, 60HZ, 3 Phase Premium Efficient Shipment to Richmond, VA	i

12.6 DATA COLLECTION

12.6.1 ELECTRIC UTILITY DATA HISTORY

Account Information:

Account Number:	4310009019
Customer Name:	MISSOURI AMERICAN WATER
Address:	3800 GREENS BOTTOM RD SAINT CHARLES MO 63304

Service Point Information:

Service Type	Service Point	Meter	Delivery Service
Electric	11960041	11184918 (Active)	Rate 2M Sm Gen Svc - 3 Ph w/Dmd

Account Activity:

Total Service Charges	Due Date	Bill	Product	Reading Dates	Usage	Service Charges
$158.68	09/03/10	Ameren	ELECTRIC SERVICE 11184918	7/22/10 - 8/22/10	1500 KWh	Service - $158.68 Taxes - $0.00
$158.68	08/05/10	Ameren	ELECTRIC SERVICE 11184918	6/22/10 - 7/22/10	1500 KWh	Service - $158.68 Taxes - $0.00
$143.01	07/07/10	Ameren	ELECTRIC SERVICE 11184918	5/22/10 - 6/22/10	1500 KWh	Service - $143.01 Taxes - $0.00
$159.11	06/07/10	Ameren	ELECTRIC SERVICE 11184918	4/22/10 - 5/22/10	2700 KWh	Service - $159.11 Taxes - $0.00
$212.42	05/06/10	Ameren	ELECTRIC SERVICE 11184918	3/24/10 - 4/22/10	4200 KWh	Service - $212.42 Taxes - $0.00
$553.60	04/08/10	Ameren	ELECTRIC SERVICE 11184918	2/23/10 - 3/24/10	13800 KWh	Service - $553.60 Taxes - $0.00
$830.81	03/09/10	Ameren	ELECTRIC SERVICE 11184918	1/26/10 - 2/23/10	21600 KWh	Service - $830.81 Taxes - $0.00
$862.06	02/09/10	Ameren	ELECTRIC SERVICE 11184918	12/28/09 - 1/26/10	22800 KWh	Service - $862.06 Taxes - $0.00
$820.01	01/13/10	Ameren	ELECTRIC SERVICE 11184918	11/22/09 - 12/28/09	21600 KWh	Service - $820.01 Taxes - $0.00
$241.85	12/07/09	Ameren	ELECTRIC SERVICE 11184918	10/21/09 - 11/22/09	5100 KWh	Service - $241.85 Taxes - $0.00
$178.78	11/05/09	Ameren	ELECTRIC SERVICE 11184918	9/22/09 - 10/21/09	3300 KWh	Service - $178.78 Taxes - $0.00
$139.86	10/06/09	Ameren	ELECTRIC SERVICE 11184918	8/23/09 - 9/22/09	1500 KWh	Service - $139.86 Taxes - $0.00
$164.49	09/04/09	Ameren	ELECTRIC SERVICE 11184918	7/23/09 - 8/23/09	1800 KWh	Service - $164.49 Taxes - $0.00

12.6.2 OBTAINING QUALIFYING FACILITY STATUS AS A COGENERATION OR SMALL POWER PRODUCTION FACILITY

What is a Qualifying Facility?

A **Qualifying Facility (QF)** is a generating facility which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978 (PURPA) and part 292 of the Commission's Regulations (18 C.F.R. Part 292), and which meets certification and registration requirements for QF status.

There are two types of QFs: cogeneration facilities and small power production facilities. A **Cogeneration Facility** is a generating facility that sequentially produces electricity and another form of useful thermal energy such as heat or steam that can be used for industrial, commercial, residential or institutional purposes, and otherwise meets their requirements of 18 C.F.R. §§ 292.203(b) and 292.205 for operation, efficiency and use of energy output.

A **Small Power Production Facility** is a generating facility whose primary energy source is renewable such as hydroelectric, wind, solar, biomass, **waste**, or geothermal resources, and that otherwise meets the requirements of 18 C.F.R. §§ 292.203(a), 292.203(c) and 292.204. Small power production facilities are limited in size to 80 MW, with the exception of certain types of facilities certified prior to 1995 and designated as "eligible" under section 3(17)(E) of the Federal Power Act (FPA) (15 U.S.C. § 796(17)(E)), which have no size limitation.

1. Additional Information on obtaining *qualifying facility* status may be found at www.ferc.gov by searching for "QF" or "qualifying facility" or using this direct link to the FERC site at http://www.ferc.gov/industries/electric/gen-info/qual-fac.asp.

2. The procedures for becoming a qualifying small power production facility or a qualifying cogeneration facility are outlined in the 18 CFR §292.207 of the Federal Energy Regulatory Commission (FERC) regulations implementing PURPA.

3. 18 C.F.R. 292.203 establishes an exemption, for generators with net power production capacities of 1 MW (1,000 KW) or less, from the requirement to file a Form 556 in order to obtain QF status. To determine if you are exempt from the requirement to file a Form 556 for your facility, based on the small size of your facility, download the Form 556 and complete section 7. If the value you obtain in line 7g is less than or equal to 1,000 KW, then your facility is exempt from the Form 556 filing requirement.

12.6.3 EXCERPTS FROM FEDERAL REGULATIONS 18 C.F.R. PART 292

PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION

§ 292.202 Definitions.

For purposes of this subpart:

(a) Biomass means any organic material not derived from fossil fuels;

(b) ***Waste means*** *an energy input that is listed below in this subsection****, <u>or</u> any energy input that has little or no current commercial value and exists in the absence of the qualifying facility industry.*** *Should a waste energy input acquire commercial value after a facility is qualified by way of Commission certification pursuant to §292.207(b), or self-certification pursuant to §292.207(a), the facility will not lose its qualifying status for that reason.*

(Analysis: In the case of Greensbottom, the energy input to the facility is water pressure)

§ 292.203 General requirements for qualification.

(a) *Small power production facilities.* Except as provided in paragraph (c) of this section, a small power production facility is a qualifying facility if it:

(1) Meets the maximum size criteria specified in §292.204(a);

(2) Meets the fuel use criteria specified in §292.204(b); and

(3) Has filed with the Commission a notice of self-certification, pursuant to §292.207(a); or has filed with the Commission an application for Commission certification, pursuant to §292.207(b) (1), that has been granted.

(b) *Cogeneration facilities.* A cogeneration facility, including any diesel and dual-fuel cogeneration facility, is a qualifying facility if it:

(1) Meets any applicable operating and efficiency standards specified in §292.205(a) and (b); and

(2) Has filed with the Commission a notice of self-certification, pursuant to §292.207(a); or has filed with the Commission an application for Commission certification, pursuant to §292.207(b) (1), that has been granted.

(Analysis: Note that Greensbottom would not qualify as a Cogeneration Facility)

(c) *Hydroelectric small power production facilities located at a new dam or diversion.* (1) A hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion (as that term is defined in §292.202(p)) is a qualifying facility if it meets the requirements of:

(Analysis: Note that Greensbottom would not qualify as a "Hydroelectric small power production facilities located at a new dam or diversion".)

§ 292.204 Criteria for qualifying small power production facilities.

(a) *Size of the facility*—1) *Maximum size.* There is no size limitation for an eligible solar, wind, waste or facility, as defined by section 3(17) (E) of the Federal Power Act. For a non-eligible facility, the power production capacity for which qualification is sought, together with the power production capacity of any other non-eligible small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts.

(b) *Fuel use.* (1)(i) The primary energy source of the facility must be biomass, **waste**, renewable resources, geothermal resources, or any combination thereof, and 75 percent or more of the total energy input must be from these sources.

(Analysis: In the case of Greensbottom, pressure reduction is considered to be "waste".)

12.6.4 EXCERPTS FROM STATE REGULATIONS 4 CSR 240-20.060

heating, central hot water heating, central ventilating and central air-conditioning systems; or

(F) For all portions of electricity in commercial units in buildings with central space heating, ventilating and air-conditioning systems.

(5) Any person or entity affected by this rule may file an application with the commission seeking a variance from all or parts of this rule (4 CSR 240-20.050) and for good cause shown, variances may be granted as follows:

(A) The variance request shall be filed in writing and directed to the secretary of the commission;

(B) If the commission deems it in the public interest, a hearing may be held by the commission as in complaint hearings before the commission; and

(C) A variance committee consisting of two (2) members of the commission's utility division staff and a member of the commission's general counsel's office shall be established by the commission within thirty (30) days from September 28, 1981. The public counsel shall be an *ex officio* member of this committee.

1. The variance committee shall consider all variance applications filed by utilities and shall make a written recommendation of its findings to the commission for its approval.

2. Each applicant for a variance shall have ten (10) days from the date of the variance committee's findings to either accede or request a formal hearing before the commission.

3. If applicant accedes, the commission may adopt the variance committee's findings or set the matter for formal hearing upon the application of any interested person or upon the commission's own motion.

(6) The commission, in its discretion, may approve tariffs filed by an electric corporation which are more restrictive of master metering than the provisions of this rule.

AUTHORITY: section 386.250, RSMo Supp. 1991. Original rule filed March 13, 1980, effective Dec. 15, 1980. Emergency amendment filed May 13, 1981, effective May 31, 1981, expired Sept. 28, 1981. Amended: Filed May 13, 1981, effective Sept. 28, 1981.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991.*

4 CSR 240-20.060 Cogeneration

PURPOSE: This rule implements Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with regard to small power production and cogeneration. The objective of Sections 201 and 210 of Public Utility Regulatory Policies Act is to provide a mechanism to set up a cogeneration program for Missouri for regulated utilities. Additional requirements regarding this subject matter are also found at 4 CSR 240-3.155.

(1) Definitions. Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this rule as they have under PURPA, unless further defined in this rule.

(A) Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, that utility would generate itself or purchase from another source.

(B) Back-up power means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(C) Interconnection costs means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent those costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(D) Interruptible power means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(E) Maintenance power means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

(F) Purchase means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(G) Qualifying facility means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of Part 292 of the Federal Energy Regulatory Commission's (FERC) regulations.

(H) Rate means any price, rate, charge or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity or any rule or practice respecting any such rate, charge or classification and any contract pertaining to the sale or purchase of electric energy or capacity.

(I) Sale means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(J) Supplementary power means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(K) System emergency means a condition on a utility's system which is likely to result in imminent significant disruption of service to consumers or is imminently likely to endanger life or property.

(2) Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978.

(A) Applicability. This section applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(B) Negotiated Rates or Terms. Nothing in this section—

1. Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this rule; or

2. Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

(C) Every regulated utility which provides retail electric service in this state shall enter into a contract for parallel generation service with any customer which is a qualifying facility, upon that customer's request, where that customer may connect a device to the utility's delivery and metering service to transmit electrical power produced by that customer's energy generating system into the utility's system.

1. The utility shall supply, install, own and maintain all necessary meters and associated equipment used for billing. The costs of any such meters and associated equipment which are beyond those required for service to a customer which is not a qualifying facility shall be borne by the customer. The utility may install and maintain, at its expense,

load research metering for monitoring the customer's energy generation and usage.

2. The customer shall supply, install, operate and maintain, in good repair and without cost to the utility, the relays, locks and seals, breakers, automatic synchronizer, a disconnecting device and other control and protective devices required by the utility to operate the customer's generating system parallel to the utility's system. The customer also shall supply, without cost to the utility, a suitable location for meters and associated equipment used for billing, load research and disconnection.

3. The customer shall be required to reimburse the utility for the cost of any equipment or facilities required as a result of connecting the customer's generating system with the utility's system.

4. The customer shall notify the utility prior to the initial testing of the customer's generating system and the utility shall have the right to have a representative present during the testing.

5. Meters and associated equipment used for billing, load research and connection and disconnection shall be accessible at all times to utility personnel.

6. A manual disconnect switch for the qualifying facility must be provided by the customer which will be under the exclusive control of the utility dispatcher. This manual switch must have the capability to be locked out of service by the utility-authorized switchmen as a part of the utility's workman's protection assurance procedures. The customer must also provide an isolating device which the customer has access to and which will serve as a means of isolation for the customer's equipment during any qualifying facility maintenance activities, routine outages or emergencies. The utility shall give notice to the customer before a manual switch is locked or an isolating device used, if possible; and otherwise shall give notice as soon as practicable after locking or use.

(D) No customer's generating system or connecting device shall damage the utility's system or equipment or present an undue hazard to utility personnel.

(E) If harmonics, voltage fluctuations or other disruptive problems on the utility's system are directly attributable to the operation of the customer, these problems will be corrected at the customer's expense.

(F) Every contract shall provide fair compensation for the electrical power supplied to the utility by the customer. If the utility and the customer cannot agree to the terms and conditions of the contract, the Public Service Commission (PSC) shall establish the terms and conditions upon the request of the utility or the customer. Those terms and conditions will be established in accordance with Section 210 of the Public Utility Regulatory Policies Act of 1978 and the provisions of this rule.

<u>(3) Electric Utility Obligations Under This Rule.</u>

<u>(A) Obligation to Purchase From Qualifying Facilities. Each electric utility shall purchase, in accordance with section (4), any energy and capacity which is made available from a qualifying facility—</u>

<u>1. Directly to the electric utility; or</u>

<u>2. Indirectly to the electric utility in accordance with subsection (3)(D) of this rule.</u>

(B) Obligation to Sell to Qualifying Facilities. Each electric utility shall sell to any qualifying facility, in accordance with section (5) of this rule, any energy and capacity requested by the qualifying facility.

(C) Obligation to Interconnect.

1. Subject to paragraph (3)(C)2. of this rule, any electric utility shall make interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this rule. The obligation to pay for any interconnection costs shall be determined in accordance with section (6) of this rule.

2. No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(D) Transmission to Other Electric Utilities. If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from a qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which energy or capacity is transmitted shall purchase energy or capacity under this subsection (3)(D) as if the qualifying facility were supplying energy or capacity directly to the electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to paragraph (4)(E)4. of this rule and shall not include any charges for transmission.

(E) Parallel Operation. Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with section (8) of this rule.

(4) Rates for Purchases.

<u>(A) Rates for purchases shall be just and reasonable to the electric consumer of the electric utility and in the public interest and shall not discriminate against qualifying cogeneration and small power production facilities. Nothing in this rule requires any electric utility to pay more than the avoided costs for purchases.</u>

(B) Relationship to Avoided Costs.

1. For purposes of this section, new capacity means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

2. Subject to paragraph (4)(B)3. of this rule, a rate for purchases satisfies the requirements of subsection (4)(A) of this rule if the rate equals the avoided costs determined after consideration of the factors set forth in subsection (4)(E) of this rule.

3. A rate for purchases (other than from new capacity) may be less than the avoided cost if the PSC determines that a lower rate is consistent with subsection (4)(A) of this rule and is sufficient to encourage cogeneration and small power production.

4. Rates for purchases from new capacity shall be in accordance with paragraph (4)(B)2. of this rule, regardless of whether the electric utility making the purchases is simultaneously making sales to the qualifying facility.

5. In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for the purchases do not violate this paragraph if the rates for the purchases differ from avoided costs at the time of delivery.

<u>(C) Standard Rates for Purchases.</u>

<u>1. There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of one hundred (100) kilowatts or less.</u>

2. <u>There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than one hundred (100) kilowatts.</u>

3. The standard rates for purchases under this subsection shall be consistent with subsections (4)(A) and (E) of this rule, and may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(D) Purchases as Available or Pursuant to a Legally Enforceable Obligation. Each qualifying facility shall have the option either—

1. To provide energy as the qualifying facility determines this energy to be available for the purchases, in which case the rates for

the purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

2. To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for the purchases, at the option of the qualifying facility exercised prior to the beginning of the specified term, shall be based on either the avoided costs calculated at the time of delivery or the avoided costs calculated at the time the obligation is incurred.

(E) Factors Affecting Rates for Purchases. In determining avoided costs, the following factors, to the extent practicable, shall be taken into account:

1. The data provided pursuant to 4 CSR 240-3.155, including PSC review of any such data;

2. The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

A. The ability of the utility to dispatch the qualifying facility;

B. The expected or demonstrated reliability of the qualifying facility;

C. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for noncompliance;

D. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

E. The usefulness of energy and the capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

F. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

G. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities;

3. The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (4)(E)2. of this rule, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of oil use; and

4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(F) Periods During Which Purchases not Required.

1. Any electric utility which gives notice pursuant to paragraph (4)(F)2. of this rule will not be required to purchase electric energy or capacity during any period which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make the purchases, but instead generated an equivalent amount of energy itself.

2. Any electric utility seeking to invoke paragraph (4)(F)1. of this rule must notify, in accordance with applicable state law or rule, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

3. Any electric utility which fails to comply with the provisions of paragraph (4)(F)2. of this rule will be required to pay the same rate for the purchase of energy or capacity as would be required had the period described in paragraph (4)(F)1. of this rule not occurred.

4. A claim by an electric utility that this period has occurred or will occur is subject to verification by the PSC as the PSC determines necessary or appropriate, either before or after the occurrence.

(5) Rates for Sales.

(A) Rates for sales shall be just and reasonable and in the public interest and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for sales which are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that those rates apply to the utility's other customers with similar load or other cost-related characteristics.

(B) Additional Services to be Provided to Qualifying Facilities.

1. Upon request of a qualifying facility, each electric utility shall provide supplementary power, back-up power, maintenance power and interruptible power.

2. The PSC may waive any requirement of paragraph (5)(B)1. of this rule if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the PSC finds that compliance with that requirement will impair the electric utility's ability to render adequate service to its customers or place an undue burden on the electric utility.

(C) Rates for Sale of Back-Up and Maintenance Power. The rate for sales of back-up power or maintenance power—

1. Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously or during the system peak or both; and

2. Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

(6) Interconnection Costs.

(A) If the utility and the qualifying facility cannot reach agreement as to the amount or the manner of payment of the interconnection costs to be paid by the qualifying facility, the PSC, after hearing, shall assess against the qualifying facility those interconnection costs to be paid to the utility, on a nondiscriminatory basis with respect to other customers with similar load characteristics or shall determine the manner of payments of the interconnection costs, which may include reimbursement over a reasonable period of time, or both. In determining the terms of any reimbursement over a period of time, the commission shall provide for adequate carrying charges associated with the utility's investment and security to insure total reimbursement of the utility's incurred costs, if it deems necessary.

(7) System Emergencies.

(A) Qualifying Facility Obligation to Provide Power During System Emergencies. A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent provided by agreement between the qualifying facility and electric utility or ordered under section 202(c) of the Federal Power Act.

(B) Discontinuance of Purchases and Sales During System Emergencies. During any system emergency, an electric utility may discontinue purchases from a qualifying facility if those purchases would contribute to the emergency and sales to a qualifying facility, provided that discontinuance is on a nondiscriminatory basis.

(8) Standards for Operating Reliability. The PSC may establish reasonable standards to ensure system safety and reliability of interconnected operations. Those standards may be recommended by any electric utility, any qualifying facility or any other person. If the PSC establishes standards, it shall specify the need for the standards on the basis of system safety and reliability.

(9) Exemption to Qualifying Facilities From the Public Utility Holding Company Act and Certain State Law and Rules.

(A) Applicability. This section applies to qualifying cogeneration facilities and qualifying small power production facilities which have a power production capacity which does not exceed thirty (30) megawatts and to any qualifying small power production facility with a power production capacity over thirty (30) megawatts if that facility produces electric energy solely by the use of biomass as a primary energy source.

(B) A qualifying facility described in subsection (1)(A) shall not be considered to be an electric utility company as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(C) Any qualifying facility shall be exempted (except as otherwise provided) from Missouri PSC law or rule respecting the rates of electric utilities and the financial and organizational regulation of electric utilities. A qualifying facility may not be exempted from Missouri PSC law and rule implementing subpart C of PURPA.

AUTHORITY: sections 386.250 and 393.140, RSMo 2000. Original rule filed Oct. 14, 1980, effective May 15, 1981. Amended: Filed Aug. 16, 2002, effective April 30, 2003.*

**Original authority: 386.250, RSMo 1939, amended 1963,1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-20.065 Net Metering

PURPOSE: This rule implements the Net Metering and Easy Connection Act (section 386.890, RSMo Supp. 2008) and establishes standards for interconnection of qualified net metering units (generating capacity of one hundred kilowatts (100 kW) or less) with distribution systems of electric utilities.

(1) Definitions.

(A) Avoided fuel cost means the current annual average cost of fuel for the electric utility as calculated from information contained in the most recent annual report submitted to the commission pursuant to 4 CSR 240-3.165. Annual average cost of fuel will be calculated from information on the Steam-Electric Generating Plant Statistics Sheets of the annual report. This annual average cost of fuel shall be identified in the net metering tariffs on file with the commission and shall be updated annually within thirty (30) days after the electric utility's annual report is submitted.

(B) Commission means the Public Service Commission of the state of Missouri.

(C) Customer-generator means the owner or operator of a qualified electric energy generation unit that meets all of the following criteria:

1. Is powered by a renewable energy resource;

2. Is an electrical generating system with a capacity of not more than one hundred kilowatts (100 kW);

3. Is located on premises that are owned, operated, leased, or otherwise controlled by the customer-generator;

4. Is interconnected and operates in parallel phase and synchronization with an electric utility and has been approved for interconnection by said electric utility;

5. Is intended primarily to offset part or all of the customer-generator's own electrical energy requirements;

6. Meets all applicable safety, performance, interconnection, and reliability standards established by the National Electrical Code, the National Electrical Safety Code, the Institute of Electrical and Electronics Engineers, Underwriters Laboratories, the Federal Energy Regulatory Commission, and any local governing authorities; and

7. Contains a mechanism that automatically disables the unit and interrupts the flow of electricity onto the electric utility's electrical lines whenever the flow of electricity to the customer-generator is interrupted.

(D) Distribution system means facilities for the distribution of electric energy to the ultimate consumer thereof.

(E) Electric utility means every electrical corporation as defined in section 386.020(15), RSMo 2000, subject to commission regulation pursuant to Chapter 393, RSMo 2000.

(F) Net metering means using metering equipment sufficient to measure the difference between the electrical energy supplied to a customer-generator by an electric utility and the electrical energy supplied by the customer-generator to the electric utility over the applicable billing period.

(G) Renewable energy resources means electrical energy produced from wind, solar thermal sources, hydroelectric sources, photovoltaic cells and panels, fuel cells using hydrogen produced by one (1) of the above-named electrical energy sources, and other sources of energy that become available after August 28, 2007, and are certified as renewable by the Missouri Department of Natural Resources.

(2) Applicability. This rule applies to electric utilities and customer-generators.

(3) Electric Utility Obligations.

(A) Net metering shall be available to customer-generators on a first-come, first-served basis until the total rated generating capacity of net metering systems equals five percent (5%) of the electric utility's Missouri jurisdictional single-hour peak load during the previous year. The commission may increase the total rated generating capacity of net metering systems to an amount above five percent (5%). However, in a given calendar year, no electric utility shall be required to approve any application for interconnection if the total rated generating capacity of all applications for interconnection already approved to date by said electric utility in said calendar year equals or exceeds one percent (1%) of said electric utility's single-hour peak load for the previous calendar year.

(B) A tariff or contract shall be offered that is identical in electrical energy rates, rate structure, and monthly charges to the contract or tariff that the customer would be assigned if the customer were not an eligible customer-generator but shall not charge the customer-generator any additional standby, capacity, interconnection, or other fee or charge that would not otherwise be charged if the customer were not an eligible customer-generator.

(C) The availability of the net metering program shall be disclosed annually to each of its customers with the method and manner of disclosure being at the discretion of the electric utility.

(D) For any cause of action relating to any damages to property or person caused by the generation unit of a customer-generator or the interconnection thereof, the electric utility shall have no liability absent clear and convincing evidence of fault on the part of the supplier.

(E) Any costs incurred under this rule by an electric utility not recovered directly from the customer-generator, as identified in (5)(F), shall be recoverable in that electric utility's rate structure.

(F) No fee, charge, or other requirement not specifically identified in this rule shall be imposed unless the fee, charge, or other requirement would apply to similarly situated customers who are not customer-generators.

(4) Customer-Generator Liability Insurance Obligation.

(A) Customer-generator systems greater than ten kilowatts (10 kW) shall carry no less than one hundred thousand dollars ($100,000) of liability insurance that provides for coverage of all risk of liability for personal injuries (including death) and damage to property arising out of or caused by the operation of the net metering unit. Insurance may be in the form of an existing policy or an endorsement on an existing policy.

(B) Customer-generator systems ten kilowatts (10 kW) or less shall not be required to carry liability insurance; however, any tariff

12.6.5 AMEREN MISSOURI – ELECTRIC POWER PURCHASE RATE

UNION ELECTRIC COMPANY ELECTRIC SERVICE

P. S. C. MO., ILL. C. C., IA. ST. C. C. SCHEDULE NO. 1 5th Revised SHEET NO. 2

CANCELLING SCHEDULE NO. 1 4th Revised SHEET NO. 2

APPLYING TO MISSOURI SERVICE AREA

A. ELECTRIC POWER PURCHASES FROM QUALIFYING FACILITIES

I. Application. This tariff applies to purchases of electric energy or electric energy and capacity from Qualifying Facilities (hereinafter referred to as "Customer") under the provisions of Rule 4 CSR 240-20.060 of the Missouri Public Service Commission.

*II. Standard Rates for Purchase. The standard rates for purchase from a customer with a design capacity of 100 kW or less are as follows:

1. Non-Time - Differentiated Energy Rate

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Summer	1.98¢ per kWh

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Winter	1.75¢ per kWh

2. Time-Differentiated Energy Rate

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Weekday (10 AM - 10 PM)	2.58¢ per kWh
Weekday (10 PM - 10 AM)	1.60¢ per kWh
Saturday, Sunday, Holiday (1)	1.73¢ per kWh

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Weekday (10 AM - 10 PM)	1.89¢ per kWh
Weekday (10 PM - 10 AM)	1.70¢ per kWh
Saturday, Sunday, Holiday (1)	1.63¢ per kWh

(1) Legal Holidays of New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Thanksgiving Friday, Christmas Eve Day, and Christmas Day.

*Indicates Change.

P.S.C. Mo. DATE OF ISSUE January 14, 2011 DATE EFFECTIVE February 15, 2011

ISSUED BY Warner L. Baxter President & CEO St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

P. S. C. MO., ILL. C. C., IA. ST. C. C. SCHEDULE NO. 1 1st Revised SHEET NO. 3

CANCELLING SCHEDULE NO. 1 ORIGINAL SHEET NO. 3 (M)

APPLYING TO MISSOURI SERVICE AREA

*A. ELECTRIC POWER PURCHASES FROM QUALIFYING FACILITIES - (CONTINUED)

3. Customer Charge (per meter required for parallel operation)

Non-Time Differentiated Energy

$4.00 per month - Single Phase

$6.00 per month - Three Phase

Time Differentiated Energy

$13.00 per month - Single Phase

$15.00 per month - Three Phase

4. Billing

Monthly billing between Company and Customer shall be in accordance with the Contract between the parties.

* Indicates Reissue

P.S.C. Mo. DATE OF ISSUE August 14, 2003 DATE EFFECTIVE August 28, 2003

ISSUED BY C. W. Mueller (NAME OF OFFICER) Chairman & CEO (TITLE) St. Louis, Missouri (ADDRESS)

12.7 CALCULATIONS

12.7.1 LIFE CYCLE COST ANALYSIS SUMMARY

NIST BLCC 5.3-10: Summary LCC

Consistent with Federal Life Cycle Cost Methodology and Procedures, 10 CFR, Part 436, Subpart A

General Information

File Name:	J:\882-55 Greensbottom\Data\Greensbottom PAT Study.xml
Analysis Type:	FEMP Analysis, Energy Project
Project Name:	Greensbottom - PAt Study
Project Location:	Missouri
Analyst:	Ross & Baruzzini
Base Date:	January 1, 2012
Service Date:	January 1, 2013
Study Period:	30 years 0 months (January 1, 2012 through December 31, 2041)
Discount Rate:	3%
Discounting Convention:	End-of-Year

Discount and Escalation Rates are REAL (exclusive of general inflation)

Alternative: Base Case - Do Nothing

LCC Summary

	Present Value	Annual Value
Initial Cost	$0	$0
Energy Consumption Costs	$121,576	$6,203
Energy Demand Costs	$0	$0
Energy Utility Rebates	$0	$0
Water Usage Costs	$0	$0
Water Disposal Costs	$0	$0
Annually Recurring OM&R Costs	$0	$0
Non-Annually Recurring OM&R Costs	$0	$0
Replacement Costs	$0	$0
Less Remaining Value	$0	$0
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Total Life-Cycle Cost	$121,576	$6,203

Alternative: One Pump PAT System

LCC Summary

	Present Value	Annual Value
Initial Cost	$75,500	$3,852
Energy Consumption Costs	-$142,240	-$7,257
Energy Demand Costs	$0	$0
Energy Utility Rebates	$0	$0
Water Usage Costs	$0	$0
Water Disposal Costs	$0	$0
Annually Recurring OM&R Costs	$9,315	$475
Non-Annually Recurring OM&R Costs	$0	$0
Replacement Costs	$23,531	$1,201
Less Remaining Value	$0	$0
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Total Life-Cycle Cost	-$33,894	-$1,729

Alternative: Two Pump PAT System

LCC Summary

	Present Value	Annual Value
Initial Cost	$121,500	$6,199
Energy Consumption Costs	-$189,802	-$9,684
Energy Demand Costs	$0	$0
Energy Utility Rebates	$0	$0
Water Usage Costs	$0	$0
Water Disposal Costs	$0	$0
Annually Recurring OM&R Costs	$9,315	$475
Non-Annually Recurring OM&R Costs	$0	$0
Replacement Costs	$23,531	$1,201
Less Remaining Value	$0	$0
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Total Life-Cycle Cost	-$35,456	-$1,809

Alternative: Three Pump PAT System

LCC Summary

	Present Value	Annual Value
Initial Cost	$155,000	$7,908
Energy Consumption Costs	-$213,465	-$10,891
Energy Demand Costs	$0	$0
Energy Utility Rebates	$0	$0
Water Usage Costs	$0	$0
Water Disposal Costs	$0	$0
Annually Recurring OM&R Costs	$9,315	$475
Non-Annually Recurring OM&R Costs	$0	$0
Replacement Costs	$23,531	$1,201
Less Remaining Value	$0	$0
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Total Life-Cycle Cost	-$25,619	-$1,307

Alternative: Four Pump PAT System

LCC Summary

	Present Value	Annual Value
Initial Cost	$189,500	$9,668
Energy Consumption Costs	-$223,224	-$11,389
Energy Demand Costs	$0	$0
Energy Utility Rebates	$0	$0
Water Usage Costs	$0	$0
Water Disposal Costs	$0	$0
Annually Recurring OM&R Costs	$9,315	$475
Non-Annually Recurring OM&R Costs	$0	$0
Replacement Costs	$23,531	$1,201
Less Remaining Value	$0	$0
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Total Life-Cycle Cost	-$878	-$45

12.8 PROJECT TASK AND OBJECTIVE SUMMARY

Investigating Pump Applications for Pressure Reduction and Electrical Energy Recovery

Sub grant # G11-SEP-RES-03

Detailed Milestones and Project Implementation Tasks

Phase I - Initial Data Collection	
Start Date:	August 24th 2010
• Collect existing water, pressure, and electrical usage profiles.	
• Survey existing facility and review existing drawings.	
• Develop one line flow, electrical, and control diagrams.	
• Research industry partnerships.	
Completion Date:	September 28th 2010
Phase 2 - Detailed Project Research Phase	
Start Date:	September 29th 2010
• Initial project review with outside consultant.	
• Contact potential industry partners and secure commitment.	
• Research existing PAT and Turbine product offerings.	
• Research existing PAT applications.	
• Research PAT calculation methodologies.	
• Research existing PAT control strategies.	
Completion Date:	December 22th 2010
Phase 3 - Data and System Analysis Phase	
Start Date:	December 23th 2010
• Research allowable operating conditions for PAT products.	
• Develop simulation methodology of PAT system.	
• Work with industry partner to develop preliminary product selection.	
• Test PAT product selections against simulation model.	
• Analyze results of simulation model.	
• Review preliminary results with outside consultant.	
• Finalize simulation and detail findings.	
Completion Date:	April 15th 2011
Phase 4 - Outside Consultant Review and Economic Analysis	
Start Date:	April 16th 2011
• Develop draft report.	
• Perform economic analysis based on detailed results.	
• Review final results and economic analysis with outside consultant.	
• Incorporate outside consultant comments into draft report.	
Completion Date:	May 21st 2011
Phase 5 - Final Report	
Start Date:	May 22nd 2011
• Develop final report.	
• Final report review by outside consultant.	
• Internal quality review of final report.	
• Issue final report.	
Completion Date:	June 21st 2011