

EVALUATION OF ENERGY SAVINGS POTENTIAL FROM DEEP WELL VARIABLE
FREQUENCY DRIVE INSTALLATION

by

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EXECUTIVE SUMMARY

Introduction: In 2016, the Madison Water Utility (MWU) used 20.5 GWh of energy to pump nearly 10 billion gallons (PSC 2016). Over the past 15 years, MWU has targeted conservation efforts and energy efficiency measures that have resulted in an annual average decrease of 1-2% in annual water production and energy use. Recent graduate student projects funded by MWU have continued to focus on finding opportunities for further energy savings (Baniel 2013, Hayes 2015). As a groundwater utility, as much as 99% of total energy consumption can be attributed to pumping water (Bohnert 2012, Elliott et al 2003), so much of the work has focused on reducing pumping energy use. This study evaluated the energy savings of variable frequency drive (VFD) installation on deep well pumps. The objectives of this work were to:

1. Develop a validated procedure to estimate energy savings from VFD installation on a deep well pump.
2. Use the developed procedure to identify the strongest deep well candidates for VFD installation.
3. Install and verify the expected energy savings of a VFD on the top-ranked deep well pump.

Background: Over 90% of water utilities in Wisconsin rely on groundwater supplies (PSC 2015b). Energy use by utilities with groundwater supplies is generally higher than that of utilities purchasing water or using surface water supplies like Lake Michigan due to the elevation that the water must be lifted. For typical groundwater systems, 99% of energy use can be attributed to pumping, except for cases where ion exchange or additional treatment is required (Bohnert 2012, Elliott et al 2003).

Pumping energy use is a function of flow rate, head, efficiency, and run time. For groundwater utilities like MWU, pumping head or lift is controlled by the drawdown in the well.

To reduce pumping energy use there are four potential alternatives: a reduction in flow rate, a reduction in head, an increase in efficiency at the pump operating point, or a decrease in pump run time. VFD installation for deep well pumps was investigated to reduce pumping energy use because reduction in pump speed with a VFD allows utilities the opportunity to control the lift by simultaneously reducing flow rate and increasing pump run time to reduce the amount of drawdown.

Methods: This work was broken into three separate chapters, with each chapter addressing a single objective. Combined, these chapters provide a comprehensive overview of energy savings from VFD installation on deep well pumps.

The first study focused on the development and validation of a method for characterizing pump operation and energy use from VFD installation. The developed method used existing pump operational data from the MWU SCADA system to estimate the static water level, pumping water level, drawdown, and specific capacity. This data was used in conjunction with friction losses estimates developed from construction drawings to generate a system head curve. Manufacturer pump curves and Affinity Laws were used to develop variable speed pump curves. Average operating flow rate, head, and efficiency were determined for each selected pump speed to estimate energy intensity. Verification of this estimation method was done through field tests at two MWU wells with VFDs currently installed. Tests were run on both well pumps, with the pump run for multiple hours at a range of pump speeds. Pump operational data and power consumption data were collected for each tested pump speed. Observed pump operating points and energy intensities were compared against estimated values to validate the estimation method.

The second study applied the developed method to characterize energy savings potential across all 22 MWU deep well pumps. Data for a week of pump operation, predominantly from

August 2015, was used to estimate pump operation and energy use with VFD installation at each site. Energy and cost savings estimates were developed based on MWU's operational strategy from 2011 – 2015, average daily well production and number of days per year operational. Daily energy savings were calculated based on deep well pump operation at the most energy-efficient speed capable of meeting average production. Cost savings were estimated based on a utility-wide average electricity cost and sites were ranked based on yearly cost savings from VFD installation.

The final study involved the installation of a VFD at the top-ranked deep well pump to validate cost and energy savings estimates. Pump operation and energy use were characterized prior to VFD installation. Energy and cost savings estimates for the new pump operating point after VFD installation were determined using methods from the first two studies. SCADA operational data and electric utility billing data were used to quantify energy and cost savings from VFD installation. Energy use at surrounding sites was also monitored to determine the impact on energy use elsewhere in the system.

Results: The method to characterize pump operation and energy use for VFD installation was verified using data from tests at Unit Wells 15 and 25. The developed method was found to capture pump behavior well for variable speed operation. Differences between estimated and observed average operating points were attributed to variations in the system head curve. Changes in static water level were found to be the most significant contributor to changes in the system head curve.

Estimated energy intensities were within 10% of observed values for nearly all tested pump speeds at Unit Wells 15 and 25. Differences between the system head curves accounted for some of the difference between estimated and observed values. The differences were most pronounced at low pump speeds where small changes in head can result in large changes in pump flow rate and efficiency. For 60% speed at Unit Well 15, observed energy intensity was 14% less than

estimated. A 7-foot difference in static water level shifted the system curve and the observed operating point had a 45% greater flow rate and 13.5% lower efficiency than the estimated operating point. Seasonal and long-term variations in the system head curve may make energy use at low pump speeds hard to accurately characterize. Observed pumping system efficiency was 3.5% – 6.0% less than estimated, but the difference was independent of flow rate.

While energy intensities were generally within 10% of estimates for a given pump speed, energy intensity savings magnitudes were more variable. At Unit Well 15, observed energy intensity savings were 50% larger than estimated. At Unit Well 25, savings were 15% greater than estimated. Variations in the system head curve made estimates of energy intensity savings magnitudes difficult to predict, but the method was found to be conservative for the combination of well and pump properties tested.

For the second study, pump operation of all 22 MWU deep well pumps was characterized and curves showing energy intensity versus flow rate were generated for each well, an example of which is shown in Figure 0-1. At Unit Well 30, the minimum energy intensity was 900 kWh/MG at 70% speed, a savings of 350 kWh/MG compared to 100% speed operation.

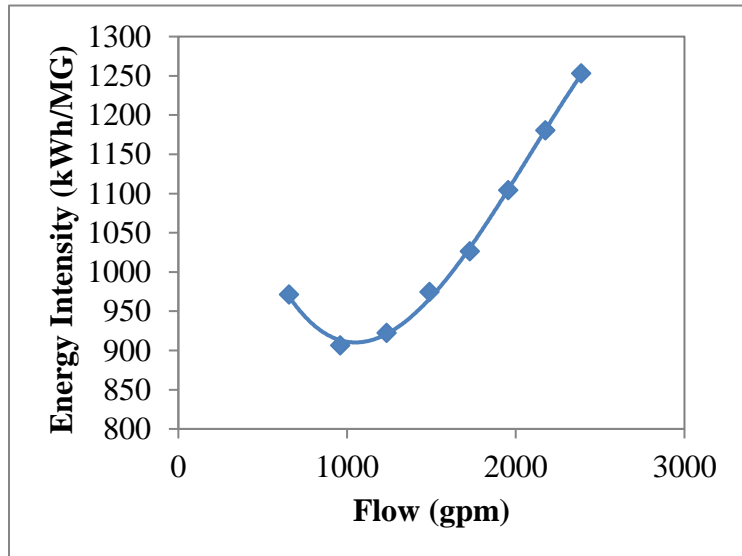


Figure 0-1 - Unit Well 30 energy intensity curve. Each point corresponds with a 5% speed interval, with 100% speed on the right end of the curve and 65% speed on the left end.

The most energy-efficient pump speed capable of meeting the average production of 1.8 MGD was 80%. Reduction to 80% speed was estimated to provide a 38% reduction in flow rate, 19%

reduction in head, and an increase of 3.1% in pump efficiency. Energy savings from VFD installation were estimated to be 500 kWh/day, providing a yearly cost savings of \$20,000.

A similar set of results were generated for each of the 22 MWU deep well pumps, and wells were ranked based on expected yearly energy and cost savings. Under current MWU operational strategy, the top five candidates for VFD installation were Unit Wells 30, 6, 13, 19, and 11. Estimated yearly energy savings for these sites ranged from 95,000 kWh at Unit Well 11 to 180,000 kWh at Unit Well 30. Cost savings were predicted to be over \$10,000 for each of these sites, with a worst-case payback period of 5.6 years at Unit Well 11. A 10-year payback period was determined to be an acceptable return on investment for MWU, and half of the 18 wells without VFDs at the time of the study met that criteria.

Energy savings potential varied widely throughout the MWU system, and depended on site-specific combinations of well properties (e.g., static level and specific capacity) and pump properties (e.g., location of best efficiency point). Energy savings potential was also independent of the magnitude of existing energy use - minimal energy savings were estimated for the highest energy use well pumps in the system. Targeting high baseline energy use sites for VFD installation would cause MWU to miss energy savings opportunities at other lower energy use sites. Pump selection played a role in energy savings magnitude. Pumps with an average operating point below the best efficiency point of the pump (greater flow rate and lower head) had increased energy savings magnitudes.

The final study analyzed actual cost and energy savings after a VFD was installed at Unit Well 30, the top-ranked candidate from the second study. Average site production was unchanged by VFD installation and speed reduction, 1.9 MGD. Observed benefits from VFD installation and pump operation at 1,450 gpm, down from nearly 2,400 gpm, were in line with estimates. Deep

well power consumption was reduced by 102 kW for an energy intensity savings of 335 kWh/MG, both values were within 5% of estimated savings. Energy use at Unit Well 30 was reduced by 540 kWh/day compared to the previous billing period, for a cost savings of nearly \$65/day. After six months of operation (December 2016 – May 2017), MWU has saved 94,400 kWh and \$8,650 compared to the same period in 2015-2016. Payback for VFD installation at Unit Well 30 should be within 1.5 – 2 years.

Energy use and site operation at Unit Well 18 and Booster Station 118 were monitored to determine if there was increased energy use increased elsewhere in the distribution system after VFD installation. Average production, energy use, and energy costs were nearly unchanged at Unit Well 18. The only changes were increased number of days operational and a one hour per day increase in booster pump run time. Booster Station 118 was sporadically used before and after VFD installation, and there was no evidence of adverse effects from changes at Unit Well 30. Changes in operation at Unit Well 30 did not yield increased energy use or costs elsewhere in the distribution system, allowing MWU to benefit from the full \$65/day of cost savings at Unit Well 30.

Energy billing information at Unit Wells 18 and 30 highlighted the impact of demand charges on cost savings for MWU. Electric utility demand charges made up nearly 40% of the bill at Unit Well 18 and nearly 40% of cost savings at Unit Well 30 were attributed to demand reduction. Demand reduction was a crucial component of cost savings from VFD installation. An increase in pump speed for less than a week at Unit Well 30 in April 2017 cost MWU \$300 of cost savings through increased on-peak demand charges. Estimation of cost savings from VFD installation based on an average electricity cost overlooked the importance of on-peak demand reduction.

Conclusions:

- MWU and other groundwater utilities can apply the developed estimation method to characterize deep well pump operation and energy use provided the requisite equipment records and operational information are available.
- The developed method can be used to predict general pump performance with VFD installation. Variations in the system curve due to changes in static water level and specific capacity will shift average operating points at given pump speeds, but the method adequately captures general behavior.
- Energy intensity estimates were within 10% of observed values at both test wells, an acceptable difference given the assumptions made to estimate energy use and the seasonal variations in the system curve. Energy savings magnitudes were less predictable, but the method appeared conservative for the tested combination of well and pump properties.
- The top remaining candidates for VFD installation under MWU operational strategy were Unit Wells 6, 13, 19, and 11.
- For MWU, a 10-year payback period was deemed to be an acceptable payback period for a VFD lifespan of 10 – 20 years and a purchase and installation cost between \$30,000 – \$60,000. Half of the eighteen MWU deep well pumps without VFDs were deemed to meet this return on investment.
- Energy savings potential was found to depend on the combination of well and pump characteristics unique to each deep well. The ranking required an examination of all relevant well and pump characteristics at each well in the system.

- Pump selection influences energy savings magnitude; energy savings magnitude will be greater for pumps with an average operating point below the BEP. For these pumps, reductions in pump speed will result in increased pump efficiency.
- Targeting deep well pumps based on high baseline energy use alone is not advised. The two highest energy use deep well pumps, Unit Wells 20 and 26, showed little energy savings potential from VFD installation.
- There is a direct link between energy savings and operational decisions to meet system demand requirements. Operation at the most energy-efficient speed may be limited by production requirements and system demands. Energy savings potential is dependent on the amount of time a pump is used.
- The methodology and rankings developed previously for MWU (Mancosky 2017 a-b) successfully predicted savings from VFD installation and confirmed the rankings for prioritizing VFD installation going forward.
- Changes in operation at Unit Wells 18 and 30 did not yield increased energy use at Unit Well 18 or Booster Station 118. The savings observed at Unit Well 30 were not offset by increased energy use elsewhere in the system, ensuring MWU receives the full benefit of savings observed at Unit Well 30.
- For time-of-use rate structures, demand charges played a significant role in energy costs. For MWU, demand charges made up 40% of total monthly energy costs at Unit Well 18 and 25% of total monthly energy costs at Unit Well 30.
- On-peak demand reduction was responsible for 25% of cost savings from VFD installation. Operating the pump at a constant, reduced speed will help ensure cost savings match expected/estimated values for time-of-use billing structures.

- After 6 months of operation, MWU saved nearly 100,000 kWh and \$8,500 at Unit Well 30. The payback period for purchase and installation should be less than 2 years.

Recommendations:

- Groundwater utilities should apply the developed method to characterize pump operation and energy intensity for variable speed operation across all deep well pumps in their system.
- When developing estimates of energy savings, groundwater utilities should be cognizant of the potential variation in pump operation due to variations in the system head curve that result from changes in static head and specific capacity. Energy savings magnitudes will be impacted by these variations in pump operation, and differences will be most significant at low pump speeds and flow rates.
- Assuming continuation of the current operational strategy with existing pumps, MWU should prioritize installation of VFDs at Unit Wells 6, 13, 11 and 18. While Unit Well 19 was the third-ranked candidate, it is slated to be replaced in the next five years and receive a filtration system, changing the operating conditions of the pump and estimates for energy savings. The change in operating conditions will likely necessitate selection of a new pump, at which point follow recommendations for new pump selection with a VFD.
- Groundwater utilities installing VFDs on deep well pumps for energy savings should ensure the following data is collected and recorded to monitor performance:
 - Pump flow rate
 - Pump speed
 - Static and pumping water levels
 - Power consumption

- Groundwater utilities should do the following to quantify the benefits of VFDs installed for energy savings purposes:
 - Use the collected data in conjunction with methods presented in this paper to characterize pump operation and energy use before and after VFD installation.
 - Use electric utility billing data to estimate observed cost savings from VFD installation. To account for changes in operation throughout the year, compare energy use and costs after VFD installation to the same time period in past years.
 - Evaluate savings on a per volume basis when quantifying long-term savings to account for differences in production.
- When replacing pumps at sites where VFD installation is not being considered, MWU pump selection should continue to prioritize matching the design operating point with the BEP of the selected pump.
- When replacing pumps at sites where VFD installation is being considered, MWU pump selection should focus on maximizing energy-efficiency at the expected average operating conditions. This would be a departure from past MWU pump selection practices, which have generally been based on a design flow rate of 2,200 gpm.
- Continue prioritizing deep well pump VFD installation based on the rankings presented in this work.
- Groundwater utilities should examine all wells as a system and understand that modifying one well could negatively impact energy requirements at another. By using its distribution system hydraulic computer model to analyze the system, MWU would be able to determine the combination of VFDs to maximize energy conservation.

- Utilities installing VFDs for energy savings should focus on managing peak demands at their facilities. Increasing the deep well pump speed will come with on-peak demand increases that will limit cost savings from VFD installation. This cost increase should be weighed against the cost of turning on another well to meet demand.
- Continue investigating strategies to reduce on-peak demands in conjunction with energy savings measures. Managing on-peak demands has the potential to provide significant cost savings benefits.

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CHAPTER 1 – INTRODUCTION

In 2016, the Madison Water Utility (MWU) used 20.5 GWh of energy to pump 9.85 billion gallons of water at a cost of \$2.10 million (PSC 2016). Total pumpage was at 11.97 billion gallons in 2002, but has declined on average by $1.3\% \pm 0.3\%$ over the past 15 years (PSC 2002-2016). In 2015, pumpage was less than 10 billion gallons for the first time since 1968, even though the city of Madison's population increased by 46% between 1970 and 2015 (United States Census Bureau 2016). Improvements in appliances and fixtures as well as increased adoption of conservation practices in outdoor watering have contributed to this reduction in water production. In addition, MWU has promoted conservation of water through its Toilet Rebate Program and Advanced Metering Infrastructure; with the latter allowing customers to track their water use online (Madison Water Utility 2016). The results of improved water conservation can also be seen in per customer water usage, shown in Figure 1-1, which decreased at an overall rate of $2.0\% \pm 0.3\%$. During the same period, water use per residential customer decreased at a rate of $2.1\% \pm 0.4\%$.

Total energy used for pumping has followed a similar trend as water production, decreasing on average by $1.1\% \pm 0.4\%$ yearly since 2002. Yearly pumpage and energy use for 2002-2016 are shown in Figure 1-2.

Over this period, the nominal cost of energy purchased for pumping has increased an average of $4.4\% \pm 1.5\%$ yearly. However, when adjusted for inflation to 2016 dollars, the cost of energy for pumping has remained nearly the same, decreasing at a rate of $0.3\% \pm 1.2\%$ per year as shown in Figure 1-3.

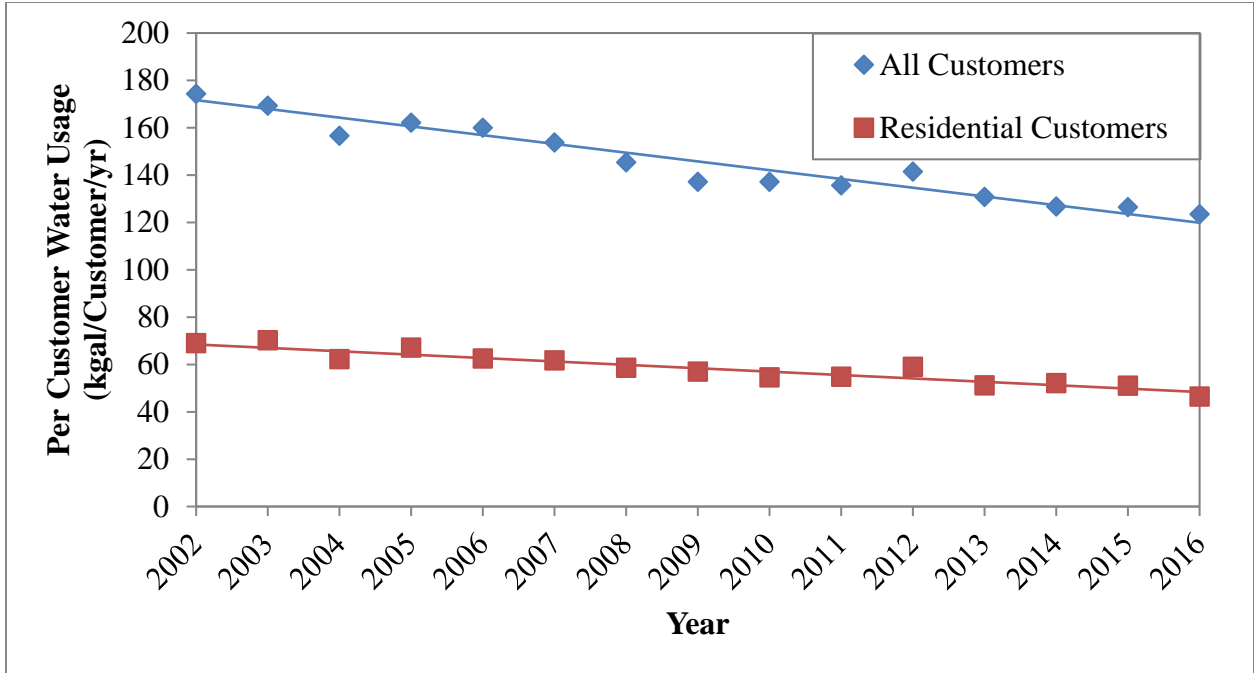


Figure 1-1 – Trends in annual per customer water usage rates for Madison Water Utility (All data from PSC 2012-2016).

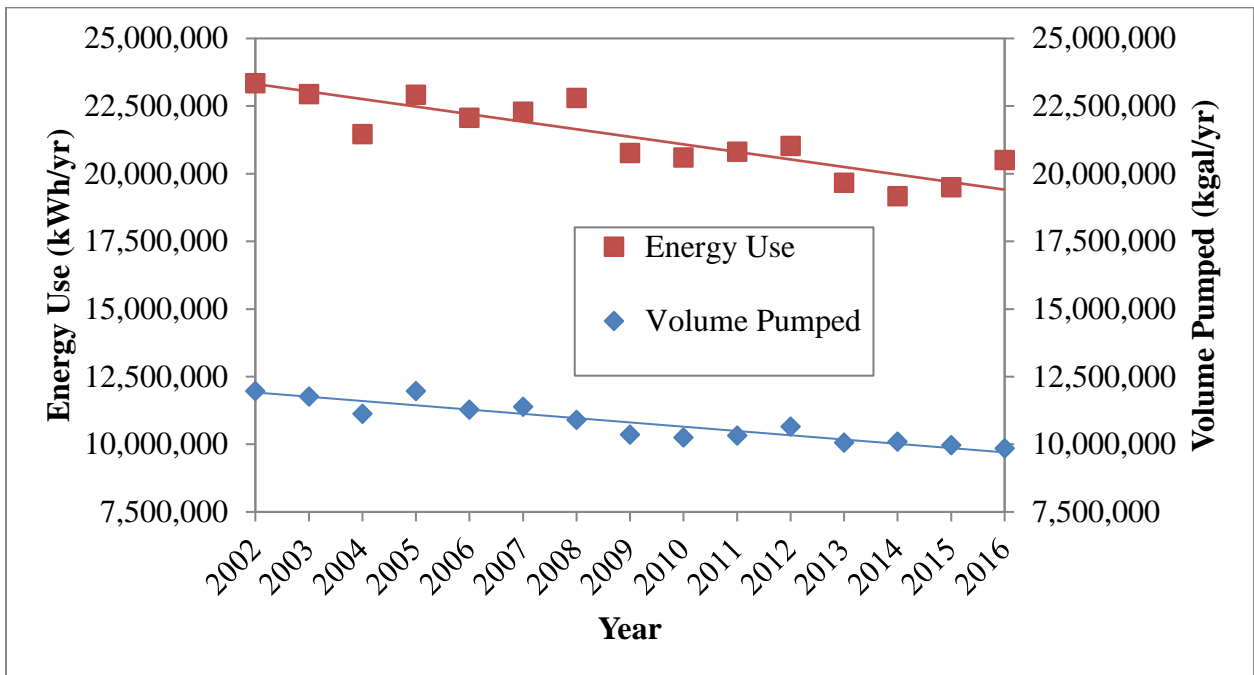


Figure 1-2 – Trends in annual MWU pumpage and energy use (all data from PSC 2002-2016).

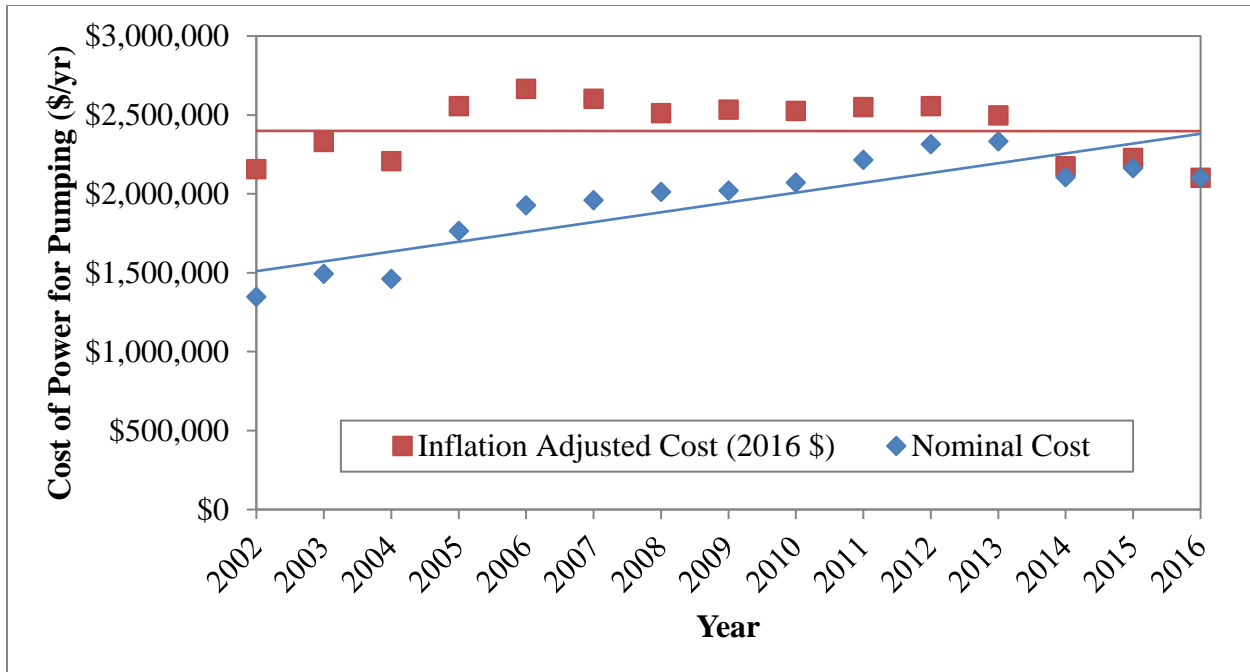


Figure 1-3 – Trends in nominal and inflation adjusted cost of energy for pumping at MWU (all data from PSC 2002-2016).

The decreases in total volume pumped and total energy use, combined with an increase in nominal energy cost has led to increasing costs per kWh of energy and MG of water pumped. When adjusted for inflation, energy costs per kWh of energy and MG of water pumped have increased over the past 15 years but have leveled off over the past 5 years as shown in Figure 1-4. MWU paid \$0.10 per kWh of energy and \$213 per MG of water pumped in 2016. Inflation-adjusted averages over the past 15 years are \$0.11 per kWh and \$222 per MG.

On an energy intensity basis, energy used per unit volume of water pumped, MWU used 2,080 kWh/MG in 2016, slightly above the Wisconsin groundwater utility average of 2,040 kWh/MG (Bohnert 2012). Energy intensity has been stable for the past 15 years at $1,980 \pm 55$ kWh/kgal, consistent with Bohnert's findings for Wisconsin groundwater utilities between 2000 and 2010.

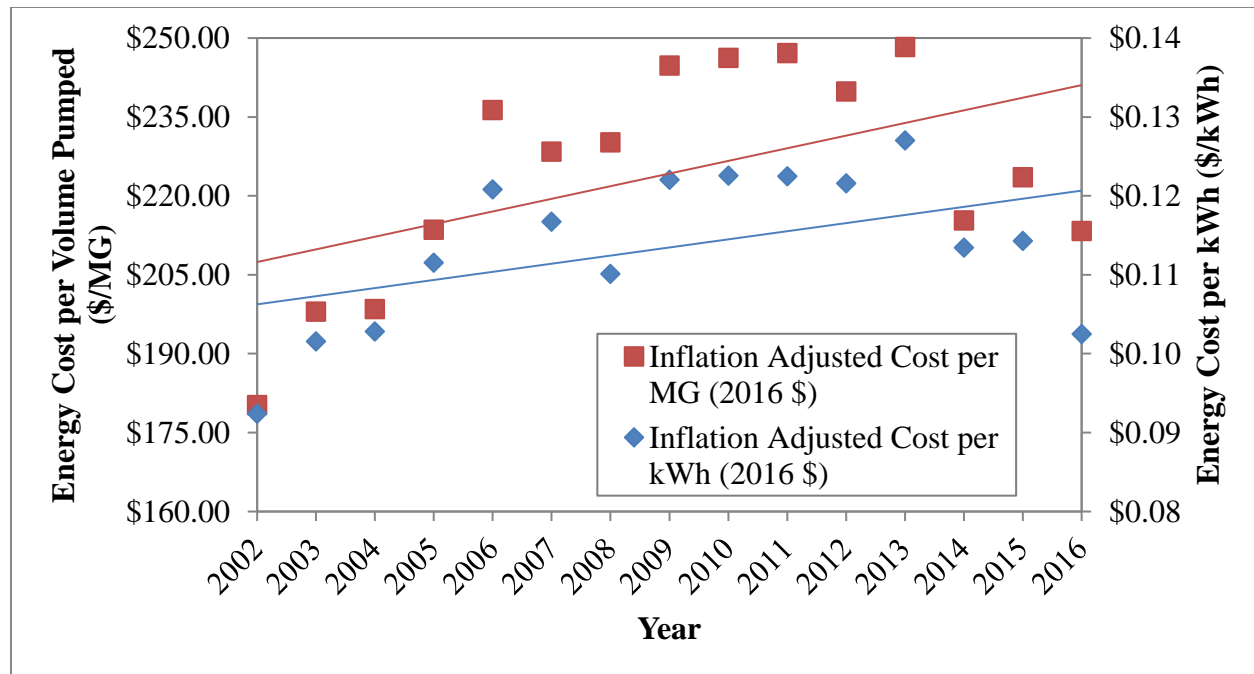


Figure 1-4 – Yearly inflation adjusted energy costs per kWh of energy and MG of pumpage at MWU (all data from PSC 2002-2016)

For continued energy and cost-savings going forward, MWU can continue to target water conservation to reduce total water production or increase energy efficiency of existing infrastructure to reduce total energy use. Conservation efforts such as those described previously are ongoing. Recent work has been conducted by UW-Madison graduate students to identify energy savings opportunities. Past work by Baniel (2013) provided a baseline overview of general operating parameters and overall site efficiency for all 22 MWU well sites. The goal was to identify sites with high energy use and low energy efficiency that could be targeted. Several sites were selected for more detailed analysis based on the results of the baseline study. Consistent with previous studies, this analysis identified that over 99% of energy use at tested sites was related to pumping operations, making this a primary target for energy-efficiency improvements (Elliott et al 2003).

Hayes (2015) built on this overview analysis and investigated the cost-effectiveness of energy-savings measures. This work focused on a detailed study of Pressure Zone 4 as well as an identification of candidate sites for variable frequency drive (VFD) installation. The study of system demand in Pressure Zone 4 showed that average operating conditions dominate energy use and costs, rather than short periods of high pumpage and electrical use. In addition, hydraulic modeling of Pressure Zone 4 revealed that hydraulic grade line reductions and distribution system pipe modifications were not cost-effective strategies for reducing system energy use. The VFD study used three sites to determine that energy-savings potential from VFD installation may be best realized for deep well pumps with low specific capacities.

The goal of this research was to expand upon Hayes' work regarding VFDs and their energy savings potential. The objectives of this work were to:

1. Develop a validated procedure to estimate energy savings from VFD installation on a deep well pump.
2. Use the developed procedure to identify the strongest deep well candidates for VFD installation.
3. Install and verify the expected energy savings of a VFD on the top-ranked deep well pump.

CHAPTER 2 – BACKGROUND

2.1. ENERGY USE BY GROUNDWATER UTILITIES

Over 90% of water utilities in Wisconsin rely on groundwater supplies (PSC 2015b). Energy use by utilities with groundwater supplies is generally higher than that of utilities purchasing water or using surface water supplies like Lake Michigan. In 2010, the typical Wisconsin groundwater utility used 2,040 kWh/MG of water pumped compared to an average of 1,850 kWh/MG for surface water utilities (Bohnert 2012). In 2016, MWU used 2,080 kWh/MG, 2.0% above the statewide average for groundwater utilities.

Energy use is typically higher for utilities with groundwater supplies due to the elevation the water must be lifted. Water must be pumped from the aquifer to the ground surface, with additional head then added to meet pressure requirements in the distribution system. For typical groundwater systems, 99% of energy use can be attributed to pumping, except for cases where ion exchange or additional treatment is required (Bohnert 2012, Elliott et al 2003).

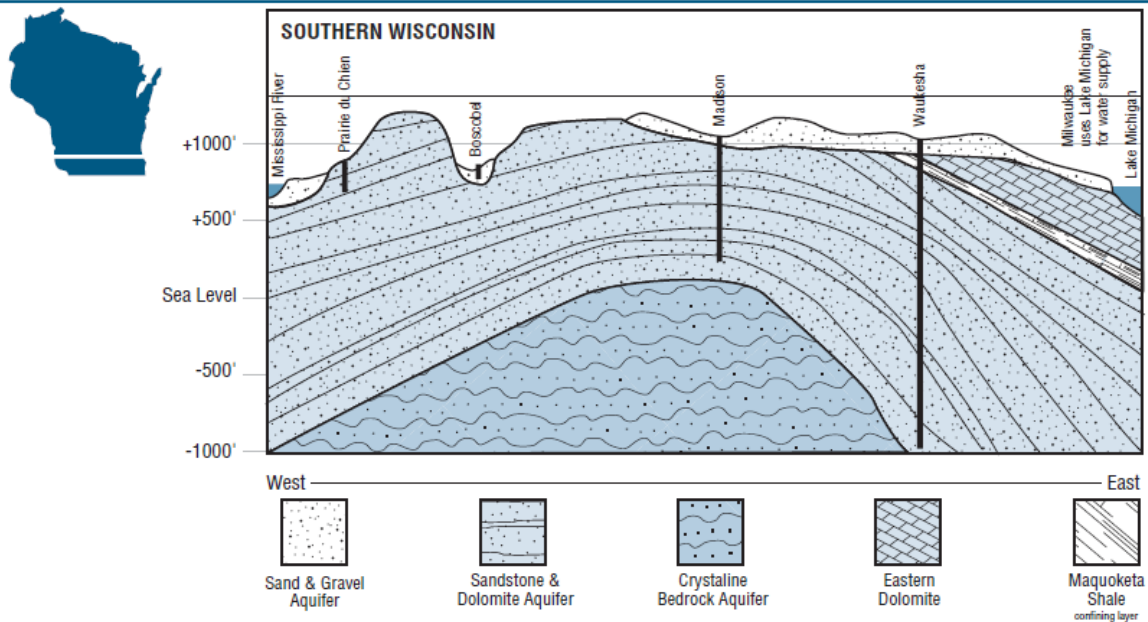
Treatment requirements for groundwater supplies in Wisconsin are usually minimal; utilities are only required to provide disinfection for groundwater supplies if they are shown to be directly influenced by a surface water source (WDNR 2013). Historically, microorganisms responsible for waterborne illness have not been thought to be a significant concern in groundwater (Burke et al 2002). However, recent investigations have shown that human enteric viruses are present in groundwater wells across the United States. A study of 6 MWU wells showed the presence of enteric virus nucleic acids in at least 30% of the samples for each well over a two-year period (Bradbury et al 2013). There was a temporal correlation in the virus types in Madison's wastewater influent and groundwater wells, showing sanitary sewer leaks as the likely source of

virus contamination. Utilities in Wisconsin are not required to test for viruses, so proper disinfection remains the best means for maintaining public health. Chlorination, which typically requires little energy input from the water utility, is the most common treatment technology used for disinfection by Wisconsin's groundwater utilities.

The primary concern for groundwater is dissolved ions from the interaction between the water and the geologic formations. Common ions present in groundwater include silica, iron, magnesium, calcium, potassium, bicarbonate, chloride, and sulfate (Harter 2003). These dissolved constituents primarily pose secondary water quality concerns, such as taste and color concerns from high iron and manganese concentrations. Multivalent cations, particularly calcium and magnesium, contribute to hardness that can cause scaling problems in premise plumbing. Treatment trains used to control these substances commonly include packed-bed technologies like granular media filtration or ion exchange as a component. The head loss exerted by these packed beds can account for a significant amount of a utility's energy consumption.

Madison's groundwater source is the Cambrian Ordovician aquifer system, which ranges across Iowa, Michigan, Minnesota, and Wisconsin. Hardness is a concern for water in the Cambrian Ordovician aquifers as it is typically very hard ($>180\text{mg/L}$ as CaCO_3). Localized pockets of iron and manganese can also exist in high enough concentrations to necessitate additional treatment (Wilson 2012). The presence of iron and manganese has led MWU to install filtration systems at two unit wells with additional filtration systems to be added over the coming years. Radium and radon are also present throughout the aquifer; occasionally at levels above established MCLs (Wilson 2012). In southern Wisconsin, the primary aquifer is the Mount Simon Aquifer, a component of the Cambrian Ordovician system, which is shown in Figure 2-1.

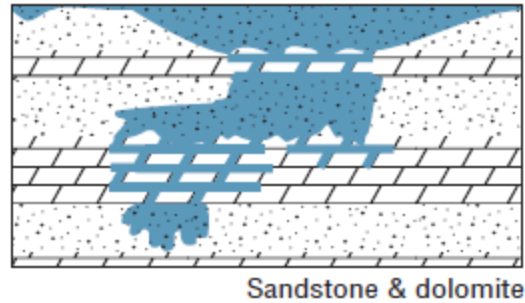
Wisconsin's Major Aquifers



Source: WDNR 1989.

Figure 2-1 – Southern Wisconsin aquifer geologic composition

The aquifer primarily consists of layers of sandstone and dolomite, a sample cross-section is shown in Figure 2-2. In general, water flow through sandstone layers in this aquifer is assumed to come from the permeability of the sandstone grains, whereas fractures provide the dominant source of water flow in dolomite layers (WDNR 1989). Recent work with the Mount Simon aquifer in the Madison area has showed that fractures can be a significant source of water flow in both sandstone and dolomite layers (Gellasch et al 2013).



Source: WDNR 1989.

Figure 2-2 – Sandstone and dolomite aquifer cross-section

2.2. MWU PUMPING INFRASTRUCTURE

MWU currently has 22 unit wells, with an additional unit well to be constructed in 2018. A typical unit well consists of a deep well pump, one to three booster pumps, a reservoir, and chemical storage. Each deep well pump lifts water to the surface where it is treated with chlorine and fluoride and discharges into an on-site reservoir. On-site booster pumps lift water from the reservoir into the distribution system to meet overall system demand. Drilled well depths range from 450 to 1,100 feet, with the pumps sitting 120 to 450 feet deep. Storage volumes range from 140,000 to 4,000,000 gallons. In 2015, each unit well produced an average of 1.6 MGD and consumed an average of 2.9 MWh of electrical energy. A schematic of a typical unit well is shown in Figure 2-3.

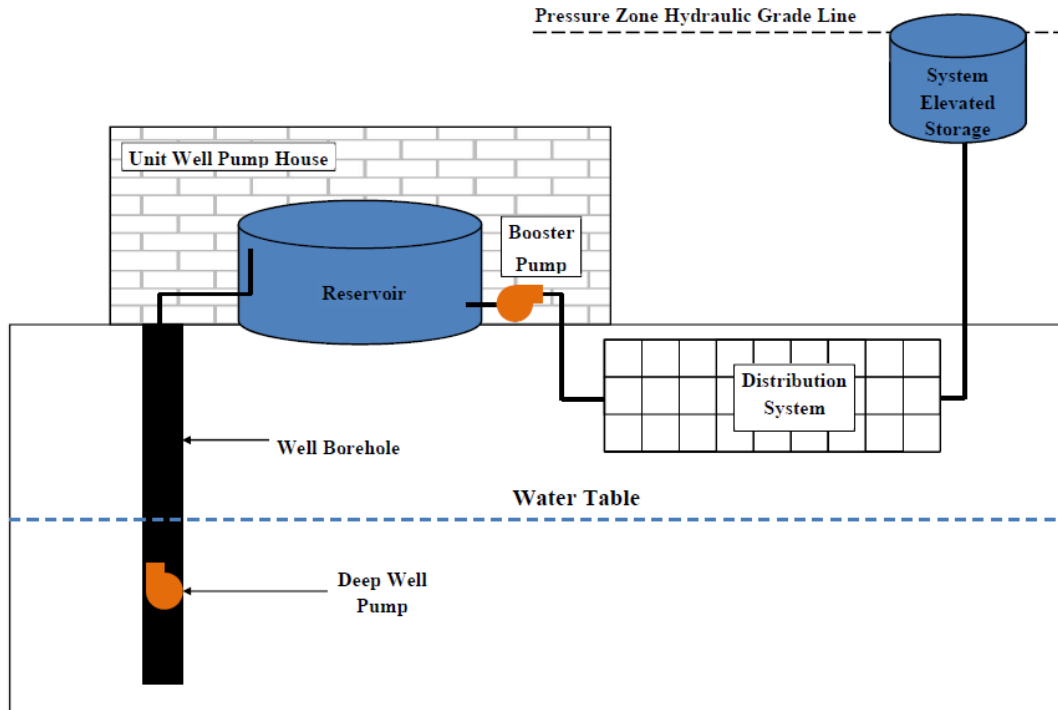


Figure 2-3 – Typical MWU unit well configuration.

This diagram and description holds true for the majority of MWU’s 22 unit wells, but there are alternative well configurations. Alternative configurations are needed to meet operational requirements of certain pressure zones as well as to address localized water quality concerns. Examples include Unit Wells 7, 15, and 29, all of which provide additional treatment beyond chlorination and fluoridation. Unit Wells 7 and 29 have filtration units to remove iron and manganese and Unit Well 15 has an air stripper to remove volatile organic compounds. Other exceptions include Unit Wells 9, 20, and 26. Both Unit Wells 20 and 26 have floating reservoirs that supply water to Pressure Zones 7 and 8, respectively. On-site booster pumps pump water to separate storage reservoirs that supply Pressure Zones 9 and 10, respectively. Refer to Hayes (2015) or Baniel (2013) for a more in-depth description of individual unit well configurations.

In addition to on-site booster pumps that supply the distribution system, MWU has p booster stations currently in-service (including booster pumps at Unit Wells 20 and 26) that supply

water between pressure zones. Booster stations transfer water from pressure zones with a lower hydraulic grade line to pressure zones with a higher hydraulic grade line. For select booster stations, valves can be opened to allow water to flow in the reverse direction. A booster station schematic is presented in Figure 2-4.

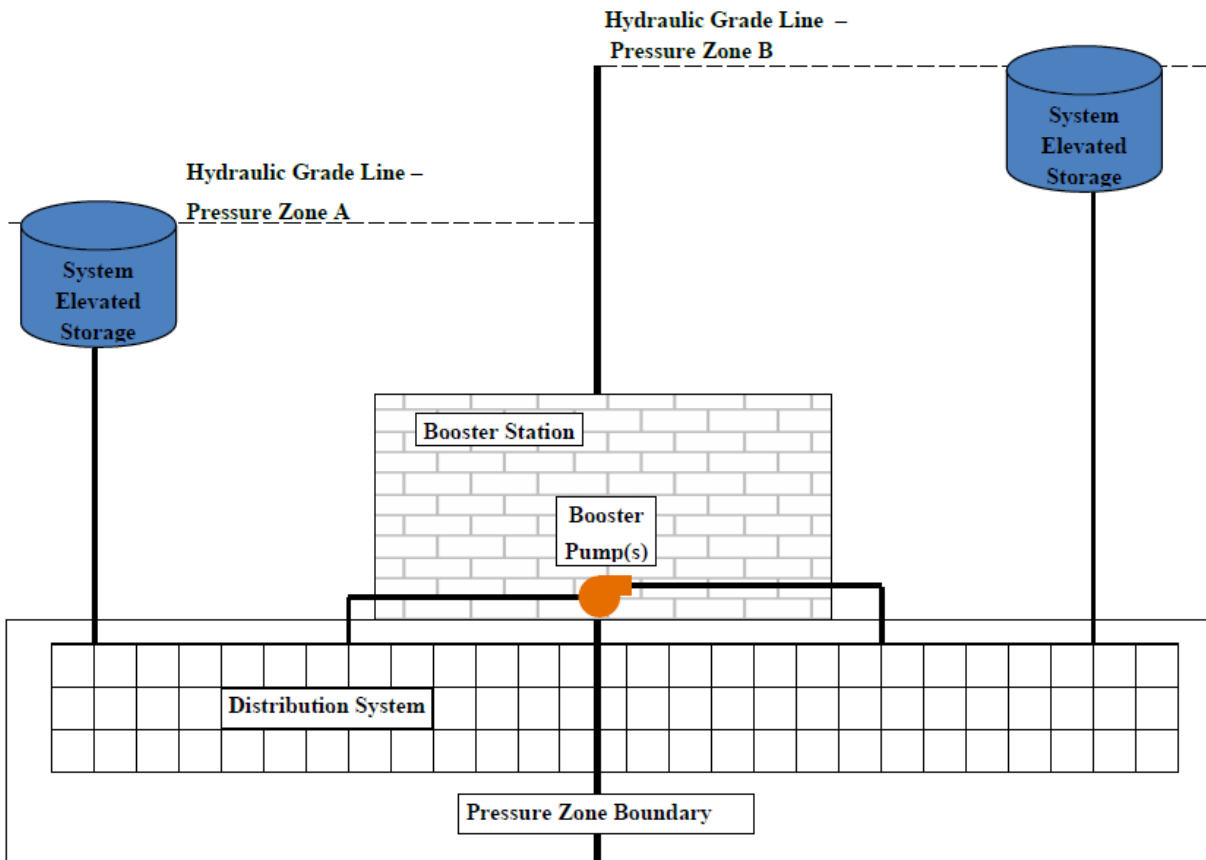


Figure 2-4 – Typical MWU booster station schematic. Booster stations pump water from zones of lower pressure (Zone A in this schematic) to zones of higher pressure (Zone B in this schematic).

An overview summary of MWU pumping infrastructure is presented in Table 2-1 through Table 2-3. Table 2-1 summarizes average production and energy use for all 22 unit wells along with an overview of deep well pump characteristics. Table 2-2 and Table 2-3 summarize booster pump characteristics at all unit wells and booster stations.

Table 2-1 – Overview of 2015 MWU unit well properties and summary of deep well pump infrastructure characteristics

Unit Well	Year Drilled	Pressure Zone	Avg. Station Pumpage (MGD) ¹	Avg. Station Daily Energy Use (MWh) ¹	Average Pumping Water Level (ft) ²	Reservoir Capacity (kgal)	Pump Age (yr)	Motor Age (yr)	Motor HP	Notes
6	1938	6W	1.59	2.84	153	155	33	61	200	Seasonal
7	1939	6E	1.15	2.26	122	500	1	1	200	VFD, filtration for iron/manganese removal
8	1945	6E	0.42	0.77	132	140	17	17	125	Seasonal
9	1950	4	1.22	1.84	174	3,000	22	65	150	Floating reservoir
11	1956	6E	1.46	2.64	141	150	17	36	100	
12	1957	7	2.26	4.04	259	150	11	58	250	
13	1959	6E	2.33	3.77	94	150	3	58	125	
14	1960	6W	2.31	2.83	46	150	9	37	50	
15	1965	6E	1.20	2.58	89	150	3	3	150	VFD, air scrubber
16	1967	8	1.53	3.35	270	279	1	49	250	
17	1966	6W	2.08	3.08	112	375	15	49	150	Seasonal
18	1968	6W	1.20	2.74	319	477	8	46	200	
19	1970	6W	1.72	3.67	195	3,000	1	43	150	
20	1973	7 and 9	1.58	3.57	394	4,200	6	4	350	Dual pressure zone floating reservoir
23	1958	6E	0.74	1.15	113	100	2	40	60	
24	1979	6W	1.41	1.52	219	4,000	15	37	150	
25	1982	3	1.14	2.39	248	325	1	7	200	VFD
26	1987	8 and 10	2.12	4.79	405	4,000	5	2	350	Dual pressure zone floating reservoir
27	1989	6W	1.28	2.19	204	315	19	25	200	Seasonal
28	1998	8	1.59	3.58	284	341	3	3	250	Seasonal
29	2002	6E	1.81	3.09	178	414	5	12	250	VFD, filtration for iron/manganese removal
30	2003	6W	1.88	4.02	280	414	12	12	250	

¹ Total for Year 2015 divided by 365 days

² Average of daily reports during Year 2015.

Table 2-2 – Booster pump infrastructure overview for all MWU unit wells.

Unit Well	Pressure Zone	Booster Type	Pump Age (yr)	Motor Age (yr)	Motor HP	HGL	Notes
6	6W	HSC	61	61	150	1055	VFD
7	6E	HSC / HSC	2 / 2	2 / 2	150 / 150	1080	VFD on both pumps
8	6E	HSC	69	69	150	1080	
9	4	HSC	61	61	100	1047	
11	6E	HSC	33	59	150	1080	VFD
12	7	HSC	58	58	150	1171	
13	6E	HSC	57	57	200	1080	VFD
14	6W	HSC	55	55	150	1055	
15	6E	VT	3	3	150	1080	VFD
16	8	VT / VT	49 / 49	49 / 49	100 / 125	1200	
17	6W	HSC / HSC	3 / 3	49 / 49	150 / 200	1055	
18	6W	HSC / HSC	33 / 46	14 / 14	125 / 150	1055	VFD on both pumps
19	6W	HSC / HSC / HSC	43 / 43 / 43	43 / 43 / 43	125 / 150 / 150	1055	
23	6E	VT	3	55	60	1080	
24	6W	HSC / HSC / HSC	65 / 3 / 42	65 / 3 / 42	100 / 150 / 200	1055	VFD on Pumps 1 and 2.
25	3	HSC / HSC	7 / 7	7 / 7	100 / 150	1140	
27	6W	HSC / HSC	25 / 25	25 / 25	125 / 150	1055	
28	8	HSC / HSC	15 / 15	15 / 15	125 / 150	1200	VFD on both pumps
29	6E	HSC / HSC	12 / 12	12 / 12	125 / 125	1080	VFD on both pumps
30	6W	HSC / HSC	11 / 11	11 / 11	150 / 150	1055	VFD on both pumps

Note: HSC = horizontal split case; VT = vertical turbine

Table 2-3 – Booster station booster pump characteristics. (Booster Stations 120 and 126 are located at Unit Wells 20 and 26, respectively).

Booster Station	Pressure Zone Served	Booster Type	Pump Age (yr)	Motor Age (yr)	Motor HP	HGL	Notes
106	6W / 7	HSC / HSC	4 / 4	4 / 4	75 / 75	1055 / 1171	Pumps from 6W to 7. Reverse flow possible. VFD on both pumps.
113	5	HSC / HSC	38 / 38	38 / 38	15 / 20	1138	VFD on both pumps.
115	3 / 6E	HSC / HSC / HSC / HSC	51 / 51 / 2 / 2	51 / 51 / 2 / 2	60 / 60 / 150 / 150	1140 / 1080	VFD on all pumps.
118	6W / 7	HSC / HSC / HSC	6 / 6 / 6	6 / 6 / 6	75 / 75 / 75	1055 / 1171	Pumps from 6W to 7. Reverse flow possible. VFD on all pumps.
120	9	HSC / HSC	4 / 4	4 / 4	75 / 75	1245	VFD on both pumps.
126	10	HSC / HSC	29 / 29	29 / 29	50 / 100	1321	VFD on Pump 1.
128	11	HSC / HSC / HSC / HSC	15 / 15 / 15 / 15	15 / 15 / 15 / 15	15 / 15 / 50 / 50	1055	VFD on Pumps 1 and 2.
129	3	HSC / HSC / HSC / HSC	21 / 21 / 21 / 21	21 / 21 / 21 / 21	10 / 10 / 30 / 30	1140	
215	3 / 6E	HSC / HSC	24 / 24	24 / 24	40 / 50	1140 / 1080	Pumps from 6E to 3. Reverse flow possible.

CHAPTER 3 – METHODOLOGY FOR ESTIMATING ENERGY SAVINGS POTENTIAL FOR VFD INSTALLATION ON DEEP WELL PUMPS

Abstract: Variable frequency drives may save groundwater-supplied utilities energy through reductions in drawdown. The purpose of this work was to develop and validate a method for predicting pump operation and energy savings from VFD installation. Existing pump operational data was used to develop a system head curve, which was used in conjunction with the Affinity Laws to estimate pump operating points and energy use. Test data for pump flow rate, drawdown, and power consumption was collected for two pumps with VFDs installed and compared against estimated values. Observed pump operation was generally predicted by the method; differences were due to changes in specific capacity and static water level. The method predicted energy intensities within 10% of observed values, and was a conservative estimator of energy savings potential for this combination of well and pump properties. Groundwater utilities can apply the developed method to identify energy savings potential of VFD installation in their systems.

3.1. INTRODUCTION

Over 90% of water utilities in Wisconsin rely on groundwater supplies (PSC 2015b). Energy use by utilities with groundwater supplies is generally higher than that of utilities purchasing water or using surface water supplies like Lake Michigan. In 2010, the typical Wisconsin groundwater utility used 2,040 kWh/MG of water pumped compared to an average of 1,850 kWh/MG for surface water utilities (Bohnert 2012). The higher energy use for groundwater systems is mostly due to the higher lift needed from water source to distribution system.

Utilities interested in energy savings can choose to pursue water conservation or energy-efficiency measures. As an example of conservation measures, a 1.3% per year decline in water production for Madison Water Utility (MWU) corresponded with a 1.1% per year decrease in energy use from 2002 to 2016. However, this was not accompanied by a change in energy intensity, which was stable at 1,980 kWh/MG during the same period.

As a result, MWU has recently focused on identifying opportunities to reduce energy intensity that are separate from their conservation efforts (Baniel 2013, Hayes 2015). Hayes (2015) identified variable frequency drive installation (VFD) on deep well pumps as having the greatest potential for energy savings, as opposed to other measures such as distribution system modifications or hydraulic grade line reductions. This is possible because groundwater utilities like MWU can use VFDs to control their lift by simultaneously reducing flow rate and increasing pump run time to reduce the amount of drawdown. Hayes (2015) also hypothesized that energy savings potential could be maximized by targeting VFD installation on those wells with low specific capacities. Such wells are associated with greater drawdown for a given flow rate.

Prior to beginning this work, MWU had installed VFDs on 4 of 22 deep well pumps, but these were primarily installed to improve operational flexibility and provide consistent operation. Although not installed for energy savings purposes, VFD installation on the deep well pump at Unit Well 25 in 2011 produced noticeable benefits from a reduction in drawdown. Reduction of the pump speed from 100% speed to 92% speed reduced the drawdown by 30 feet and provided MWU with 100 kWh/MG of energy savings at Unit Well 25. Combined with Hayes' findings, this VFD installation was enough to demonstrate the potential benefits for VFD installation at additional sites in the MWU system.

This paper is the first of three papers designed to (1) develop a validated procedure to estimate energy savings from VFD installation on a deep well pump, (2) use the procedure to identify the strongest deep well candidates for VFD installation, and (3) install and verify the expected energy savings of a VFD on the top-ranked deep well pump. The goal of this paper is to meet the first of these objectives. The specific objectives of this work were to:

1. Use the framework developed by Hayes to develop a method for using MWU SCADA data and site information to estimate pump operation and energy savings potential for VFD installation on existing MWU deep well pumps.
2. Use existing MWU deep well pumps with VFDs installed (Unit Wells 15 and 25) demonstrate observed pump behavior and energy use under variable speed operation.
3. Use observed data to validate the estimation methods used to characterize pump operation and energy savings for variable speed operation of deep well pumps.

Taken together, these three papers can assist all utilities with groundwater supplies in developing an energy savings approach to groundwater pumping.

3.2. BACKGROUND

3.2.1. MWU Deep Well Pump Infrastructure

MWU currently has 22 unit wells, each consisting of a deep well pump, one to three booster pumps, a reservoir, and chemical storage. Each deep well pump lifts water to the surface where it is treated with chlorine and fluoride and discharged into an on-site reservoir. On-site booster pumps lift water from the reservoir into the distribution system to meet overall system demand.

3.2.2. Deep Well Pump Energy Use

A schematic of a typical deep well pump configuration is shown in Figure 3-1. Static water level is the difference between the ground elevation and the water table when the pump is not operating. This water level fluctuates over time due to seasonal and long-term climatic changes in groundwater levels and pumping operations. The pumping water level is the depth to water in the pump column when the pump is operating. Drawdown is the difference between the pumping water level and static water level. Specific capacity of a well is a measurement of the change in drawdown as a function of pump flow rate (units of gpm/ft), which is estimated by dividing the pump's operating flow rate by the observed drawdown at that flow rate. All MWU deep well pumps lift water to a fixed-elevation inlet above the stored water level in an on-site reservoir, so the pump must lift the water the additional elevation above ground to the reservoir inlet. When the pump is operating, the total elevation the water must be lifted is predominantly the pumping water level plus the reservoir lift.

Pumping water level and drawdown depend on flow rate, which is captured in the measurement of a well's specific capacity. For example, at MWU's Unit Well 30 with a specific capacity of 17 gpm/ft, increasing the flow rate 17 gpm results in an increased drawdown of 1 ft, lowering the pumping water level 1 ft. The result is an increase in lift needed for the pump. Conversely, a reduction in pump operating speed and flow rate decreases total drawdown and lift needed. This reduced lift provides the potential for energy savings from VFDs on deep well pumps.

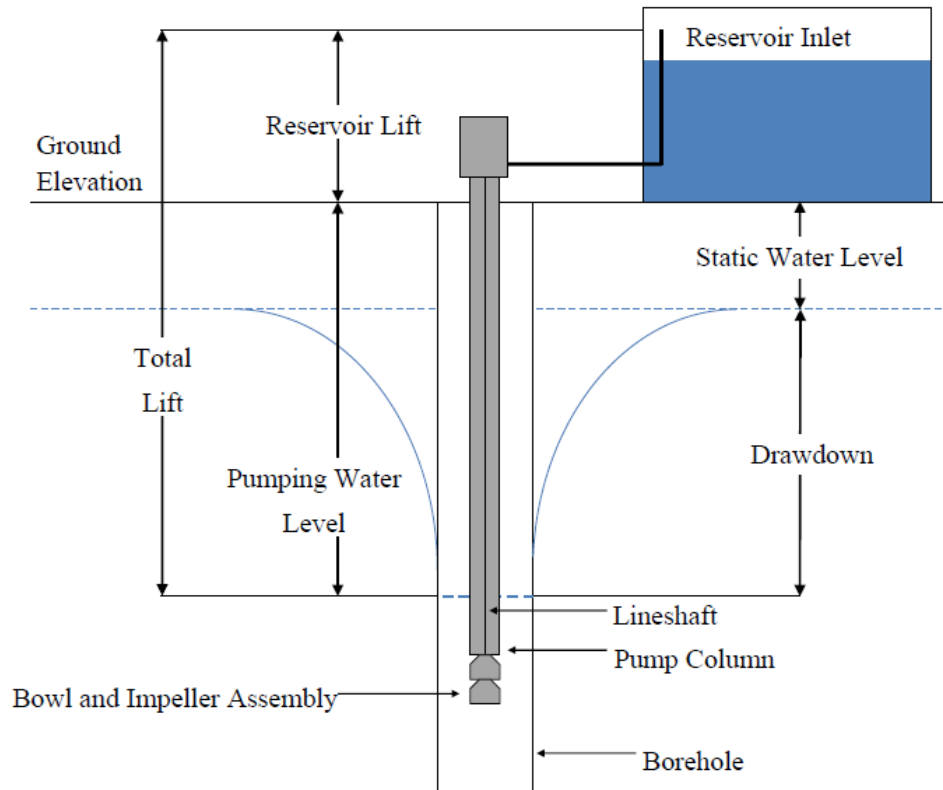
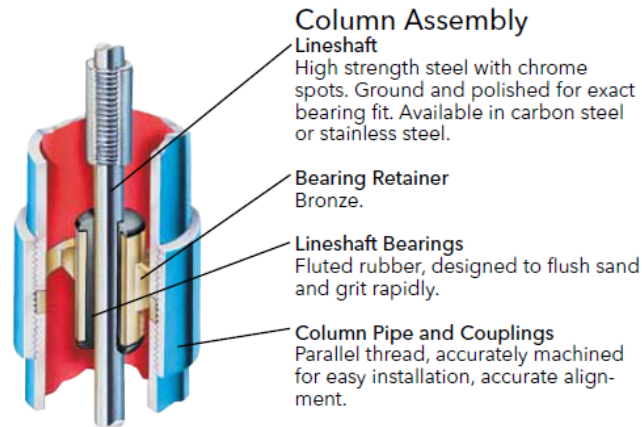


Figure 3-1 – Typical MWU deep well pump configuration with relevant geologic and pump properties

While the pumping water level and reservoir lift make up the majority of head for the deep well pumps, additional head must be provided to account for friction losses in the piping and pump column. The amount of additional head and energy needed to account for friction loss depends on each site's configuration. An overview of a typical column assembly for the lineshaft vertical turbine style pumps used by MWU is shown in Figure 3-2. In these column assemblies, friction losses are associated with the column wall, the shaft surface, the bearings, and the bearing retainers. Above ground, additional head losses are associated with check valves, isolation valves, pipe bends, and flow meters where present. Unit wells with treatment systems or sand separators have additional friction losses that add to the total head the deep well pumps lift against.



Source: Xylem Inc. 2012.

Figure 3-2 – Vertical turbine pump column assembly

As mentioned previously, energy use for groundwater utilities like MWU is predominantly driven by the elevation water must be lifted. At the time of this study, MWU's deep wells had an average pumping water level of 200 ± 97 feet, reservoir lift was 16 ± 27 feet, and head loss was 12 ± 9 feet. Accounting for pumping water level, reservoir level above ground, and friction losses, the lowest total lift is 50 feet at Unit Well 14 and the highest total lift is 450 feet at Unit Well 26.

The final component of energy use for deep well pumps is pump efficiency. Pump efficiency depends on the flow rate and head, so pumps are often sized to yield a design operating point that falls close to the pump's best efficiency point (BEP). Pump efficiencies are provided with manufacturer performance curves, with an example for MWU's Unit Well 27 shown in Figure 3-3. The installed pump is Curve A, with a peak efficiency of 86% (shown with a red diamond). The design point is shown with a blue star and the average operating point in 2015 shown with a yellow circle. Both points are at about 85.3% efficiency, within 1% of peak efficiency. This close proximity to the BEP is desired for single speed pump operations. Single-speed pumps with

operating points at efficiencies well below the BEP may indicate a poorly performing pump or poorly sized pump.

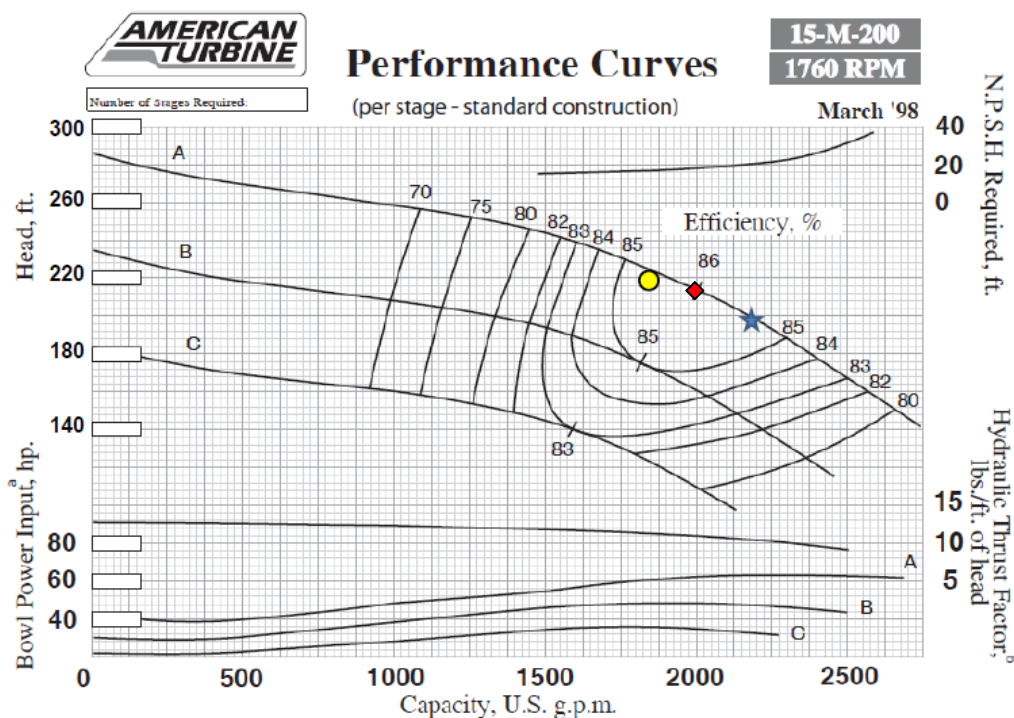


Figure 3-3 – Manufacturer Curve A used for Unit Well 27 deep well pump with MWU design point shown with a blue star and August 2015 average operating point shown with yellow circle.

The three primary components of pump energy use are flow rate, head, and efficiency as shown in Equation 3-1. From Equation 3-1, there are three potential alternatives for reducing energy use: a reduction in head, a reduction in flow rate or an increase in efficiency at the average operating point. A reduction in flow rate will only reduce energy use if the total volume pumped is reduced via management of on/off cycling. Otherwise, the reduction in flow rate is counteracted by an increase in operating time and no real energy savings are achieved. For pumps not operating close to the best efficiency point, selection of a new pump could increase efficiency and lower energy use.

VFDs were investigated because of their potential to reduce flow rate and head by reducing pump operating speed. This potential for head reduction and energy savings is generally much greater for deep well pumps where the reduction in flow rate results in less drawdown. For booster pumps, head on the pump is controlled by the hydraulic grade line in the system. Reductions in speed and flow rate offer little head reduction and increase pump run time, providing very little energy savings potential.

$$E = \frac{Q * H}{3,960 \frac{gpm-ft}{Hp} * \eta} * \frac{0.746 kW}{Hp} * t \quad (3-1)$$

Where: E = Pump energy use (kWh)
 Q = Pump flow rate (gallons per minute)
 H = Head (ft)
 η = Pump efficiency (unitless)
 t = time period for which operating conditions remain valid (hr)

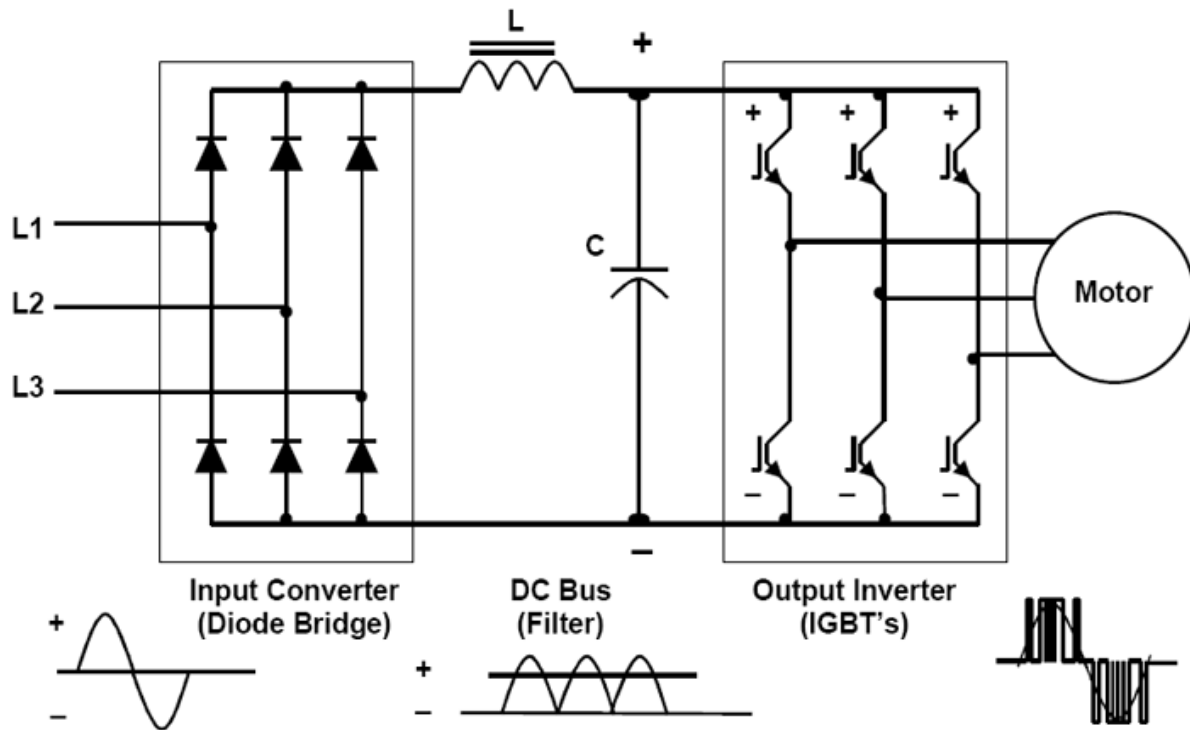
Energy intensity is defined as the energy used per unit volume pumped, in this case kWh/MG. Energy intensity can be estimated for any given day by dividing total energy use by volume pumped.

3.2.3. Variable Frequency Drives

Variable frequency drives have been shown to save energy and improve operational flexibility in a variety of pumping applications (Hydraulic Institute, Europump, and U.S. DOE 2004). Prior to this study, MWU had installed VFDs on 4 of 22 deep well pumps, 19 of 37 unit well booster pumps, and 15 of 25 booster pumps at booster stations. For MWU, VFDs have been installed primarily to improve operational flexibility and provide consistent operating conditions at system sites. To illustrate the energy savings possible on a deep well pump, VFD installation at MWU's Unit Well 25 produced noticeable energy savings benefits from a reduction in pumping water level. Operation at 88% speed in March-May 2012 instead of 100% speed in March-May

2011 resulted in a drop of pumping water level from 268 ± 16 feet to 233 ± 5 feet and a reduction in energy intensity from $2,170 \pm 200$ kWh/MG to $2,020 \pm 140$ kWh/MG. A similar trend was observed from 100% speed to 92% speed for June-August 2011 and June-August 2013, respectively. For this case, pumping water level was reduced from $281 \text{ feet} \pm 5$ feet to $253 \text{ feet} \pm 4$ feet and energy intensity decreased from $2,210 \pm 150$ kWh/MG to $2,100 \pm 80$ kWh/MG. Static water levels were consistent between analyzed periods, demonstrating that changes in water level and energy use were mainly attributable to the change in pump speed.

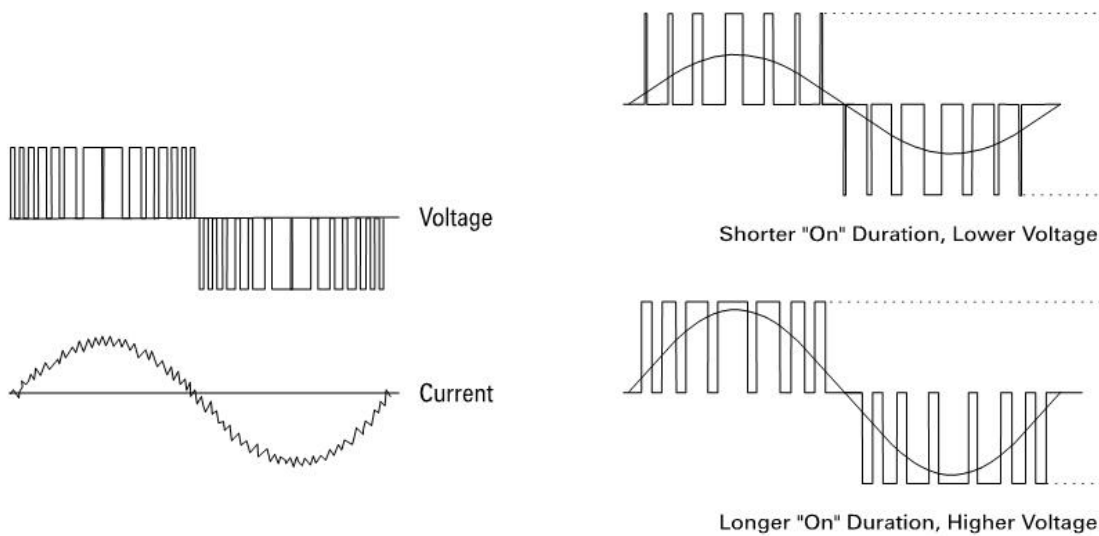
The most common type of VFD used for electric induction motors is a voltage source pulse-width modulation system. The three basic components for a pulse-width modulation VFD are shown in Figure 3-4: a rectifier (or input converter), DC bus, and an inverter. All deep well pumps installed by MWU have electric induction motors supplied by a three-phase, 480 V, alternating current (AC) power supply. The rectifier converts this incoming three phase AC supply into a constant DC voltage supply. For three-phase power a minimum of 6 rectifiers are used, two rectifiers are needed for each phase of power. One rectifier only allows positive AC current to pass through and the other rectifier only allows negative AC current to pass through. The DC bus has capacitors to accept, store, and deliver power from the rectifier while inductors help filter out AC waveforms to provide smooth DC output waveforms (Carrier Corporation 2005).



Source: AC Technology Corporation 2017

Figure 3-4 – Pulse-width modulation VFD components. Graphs below show plots of voltage versus time. The first graph shows a single-phase AC sine wave input into the VFD. The second graph shows DC output from the DC bus. The final graph shows a “sine-weighted” on-off pattern for a VFD with the desired sine wave form.

The final component of a VFD is the inverter that delivers power to the motor. In modern VFDs, the inverter is an Insulated Gate Bipolar Transistor (IGBT). The IGBT switches the DC bus on and off several thousand times per second to provide the desired voltage and frequency. The IGBT alternates between the positive and negative DC bus to approximate 3 phase AC output. The IGBT uses pulse width modulation, varying the time the inverter is open to provide a stream of variable width voltage pulses with constant amplitude. The result of these variable width pulses is a “sine-weighted” voltage wave that approximates an AC sine wave, shown in Figure 3-5. The on and off times of the IGBT cycling dictate the output voltage and frequency, with output voltage and frequency increasing with increasing IGBT on time (AC Technology Corporation 2017).



Source: LHP 2017.

Figure 3-5 – On left, “Sine-weighted” on-off voltage pattern and current pattern of a pulse width modulation VFD to simulate the desired sine waveform. Graphs on the right show two curves to achieve different output voltages.

The Affinity Laws provide relationships for estimating the impacts of VFD operation on the flow rate and head delivered by centrifugal pumps, as well as the amount of energy consumed. These relationships describe the resulting changes in flow rate, head, and power with changes in pump speed as shown in Equations 3-2 through 3-4, respectively (Jones et al 2008).

$$\frac{Q_1}{Q_2} = \frac{n_1}{n_2} \quad (3-2)$$

$$\frac{H_1}{H_2} = \left(\frac{n_1}{n_2}\right)^2 \quad (3-3)$$

$$\frac{P_1}{P_2} = \left(\frac{n_1}{n_2}\right)^3 \quad (3-4)$$

Where: Q = pump flow rate (gallons per minute)
 H = head (ft)
 P = pump input power (hp)

n = rotational speed (rpm)
 $1,2$ = corresponding initial and final values

As seen in Equations 3-2 and 3-3, flow rate reduction is linear and head reduction is parabolic with respect to a reduction in rotational speed. As a result, for a given flow rate, head, and speed, corresponding combinations of flow rate and head at different speeds fall on a parabola that goes through the origin (Jones et al 2008). The third Affinity Law (Equation 3-4) assumes that pump efficiency translates to corresponding points at different speeds, so pump efficiencies remain constant along the parabolas defined for flow rate and head. This assumption has been shown to be incorrect - pump efficiency decreases with pump speed, particularly for small pumps (Simpson and Marchi 2013). A formula developed by Sarbu and Borza, presented in Simpson and Marchi (2013), has been used to estimate decreases in pump efficiency. The effect of this decrease was examined for low pump speeds (~60% speed) and low pump efficiencies (<70%), and the difference between this estimated efficiency and the assumed efficiency based on the Affinity Laws was only 1-2%. Given this small difference, efficiencies based on the assumptions in the Affinity Laws were used for this analysis.

Barring changes in MWU operational strategy for a given unit well, the same total of volume of water must be delivered regardless of flow rate, meaning the primary means of savings with VFD installation comes through head reduction. For cases where the pump is not operating at the BEP, VFD installation has the potential to also increase pump efficiency. An example of the savings potential is explored using the deep well pump at Unit Well 30, shown in Figure 3-6.

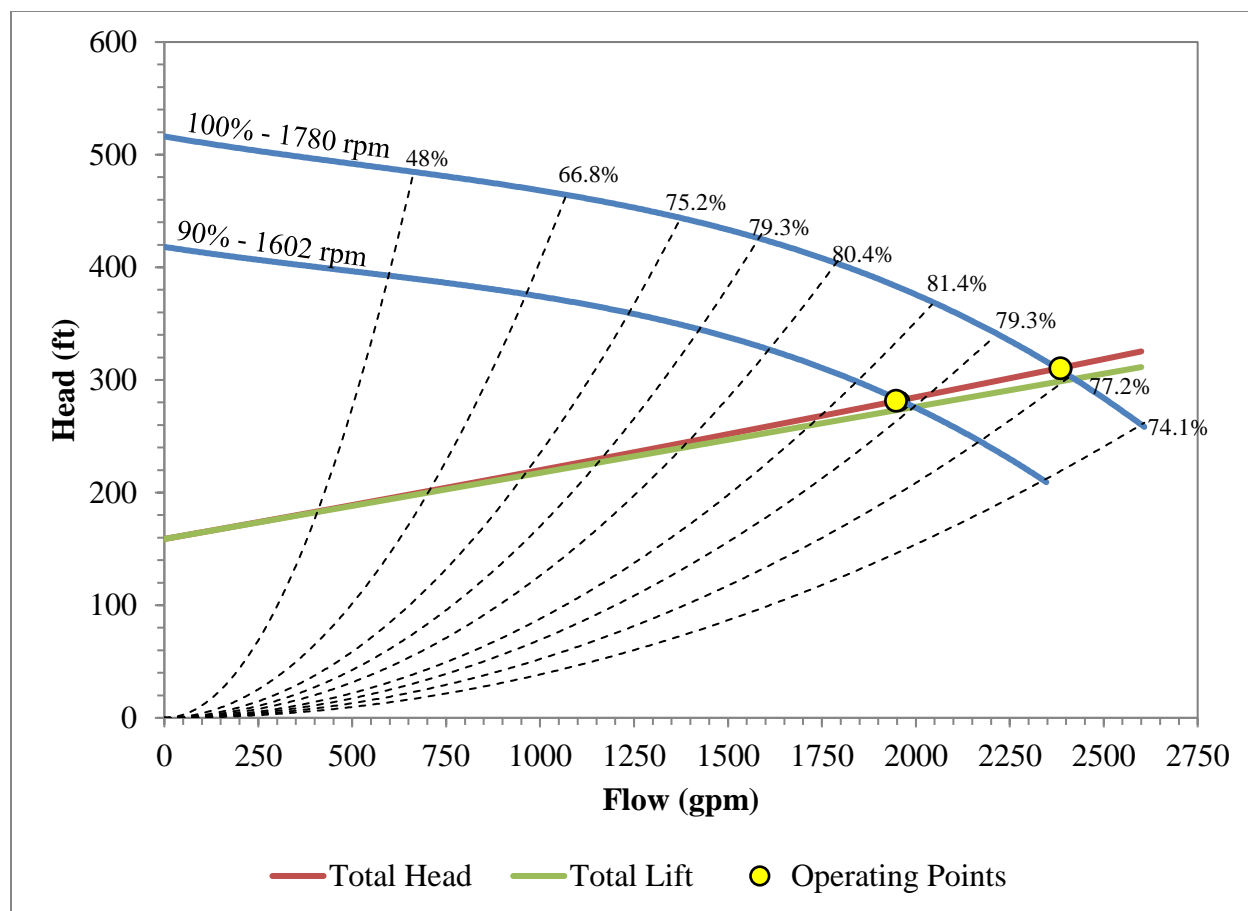


Figure 3-6 – UW 30 deep well pump performance curves with 100% and 90% speeds shown to demonstrate head and flow rate reduction with VFD installation. Dashed curves show parabolas with constant pump efficiency.

For this particular combination of deep well properties and pump attributes, reducing the speed by 10% from 1780 rpm to 1602 rpm translates to an 18% reduction in flow rate (2,390 gpm to 1,960 gpm), a 9% reduction in head (310 ft to 281 ft), and an increase of 2.3% in pump efficiency. This translates to a 28% reduction in input power required for the pump (180 kW to 130 kW) and a 12% savings in energy use when pumping the unit well daily average of 1.9 MG. All of these effects of speed reduction are beneficial to MWU energy use while still meeting operational requirements.

Reduction in head and energy use is the primary benefit for VFD installation on deep well pumps, but there are additional energy and system benefits. Operating at lower speeds and flow rates increases the duration of pump run time and lessens the number of pump starts, saving additional energy. VFDs can be set up to provide “soft-starts” for the pump, with the drive slowly increasing pump speed until the desired speed is reached. This slow ramp up can reduce current spikes during startup, even more so than other pump soft-starters (Carrier Corporation 2005). This limits power spikes during pump startup that contribute towards demand charges for the utility. Soft starts also help limit water hammer conditions and improve the life of pumping system components (Pemberton 2005). Finally, VFDs provide improved system operational flexibility through the ability to match flow rates and desired system pressures. MWU utilizes VFDs on booster pumps primarily for this purpose, as they use pressure setpoints to allow the pumps to adjust speeds in response to system demands.

While there are potential energy savings benefits, there are drawbacks for VFDs that must be considered for installation and operation. VFD efficiency is generally high, but efficiency decreases as motor load decreases, particularly for small horsepower motors (U.S. DOE 2012). Harmonics produced by the conversion from DC to AC generate heat losses that must be accounted for when installing VFDs. Adequate ventilation must be provided to ensure the added heat does not damage the drive or other motor control equipment. The lifecycle of pulse-width modulation VFDs can be related to the temperature of the drive components, and lead to premature failure without sufficient heat dissipation (Hydraulic Institute, Europump, and U.S. DOE 2004). VFD efficiency varies from installation to installation based on setup and the motor, but an overview of VFD efficiency ranges is presented in Table 3-1.

Table 3-1 – Variable frequency drive efficiencies at different operating loads. Loads are in % of rated motor horsepower.

Load, % of Drive Rated Power Output	Drive Efficiency (%)		
	50 hp	100 hp	200 hp
100%	97	97	97
75%	96	97	98
50%	95	96	96
25%	92	94	95
12.5%	87	89	81

Source: U.S. DOE 2012.

Burt et al (2008) found VFD efficiencies to be high when tested for a range of motors at varying loads. VFD efficiency did not fall below 97% for VFDs operated at 100% of rated RPM and horsepower ranges between 20% and 100% of rated horsepower. For VFDs operated at 40% of rated RPM and low load (20-30% of rated horsepower), VFD efficiency remained above 95%. The majority of MWU's VFDs operate at speeds greater than 75% during normal operation, so VFD efficiency costs are unlikely to outweigh energy savings from reduced head.

The biggest operational concern for VFD systems is structural resonance. Pump column components have natural resonance frequencies at which excessive noise and vibration can occur (Hydraulic Institute, Europump, and U.S. DOE 2004). For single-speed applications, these frequencies are usually outside the operating range. Reduction in speed and frequency increases the potential for interacting with a natural resonance frequency of one of the pumping system components. Excessive vibration can damage pumping system components and reduce the lifetime of the system. In addition, retrofitting VFDs on older motors with insufficient ability to handle occasional harmonic voltage spikes from the drive can damage the motor (Pemberton 2005). Finally, reducing the pump speed with a VFD reduces the motor load. As motor load drops below 60%, there can be as much as a 10% drop in the efficiency of the motor (Burt et al 2008). In

general, the speeds at which MWU operates VFDs are high enough that motor efficiency is not significantly affected. The inefficiencies of the VFD and motor combined with energy required to ventilate the drive all affect the magnitude of energy savings potential. Due to the difficulties of assessing and measuring these values, these factors are not generally considered. Energy savings potential estimates are constrained to looking at energy savings for the pump from head reduction and/or efficiency gains with speed reduction.

3.3. METHODS

3.3.1. Data Analysis Methods

3.3.1.1. *Overview of Approach*

To estimate the highest energy savings potential of alternative VFD installations, there was a need to characterize each deep well pump using MWU operational data, equipment records, and construction drawings. Data were taken from the MWU SCADA system to characterize operation of each unit well. Measurements of system parameters such as flow rate and water level were stored in the MWU SCADA historian on an hourly basis. Details on variables used from SCADA are presented later in this section. Analysis of each site was conducted using a week of data to provide an estimate of average operating conditions. The analyzed week was the second week of August 2015 for Unit Well 15 and the second week of August 2016 for Unit Well 25. Data were taken from August because all MWU wells are generally in service and operated consistently during that time of year, allowing for meaningful well-to-well comparisons.

Average operating points were used when estimating energy savings because the average operating conditions dominate overall energy use (Hayes 2015). Important components for the VFD study included the following:

- Pump curve for the deep well pump
- Average operating point for the deep well pump (flow rate and head)
- System head curve
 - Friction loss estimates for each site configuration
 - On-site reservoir inlet elevation
 - Average static water level
 - Average pumping water level

3.3.1.2. Pump Curves

When possible, pump curves were taken from MWU records. In other cases, MWU equipment lists with pump model numbers, impeller sizes, number of stages, and design points were used in conjunction with manufacturer pump catalogs to get the correct pump curve for each site. Pump curves were digitized into Microsoft Excel for further analysis. For wells where manufacturer performance reports with flow rates, heads, and efficiencies were provided in tabular form, these points were input into Excel and fit with a polynomial regression to estimate dynamic head for any given flow rate at maximum speed. Otherwise, a minimum of ten points from the manufacturer's curve were input into Excel and fit with a polynomial model.

3.3.1.3. System Head Curve Development

3.3.1.3.1. Overview

The digitized pump curves were used in conjunction with an estimate of the system head curve to determine an expected operating point of the pump. The operating point of the pump occurs at the intersection of the system head curve and pump curve, which defines the expected operating flow rate and dynamic head. The system head curve for each site was generated using

the well's static water level, the well's specific capacity, the reservoir's inlet elevation, and friction losses in the pump column and pipe from the pump to the reservoir inlet. The process used to develop this information is described in the following subsections.

3.3.1.3.2. Static Water Level

As noted in the Background Section, static water level for a well is the difference between the ground elevation and the water table elevation with the pump off for an extended period of time. This can fluctuate over time due to seasonal changes in groundwater levels and pumping operations. Instantaneous water level in the well was monitored and logged in SCADA. While the best representation of static water level would be the observed water level after an extended period of off-time for the deep well pump, this was not always possible given the frequent cycling of the deep well pumps at many of the sites. The minimum recorded static level for each hour of the day was taken from SCADA, with the minimum of these hourly values taken to be the static water level for a given day. These values were then averaged over the span of seven days to represent the static water level for each site.

3.3.1.3.3. Specific Capacity/Pumping Water Level

In order to determine drawdown and specific capacity for each site, an estimate of the water level during pumping operations was needed. As noted in the Background Section, pumping water level is the difference between the ground elevation and the water level in the well when the pump is operating. For each day, the pumping water level was found by looking at the average hourly water level in SCADA. To eliminate the influence of water level recovery after pump shut-off, only hours where the pump ran the entire hour were used to determine the pumping water level. Thus, for a given day, the pumping water level was determined to be the average water level for all hours of the day when the pump ran for the entire hour. Drawdown for each well was then taken

to be the difference between the average static and pumping water levels. Specific capacity was then calculated by dividing the average operating flow rate by the average drawdown for the well.

3.3.1.3.4. *Elevation of Deep Well Reservoir Inlet*

All MWU deep well pumps discharge to a storage reservoir on-site, via a fixed-elevation reservoir inlet bell located above the maximum water level in the reservoir. Reservoir inlet elevations were determined from design drawings for each site.

3.3.1.3.5. *Friction Losses*

Friction losses for each site were estimated by examining MWU design drawings and piping configurations for each unit well. In addition to losses in the pipes, friction losses in the pump column were also considered. Major losses, head loss due to friction between the water and pipe surface, were determined using the Hazen-Williams equation, Equation 3-5 (Jones et al 2008).

$$h_{L,major} = \left(\frac{149*Q}{C*D^{2.63}} \right)^{1.85} * \left(\frac{L}{1000} \right) = L * \left(\frac{v}{1.318*C*R^{0.63}} \right)^{1.85} \quad (3-5)$$

Where: $h_{L,major}$ = major head losses for pipe segment (ft)

Q = flow rate (gpm)

C = Hazen-Williams roughness coefficient (unitless)

D = diameter of pipe segment (in.)

L = length of pipe segment (ft)

v = velocity of water in pipe segment (ft/s)

R = hydraulic radius of pipe segment (ft)

The length and hydraulic radius of pipe segments, variables L and R in Equation 3-5, were taken from MWU design drawings for each well. C values were taken to be a value of 100 for all analyses, a conservative value for the ductile and cast-iron piping used at all unit wells. The majority of deep well discharge piping configurations consists of 12” or larger pipe of relatively short lengths, so the effect of using a conservative C value is very small. Even for the worst-case

pipng configuration, Unit Well 26, using a C value of 140 instead of 100 decreases major losses by 19”, less than 1% of the average operating head for the deep well pump.

Minor losses, head loss due to turbulence and disruptions in fluid flow from piping components such as valves and bends, were calculated using Equation 3-6 (Jones et al 2008). Minor loss coefficients for standard piping components were taken from Baniel (2013), Hayes (2015) and Jones et al (2011).

$$h_{L,minor} = k \frac{v^2}{2g} \quad (3-6)$$

Where: $h_{L,minor}$ = minor head loss for component (ft)
 k = minor loss coefficient for component (unitless)
 v = velocity of water in component (ft/s)
 g = gravitational constant (ft²/s)

Additional head losses occur in the pump column due to the pump shaft, bearings, couplings, and spiders. Estimating these losses relied on empirical head loss relationships from Layne/Verti-Line (2005) due to the difficulty in accounting for all the individual components. A reference for estimating head loss in the pump column is shown in Table 3-2.

Table 3-2 – Empirical friction loss estimates for an 8-inch pump column based on lineshaft size and flow rate.

Column and Open Lineshaft Size	Friction Loss in Feet Per 100 Feet of Setting								
	1000 - 2600 GPM								
	1000	1200	1400	1600	1800	2000	2200	2400	2600
8" x 1"	1.90	2.60	3.50	4.50	5.50	6.70	7.90	9.40	11.00
8" x 1-1/4"	3.30	4.50	5.95	7.55	9.40	12.50	15.10	---	---
8" x 1-1/2"	3.90	5.50	7.20	9.20	14.00	---	---	---	---
8" x 1-15/16"	5.40	7.50	9.98	13.00	16.40	---	---	---	---

Source: Adapted from Layne/Verti-Line 2005.

MWU equipment inventories and construction records were used to determine the column and lineshaft size for each well. Friction losses per 100 feet of setting at various flow rates, as

shown in Table 3-2, were fit with a second-order regression in Excel to estimate friction loss at any flow rate within the pump's operating range. Values were fit with a second-order equation because head loss depends on the square of velocity as shown in Equation 3-6. Sample equation fits for the pump column friction loss values presented in Table 3-2 are shown in Figure 3-7.

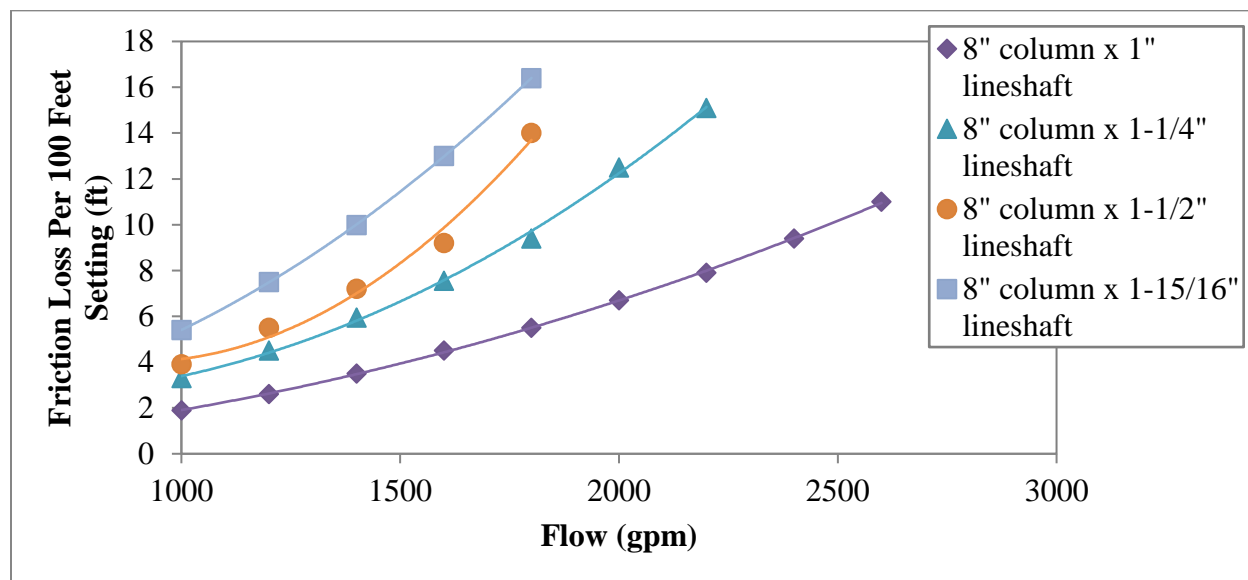


Figure 3-7 – Second-order polynomial fits for pump column friction loss (Values from Table 3-2).

Total column friction losses were then determined by multiplying the friction loss per 100 feet by total length of the pump column for each well. Total friction losses at any flow rate were calculated by summing the major losses, minor losses, and column losses at a given flow rate.

3.3.1.3.6. System Curve

The system curve was generated using the information previously described. To start, the total lift was considered, regardless of flow rate. For the pump configurations used by the MWU, total lift was equal to the sum of the pumping water level at a given flow rate and the height of the reservoir inlet bell above ground. Total static lift was equal to the static water level and reservoir lift. Graphically, this latter value is the y-intercept of the system head curve as shown in Figure

3-8 (although this figure shows an example from Unit Well 28, the same approach was applied to the two unit wells studied for this paper).

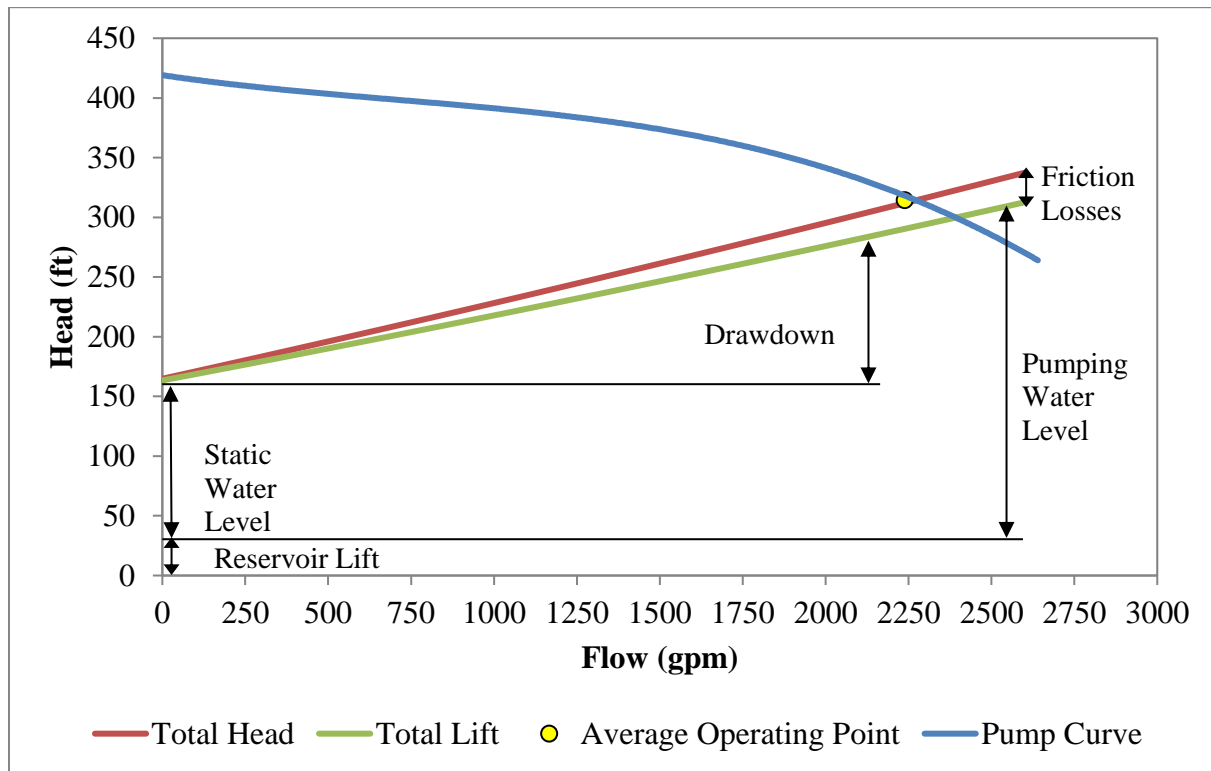


Figure 3-8 – System head and pump curve components (UW 28 shown).

The slope of the total lift is the inverse of the specific capacity of the given well. Specific capacity measures the increase in drawdown with an increase in flow rate and is unique to each well and its surrounding geologic formation. For Unit Well 28, with a specific capacity of 16 gpm/ft, each one foot increase in drawdown translates to an increase of 16 gpm. The total lift can be constructed using the static lift and specific capacity, which provides a measure of the total elevation the water must be pumped at any given flow rate. The total lift is shown as a green line in Figure 3-8, and is solely a function of the well’s geologic formation and the reservoir’s inlet configuration. The system head curve, shown in red, differs from the total lift curve in that it includes friction losses. As shown in Equations 3-5 and 3-6, friction losses increase with an

increase in velocity and, therefore, the gap between the system head curve and total head line increases with increasing flow rate. System head was estimated at flow rate intervals of 100 gpm and then fit with a second-order polynomial to generate a smooth curve for all flow rates.

3.3.1.4. Average Operating Point

The average operating point consisted of the average operating flow rate and head for a one-week period. For Unit Well 15, the second week of August 2015 was used for analysis and for Unit Well 25 the second week of August 2016 was used.

At the time of this study, flow meters were operating at both wells to monitor deep well pump flow rate (Toshiba LF654 magmeter at Unit Well 15 and Toshiba LF434 magmeter at Unit Well 25). For the August 2015 data at Unit Well 15, average deep well pump flow rate was calculated by dividing the total volume pumped in a day by the total run time of the deep well pump. Data from August 2016 at Unit Well 25 was available in approximately 30-second intervals, and the average deep well pump flow rate was taken as the average of these values while the pump was running.

Average head was calculated by summing the recorded pumping water level from SCADA, the elevation of the reservoir inlet from drawings, and estimated total friction losses at the average operating flow rate (Equations 3-5 and 3-6).

The average operating point was then plotted on the same graph as the system curve and the manufacturer's pump curve to assess whether the pump was operating as expected. A pump was deemed to be operating as expected if the head at the average operating flow rate was within 5% of the head predicted at that flow rate based on the pump curve.

3.3.1.5. *Operating Points at Alternative Speeds*

To estimate VFD energy savings, variable speed pump curves were generated from Affinity Laws (Jones et al 2008). To do this for a given alternative speed, the Affinity Laws were applied to the flow rate and head values used to digitize the original or shifted pump curve and the resulting points at the new speed were fit with a polynomial regression to create a smooth curve. This was repeated in 5% speed intervals for several speeds and the results were plotted along with the original or shifted pump curve, the system curve, and the average operating point. An example for UW 30 is shown in Figure 3-9, where the variable speed pump curves are shown in blue along with the system curve in red and the average operating point in yellow (the same approach was applied for the two wells studied in this paper). Intersections between the variable speed pump curves and the system curve represent the expected average operating point at each reduced speed. As seen in Figure 3-9, reduction in VFD speed shifts the average operating point to the left along the system head curve.

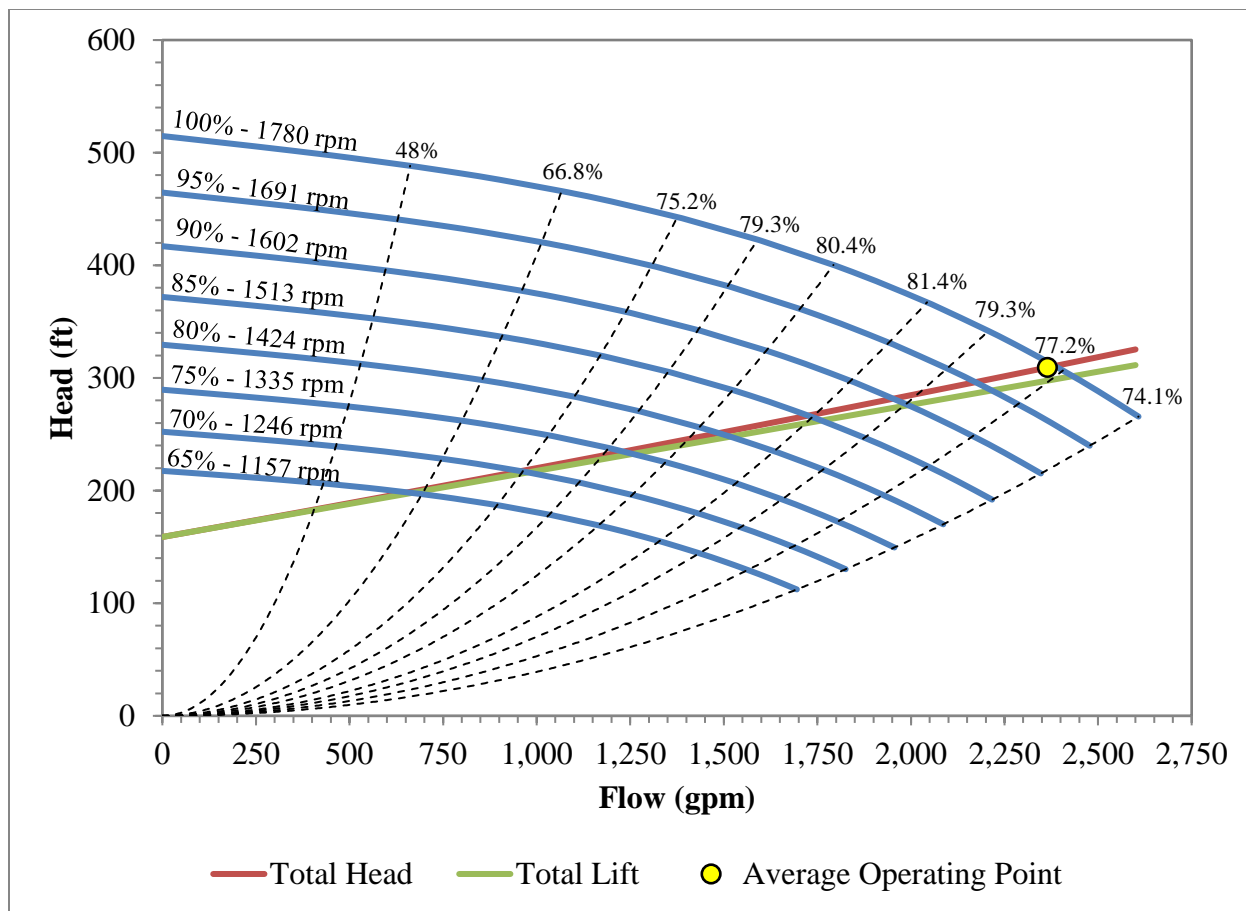


Figure 3-9 – UW 30 variable speed curves and pump efficiencies with system head curve and average operating point.

Flow rate and total head were estimated for each intersection from the polynomial equation for the system curve and from the polynomial equation for the appropriate pump curve. As shown below, these estimates were needed to develop estimates of energy savings.

3.3.1.6. *Pump Efficiency at Alternative Operating Points*

Pump efficiencies were also needed for all operating points to estimate energy use at each VFD speed. For deep well pumps where performance test results were provided with the pump, efficiencies were taken directly from this information. For the remaining pumps, efficiencies were estimated when digitizing the original pump curve, usually at 200 gpm intervals. Pump efficiency

for a given flow rate and head at 100% speed was assumed to be the same for the corresponding flow rate and head determined from Affinity Laws at a lower speed. Pump efficiency contours were fit with parabolic curves, shown as black dashed lines in Figure 3-9. When operating points fell between two pump efficiency contours, efficiencies were linearly interpolated between the two contours.

3.3.1.7. Energy Consumption at Alternative Operating Points

Figures such as Figure 3-9 were used to determine energy savings potential. Using the estimated average operating point and pump efficiency for several variable speed pump curves, Equations 3-7 to 3-11 were used to estimate pump power use, energy use, and energy intensity. Pump output power required for a given flow rate and head was estimated using Equation 3-7.

$$P_o = \frac{Q*H}{3,960 (gpm-ft)/Hp} * \frac{0.746 kW}{Hp} \quad (3-7)$$

Where: P_o = pump output power (kW)
 Q = pump flow rate (gallons per minute)
 H = head (ft)

Input power required to the pump was then estimated with Equation 3-8.

$$P_i = \frac{P_o}{\eta} \quad (3-8)$$

Where: P_i = pump input power (kW)
 η = pump efficiency (unitless)

Daily pump energy use for any given average operating flow rate and head was estimated as pump input power multiplied by the total daily pump run time, Equation 3-9.

$$E_p = P_i * t \quad (3-9)$$

Where: E_p = pump energy use (kWh)
 t = pump run time (hr)

Energy intensity is defined as the energy used per unit volume pumped, in this case kWh/MG. Energy intensity can be estimated for any given day by dividing total energy use by volume pumped. Energy intensity for estimated operating points was estimated with Equation 3-10 or the simplified Equation 3-11.

$$EI = \frac{P_i (kW)}{Q(gpm) * \frac{60 \text{ min}}{1 \text{ hr}} * \frac{1 \text{ Mgal}}{10^6 \text{ gal}}} \quad (3-10)$$

$$EI = \frac{H * 0.746 \text{ kW} / \text{Hp} * 10^6 \text{ gal} / \text{Mgal} * \frac{1}{60} \text{ hr} / \text{min}}{3960 \text{ gpm} \cdot \text{ft} / \text{Hp} * \eta} \quad (3-11)$$

Where: ***EI*** = energy intensity (kWh/MG)
P_i = pump input power (kW)
Q = pump flow rate (gpm)
H = head (ft)
η = pump efficiency (unitless)

As shown by Equation 3-11, energy intensity for any given combination of flow rate and speed is only a function of the head the pump is pumping against and the pump efficiency at that operating point.

The previous equations only consider the energy use of the pump itself, with no inclusion of the motor efficiency. Actual energy use by the motor and pump would be greater than the estimates of pump energy use alone, differing only by the motor efficiency. However, this additional energy was not considered in this evaluation. A previous study of MWU motors have found that motor efficiencies were generally 93% or greater. In addition, the VFD has additional efficiency and energy costs compared to a constant speed drive, but this was not considered in the analysis either. VFD efficiency is typically above 95% for the range of speeds applicable to the deep well pumps studied in this analysis (U.S. DOE 2012).

3.3.2. Field Test Verification

3.3.2.1. Overview of Approach

The goal of the field tests was to utilize sites with VFDs already installed on the deep well pump to verify the energy savings estimation methodology and results for MWU deep well pumps.

3.3.2.2. Experimental Methods

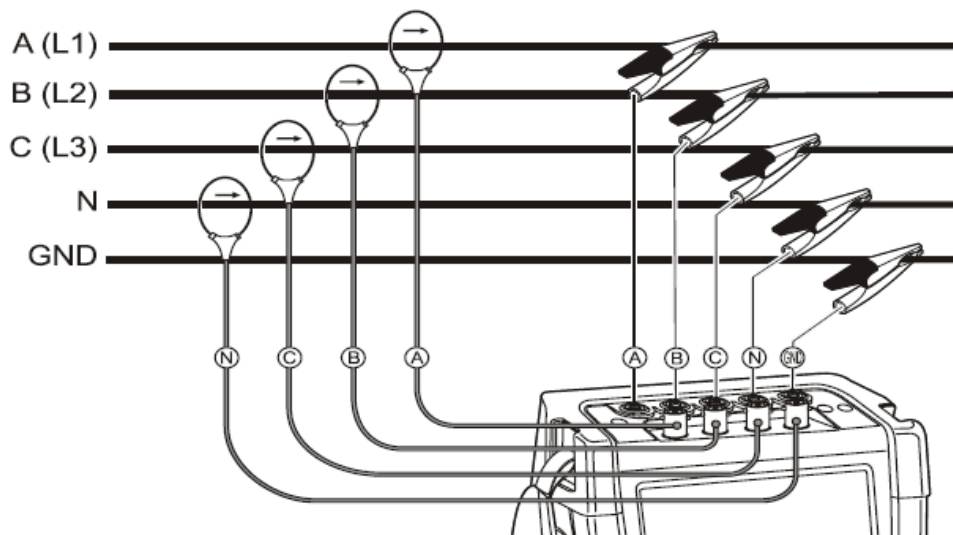
Field tests were designed and run at two sites with VFDs on the deep well pumps (Unit Wells 15 and 25). These two wells were selected for ease of analysis because under average operation they pump to a constant discharge head. The other two wells with VFDs installed (Unit Wells 7 and 29) have variable discharge heads due to the presence of pressure filtration systems. Prior to this work, no MWU protocol existed to characterize energy use at different VFD speeds. A field sampling and operational procedure was created to characterize deep well pump operation and energy use across a range of pump speeds for select MWU deep well pumps.

3.3.2.2.1. Data Collection

At the time of this study, daily station energy use was read at all MWU unit wells and recorded from an on-site power meter by MWU staff, but energy use from individual pumps was generally not measured. However, for pumps with VFDs installed, the drive provides a measurement of power stored in the MWU SCADA system. This measurement of VFD power was the basis for characterizing energy use for all tested pumps. To supplement this data, an additional source of power and energy use data was collected by setting up a power meter on-site.

The first step in setting up the field test was to connect a FLUKE 435 Series II Power Quality and Energy Analyzer (“power meter”) to the deep well pump on-site for measurement of energy use. The MWU licensed electrician installed the power meter per the instructions provided

in the power meter manual as shown in Figure 3-10. Current loops were connected on the three leads (L1, L2, L3) and voltage clamps connected to the three leads (L1, L2, L3) and the ground (GND).



Source: Fluke Corporation 2012.

Figure 3-10 – Fluke power meter connection diagram for three phase power system. Current loops measure amperage and voltage clamps measure voltage.

The pulse width modulation used to simulate a sinusoidal wave was found to create unstable power readings when installed on the load side of the VFD. During the setup at Unit Well 15, there were issues installing the power meter on the line side of the VFD. The power meter was connected to the load side of the drive, as shown in Figure 3-11, and the pump was turned on. The power meter appeared to produce readings comparable to output measurements from the drive, so this configuration was maintained for the test.

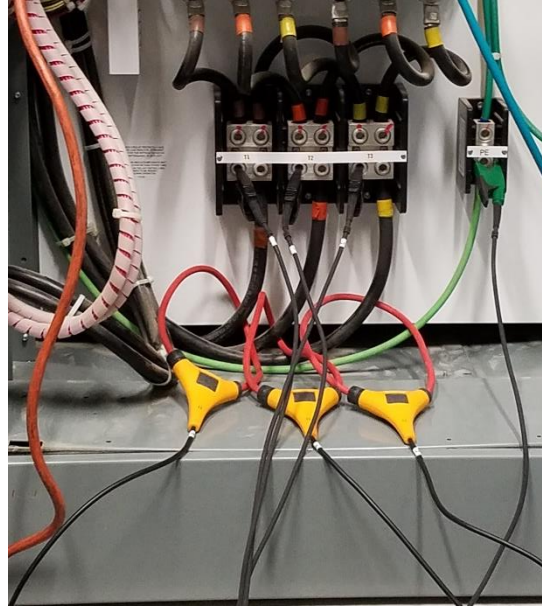


Figure 3-11 – Field connection of power meter on load side of VFD at UW 15 with voltage clamps (L1, L2, L3, and G) and current loops (L1, L2, L3) shown.

During the sampling period, the power meter was connected to an external power source and stored within the electrical cabinet housing the VFD to prevent any disturbance during sampling. The power meter was programmed to store average, minimum, and maximum values for 30 second intervals over the test period. The meter was programmed to log values for up to 30 days to ensure a sufficient time window to conduct the VFD test. Variables logged or calculated by the power meter are shown in Table 3-3. Methods for determining calculated values are presented in the power meter manual (Fluke Corporation 2012).

Table 3-3 – Values collected or calculated by power meter

Collected or Calculated (*) Values		
RMS Voltage (V)	Frequency (Hz)*	Active Energy (Wh)*
Peak Voltage (V)	Unbalance (%)*	Reactive Energy (VARh)*
Overdeviation (%)*	Active Power (W)*	Apparent Energy (VAh)*
Underdeviation (%)*	Apparent Power (kVA)*	Wh Forward (Wh)*
Current (A)	Power Factor*	Wh Reverse (Wh)*
Peak Current	Efficiency Factor*	

Upon completion of field testing at each site, the power meter was removed and relevant data was downloaded using the PowerLog software provided by FLUKE.

At the conclusion of each test, the following SCADA variables were collected from the MWU historian for analysis of operating conditions and energy use: VFD speed, VFD power, VFD current, well pump flow rate, and pumping water level.

3.3.2.3. *Variable Speed Test Protocol*

After the power meter was installed, operational test methods were created for each site. Tests were designed in conjunction with MWU water supply staff and operators to ensure customer demand was met and satisfactory water quality was maintained. Tested VFD speeds were selected to encompass the same range as used for initial estimates as part of the procedure described in Section 3.3.1. The tested speeds were constrained to a range at which MWU could maintain normal system operation. Tests were generally conducted at each site over the span of a week, with one VFD speed tested for each day.

After selecting a range of speeds for testing at each site, a test procedure for each individual speed was generated. No standardized test condition was created for each speed because MWU needed to meet customer water demands, which vary by day. Tests were designed to provide at least 4 hours of deep well run time. This run length was deemed to be sufficient pump runtime for drawdown and flow rate to stabilize based on analysis of trends at various MWU unit wells. For an accurate and consistent estimate of static water level across all tests, the deep well pump would have to be off for an extended time period prior to each run. In practice, this was not possible at all sites or tested speeds, but attempts were made to provide rest periods prior to the beginning of each test. MWU operators were informed of the timing of ongoing tests and made attempts to shut down deep well pumps overnight prior to a test the following day. However, each operator

operated the system differently, so test conditions for each speed varied. As a compromise, an attempt was made to ensure the pump was off for at least 2 hours prior to testing a speed to ensure some recovery of the water level in the pump column. Booster pump operation was adjusted, where possible, to ensure at least a 4-hour test run for the deep well pump. A summary of specific test conditions at each site is presented below.

3.3.2.3.1. Unit Well 15

At the time of this study, operation of Unit Well 15 was adjusted throughout the year to match changes in seasonal demands. During the winter months when demand was low, the deep well pump was set to provide a constant flow of 1,100 gpm, which resulted in an average VFD speed close to 65%. The booster pump was set at 1,050 gpm to let the deep well pump shut off once per day. During summer months when demand was high, the deep well pump was set to provide a constant flow rate of 1,500 gpm and an average VFD speed close to 75%. The booster pump was set at 1,460 gpm to maintain one deep well shut off per day.

VFD speeds were tested in 10% intervals from 60% to 90%. The tests were conducted in July and August 2016 during high demand times. Tests below 60% were expected to compromise system operation. Tests were not run at speeds higher than 90% due to flow limitations on the air stripping system. Estimated flows at speeds greater than 90% were expected to be greater than the rated capacity of the air strippers on-site. Flow rate at 100% speed was also estimated to exceed booster pump flow rate and result in the reservoir filling before reaching at least 4 hours of pump run time. On-site limitations with the air stripping system combined with only one booster pump and a small reservoir, made it impossible to test speeds greater than 90% for the deep well pump.

The field test at Unit Well 15 was conducted over an 8-day period from July 27-August 3, 2016, test conditions are presented in Table 3-4.

Table 3-4 - Overview of UW 15 test conditions

Tested Speed	60%	70%	80%	90%
Date	8/3/16	7/28/16	8/3/16	8/1/16
Deep Well Off Time Prior to Test (hr)	8.0	16.6	2.6	1.5
Test Run Time (hr)	5.9	7.9	10.2	5.2

3.3.2.3.2. Unit Well 25

At the time of this study, the VFD at Unit Well 25 was typically operated at a constant speed of 92%. On-site booster pumps were single-speed pumps and Booster Pump 1 operated at a flow rate between 1,450 gpm and 1,500 gpm. Operation of the booster pumps was controlled by the water level of a storage tank within the distribution system, Sphere 225. Booster Pump 1 was set to turn on at a tank level of 143 feet and off at a tank level of 150 feet. For the test, booster pumps were shut off overnight to lower the water level in the sphere to ensure the booster pumps were operational for the entire test the following day.

VFD speeds were tested in 5% intervals beginning with 80% speed. Speeds below 80% speed were not tested because deep well flow rates were estimated to be insufficient to maintain acceptable reservoir levels. Without control of booster pump flow rate, this was the lowest speed deemed testable. To maintain water quality, chlorine and fluoride chemical feed rates were adjusted as necessary by MWU staff to ensure residuals remained within MWU acceptable ranges.

The field test at Unit Well 25 was conducted over an 11-day period from December 4 – December 14, 2016, a summary of test conditions is presented in Table 3-5. One pump cycle at the normal 92% speed set point was also included for comparison in the analysis.

Table 3-5 – Overview of test conditions at Unit Well 25

Tested Speed	80%	85%	90%	92%	95%	100%
Date	12/14/16	12/7/16	12/5/16	12/4/16	12/6/16	12/8/16
Deep Well Off Time Prior to Test (hr)	9.4	7.6	10.4	13.3	8.4	9.2
Test Run Time (hr)	6.0	6.3	6.0	4.0	6.1	2.9

After the test at Unit Well 15, the intent was to provide a more consistent test pattern at Unit Well 25 and run each speed test for 6 hours. However, for the 100% speed test, the test was cut short after the water level in the well triggered an automatic pump shut off after nearly 3 hours of run time. The VFD at Unit Well 25 was originally installed partly due to drawdown levels in the wells approaching the bowls of the pump impeller. Operation at 100% speed brought the water level in the column to the automatic shut-off point, making a longer test run time impossible.

3.3.3. Field Test Data Analysis Methods

3.3.3.1. Overview of Approach

Data used to analyze each test condition was taken from the power meter, MWU SCADA historian, and from data logs completed every day by MWU staff. Power meter data was averaged and stored every 30 seconds while measurements in SCADA were generally stored in 30 to 45 second intervals. MWU staff visit each well once per day and manually record measurements from on-site meters and gauges. The following data collected from various sources were used for analysis:

- Pumping water level
- Pump run times
- Pump flow rates

- VFD power use
- VFD speed
- Station power use
- Station discharge pressure
- Reservoir level

3.3.3.2. *System Head Curves*

System head curves were developed from observed data in a manner similar to previously discussed. Modifications and differences in the method are presented below.

Although multiple speeds were tested for each pump, one composite system head curve was developed based on data from each tested speed. When testing a specific VFD speed, the static water level for that test was taken to be the measured water level in SCADA immediately prior to starting a test run. Drawdown and specific capacity were also estimated based on the average pumping water level and flow rate. Static water levels and specific capacities estimated were averaged and used to create an observed, composite system head curve.

3.3.3.3. *Field Test Operating Points*

Average test operating points were determined in a similar manner as described in previous methodology. Deep well pump flow rate and pumping water level data from SCADA were averaged and total dynamic head was estimated using the same procedure. All average operating points were taken for a consistent length of pump run time. For Unit Well 15, five hours of data were used and for Unit Well 25 six hours of data were used.

3.3.3.4. *Power/Energy Measurements and Calculations*

Per discussions with outside contractors for MWU, it was determined that the VFD power measurement monitored in SCADA was measurement of power on the load side of the drive. Power data collected from the power meter was also measured on the load side of the drive, measuring power input to the motor.

Observed energy intensity was calculated using Equation 3-10 with the average test operating flow rate and average power (from power meter and SCADA data). An observed wire-to-water efficiency was calculated for each tested speed. Pump output power was estimated for each test average operating point using Equation 3-7, and wire-to-water efficiency was calculated using the following Equation 3-12. This observed wire-to-water efficiency was compared to previous estimates made from interpolating pump efficiency and MWU motor efficiencies.

$$\eta_{W2W} = \frac{P_o}{P_{o,VFD}} \quad (3-12)$$

Where: η_{W2W} = Average wire-to-water efficiency (%)
 P_o = Estimated pump output power (kW)
 $P_{o,VFD}$ = Average VFD output power as measured by SCADA (kW)

3.4. RESULTS AND DISCUSSION

3.4.1. Unit Well 15

3.4.1.1. *Estimated Pump Behavior and Energy Use*

Unit Well 15 operation and energy use were characterized using operational data from August 10 to 16, 2015. During the examined week, the pump was operated at a constant flow set point of 1,250 gpm. The system head curve, variable speed pump curves, and the average operating point were generated as described in Section 3.3.1 and are presented in Figure 3-12. Speed curves

are shown in 5% intervals down to the lowest speed where the operating point had an estimable pump efficiency. Pump efficiencies were taken from the manufacturer performance test report and parabolic pump efficiency curves are plotted back to the origin. The total head and total lift curves are shown in red and green, respectively, with the average operating point of $1,240 \pm 2$ gpm and 118 ± 3.7 feet shown with the yellow circle. For constant-flow operation, the VFD increases pump speed to maintain a constant flow rate as drawdown in the well increases with increasing pump run time. Over the examined week of operation, average VFD speed was $70.1\% \pm 2.7\%$.

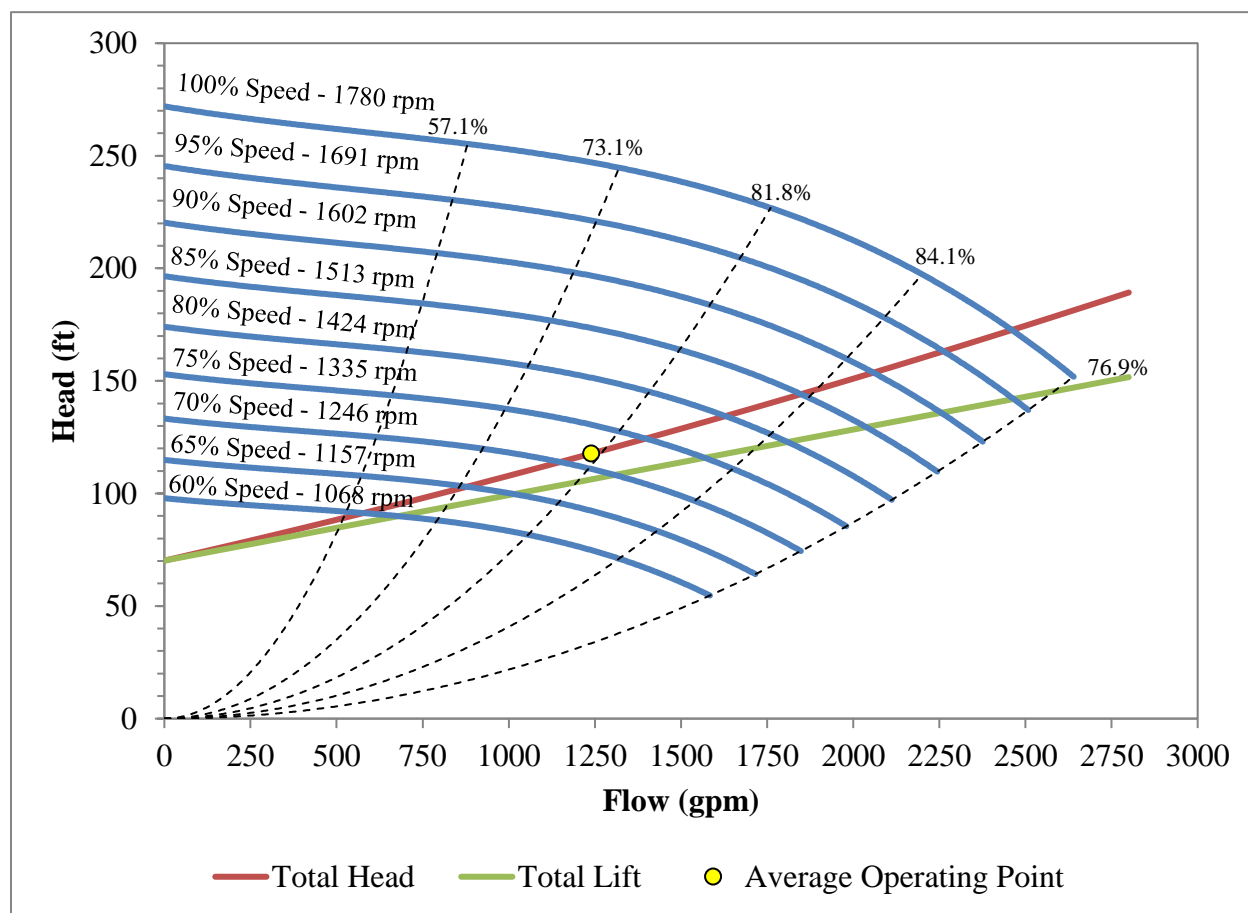


Figure 3-12 – Unit Well 15 variable speed curves with estimated system head curve and observed average operating point for August 10 to August 16, 2015.

The estimated average rpm operating point aligned with a 71.5% pump speed rather than the observed 70.1% pump speed. The difference between the average operating head and estimated

operating head at 70.1% pump speed was 6 ft. This difference was reasonable given the uncertainties present in estimating the system head curve and average operating points.

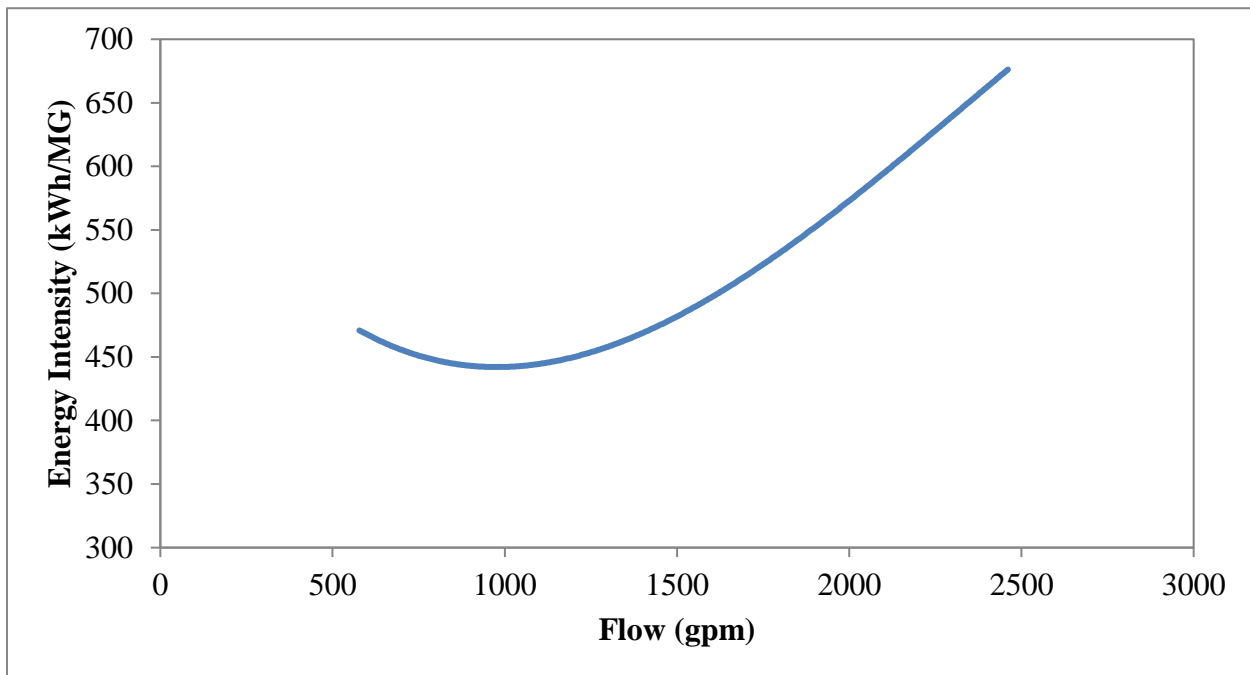


Figure 3-13 – Estimated pump energy intensity versus flow rate curve for Unit Well 15.

Estimated energy intensity was plotted against the average operating flow rate as shown in Figure 3-13. The minimum estimated energy intensity was 440 kWh/MG at a pump speed of 65%. With an estimated energy intensity of 677 kWh/MG at 100% pump speed, a reduction in pump speed to 65% would provide savings of 237 kWh/MG. Below 65% speed, decreases in pump efficiency outweigh savings from reduction in head and flow rate.

3.4.1.2. Field Test Results

3.4.1.2.1. Observed Performance

Observed data from variable speed tests run in July and August 2016 are shown in Figure 3-14 through Figure 3-21. Deep well pump flow rate and pumping water level were used in

conjunction with friction loss estimates to determine an operating head for each data point for all speed tests. Operating points for all tested speeds are plotted along with the relevant variable pump speed curves in Figure 3-14.

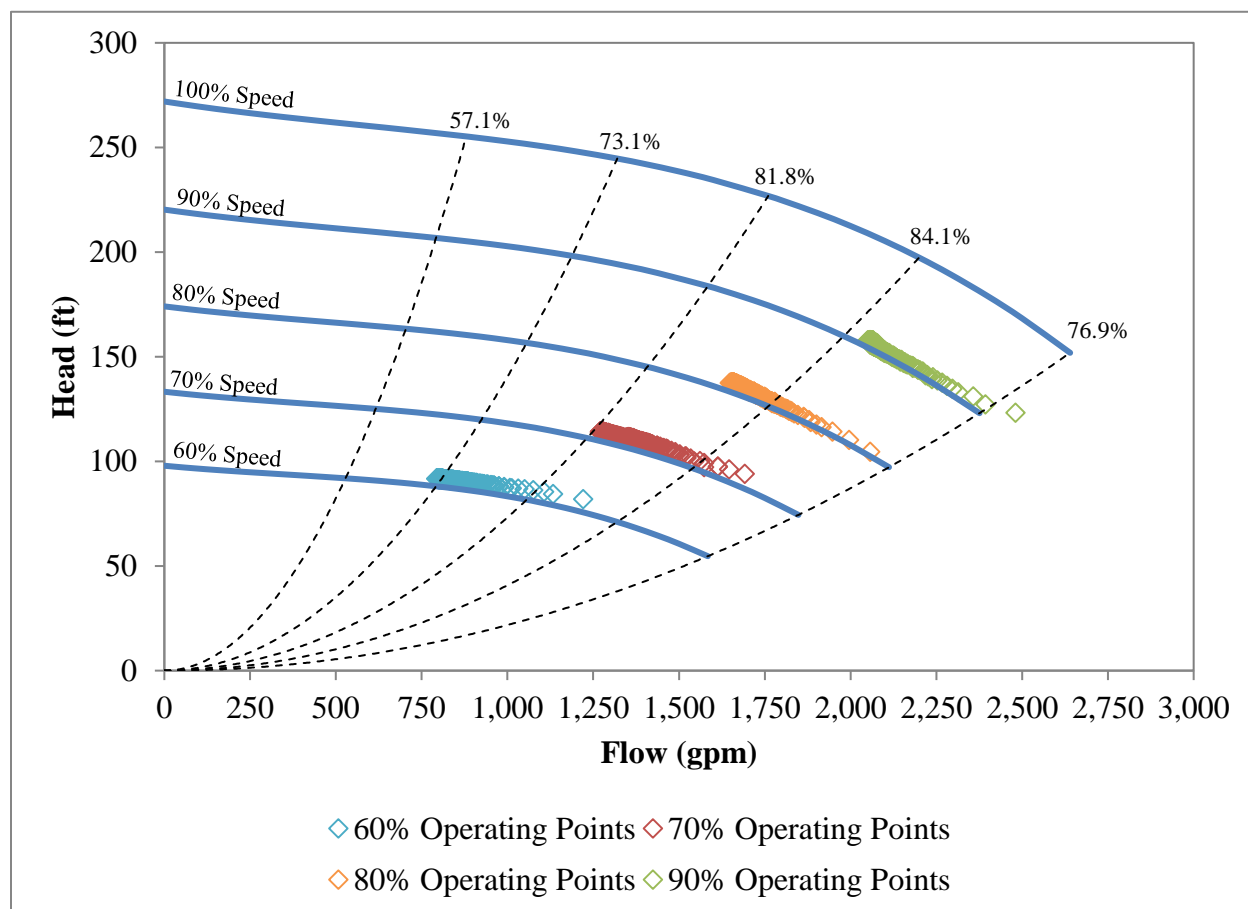


Figure 3-14 – Operating points based on observed flow rates and water levels with estimated friction coefficients for each tested pump speed at Unit Well 15. Each point represents a single time point with a recorded measurement from SCADA.

Pumping water level versus run time is shown in Figure 3-15. The decrease in pump speed from 90% to 60% resulted in a 52-foot decrease in steady-state pumping water level. As expected, pumping water level and drawdown increased with longer pump run time. Between the first and second hour of pump run time, drawdown increased two to three feet. By the fourth or fifth hour of run time, drawdown increased a foot an hour or less.

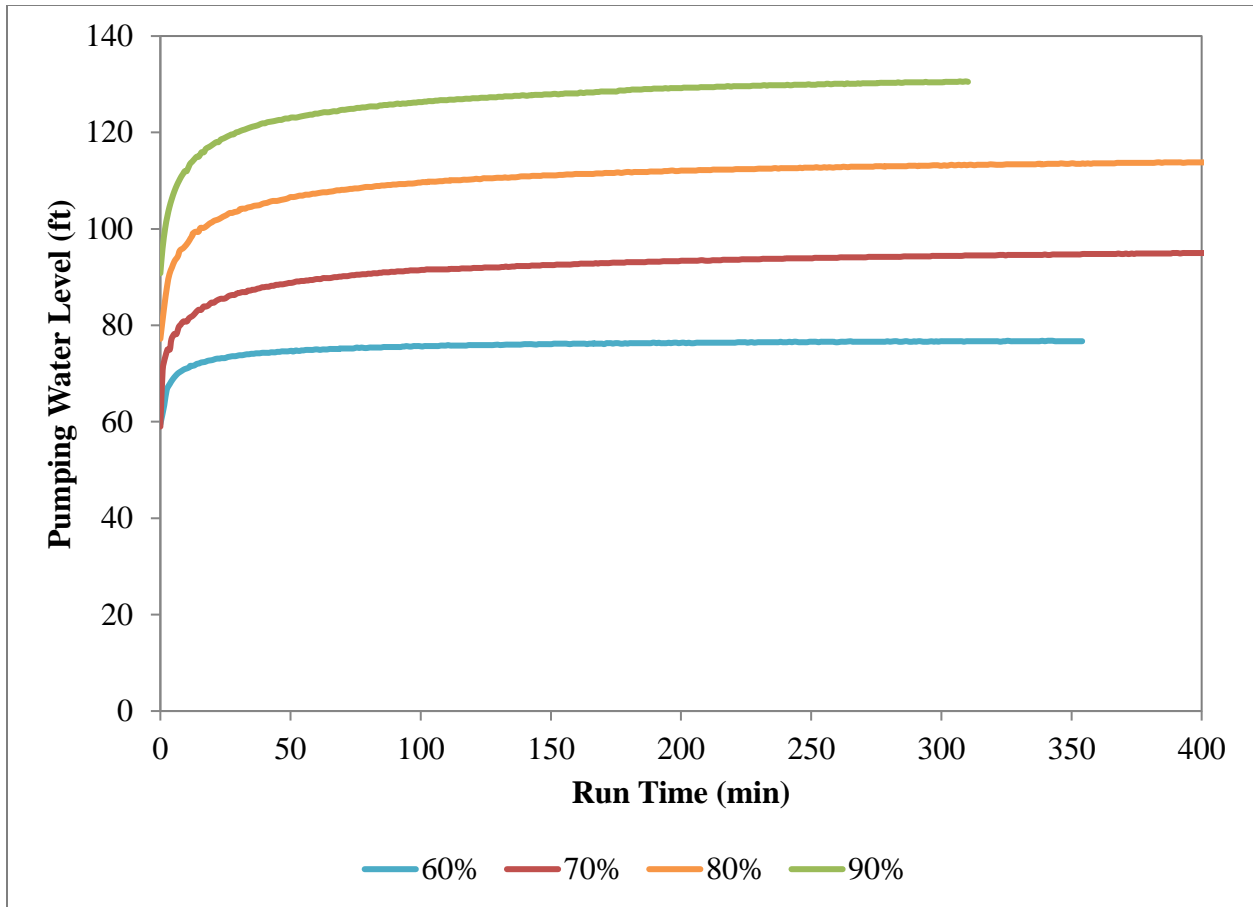


Figure 3-15 – Observed pumping water level versus run time for multiple deep well pump speeds at Unit Well 15.

Pump flow rate versus run time for each tested speed is highlighted in Figure 3-16. Reduction in pump speed from 90% to 60% resulted in a difference of pump flow rate of 1,200 gpm. As expected, well pump flow rate under constant-speed pump operation decreased towards a steady state flow rate as pump run time increased. As the pumping water level increased towards a steady state level with pump run time, as shown in Figure 3-15, the total dynamic head (TDH) for the pump increased towards a steady state head. Increased TDH translates to reduced pump flow rate for constant-speed operation.

Figure 3-14 shows this interaction between drawdown and flow rate for all speed tests. Initial points far to the right for a given speed represent operation at the beginning of the test.

Increased drawdown results in increased TDH on the pump, shifting operation along the pump curve with reduced pump flow rate. As pumping water level and pump flow rate trended towards steady state, operating points in Figure 3-14 also approached a steady state value.

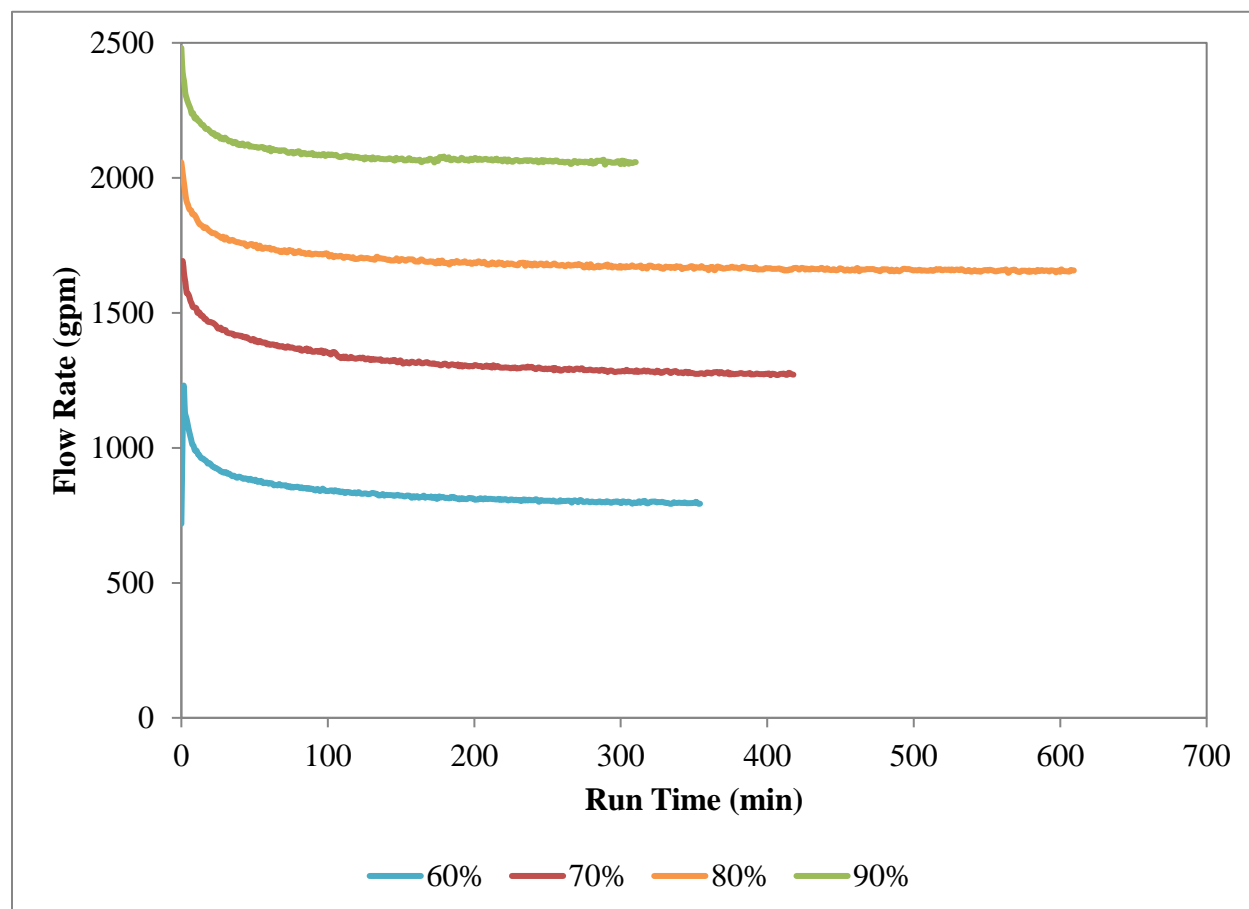


Figure 3-16 – Observed deep well pump flow rate versus time for multiple deep well pump speeds at Unit Well 15.

Observed pumping system efficiency versus run time is shown in Figure 3-17. Pump efficiency changes with pump run time based on the operating point of the pump. The operating points shown in Figure 3-14 demonstrate how efficiency was expected to change with pump run time and matched the observed efficiencies shown in Figure 3-17. For a given speed, drawdown increased throughout the test, resulting in each operating point moving left along the variable pump speed curve. The change in efficiency over time depends on the pump speed and system curve.

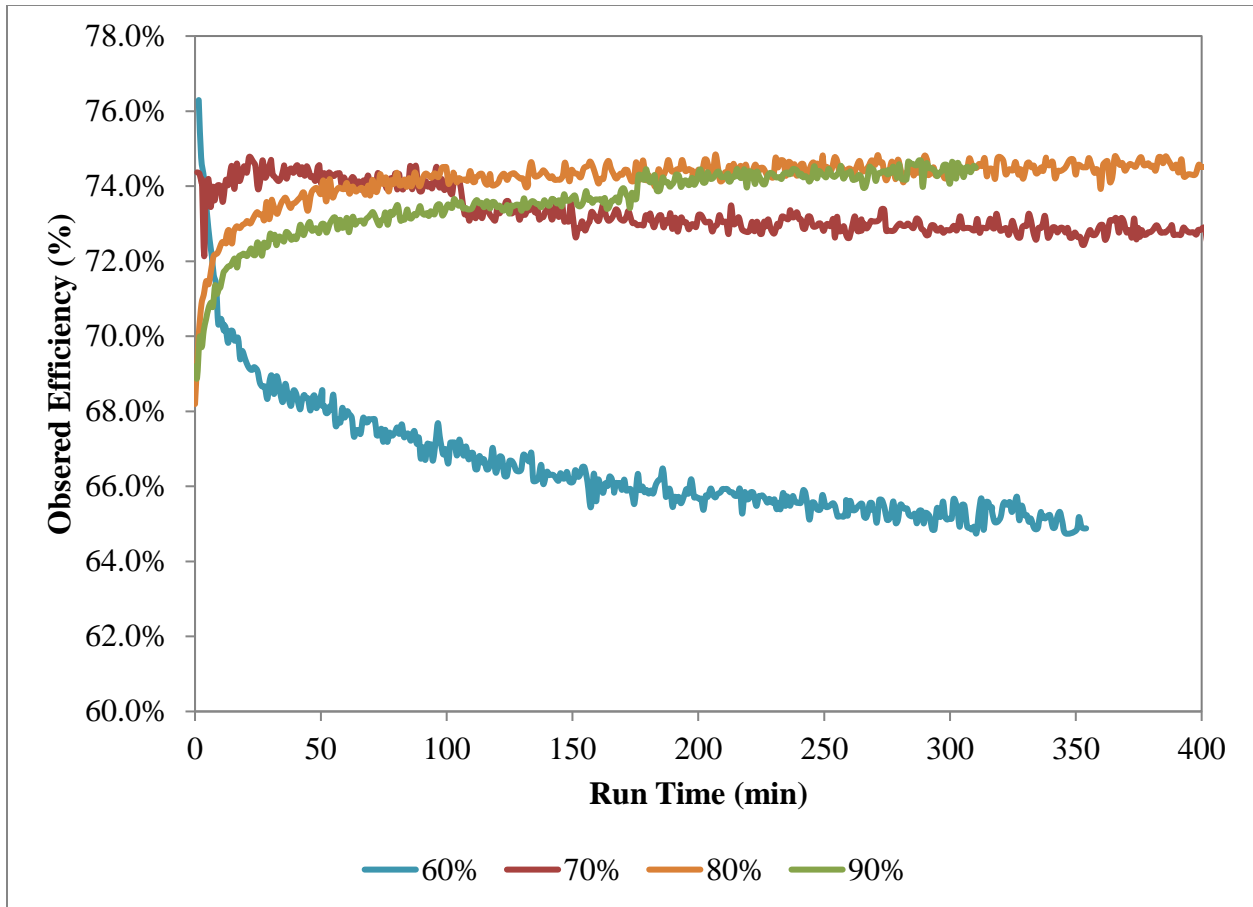


Figure 3-17 – Observed pump efficiency versus run time for multiple pump speeds tested at Unit Well 15.

Power versus run time is shown in Figure 3-18 and Figure 3-19. Like pump flow rate, measured power was greatest during the initial hour of pump operation and decreased to a steady-state power after nearly 3 hours of pump operation. Thus, the power needed to manage the increasing head with pump run time was offset by the power needed to manage the decreasing flow rate with pump run time.

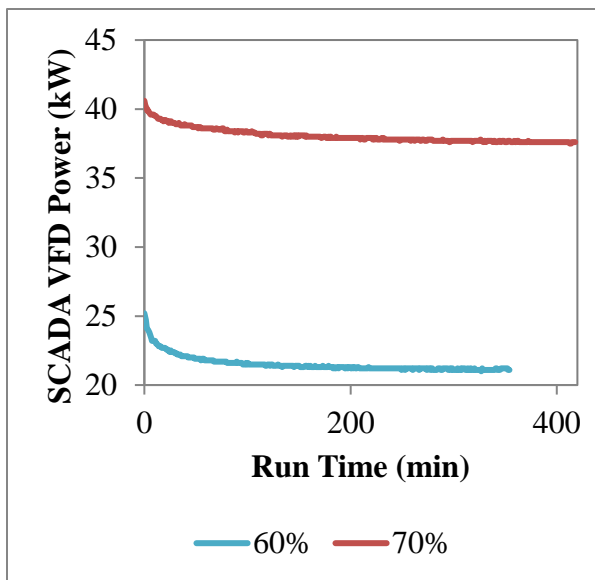


Figure 3-18 – Observed SCADA VFD Power measurements versus pump run time for 60% and 70% pump speed.

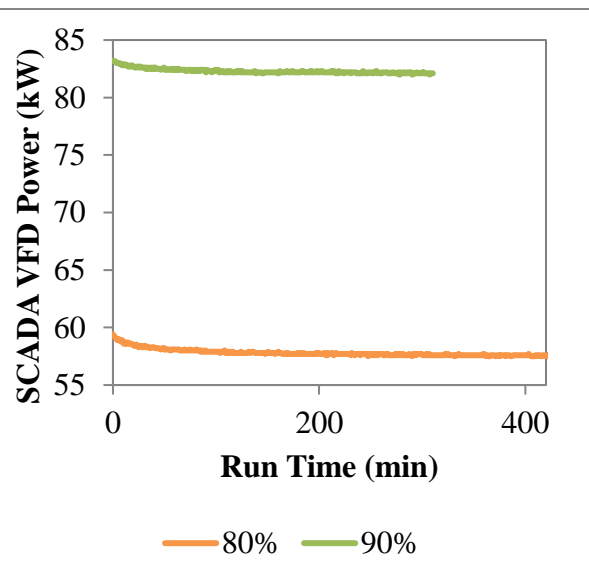


Figure 3-19 – Observed SCADA VFD Power measurements versus pump run time for 80% and 90% pump speed.

Energy intensity versus pump run time is shown in Figure 3-20. As demonstrated in Equation 3-11, energy intensity depends only on the ratio of TDH to pumping system efficiency. Since TDH increases with pump run time, as shown in Figure 3-15, energy intensity was found to increase with pump run time. Like all other observed variables, energy intensity trends towards a steady-state value as the operating point of the pump approaches a steady-state value.

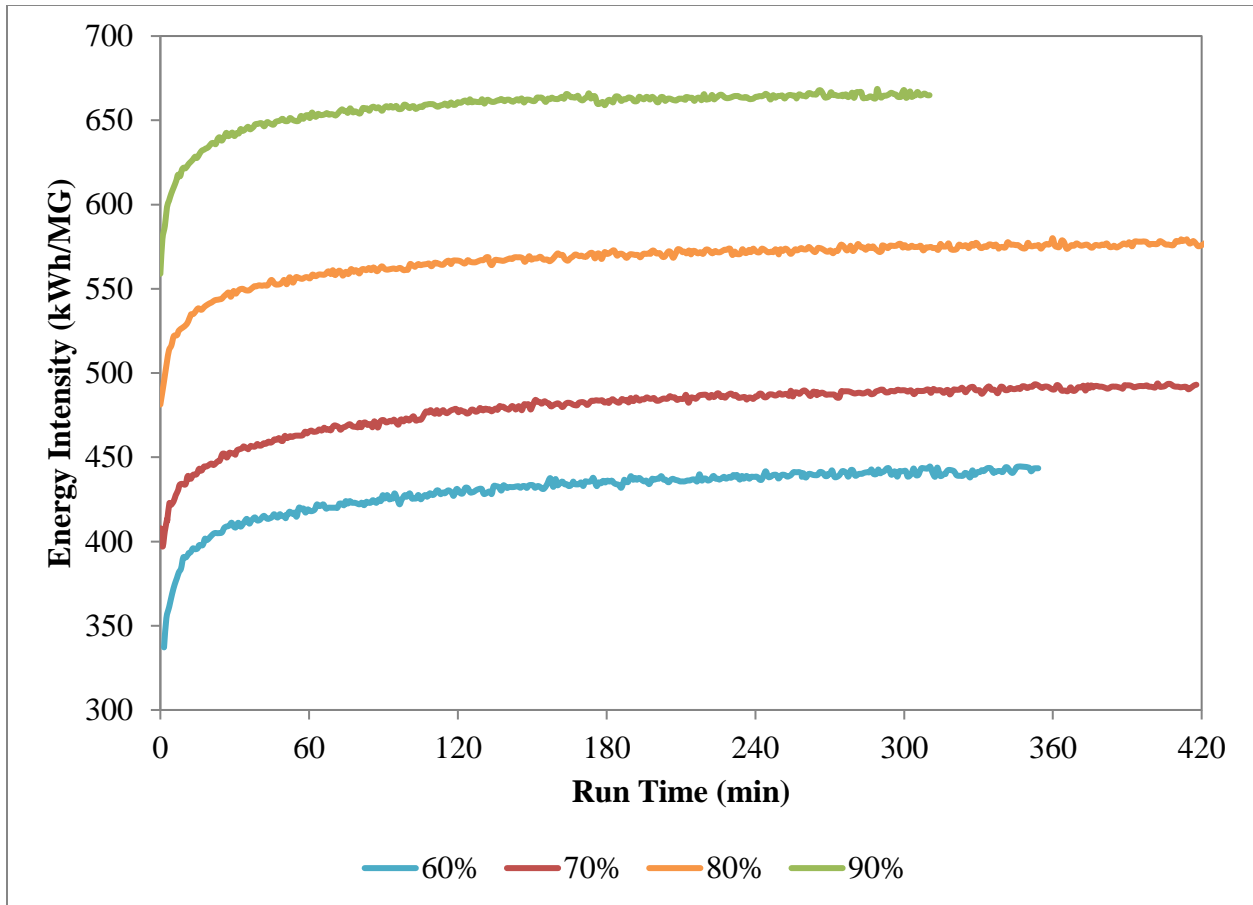


Figure 3-20 – Energy intensity versus run time for all tested pump speeds.

Energy intensity was also plotted against flow rate as shown in Figure 3-21. Each marker represents a single point in time during the test, with points to the lower right representing the first minutes of operation. For the initial time points at a given speed, pumping water level and TDH were low, resulting in lower energy intensity. As TDH increased with pump run time, energy intensity increased.

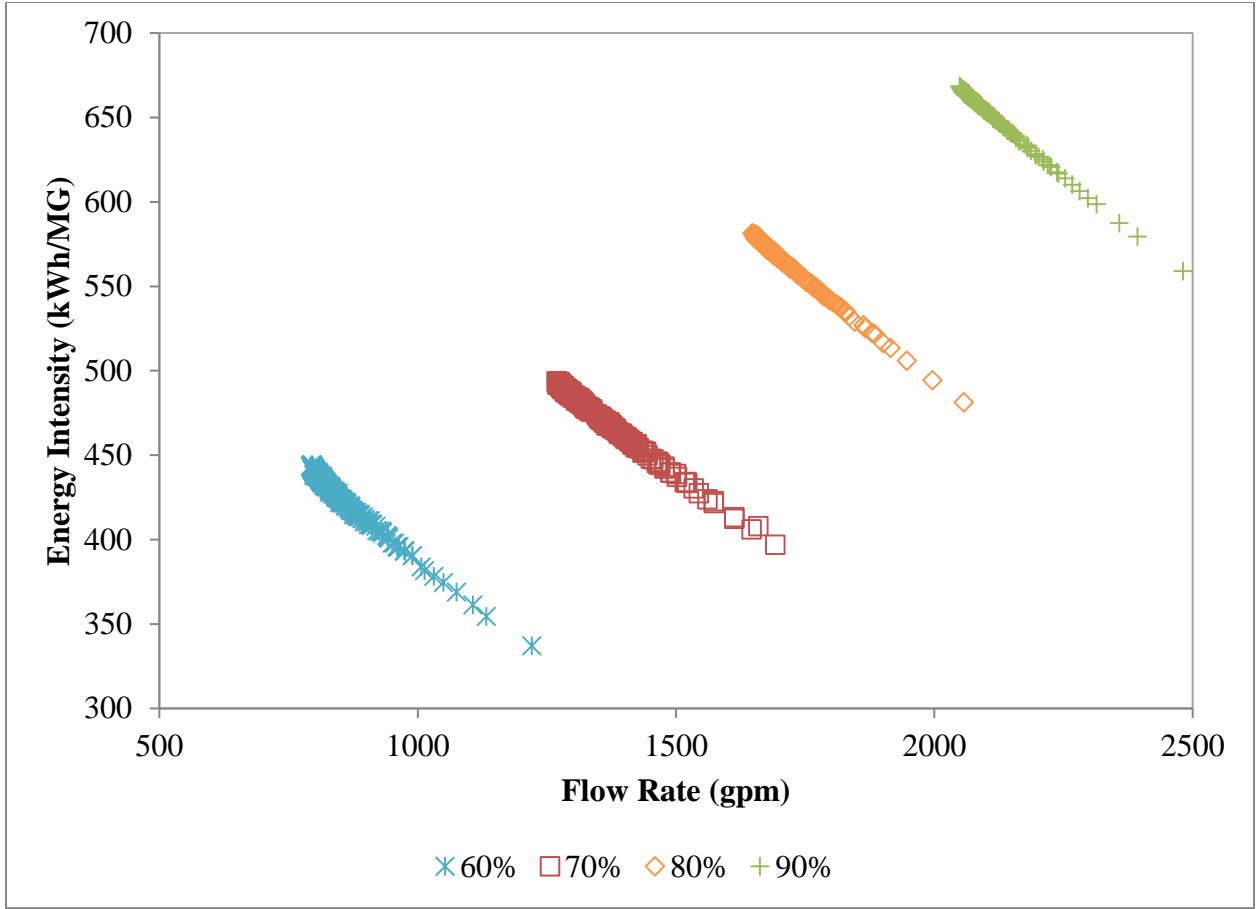


Figure 3-21 – Energy intensity versus flow rate for all tested speeds (Each value represents a single time point during the test).

3.4.1.2.1. Average Operating Conditions and Energy Use

Average operating values and energy use for each tested speed are presented in Table 3-6. Test run length varied, but average operating conditions were only calculated from data collected after five hours of run time.

Table 3-6 – Unit Well 15 test data averages (all values after five hours pump run time).

% Pump Speed	60%	70%	80%	90%
Rotational Speed (rpm)	1,062	1,239	1,416	1,770
Flow Rate (gpm)	843	1,340	1,710	2,080
Pumping Water Level (ft)	75	92	109	127
SCADA VFD Power (kW)	22	38	58	82
SCADA VFD Energy Intensity (kWh/MG)	428	476	564	658

3.4.1.3. *Comparison of Observed Performance with Estimated Performance for Unit Well*

15

System head curves and average operating points from the estimation and field test are plotted with the variable speed curves in Figure 3-22. Based on visual inspection of Figure 3-22, the estimated operation of Unit Well 15 generally matched observed behavior. The difference between observed and estimated behavior was mostly attributed to a 7-foot difference in static water level. The static water level was 54 feet during the August 2016 field test, 11% less than the 61 feet used for the estimate based on August 2015 data. Observed specific capacity was 6% less than previously estimated, 32 gpm/ft observed compared to the previous estimate of 34 gpm/ft. This percent difference in specific capacity was about half of the percent difference in static water level, further illustrating the main difference was the static water level.

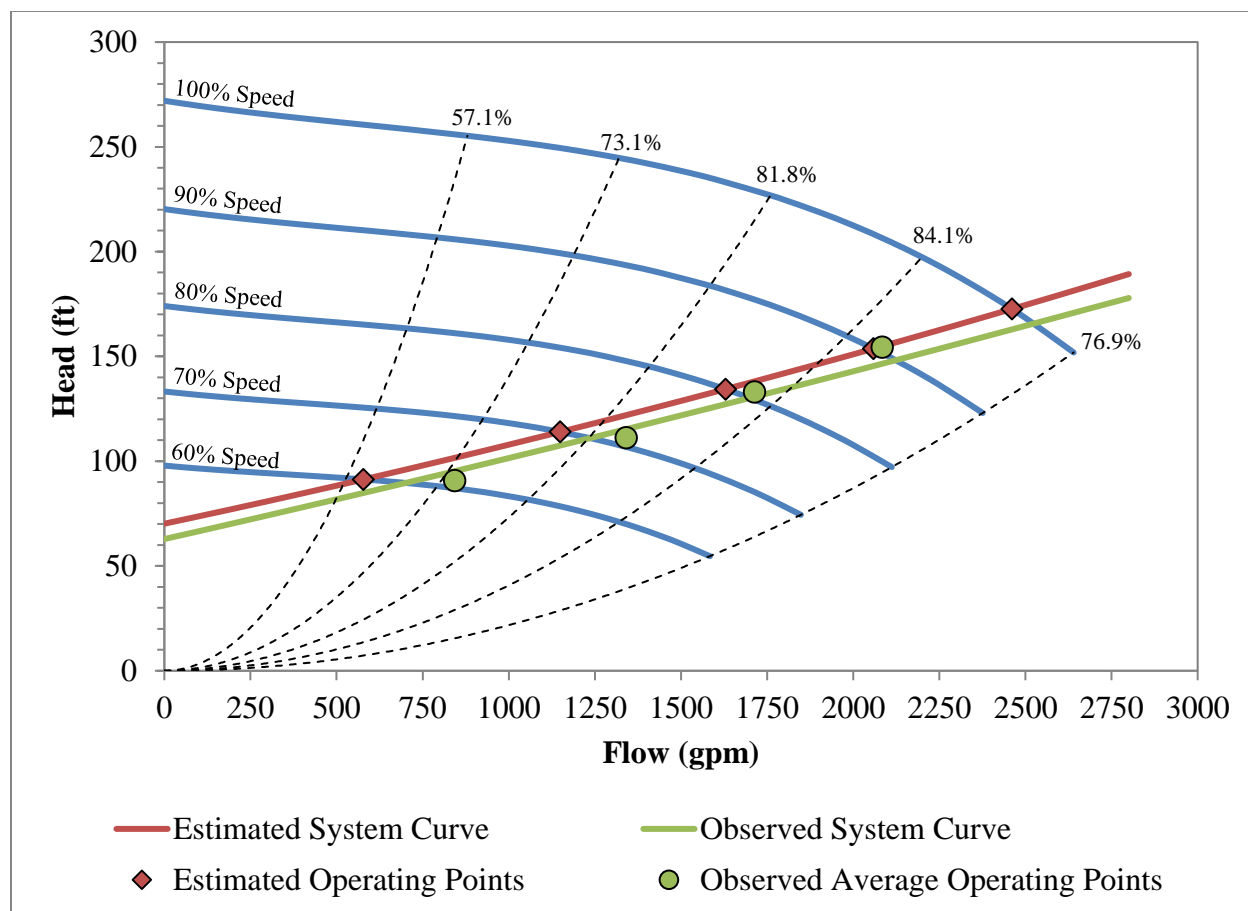


Figure 3-22 – Comparison between estimated and observed operating conditions for Unit Well 15. Estimates were based on observed static water level from August 2015, as well as estimated specific capacity and friction coefficients. Observations were based on observed static water level and specific capacity from August 2016, as well as estimated friction coefficients.

3.4.1.4. Verification of Energy Use Estimation at Unit Well 15

3.4.1.4.1. Comparison of Observed and Estimated Energy Intensities

In order for the developed method to be beneficial for MWU going forward, it was necessary to determine if estimated energy intensity was comparable to observed energy intensity.

A comparison between estimated and observed energy intensities is shown in Figure 3-23.

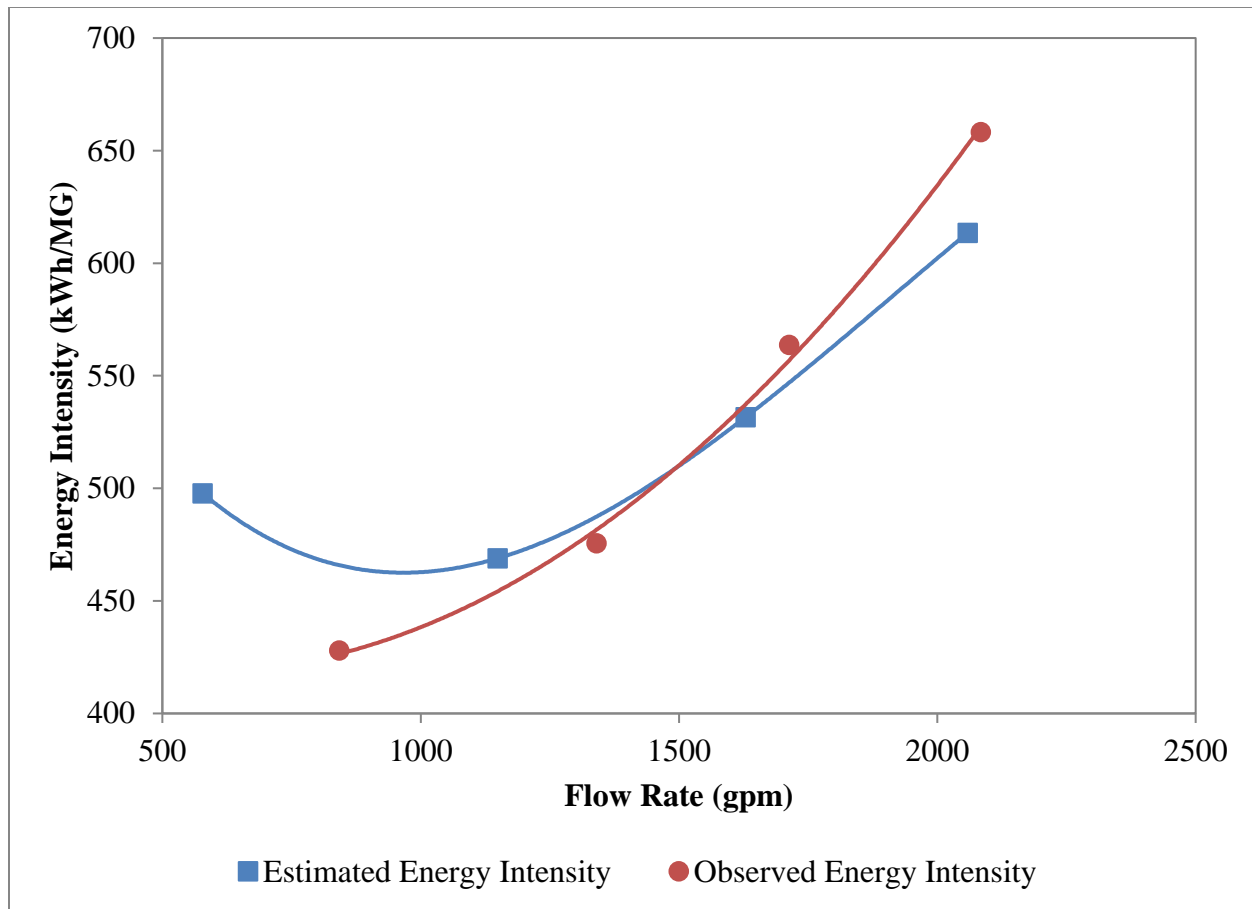


Figure 3-23 – Comparison of observed and estimated energy intensity at Unit Well 15. Estimated energy intensity based on estimated average operating flow rate and head generated from August 2015 data. Observed energy intensity based on August 2016 observed average flow rate and water level with estimated friction coefficients.

Only the tested speeds were compared with estimates, and each point from left-to-right represents one pump speed (60%, 70%, 80%, and 90%). For the range of energy intensities between 70% and 90% speed, the estimated and observed energy intensity curves aligned well. At 70% pump speed, observed energy intensity was 7 kWh/MG less than estimated (1.5%) even though observed flow rate was 17% larger than estimated. For 80% pump speed, observed energy intensity was 6% larger than estimated while the observed flow rate was 5% larger than estimated. At 90% pump speed, observed energy intensity was 44 kWh/MG (or, 7.2%) greater than estimated even though flow rate and TDH were nearly identical. Although the observed average operating

points of the pump were not the same as estimated operating points, the energy intensity curves were comparable for flow rates between 1,250 gpm and 2,000 gpm.

Outside this range of flow rates, there were more noticeable differences between estimated and observed energy use. Observed energy intensity at 60% speed was 430 kWh/MG, 14% less than the estimated 500 kWh/MG.

Some of the difference between estimated and observed can be attributed to the differences in the system head curves. Higher static head combined with higher specific capacity for the estimated energy use resulted in estimated average operating points with lower flow rate and higher TDH, and different pumping efficiencies. In the most extreme case, the observed flow rate at 60% speed was 840 gpm compared to an estimated 580 gpm, a difference of 45%; while the head values for both cases were approximately 91 feet. From interpolation of pump efficiency at each operating point, the result was an estimated 13.5% difference in pump efficiency (74.1% at the observed 840 gpm and 60.6% at the estimated 580 gpm). Going back to Equation 3-11 in Section 3.3.1, energy intensity is a function of head and efficiency. Both operating points at 60% speed had the same head, but the large difference in efficiency accounts for the difference in energy intensity.

The significant difference in the average operating point and energy use at 60% speed highlights potential issues for operation at low pump speeds. At low pump speeds and flow rates, the average operating point may fall on the portion of the variable speed pump curve where relatively small changes in TDH result in large changes in pump flow rate. Static water level fluctuates throughout the year for MWU wells, which could shift the system head curve and potentially have significant effects on pump flow rate and efficiency at these low pump speeds.

Energy intensity at low speeds may vary throughout the year, making estimates of energy use and savings harder to characterize.

Energy intensity estimates were within 10% of observed values (except for 60% pump speed), an acceptable difference given the assumptions made to estimate energy use. Even with seasonal and long-term variations in the system head curve, the developed method should generally capture energy intensity for a given pump speed.

Figure 3-23 compared observed energy intensity from August 2016 with energy intensity estimates based on (1) the estimated system head curve from August 2015, which was based on the observed static head and specific capacity from August 2015, and (2) the pump efficiencies derived from the Affinity Laws and the manufacturer's pump curve. To further illustrate that a difference in static water level was the primary cause of differences between observed and estimated values, Figure 3-24 provides a comparison of observed energy intensity from August 2016 with energy intensity estimates based on static water level and specific capacity that were observed during that same time period. Thus, for this figure, the pump efficiencies derived from the Affinity Laws and the manufacturer's pump curve provide the only differences between the observed energy intensities and the estimated energy intensities.

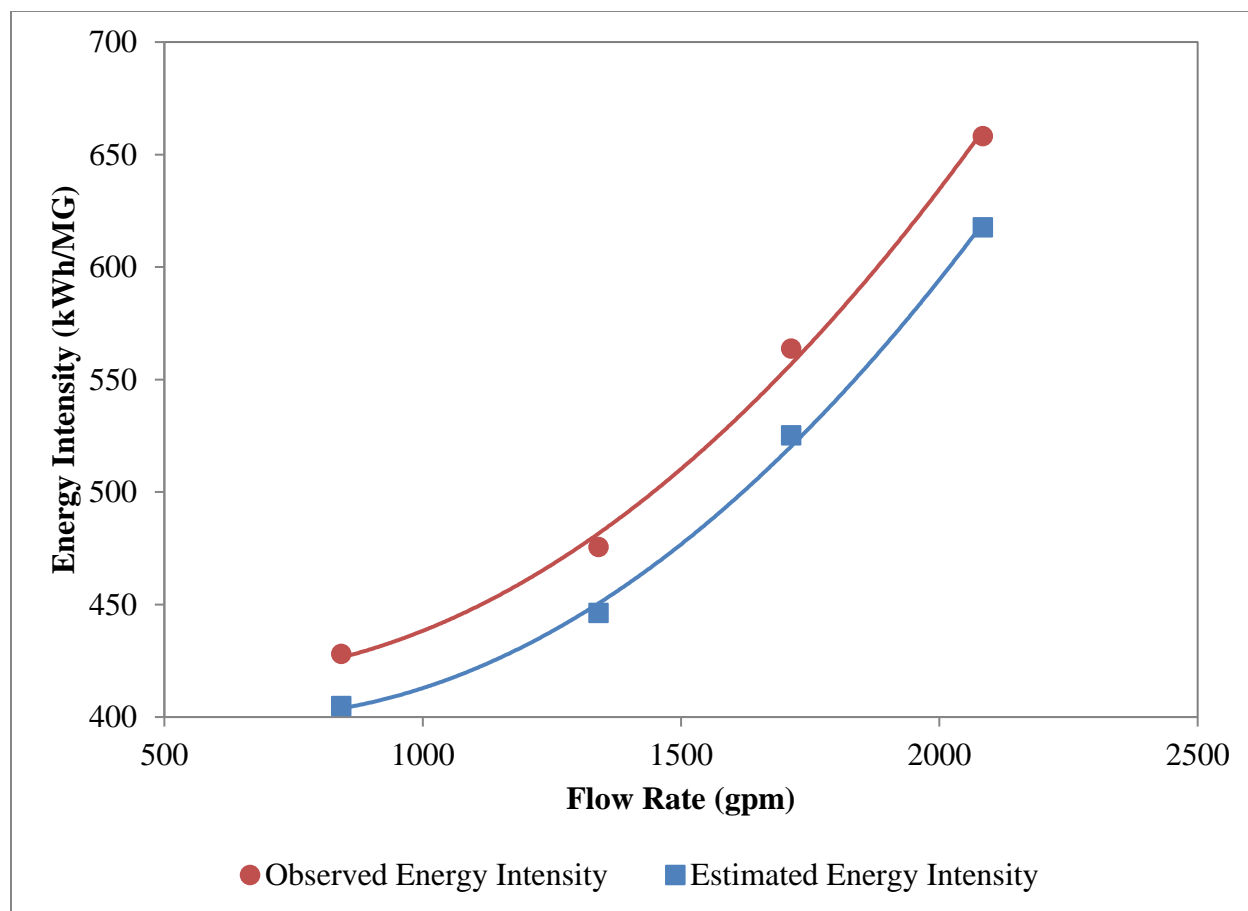


Figure 3-24 – Comparison of energy intensities for test average operating conditions. The observed energy intensity based on SCADA VFD power is shown in red. Energy intensity calculated using estimates of pump and motor efficiency is shown in blue.

Estimated energy intensities for this analysis were 93-95% of observed energy intensity based on SCADA measurements of VFD power, compared to 86-107% of observed energy intensity for Figure 3-23. This estimated energy intensity curve was essentially parallel to the observed curve, indicating the difference was likely due to an efficiency factor that was independent of flow rate. For this analysis, the observed wire-to-water efficiency was 3.5-5.5% less than the estimated wire-to-water efficiency. A lower operating motor efficiency or diminished pump efficiency could have resulted in the uniform gap noted in Figure 3-24.

3.4.1.4.1. Energy Intensity Savings Magnitude

The differences between the observed and estimated energy intensity curves, shown in Figure 3-23, had a significant effect on the predicted energy savings. Observed energy intensity savings magnitude was greater than previously estimated. Energy intensity at 90% speed was observed to be 658 kWh/MG with a minimum observed value of 428 kWh/MG at 60%, a savings of 230 kWh/MG. Maximum estimated pump energy intensity savings from August 2015 estimates were 237 kWh/MG from reduction in speed from 100% speed to 65% speed. Estimated pump energy intensity savings from 90% speed to 60% were only 116 kWh/MG, 50% less than observed. The difference in the average operating point and pumping system efficiency for the estimated and observed operating points at 60% speed were mainly responsible for this noticeable difference in savings magnitudes. When the energy intensity curves shown in Figure 3-24 were compared, energy savings magnitude was more comparable. Observed energy savings of 230 kWh/MG were 8% larger than the 213 kWh/MG estimated.

While observed energy intensities at each pump speed were within 10% of estimated values, observed energy savings magnitudes differed by as much as 50% from estimates, due to the differences in the average operating points and efficiency. The variability in the system head curve could make estimates of energy savings magnitudes difficult to accurately predict, but the method appears conservative for this combination of well and pump properties.

3.4.1.5. Comparison of SCADA and Power Meter Data

Power measurements collected with the power meter were compared with SCADA measurements and showed differences between the two data sources. SCADA VFD power was greater than measured with the power meter for all tested pump speeds. For tests at 70%, 80%, and 90%, SCADA VFD power was 1-5% (1 to 3 kW) larger than the average power across all three

phases measured by the power meter. At 60% speed, the SCADA measurement was 14% larger, but the magnitude of the difference was only 2.6 kW. A comparison of the estimated energy intensity using the average power measured by SCADA and the power meter is presented in Figure 3-25.

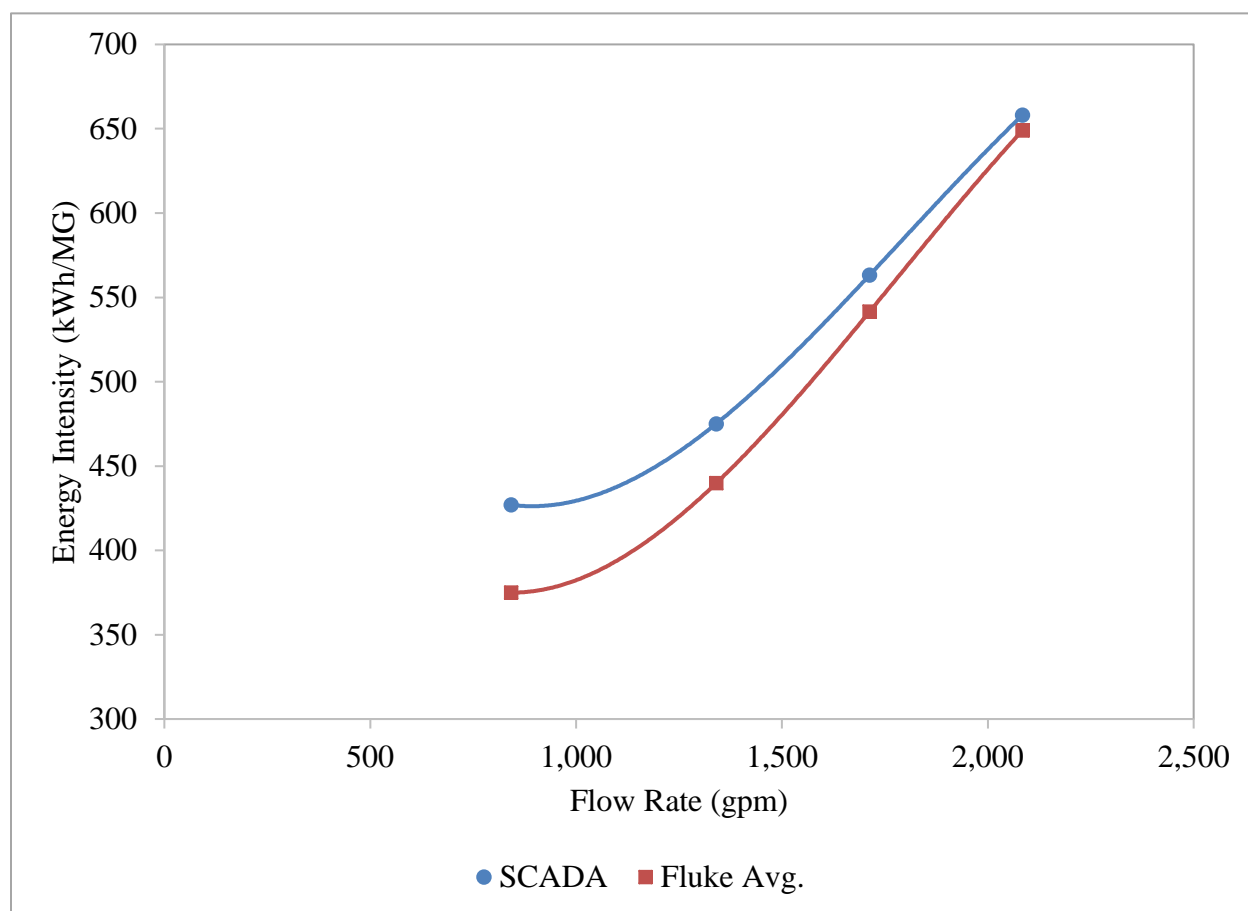


Figure 3-25 – Energy intensity curves for Unit Well 15 based on the two sources of power measurements. Energy intensity derived from SCADA measurements shown in blue and energy intensity derived from power meter measurements shown in red.

Compared to the power meter data, SCADA measured power appears to overestimate energy use. Use of power meter data would result in a larger discrepancy between observed and energy intensity estimates. Given the difficulties in the past with connecting power meters on pumps with VFDs installed, it was unclear if the SCADA measurement was overestimating energy

use or the or if there were measurement errors with the power meter data. The measured power from the two data sources was of similar magnitude, indicating power and energy use were adequately captured with both measurement methods. Going forward, use of SCADA power measurements should be sufficient for characterization of energy use for MWU. The same energy savings benefits were observed using both measurements of pump power.

3.4.2. Unit Well 25

Estimates of pump performance and energy use were based on a week of operating data from August 5 – 11, 2016. The process used to generate estimates for Unit Well 25 was the same as that presented in Section 3.4.1.1 for Unit Well 15. Graphs and full results for estimates at Unit Well 25 are presented in APPENDIX A. Maximum energy intensity savings at Unit Well 25 were estimated to be 250 kWh/MG for a reduction in pump speed from 100% to 75%. The pump was operated at 92% speed during August 2016.

The field test at Unit Well 25 was conducted during December 2016. Similar data to the test at Unit Well 15 were collected, and a full set of data and graphs can be found in APPENDIX A. Average test conditions were determined for a pump run time of 6 hours and are shown in Table 3-7.

Table 3-7 – Unit Well 25 December 2016 VFD test data averages (averages for six hours of pump run time).

% Pump Speed	80%	85%	90%	92%*	95%	100%**
Rotational Speed (rpm)	1,416	1,505	1,593	1,628	1,682	1,770
Flow Rate (gpm)	1,180	1,370	1,560	1,670	1,750	1,960
Pumping Water Level (ft)	206	228	249	255	270	287
SCADA VFD Power (kW)	73	90	109	118	131	155
SCADA VFD Energy Intensity (kWh/Mgal)	1,030	1,090	1,160	1,180	1,250	1,320

*Normal pump cycle run (~4 hours)

**Test only run for 2.9 hours

3.4.2.1. Comparison of Observed Performance with Estimated Performance for Unit Well

25

System head curves and average operating points from the estimation and field test are plotted with the variable speed curves in Figure 3-26. The difference between estimated and observed pump operation was mainly attributed to a 9-foot difference in static water level. The static water level was 94 feet during the December 2016 field test, 9% less than the 103 feet used for the estimate based on August 2016 data. Observed specific capacity was 5% greater than estimated, 10.2 gpm/ft compared to 9.8 gpm/ft. Overall, estimated behavior from August 2016 data was sufficiently close to observed results in December 2016.

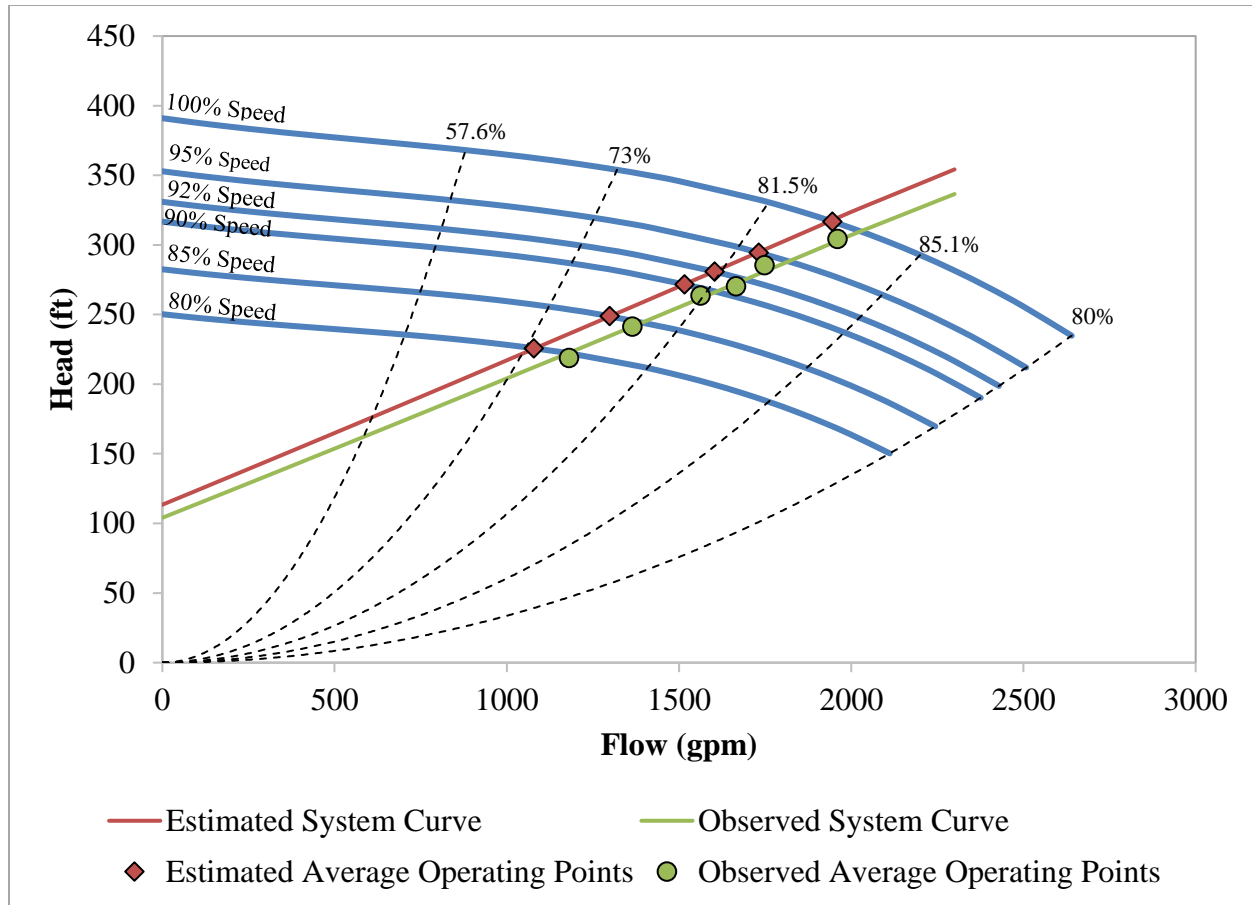


Figure 3-26 – Comparison between estimated and observed operating conditions for Unit Well 25. Estimates were based on observed static water level from August 2016, as well as estimated specific capacity and friction coefficients. Observations were based on observed static water level and specific capacity from December 2016, as well as estimated friction coefficients.

3.4.2.2. Verification of Energy Use Estimation at Unit Well 25

3.4.2.2.1. Comparison of Observed and Estimated Energy Intensities

The comparison between estimated and observed energy intensities is shown in Figure 3-27. Energy intensity estimates made prior to the field testing matched well with observed field test results. Observed energy use values based on the SCADA measured VFD power were 1 – 3% greater than estimated for all speeds tested except for 80% speed (1% less than estimated). Energy intensity estimates closely matched observed values even though the observed average operating

points differed from those estimated. Observed TDH was 3 – 4% lower than estimated (consistent with lower static water level) and pump flow rates were within 5% for all speeds greater than 85%. Energy intensities estimated were all within 5% of observed values even with differences in average operation; showing the estimation method to be highly effective at Unit Well 25 even with variations in the system head curve.

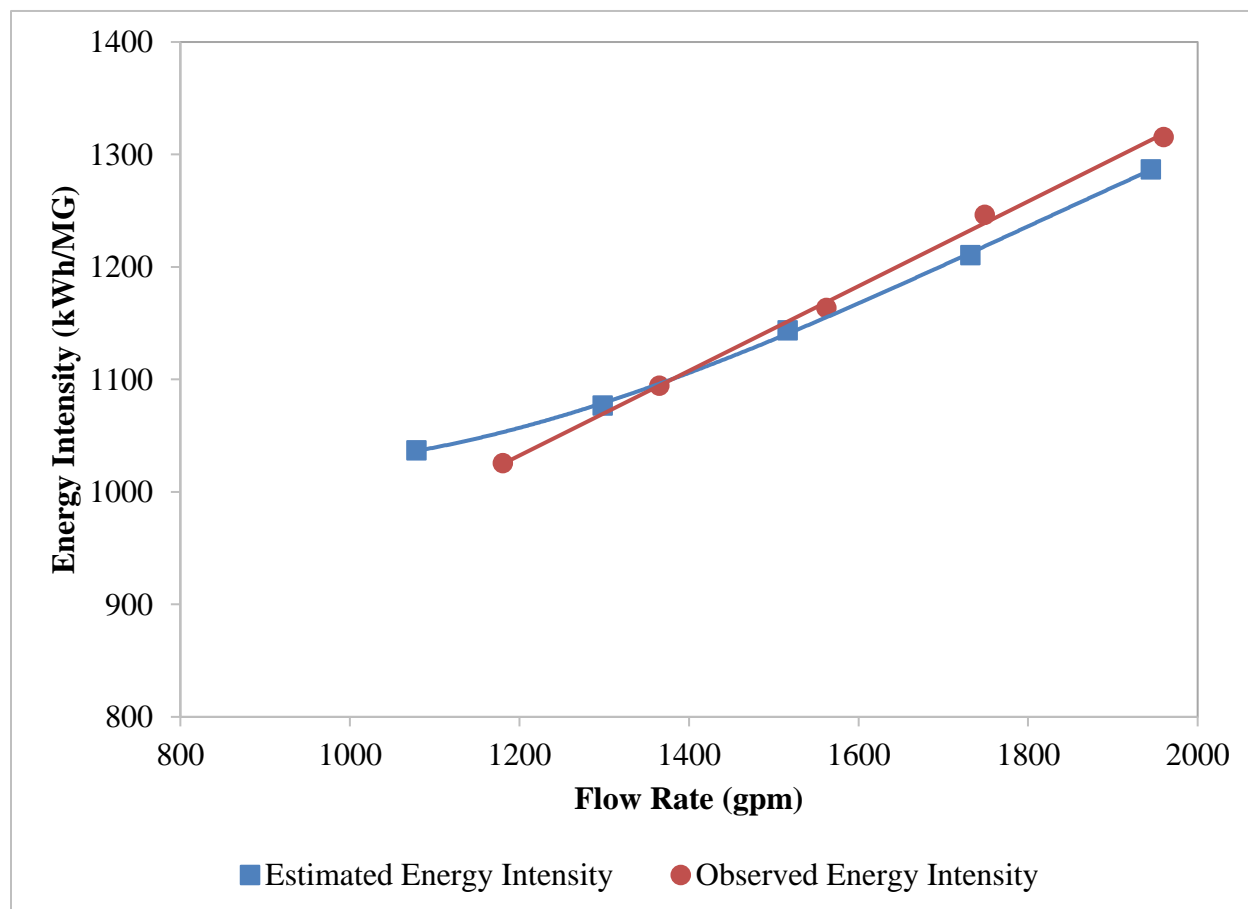


Figure 3-27 – Comparison of observed and estimated energy intensity at Unit Well 25.

3.4.2.2.2. Validation of Pumping System Efficiency Estimation

Like at Unit Well 15, this section provides a comparison of observed energy intensity from December 2016 with energy estimates based on static water level and specific capacity observed during this period. Figure 3-28 shows this comparison.

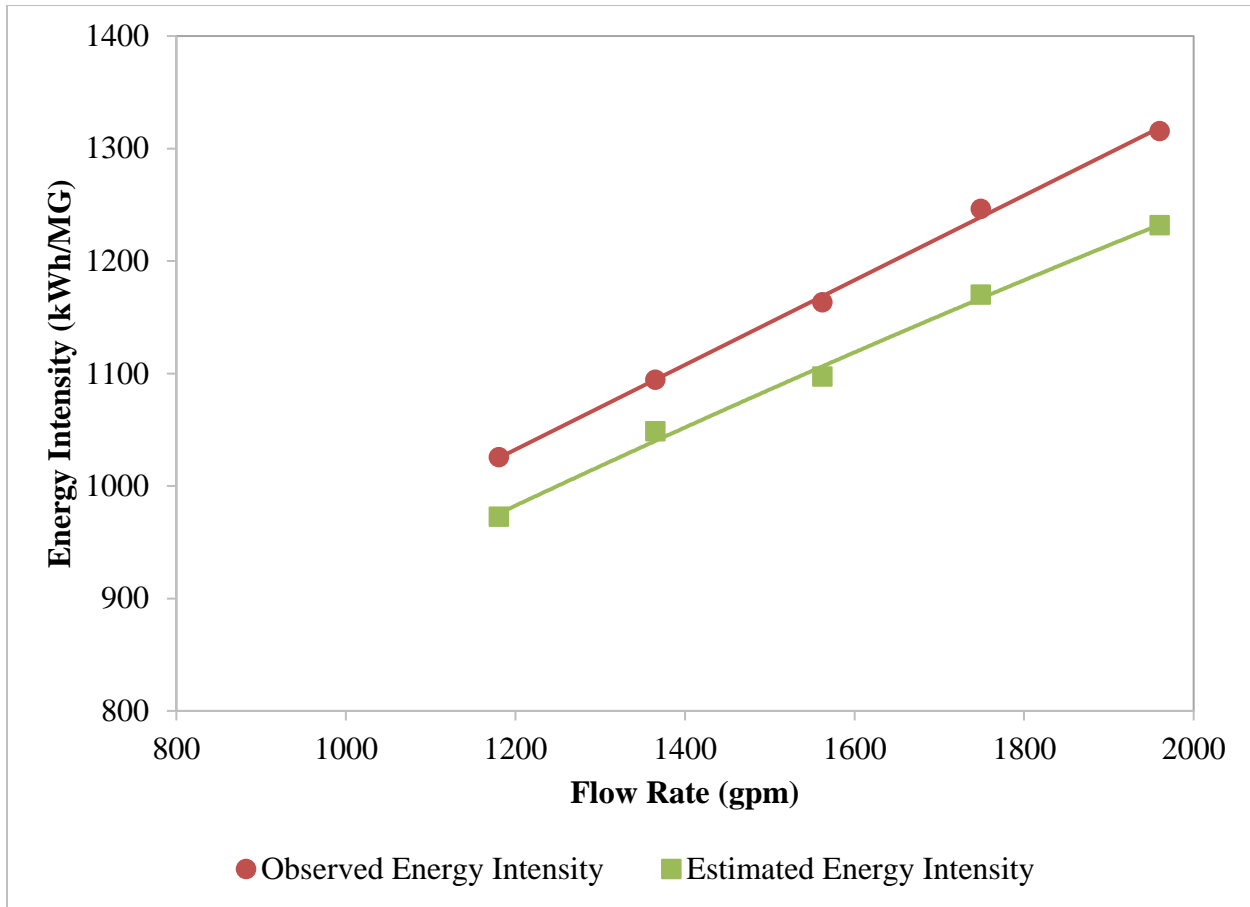


Figure 3-28 – Comparison of energy intensities for test average operating conditions. The observed energy intensity based on SCADA VFD power is shown in red. Energy intensity calculated using estimates of pump and motor efficiency is shown in blue.

Estimated energy intensities from this analysis were 93.5 – 95.8% of observed values, compared to 99 – 103% of observed energy intensity in the previous section. Like at Unit Well 15 the energy intensity curves were nearly parallel due to an efficiency factor independent of flow rate. Observed wire-to-water efficiencies were 4 – 6% less than estimated.

3.4.2.2.3. *Energy Intensity Savings Magnitude*

Once again, the magnitude of observed energy intensity savings was greater than estimated, as shown in Figure 3-27. Observed savings for reduction in pump speed from 100% speed to 80% speed were 290 kWh/MG, 16% greater than the estimated 250 kWh/MG. The difference was

partially attributed to the differences in average operating point. For the 80% speed average operating points, the estimated head was 7 ft greater than observed (226 ft to 219 ft) and pump efficiency was estimated to be 2.4% less (73.4% to 75.8%). Combined, these resulted in a higher estimated energy intensity for 80% speed operation than observed. For the energy intensity curves shown in Figure 3-28, the observed savings of 290 kWh/MG were 12% larger than the estimated 259 kWh/MG. The savings method was shown to be conservative again for this combination of well and pump properties.

3.5. CONCLUSIONS AND RECOMMENDATIONS

The primary objectives of this work were to develop and validate a method for estimating energy savings potential for variable speed operation of existing MWU deep well pumps.

3.5.1. Conclusions

The following conclusions were developed as part of this work:

- MWU and other groundwater utilities can apply the estimation method developed in this paper provided the following information is available:
 - manufacturer's pump curve
 - average flow rate and head under normal operating conditions
 - SCADA operational data for pump flow rates and water levels
 - system head curve
 - static and pumping water levels
 - friction losses
 - reservoir inlet bell elevation

- The estimation method developed in this paper can be used to predict the general performance of a deep well pump with a VFD installed. Variations in the system curve due to changes in static water level and specific capacity will shift the pump's average operating points, but the method adequately captures general pump behavior under variable speed operation.
- Although they were installed to provide greater operational flexibility, installation of VFDs on deep well pumps at Unit Wells 15 and 25 reduced drawdown and head as expected, and provided noticeable energy savings.
 - At Unit Well 15 reduction in pump speed from 90% to 60% decreased pump flow rate by 1,240 gpm and reduced TDH by 64 feet, for an energy savings of 230 kWh/MG.
 - At Unit Well 25 reduction in pump speed from 100% to 80% speed decreased pump flow rate by 780 gpm and reduced TDH by 85 feet, for an energy savings of 290 kWh/MG.
- Energy intensity estimates were generally within 10% of observed values at both tested wells, an acceptable difference given the assumptions made to estimate energy use. Variations in the system head curve, seasonal or long-term, made predictions of energy savings magnitudes more difficult to accurately predict. The method for estimating energy savings still effectively captures general behavior, and appears to be conservative for this combination of well and pump properties.
- Observed pumping system efficiency was shown to be 4 – 6% lower than values estimated based on the Affinity Laws and manufacturer's performance curves for both wells. The difference was shown to be independent of flow rate, and energy savings benefits were still

observed even with this decreased efficiency. The methods for described in this paper are still effective for capturing pumping system efficiency under variable speed operation.

3.5.2. Recommendations

- Groundwater utilities should apply the developed method to characterize pump operation and energy intensity for variable speed operation across all deep well pumps in their system. For example, MWU should expand this analysis to all 22 wells in its system.
- Groundwater utilities should use their estimated energy intensities to quantify the energy savings potential for each deep well pump in their system. It is important to consider the average operation of each well and identify the most energy-efficient speed capable of meeting average daily production. Use this speed when estimating energy savings. MWU should consider the average production of all 22 wells in its system.
- When developing estimates of energy savings, groundwater utilities should be cognizant of the potential variation in pump operation due to variations in the system head curve that result from changes in static head and specific capacity. Energy savings magnitudes will be impacted by these variations in pump operation, and differences will be most significant at low pump speeds and flow rates.
- Use estimated energy savings to rank candidates for VFD installation based on expected yearly cost savings to maximize return on investment. For well pumps with adequate return on investment, develop capital and operational plans needed to proceed with VFD installation.

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CHAPTER 4 – IDENTIFICATION OF DEEP WELL PUMP CANDIDATES FOR VFD INSTALLATION FOR MADISON WATER UTILITY

Abstract: Variable frequency drives (VFD) may save groundwater-supplied utilities energy through reductions in drawdown. The purpose of this work was to identify the strongest deep well candidates for VFD installation in the Madison Water Utility (MWU) system. The previously developed method from Mancosky (2017a) was used to estimate pump operation and energy intensity for all deep well pumps. Energy savings were estimated for MWU’s current operational strategy, and cost savings were based on the average energy cost for MWU. Energy savings potential from VFD installation was found to depend on each well’s unique combination of well and pump characteristics. Half of the deep well pumps were estimated to meet MWU’s desired return on investment, with multiple wells estimated to save over \$15,000 per year. Groundwater utilities are encouraged to perform a similar analysis for their systems.

4.1. INTRODUCTION

Drinking water utilities supplied with groundwater may save energy by installing variable frequency drives (VFDs) on deep well pumps, provided there is operational flexibility to do so. For example, a constant-speed deep well pump that meets system demand at 12 hours/day could meet system demand at 18 hours/day with a VFD installed, pumping with a 33% reduction in flow rate. The maximum possible reduction in flow rate would be 50%, because this would require 24 hour/day operation. This reduced flow rate would reduce the drawdown in the well, thereby reducing the amount of lift needed to elevate the water from the aquifer to the drinking water

distribution system. The attained reduction in lift depends on the specific capacity of the well – wells with lower specific capacity provide greater reductions in lift. The energy saved depends on the lift reduction achieved (i.e., the specific capacity of the well), the performance curve and efficiencies of the pump, and the amount of flow reduction permitted by demand needs and system storage capacity.

As an example, Madison Water Utility (MWU) has installed VFDs on several wells, including Unit Wells 15 and 25 (Mancosky 2017a). At Unit Well 15, the deep well pump has the capacity to operate at 2,520 gpm with a total lift of 166 ft. With a VFD controlling the pump to 70% of full speed, this pump has operated at 24 hr/day and 1,250 gpm with a total lift of 111 feet. Thus, this VFD achieved a 32% reduction in head in exchange for a doubling of the pump's run time, corresponding to a 36% reduction in energy intensity from 744 kWh/MG to 476 kWh/MG. At Unit Well 25, VFD installation and pump operation at 92% speed reduced energy intensity by 136 kWh/MG with a 35-foot reduction in total lift and a 295 gpm reduction in flow rate.

Based on these observations, MWU sought to determine which wells in the system would yield the most significant energy savings upon VFD installation. This paper is the second of three papers centered on energy savings benefits from deep well pump VFD installation, (1) developing a method for estimating energy savings from deep well VFD installation, (2) utilizing the method to rank wells based on energy savings, and (3) demonstrating the observed benefits through installation of a VFD at the top-ranked well. The objectives of this work were to:

1. Use the method developed and verified in the previous paper (Mancosky 2017a) to characterize pump operation and energy use for variable frequency drive installation on all 22 MWU Unit Wells.

2. Rank all 22 deep well pumps based on MWU's existing operational strategy to identify the strongest candidates for future installations.
3. Establish an acceptable return on an investment to determine project feasibility.
4. Determine whether specific capacity and pump characteristics are indicators of energy savings potential.

4.2. METHODS

4.2.1. Data Analysis Methods

4.2.1.1. *Overview of Approach*

A schematic of a typical MWU unit well configuration is shown in Figure 4-1. All MWU deep well pumps lift water to a fixed-elevation inlet above the stored water level in an on-site reservoir. When the deep well pump is operating, the total elevation the water must be lifted is predominantly the pumping water level plus the reservoir lift. Booster pumps are used to lift water from each reservoir into the distribution system. As discussed later, flow rate is monitored on the reservoir inlet for 12 of the 22 unit wells and on the reservoir outlet for all 22 unit wells.

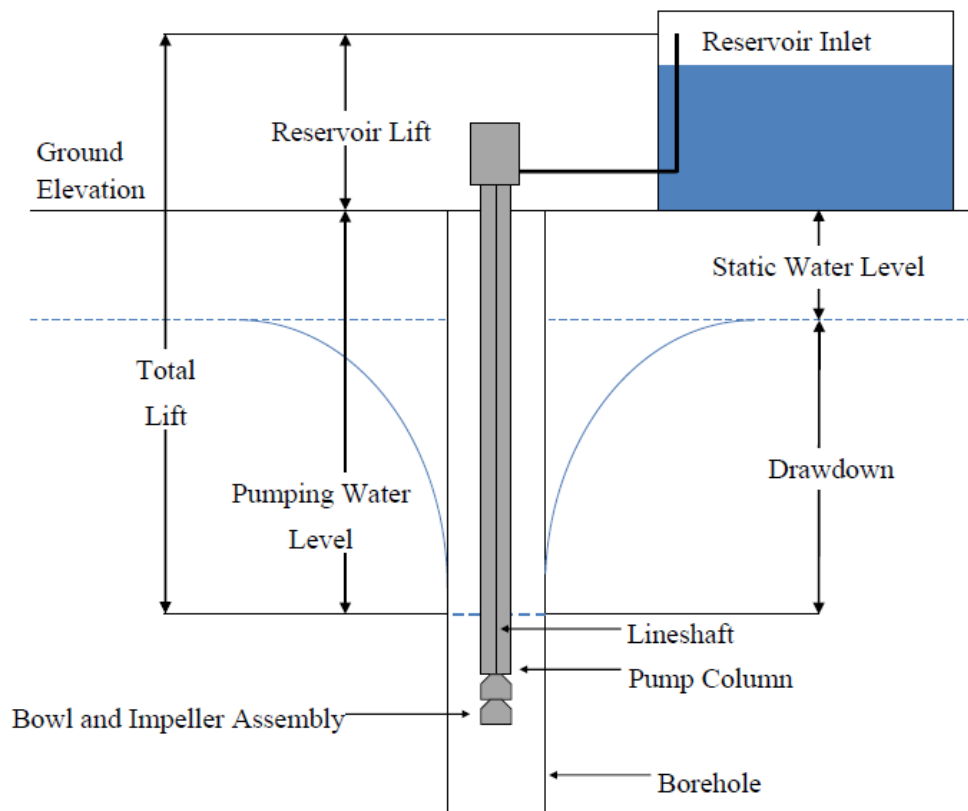


Figure 4-1 – Typical MWU deep well pump configuration with relevant geologic and pump properties.

To identify the top candidates for VFD installation, the previously validated method (Mancosky 2017a) was applied to each of the 22 deep well pumps in the MWU system. Methods presented here highlight further details and differences from the standard methodology. Site-specific differences and alternative methods are covered in APPENDIX B.

4.2.1.2. Average Operating Points

Average operating flow rate and head for a one-week operating period were used to determine the existing average operating point at all wells. For 16 of the 22 analyzed wells, the selected week was the second week of August 2015. The weeks used for the remaining 6 wells are

described in APPENDIX B. Data were taken from August because all MWU wells are generally in-service and operating.

At the time of this study, flow meters were installed on the discharge from 12 of the 22 deep well pumps to monitor flow rate. For 8 of these 12 wells, average flow rate was calculated by dividing the total volume pumped in a day by the total run time of the deep well pump. For the other four wells a more complete set of flow rates were available at approximately 30-second intervals, and the average deep well pump flow rate was taken as the average of these values while the pump was running.

For the remaining ten sites, deep well flow rate was estimated using total station water pumpage, which is monitored at the reservoir outlet for all unit wells. Over an extended time, the total volume pumped by the deep well pump is equivalent to the volume of water pumped from the site. Average daily flow rate was estimated by dividing the total station discharge volume by the total deep well pump run time for each day of the week. These daily flow rates were averaged to give the operating flow rate for the deep well pump.

The average operating point was plotted on the same graph as the system curve and the manufacturer's pump curve to assess whether the pump was operating as expected. For 16 of the 22 wells evaluated, the pump was operating as expected. A pump was deemed to be operating as expected if the head at the average operating flow rate was within 5% of the head predicted at that flow rate based on the manufacturer's pump curve. For the remaining 6 wells, the average operating point fell on the system head curve, but more than 5% below the head on the manufacturer's pump curve, as shown in Figure 4-2 for Unit Well 14. Reasons for the decrease in pump performance at the 6 wells were not investigated as part of this analysis but can include wearing of the pump impeller, misalignment of pumping components, or development of holes in

the pump column. After consulting with MWU staff, wells with operating points well below the 100% speed curve were analyzed as if the impeller size had decreased. For these sites, the intercept of the polynomial fit for the 100% speed curve was shifted so the adjusted pump curve went through the estimated operating point. Shifted curves corresponded to a 1/8" – to 3/4" reduction in impeller diameter. All estimates of energy savings benefits from VFD installation were based on this shifted pump curve.

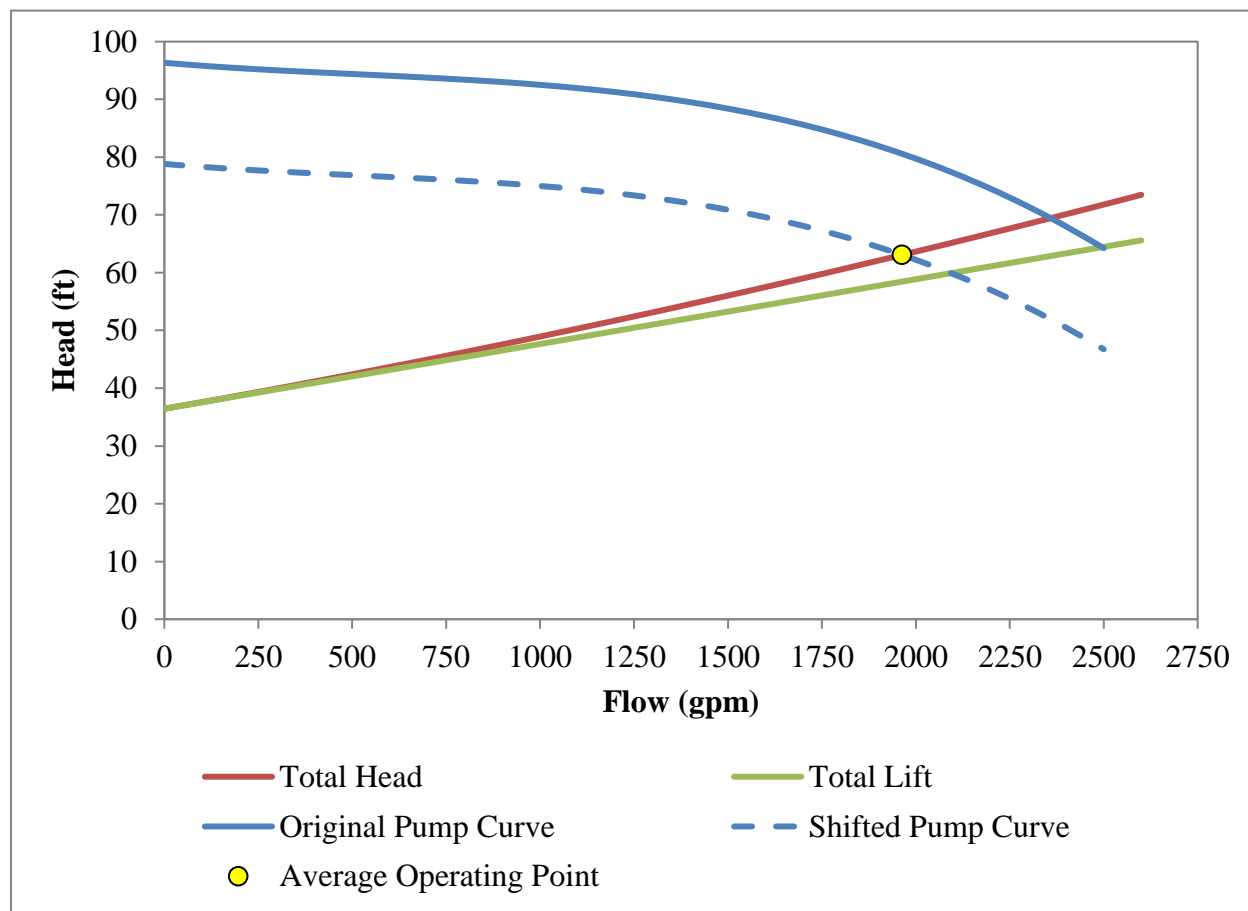


Figure 4-2 – Original UW 14 deep well pump curve with shifted pump curve to reflect average operating conditions.

4.2.1.3. *Estimated Energy and Cost Savings*

Estimated energy savings were calculated relative to energy use at 100% speed using Equation 4-1. Cost savings estimates were calculated using the 2015 average energy cost across all unit wells of \$0.11 per kWh, as shown in Equation 4-2 (PSC 2015). Additional savings from VFD speed reduction can be realized through fewer daily pump start-ups and lower peak energy demand during pump start up, but these benefits were not accounted for in savings estimates.

Well rankings were based on yearly cost savings for two different operating scenarios. The first ranking was based on MWU's average operational strategy for all 22 unit wells between 2011 and 2015. Utility pumpage records were used to determine the average volume pumped at each site on days the site was operational (see Table 4-1). Daily energy savings were based on this average deep well pump production. The most energy-efficient VFD speed capable of providing this average daily volume was selected for energy savings calculations. Yearly savings were based on the average daily savings, which was multiplied by the average number of days operational (2011-2015). Sites were ranked based on estimated yearly cost savings from VFD installation and operation at the selected speed.

Energy and cost savings were also ranked for uniform operation of all 22 unit wells as a second scenario. Total utility-wide production for all 22 unit wells was averaged over the 2011-2015 period and divided by 22 to approximate an operational strategy where all wells produce equally at 1.3 MGD. All wells were assumed to operate 365 days per year pumping this volume.

$$\text{Daily Energy Savings} \left(\frac{\text{kWh}}{\text{day}} \right) = (EI_{100\%} - EI_i) * V \quad (4-1)$$

$$\text{Cost Savings} \left(\frac{\$}{\text{year}} \right) = (EI_{100\%} - EI_i) * V * \# * \$0.11 \frac{\$}{\text{kWh}} \quad (4-2)$$

Where: $EI_{100\%}$ = pump energy intensity at 100% speed (kWh/MG)

EI_i = pump energy intensity at i% of full speed (kWh/MG)

V = average daily volume pumped (MG)

= average number of days deep well operating per year (Days)

4.2.2. Overview of Average Operating Conditions

Average operating conditions for MWU's deep well pumps varied greatly across the system (See Table 4-1).

Table 4-1 – Summary of deep well average operating conditions for the second week of August 2015 (See APPENDIX B for descriptions of wells with operating data other than August 2015).

Unit Well	Operating Flow Rate (gpm)	Static Water Level (ft)	Pumping Water Level (ft)	Drawdown (ft)	Specific Capacity (gpm/ft)
6	2,810	31	153	122	23.1
7 ^a	1,490	59	124	66	22.7
8	1,980	64	136	72	27.6
9	1,710	114	179	64	26.5
11	2,140	35	148	114	18.9
12	2,400	191	262	71	33.7
13	2,570	17	95	78	33.1
14	1,960	29	51	22	89.2
15 ^b	1,240	61	97	36	34.3
16	2,370	176	266	89	26.5
17	2,350	51	117	66	35.7
18	1,830	102	309	207	8.5
19	2,440	67	217	150	16.3
20	2,000	288	400	112	17.8
23	1,220	59	118	59	20.5
24	1,970	43	205	162	12.1
25 ^c	1,580	103	264	161	9.8
26	1,990	347	412	65	28.4
27	1,850	104	203	100	18.5
28	2,240	159	296	137	16.4
29 ^d	1,150	102	179	77	14.9
30	2,370	148	287	139	17.0

^aVFD set for flow rate of 1,500 gpm

^bVFD set for flow rate of 1,250 gpm

^cVFD set to run at 92% speed

^dVFD set for flow rate of 1,150 gpm

Operating flow rates ranged from 1,150 to 2,810 gpm. Wells on the low end of this range either had VFDs (Unit Wells 15 and 29), or in the case of Unit Well 23, had a smaller pump sized for 1,200 gpm design flow rate. Excluding these wells, representative midrange wells were Unit Wells 11 and 28 (2,140 and 2,240 gpm) with Unit Wells 6 and 13 (2,810 gpm and 2,570 gpm) representing the high end.

The average pumping water level for all wells was 205 ± 97 feet. Unit Well 14 represented the low end at 51 feet, Unit Well 27 represented the middle of the wells at 203 feet, and Unit Well 26 represented the high end at 412 feet.

Average drawdown for all wells was 99 ± 46 feet, representing about half of the depth to the average pumping water level. Unit Well 14 (22 feet) represented the low end, Unit Well 27 represented the middle (100 feet), and Unit Well 24 represented the high end (162 feet).

The average static water level for all the wells was 107 ± 84 feet. To simplify discussion, wells were classified into three groups based on their static water level: low (<100 feet; Unit Wells 6, 7, 8, 11, 13, 14, 15, 17, 19, 23, and 24), medium (100-200 feet; Unit Wells 9, 12, 16, 18, 25, 27, 28, 29, and 30), and high (>200 feet; Unit Wells 20 and 26).

The average specific capacity for all wells was 25.3 ± 16.2 gpm/ft with Unit Well 14 an outlier at 89 gpm/ft, almost four standard deviations greater than the average. Excluding Unit Well 14, average specific capacity was 22.3 ± 7.8 gpm/ft. Like the classification of static water level, wells were classified by specific capacity to simplify discussion, such that 50% of all wells were medium specific capacity wells. Low specific capacity wells were below 16.6 gpm/ft (Unit Wells 18, 19, 24, 25, 28, and 29), medium specific capacity wells were between 16.7 and 28.0 gpm/ft (Unit Wells 6, 7, 8, 9, 11, 16, 20, 23, 27, and 30), and high specific capacity wells were greater than 28.1 gpm/ft (Unit Wells 12, 13, 14, 15, 17, and 26).

4.3. RESULTS AND DISCUSSION

4.3.1. Energy Savings from VFD Installation

Energy savings potential from VFD installation was examined for all MWU deep well pumps. This section shows full results and detailed analysis for Unit Well 30 and summary results for the remaining 21 wells. Detailed results for these all wells are presented in APPENDIX C.

4.3.2. Energy savings at Unit Well 30

Unit Well 30 used 2,140 kWh/MG in 2015, above the MWU average of 1,860 kWh/MG. Unit Well 30 had a specific capacity of 17.0 gpm/ft, below the average of 22.3 gpm/ft (UW 14 excluded). It is in the middle 50% of MWU specific capacities, but is at the low end of the range of 16.7 – 28.0 gpm/ft.

The system head curve, variable speed curves, and parabolic pump efficiency curves for the Unit Well 30 deep well are shown in Figure 4-3. Variable speed curves (blue) are shown in 5% intervals down to the lowest speed where the operating point had an estimable pump efficiency, in this case 65% speed. Parabolic pump efficiency curves (black dashes) were plotted back to the origin based on pump efficiencies from the manufacturer's performance test report. Total head and total lift are shown in red and green, respectively, with the estimated average operating point shown with a yellow dot at 2,365 gpm and 309 ft of total head. The slope of the total lift line is equal to the inverse of the well's specific capacity.

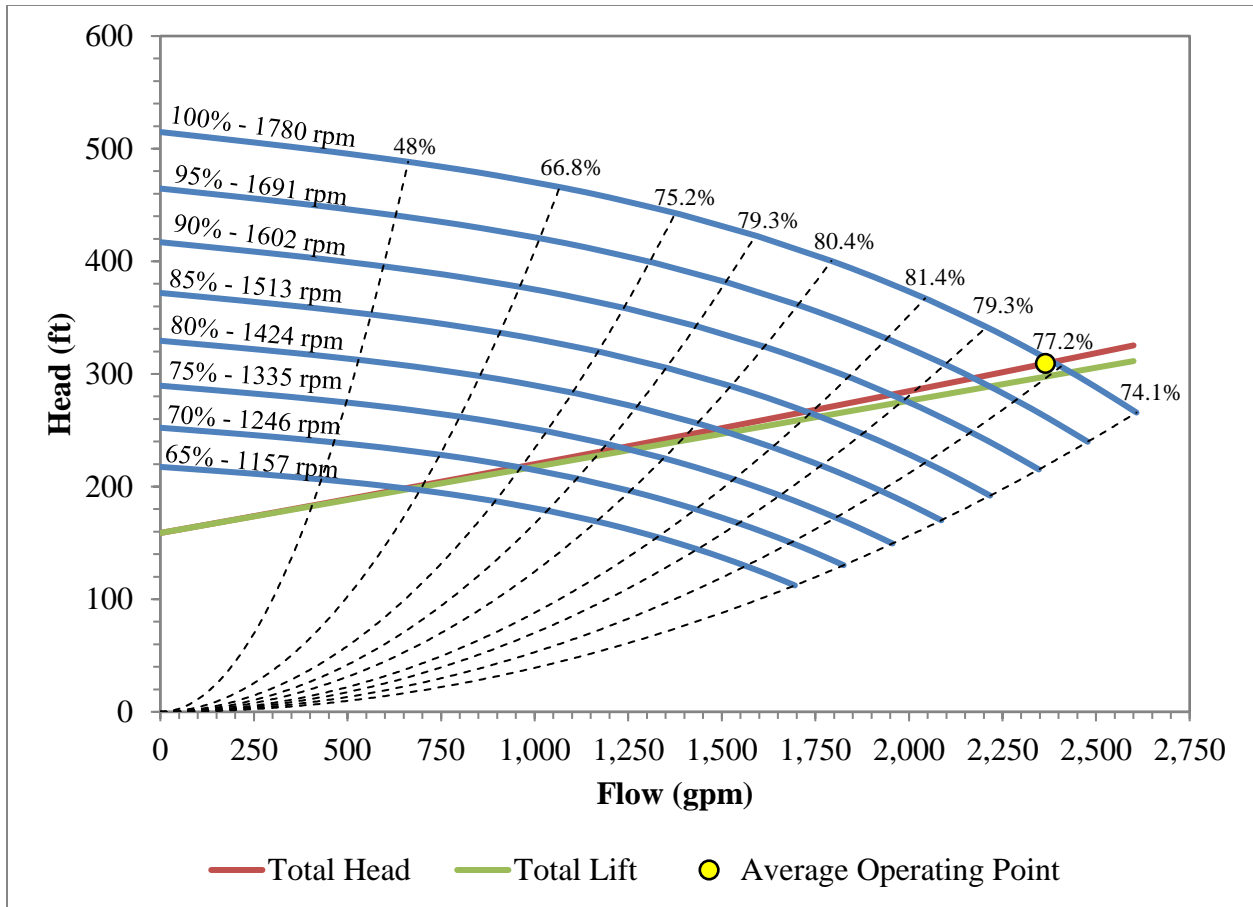


Figure 4-3 – UW 30 variable speed curves and pump efficiencies with system head curve and average operating point.

For each intersection between the total head curve and the variable speed curves, pump flow rate, head, and efficiency were estimated. Interpolated pump efficiencies for each alternative speed operating point are plotted against flow rate in Figure 4-4. Required pump input power was calculated for each alternative speed operating point using interpolated efficiencies to generate the curve shown in Figure 4-5.

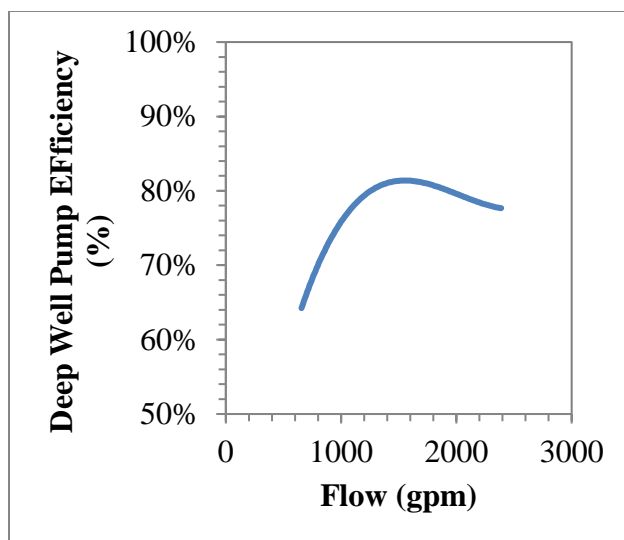


Figure 4-4 – Estimated pump efficiency at reduced speed and flow rates for Unit Well 30.

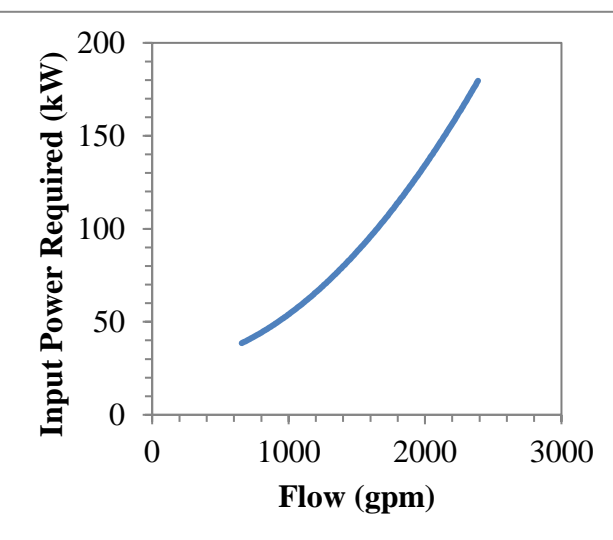


Figure 4-5 – Pump input power requirements at reduced speed and flow rates for Unit Well 30.

Estimated energy intensity was plotted against flow rate in Figure 4-6. Two energy intensity curves are shown: the blue curve shows energy intensity with interpolated, manufacturer-stated pump efficiencies for the real pump and the green curve shows energy intensity for an ideal pump with 100% efficiency. As noted elsewhere, energy intensity is the energy used per unit volume of water pumped and this is equivalent to the total head provided by the pump divided by the efficiency of the pump (Mancosky 2017a). For an ideal, 100% efficient pump, energy intensity reduction comes only from reductions in head. Consequently, the slope of the ideal pump's energy intensity curve depends only on the specific capacity for the well. The cost of pump inefficiencies is represented by the gap between the 100% efficient curve for an ideal pump and the estimated energy intensity curve for the real pump. For the real pump, the change in energy intensity due to head reduction is offset by the semi-parabolic dependence of pump efficiency on pump speed, revealing an optimal speed and flow rate for minimizing energy intensity. At Unit Well 30, the minimum estimated energy intensity was 910 kWh/MG at 70% speed. Operation of the pump at 70% speed would produce an estimated 350 kWh/MG energy intensity savings compared to 100%

speed operation, a 28% reduction in energy intensity and a cost savings of \$38.50/MG. The effect of pump efficiency is discussed in more depth in Section 4.3.8.

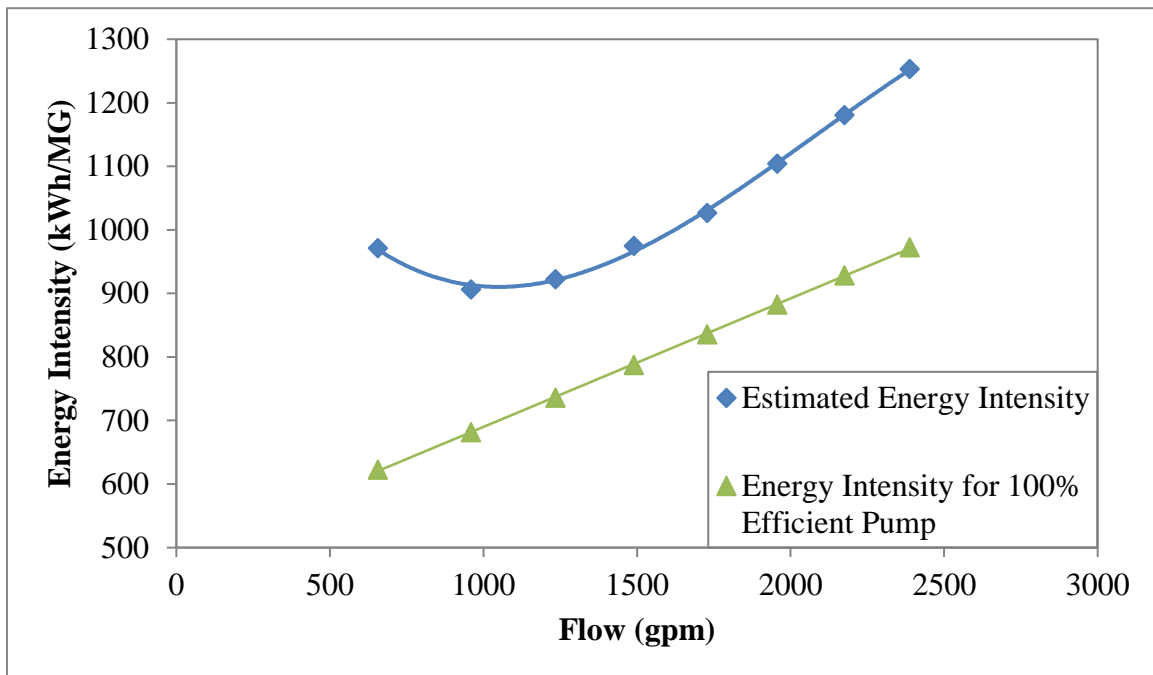


Figure 4-6 – UW 30 energy intensity versus flow rate. Maximum flow rate corresponds to 100% operating speed; each subsequent point represents a 5% reduction in pump speed. Energy intensity if pump were 100% also shown in green.

The presence of an optimal speed at which energy use is minimized does not necessarily imply that the utility should strive to operate at that speed. For example, choosing to operate 24 hr/day at 70% speed, with an estimated flow rate of 960 gpm, would limit MWU to 1.4 MGD of deep well pump production. This is only 40% of the 3.4 MGD production capacity when the pump is operated 24 hr/day at 100% speed. It is also 0.4 MGD lower than the 1.8 MGD average production at Unit Well 30 from 2011 through 2015, and the 0.4 MGD in lost production would need to be made up from other wells in the system, such as Unit Well 18. Increased production from other wells in the system would increase cost at those sites, potentially negating the benefits of VFD installation and reduced energy use at Unit Well 30.

An additional consideration to operating the deep well pump at the most energy-efficient speed is booster pump operation. At the time of this study, booster pumps at Unit Well 30 operated at a constant pressure setpoint with a VFD adjusting speed to meet water demand in the system. Average booster pump flow rate for Year 2015 was close to 1,300 gpm. If the deep well pump were operated at 70% speed, a flow rate of 960 gpm, booster pump operation would need to be altered to ensure the on-site reservoir remains full.

Although the deep well may not be able to successfully operate at the speed of minimum energy intensity, the estimates shown in Figure 4-6 reveal the possibility of significant energy savings at other pump speeds. An average production of 1.8 MGD corresponds to 24 hr/day operation at a flow rate of 1,250 gpm, about a 75% pump speed for the deep well pump at Unit Well 30. Under these conditions, the pump would operate at 922 kWh/MG for 24.0 hr/day with a VFD compared to operating at 1,253 kWh/MG for 14.4 hr/day without a VFD. This translates to an energy savings of 596 kWh/day and a cost savings of \$23,000/year.

Given this analysis, energy savings estimates were based on MWU continuing current operational choices as illustrated in the previous paragraph, producing the same average daily volume as over the last five years (2011-2015). Energy savings at Unit Well 30 were calculated relative to energy use at 100% speed for an average daily production of 1.81 MGD. Estimated energy savings for each analyzed operating speed are shown in Table 4-2.

Table 4-2 – UW 30 VFD energy savings for 2011-2015 average daily pumpage of 1.81 MGD. Gray cells show speeds too slow to provide average daily pumpage.

Pump Speed (%)	Speed (rpm)	Flow (gpm)	Head (ft)	Pumpage (MGD)	Max. Pumpage at Operating Speed (MGD)	Energy Intensity (kWh/MG)	Daily Energy Savings (kWh)	Cost Savings (\$/year)
100%	1,780	2,390	310	1.81	3.44	1,250	0	0
95%	1,691	2,180	296	1.81	3.13	1,180	132	\$5,290
90%	1,602	1,960	281	1.81	2.82	1,100	270	\$10,800
85%	1,513	1,730	266	1.81	2.49	1,030	411	\$16,500
80%	1,424	1,490	251	1.81	2.15	975	505	\$20,200
75%	1,335	1,240	234	1.81	1.78	922		
70%	1,246	960	217	1.81	1.38	906		
65%	1,157	656	198	1.81	0.95	971		

From Table 4-2, the lowest estimated speed capable of producing 1.81 MGD requirements was 80% speed. Operation of the pump at 80% speed results in an estimated 38% reduction in flow rate, 19% reduction in head, and an increase of 3.1% in pump efficiency. Energy savings were estimated to be 505 kWh/day, a 12% reduction in energy use from the 2015 average site energy use of 4,200 kWh/day. Unit Well 30 was operational year-round when this study was done, and yearly savings were estimated to be 184,000 kWh. At an average energy cost for pumping of \$0.11/kWh, operation at 80% speed would provide an estimated yearly savings of \$20,000. This would translate to a payback period of 1.4 to 2.9 years for the VFD (based on total VFD purchase and installation cost of \$30,000-\$60,000).

Additional energy savings could also be realized from reductions in the total number of pump starts. At the time of this study, the deep well pump cycled on and off around seven times a day. Energy use is highest during pump start-up and pump starts have the potential to contribute to on-peak energy charges from the electric utility. The slow ramp up of speed during pump starts

under VFD operation could reduce startup energy use and lower MWU demand charges. Running the pump close to 24 hours per day would also reduce the number of starts, an additional potential source of savings for MWU. These additional energy and cost savings were not quantified in this analysis.

4.3.3. Utility-wide Energy Intensity Curves

The analyses detailed for Unit Well 30 were conducted for all 22 of MWU's deep well pumps. Analogs to Figure 4-4 through Figure 4-6 for Unit Well 30 were generated for all deep well pumps (see APPENDIX C), and these results were used to generate Figure 4-7 through Figure 4-9. Figure 4-7 includes all wells that served Pressure Zones 3, 4, 5, and 6E, Figure 4-8 includes all wells that served Pressure Zone 6W, and Figure 4-9 includes all wells that served Pressure Zones 7, 8, 9, 10, and 11.

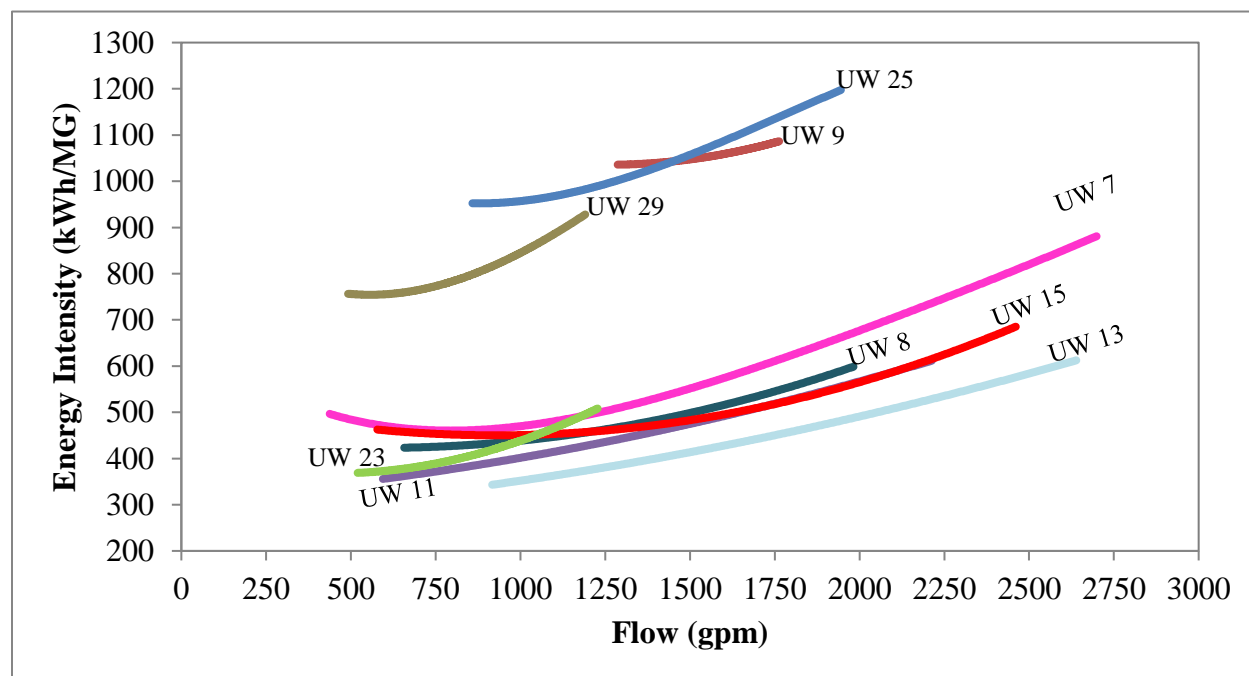


Figure 4-7 – Estimated energy intensity versus flow rate for all MWU deep well pumps that serve Pressure Zones 3, 4, 5, and 6E.

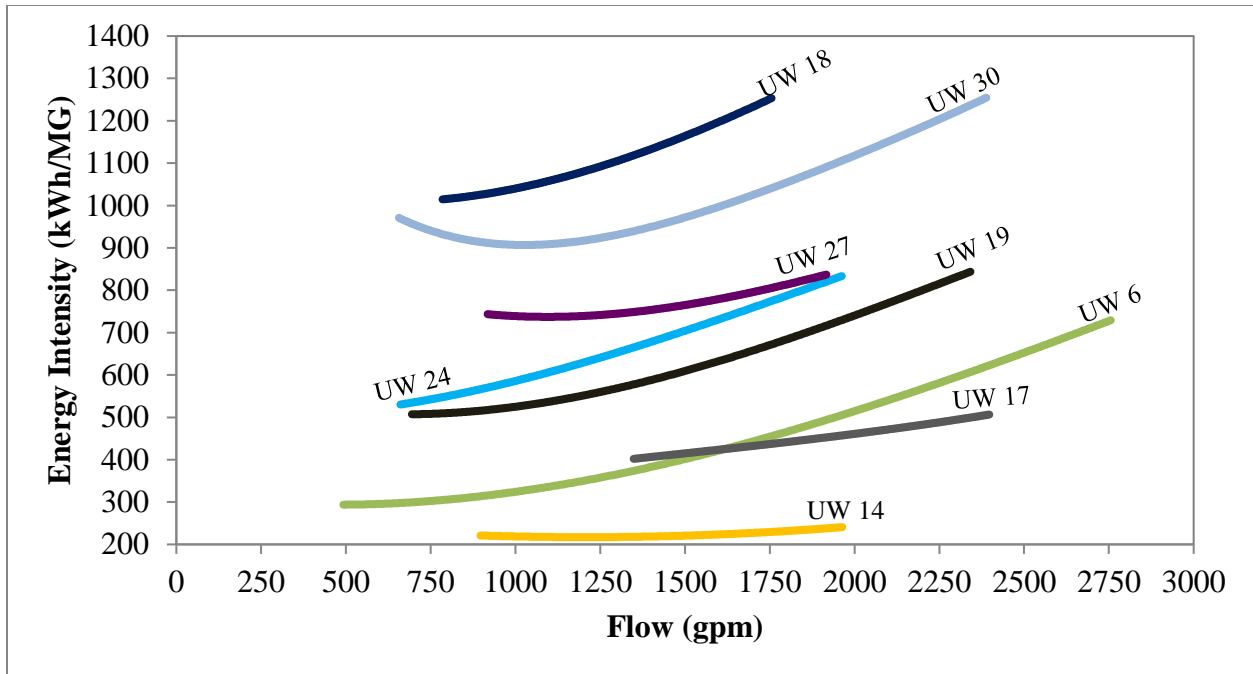


Figure 4-8 – Estimated energy intensity versus flow rate for all MWU deep well pumps that serve Pressure Zone 6W.

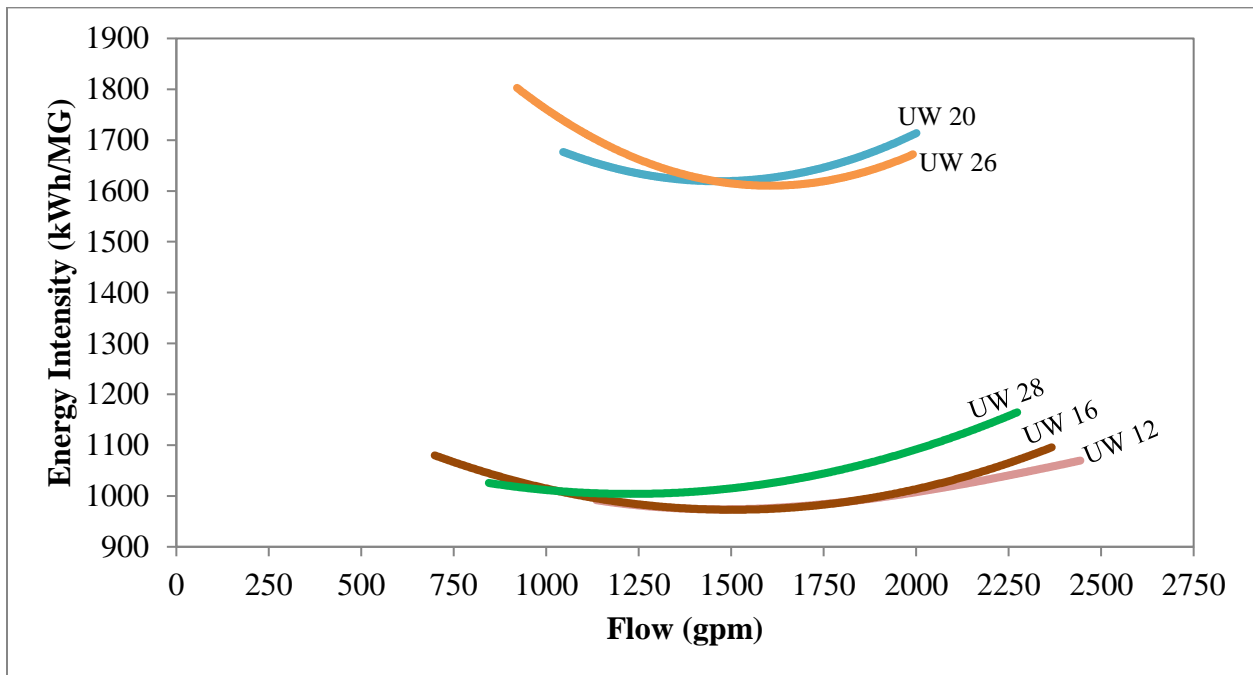


Figure 4-9 – Estimated energy intensity versus flow rate for all MWU deep well pumps that serve Pressure Zones 7, 8, 9, and 10.

The maximum energy intensity savings for each well shown in Figure 4-7 through Figure 4-9, is the difference between the maximum and minimum point of the energy intensity curve. Wells with steeper energy intensity curves were sites with greater energy savings potential

Looking at the results for all 22 wells, there was no indication that energy intensity savings potential was tied to the magnitude of existing energy use. Energy-efficiency upgrades are often focused at the highest energy use components in a system. In the MWU system, Unit Wells 20 and 26 were the highest energy use deep well pumps due to the high static water levels (288 ft and 347 ft, respectively). However, neither well had significant energy intensity savings; Unit Well 26 had a maximum energy intensity savings of 40 kWh/MG and Unit Well 20 had a maximum energy intensity savings of 97 kWh/MG. Targeting these deep well pumps for VFD installation based on their high energy use alone would not maximize energy savings for MWU. Energy savings from VFD installation are present at deep well pumps across a wide variety of baseline energy use levels. Low energy use deep well pumps such as Unit Well 13 had significant energy savings potential. Prioritizing high-energy use deep well pumps for VFD installation is not an effective method for MWU to maximize energy savings.

Figure 4-7 through Figure 4-9 show a wide variety of energy intensity savings potentials for the 22 MWU deep well pumps. Maximum energy savings potential was found to be highly well specific, even when well characteristics were similar. The worst candidates for VFD installation were Unit Wells 8, 14, and 23. Unit Wells 8 and 23 were poor candidates because they were both seasonal wells under MWU's operational strategy at the time of this study, and were used for less than half the year. Outside of seasonal wells, Unit Wells 9 and 14 were the worst candidates for VFD installation. Unit Well 14 was a low energy use site due to a low static water level and had MWU's highest specific capacity at 89.2 gpm/ft. Unit Well 9 was clustered in the

middle of sites based on baseline energy use and had a medium static water level and specific capacity.

On the opposite end of the spectrum were Unit Wells 6 and 30, which had the steepest energy intensity curves and the two largest maximum energy savings potentials of the 22 wells. While both wells were good energy savings candidates, well characteristics were highly different. Unit Well 30 operated close to 2,400 gpm at 100% speed with a moderate static water level (148 feet) and a relatively low specific capacity at 17 gpm/ft. Unit Well 6 operated close to 2,800 gpm with a low static water level (31 feet) and a moderate specific capacity of 23.1 gpm/ft.

Even when examining wells with relatively similar characteristics and baseline energy use, energy savings potential was highly variable. To further demonstrate this variability, Unit Wells 18 and 30 were compared. At 100% speed operation, both wells were estimated to use 1,250 kWh/MG. Unit Well 18 had a moderate static water level (102 feet) and low specific capacity (8.5 gpm/ft), whereas Unit Well 30 had a static water level of 148 feet and specific capacity of 17 gpm/ft. However, Unit Well 30 was a better candidate for VFD installation in terms of maximum energy intensity savings potential (350 kWh/MG to 240 kWh/MG), this difference is highlighted in Figure 4-10. Similar trends were discovered across the 22 unit wells, showing that energy savings potential depended highly upon individual well characteristics and the characteristics of their pumps.

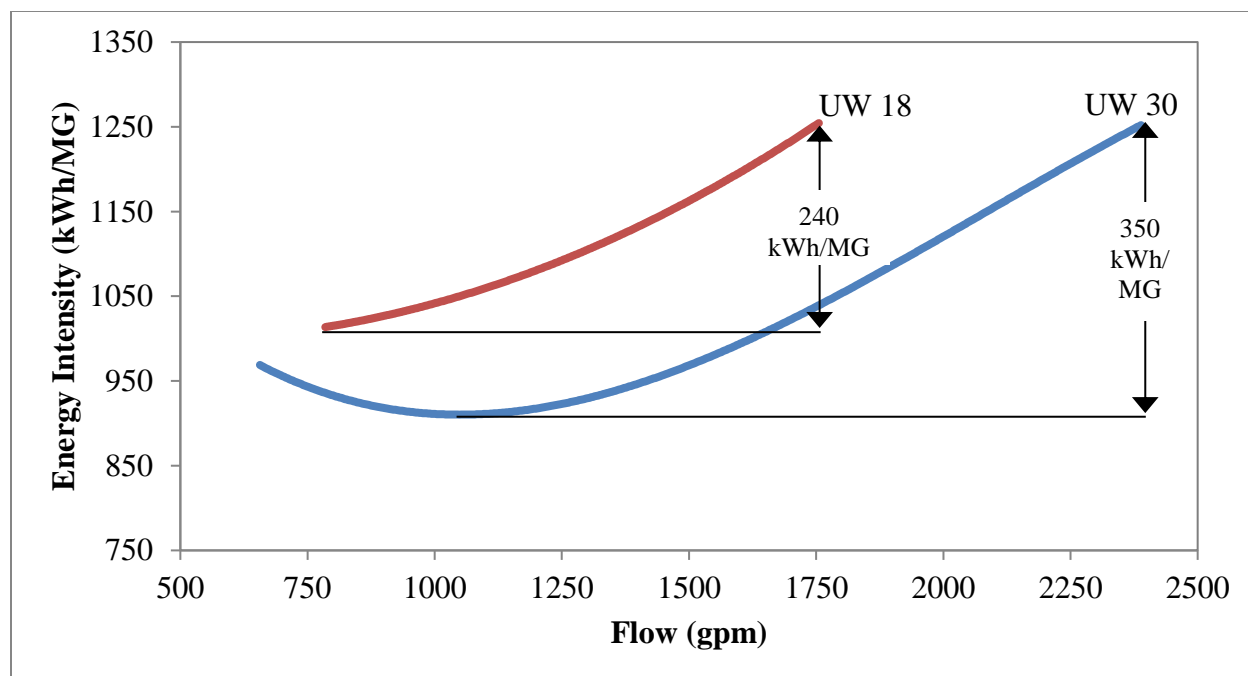


Figure 4-10 – Comparison of energy intensity savings potential between two wells with similar characteristics: Unit Well 18 (in red) and Unit Well 30 (in blue).

4.3.4. Ranking of Sites Based on Current Operational Strategies

Yearly energy savings were estimated for all 18 wells without VFDs installed. Estimates were based on the average production and number of days operational for 2011 to 2015 to represent MWU operational strategy at the time of the study. A ranking of all 18 wells without VFDs based on estimated yearly cost savings is presented in Table 4-3. All estimates were made for the existing pumps at each site. Selection of a new pump would produce different energy savings magnitudes.

Table 4-3 – Unit wells ranked on estimated yearly cost savings from VFD installation (using 2011-2015 average pumpage and number of days operational). Black line delineates cutoff for wells deemed to have an acceptable return on investment, a 10-year payback for \$60,000 VFD purchase and installation.

Unit Well	Average Pumpage (MGD)	Days Operational	Lowest Viable Pump Speed	Energy Intensity at 100% Speed (kWh/MG)	Energy Intensity at Lowest Viable Pump Speed (kWh/MG)	Estimated Daily Energy Savings (kWh)	Estimated Yearly Cost Savings	Estimated Payback Period* (yr)
30	1.8	364	80%	1,253	975	505	\$20,200	1.4 - 2.9
6	1.9	224	65%	731	382	660	\$16,200	1.8 - 3.6
13	2.1	347	75%	610	420	392	\$15,000	2.0 - 4.0
19	2.0	307	80%	845	623	436	\$14,700	2.0 - 4.0
11	1.7	311	75%	610	429	309	\$10,600	2.8 - 5.6
18	1.6	321	85%	1,254	1,073	290	\$10,300	2.9 - 5.8
24	0.9	286	70%	834	552	267	\$8,380	3.5 - 7.1
12	1.9	340	85%	1,069	975	176	\$6,590	4.5 - 9.1
20	1.9	316	90%	1,712	1,615	179	\$6,240	4.8 - 9.6
16	1.5	306	85%	1,091	975	170	\$5,720	5.2 - 10.4
28	1.4	179	80%	1,162	993	237	\$4,650	6.4 - 12.9
27	1.5	189	85%	837	738	148	\$3,070	9.7 - 19.5
17	1.8	174	80%	507	419	159	\$3,050	9.8 - 19.6
26	1.9	310	90%	1,666	1,626	75	\$2,790	10.7 - 21.4
9	1.3	365	90%	1,109	1,073	46	\$1,830	16.3 - 32.7
23	0.7	150	70%	506	371	96	\$1,590	18.9 - 37.8
14	2.3	364	95%	240	229	25	\$985	30.4 - 60.9
8	0.5	40	65%	598	424	79	\$348	86.2 - 172.5

*Assumes cost for purchase and installation of VFD to be between \$30,000 and \$60,000

Based on 2011-2015 operational strategies, the five best candidates for VFD installation were Unit Wells 30, 6, 13, 19, and 11. The worst-case payback period for any of these wells was an estimated maximum of 5.6 years for Unit Well 11. Typical energy efficiency upgrades at water and wastewater utilities were found to result in 10-30% energy savings and have payback periods of 1 to 5 years (Liu et al 2012). The top five candidates for VFD installation generally fell within this comparable payback period. An additional benefit in terms of payback for MWU is the ability to apply for Wisconsin Focus on Energy grants, which are available to help pay for energy savings measures like VFD installation. Grants for VFD installation provide \$40/HP for the drive, which would be \$10,000 for the 250 HP motor at Unit Well 30 (Focus on Energy 2016). Should MWU receive Focus on Energy grant money for VFDs, payback periods would be shorter than estimated.

Of the 18 analyzed wells without VFDs, 9 were found to have payback periods less than 10 years for a VFD purchase and install cost of \$60,000 per well. For a VFD lifetime of 10 – 20 years, this would ensure VFD installation would, at worst, be cost-neutral for MWU. Based on this, a 10-year payback period was deemed to be an acceptable return on investment for MWU when determining the financial feasibility of a project going forward.

Sites like Unit Wells 6 and 30 provide MWU with the potential to benefit from energy savings for the majority of the installed VFD lifetime. Select wells would provide MWU with significant energy and cost savings benefits. Beyond the energy savings benefits, all sites would benefit from the increased operational flexibility provided with VFD installation.

Yearly savings estimates for Unit Wells 30, 6, and 13 were \$15,000 or greater based on pump energy intensity reductions alone. Unit Wells 6 and 13 had small on-site reservoirs, which led to the deep well pumps starting up 6 and 11 times per day, respectively. VFD installation could potentially provide additional energy and costs savings from reductions in well pump starts.

Another operational consideration for energy savings for MWU deep well pumps is the number of days operational. MWU had several seasonal wells, which limits the amount of yearly energy savings potential. For example, Unit Well 6 had the greatest daily energy savings potential, but it was ranked as the second-best candidate because it was operational for 60% of the year instead of 100% of the year. Similarly, Unit Well 28 had the 6th highest estimated daily savings at 237 kWh/day, but was a middling candidate for VFD installation based on 2011-2015 operational strategies as it was only operated half the year. Increased use of these sites would shorten payback periods for VFD installation, but would have to be balanced out by changes in operations of other wells.

Even though this study looked only at energy savings for deep well pumps, it is important to consider operation of the entire system. Changes in the operation of individual sites will change operation of the entire system. Looking forward, development and population growth in Madison is occurring on the far west and northeast portions of the city. Operational strategy for wells in Pressure Zone 6E and 6W is unlikely to change significantly in the oncoming years, as the area served by these wells is mostly built out. Wells on the far end of 6E like Unit Well 7 and 13 may see a change in operation in 2017, when Madison's second largest water user, Oscar Meyer, closes its plant. Wells most likely to see change in operational strategy are in the growth regions in the far west and northeast portions of the city (Pressure Zones 8, 10, and 11 on the west side and Pressure Zone 3 in the northeast). The three wells serving Pressure Zones 8, 10, and 11 (Unit Wells 16, 26, and 28) will likely see increased operation as additional development and population growth occur. If UW 28 moves to year-round operation, it will be a stronger candidate for VFD installation. Operational strategy for Unit Well 9 will also change when Unit Well 31 is put into service. Use of Unit Well 9 will decrease, making it a worse candidate for future VFD installation.

As MWU operational strategies evolve, energy savings benefits of VFD installation should be reevaluated to reflect these changes.

4.3.5. Ranking of Sites Based on Equal Operation

To examine the effect of an alternative operational strategy, all sites were also ranked on an equal volume basis, with each site assumed to operate all year and produce the utility-wide average daily well production from 2011-2015. A ranking of all 18 wells without VFDs based on this equal operation strategy is presented in Table 4-4.

Table 4-4 – Unit wells ranked on estimated yearly cost savings from VFD installation (assuming MWU adopt an operational strategy with all wells producing equal volume and operating 365 days per year).

Unit Well	Average Pumpage (MGD)	Days Operational	Lowest Viable Pump Speed	Energy Intensity at 100% Speed (kWh/MG)	Energy Intensity at Lowest Viable Speed (kWh/MG)	Estimated Daily Energy Savings (kWh)	Estimated Yearly Cost Savings	Estimated Pay Back Period* (yr)
6	1.3	365	55%	731	317	526	\$21,100	1.4 - 2.8
30	1.3	365	70%	1,253	906	442	\$17,700	1.6 - 3.3
19	1.3	365	65%	845	514	421	\$16,900	1.7 - 3.5
13	1.3	365	60%	610	346	337	\$13,500	2.2 - 4.4
24	1.3	365	75%	834	592	309	\$12,400	2.4 - 4.8
18	1.3	365	80%	1,254	1,034	279	\$11,200	2.6 - 5.3
11	1.3	365	70%	610	400	268	\$10,800	2.7 - 5.5
28	1.3	365	80%	1,162	993	214	\$8,600	3.4 - 6.9
8	1.3	365	70%	598	430	213	\$8,570	3.5 – 7.0
16	1.3	365	85%	1,091	975	147	\$5,920	5.0 - 10.1
17	1.3	365	75%	507	402	133	\$5,320	5.6 - 11.2
27	1.3	365	85%	837	738	126	\$5,050	5.9 - 11.8
20	1.3	365	90%	1,712	1,615	123	\$4,940	6.0 - 12.1
12	1.3	365	85%	1,069	975	120	\$4,830	6.2 - 12.4
23	1.3	365	90%	506	446	76	\$3,050	9.8 - 19.6
26	1.3	365	90%	1,666	1,626	51	\$2,250	13.3 - 26.6
9	1.3	365	90%	1,109	1,073	46	\$1,840	16.3 - 32.6
14	1.3	365	85%	240	216	30	\$1,220	24.6 - 49.2

*Assumes cost for purchase and installation of VFD to be between \$30,000 and \$60,000

The top five candidates for VFD installation based on yearly savings changed slightly with Unit Well 24 replacing Unit Well 11 as the fifth best candidate. However, the order in which the sites are ranked changed, with Unit Well 6 the top candidate. Unit Well 6 remained the highest in terms of magnitude of daily energy savings and the increase to yearly operation made it the top candidate for VFD installation. Seasonal wells like Unit Well 8 became much better candidates primarily due to increased number of days operational. This strategy is not a feasible option for MWU, but shows that the benefits from VFD installation will change based on operational strategy.

4.3.6. Impact of Specific Capacity on Energy Intensity Curve

The inverse of the specific capacity defines the slope of the Total Lift curve for each well. For wells without treatment systems or sand separators (16 of 22 wells), friction losses were an average of $3.5\% \pm 1.5\%$ of the total head at average operating conditions. The decrease in friction losses with reduced pump speed is minimal, so specific capacity dictates the reduction in head. Energy intensity is a function of head and pump efficiency, so specific capacity also helps define the slope of the energy intensity curve. Wells with lower specific capacities will see greater reduction in energy intensity due to greater reduction in head. This is visually represented in a steep slope for the total lift and energy intensity curves. The effect of specific capacity on the slope of the energy intensity curves is demonstrated in Figure 4-11 with Unit Well 17 and Unit Well 23. Both wells had similar static water levels but their respective specific capacities were 36 gpm/ft and 21 gpm/ft. The slope of the energy intensity curve for Unit Well 23 is greater than that of Unit Well 17, which had a higher specific capacity.

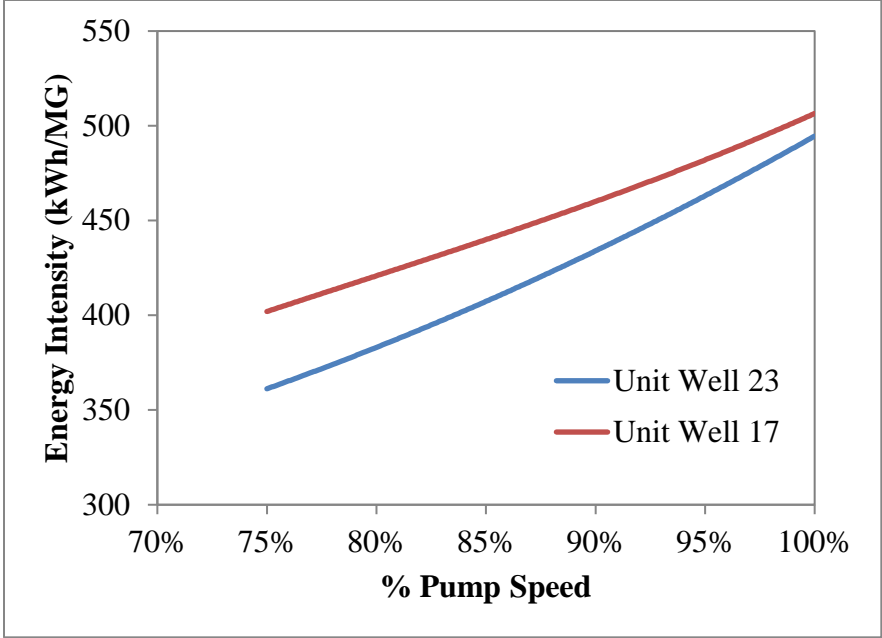


Figure 4-11 – Effect of specific capacity on slope of energy intensity curve as shown with a plot of energy intensity versus pump speed for Unit Well 17 and Unit Well 23.

The effect of specific capacity on the slope of the energy intensity curve was most pronounced at high pump speeds and pump efficiencies. This is shown using Unit Well 30 as an example in Figure 4-12. The curve in blue shows energy intensity at 5% speed intervals with estimated efficiencies and the curve in red shows energy intensity at 5% speed intervals if efficiency was independent of pump speed. Efficiency was assumed to be 77.6% (estimated pump efficiency at 100% pump speed, as shown in Figure 4-3). If efficiency were to be independent of pump speed, like the curve in red, changes in energy intensity would come solely from head reduction as defined by the specific capacity.

For pump speeds close to 100% speed, specific capacity dominates the reduction in energy intensity. At Unit Well 30, pump efficiencies for 95% speed and 90% speed were 78.6% and 79.9%, respectively. For these pump speeds close to 100% speed, pump efficiency was within 2% of the 77.6% efficiency for the constant-efficiency curve, and the two energy intensity curves were

within 3%. Reduction in head was primarily responsible for energy intensity savings for 90% and 95% speed pump operation. Specific capacity dictates the slope of the energy intensity curve if pump efficiency remains close to efficiency at 100% speed.

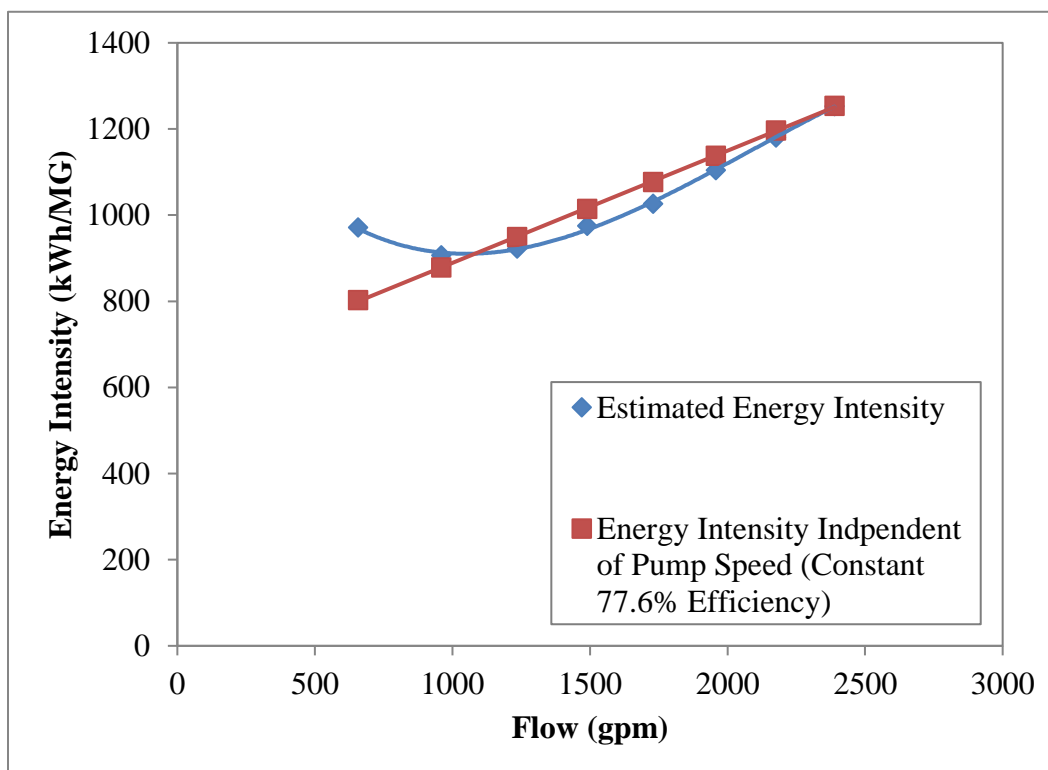


Figure 4-12 – Energy intensity for Unit Well 30 at reduced flow rates. Energy intensity when actual pump efficiency is accounted for is shown in blue. Energy intensity if pump efficiency were independent of pump speed and a constant 77.6% efficiency shown in red.

4.3.7. Impact of Specific Capacity on Energy Savings Potential

Hayes (2015) recommended installing VFDs on pumps with low specific capacity, as low specific capacity sites were expected to see greater head savings with reductions in pump speed. This recommendation was based on an examination of three MWU wells. After analyzing all 22 wells in the system, energy savings potential was found to vary greatly across all wells, and did not depend on specific capacity alone.

4.3.8. Impact of Pump Selection on Energy Savings

For the analyzed pumps, pump selection was shown to have an impact on energy savings magnitude, but was not indicative alone of energy savings. The primary effect of pump selection was related to the location of the average operating point relative to the pump curve's best efficiency point (BEP). For most efficient operation of a single-speed pump, the design operating point of the pump should fall as close as possible to the BEP.

For VFD installation on existing pumps, this is not the case. Energy savings with VFD installation were maximized when the average operating point was located at lower head and higher flow rate than the head and flow rate of the BEP. The effect of this is shown in Figure 4-13 with Unit Well 6, where the average operating point is shown with a yellow dot and the BEP is shown with a red star. Because the average operating point is below the BEP, reductions in speed and head will also result in increases in pump efficiency. For pumps with the average operating point at or above the BEP, such as the pump at Unit Well 24, reductions in speed result in reductions in pump efficiency for all speed reductions as shown in Figure 4-14. For all pumps with VFDs, energy savings benefits from head reduction will eventually be outweighed by the drops in pump efficiency.

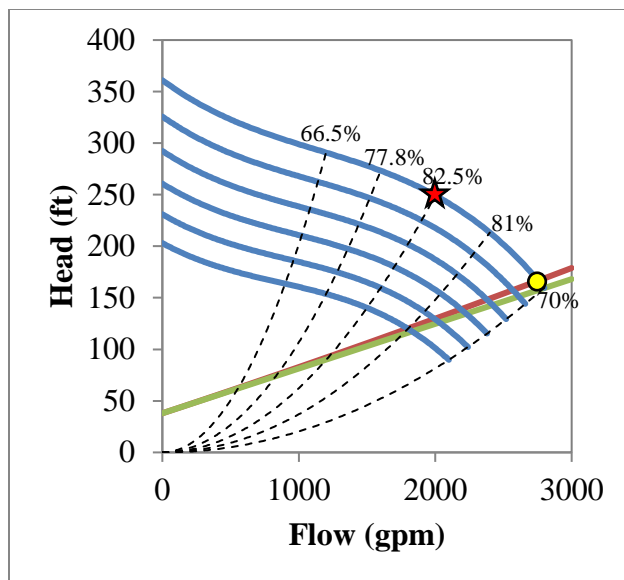


Figure 4-13 – UW 6 showing relation of average operating point below the BEP.

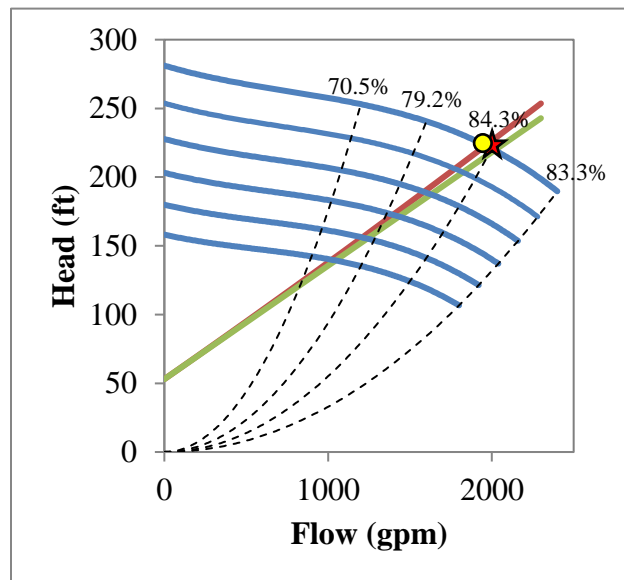


Figure 4-14 – UW 24 showing relation of average operating point above the BEP.

The effect of pump selection and location of the average operating point is further detailed in Figure 4-15. Unit Well 24 is shown in blue and Unit Well 6 is shown in red, and the dashed lines show energy intensity if efficiency were independent of pump speed. This dashed energy intensity curve represents the energy savings from flow rate and head reduction alone. For Unit Well 24, efficiency at 100% pump speed was estimated to be 83.9% and for Unit Well 6, efficiency at 100% speed efficiency was estimated to be 71.6%. For pumps operating below the BEP like UW 6 in red, the increase in efficiency provides additional energy intensity savings greater than that from reduction in flow rate and head. For pumps at or above the BEP like Unit Well 24, reductions in speed provide less energy savings magnitude than that predicted from reduction in flow rate and head. The cost of decreasing pump efficiency is lessened energy savings magnitude.

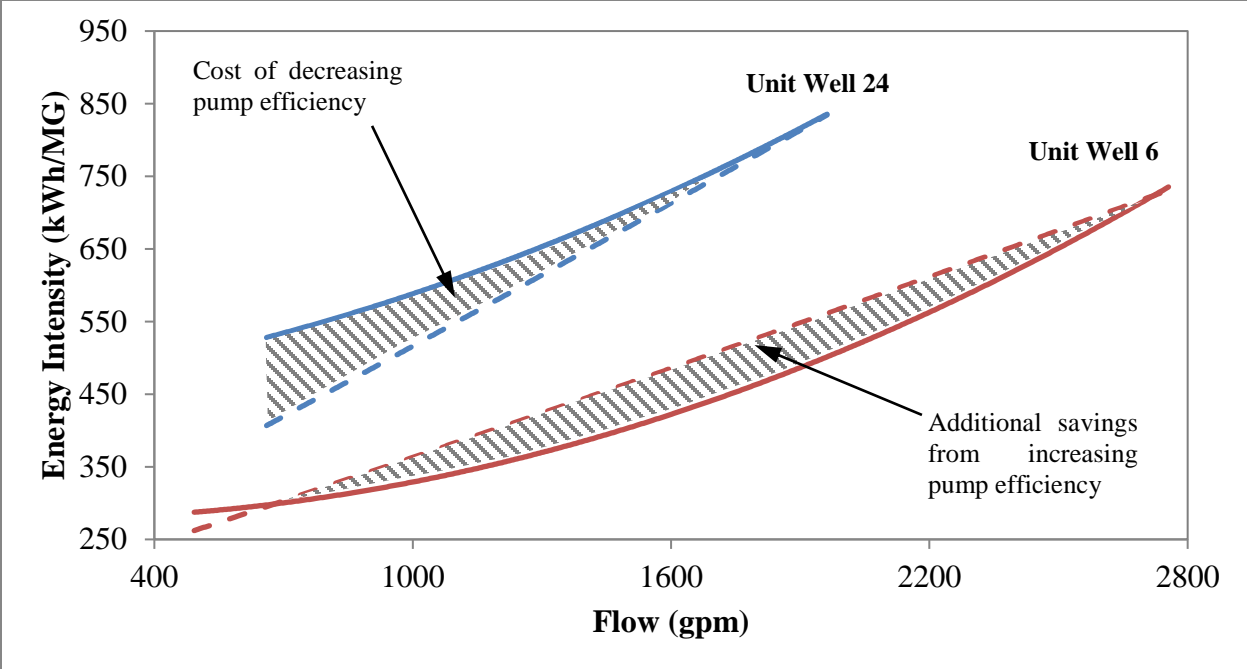


Figure 4-15 – Effect of location of average operating point to energy savings shown with UW 24 in blue and UW 6 in red. Dashed lines show no dependence of pump efficiency on VFD speed while solid lines include this dependence. Pumps like Unit Well 6 with operating points to the right of the BEP see energy savings greater than those from head reduction alone.

Although energy savings magnitude can be affected by the location of the average operating point, this alone was not indicative of energy savings potential from VFD installation. Energy intensity savings are shown in Figure 4-15 for all estimated pump speeds at Unit Well 24 even though the average operating point lies at the BEP. There were still significant observable energy savings at Unit Well 11, 13, and 24 even though they were operating at the BEP. Of note, none of the top energy savings candidates had an average operating point above the BEP. Wells with operating points above the BEP include 14 and 26, cases where the pump curve was shifted down to match the average operating point. In such cases, pump replacement would be recommended in conjunction with VFD installation to ensure maximum savings potential.

4.3.9. New Pump Selection for VFD Installation

For installation of a new pump with a VFD, pump selection should consider expected average operating conditions. Average operating conditions dominate overall energy use, so pump efficiency should be highest at the flow rate or speed the pump is expected to be operated. For pumps where desired VFD speed or deep well flow rate is known during design, pump selection should prioritize pumps with high efficiencies in this range.

Should MWU wish to continue providing a flow rate of 2,200 gpm to meet maximum day pumpage scenarios, pump selection should also consider this. Pump selection with a VFD should begin with the estimation of the system head curve in a similar manner to that presented previously in Mancosky (2017a). Affinity Laws for each potential pump should also be applied. Pump selection should ensure that 2,200 gpm can be provided at 100% speed, but this should not be the most efficient point for the pump. The BEP of the pumps being considered should fall close to the expected average operational speed or flow rate of the pump. Pump selection should not consider the maximum energy intensity savings between 100% speed and the desired operating speed, but should ensure that the pump is most efficient at the expected average operating speed and flow rate.

4.4. CONCLUSIONS AND RECOMMENDATIONS

The primary objective of this work was to identify top deep well pump candidates for VFD installation using the method developed previously in Mancosky (2017a).

4.4.1. Conclusions

The following conclusions were developed from this analysis:

- In order, the top candidates for VFD installation under current MWU operational strategy were Unit Wells 30, 6, 13, 19, and 11.
- Energy savings of over 300 kWh/day were estimated for each of the top five ranked wells.
- Cost savings of over \$6,000/year were estimated for each of the top five ranked wells, with cost savings of at least \$15,000 for the top three wells (Unit Wells 30, 6, and 13). Payback periods for the top five wells were estimated to be less than 6 years.
- For MWU, a 10-year payback period was deemed to be an acceptable payback period for a VFD lifespan of 10 – 20 years and a purchase and installation cost between \$30,000 – \$60,000. Half of the eighteen MWU deep well pumps without VFDs were deemed to meet this return on investment.
- Energy savings potential was found to depend on the combination of well and pump characteristics unique to each deep well. For example, ranking the 22 wells for energy savings potential could not be solely derived from specific capacity or from the position of the operating point to the best efficiency point. The ranking required an examination of all relevant well and pump characteristics at each well in the system.
- Pump selection influences energy savings magnitude; energy savings magnitude will be greater for pumps with an average operating point below the BEP. For these pumps, reductions in pump speed will result in increased pump efficiency.
- Targeting deep well pumps based on high baseline energy use alone is not advised. The two highest energy use deep well pumps, Unit Wells 20 and 26, show little energy savings potential from VFD installation.

- There is a direct link between energy savings and operational decisions to meet system demand requirements. Changes in the average production or seasonal operation of wells will alter the benefits from VFD installation.
 - Operation at the most energy-efficient speed may be limited by production requirements and system demands.
 - Energy savings potential is dependent on the amount of time a pump is used. For example, if 300 kWh/day of savings are available for a pump used year-round, this would be a better candidate for VFD installation than a pump with a potential 600 kWh/day of available savings that is operated only four months a year.

4.4.2. Recommendations

- Prioritize VFD installation at Unit Well 30 where savings of \$20,000 per year are estimated.
 - Use Unit Well 30 as a test case of VFD installation for energy savings benefits.
 - Adapt plans for future VFD installation based upon the observed results at this site.
- Assuming continuation of the current operational strategy with existing pumps, prioritize installation of VFDs at Unit Wells 30, 6, 13, 11 and 18. While Unit Well 19 was the third-ranked candidate, it is slated to be replaced in the next five years and receive a filtration system, changing the operating conditions of the pump and estimates for energy savings. The change in operating conditions will likely necessitate selection of a new pump, at which point follow recommendations for new pump selection with a VFD.
- Groundwater utilities installing VFDs on deep well pumps for energy savings should ensure the following data is collected and recorded to monitor performance:

- Pump flow rate
- Pump speed
- Static and pumping water levels
- Power consumption
- Groundwater utilities should do the following to quantify the benefits of VFDs installed for energy savings purposes:
 - Use the collected data in conjunction with methods presented in this paper and Mancosky (2017a) to characterize pump operation and energy use before and after VFD installation.
 - Use electric utility billing data to estimate observed cost savings from VFD installation. To account for changes in operation throughout the year, compare energy use and costs after VFD installation to the same time period in past years.
 - Evaluate savings on a per volume basis when quantifying long-term savings to account for differences in production.
- Utilities should update energy savings estimates periodically as operation of the system changes. For MWU, these changes could include further development and water demand in Pressure Zones 8, 10, and 11 or UW 31 being placed on-line in Pressure Zone 4. All energy savings estimates in this report were for the operational strategy employed by MWU from 2011-2015.

4.4.3. Pump Selection Recommendations

- When replacing pumps at sites where VFD installation is not being considered, MWU pump selection should continue to prioritize matching the design operating point with the BEP of the selected pump.

- Should MWU replace a deep well pump with the idea to install a VFD at a future date, consider the payback period and expected pump lifetime.
- When replacing pumps at sites where VFD installation is being considered, MWU pump selection should:
 - Focus on maximizing energy-efficiency at the expected average operating conditions. Use the estimated system head curve and the Affinity Laws to match the BEP of the selected pump with the expected operating speed/flow rate.
 - This would be a departure from past MWU pump selection practices, which have generally been based on a design flow rate of 2,200 gpm to meet maximum day pumping scenarios.
 - Should MWU wish to be able to provide 2,200 gpm to meet maximum day demands, ensure the selected pump can produce this flow rate at 100% pump speed while achieving highest efficiency at the average operating speed.

ACKNOWLEDGMENTS

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CHAPTER 5 – OBSERVED BENEFITS OF VFD INSTALLATION FOR THE MADISON WATER UTILITY

Abstract: Madison Water Utility (MWU) installed a variable frequency drive (VFD) on a deep well pump at Unit Well 30 to save energy through reductions in drawdown. The purpose of this work was to quantify and verify the energy and cost savings estimated for VFD installation at this well. Methods presented in Mancosky (2017 a-b) were used to estimate the energy and cost savings after VFD installation. Operational data and electric utility billing data were used to determine observed savings. MWU saved nearly 95,000 kWh and \$8,600 after six months of operation. Energy use was unaffected at other wells in the system by the change in operation. The methods used to identify Unit Well 30 as the strongest candidate for VFD installation (Mancosky 2017 a-b) were verified in this study. Other groundwater utilities may also see significant energy and cost savings with a similar analysis and VFD installation at their deep wells.

5.1. INTRODUCTION

Energy use by groundwater utilities in Wisconsin is generally higher than that of utilities purchasing water or using surface water supplies. Although surface water utilities usually have higher electricity needs for treatment, this is offset by the greater lift required for groundwater systems to move water from below ground to the distribution system (Bohnert 2012, Elliott et al 2003). In 2016, Madison Water Utility (MWU) used 20.5 GWh of electricity to deliver 9.85 billion gallons of water at a cost of \$ 2.1 million (PSC 2016). MWU has identified variable frequency drive (VFD) installation on deep well pumps as a source of energy savings because VFDs allow MWU to reduce lift by reducing pump flow rate and drawdown.

Studies of two MWU wells, with VFDs installed for operational flexibility, validated a method for estimating pump operation and energy savings from VFD installation (Mancosky 2017a). Use of this method to analyze all deep well pumps in the MWU system showed Unit Well 30 to be the best candidate for VFD installation (Mancosky 2017b). It was predicted that MWU could reduce the pump speed to 80%, thus providing a 38% reduction in flow rate, 19% reduction in head, and 22% reduction in energy intensity. This reduced-speed operation translated to an estimated energy savings of 500 kWh/day, a 12% reduction in station energy use, and yearly savings of \$20,000.

This paper is the last of three papers designed to (1) develop a verified procedure to estimate energy savings from VFD installation on a deep well pump, (2) rank the strongest candidates for VFD installation, and (3) verify expected savings through installation of a VFD on the top-ranked deep well pump. The goal of this paper is to meet the third of these objectives. The specific objectives of this work were to:

1. Install a VFD at Unit Well 30 to quantify and verify energy and cost savings from VFD installation.
2. Determine the impact of time-of-use billing rate structures on cost savings.

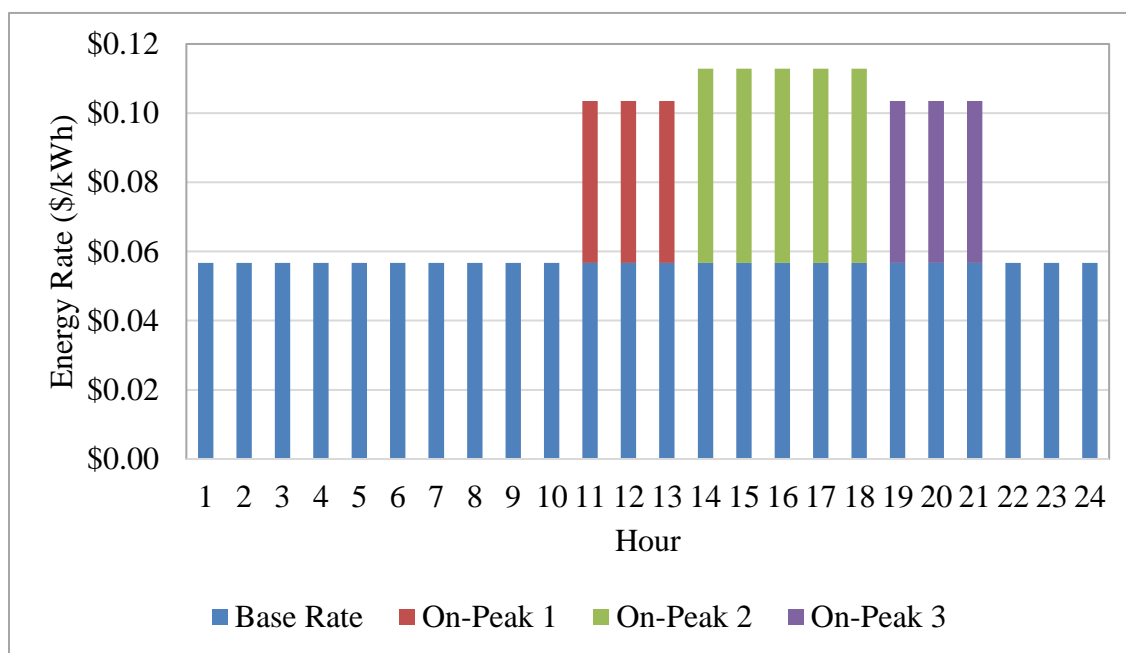
5.2. BACKGROUND

5.2.1. Electric Utility Billing Structures

Electricity for the 20 of 22 MWU unit wells is provided by Madison Gas and Electric (MG&E), and MWU is billed as a commercial/industrial user on a time-of-use rate structure. Time-of-use rate structures incentivize use of electricity during designated off-peak periods and limit energy consumption during peak energy use periods. This poses a challenge for typical water

suppliers; peak water demand and need for pumping usually coincide with peak electricity charges. Utilities can utilize storage capacity and off-peak pumping as means to save cost, without pursuing energy savings.

This section provides a breakdown and examples of the rate structure and billing for Unit Well 30 in 2015 and 2016. At the time of this study, all base electricity use was billed at a fixed rate per kWh. Additional surcharges were added for energy use during on-peak hours, between 10 am and 9 pm, Monday through Friday. On-peak hours were further divided into three periods: On-Peak 1 (10 am to 1 pm), On-Peak 2 (1 pm to 6 pm), and On-Peak 3 (6 pm to 9 pm). Weekend energy use was billed at the base fixed rate per kWh with no on-peak additional surcharges. Hourly electricity rates at Unit Well 30 for Summer 2016 are shown in Figure 5-1.



Source: MG&E 2016.

Figure 5-1 – Hourly energy billing rates at Unit Well 30 (Summer 2016). Hour of day represents end of hour listed (e.g., Hour 11 = 10:00 am to 11:00 am). Base energy rate (blue) is applied for all energy use. On-peak surcharges are added to the base rate for energy used between 10 AM and 9 PM (red, green, and purple).

The other key component of the time-of-use rate structure is the demand charge. These demand charges are separate from the on-peak surcharges added to the base energy rate that are shown in Figure 5-1. At the time of this study, MG&E charged commercial and industrial users for the demand, or load, they put on the electric grid during on-peak hours. MG&E averaged the metered demand in 15-minute intervals, and MWU was billed for the largest on-peak demand on a per kW per day basis. For example, on the November 2016 bill for Unit Well 30, the highest 15-minute on-peak average power consumption was 275.5 kW on October 31, 2016 from 10:30 am to 10:45 am. This resulted in a charge of \$ 2,964.10 (\$ 0.371/kW/day) for that billing period.

In addition to the monthly on-peak demand charge, MG&E also charged MWU and other commercial/industrial users for a yearly maximum demand. This yearly maximum demand was based on a rolling 12-month window. The maximum 15-minute average demand metering during the billing period and preceding 11 months is charged to MWU, also on a per kW per day basis. For example, on the December 2015 bill for Unit Well 30, the yearly maximum demand charge was re-set at 308.7 kW, exceeding the previous maximum of 290.9 kW set in May 2015. The maximum 15-minute average was set on December 10, 2015 from 3:30 pm to 3:45 pm. This resulted in a charge of \$981.67 (\$ 0.106/kW/day) for the December 2015 bill. MWU was billed for this 308.7 kWh maximum demand until April – May 2016 when the maximum demand was re-set at 330 kW.

At the time of this study, MG&E also billed MWU with additional fees and credits applied as part of the monthly bills. The fees included a grid connection fee and a low-income assistance fee, neither of which was based on power or energy used. MWU also received credit for on-site generation due to the presence of an MWU-owned emergency power supply at Unit Well 30. This credit is given on a kW/day basis using the highest on-peak 15-minute average power consumption

for the month, offsetting the monthly on-peak demand charge by 30%. A second credit was given for fuel costs based on the base level of kWh used during the month. This latter credit allows MG&E to rapidly adjust revenues in response to rapidly changing fuel prices. The minimum charge for MWU in a given month is based on the grid connection charge and yearly maximum demand charge, even if a well is out-of-service.

A breakdown of the electricity bill at Unit Well 30 for June – July 2016 (6/21/2016 – 7/21/2016) energy use is presented in Table 5-1. For the billing period shown, demand charges made up 30% of the total bill, the 269.4 kW on-peak demand accounted for 21% of the total and the 330 kW maximum demand accounted for 9% of the total. Base electricity charges made up 50% of the bill, and on-peak surcharges made up 16% of the bill. Combined, demand charges and electricity rates make up 96% of the bill.

Table 5-1 – Breakdown of electricity bill at Unit Well 30 for June – July 2016 (6/21/2016 – 7/21/2016) energy use. Numbers in red represent credits applied.

Charge	Unit	Rate	Total
Grid Connection	30 days	\$8.93449/day	\$268.03
State Low-Income Assistance Fee	30 days	\$5.09848/day	\$149.67
Yearly Maximum Demand	330 kW	\$0.106/kW/day	\$1,049.40
On-Peak Demand	269.4 kW	\$0.451/kW/day	\$3,644.98
On-Site Generation Credit	269.4 kW	(\$0.1351/kW/day)	(\$1,062.86)
Base Energy Use	114,974 kWh	\$0.05668/kWh	\$6,516.73
On-Peak 1 Energy Use	10,953 kWh	\$0.04682/kWh	\$512.82
On-Peak 2 Energy Use	18,234 kWh	\$0.05622/kWh	\$1,025.12
On-Peak 3 Energy Use	10,345 kWh	\$0.04682/kWh	\$484.35
Fuel Cost Credit	114,974 kWh	(\$0.00256/kWh)	(\$294.33)
		Total	\$12,293.91

Billing rates change between winter and summer, but the general structure remains the same. A comparison of the winter and summer billing rates at Unit Well 30 during 2016 are

presented in Table 5-2. Summer billing rates were applied for all energy use between June and September, with winter rates applied for all other months.

Table 5-2 – Comparison of summer (June – September energy use) and winter (October – May) energy use rates for Unit Well 30 in 2016.

Charge	Winter Rate	Summer Rate
Grid Connection	\$8.93449/day	\$8.93449/day
State Low-Income Assistance Fee	\$5.09868/day	\$5.09848/day
Yearly Maximum Demand	\$0.106/kW/day	\$0.106/kW/day
On-Peak Demand	\$0.371/kW/day	\$0.451/kW/day
On-Site Generation Credit	(\$0.1351/kW/day)	(\$0.1351/kW/day)
Base Energy Use	\$0.05668/kWh	\$0.05668/kWh
On-Peak 1 Energy Use	\$0.03843/kWh	\$0.04682/kWh
On-Peak 2 Energy Use	\$0.03843/kWh	\$0.05622/kWh
On-Peak 3 Energy Use	\$0.03843/kWh	\$0.04682/kWh
Fuel Cost Credit	(\$0.00256/kWh)	(\$0.00256/kWh)

5.3. METHODS

5.3.1. Field Test Prior to VFD Installation

5.3.1.1. Data Collection

Prior to installation of a VFD, field data were collected to determine if deep well pump operation and energy use were in line with expected values. Data were collected from June 15 to June 22, 2016. Data for deep well pump flow rate, pumping water level, and static water level were collected from SCADA in 30-second time intervals. The procedure detailed in Mancosky (2017a) was used to estimate average operating points for comparison against the manufacturer 100% speed curve. Estimates were compared to measurements collected by the power meter installed on-site. A FLUKE 435 Series II Power Quality and Energy Analyzer (“power meter”) was also

connected to the line side of the motor to collect pump power measurements (see Mancosky 2017a for discussion of power meter).

5.3.1.2. *Operating Conditions*

A summary of the average deep well operating conditions for the test period are presented in Table 5-3.

Table 5-3 – Average deep well operating conditions for June 15-22 field test

	Volume Pumped (kgal)	Run Time (hr)	Flow Rate (gpm)	Pumping Water Level (ft)	Static Water Level (ft)
15-Jun	767	5.3	2,412	273	132
16-Jun	1,761	12.2	2,405	278	138
17-Jun	1,921	13.3	2,407	279	137
18-Jun	2,179	15.2	2,390	282	139
19-Jun	2,114	14.8	2,380	284	140
20-Jun	1,939	13.5	2,394	280	141
21-Jun	1,660	11.5	2,406	279	138
22-Jun	965	6.7	2,400	277	138
Averages	1,901	13.2	2,399	279	138
Standard Deviation	200	1.4	90	12	2.7

Pump operation for the test period is compared with the manufacturer's curve in Figure 5-2. The manufacturer's pump curve is shown in blue, with the average system head curve for the test shown in red, and the average operating point with a yellow circle. Also included is a set of estimated operating points (orange diamonds) for a complete two-hour pump cycle on June 17. Parabolic pump efficiency curves are also plotted with dashed lines.

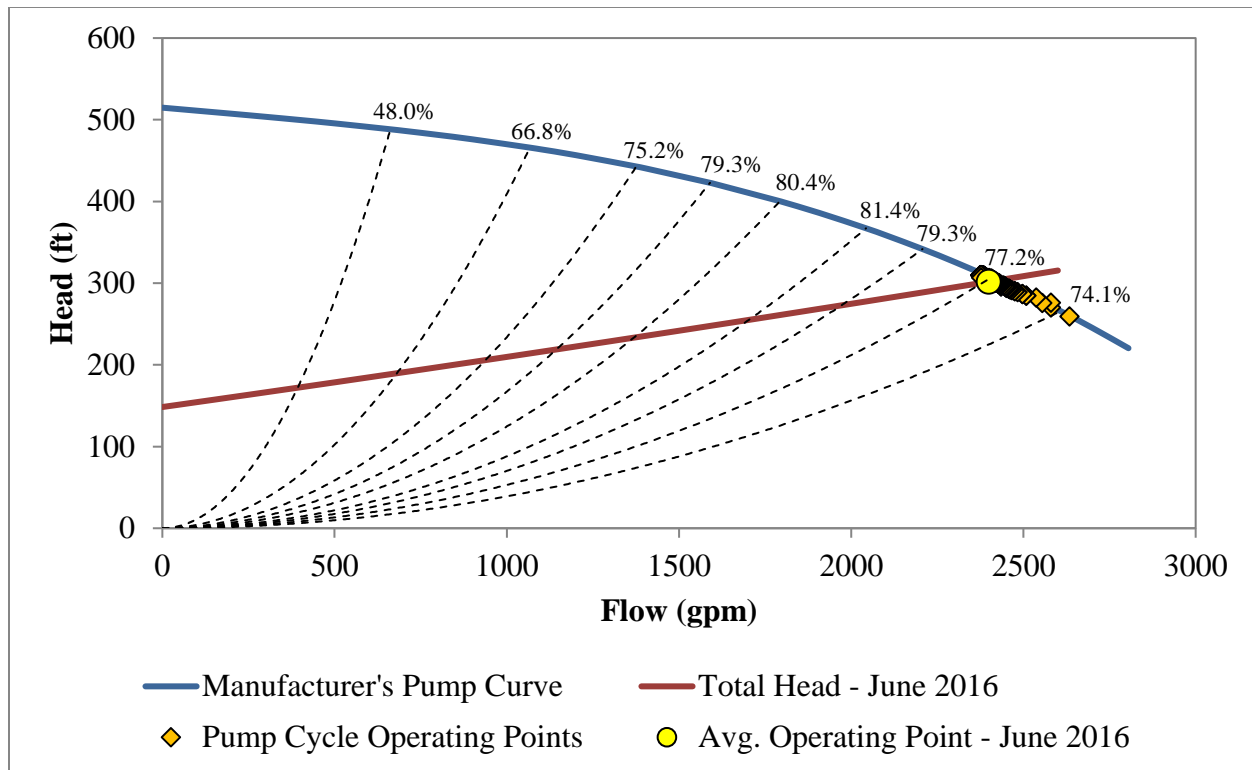


Figure 5-2 – Confirmation of Unit Well 30 deep well pump performance prior to VFD installation. Data collected during field test from June 15 – 22, 2016.

Data collected at the time of the field test indicated the pump was performing in-line with expectations. Individual pump operating points and the average operating point were on the manufacturer's pump curve. As expected, points to the far-right represented time points just after the pump was turned on, where flow rates were higher due to low drawdown during initial operation. As drawdown increased, TDH increased and operating points moved left along the pump curve (with lower flow rate and higher TDH). The pump operated as expected in terms of flow rate and head compared to the original manufacturer's curve.

Observed energy use also matched estimated values. Interpolated pump efficiency for the test average operating point was 77.2%, and motor efficiency was taken to be 94.4% (from MWU Motor Master Report, 2011). This translated to an estimated motor input power of 187 kWh and an energy intensity of 1,300 kWh/MG. Average power measured by the power meter was $187.9 \pm$

3.0 kW, for a motor energy intensity of 1,305 kWh/MG. From MWU staff readings of station energy use, it was determined that the deep well pump accounted for almost 60% of total station energy use. Estimated energy use was nearly identical to observed values, and there were no signs of diminished pump performance or efficiency based on the available data in June 2016.

The test of the deep well pump at Unit Well 30 indicated the pump performed as expected in terms of operating flow rate, head, and energy use. Based on these results, installation of a VFD proceeded. Energy savings from VFD installation were expected to be comparable to estimates since the pump was performing satisfactorily.

5.3.2. Selection of Pump Operating point

The location of Unit Wells 18 and 30 are shown in Figure 5-3. Unit Well 30 is in a relatively isolated section of Pressure Zone 6W, with Unit Well 18 the only nearby well. Booster pumps at both Unit Wells 18 and 30 operated with VFDs set to provide constant discharge pressure. For this mode of operation, booster pump speed and flow rate adjust to maintain a constant discharge pressure as demand in the system varies.

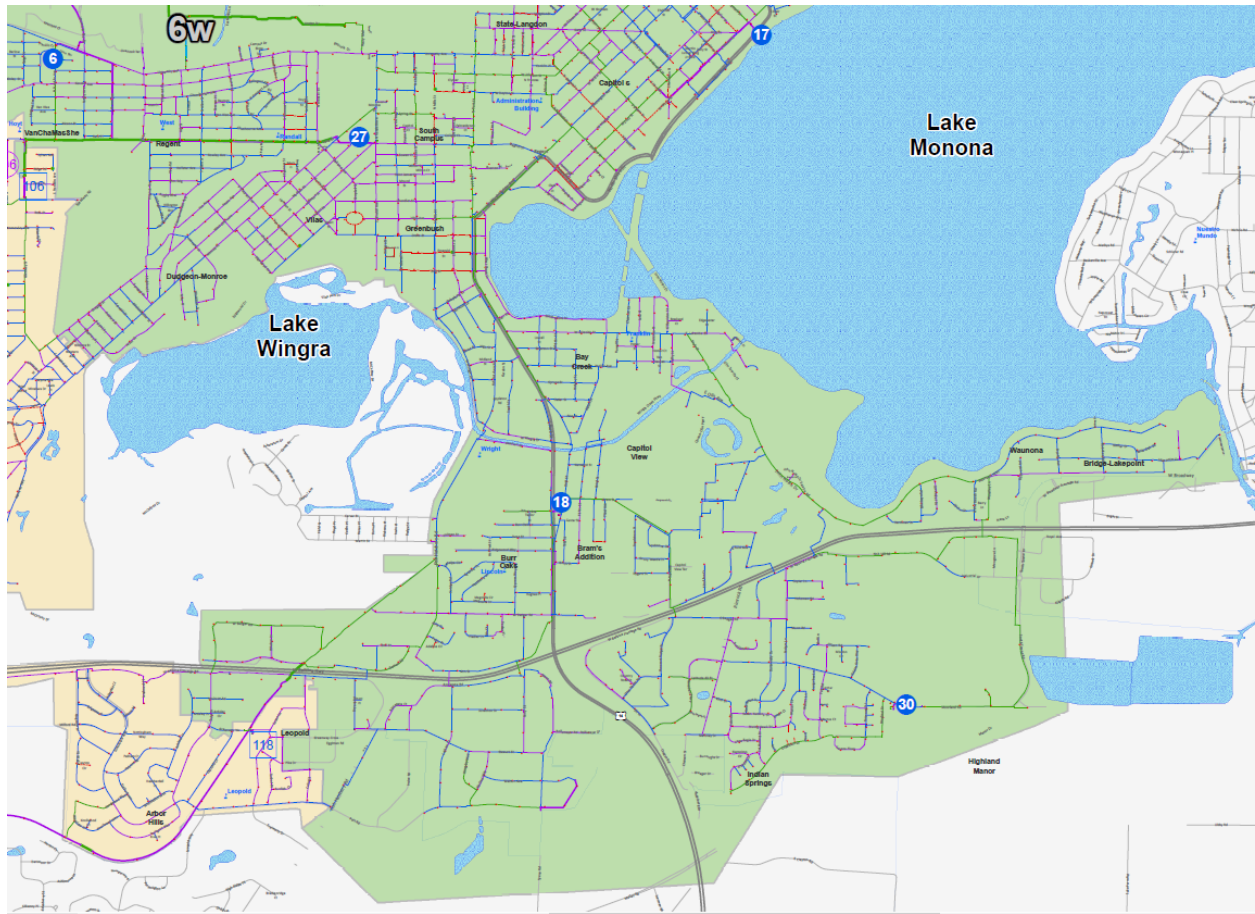


Figure 5-3 – Overview of southeastern portion of Pressure Zone 6W showing the locations of Unit Wells 18 and 30.

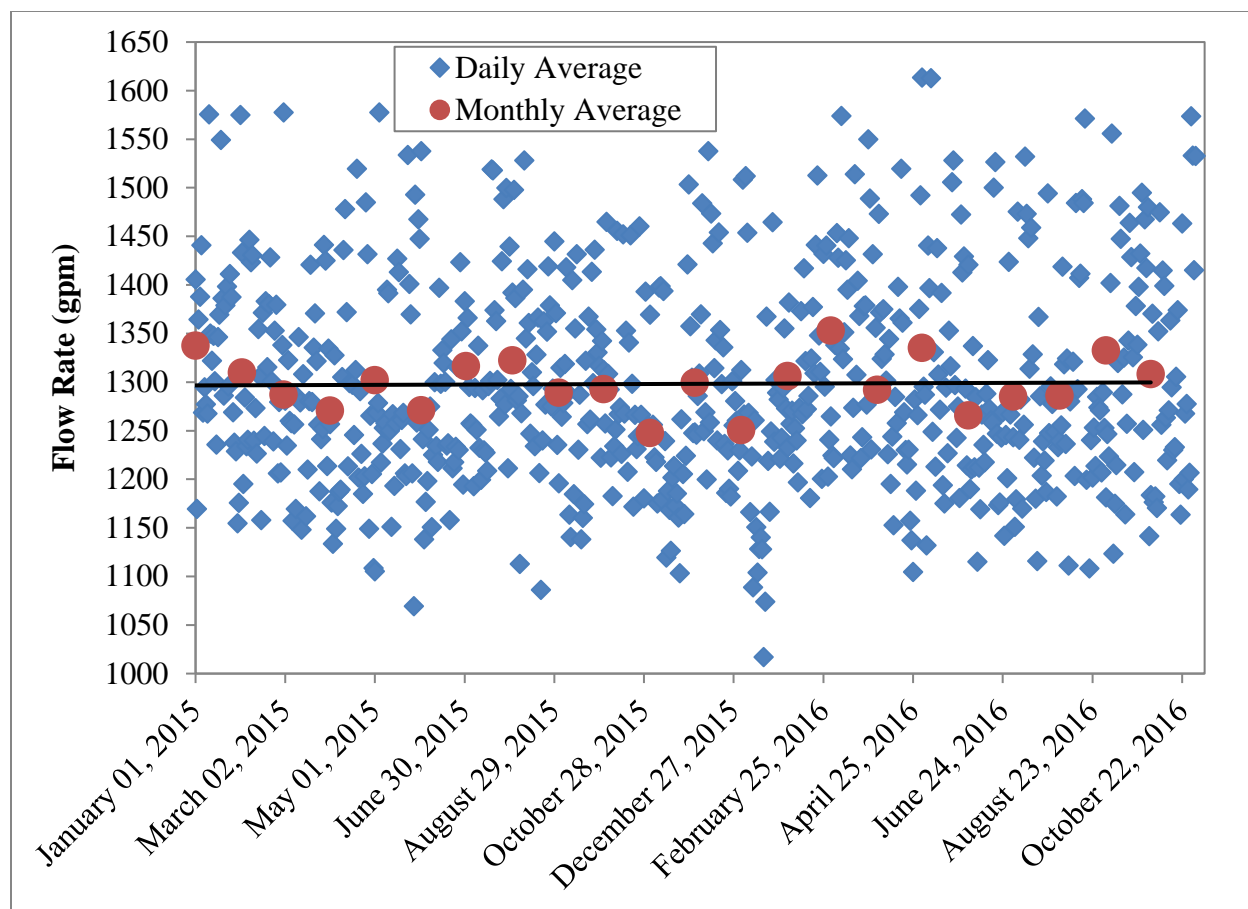


Figure 5-4 – Daily average booster pump flow rate (blue diamonds) and monthly average booster pump flow rate (red circles) at Unit Well 30 between January 2015 and November 2016. Black trend line shows 1,300 gpm average flow rate.

Average monthly booster pump flow rate from Unit Well 30 between January 2015 and November 2016 was $1,300 \pm 30$ gpm, as shown in Figure 5-4 with the black trend line. Initially, the intent was to operate the deep well pump close to 1,300 gpm to match average booster pump flow rate. Further analysis of daily average flow rates, blue diamonds in Figure 5-5, showed that daily average flow rates varied by 20% above and below the 10-month average of 1,300 gpm.

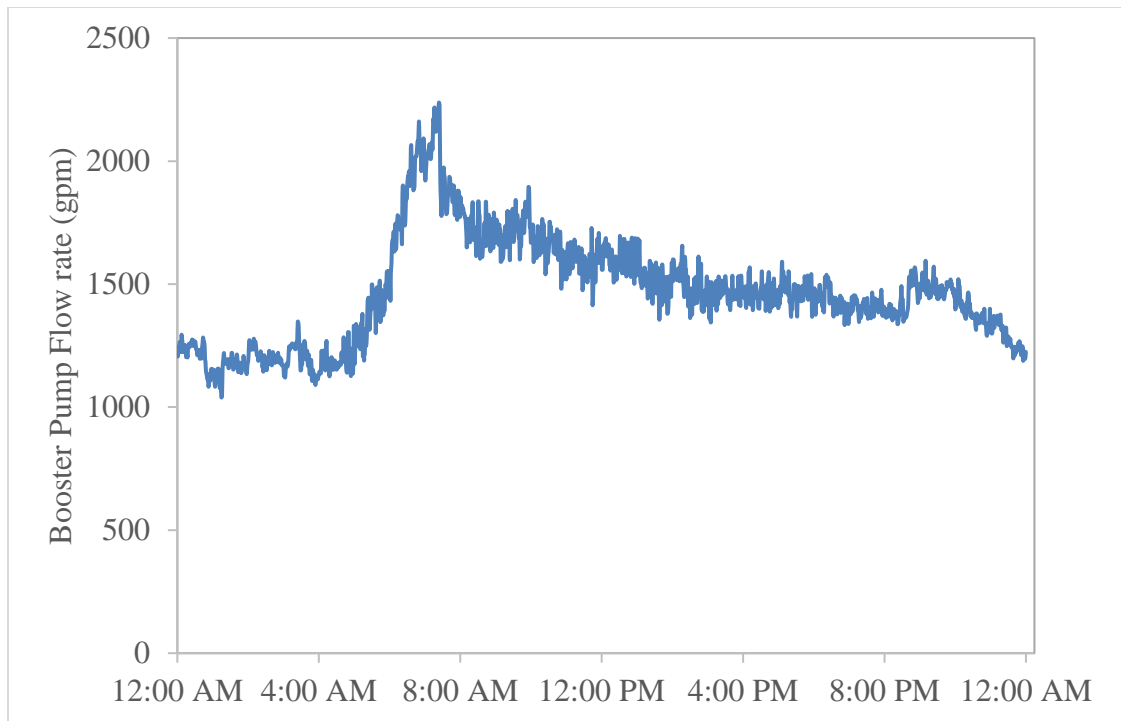


Figure 5-5 – Booster pump flow rate at Unit Well 30 for October 7, 2016.

Water demand in the system determines booster pump operation at Unit Well 30, and Unit Well 18 impacts the demand at Unit Well 30. When Unit Well 18 is off, water production from Unit Well 30 is greater to meet the demand of the entire area. When both wells are operational, demand is met by both sites, and production at Unit Well 30 decreases. This is highlighted further in Figure 5-5, which shows booster pump flow rate at Unit Well 30 on October 7, 2016, a day when Unit Well 18 was not used. Water demand at Unit Well 30 was generally greatest during morning hours between 6 am and 9 am. Booster pump flow rate on October 7th exceeded 2,000 gpm during this window and was close to 1,500 gpm for most of the day. Similar trends were observed on other days when Unit Well 18 was not operational, average flow rate from Unit Well 30 was close to 1,500 gpm for the entire day. Even on days when Unit Well 18 was operational during the peak demand morning hours, flow rates at Unit Well 30 could reach 1,800 gpm.

These observations indicated a deep well pump set point of 1,300 gpm would be insufficient to consistently meet customer demands. After analyzing more daily operational data for Unit Well 30, the decision was made to operate the deep well pump at 1,450 gpm. This flow rate was selected to ensure the reservoir would not drain significantly during peak water demand hours. In conjunction with the selection of this flow rate, MWU operators were instructed to ensure Unit Well 18 was operational each morning to mitigate the effect of peak water demands.

5.3.3. Estimated Savings at 1,450 gpm operation

After VFD installation, an error was discovered with the SCADA measurement of pumping water level. MWU staff investigated the issue, and the source of the error was deemed to be the transducer. The transducer was installed at a level of 322.5 feet in the pump column, 27.5 feet higher than the 350 feet used as a reference point in SCADA, causing all measurements of water level prior to March 14, 2017 to be deeper than the true depth. Methods for estimating energy savings presented in this paper used data after the error was corrected.

SCADA data from one week of pump operation at 1,450 gpm were used to develop a system curve using the methods described in Mancosky (2017a). Affinity Laws were used in conjunction with the system curve to identify a pump speed and average operating point for 1,450 gpm average flow rate operation. Energy and cost savings were estimated relative to 100% speed operation using methods described in Mancosky (2017b). Analysis of SCADA data collected after the correction to the water level measurements resulted in the 100% speed curve being shifted down to match observed data, similar to corrections described in Mancosky (2017b).

Figure 5-6 shows the magnitude of the adjustments in both the system head curve and in the 100% speed pump curve, along with an adjusted pump curve at reduced speed. Original energy savings estimates for deep well pump operation at 1,450 gpm were based on the system head curve

determined from August 2015 data (red, Mancosky 2017b). The corrected system head curve (green) was based on June 2017 data after correction of water level measurements. Solid blue lines represent pump curves from original manufacturer data and dashed blue lines show shifted pump speed curves based on corrected data.

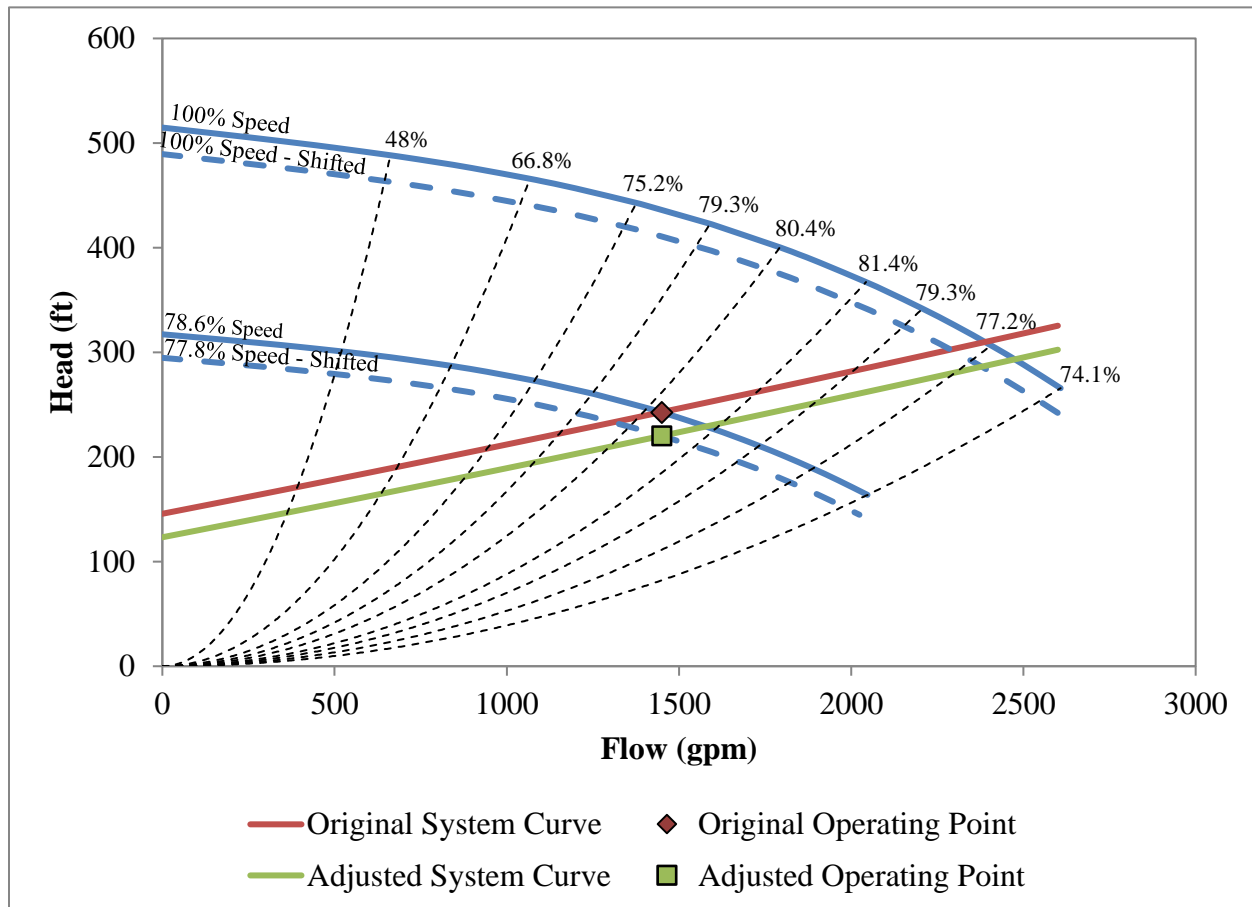


Figure 5-6 – Comparison between estimated pump operation at 1,450 gpm. Solid blue lines show original pump speed curves based on manufacturer data. Dashed blue lines show shifted pump curves. The original estimate is shown in red and the updated estimate is shown in green.

For August 2015 data, 78.6% pump speed was estimated to provide a pump flow rate of 1,450 gpm. At 100% pump speed (2,390 gpm and 310 feet TDH) motor input power was estimated to be 191 kW, an energy intensity of 1,327 kWh/MG. Operation at 78.6% speed (1,450 gpm and

243 feet TDH) was estimated to be an input power of 87 kW and an energy intensity of 1,000 kWh/MG.

Based on these estimates, operation at 1,450 gpm with installation of a VFD was expected to provide the following benefits:

- Reduction in input power demand by 103 kW.
- Energy intensity savings of 327 kWh/MG, for a \$36/MG savings.
- Daily energy savings of 592 kWh for 1.8 MGD total deep well pumpage.
- Cost savings of \$65 per day at an average energy cost of \$0.11/kWh.

For the updated pump and system curves and June 2016 data, 77.6% speed was estimated to provide a pump flow rate of 1,450 gpm. For an operating point of 2,380 gpm and 286 feet TDH at 100% speed, power and energy intensity were estimated to be 177 kW and 1,238 kWh/MG. Operation at 77.6% speed (1,450 gpm gpm and 220 feet TDH) was estimated to result in power and energy intensity of 79 kW and 907 kWh/MG, respectively. Using these updated estimates, operation at 1,450 gpm was estimated to provide the following benefits:

- Deep well pump demand reduction of 98 kW.
- Energy intensity savings of 331 kWh/MG, for a \$36/MG savings.
- Daily energy savings of 595 kWh for 1.8 MGD total deep well pumpage.
- Cost savings of \$65 per day at an average energy cost of \$0.11/kWh.

New estimates of energy savings and benefits were within 3% of the original estimates. Going forward, all observed savings were compared against the corrected, updated values.

5.3.4. Test Set-up after VFD installation

After 1,450 gpm was selected as the average operating point, MWU operators were briefed on the operational changes associated with VFD installation at Unit Well 30. The deep well pump was to be operated at 1,450 gpm and booster pump operation was unchanged. With the decreased deep well flow rate, reservoir level at Unit Well 30 was monitored more closely. Operators were also instructed to use Unit Well 18 to lessen water demand during the morning hours, and then the well could be shut down at night. These instructions were consistent with the general operation of the wells prior to VFD installation. The aim was to continue MWU's general operational strategy for Unit Wells 18 and 30 so that the change in Unit Well 30 operation did not correspond with increased energy use from Unit Well 18.

The VFD was installed on November 15 and 16, 2016. The intent of this study was to catalog energy use across an entire MG&E billing period to quantify observed savings. The billing period analyzed for constant flow operation at 1,450 gpm was November 18-December 20, 2016.

Energy use data was collected using the power meter and SCADA power measurements to characterize operation and energy use. The power meter was connected to the load side of the VFD (i.e., line side of the motor), providing a comparison with the SCADA VFD power measurements (also based on the load side of the VFD). Pump operational data such as flow rate and pumping water level were collected from the SCADA historian.

5.3.5. Observed Cost and Energy savings

Observed cost and energy savings from VFD installation were determined using billing data from MG&E.

For detailed comparison of the billing periods before and after VFD installation, MG&E furnished data showing 15-min demands for both Unit Wells 18 and 30. Energy use was calculated from this 15-min demand dataset, and was confirmed to be equal to values shown in monthly billing statements. With this confirmed, energy use and cost were calculated for each day in the two billing periods. Average daily energy use and cost were calculated for the two periods (October 20 – November 18 and November 18 – December 20) at Unit Wells 18 and 30.

At Unit Well 30, the VFD was installed on November 15 and 16, with the first day of full operation on November 17. These days were excluded from the analysis because they did not represent normal operation and energy use prior to VFD installation. Unit Well 18 was not operational for 5 days between October 20 and November 18, and 2 days between November 18 and December 20. These days where the well was not operational were not considered when determining average energy use or cost.

Energy savings were calculated using the average daily energy use values determined from the billing data. Cost savings were also calculated on a per day basis.

5.4. RESULTS AND DISCUSSION

5.4.1. Observed Energy and Cost Savings for Unit Well 30 VFD Installation

5.4.1.1. *Pump Operation at 1,450 gpm*

Data from the SCADA historian and MWU staff were analyzed for the entire billing period (November 18 – December 20, 2016) the deep well pump was operated at 1,450 gpm. Average static water level was 135 feet \pm 3 feet, 3 feet lower than the level during the June 2016 test period. The average pumping water level at 1,450 gpm operation was 228 feet \pm 1.5 feet. VFD average speed for the entire test cycle was 76% speed. Operation at 1,450 gpm instead of 2,400 gpm

resulted in a 50-foot decrease in TDH on the pump. Static water level, pumping water level, and pump speed were consistent for the entire billing period. Data collected from operation in June 2017, after corrections to the measurement of water level were made, showed a static water level of 113 ± 1.5 feet and a pumping water level of 205 ± 3.7 feet.

5.4.1.1.1. Pump Cycling

The change in pump operation significantly reduced the number of deep well pump starts from 194 between October 20th and November 14th down to 50 between November 18th and December 20th. The average number of starts per day decreased from 7.5 to 1.5. The change in a typical day of operation at Unit Well 30 is shown in Figure 5-7.

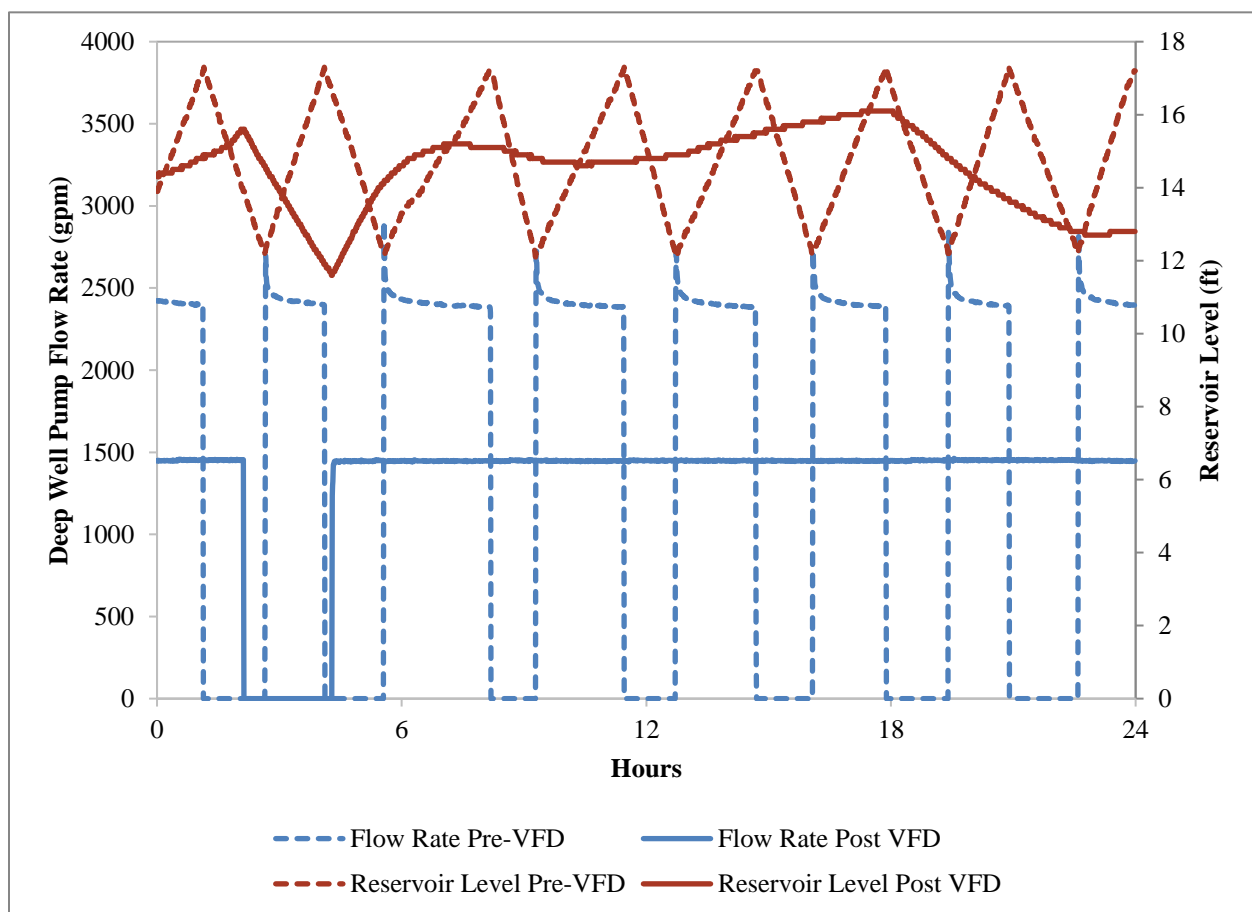


Figure 5-7 – Daily operational comparison of Unit Well 30 deep well pump before (November 8, 2016) and after (November 27, 2016) installation of a VFD set to operate at 1,450 gpm.

Before VFD installation the pump would cycle on and off 7 to 8 times per day, filling and draining the reservoir in consistent cycles. After VFD installation and operating at 1,450 gpm, the pump generally shut off once early in the morning and once in the afternoon or early evening. Time of day and number of pump shut-offs depended on water demand and the operation of Unit Well 18, but it was common for the pump to be off for 1 to 2 hours between 2 and 6 am daily.

5.4.1.2. *Deep Well Pump Energy Use*

Average motor input power at 100% pump speed was 187.9 ± 3.0 kW when measured with the power meter in June 2016 and 186.1 ± 0.3 kW when 100% speed was tested after VFD installation (see APPENDIX D for discussion of the VFD test). Estimated power at 100% speed was 177 kW, 5% less than observed. Observed wire-to-water efficiency was 68.7% compared to the estimated 72.6%. The decrease in flow rate and head that resulted in the shifting of the pump curve was the likely cause of the lower pumping system efficiency.

Power measured by SCADA for operation at 1,450 gpm was 83.7 ± 2.5 kW. The change in pump operation reduced motor input power by 102 kW, 4% larger than the estimated 97 kW. Observed energy intensity savings for the deep well pump alone were 335 kWh/MG, 1% greater than estimated. Estimated values for power and energy intensity reduction were within 5% of observed values.

5.4.1.3. *Station-wide Operation and Energy Use*

5.4.1.3.1. *Average Station Operation*

For the portion of the billing period prior to VFD installation where the pump operated at 100% speed, average deep well production was 1.88 ± 0.22 MGD. The deep well pump was

operational for 13.0 hr/day at a flow rate of $2,410 \pm 11$ gpm. Booster Pump 1 or 2 was operational for 24 hr/day at an average flow rate of $1,300 \pm 120$ gpm (1.87 ± 0.20 MGD).

For the 32-day billing period after VFD installation, average daily water production was essentially unchanged at 1.87 ± 0.11 MG. The decrease in pump flow rate to 1,450 gpm increased well pump run time to 21.5 hr/day, while booster pump operation was nearly unchanged with one booster pump operational 24 hrs/day at an average flow rate of $1,280 \pm 66$ gpm (1.86 ± 0.65 MGD).

5.4.1.3.2. Station Energy Use

Average daily energy use for the 32-day billing period after VFD installation was $3,440 \pm 170$ kWh/day. For the previous billing period, when the deep well pump was operating at 100% speed, average daily station energy use was $3,980 \pm 410$ kWh/day. The reduction in deep well pump speed resulted in an observed 13% decrease in station-wide energy use, a savings of 540 kWh/day. Compared to the same billing period in 2015, energy use was 600 kWh/day less ($4,040$ kWh/day to $3,440$ kWh/day), a 15% savings.

Station energy intensity for operation at 1,450 gpm was $1,850 \pm 42$ kWh/MG in December 2016, a savings of 280 kWh/MG compared to $2,130 \pm 60$ kWh/MG in the billing period prior to VFD installation. Energy intensity for the December 2015 billing period was $2,130 \pm 40$ kWh/MG. The observed energy intensity savings of 280 kWh/MG were 15% less than the estimated savings for the deep well pump alone. Station energy intensity savings estimates accounted for variations in booster pump operation, and the increased usage of Unit Well 18 likely changed the booster pump flow pattern. Average booster pump efficiency was estimated to be 2.8% lower, and booster pump energy intensity was estimated to be 48 kWh/MG greater for the billing period after VFD installation. This 48 kWh/MG increase accounted for nearly all the 55 kWh/MG difference between deep well pump energy intensity savings and station energy intensity savings.

5.4.1.3.3. *On-Peak Demand and Energy Use*

The on-peak demand for the billing period with 1,450 gpm operation of the deep well pump was 172.5 kW, 103 kW less than the 275.5 kW demand during the previous billing period with the deep well pump at 100% speed. This reduction in station-wide on-peak demand was 6% greater than the estimated 97 kW reduction in deep well pump input power and 1% larger than the observed 102 kW reduction in deep well input power. On-peak demand savings relative to the December 2015 billing period were 136 kW, 308.7 kW to 172.5 kW.

While MG&E on-peak demand charges consider the entire station, change in deep well pump operation was the main driver for demand reduction. Demand charges at Unit Well 30 were set when both the deep well pump and booster pump were operating. The on-peak demand charge of 275.5 kW for the billing period October 20 – November 18 was set with the deep well pump producing 2,470 gpm at a pumping water level of 288 feet and with Booster Pump 2 operating at 90% speed and an average flow rate of 1,850 gpm. For the period after VFD installation (November 18 – December 20), the on-peak demand charge of 172.5 kW was set with the deep well pump operating at 1,450 gpm and a pumping water level of 229 feet while the booster pump operated at 89.2% speed and a flow rate of 1,780 gpm. The booster pump operated at similar conditions for the two periods, so reduction in deep well pump speed was responsible for the on-peak demand reduction.

While booster pump operation did not affect on-peak demand charges for the two billing periods in 2016, it can still play a large role in setting on-peak demand charges. For example, on-peak demand was 308.7 kW during the December 2015 billing period and was set on December 10, 2015 for the 15-minutes from 3:30 pm to 3:45 pm. During this time, the deep well pump was operating at a flow rate of 2,400 gpm with a pumping water level of 282 feet, lower flow rate and

head than in October and November 2016. Likely due to fire flow demands, average booster pump flow rate during this 15-minute period was 3,200 gpm; both booster pumps were operational for half of this 15-minute period. Thus, the booster pumps were responsible for this increased on-peak demand value in December 2015. Events of this nature are outside the control of MWU, but could still have substantial effects on energy bills.

Prior to the change in deep well operation, average operation of Unit Well 30 was consistent over 2015 and 2016. Consistent operation of wells results in similar on-peak demand charges from month to month. Average on-peak demand at Unit Well 30 for the past two years has been $280 \text{ kW} \pm 13 \text{ kW}$. This includes two months where on-peak demand values were 309 and 330 kW, likely due to fire-flow conditions. Excluding those months, average on-peak demand was $275 \text{ kW} \pm 5 \text{ kW}$. Significant changes in on-peak demand charges at Unit Well 30 have only come from the installation of a VFD or fire-flow conditions.

If MWU maintains operation of the deep well pump at 1,450 gpm for one calendar year, there is the potential to provide additional cost savings. The maximum 12-month demand would be reset to a new lower level. Resetting the maximum demand charge from 330 kW to 200 kW would save MWU an additional \$10-\$15 per day, assuming the billing rate structure does not change significantly.

On-peak energy use showed a similar trend to energy use overall, decreasing by 13% (1,810 kWh/day to 1,580 kWh/day). Decreased energy use during on-peak peak hours saved MWU \$9 per day in on-peak surcharges.

5.4.1.3.4. Cost Savings

A comparison of operational day energy use and cost for the three examined billing periods is presented in Table 5-4. Observed daily cost savings from the billing period before and after VFD

installation were \$60/day. Compared to the December 2015 billing period, cost savings with VFD installation were \$74/day. Savings compared to December 2015 were greater because the daily demand charge cost was higher and daily energy use was higher than in November 2016. Observed savings were comparable to the estimated \$65 daily savings. On a per volume basis, the operational change resulted in a cost savings of \$36/MG also comparable to the estimate of \$36/MG. Compared to the 2015 December billing period, daily energy costs were \$74 less and \$36/MG lower.

Table 5-4 – Comparison of energy use and costs for Unit Well 30. Billing periods 11/18/15-12/18/15 and 10/20/16 were prior to VFD operation.

Billing Period	Pre-VFD Installation		Post-VFD Installation
	11/18/15-12/18/15	10/20/16-11/18/16	11/18/16-12/20/16
Average Energy Use (kWh/d)	4,040	3,980	3,440
Daily Production (MGD)	1.90	1.87	1.86
Average Energy Cost (\$/day)	\$392	\$378	\$318
Energy Cost per Volume Pumped (\$/MG)	\$207	\$203	\$171
On-Peak Demand (kW)	308.7	275.5	172.5
On-Peak Demand Cost (\$/day)	\$73	\$65	\$41
Max Demand (kW)	308.7	330	330
Max Demand Cost (\$/day)	\$33	\$35	\$35

It is important to note that the reduction in demand accounted for nearly \$25/day of the \$60/day of savings, almost 40% of total savings. The impact of demand charges is discussed further in Section 5.4.4.

The \$60/day of observed savings closely matched estimated savings. Should MWU continue to operate the deep well pump at 1,450 gpm and maintain current operational strategies, the payback period for the VFD installation should be close to the estimated 2 years. Crucial to maintaining this payback will be managing on-peak operation. Increases in the speed of the pump during on-peak hours will increase on-peak demand charges and cut into the savings and potentially lengthen the payback period.

5.4.2. Unit Well 18 Operation and Energy Use

While energy savings estimates can be based on changes in operation of individual pumps and unit wells, actual energy savings are dependent on the operation of the entire MWU system. Changes in Unit Well 30's operation had the potential to impact the operation of the Unit Well 18. Operational data and energy bills were also examined for Unit Well 18 to ascertain changes in operation that could negate some of the observed savings at Unit Well 30.

5.4.2.1. Station-wide Energy Use and Operation

5.4.2.1.1. Average Station Operation

For the billing period prior to VFD installation (October 20 – November 14), average daily water production from Unit Well 18, was 1.18 ± 0.31 MG. On average, the deep well pump was operational for 10.6 hrs/day at a flow rate of $1,750 \pm 16$ gpm while Booster Pump 2 was operational for 14.6 hrs/day at a flow rate of $1,340 \pm 120$ gpm. When system demand was low, MWU operators

shut down Unit Well 18 for entire days. During this time, Unit Well 18 did not operate for 5 of the 26 days.

For the billing period after VFD installation at Unit Well 30 (November 18 – December 20), average daily water production from Unit Well 18 was 1.16 ± 0.34 MG, virtually unchanged from the average before VFD installation. On average, the deep well pump operated for 11 hours per day at $1,760 \pm 18$ gpm and Booster Pump 2 operated 15.8 hours per day at a flow rate of $1,210 \pm 130$ gpm. Unit Well 18 was not operated for only 2 of the 32 days.

Overall water production did not change significantly with the change in operation at Unit Well 30, decreasing only 0.02 MG per day operational. The primary differences in operation at Unit Well 18, with the change at Unit Well 30, were increased frequency of use of the well and longer run times for the booster pump, both of which were expected based on the directions given to the pump operators when the VFD was installed.

5.4.2.1.2. Station Energy Use

Total energy use between October 20 and November 14 was 55,993 kWh at Unit Well 18. The well was completely shut down 3 days in this billing period. On two additional days, the deep well pump pumped a combined 100,000 gallons without the booster pump operating. Effectively, the site was operational for 21 of 26 days. Energy use for days where no water was pumped was an average of 20 kWh, 0.1% of the total used in the 26 days. This was consistent with Baniel's (2013) observation that 99% of energy use at unit wells was attributable to pumping operation. Average energy use for the 21 days operational was $2,630 \pm 680$ kWh/day for 1.18 ± 0.31 MGD of production, and energy intensity was $2,260 \pm 72$ kWh/MG.

As mentioned previously, for the billing period after VFD installation, Unit Well 18 produced 1.16 MGD and was operational 30 of 32 days. Average energy use and energy intensity

on days the well was operational were $2,640 \pm 800$ kWh/day and $2,270 \pm 75$ kWh/MG. There were no significant observed impacts of the change in Unit Well 30 operation on energy use at Unit Well 18.

5.4.2.1.3. On-Peak Demand Charges and Energy Use

Maximum on-peak demand was nearly identical over the two billing periods. Prior to VFD installation, on-peak demand was set at 247.4 kW when the deep well was operating at a flow rate of 1,730 gpm with a pumping water level of 310 feet and the booster pump was operating at an average flow rate of 2,010 gpm and at 96% pump speed. After VFD installation, on-peak demand was set 248 kW when the average deep well flow rate and pumping water level were 1,760 gpm and 308 feet while booster pump average flow rate and VFD speed were 2,000 gpm and 94.6% speed. Maximum on-peak operation of the deep well pump and booster pump were not changed significantly by the changes in Unit Well 30 operation. The small difference in on-peak demand resulted in a cost increase of \$0.22 per day. The annual maximum demand charge was previously set in July 2017 at 267.3 kW, and was unaffected by the operation before or after VFD installation.

On-peak energy use and production were not significantly affected by the change in operation of the two wells. Average on-peak energy use and production prior to VFD installation was 1,870 kWh/day and 0.79 MGD, and 1,850 kWh/day and 0.78 MGD post-VFD installation. This was consistent with previous observations that there were no significant impacts from the change in operation at Unit Well 30.

5.4.2.1.4. Cost of Operation

Analysis of the energy billing data further reinforced the conclusion that the change in operation at Unit Well 30 produced no observable adverse effects at Unit Well 18. Average cost per day operational was $\$341 \pm \70 for the 24 operational days between October 20 and November

18. For the 30 operational days between November 18 and December 20, average cost per day operational was $\$344 \pm \71 . Daily energy costs were nearly identical before and after VFD installation. Observed savings at Unit Well 30 were not reduced by any increases in energy use at Unit Well 18.

While there were no observed changes in daily energy costs at Unit Well 18, examination of the energy use and billing structure resulted in some interesting observations. MWU was billed for multiple daily charges at Unit Well 18. The most important ones were the monthly on-peak demand, customer yearly maximum demand, and the backup generation charge. Unlike Unit Well 30, MWU leases the on-site generator at Unit Well 18 and was charged nearly $\$0.07$ per kW of customer max demand per day. When all the daily charges were applied, baseline cost at Unit Well 18 was $\$150$ per day. MWU was billed this amount each day regardless if water was pumped. While shutting down the site for a day saves energy use, this charge still cost MWU nearly $\$150$ each day in November and December 2016. The average operational cost per day was $\$350$ over these two months, and this daily charge makes up over 40% of costs at Unit Well 18. An additional observed effect of this billing structure and occasional shutdown of the well was a greater effective energy cost. Average energy costs were $\$0.14$ per kWh over 2016 and 2017, greater than the utility-wide average of $\$0.11$ per kWh.

MWU should be aware of this situation when choosing how to operate wells. Shutting down a well like Unit Well 18 on a low demand weekday may save energy and money at Unit Well 18, but could cost nearly $\$150$ for the billing rates in 2016 and 2017. If this choice resulted in the booster pumps operating at a higher flow rate at Unit Well 30, it could result in increased demand costs at that site. Resetting the on-peak demand at Unit Well 30 could cost MWU more than the one day of savings at Unit Well 18.

While this was not examined at any other sites, it is expected that similar relationships exist throughout the system. For the commercial rate structure MWU is billed at, any well that is used during a billing period will cost money even on days when shut down. Demand charges will be applied each day, and depending on the well, could be a significant portion of the overall bill.

5.4.3. Booster Station 118 Operation and Energy Use

Operational changes at Unit Well 30 also had the potential to have a negative impact on operation of Booster Station 118. Booster Station 118 is used to transfer water between Pressure Zones 6W and 7. Booster pumps can lift water from Pressure Zone 6W to 7, or pressure-reducing valves can allow return flow from Pressure Zone 7 to 6W. Decreased production from Unit Well 30 could have been offset by an increase in return flow from Booster Station 118, which would have resulted in increased energy use from Pressure Zone 7 wells. Conversely, increased pumpage from Booster Station 118 would have increased production and energy use at Unit Wells 18 or 30.

An analysis of operational data showed sparse use of the site before and after VFD installation. Prior to VFD installation, Booster Station 118 was used for two days to pump 0.6 MG to Pressure Zone 7, with no use of the pressure-reducing valve to allow return flow to Pressure Zone 6W. After VFD installation, there was an increase in usage of the site to transfer water from Pressure Zone 7 to Pressure Zone 6W, with a total of 1 MG of water transferred to Pressure Zone 6W on 5 separate days. Unit Well 30 produced nearly 60 MG in this time frame, so this value was inconsequential.

5.4.4. Effect of Demand Charges on MWU Energy Bills

Demand charges made up a significant portion of the monthly electricity bill at both Unit Wells 18 and 30. At Unit Well 18 demand charges accounted for 37% of the monthly bills

examined between January 2016 and May 2017. When the charge for back-up generation was also included at Unit Well 18 (billed based on the yearly maximum demand on a per kW per day basis), demand related charges made up 42% of the total bill. At Unit Well 30, demand charges made up 38% of monthly billed costs between December 2015 and November 2016, prior to VFD installation. After VFD installation and reduction in deep well speed, demand charges have made up 33% of bills between November 2016 and May 2016. When the credit for on-site generation capacity was included, demand related charges made up 28% of the bill prior to VFD installation and 25% post-installation.

The impact of demand charges on energy bills at Unit Wells 18 and 30 highlighted an issue with the use of a utility-wide average electricity cost for estimating savings. Demand charges and different rate structures for different sites result in variable energy costs throughout the system. This was demonstrated at Unit Wells 18 and 30, where average energy costs were \$0.14 per kWh and \$0.10 per kWh, compared to the MWU average of \$0.11 per kWh. Observed cost savings will be determined by more than just total energy savings alone. For example, demand reductions could provide noticeable cost savings even when energy savings were not estimated to be significant. As an example, the average cost of electricity at Unit Well 18 based only the base rate and on-peak surcharges is \$0.065/kWh. From Mancosky 2017b, reduction in speed from 100% to 95% at Unit Well 18 was estimated to provide 72 kWh/MG of savings and reduction in power of 22 kW. For 1.3 MGD of production and 30 days of operation, savings would be \$240 when using \$0.11/kWh. When savings from demand reduction are considered and the \$0.065/kWh rate is applied, estimated savings would be \$380. Reduction in demand is a crucial component of cost savings from VFD installation.

The effect of demand charges on energy costs also impacts estimates of payback periods. Cost savings can come from reductions in the total energy used and from decreases in the on-peak demand. Savings from reductions in energy use can be calculated using the rates from the electric utility. Demand reduction savings can also be calculated, but those are billed on a per kW per day basis. When the two savings were combined, and looked at from an average cost per kWh, lowering the on-peak or maximum demand changed the overall average electricity cost per kWh. For on-peak days, electricity costs based on energy use and on-peak surcharges alone averaged out to about \$0.07 per kWh before and after VFD installation and \$0.05 per kWh for off-peak days. When fees and daily demand charges were included, average electricity cost decreased by half a cent after VFD installation. In general, average electricity cost at Unit Well 30 was closer to \$0.10 per kWh over 2015 and 2016, a lower cost than estimated. There is the potential to lower effective electricity cost at certain sites with reduction in demand charges. In these cases, MWU would be paying a lower effective rate for electricity going forward.

Reduction in demand charges made up a significant component of cost savings from VFD installation at Unit Well 30. The net charge for on-peak demand at Unit Well 30 was \$0.24 per kW per day. The 103 kW reduction in on-peak demand provided MWU with \$24.70 per day of savings, 40% of the \$60 per day of observed cost savings. Reductions in demand charges provided substantial cost savings benefit.

Analysis of later billing periods after VFD installation further highlighted the impact of on-peak demand charges. In April 2017, deep well pump flow rate was increased to 2,000 gpm when other wells in the system were down for maintenance. The new flow rate set-point increased pump speed from 77% to 91%, which increased measured power by 55 kW. The pump operated at this higher flow rate for less than a week, and the average energy use for the billing period was

comparable to other months with consistent 1,450 gpm operation. However, the demand charge for the month increased 45 kW relative to months at 1,450 gpm. This increased on-peak demand increased the cost per day of operation by \$11. Over the entire billing period, this increased on-peak demand cost MWU \$300 of savings alone.

Going forward, MWU should be mindful of the on-peak demand charge when considering how to operate Unit Well 30 and other wells. Operating the deep well pump at higher speeds during on-peak hours at any time during a billing period will reset the on-peak demand charge and eat into cost savings.

Cost savings and payback estimates are also susceptible to changes in the electric rate structure. Increases in electricity costs could lessen the payback periods for VFD installation. Given the complex rate structures for energy use at many of the unit wells, estimation of cost savings is not perfectly represented with the use of an average electricity cost. A large portion of cost savings come from a reduction in the on-peak demand charge.

5.4.5. Long Term Savings

Long-term cost and energy savings associated with VFD operation were examined after six months of operation post-installation. A long-term comparison of Unit Well 18 and 30 station energy intensities is shown in Figure 5-8 and Figure 5-9. The black line delineates the date the Unit Well 30 VFD was fully operational with the deep well pump speed at 1,450 gpm. The change in pump speed at Unit Well 30 has produced an observed 275 kWh/MG of energy savings (2,125 kWh/MG to 1,850 kWh/MG). Energy intensity at Unit Well 18 has been more variable, between 2,000 and 2,500 kWh/MG, but there was no evidence of an upward or downward change in average energy intensity.

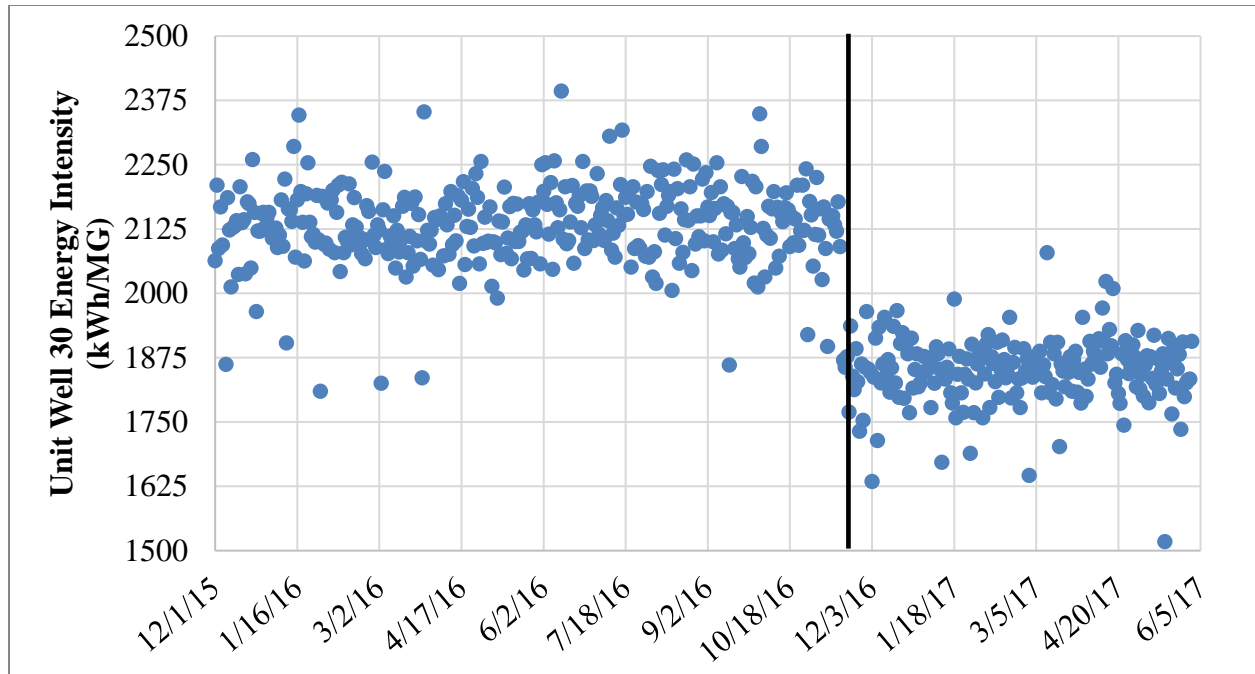


Figure 5-8 – Station energy intensity at Unit Well 30 (December 2015 – May 2017). Black line delineates time of VFD installation and switch to 1,450 gpm operation of the deep well pump.

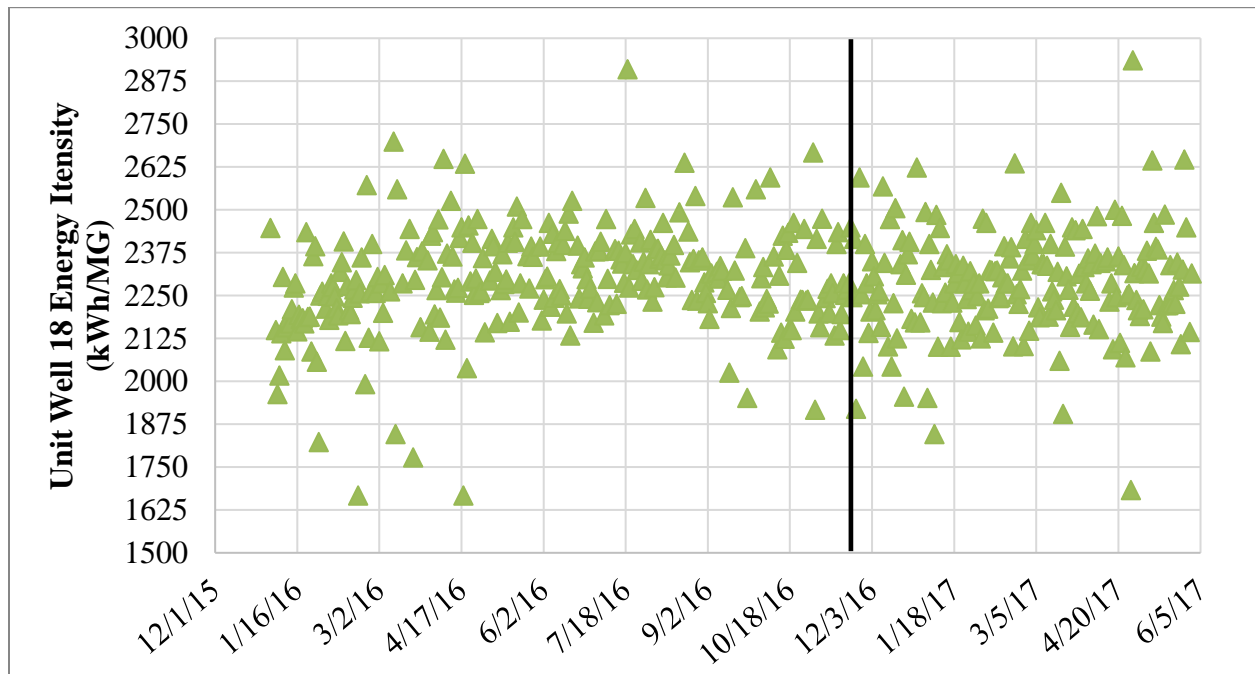


Figure 5-9 – Station energy intensity at Unit Well 18 (December 2015 – May 2017). Black line delineates time of VFD installation at Unit Well 30.

MG&E billing data was examined for the six billing periods after VFD installation (November 2016 – May 2017), the same billing periods the previous year (November 2015 – May 2016), and the six billing periods prior to VFD installation (May 2016 – November 2016). Compared to the year before VFD installation at Unit Well 30, station energy intensity was 288 kWh/MG less, and 277 kWh/MG less than the previous six months of operation. Savings on a per MG basis have been \$26.71 and \$25.39, respectively. Based on these per volume savings, MWU has saved between 94,500 and 98,000 kWh of energy, with \$8,660 to \$9,090 of savings. These savings have come even though deep well speed was increased in March and April 2017, increasing the on-peak demand charge. On-peak demand was 45 and 95 kW greater than the other months of constant operation at 1,450 gpm. These demand increases prevented MWU from saving an additional \$1,000. Even with these increased demands, MWU is on-line to save \$15,000 - \$20,000 for the first year of VFD operation at Unit Well 30. After Focus on Energy grants, total cost for VFD installation was \$23,800. Payback should be within 1.5 years, the low end of predicted payback.

5.5. CONCLUSIONS AND RECOMMENDATIONS

The objective of this work was to verify the cost and energy savings from VFD installation at Unit Well 30.

5.5.1. Conclusions

- The methodology and rankings developed previously for MWU (Mancosky 2017 a-b) successfully predicted savings from VFD installation and confirmed the rankings for prioritizing VFD installation going forward.

- For Unit Well 30 VFD installation, the estimated benefits were verified with observed results:
 - 537 kWh/day of savings compared to operation prior to VFD installation (600 kWh per day estimated savings)
 - 103 kW reduction in billed on-peak demand charge
 - 102 kW reduction in average motor input power (97 kW estimated)
 - \$60 per day cost savings (\$65 per day estimated)
- Provided average operation of a site is unchanged with VFD installation, the developed method accurately estimates the energy savings benefits.
- Changes in operation at Unit Wells 18 and 30 did not yield increased energy use at Unit Well 18 or Booster Station 118. The savings observed at Unit Well 30 were not offset by increased energy use elsewhere in the system, ensuring MWU receives the full benefit of savings observed at Unit Well 30.
- For time-of-use rate structures, demand charges played a significant role in energy costs. For MWU, demand charges made up 40% of total monthly energy costs at Unit Well 18 and 25% of total monthly energy costs at Unit Well 30.
- On-peak demand reduction was responsible for 25% of cost savings from VFD installation. Operating the pump at a constant, reduced speed will help ensure cost savings match expected/estimated values for time-of-use billing structures.
- After 6 months of operation, MWU saved nearly 95,000 kWh and \$8,600 at Unit Well 30. The payback period for purchase and installation should be less than 2 years (total cost of ~\$23,800 after Focus on Energy grant).

5.5.2. Recommendations

- Continue prioritizing deep well pump VFD installation based on the rankings presented in Mancosky (2017b).
- Prioritize VFD installation at Unit Well 6. Ability to flow match the deep well pump with the booster pump will make selection of average operating conditions easiest.
- Groundwater utilities with wells whose operation is impacted by other sites should expand energy savings benefits analyses beyond individual deep well pumps. For MWU, system operation and production was not altered significantly with VFD installation at Unit Well 30, but this may not hold true for other wells and pressure zones. For VFD installation to be most beneficial, energy use and costs should not increase in other components of the system.
- Utilize hydraulic modeling software to determine how VFD installation impacts energy use and operation for entire Pressure Zones, and eventually the entire distribution system.
- Utilities installing VFDs for energy savings should aim to maximize the return on investment from VFD installation. Cost savings will be maximized by managing the on-peak demand charges. Increasing the deep well pump speed will come with on-peak demand increases that will limit cost savings from VFD installation. This cost increase should be weighed against the cost of turning on another well to meet demand.
- When considering VFD installation in the future, consider the expected energy savings and the expected cost savings from reduced electrical demand. Electrical demand reduction could provide noticeable cost savings even at wells where energy savings from VFD installation are lower.

- Continue investigating strategies to reduce on-peak demands in conjunction with energy savings measures. Managing on-peak demands has the potential to provide significant cost savings benefits.

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CHAPTER 6 – CONCLUSIONS AND RECOMMENDATIONS

6.1. CONCLUSIONS

The following conclusions were developed from the work presented in this document:

- MWU and other groundwater utilities can apply the developed estimation method to characterize deep well pump operation and energy use provided the requisite equipment records and operational information are available.
- The developed method can be used to predict general pump performance with VFD installation. Variations in the system curve due to changes in static water level and specific capacity will shift average operating points at given pump speeds, but the method adequately captures general behavior.
- Energy intensity estimates were within 10% of observed values at both test wells, an acceptable difference given the assumptions made to estimate energy use and the seasonal variations in the system curve. Energy savings magnitudes were less predictable, but the method appeared conservative for the tested combination of well and pump properties.
- The top remaining candidates for VFD installation under MWU operational strategy were Unit Wells 6, 13, 19, and 11.
- For MWU, a 10-year payback period was deemed to be an acceptable payback period for a VFD lifespan of 10 – 20 years and a purchase and installation cost between \$30,000 – \$60,000. Half of the eighteen MWU deep well pumps without VFDs were deemed to meet this return on investment.

- Energy savings potential was found to depend on the combination of well and pump characteristics unique to each deep well. The ranking required an examination of all relevant well and pump characteristics at each well in the system.
- Pump selection influences energy savings magnitude; energy savings magnitude will be greater for pumps with an average operating point below the BEP. For these pumps, reductions in pump speed will result in increased pump efficiency.
- Targeting deep well pumps based on high baseline energy use alone is not advised. The two highest energy use deep well pumps, Unit Wells 20 and 26, showed little energy savings potential from VFD installation.
- There is a direct link between energy savings and operational decisions to meet system demand requirements. Operation at the most energy-efficient speed may be limited by production requirements and system demands. Energy savings potential is dependent on the amount of time a pump is used.
- The methodology and rankings developed previously for MWU (Mancosky 2017 a-b) successfully predicted savings from VFD installation and confirmed the rankings for prioritizing VFD installation going forward.
- Changes in operation at Unit Wells 18 and 30 did not yield increased energy use at Unit Well 18 or Booster Station 118. The savings observed at Unit Well 30 were not offset by increased energy use elsewhere in the system, ensuring MWU receives the full benefit of savings observed at Unit Well 30.
- For time-of-use rate structures, demand charges played a significant role in energy costs. For MWU, demand charges made up 40% of total monthly energy costs at Unit Well 18 and 25% of total monthly energy costs at Unit Well 30.

- On-peak demand reduction was responsible for 25% of cost savings from VFD installation. Operating the pump at a constant, reduced speed will help ensure cost savings match expected/estimated values for time-of-use billing structures.
- After 6 months of operation, MWU saved nearly 95,000 kWh and \$8,600 at Unit Well 30. The payback period for purchase and installation should be less than 2 years.

The following conclusions were developed from work not presented in this document:

- The lack of head savings with speed reduction, like those observed for deep well pumps, makes VFDs on booster pumps a poor choice for energy savings for MWU. This will hold true for other pumping systems where TDH is near-constant at all operating speeds.
- Based on data from four MWU deep well pumps, pump starts do not appear to be a significant source of energy use, nor do they significantly increase on-peak demand charges. For MWU pumps with soft-starters or VFDs with soft-start programming, the majority of MWU deep well pumps, pump starts are likely inconsequential from an energy standpoint. Reductions in pump starts from VFD installation or other operational changes still will prove beneficial in reducing wear on the pump and motor.
- Operational data on pump flow rate, water level, and power consumption can be used to identify deterioration of pump performance. Analysis of MWU data for Unit Well 25 through June 2016 pump failure showed decreasing pump flow rate and increasing energy intensity for constant speed pump operation with a VFD. Periodic analysis of operational data can help utilities identify pumps that are performing poorly and better prepare them for potential failure.
- Pump replacement at Unit Well 25 increased well pump flow rate and production capacity and decreased energy intensity for MWU's chosen operational speed. Tests of both pumps

showed pump replacement increased flow rate by 15%, increased pumping water level by 6.5%, and decreased energy intensity by 9%. Increased flow rate and head increased power deep well pump power by 7 kW.

6.2. RECOMMENDATIONS

The following recommendations were based on the work presented in this document:

- Groundwater utilities should apply the developed method to characterize pump operation and energy intensity for variable speed operation across all deep well pumps in their system.
- When developing estimates of energy savings, groundwater utilities should be cognizant of the potential variation in pump operation due to variations in the system head curve that result from changes in static head and specific capacity. Energy savings magnitudes will be impacted by these variations in pump operation, and differences will be most significant at low pump speeds and flow rates.
- Assuming continuation of the current operational strategy with existing pumps, MWU should prioritize installation of VFDs at Unit Wells 6, 13, 11 and 18. While Unit Well 19 was the third-ranked candidate, it is slated to be replaced in the next five years and receive a filtration system, changing the operating conditions of the pump and estimates for energy savings. The change in operating conditions will likely necessitate selection of a new pump, at which point follow recommendations for new pump selection with a VFD.
- Groundwater utilities installing VFDs on deep well pumps for energy savings should ensure the following data is collected and recorded to monitor performance:
 - Pump flow rate

- Pump speed
- Static and pumping water levels
- Power consumption
- Groundwater utilities should do the following to quantify the benefits of VFDs installed for energy savings purposes:
 - Use the collected data in conjunction with methods presented in this work to characterize pump operation and energy use before and after VFD installation.
 - Use electric utility billing data to estimate observed cost savings from VFD installation. To account for changes in operation throughout the year, compare energy use and costs after VFD installation to the same time period in past years.
 - Evaluate savings on a per volume basis when quantifying long-term savings to account for differences in production.
- When replacing pumps at sites where VFD installation is not being considered, MWU pump selection should continue to prioritize matching the design operating point with the BEP of the selected pump.
- When replacing pumps at sites where VFD installation is being considered, MWU pump selection should focus on maximizing energy-efficiency at the expected average operating conditions. This would be a departure from past MWU pump selection practices, which have generally been based on a design flow rate of 2,200 gpm.
- Continue prioritizing deep well pump VFD installation based on the rankings presented in Mancosky (2017b).
- Groundwater utilities should examine all wells as a system and understand that modifying one well could negatively impact energy requirements at another. By using its distribution

system hydraulic computer model to analyze the system, MWU would be able to determine the combination of VFDs to maximize energy conservation.

- Utilities installing VFDs for energy savings should focus on managing peak demands at their facilities. Increasing the deep well pump speed will come with on-peak demand increases that will limit cost savings from VFD installation. This cost increase should be weighed against the cost of turning on another well to meet demand.
- Continue investigating strategies to reduce on-peak demands in conjunction with energy savings measures. Managing on-peak demands has the potential to provide significant cost savings benefits.

The following recommendations were based on work not presented in this document:

- MWU should not install VFDs on booster pumps for energy savings purposes. Continue installing VFDs on booster pumps for operational flexibility purposes. Greater control of system operation could make it easier for MWU to pursue other energy savings or demand reduction strategies.
- Where data is available, MWU and other groundwater utilities should periodically monitor pump production and energy intensity to identify pumps with diminishing performance. This could allow utilities to better prepare for pump failure or prioritize pump replacement plans.

6.3. RECOMMENDATIONS FOR FUTURE RESEARCH WORK

The following recommendations are for future research work:

- Continue to investigate the feasibility of VFD installation on deep well pumps. Use hydraulic modeling to explore the effect on energy use at other sites in the distribution system. Build on the analysis framework developed for Pressure Zones 8, 10, and 11 to analyze energy use on a Pressure Zone level.
- Energy savings investigations should move from analyzing individual components to entire Pressure Zones, and eventually the entire distribution system. Use hydraulic modeling to optimize operation of Pressure Zones based on energy use considerations.
- To better understand and characterize energy use, MWU should consider installing instruments to measure power consumption across more sites in the system. This will give MWU the ability to track energy intensity and power demands from more pumps. Analysis of this data could help operators make operational choices with energy use considerations in mind.
- Investigate ways to reduce on-peak demands in the system, such as:
 - Off-peak pumping. Investigate the potential to fill system storage during off-peak hours. Determine if operation of certain wells can be shifted so that pumping occurs only during off-peak hours.
 - Evaluate the benefits of designating constant-operation wells. Determine the desired flow rate for the deep well and booster pumps, and operate the well at that setpoint without changes. Energy use and demand charges will be consistent month-to-month. Use other wells to manage system demand when needed.

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APPENDIX A – UNIT WELL 25 FIELD TEST DATA

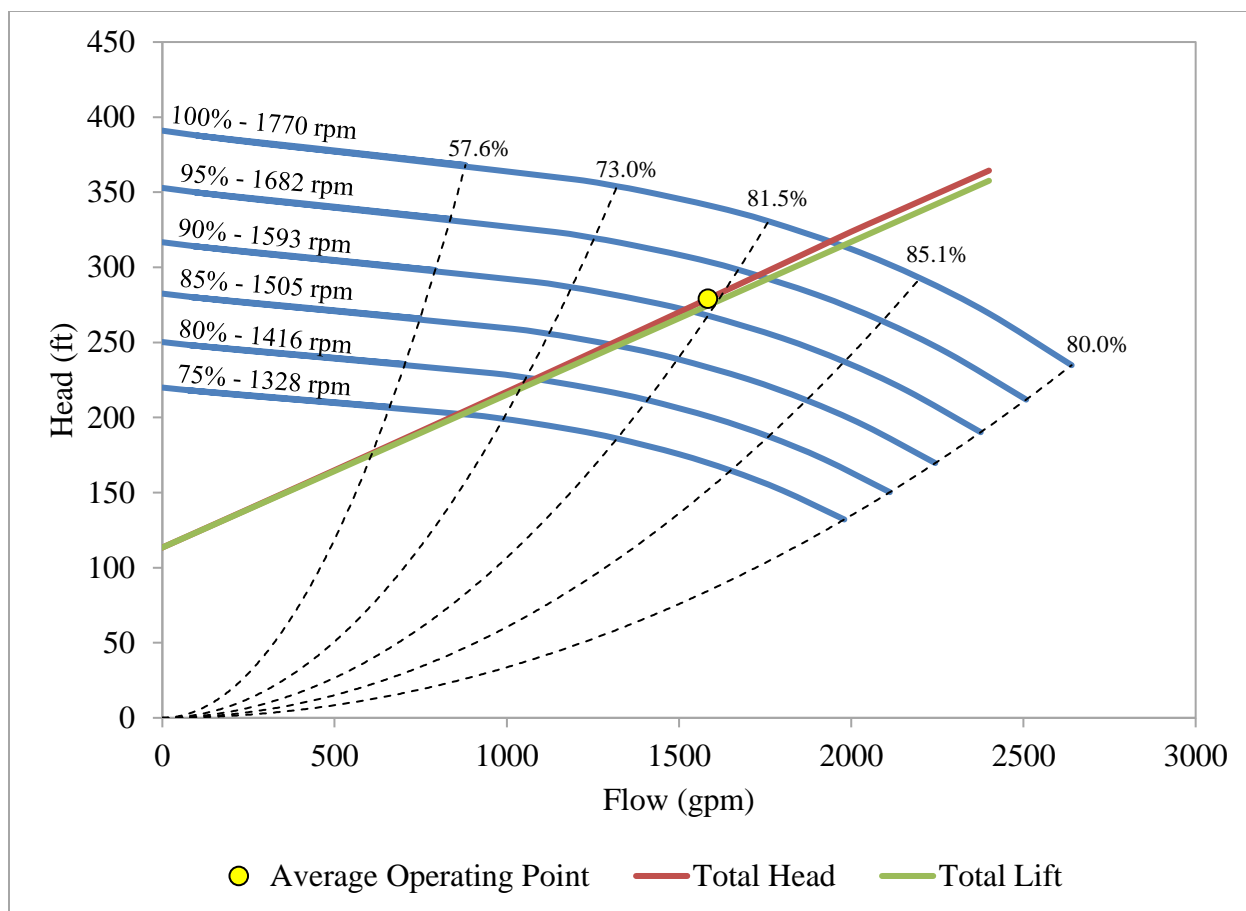


Figure A-1 – Unit Well 25 variable speed curves with estimated system head curve and observed average operating point for August 5 to August 11, 2016 (92% pump speed setpoint).

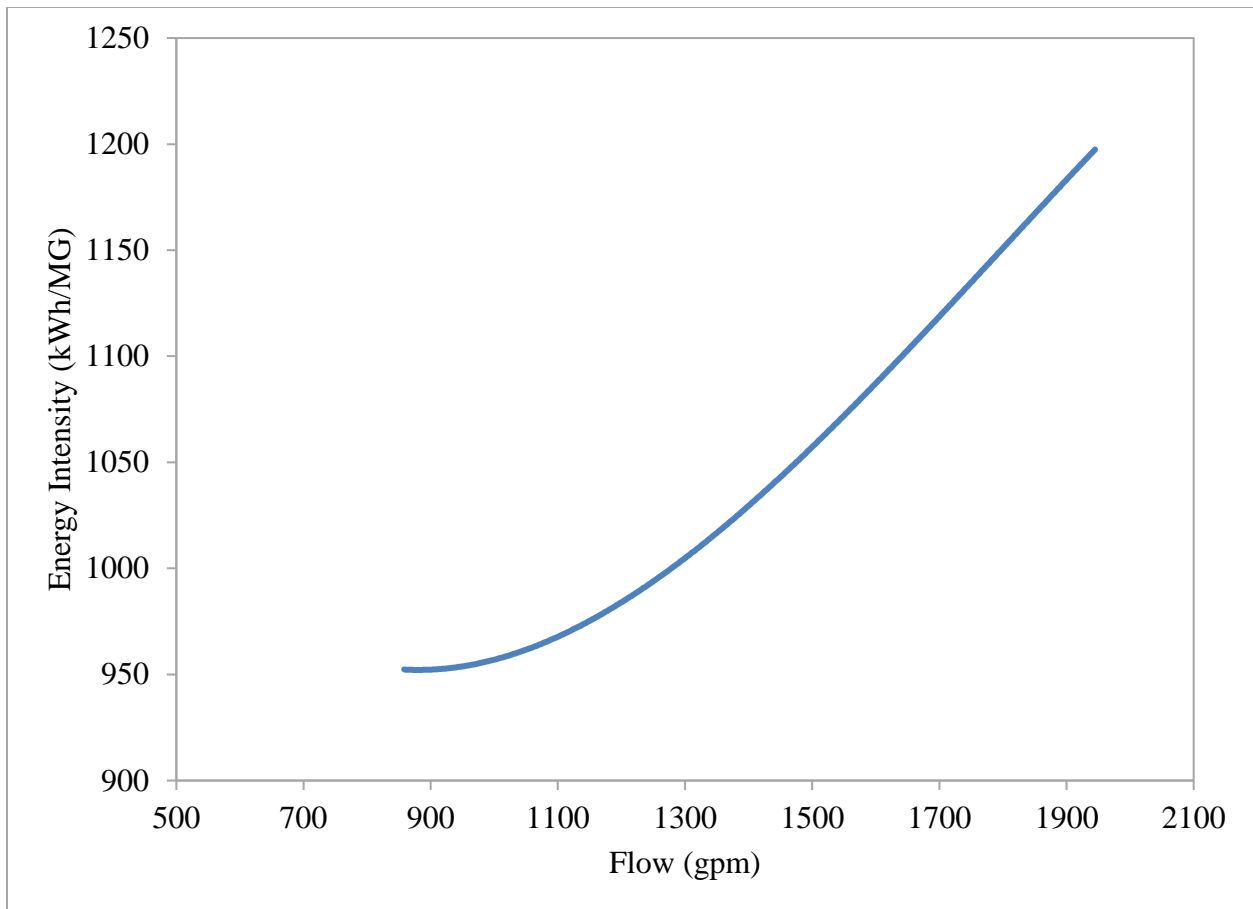


Figure A-2 – Estimated pump energy intensity versus flow rate curve for Unit Well 25.

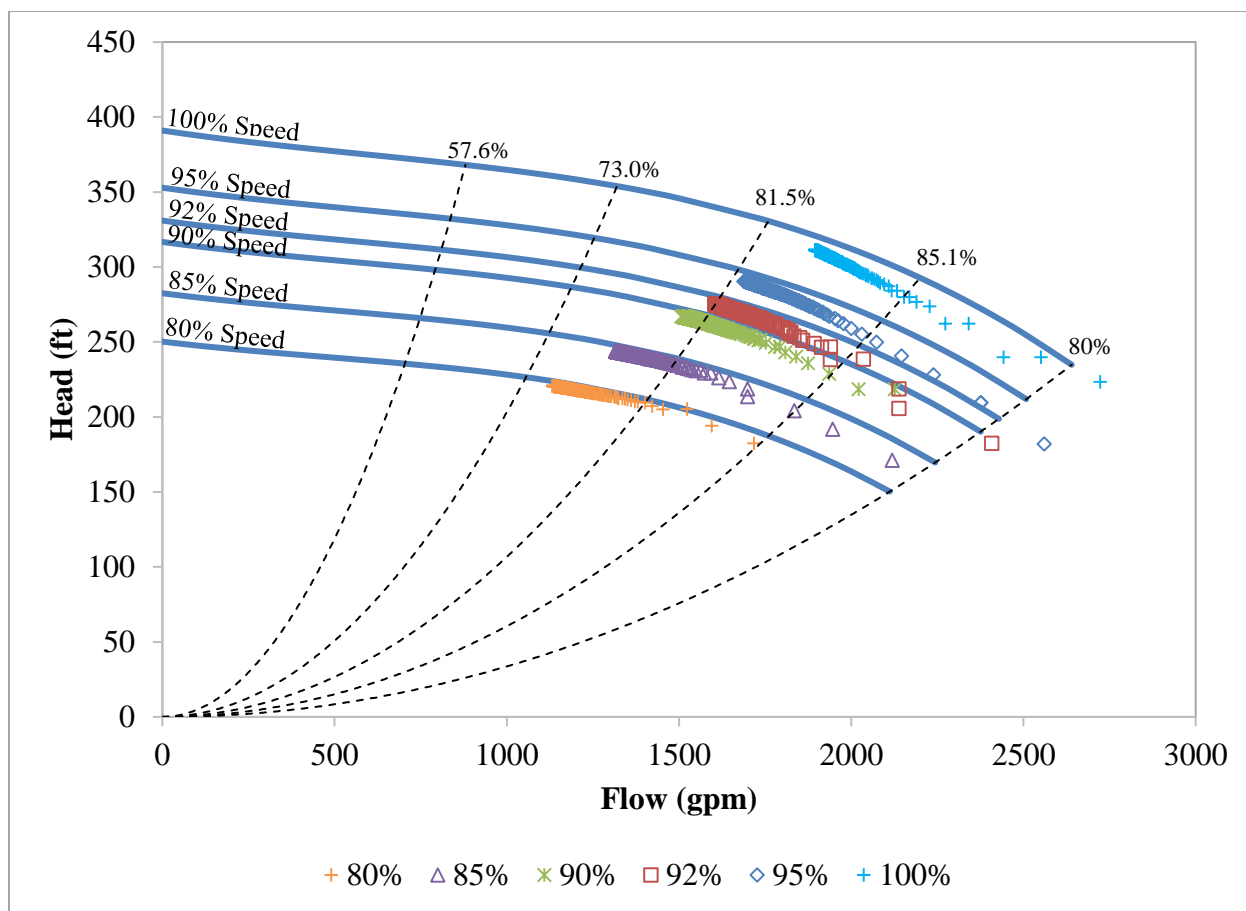


Figure A-3 – Operating points based on observed flow rates and water levels with estimated friction coefficients for each tested pump speed at Unit Well 25. Each point represents a single time point with a recorded measurement from SCADA.

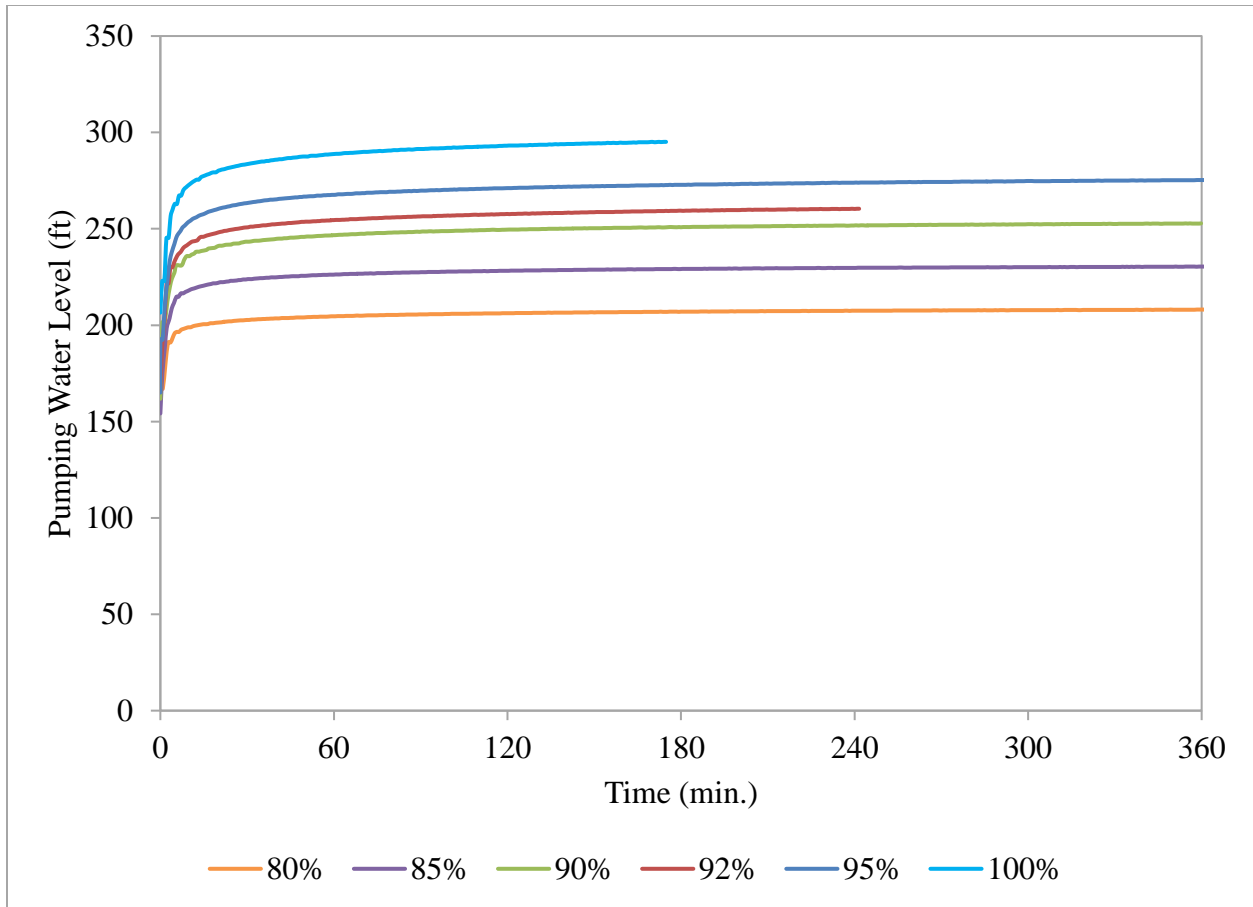


Figure A-4 – Observed pumping water level versus run time for multiple deep well pump speeds at Unit Well 25.

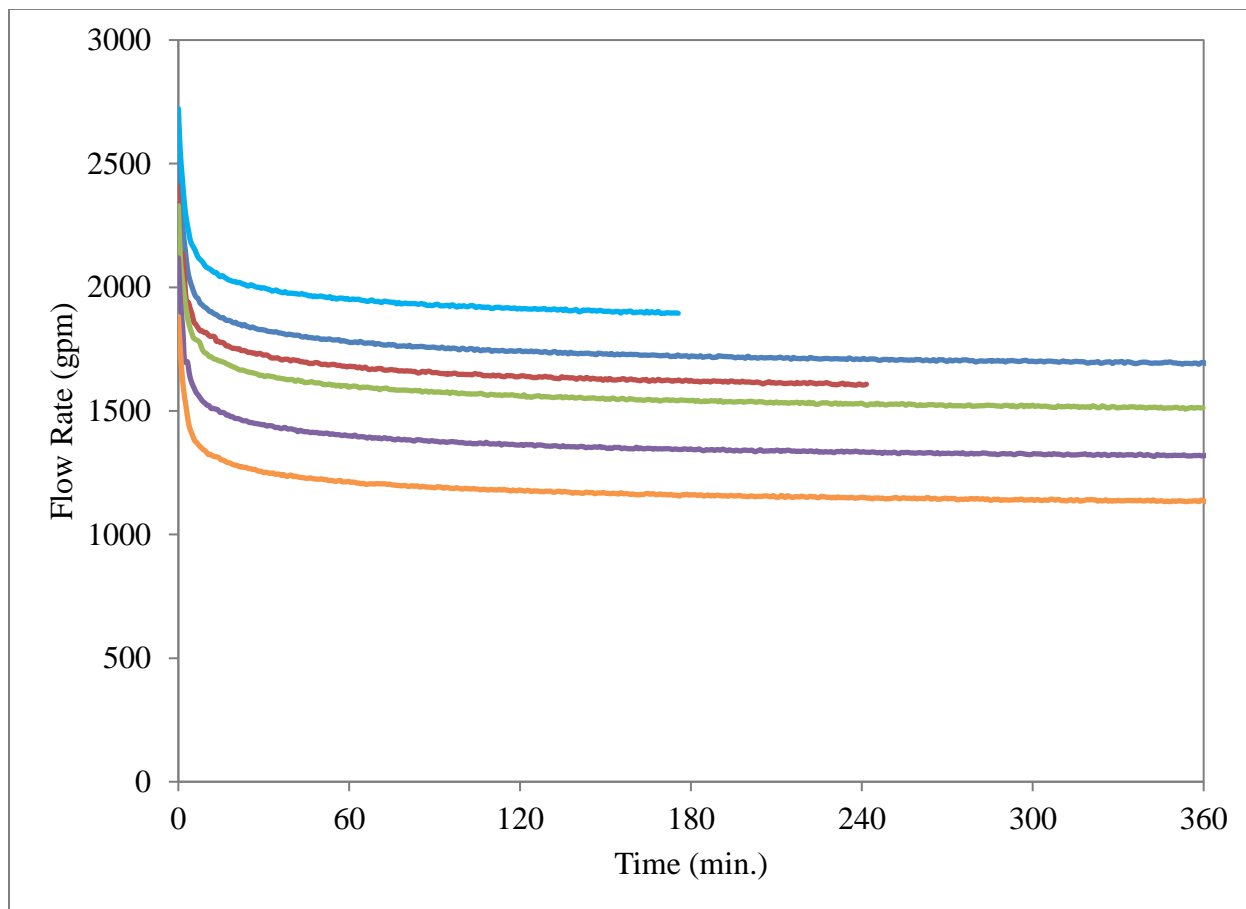


Figure A-5 – Observed deep well pump flow rate versus time for multiple deep well pump speeds at Unit Well 25.

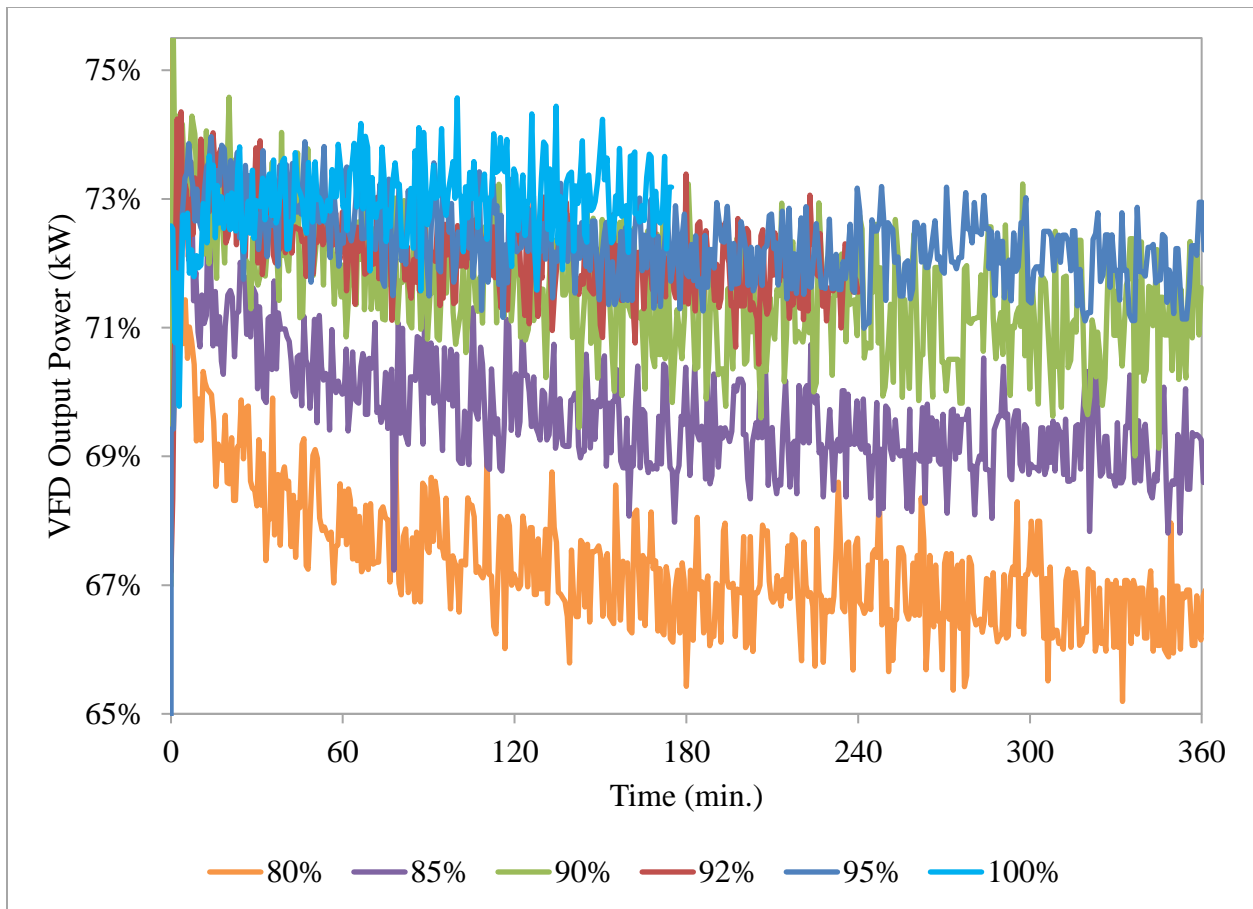


Figure A-6 – Observed pump efficiency versus run time for multiple pump speeds tested at Unit Well 25.

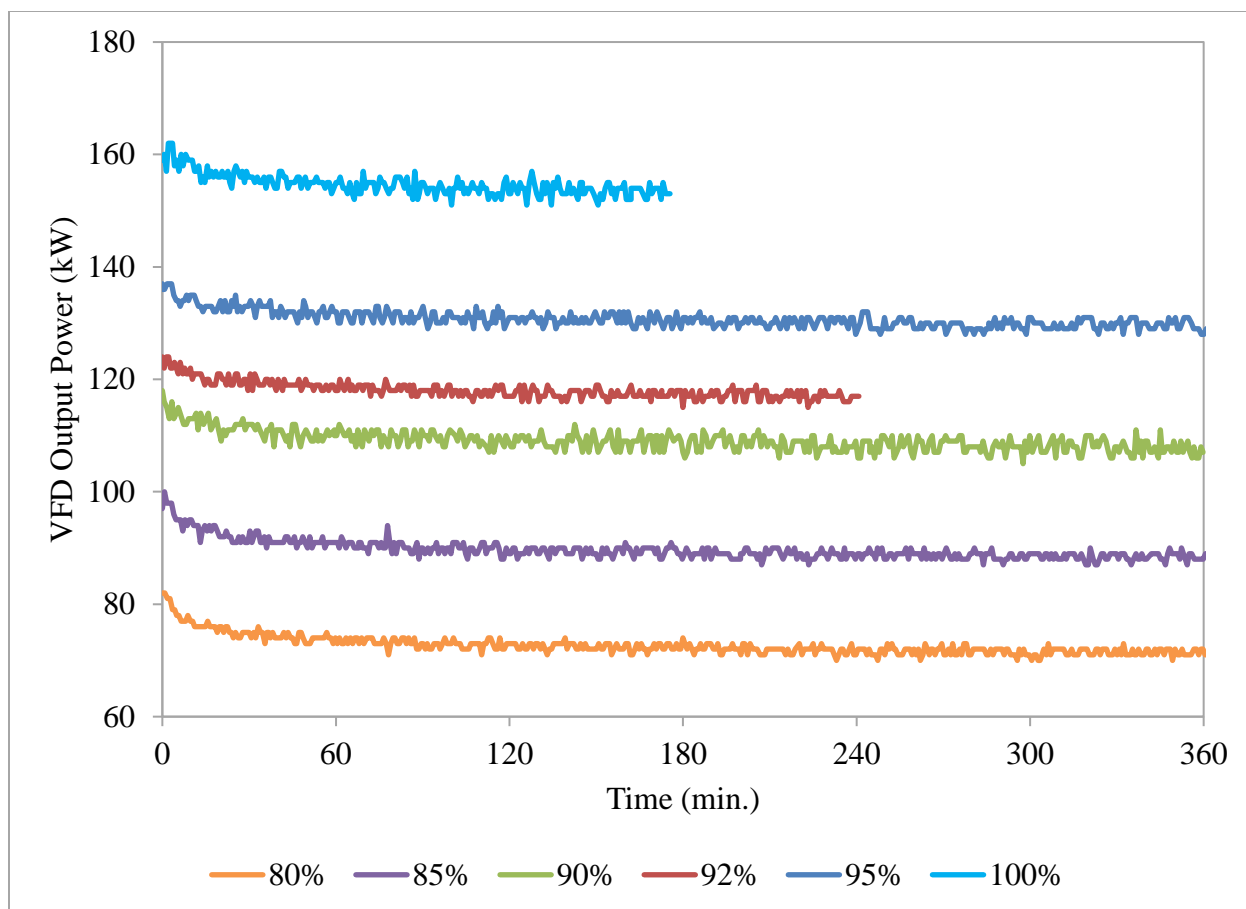


Figure A-7 – Observed SCADA VFD Power measurements versus pump run time for Unit Well 25.

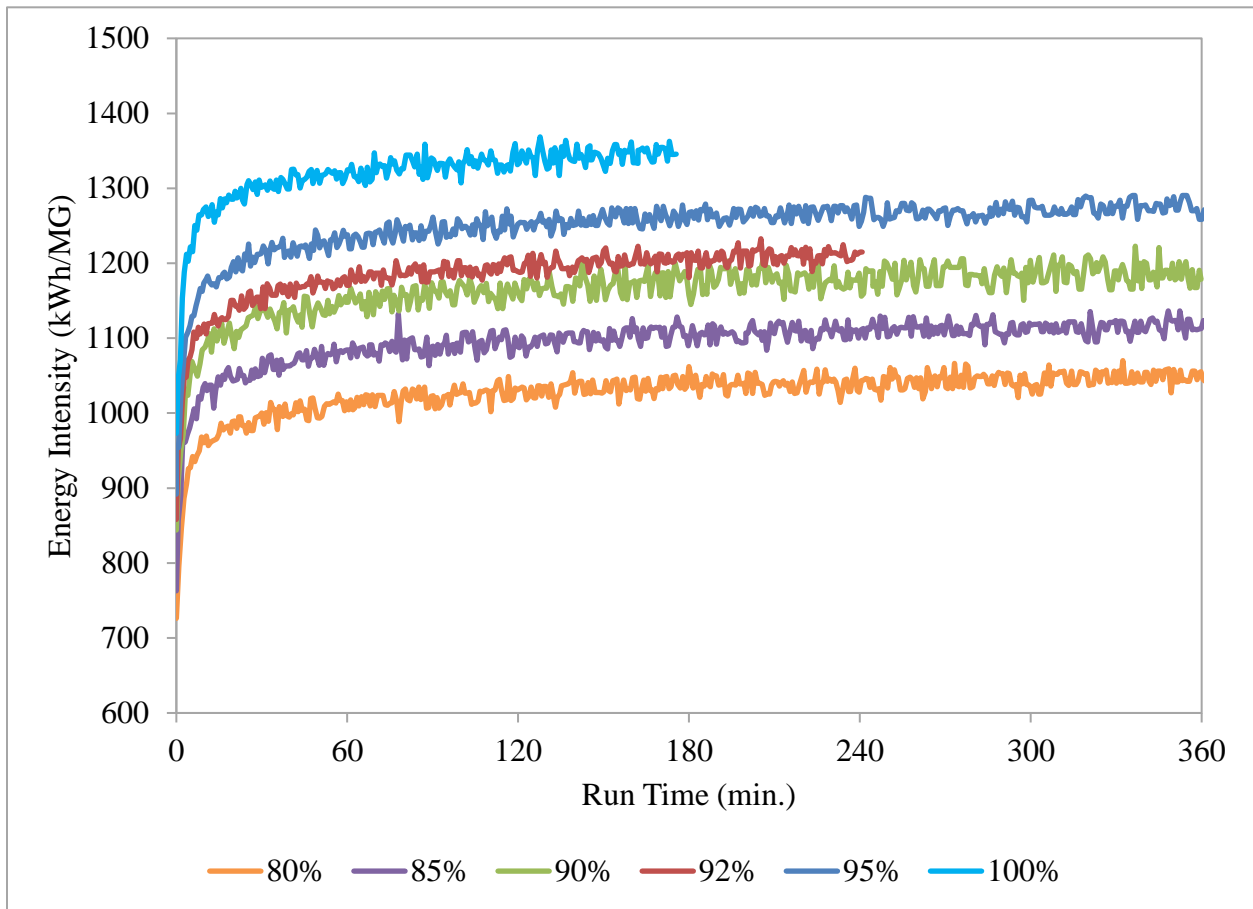


Figure A-8 – Energy intensity versus run time for all tested pump speeds at Unit Well 25.

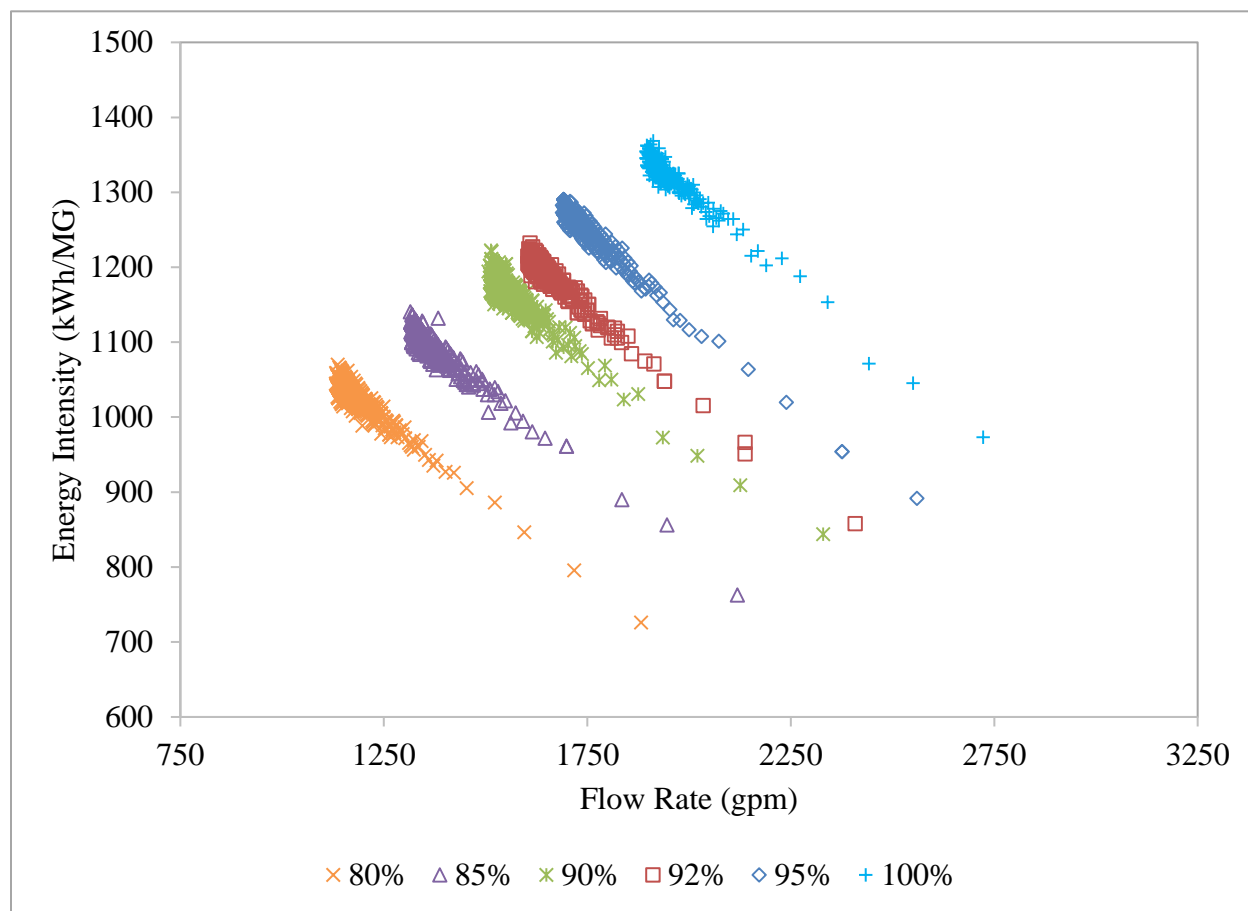


Figure A-9 – Energy intensity versus flow rate for all tested speeds at Unit Well 25 (Each value represents a single time point during the test).

APPENDIX B– SITE SPECIFIC METHODOLOGY DIFFERENCES

Wells with Pump Curve Shifted to Match Operating Point:

- Unit Well 8
- Unit Well 14
- Unit Well 16
- Unit Well 20
- Unit Well 24
- Unit Well 26

Unit Well 7**SCADA Data Source:**

SCADA data for Unit Well 7 for August 2015 was stored in MWU's new historian client. MWU's control software polls the system approximately every 30 seconds. The new historian stores data every time it is received for an individual variable. SCADA data used to analyze Unit Well 7 utilized this full data set, with values stored for each variable approximately every 40 seconds.

Pumping Water Level and Average Flow Rate:

Water level was averaged for all time points where the pump was on to determine pumping water level. Similarly, all recorded flow rate measurements when the pump was on were averaged to determine average operating flow rate.

Static Water Level:

The minimum stored value for water level in a day was taken to be the static water level.

Friction Losses:

Unit Well 7 has a filtration system for the removal of iron and manganese. SCADA records the pressure drop from the entrance of the filtration units to the finished filtered water. As average conditions dominate energy use and operation, the average filter loss at the 1,250 gpm operation setpoint for August 2015 was found.

Without any understanding of the variability of head loss with flow rate, losses due to the filter were applied in a linear fashion. Average head loss across the filters was 4 feet and an average flow rate of 1,490 gpm. A linear trend was fit, and filter losses were assumed to increase at a rate of 0.0027 ft/gpm when developing the system head curve.

Unit Well 8:

Analysis Period:

Unit Well 8 is a seasonal well and is not operated for extended periods of time. The pump only ran for a few hours a day for the second week of August 2015. The average operating conditions (flow rate, pumping water level, static water level) for Unit Well 8 were determined using the entire month of data. Average flow rate was determined based on the total station pumpage for the month divided by total runtime for the deep well pump. Pumping water level was found by averaging the water level for all hours during the month the pump ran the entire hour. Static water level was found by averaging the water level for all hours in the month where the pump was off for the entire hour.

Unit Well 11:

Analysis Period:

Unit Well 11 only ran for 4 to 5 hours per day during the second week of August 2015, providing only a handful of data points to determine average operating conditions for a given day. Similar to Unit Well 8, hourly data from the entire month of August 2015 was used to determine average operating conditions. Average flow rate was determined based on the total station pumpage for the month divided by total runtime for the deep well pump. Pumping water level was found by averaging the water level for all hours during the month the pump ran the entire hour. Static water

level was found by averaging the water level for all hours in the month where the pump was off for the entire hour.

Unit Well 12:

The analyzed time period for Unit Well 12 was the second week of October 2015.

Unit Well 13:

Friction Losses:

Unit Well 13 has a Lakos Sand Separator installed. The brochure for the installed model indicates head loss of 9 – 14 feet for the flow rates 1,640 gpm to 2,560 gpm. These values were fit with a linear trendline as shown below in Figure B-1 to estimate friction losses at any flow rate for developing the system head curve.

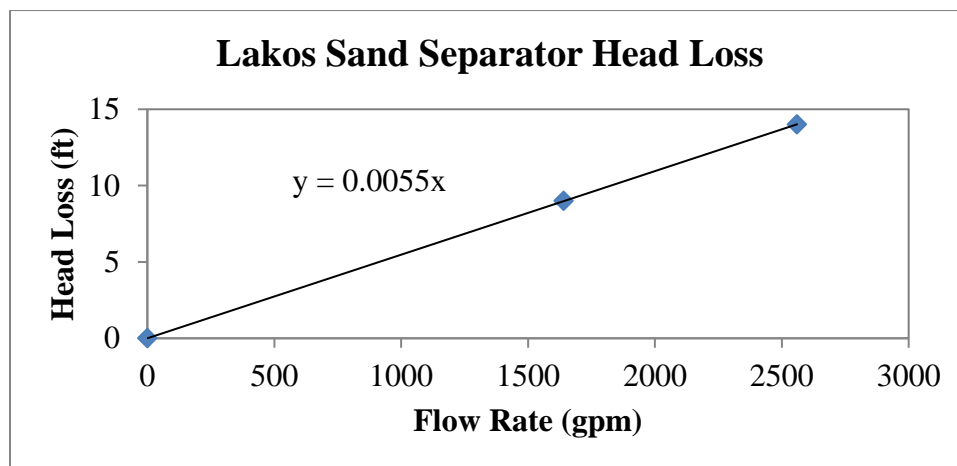


Figure B-1 – Linear regression fit to estimate head losses from Lakos Sand Separator at Unit Well 13.

Unit Well 15:

Unit Well 15 has a VFD installed on the deep well pump. For the analyzed time period, the VFD was set to provide 1,250 gpm. VFD speed varies to match this flow rate. Unit Well 15 has an air stripper unit to remove VOCs. Water is pumped from the deep well pump and discharges open to the atmosphere at the top of the air stripper. This discharge point in the air stripper was used as the reservoir inlet and friction losses were calculated up to this point.

Friction Losses:

Unit Well 15 has a Lakos Sand Separator installed. The brochure for the installed model indicates head loss of 9 – 14 feet for the flow rates 1,640 gpm to 2,560 gpm. These values were fit with the same trendline shown in Figure B-1 to estimate friction losses at any flow rate for developing the system head curve.

Unit Well 16:**Analysis Period:**

The deep well pump at Unit Well 16 was taken out of service during the summer of 2015 to repair the pump column and install a new pump. The pump was out of service during August 2015. The analyzed time period for Unit Well 16 was the second week of March 2016. Data was taken from the new historian, with values stored for each variable every 40 seconds.

Pumping Water Level and Average Flow Rate:

Water level was averaged for all time points where the pump was on to determine pumping water level. Similarly, all recorded flow rate measurements when the pump was on were averaged to determine average operating flow rate.

Static Water Level:

The minimum stored value for water level in a day was taken to be the static water level.

Friction Losses:

Unit Well 16 has a Lakos Sand Separator installed. The brochure for the installed model indicates head loss of 9 – 14 feet for the flow rates 1,640 gpm to 2,560 gpm. These values were fit with the same trendline shown in Figure B-1 to estimate friction losses at any flow rate for developing the system head curve.

Unit Well 25:Analysis Period:

The deep well pump failed in June 2016. Pump was replaced and was fully operational in August 2016. The analyzed time period for Unit Well 25 was the second week of August 2016. Data was taken from the new historian and was available in approximately 40 second intervals.

Unit Well 27:Analysis Period:

The deep well flow meter was not functioning properly in August 2015. The flow meter was repaired in early 2016. At this point, data was accessible from the new historian. The analyzed time period for Unit Well 27 was the third week of April 2016. Values were stored in the new historian system every 40 seconds.

Pumping Water Level and Average Flow Rate:

Water level was averaged for all time points where the pump was on to determine pumping water level. Similarly, all recorded flow rate measurements when the pump was on were averaged to determine average operating flow rate.

Static Water Level:

The minimum stored value for water level in a day was taken to be the static water level.

Unit Well 29

Unit Well 29 has a single filtration skid installed. There is a sand separator installed prior to raw water being pumped into the filter. The limit for this sand separator is 1,200 gpm. Space exists on-site for a second treatment train to be installed, but operation of the pump is currently limited to 1,200 gpm. The VFD was set to 1,150 gpm for the analyzed time period.

Friction Losses:

The brochure for the installed sand separation unit lists head losses of 3 to 12 psi (7 to 28 feet) for an operational range of 650 – 1,200 gpm. A second-order regression was found to fit these head losses best as shown below. This second-order polynomial was used to estimate friction losses due to the sand separation at 100 gpm intervals for generation the system head curve. Similar to Unit Well 7, pressure drop across the filtration units is monitored in SCADA. As average conditions dominate energy use and operation, the average filter loss was found for the 1,150 gpm operation. With no understanding of the change in head loss with flow rate, friction losses from the filter were applied in a linear fashion when generating the system head curve. The average filter losses at 1,150 were assumed to change linearly from 0 feet at 0 gpm to the average filter losses at 1,150 gpm. The slope of this linear fit was used to account for filter losses when generating the system head curve at 100 gpm intervals.

APPENDIX C – UTILITY-WIDE STUDY RESULTS

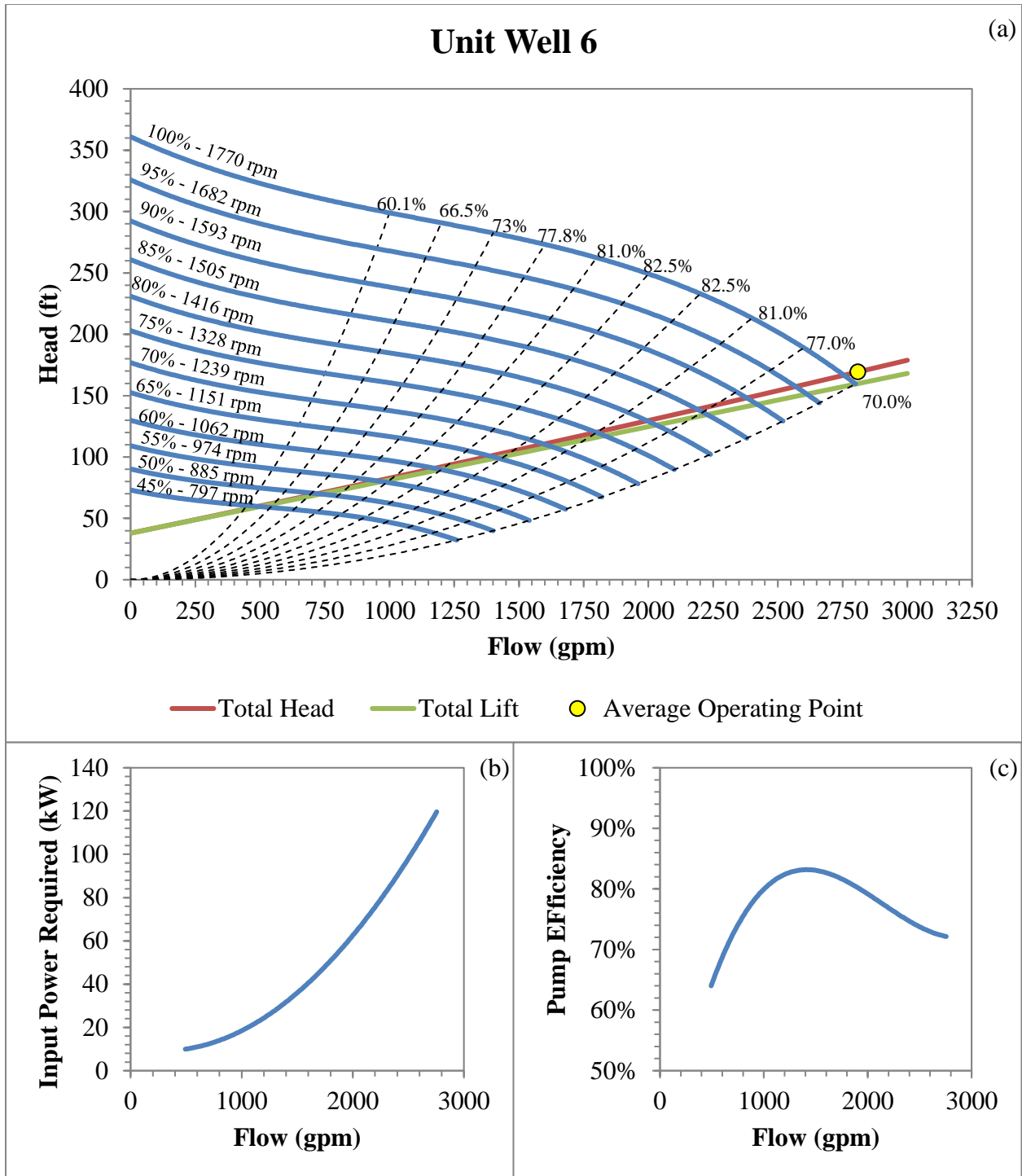


Figure C-1 – (a) Unit Well 6 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

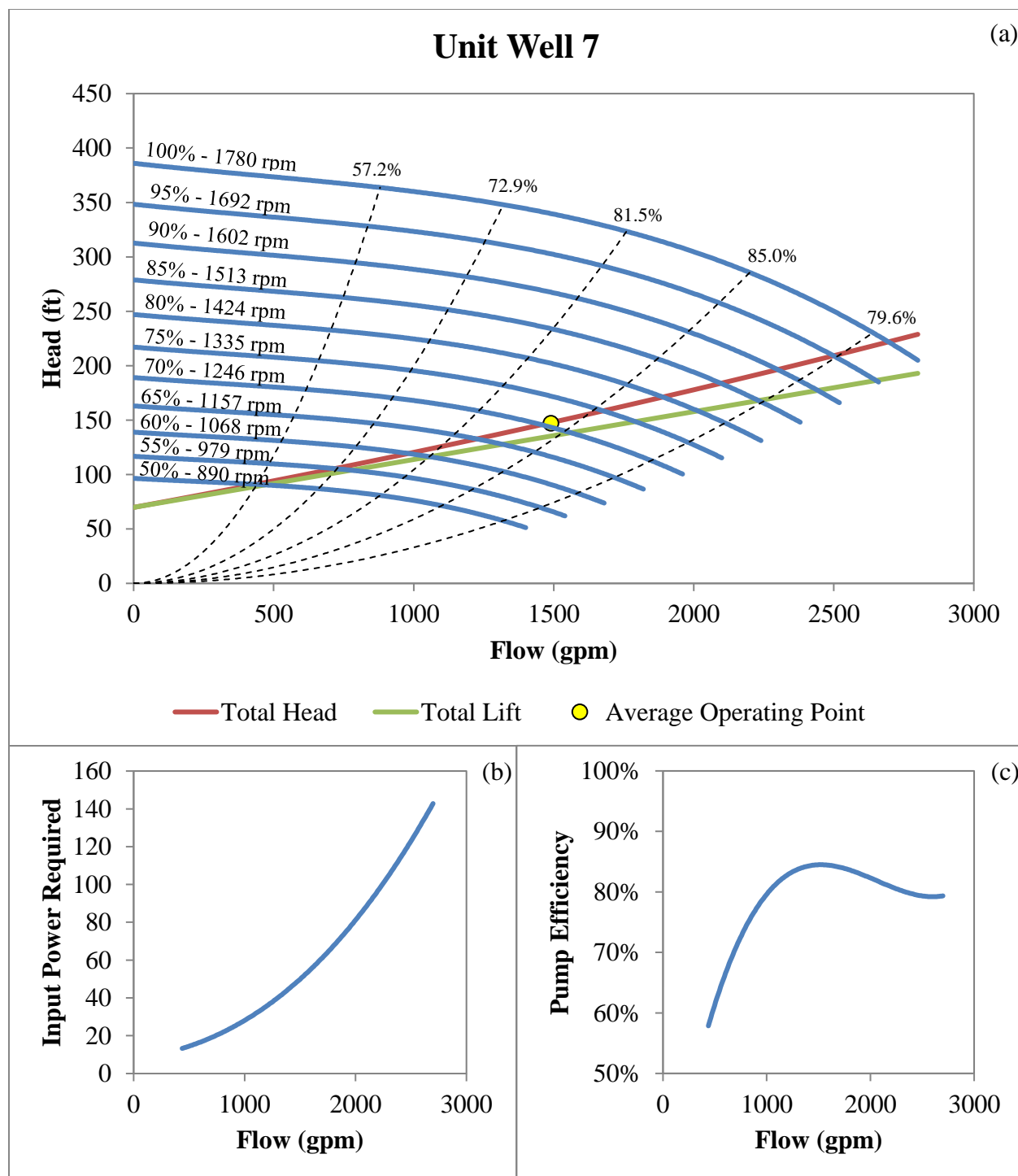


Figure C-2 – (a) Unit Well 7 variable speed curves and pump efficiencies with system head curve and average operating point (1,500 gpm constant flow setpoint in August 2015). (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

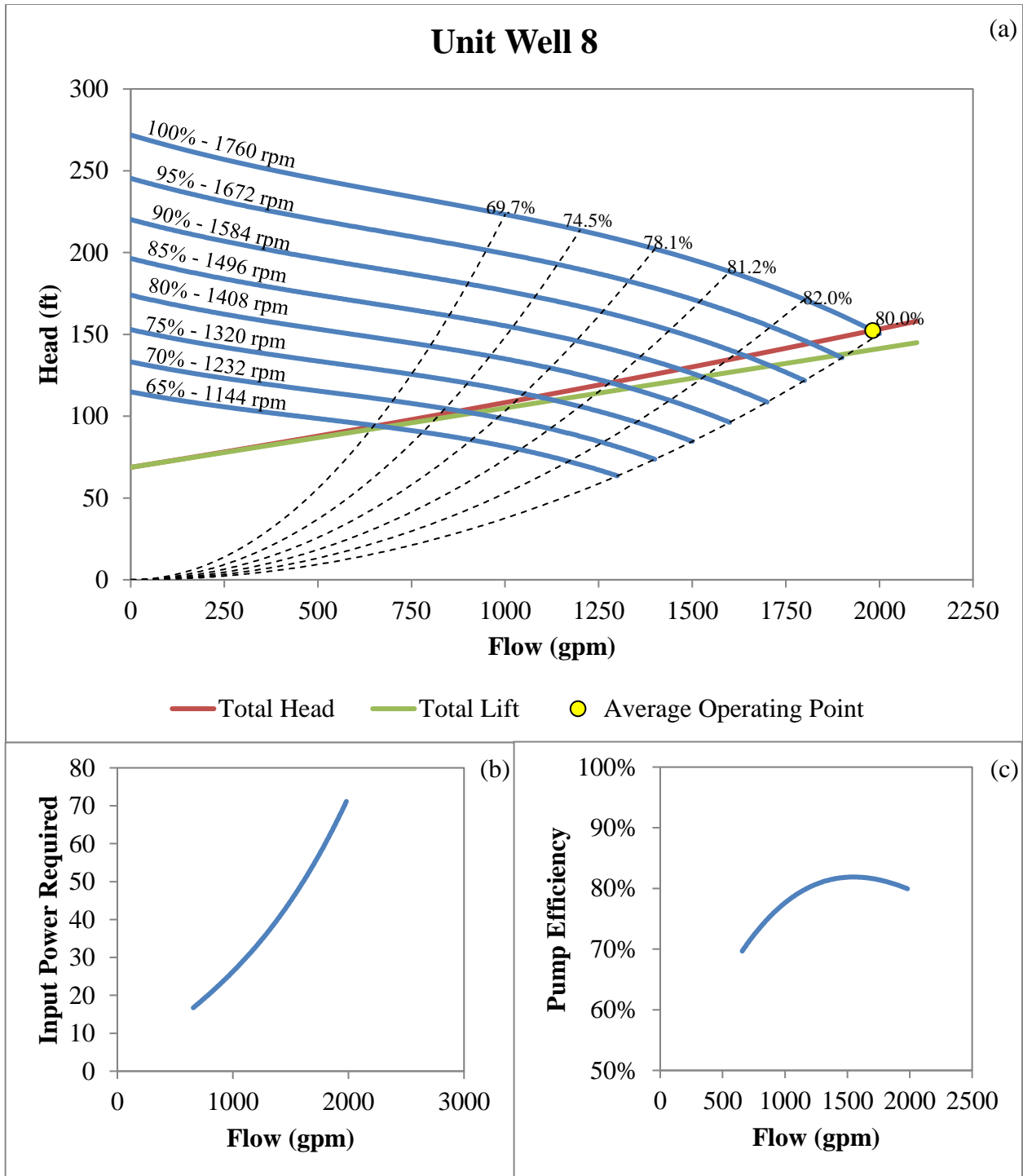


Figure C-3 – (a) Unit Well 8 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

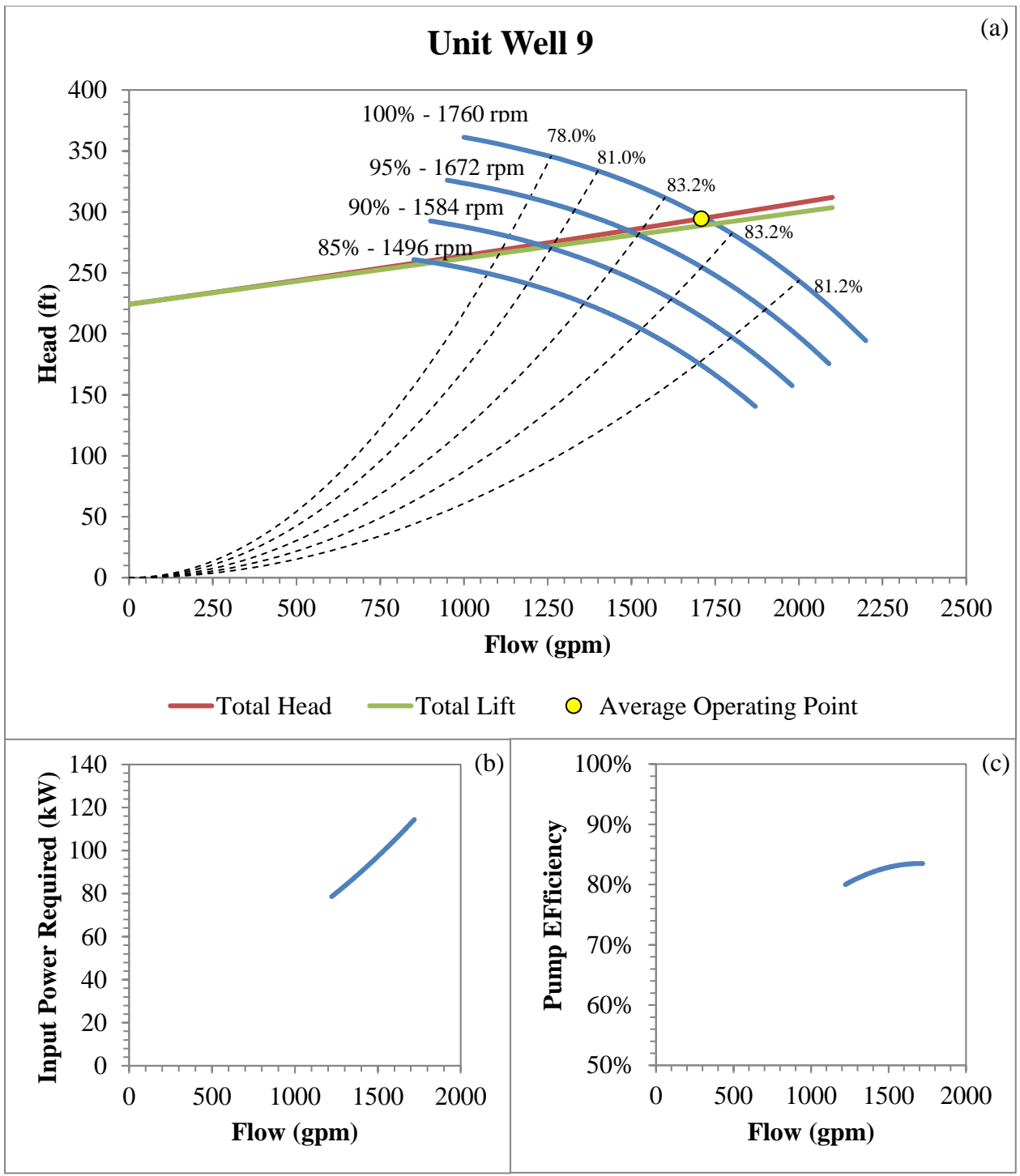


Figure C-4 – (a) Unit Well 9 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

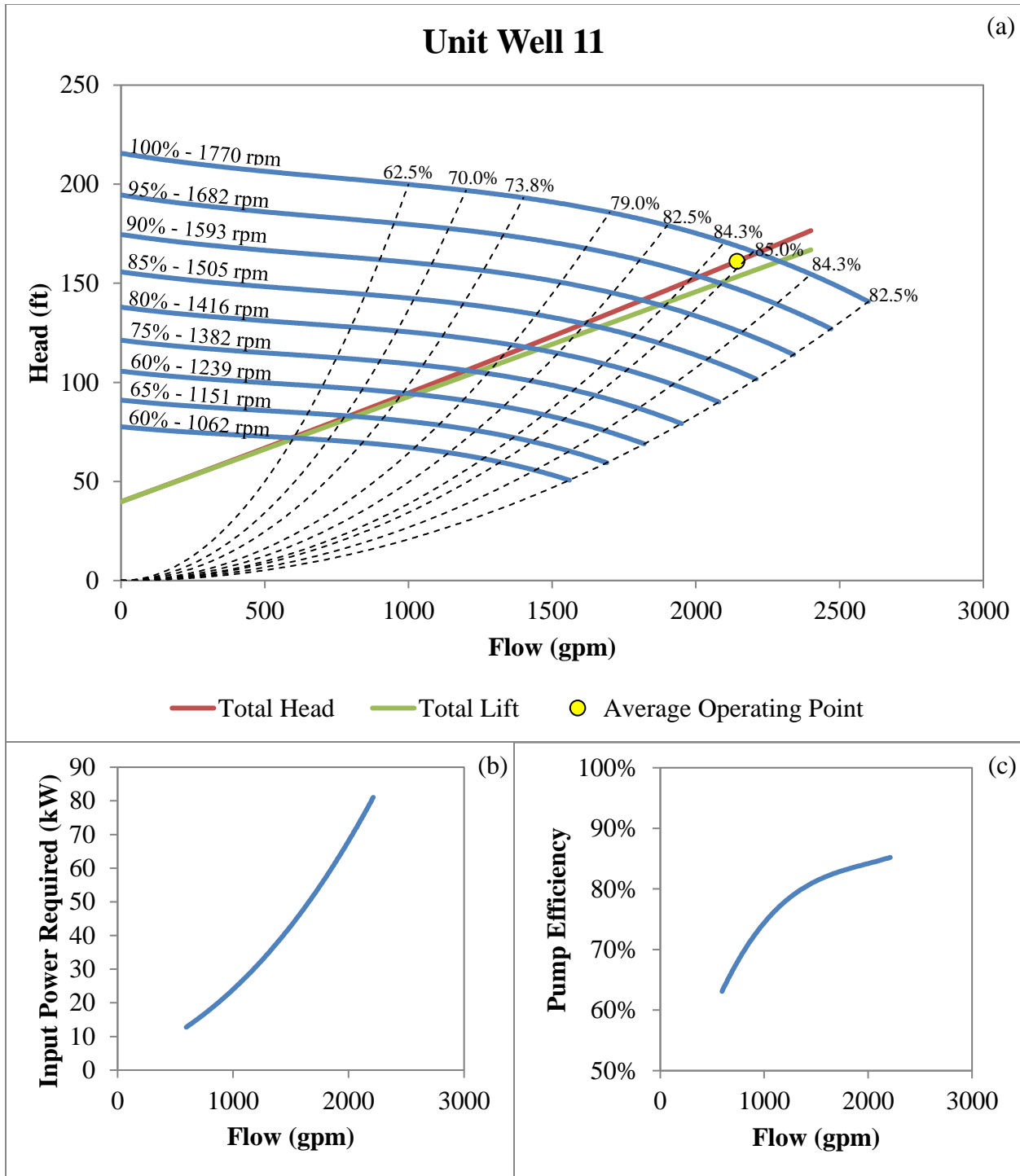


Figure C-5 – (a) Unit Well 11 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

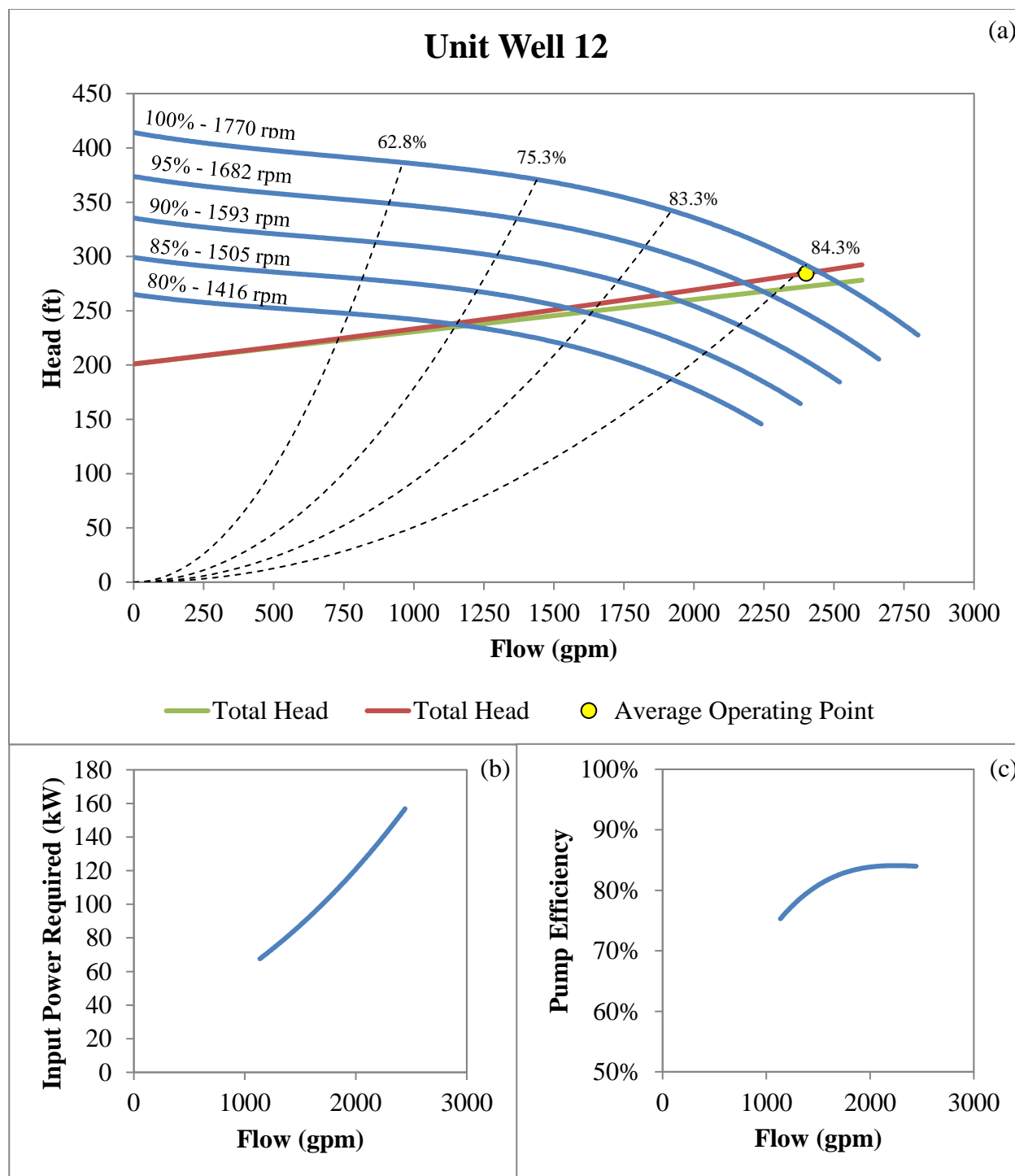


Figure C-6 – (a) Unit Well 12 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

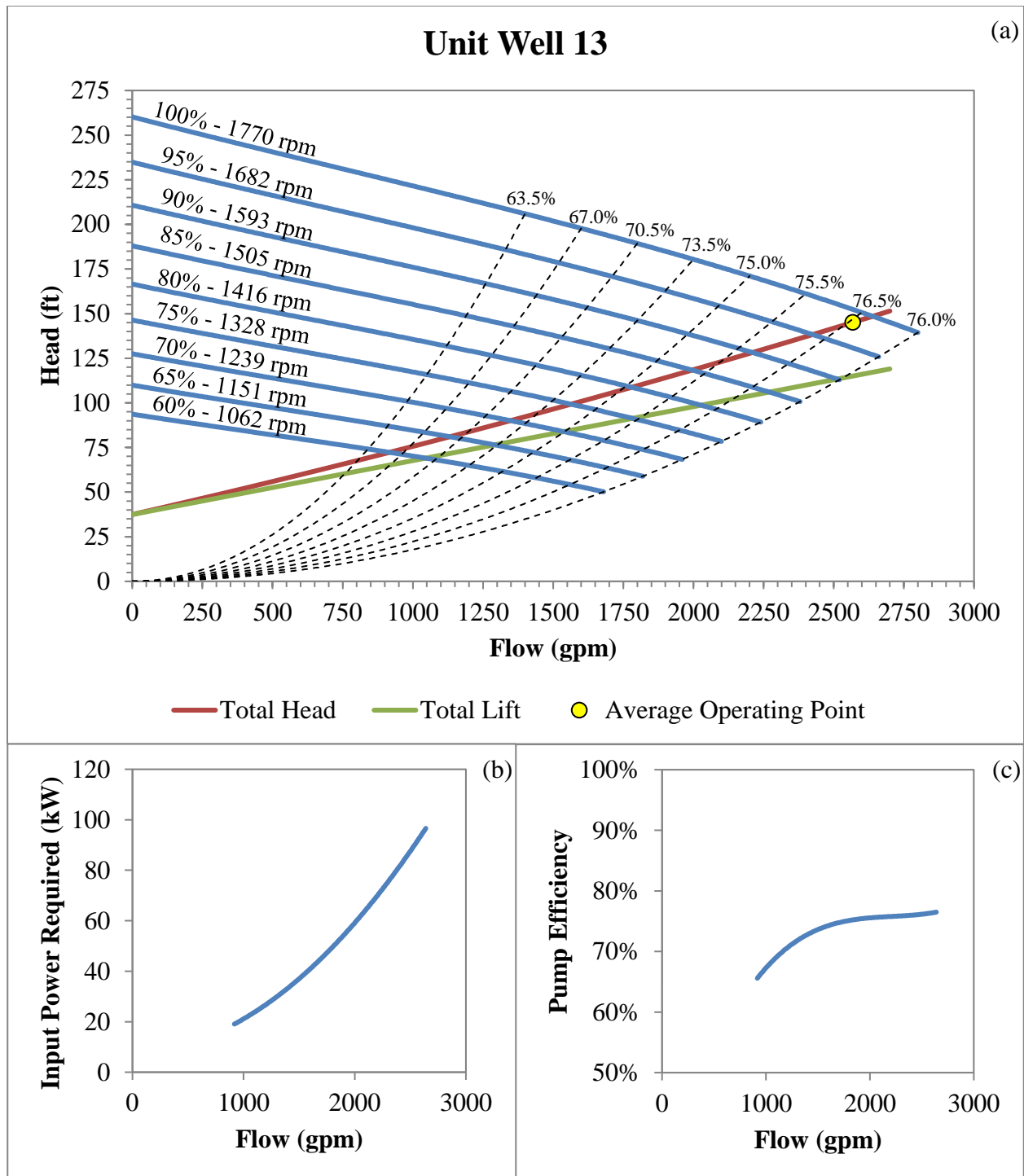


Figure C-7 – (a) Unit Well 13 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

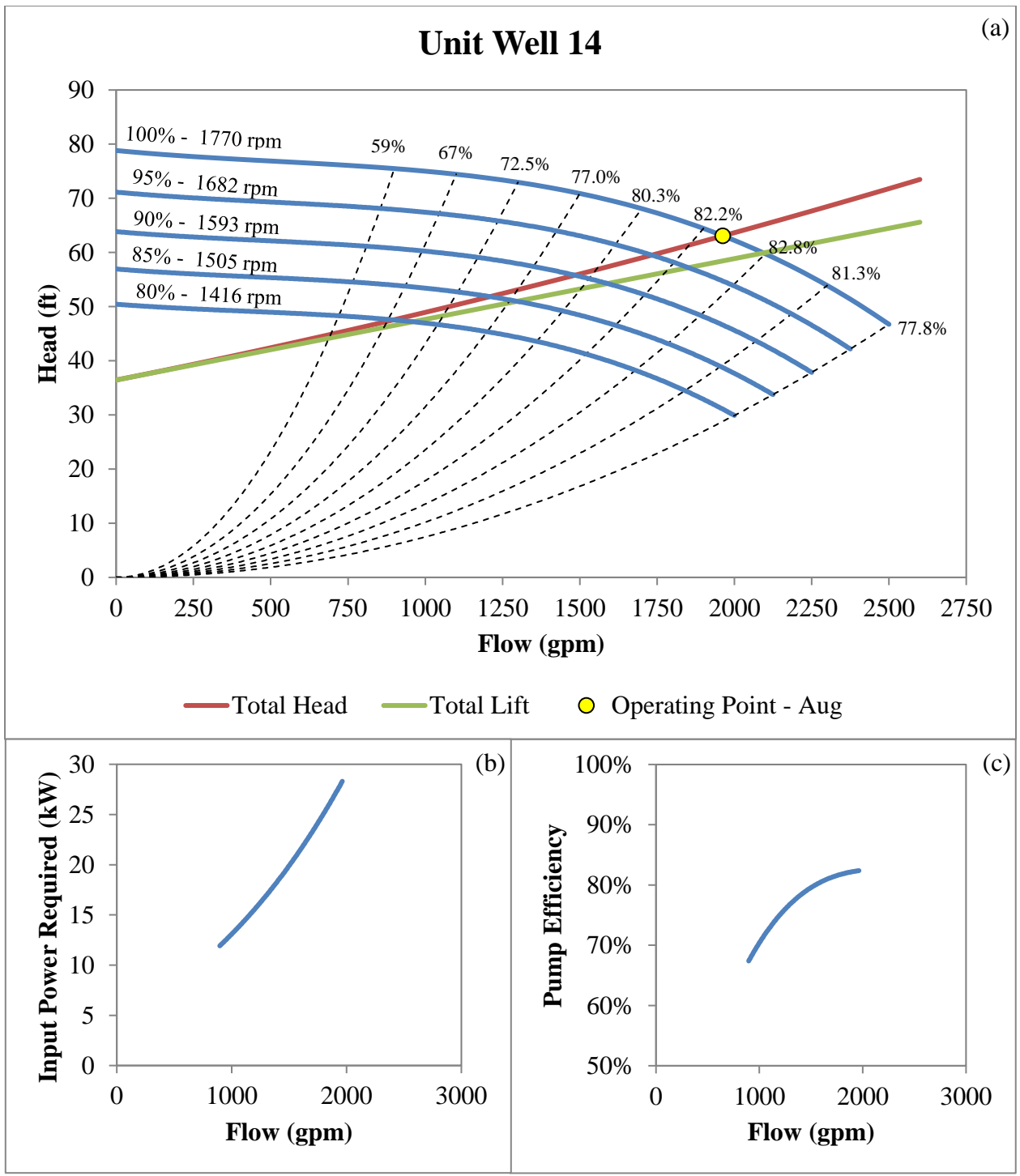


Figure C-8 – (a) Unit Well 14 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

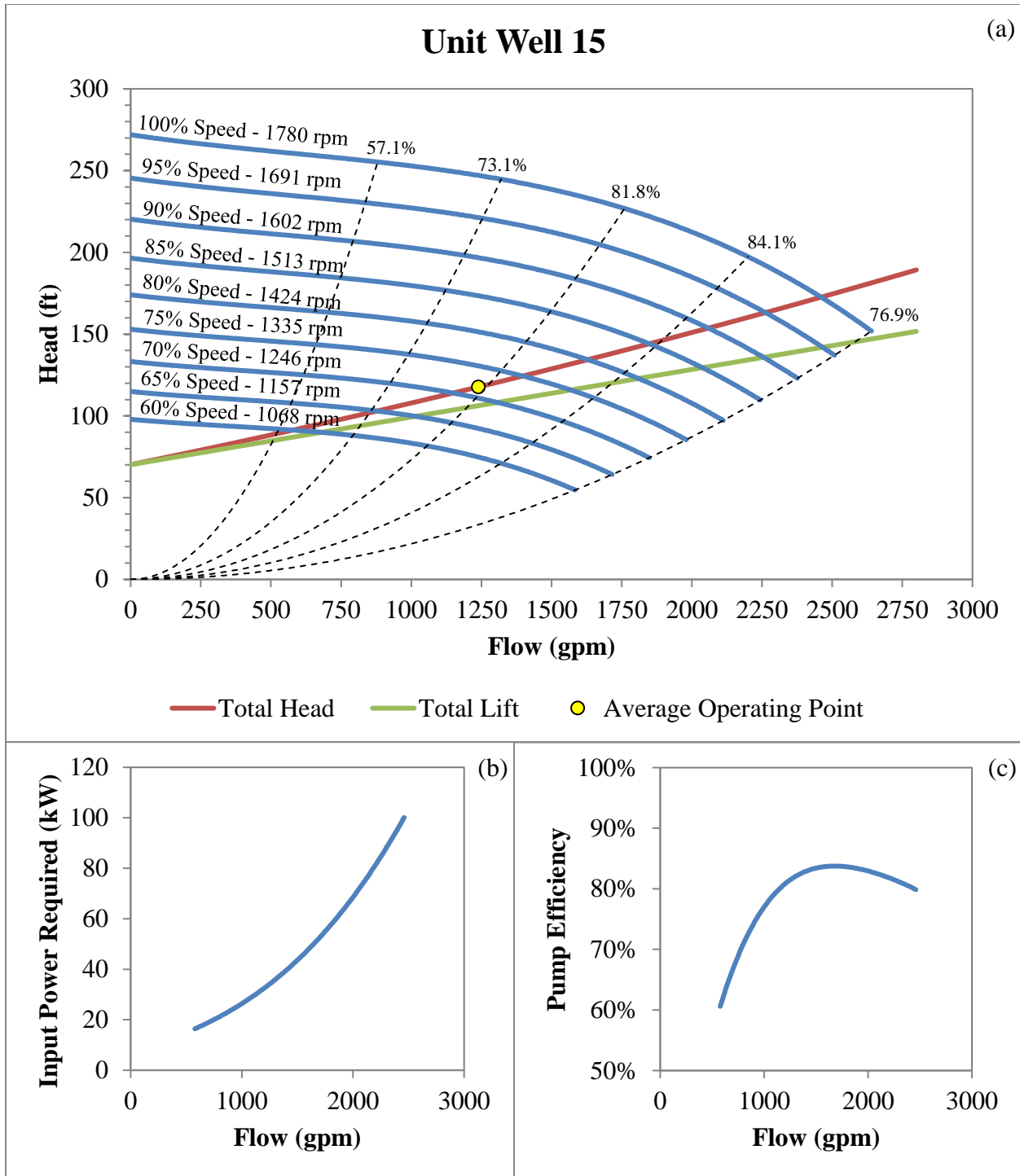


Figure C-9 – (a) Unit Well 15 variable speed curves and pump efficiencies with system head curve and average operating point (1,250 gpm constant flow setpoint in August 2015). (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

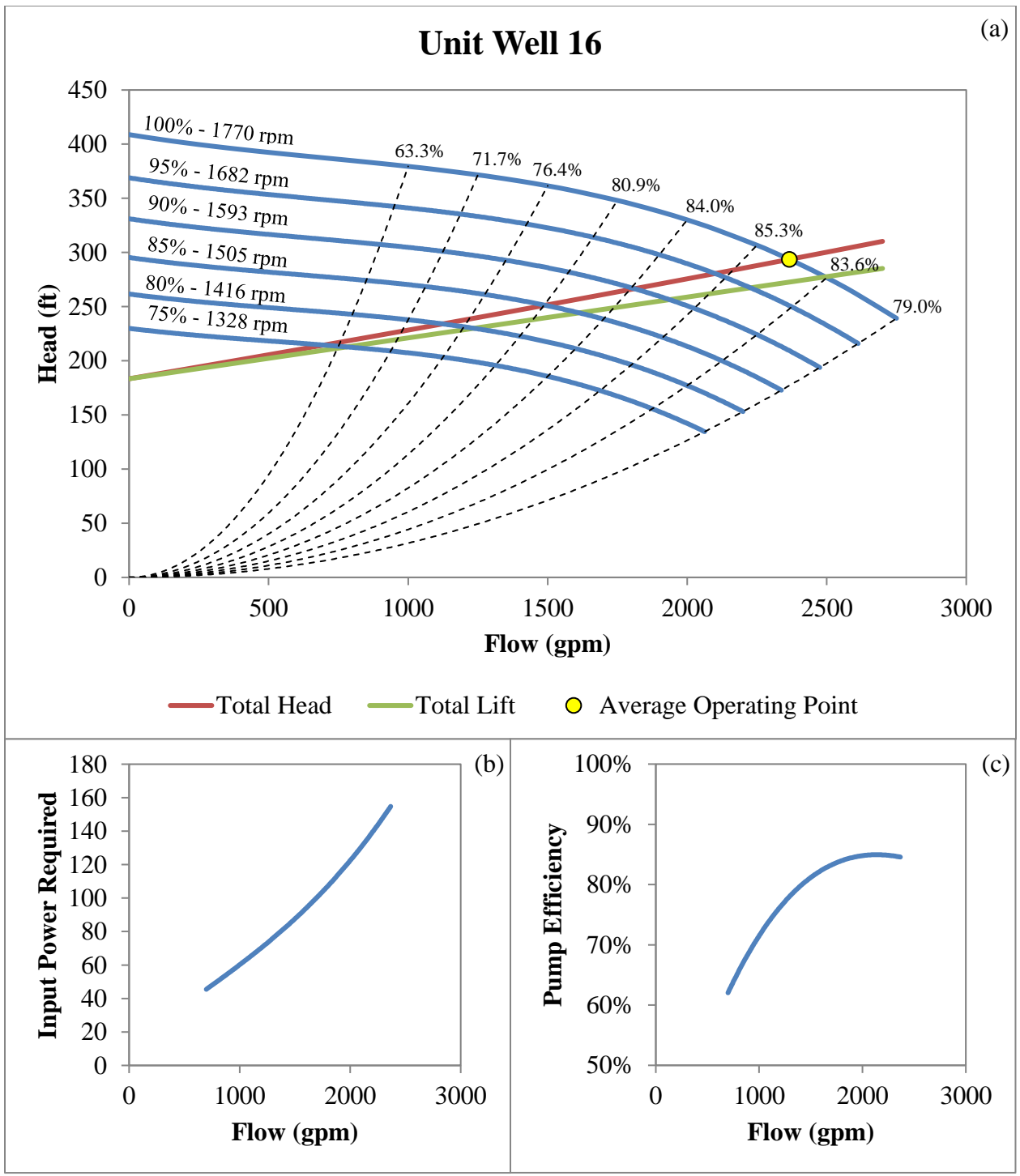


Figure C-10 – (a) Unit Well 16 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

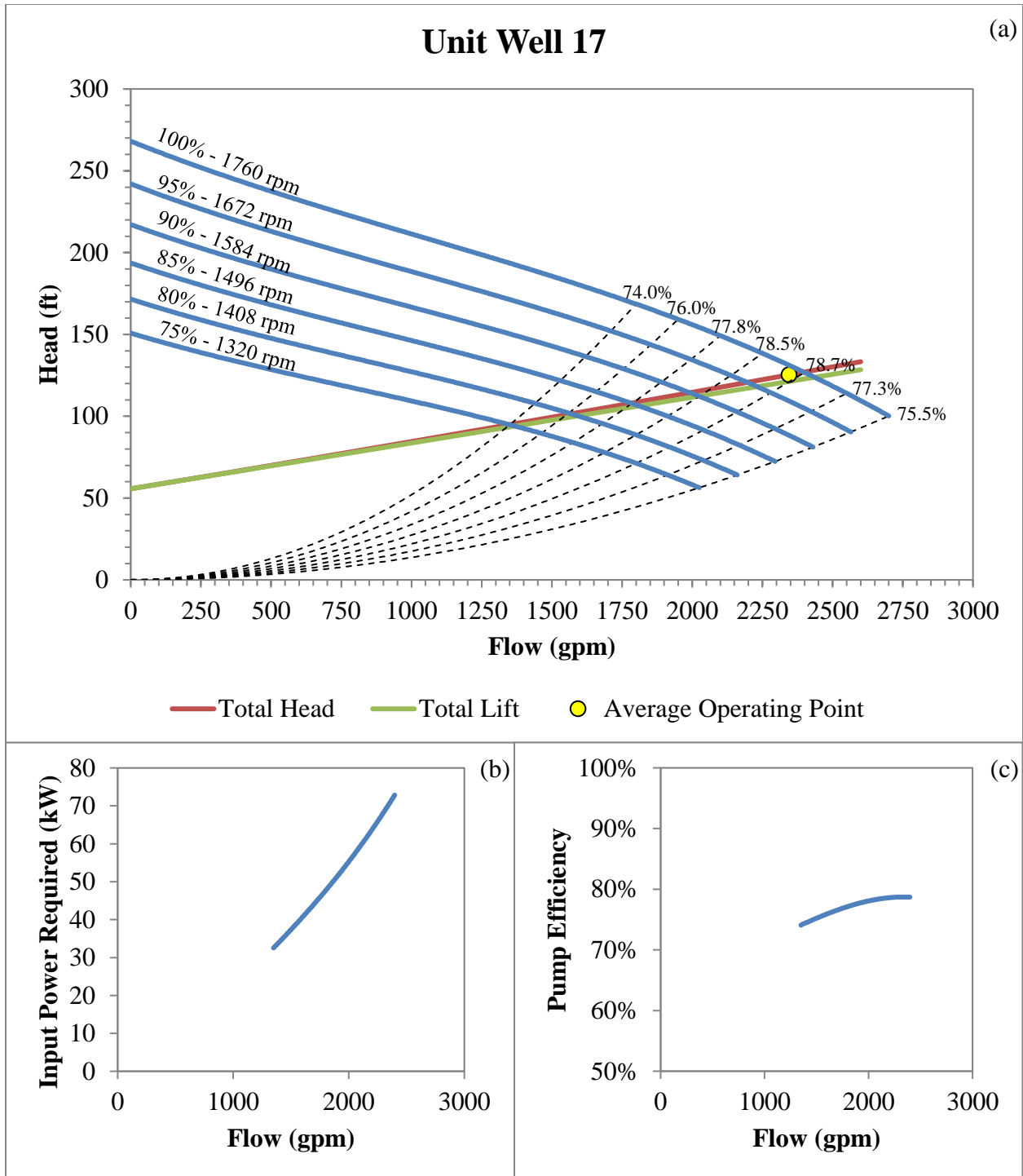


Figure C-11 – (a) Unit Well 17 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

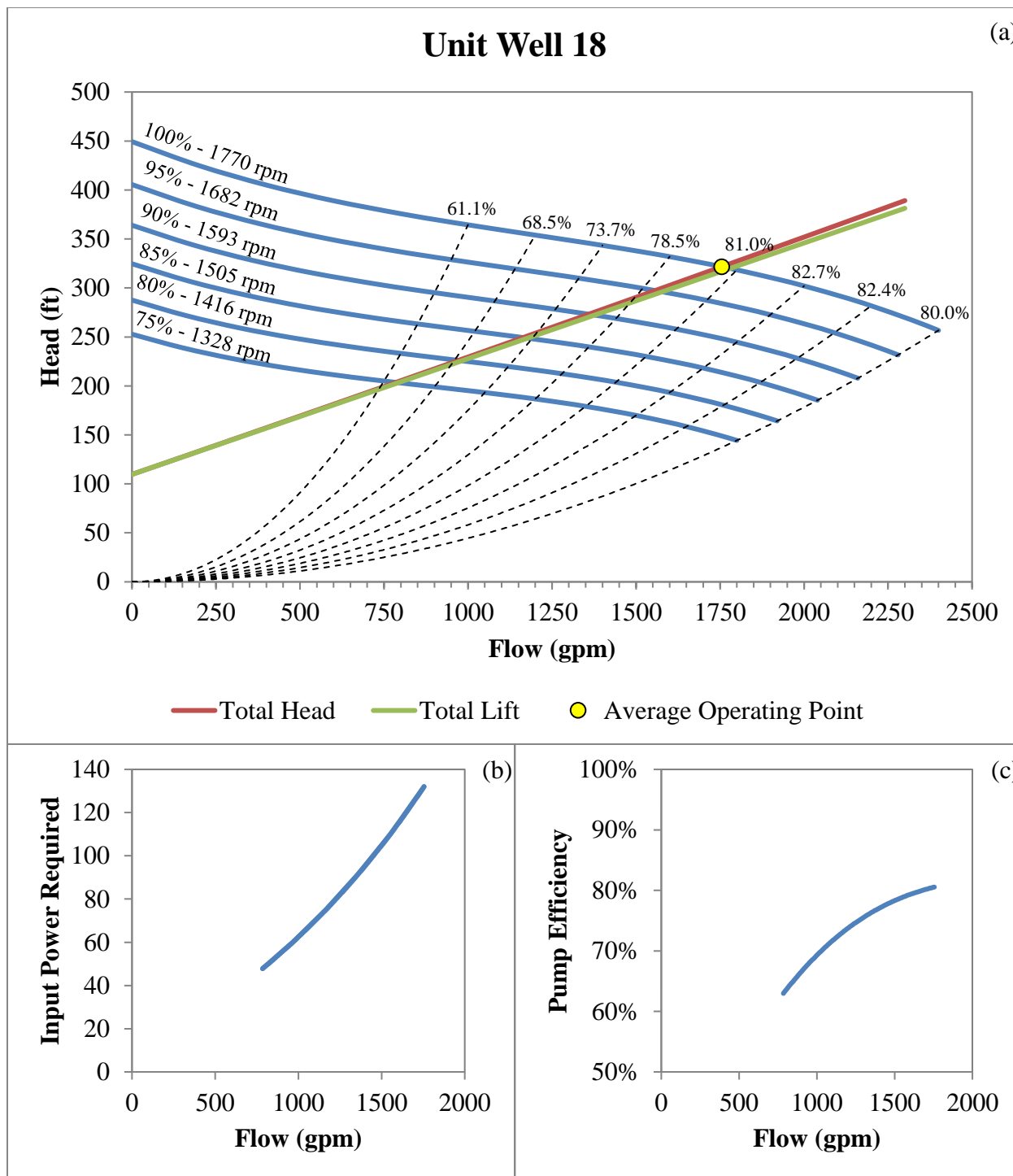


Figure C-12 – (a) Unit Well 18 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

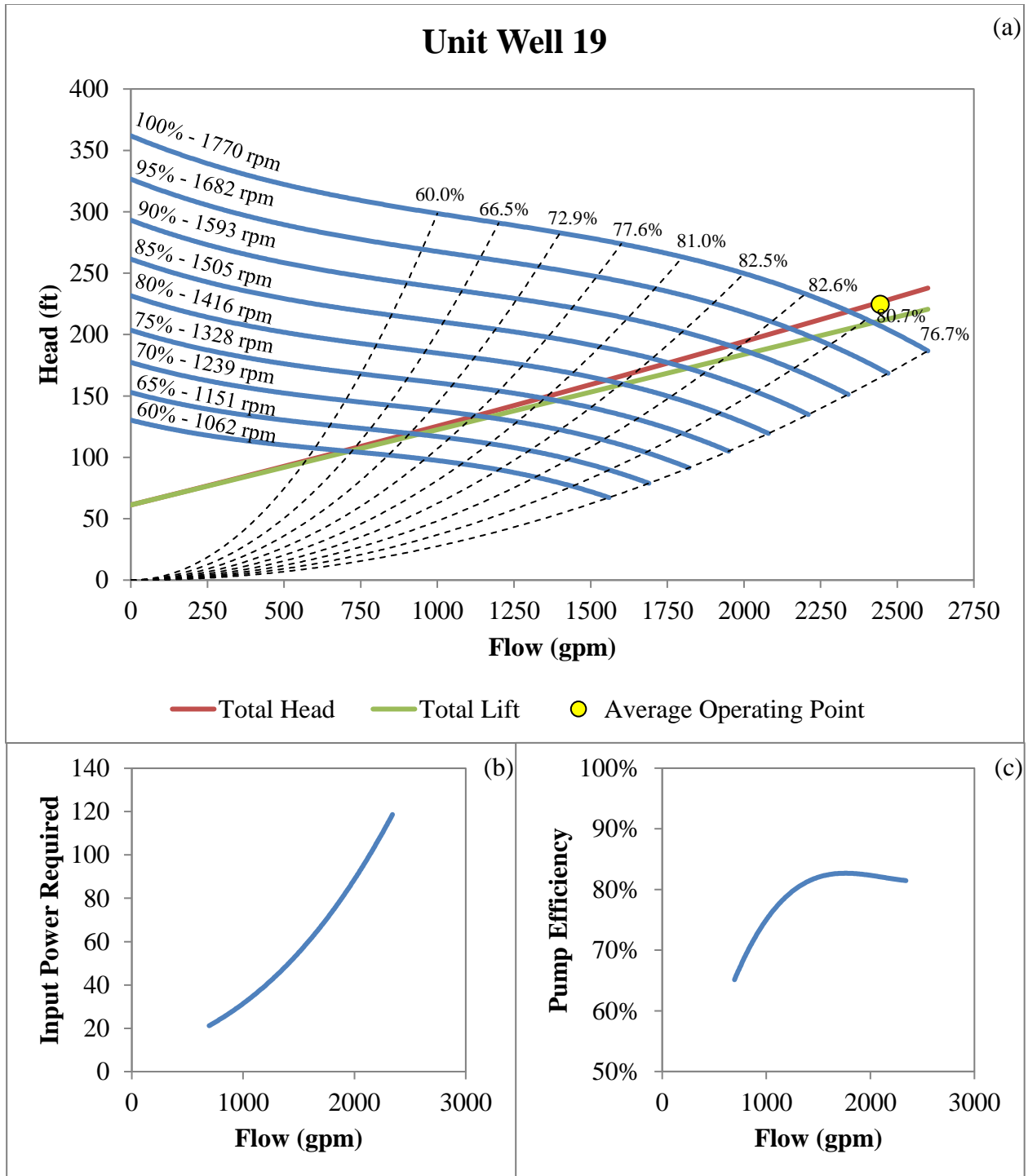


Figure C-13 – (a) Unit Well 19 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

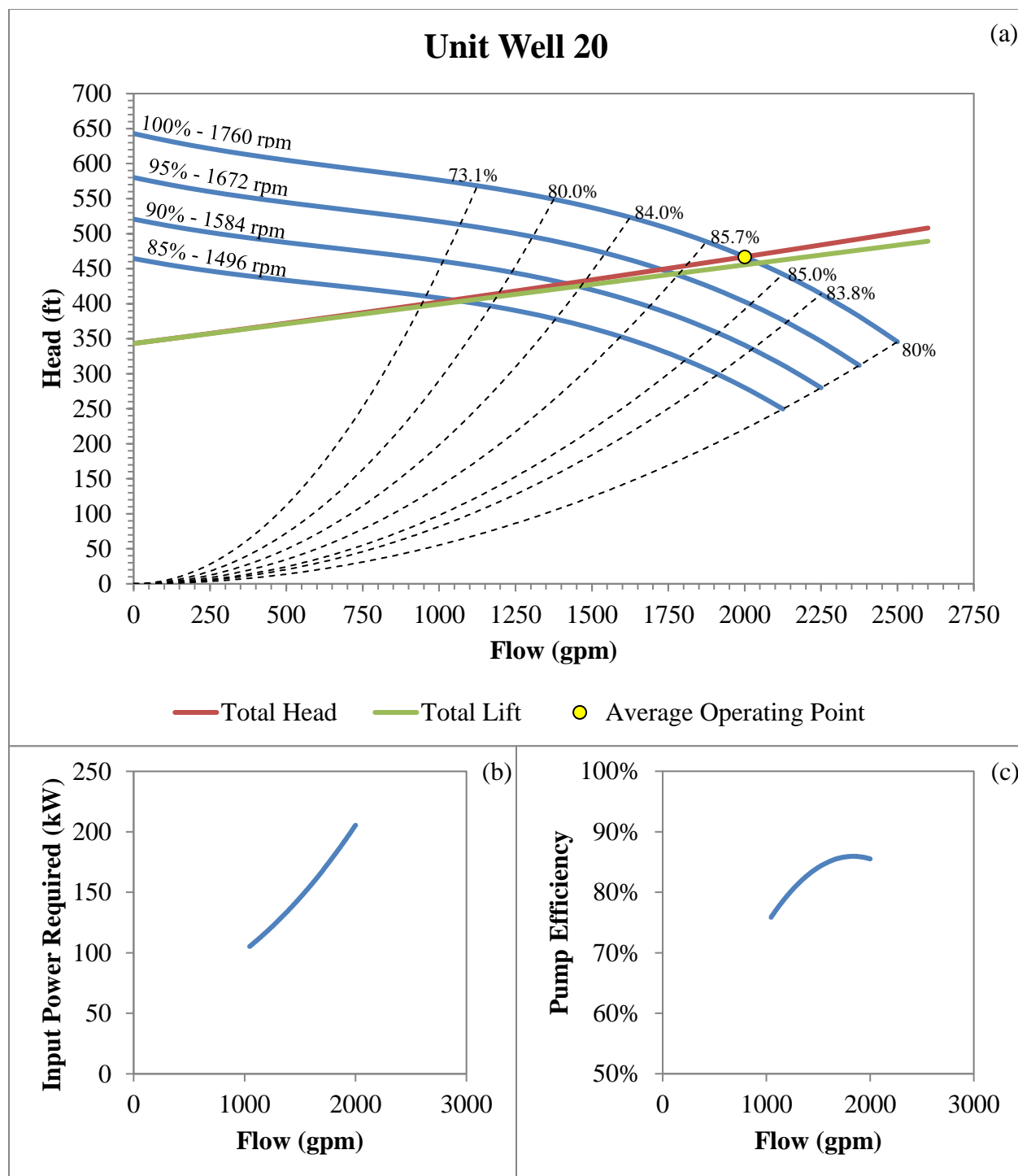


Figure C-14 – (a) Unit Well 20 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

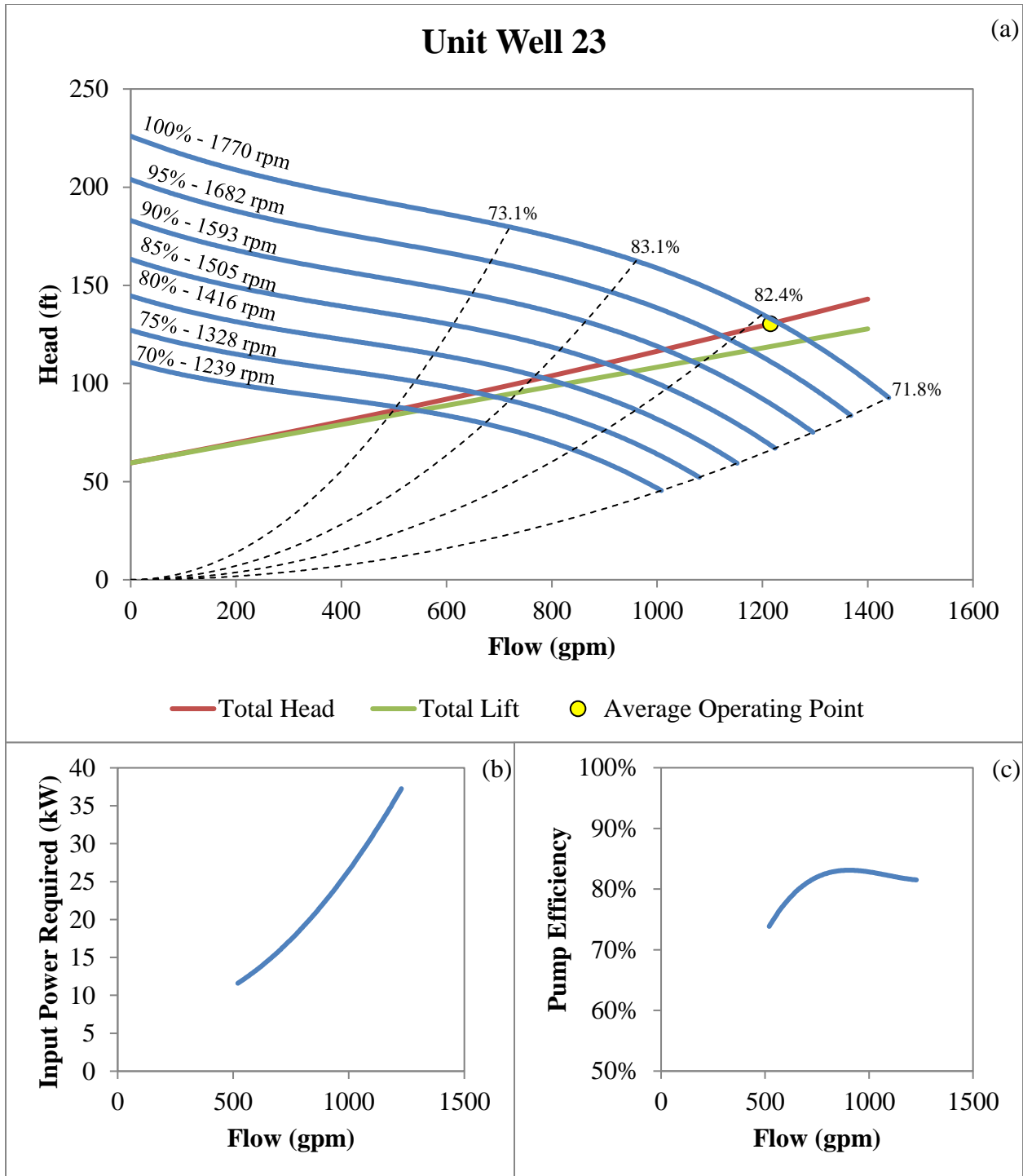


Figure C-15 – (a) Unit Well 23 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

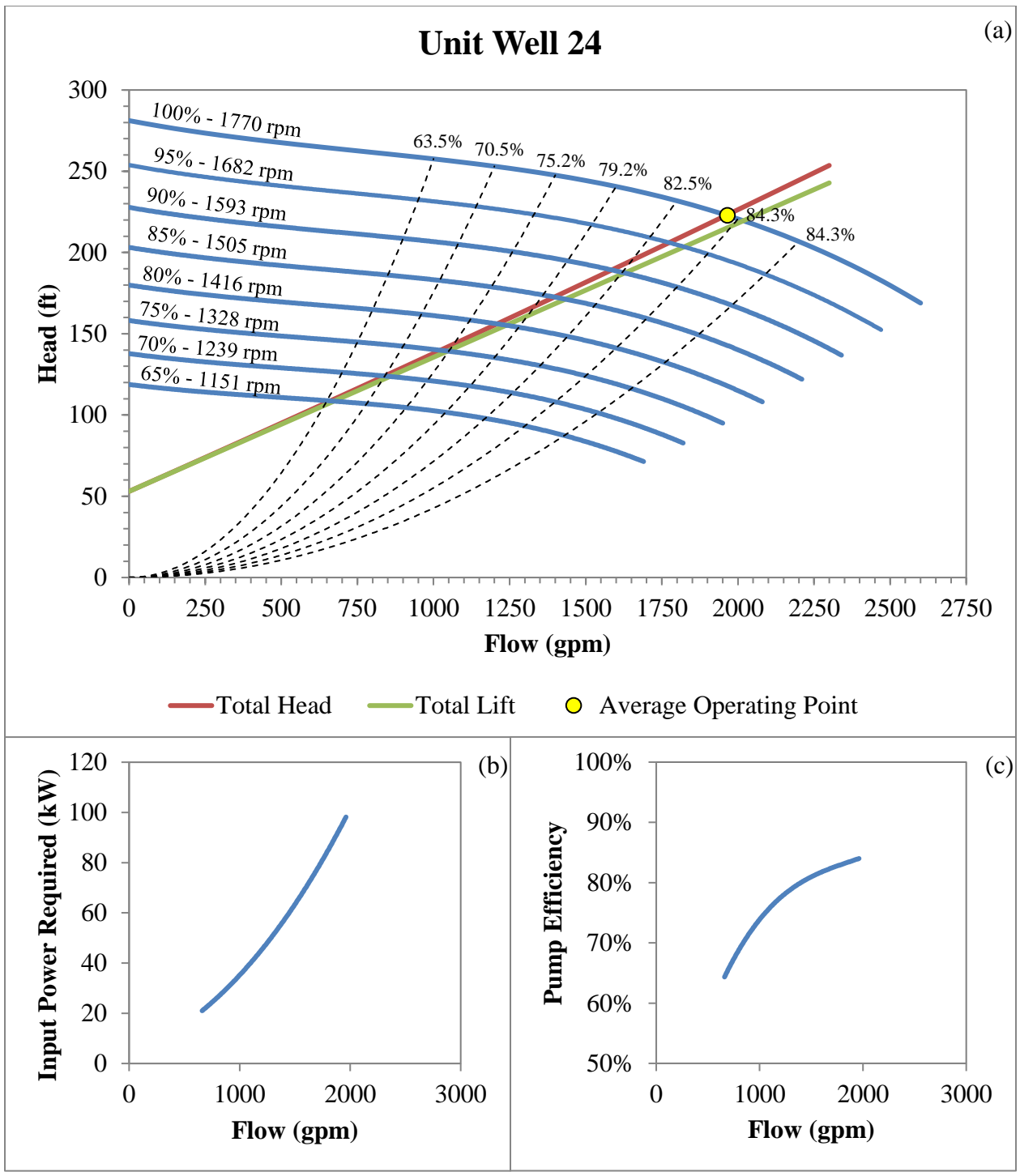


Figure C-16 – (a) Unit Well 24 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

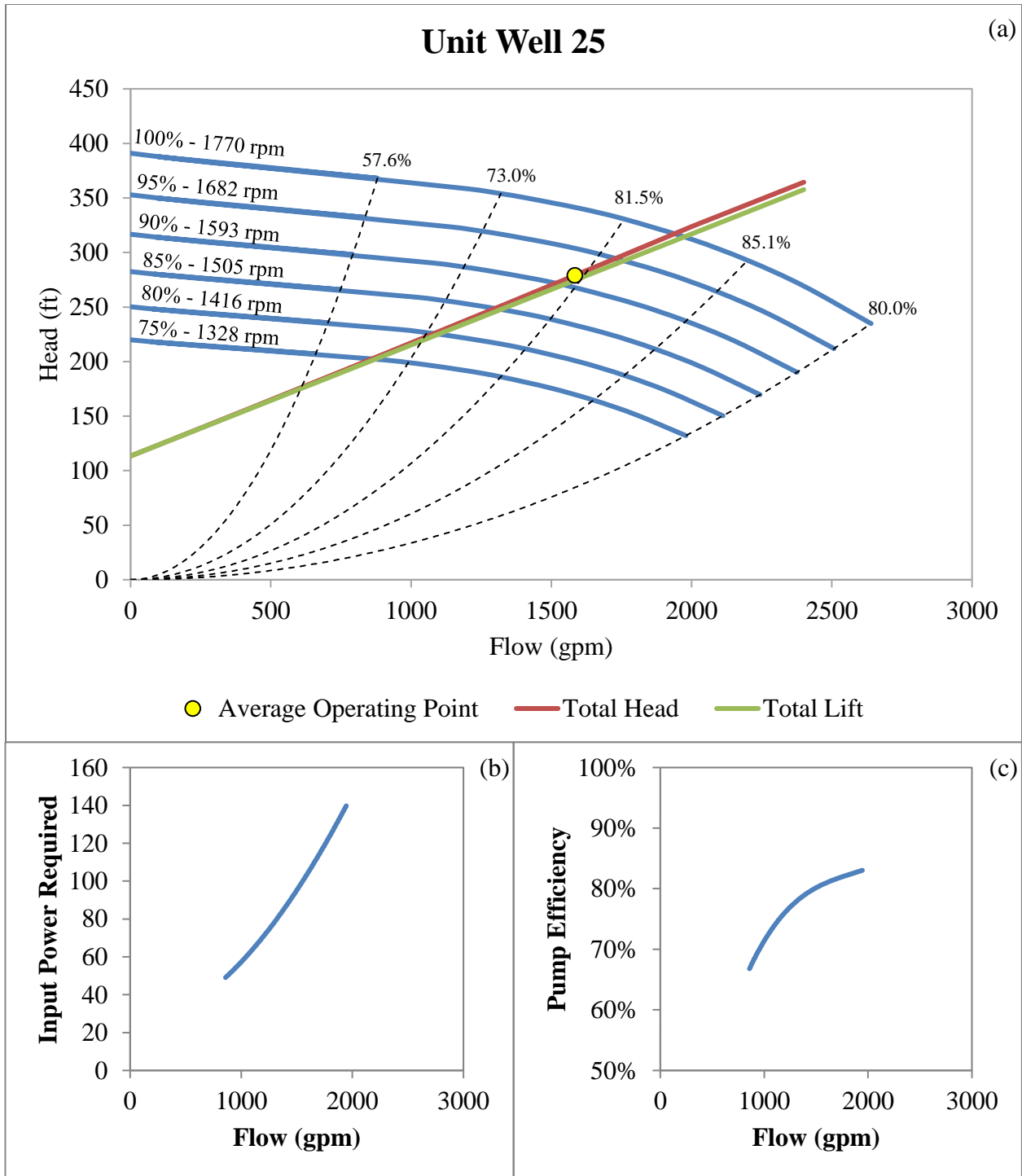


Figure C-17 – (a) Unit Well 25 variable speed curves and pump efficiencies with system head curve and average operating point (Pump speed set to 92% in August 2016). (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

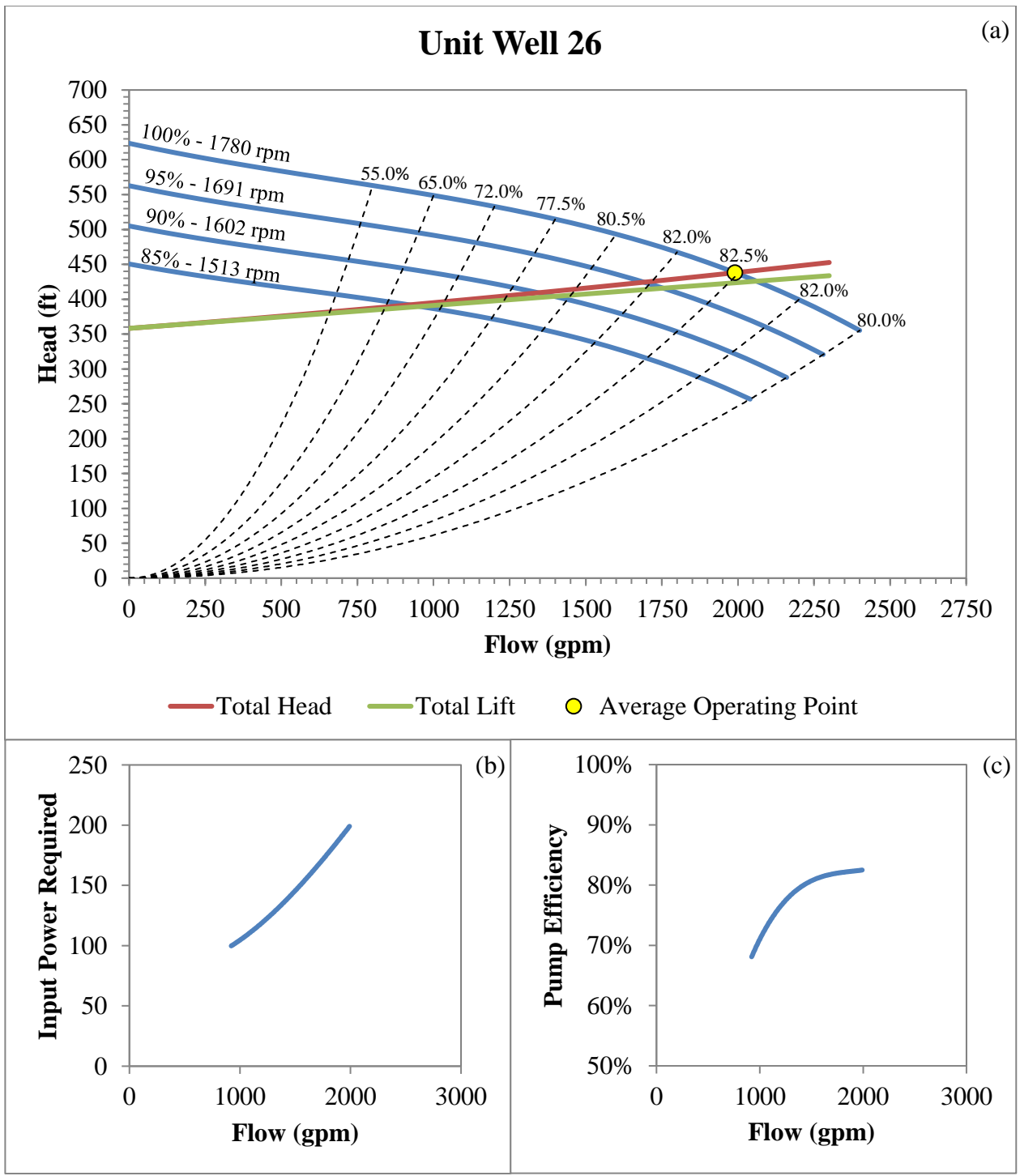


Figure C-18 – (a) Unit Well 26 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

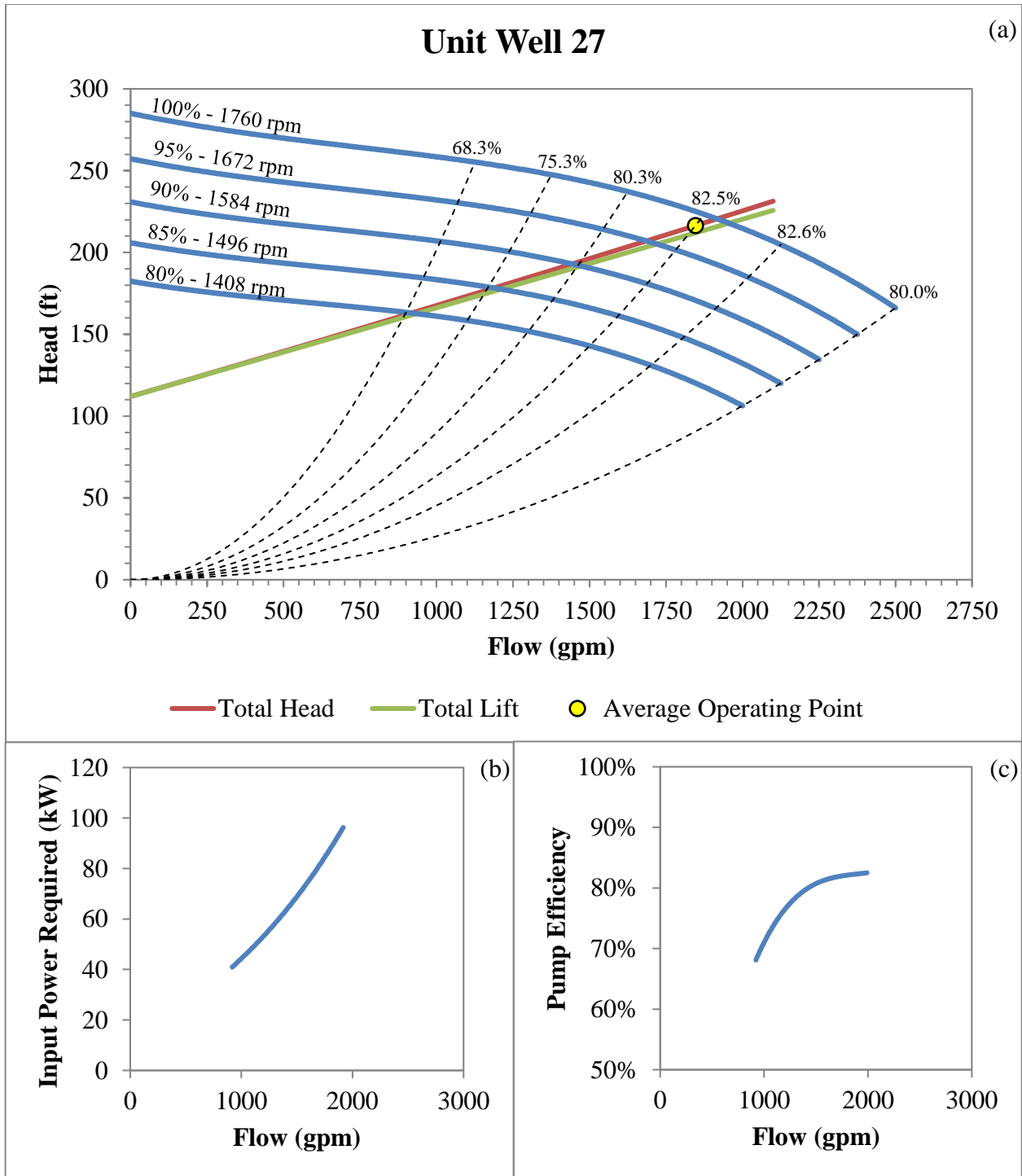


Figure C-19 – (a) Unit Well 27 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

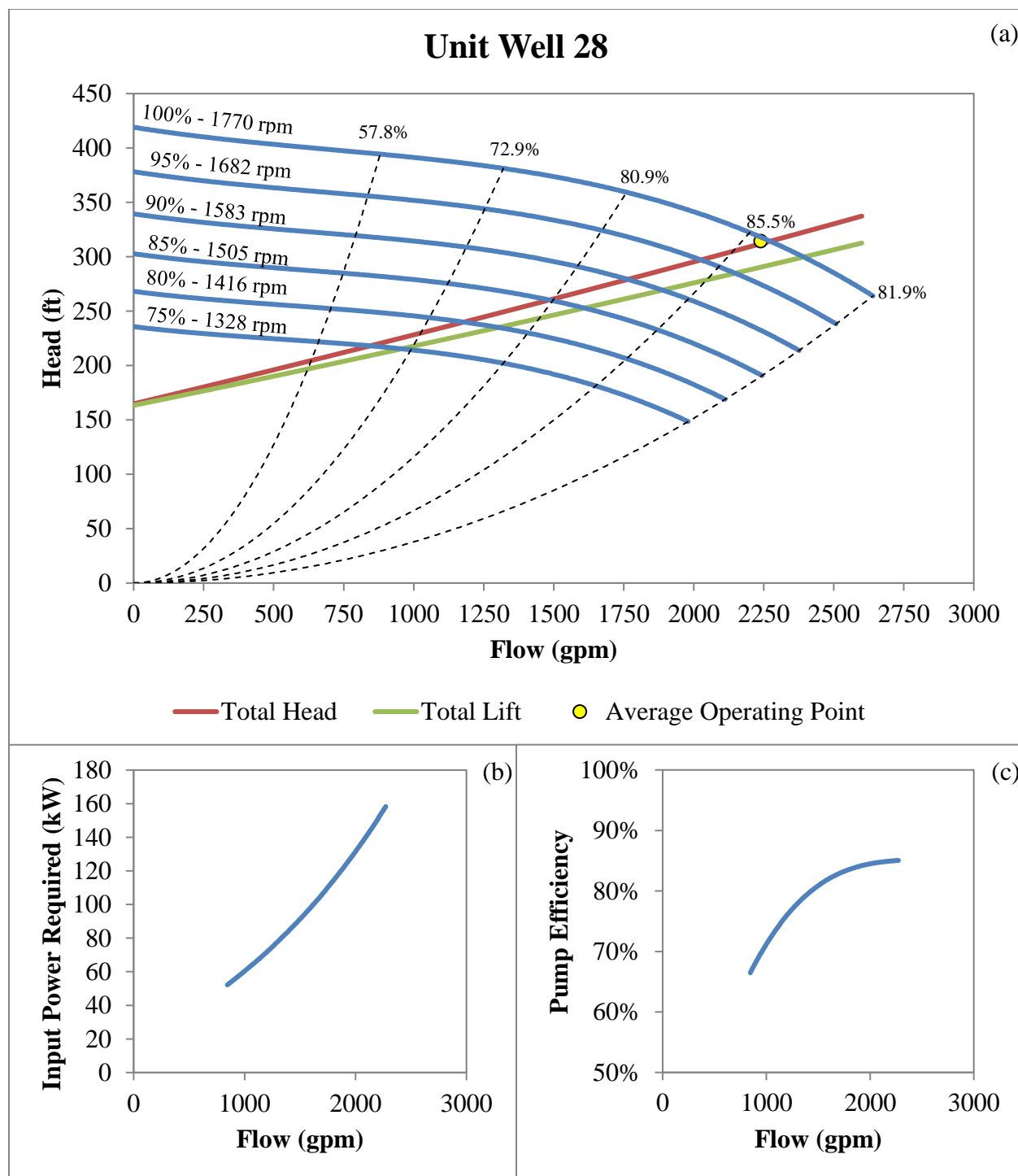


Figure C-20 – (a) Unit Well 28 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

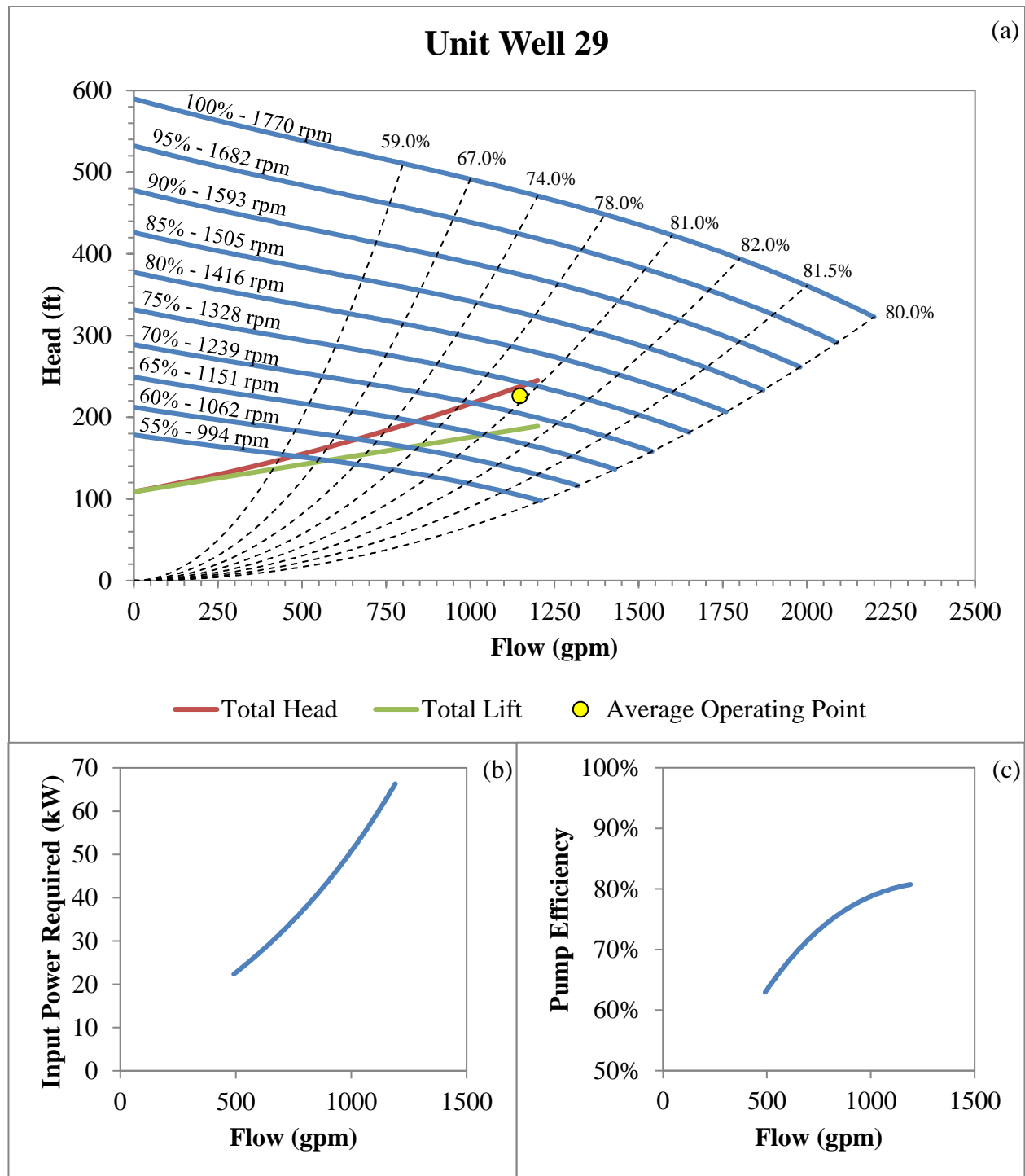


Figure C-21 – (a) Unit Well 29 variable speed curves and pump efficiencies with system head curve and average operating point (1,150 gpm constant flow setpoint in August 2015). (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

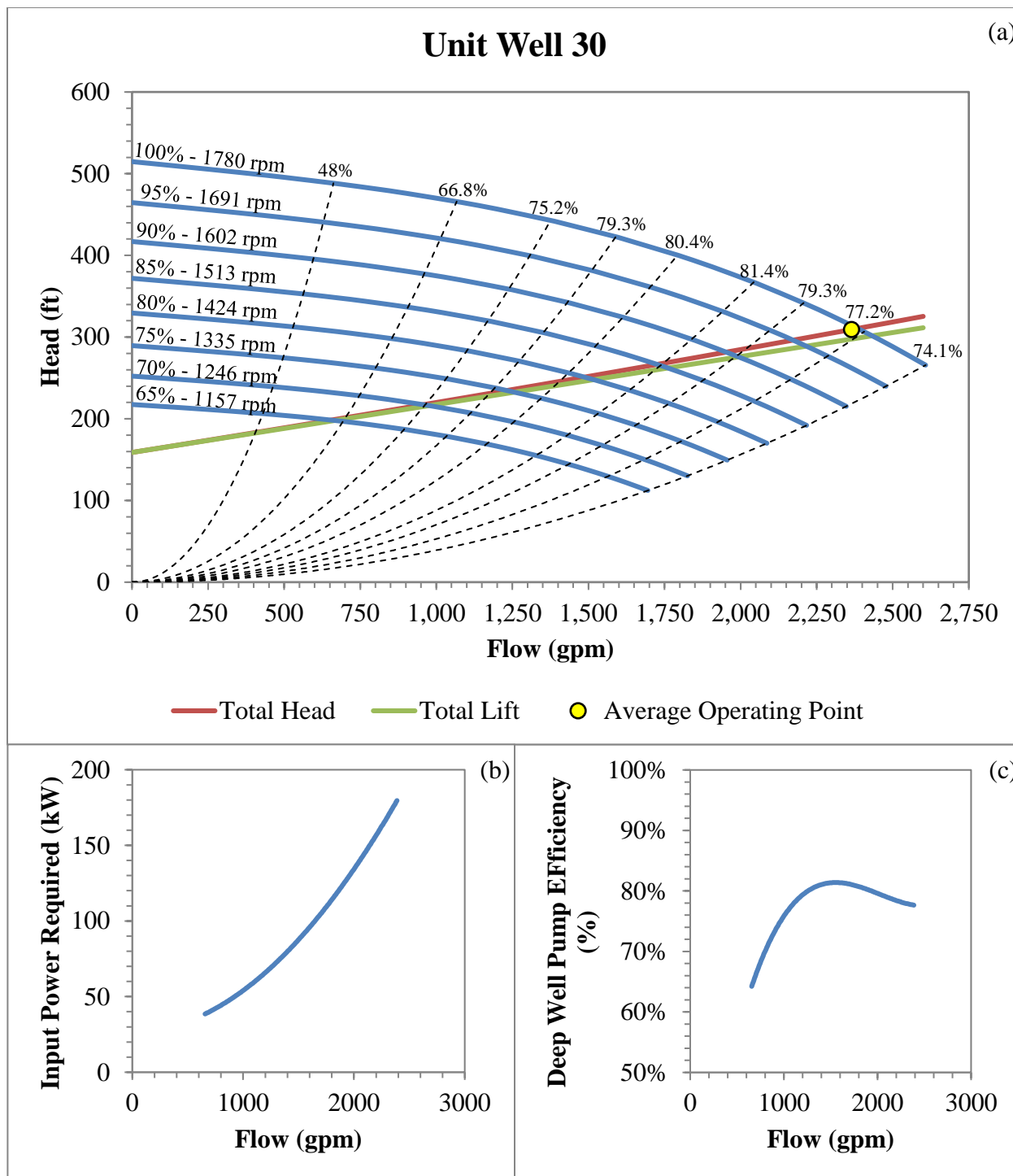


Figure C-22 – (a) Unit Well 30 variable speed curves and pump efficiencies with system head curve and average operating point. (b) Pump input power requirements at reduced speed and flow rates. (c) Estimated pump efficiency at reduced speed and flow rates.

APPENDIX D – UNIT WELL 30 VFD TEST RESULTS

Variable Speed Test at Unit Well 30

A similar test to those run at Unit Wells 15 and 25 (Mancosky 2017a) was conducted at Unit Well 30. This test was run prior to correction of the transducer location. All measured pumping water levels for this test were deeper than the true depth.

Speeds were tested in 10% speed intervals. The field test was conducted over a week time period from March 6 to 10, 2017. A summary of conditions for the VFD speed test at Unit Well 30 is shown in Table D-1.

Table D-1 – Unit Well 30 VFD Speed Test Conditions

Tested Speed	60%	70%	80%	90%	100%
Date	3/7/17	3/8/17	3/6/17	3/9/17	3/10/17
Deep Well Off Time Prior to Test (hr)	1.3	1.0	1.1	1.3	1.7
Test Run Time (hr)	6.0	6.0	6.1	6.0	5.1

Estimated Pump Behavior

Refer to Mancosky (2017b) for average operating conditions and estimated energy intensities at Unit Well 30. Maximum energy intensity savings estimated were 350 kWh/MG for a reduction to 70% pump speed.

Average Operating Conditions and Energy Use

Average deep well pump operating conditions for each tested speed in March 2017 are presented in Table D-2. All averages are for six hours of pump run time, except for 100% speed. Flow rate at 100% speed far exceeded average booster pump flow rates, and the reservoir filled after 5.1 hours of pump run time.

Table D-2 – Unit Well 30 March 2017 VFD test data averages (averages for six hours of pump run time).

	60%	70%	80%	90%	100%*
Flow Rate (gpm)	698	1,203	1,609	1,994	2,382
Pumping Water Level (ft)	178	212	238	264	285
SCADA VFD Power (kW)	35	64	98	138	186
SCADA VFD Energy Intensity (kWh/Mgal)	836	886	1,020	1,150	1,300

*5.1 hour test run time

System head curves and average operating points from the estimation and field test are plotted with the variable speed curves in Figure D-1. Estimated average operating points only went as low as 70% speed, whereas the field test went as low as 60% speed.

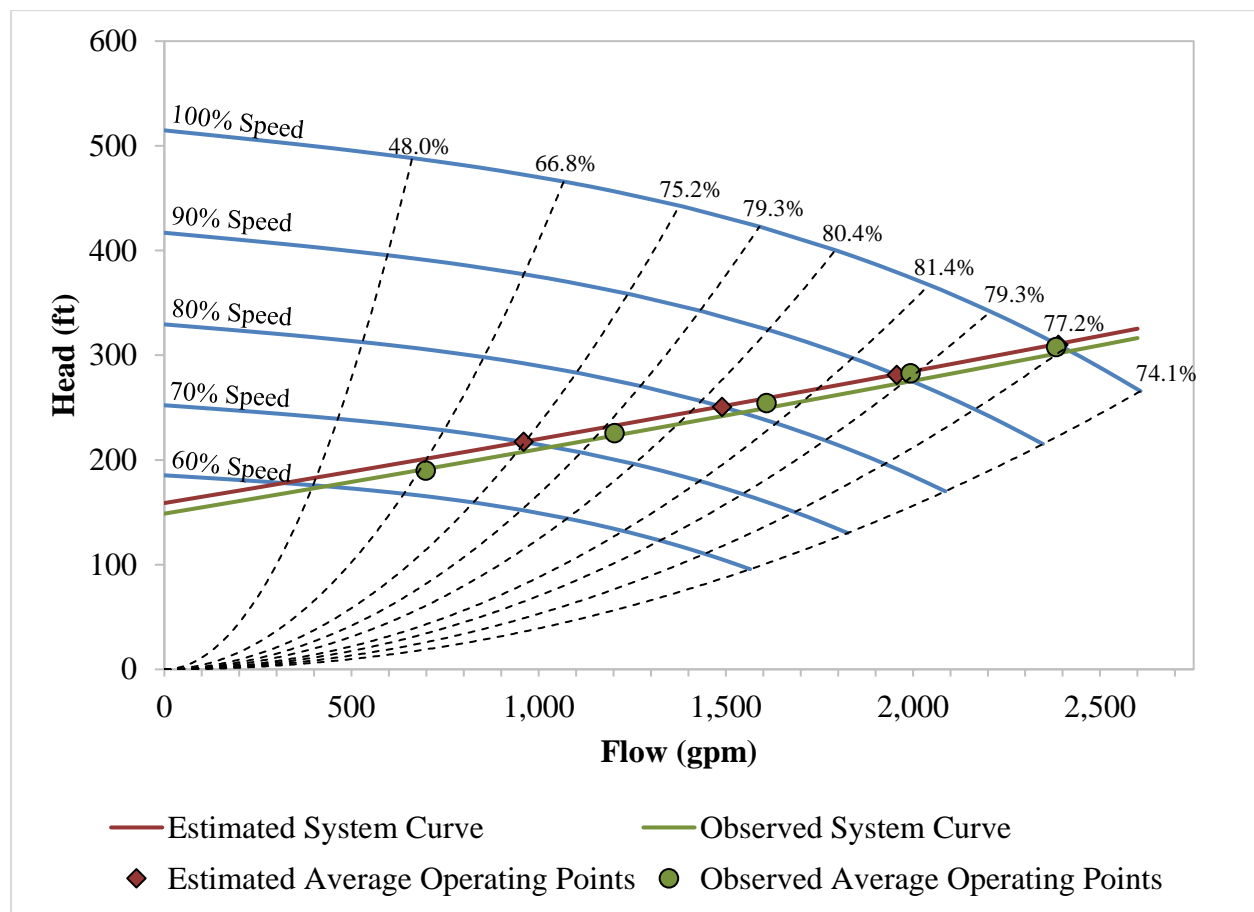


Figure D-1 – Comparison between estimated and observed operating conditions for Unit Well 30. Estimates were based on observed static water level from August 2015, as well as estimated specific capacity and friction coefficients. Observations were based on observed

static water level and specific capacity from March 2017, as well as estimated friction coefficients.

Average operating points at 90% speed and 100% appeared to align with the pump curve. Operating points at 60%, 70%, and 80% did match the respective speed curves determined by the Affinity Laws. The average operating point for 60% speed was 25 feet above the variable speed curve.

Estimated and observed energy intensity were compared in Figure D-2. Unlike at Unit Wells 15 and 25 (Mancosky 2017a), estimated energy intensities were greater than observed values. The incorrect measurements of water level resulted in greater TDH estimates, which would have resulted in higher estimated energy intensities than observed. Observed and estimated energy intensity were within 2% for 80%, 90% and 100% speeds. Observed energy intensity at 70% was 8% less than estimated. Energy intensities were still within 10% of estimated values even with the measurement errors impacting the estimates of pump TDH.

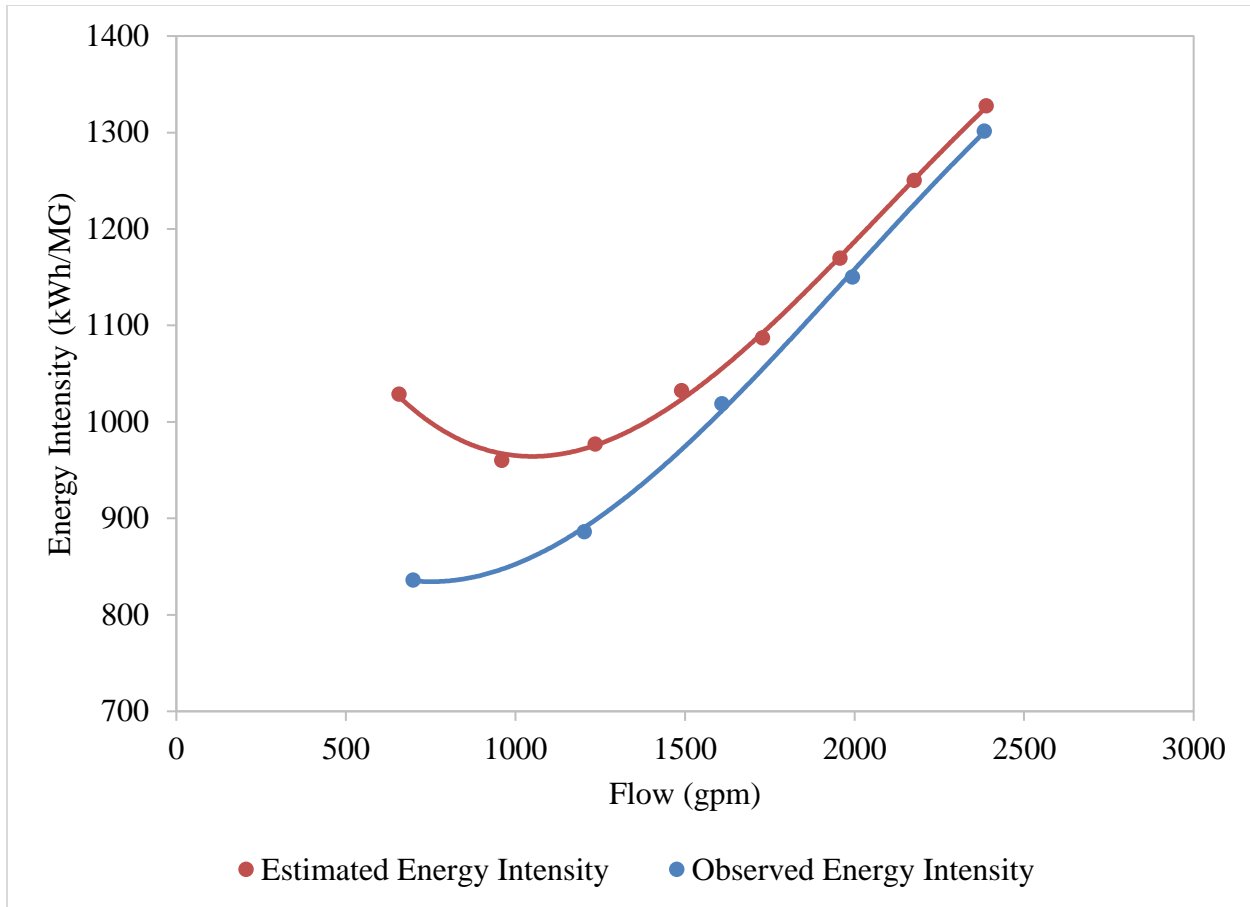


Figure D-2 – Comparison of observed and estimated energy intensity at Unit Well 30. Each marker for estimated energy intensity represents a 5% speed interval (65% through 100% speed). Each marker for observed energy intensity represents a 10% speed interval (70% through 100% speed).

Maximum observed energy intensity savings were 465 kWh/MG for a reduction in pump speed from 100% to 60% speed. Observed savings for reduction in pump speed from 100% to 70% speed were 420 kWh/MG, 13% larger than the 370 kWh/MG estimated. Estimates of energy intensity may have been impacted by inaccuracies in water level measurements. Even so, significant energy savings benefits were observed at Unit Well 30. The method for estimating energy savings was once again found to be conservative.

Measurement Correction

A brief variable speed test was conducted in May 2017 after the measurements of water level were corrected previously in March 2017. The intent of the test was to determine if the correction made regarding the location of the transducer solved the inconsistencies in observed water level measurements. The pump was tested for approximately ten minutes across a range of pump speeds (65%, 70%, 80%, 90%, and 100%). Operating points are compared against variable speed curves based on the original manufacture curve in Figure D-3.

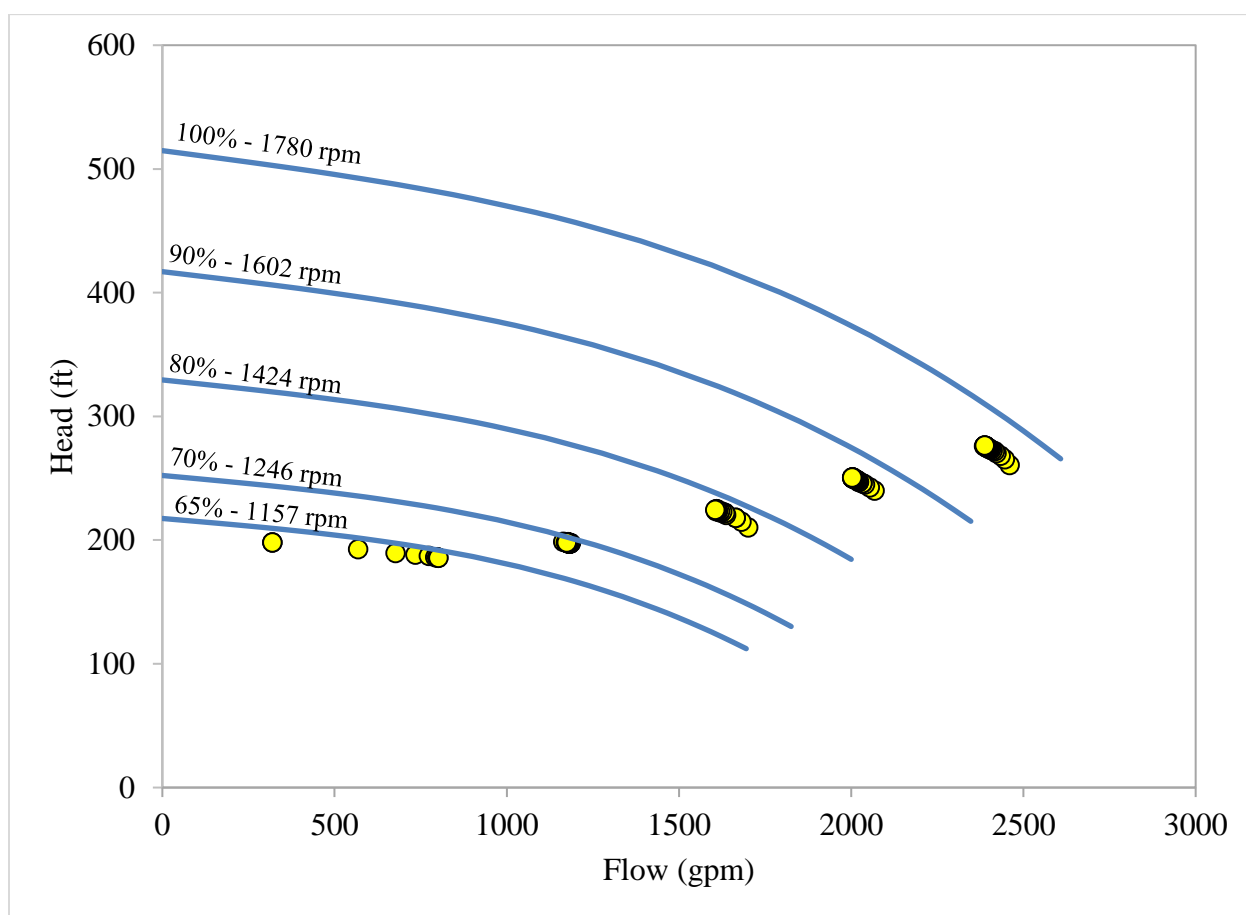


Figure D-3 – Variable speed curves and observed operating points from May 11, 2017 test. Variable speeds determined using original manufacturer performance curve.

Average operating points were the opposite of those shown in Figure D-1, nearly on the manufacturer curve at 65% and 70% with the discrepancy increasing with pump speed. Operating

points at 100% pump speed were nearly 35 feet below the manufacturer curve. Similar to the procedure detailed in Mancosky (2017b), the pump curve was shifted down to match observed operating points.

When shifting the curve, the error was defined as the difference in head between the observed operating head and the head determined from the Affinity Laws. This error was summed for all individual operating points and the intercept of the 100% speed curve was shifted to minimize error across all pump speeds. The resulting shifted curve and associated curves determined from the Affinity Laws are compared against the observed operating points in Figure D-4. The 100% speed curve was shifted 25 feet as a result of this analysis.

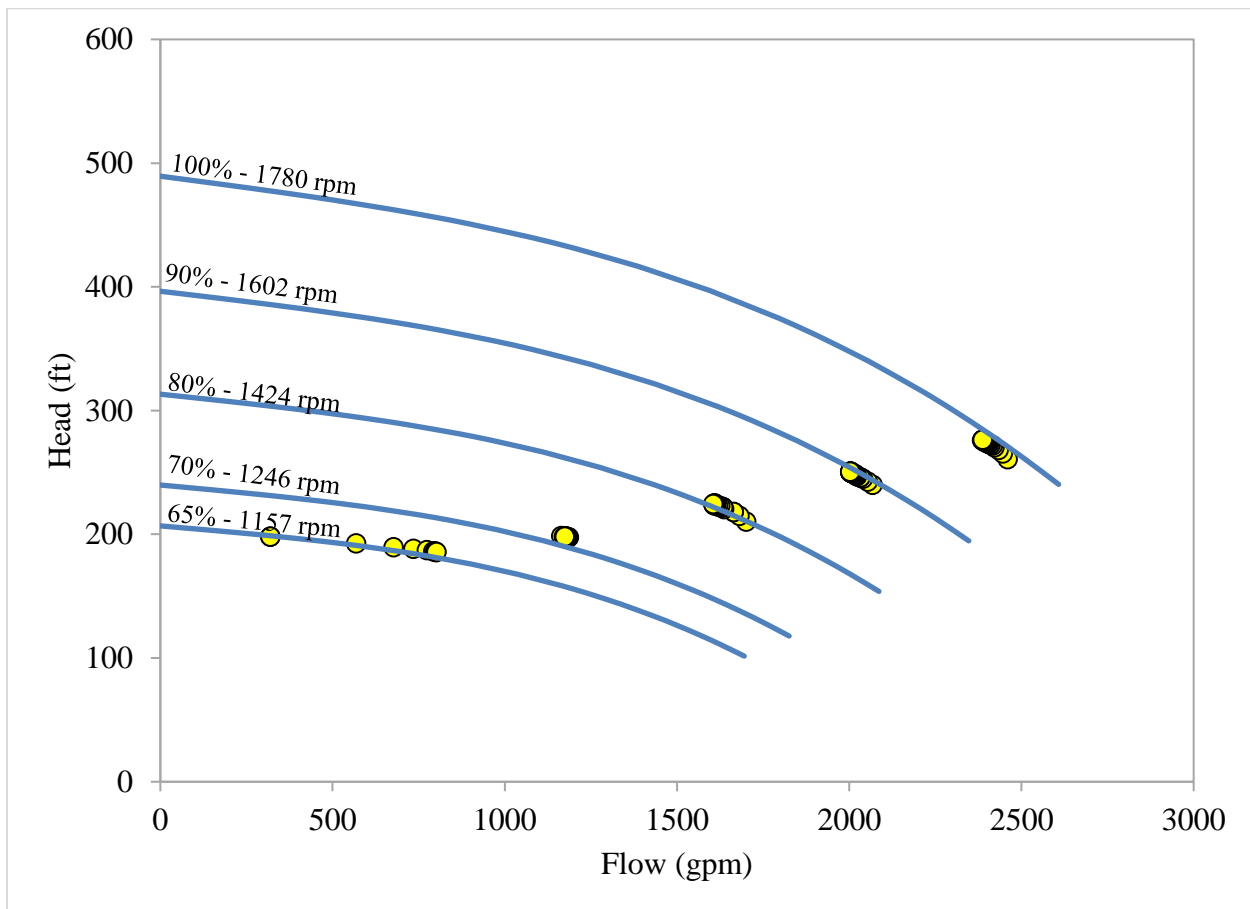


Figure D-4 – Variable speed curves and observed operating points from May 11, 2017 test. Variable speeds determined using shifted 100% speed curve to match observed data.