

Drilling Fluid Storage and Transfer Methods at Perdido

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Abstract

Recent operations have highlighted three issues with the drilling fluid storage and transfer methods currently used at Shell's Perdido spar:

1. barite settling and loss of emulsion during transport
2. the mud transfer rate between the motor vessels (M/Vs) and the spar is inadequate
3. the mud transfer rate between the drilling rig active and auxiliary pits is inadequate.

The first issue leads to costly re-conditioning once the drilling fluid is transferred from the M/Vs and the second two issues restrict wellbore displacement rates below optimal levels.

Examination of the drilling fluid systems aboard the drilling rig, spar, and an M/V has led to three recommendations to mitigate the effects of the above three issues:

1. limit drilling fluid transport time and investigate modifications to the M/V drilling mud circulation lines
2. increase the impeller diameter on the M/V drilling fluid transfer pump
3. increase the impeller diameter on the drilling rig drilling fluid transfer pumps and investigate whether the pumps can be operated in series or parallel.

This paper presents an in-depth analysis of the three recommendations and proposes a potential solution for the storage and transfer issues currently experienced at Shell's Perdido spar.

Introduction

The Perdido spar is located about 200 miles South of Galveston, Texas. The current support fleet of three motor vessels (M/Vs) operates out of the Shell terminal in Galveston. Typical M/V cruise speeds of 10 knots dictate arrival at the spar approximately 20 hours after departure from the Galveston terminal. One M/V has storage room for 11,000 bbls of drilling fluid and quoted mud discharge rate of 750 gpm at 220 feet of hydraulic head. The increased logistics lead time, due to travel time from the terminal, combined with operational variability occasionally causes drilling fluid to remain on an M/V as long as two or three weeks before it is offloaded to the rig.

The drilling fluid supplier has a facility located at the Galveston terminal and batch mixes large quantities of drilling fluid to load onto the M/Vs in terminal. The current drilling

program requires both water- and synthetic-based mud (WBM and SBM, respectively) that range in density from 9.0 ppg to 9.8 ppg. The plastic viscosity (PV) is generally between 18 - 24 cP. A typical wellbore volume is almost 2,600 bbls.

The drilling rig on the Perdido spar has four 500 bbl auxiliary tanks and an active pit volume of about 500 bbls. As currently configured, the rig mud pumps are capable of pumping as high as 1,000 gpm, while the centrifugal transfer pumps can pump at about 420 gpm. The drilling rig is set on the main deck of the spar, about 150' above sea level. The auxiliary and active mud systems are an additional 20' above the main deck, equivalent to 170' above sea level.

Issues Encountered

Drilling operations on Perdido are currently coping with two primary mud supply issues:

Loss of Emulsion during Transport

SBM is an emulsion of water in base oil. SBM drilling fluid density is manipulated by changing the concentration of barite particles. To ensure a good emulsion, the drilling fluid supplier adds chemicals to help ensure that the water mixes into the base oil. Despite the best chemistry, after extended periods without adequate circulation of the entire fluid volume, the dense barite particles will begin to settle out to the bottom of the fluid and the low density base oil will rise to the top of the fluid. The best method to prevent this is circulation and agitation of the entire drilling fluid volume.

This problem is encountered after a long break from full-volume circulation and when drilling fluid has been in transit on M/Vs for an extended period of time. In an extreme example, 9.8 ppg SBM left on an M/V for six weeks, twice as long as desired, separated into an 11.2 ppg fluid in the bottom of the tank and a 6.5 ppg fluid in the top of the tank. This density stratification indicates both loss of emulsion and barite settling in the lower tank volume. This fluid required extensive treatment that was costly in both chemicals and time. This stresses both timely offloading of drilling fluid from the M/V as well as adequate circulation of the entire volume aboard the vessel.

Aboard the M/Vs, the drilling fluid tanks are circulated for one hour every four hours. This circulation scheme appears adequate; however, both the pump suction line and the circulation discharge lines are located in the bottom two feet of an almost 16 foot deep tank. This setup may reduce barite settling on the tank bottom, but it is not be

able to provide adequate circulation to the entire volume of drilling fluid in the tank. Even with a well-kept circulation schedule, discharging into the region around the suction line will not prevent separation of the oil-water emulsion.

Transfer Rates

The drilling fluid transfer rates between the rig active system and auxiliary tanks, and between the rig and M/Vs, are 420 gpm and 350 gpm, respectively. When displacing the wellbore, the mud pump rate is currently limited to less than 50% of configured capacity to keep pace with the transfer pumps. The 1,000 gpm mud pump capacity is reduced during displacements due to an inability to transfer mud at an equal rate. This requires displacements to take over twice as long as technically possible and can reduce displacement effectiveness.

The drilling rig has 8x6x14 centrifugal pumps with 10" impellers to transfer mud between active and auxiliary tanks and to the M/Vs. Each pump is powered by a 1775 RPM 75 hp motor. According to the pump curve in Fig. 1, 500 gpm of 9.8 ppg mud with a 10" impeller produces about 75 feet of hydraulic head, but the pump is only 40% efficient and requires over 30 bhp. Note that while hydraulic head and flow rate are independent of fluid density, power required must be corrected for specific gravity.

Investigation and Analysis

Loss of Emulsion during Transport

The circulating pumps and tank rolling schedule are adequate to prevent excessive barite settling and phase separation; however, the arrangement of the circulation lines and pump suction will not prevent oil-water emulsion separation. Additionally, excessive storage of the drilling fluid in tanks where treatment of fluid properties is not possible should be avoided.

The best solution to this problem would be moving the circulation lines to the top third of the tank and installing agitators on the bottom of the tank to prevent barite settling. A simpler solution would be to place another circulation line in the top of the tank. A choke plate could be installed in the lower circulation line to direct about 50% of the circulating flow to the top line.

Both modifications would be relatively complicated and require substantial time to complete both engineering and installation. Moreover, an overhaul of M/V drilling fluid system is expected to be prohibitively expensive.

Transfer Rates

The drilling rig fluid transfer pumps are powered by 1775 RPM 75 hp motors. From the pump curve in Fig. 1, rig transfer pumps with 11" impellers would require approximately 60 bhp to transfer 9.8 ppg SBM at 1,000 gpm and 100 feet of hydraulic head. A larger impeller would require an increased motor size.

One M/V has two 8x6x18 centrifugal pumps to transfer drilling fluid. Each pump is powered by a 300 hp motor with variable speed to a maximum of 1790 RPM. The pumps currently have 15" impellers installed. The piping layout of the discharge pumps is shown in detail in Fig. 2. Each pump

has a gauge located at the discharge to determine operating pressure and, if drilling fluid density is known, hydraulic head. Typical discharge parameters are about 350 gpm at 120 psi pump pressure. The discharge piping has a working pressure (WP) of 200 psi. With 9.8 ppg SBM, the current 120 psi operating pressure is equivalent to 200 feet of hydraulic head.

The current pump operating point is indicated by the red circle in Fig. 3. The motor is likely turning slightly below 1750 RPM. Pumping 9.8 ppg SBM at less than 40% efficiency requires almost 75 bhp, substantially less than the available 300 hp. Note that operating with 9.8 ppg SBM instead of 8.3 ppg water will change the power required, but will not noticeably affect the hydraulic head output. With 9.8 ppg SBM, the maximum power this pump would require is about 240 hp, 80% of the motor capacity.

The simplest solution to increase the transfer rate is to increase the impeller diameter from 15" to the maximum 18". The current motor has sufficient power to pump the drilling fluid, and the maximum supplied hydraulic head of about 335' is equivalent to 170 psi with 9.8 ppg SBM, or 85% of the discharge system WP. The pump curves and system curve, obtained by following the methods outlined in Hodge and Taylor, are shown in Fig. 4 and indicates how increasing the impeller size may affect discharge capabilities. Note that this is a theoretical system curve and that there is some uncertainty about the interior condition of the transfer pipe over its entire length. The true system curve may be more or less steep; however, increasing the impeller size will allow more flow rate at increased hydraulic head regardless of the system curve.

This particular curve shows a new operating point of 700 gpm at 315 feet of hydraulic head. With 9.8 ppg SBM, this is equivalent to 160 psi, which is 80% WP. However, 315 feet of hydraulic head will equal 200 psi (100% WP) with 12.1 ppg SBM. Installation of a pressure relief valve is recommended to prevent exceeding the discharge system WP. At any drilling fluid density, the motor speed can be reduced to decrease the hydraulic head and pressure applied to the discharge system. The effect of reduced motor speed on this pump, for both 15" and 18" impellers is illustrated in Fig. 4. An 18" impeller for this pump is listed at less than 2,000 USD, and impeller swap out should take fewer than six hours to complete.

Modifying the piping around the pumps such that they can be run in parallel or in series is also considered. When running identical centrifugal pumps in series, the hydraulic head available at each flow rate is doubled (Fig. 5). When running identical centrifugal pumps in parallel, the flow rate at each level of hydraulic head is doubled (Fig. 6). Two pumps with 15" impellers may be able to pump at almost 900 gpm with about 380 feet of hydraulic head when arranged in series. This is equivalent to about 190 psi and 95% WP. However, Fig. 5 displays that the WP may be easily exceeded when operating at full rotational speed. The maximum fluid density that may be pumped at 1750 RPM in this arrangement would be 10.0 ppg. A parallel orientation may only increase available flow at a minor margin; however, if the actual system curve increases more gradually, the gained margin would be larger. Necessary

modifications to the suction and discharge piping system are shown in Fig. 2. Here again, as with the drilling fluid storage tanks, these modifications are expected to be uneconomical.

Conclusions

1. Minimize the amount of time drilling fluid is stored on M/Vs and consider modifying the M/V drilling fluid circulation lines. This is not a minor change and will require engineering, installation within a confined space, and any necessary recertification. This work would almost certainly not be conducted at the Galveston terminal. If economical, this project would take significant lead time.

2. Discuss with the drilling contractor the opportunity to install larger impellers on the rig transfer pumps. The current motors should power 11" impellers, but 12" impellers will likely be too large. Ultimately, the pumps may need larger motors, which will be more difficult to implement. Changing impellers is comparatively inexpensive and simple. It is a "quick fix" that may provide the desired increased performance; however, if 11" impellers yield no improvement, it may indicate the need to upsize both the electric motor and impeller.

3. Suggest that the M/Vs increase the drilling fluid discharge pump impeller from 15" to 18". This may almost double discharge pump capacity for this system. Two 18" impellers should cost less \$4,000 total and can likely be changed with minimal lead and execution time. This is the best option and easiest potential solution.

4. Arranging the discharge pumps in series is not recommended as the piping system WP is insufficient for the pressures anticipated with current drilling fluid densities. A parallel pump system may provide additional capacity according to the slope of the system curve.

5. If not currently present, the M/Vs may benefit from appropriate pressure relief valves in the discharge piping to prevent over-pressuring of the pipe system, depending on current regulations and best practices.

Acknowledgments

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Figures

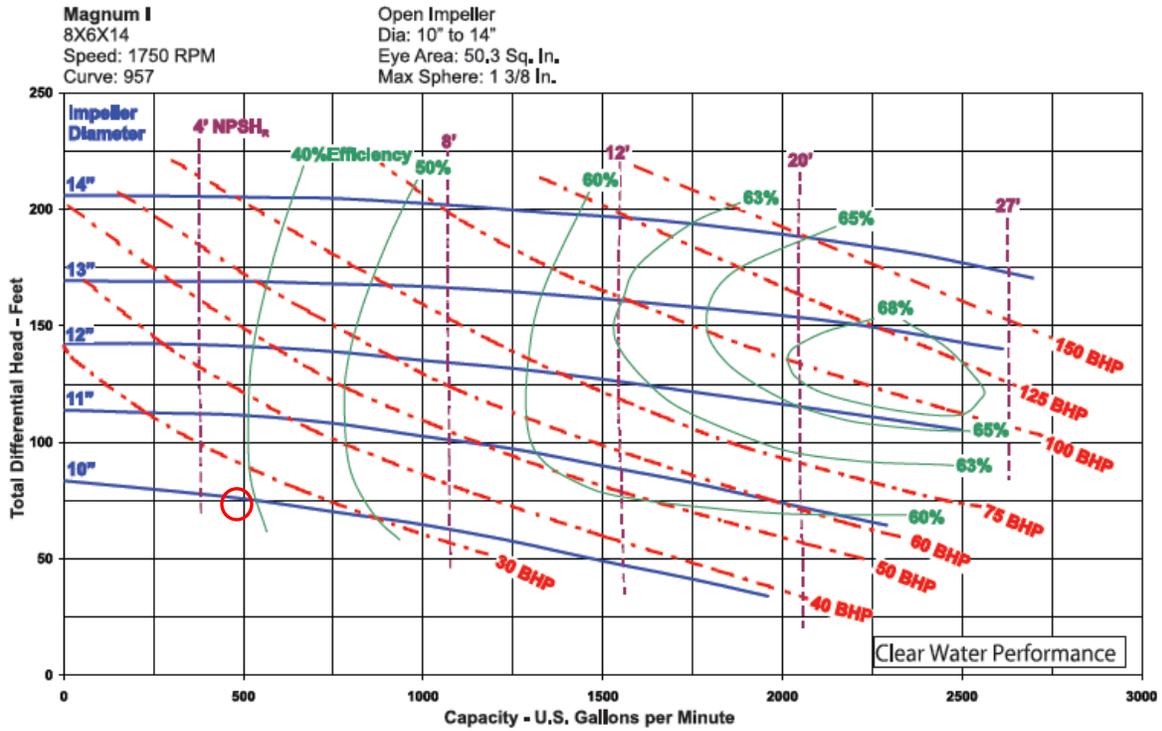


Figure 1: Pump curve for drilling rig drilling fluid transfer pumps. Current operating point is circled in red.

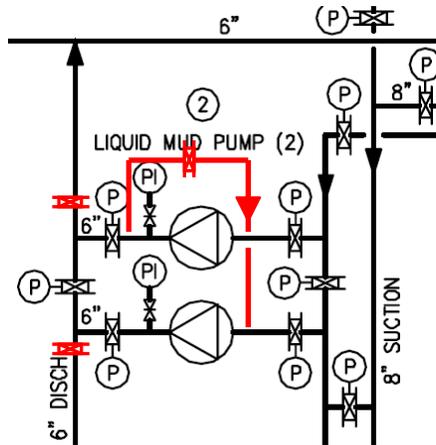


Figure 2: Detail of liquid mud pumps on M/V. Potential piping to operate the pumps in parallel or series is shown in red.

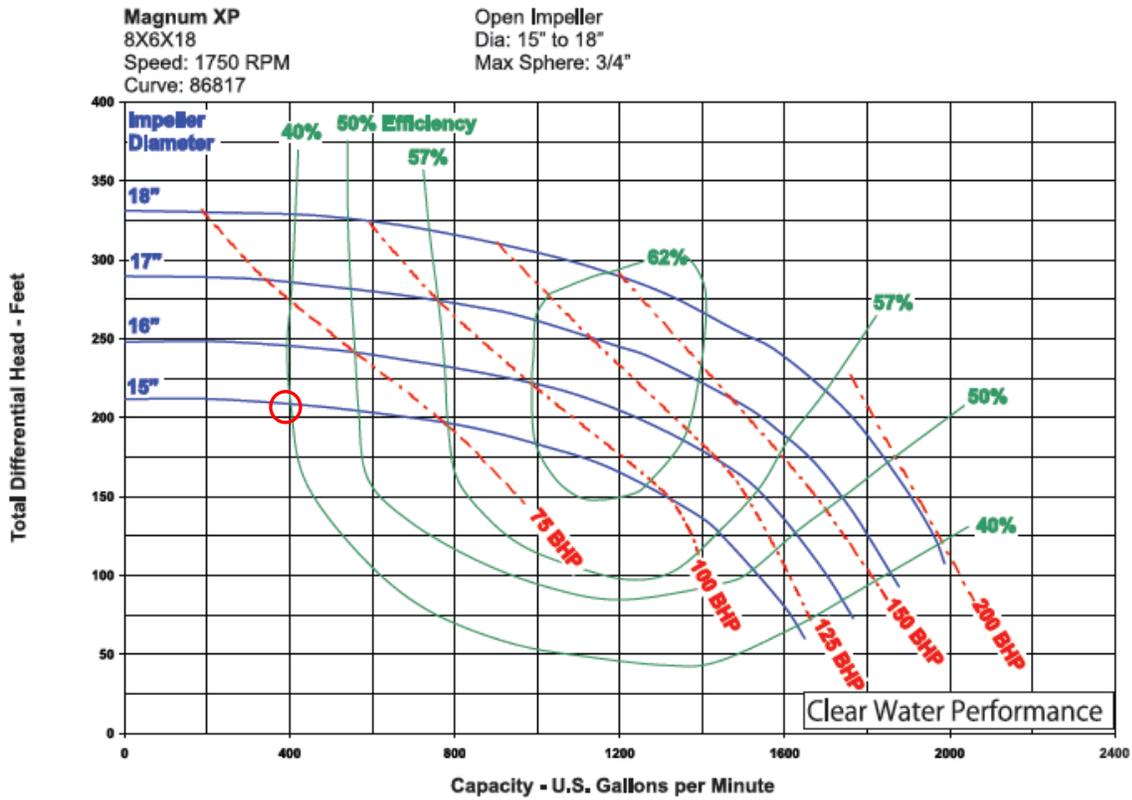


Figure 3: Pump curve for M/V drilling fluid transfer pump. The current operating point is circled in red.

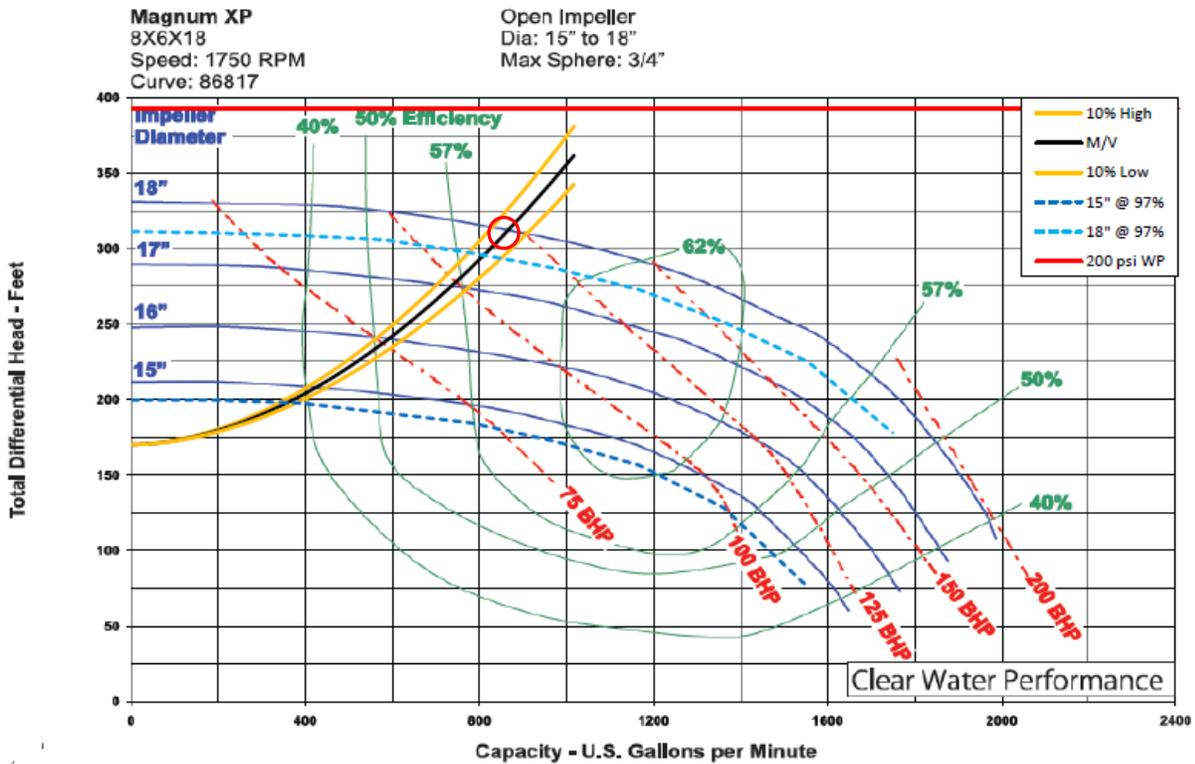


Figure 4: System and pump curves for M/V. Theoretical operating point is circled in red.

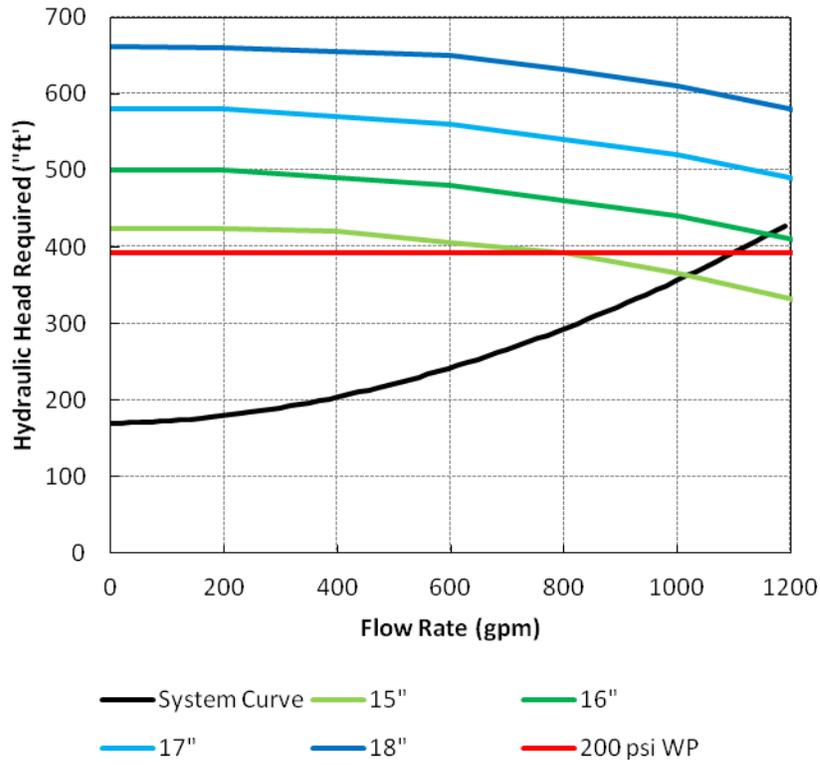


Figure 5: Combined pump curve for two M/V transfer pumps arranged in series. Note that the pump can easily exceed the WP even with the smallest possible impeller.

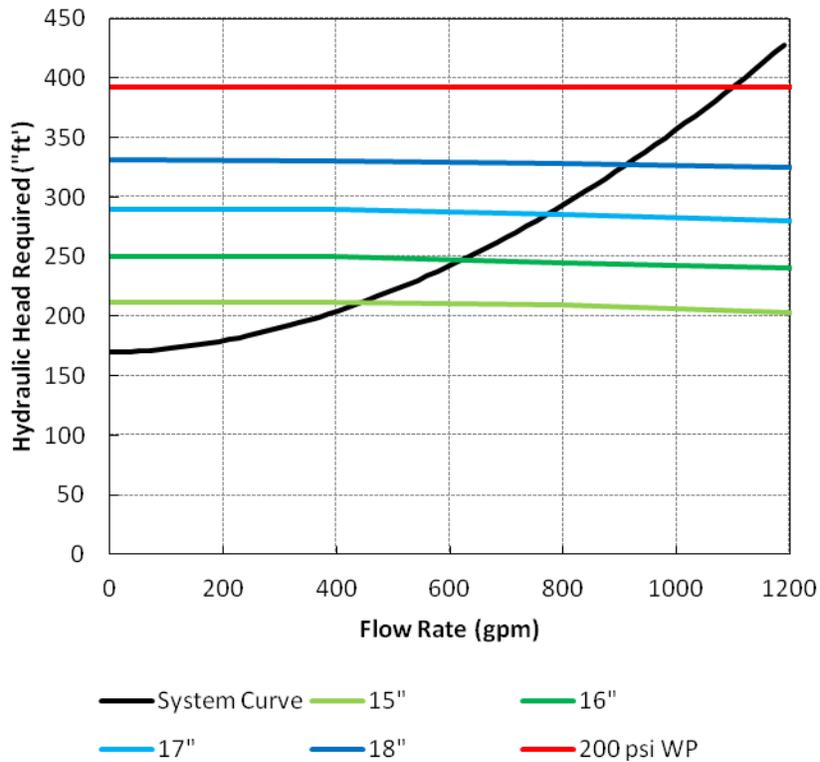


Figure 6: Combined pump curve for two M/V transfer pumps arranged in parallel. Note the improvement compared with increased impeller size, shown in Fig. 4, is minimal.