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Challenges of ESP Test Facility Development to Simulate Expected Downhole Conditions

Becki Owston, Ph.D.

Southwest Research Institute

TURBOMACHINERY LABORATORY
TEXAS A&M ENGINEERING EXPERIMENT STATION
TEXAS A&M UNIVERSITY

Dr. Owston is a Research Engineer in the Fluid Dynamics and Multiphase Flow Section at Southwest Research Institute. Her professional interests include computational fluid dynamics (CFD), multiphase flow phenomena, thermal science, and combustion. At Southwest Research Institute, Dr. Owston conducts simulations for clients in the areas of fluid and thermal science using various commercial codes. She is also heavily involved in experimental multiphase flow testing as a project manager at the Multiphase Flow Facility.

Agenda

- Introduction
- Testing Protocols
- Designing for Sensitivity Testing of:
  - Gas Volume Fraction
  - Inlet Pressure
  - Fluid(s) and Mixing
  - Viscosity
- Conclusions/Experimental Challenges

Why do testing at operating conditions ….?

Testing with water is easy; can't we just use correlations to predict performance downhole?

- There is no universal relationship for determining the operation regime of pumping systems operating with liquid and gas based on predetermined boundary conditions (Gamboa and Prado, 2011)
- Currently there are no universal correlations for accurately determining ESP head operations with viscous oil and natural gas at any conditions (Foresti et al., 2015)

Fine, we have a well; can't we just do a field trial?

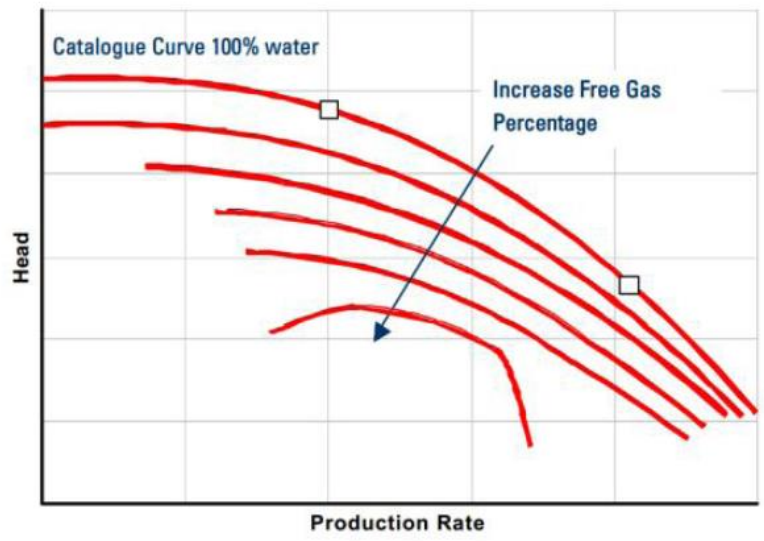
- Laboratory testing allows performance analysis to be:
  - Under controlled conditions
  - Repeatable (important for comparison of later prototypes)
  - Well instrumented (even inter-stage)

Variety of ESP Testing Protocols

- Criteria uniquely defined for different standards, for instance stability:
  - Hydraulic Institute 11.6 (2012), *Rotodynamic Submersible Pumps*, provides three grade levels for permissible amplitudes of fluctuations. It also suggests electronic data averaging as a method to reduce fluctuation amplitude to within acceptable limits
  - Hydraulic Institute 3.6 (2010), *Rotary Pump Tests for Hydraulic Performance, Hydrostatic Pressure, Mechanical, and Electrical Acceptance Tests*, provides fluctuation level limits for two different test grades
  - Hydraulic Institute 14.6 (2011), *Rotodynamic Pumps for Hydraulic Performance Acceptance Tests*, provides fluctuation level limits for three different test grades
  - American Petroleum Institute 11S2 (1997), *Recommended Practice for Electric Submersible Pump Testing*, provides no specific guidance on fluctuation limits
  - ISO 15551-1 (soon to be released), *Petroleum and Natural Gas Industries – Drilling and Production Equipment – Part 1: Electric Submersible Pump Systems for Artificial Lift*
- Customer provides guidance on testing standards

Gas Volume Fraction Effects

- Head performance degradation
- Surging/slugging – intermittent production of free gas and liquid causing pump flow to vary
- Gas blocking – collection of gas bubbles on low pressure side of the impeller vane, partially blocking the flow area
- Gas locking – collection of gas in the impeller which completely stops fluid flow



(Villamizar, SPE ESP Workshop, 1993)

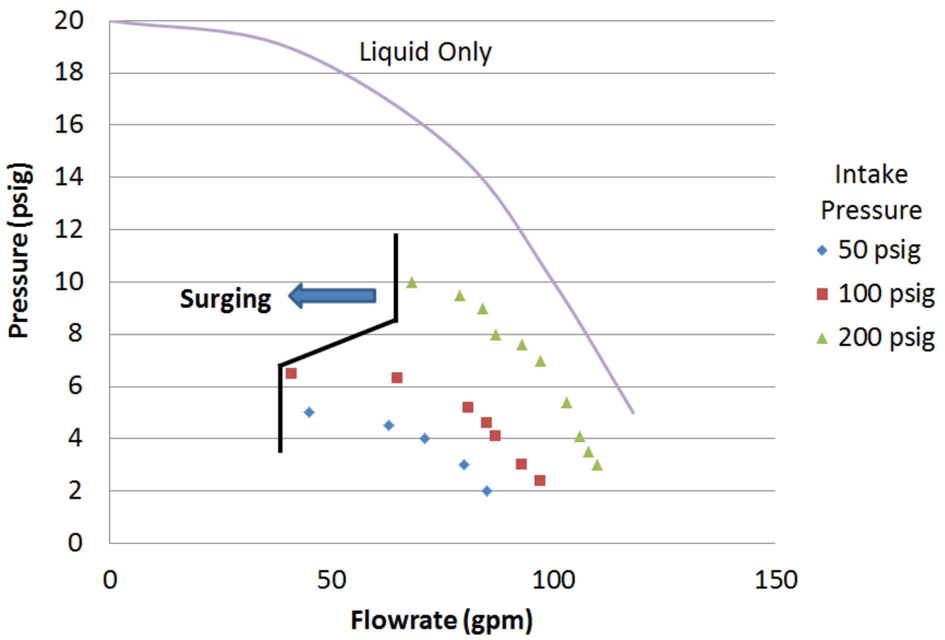
ESP Multiphase Flow Loop: Case 1

- Customized closed-loop test facility assembled for 2-phase ESP testing
- Fluids: water/nitrogen and oil/methane
- ESP inlet pressure: 200 psi to 600 psi
- GVF: 0% to 32%
- Liquid flow up to 2,700 bpd
- Measured performance parameters: average head rise per stage, pump power consumption, and overall efficiency

Inlet Pressure Effects

- ESP performance a function not only of GVF, but also pump intake pressure
- Higher P_{in} leads to lower percent gas compression through the ESP

Example: Diesel/CO2 test at 15% GVF



(Turpine et al., Int. Pump Symp., 1986)

High Pressure Flow Loop: Case 2

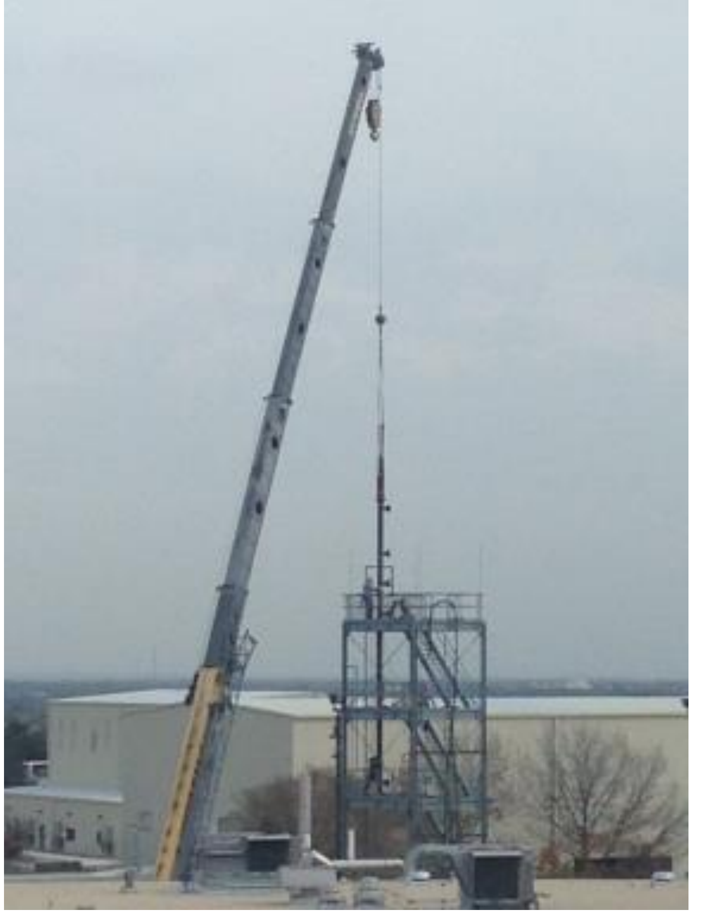
- Tested at pressures up to 3,600 psig
- Multiphase flows, liquid rates up to 32,000 bpd
- Gas: natural gas or nitrogen; Liquid: fresh water, brine, oils
- 216 ft. variable inclination angle test stand (0˚ – 90˚)

Fluid(s) and Mixing Effects

- PVT data and bubble point information can be used to predict dissolved gas in liquid phase → use model fluids that reflect downhole densities
- Model Gas Caution: Test oil does not absorb air or nitrogen as readily as natural gas. This can lead to performance differences due to density and viscosity changes of the liquid phase. (Barrios et al., 2015)
- Multiphase flow regime at pump intake can significantly effect performance (e.g., bubble vs. slug flow)
- Introduction of solids into ESP flow stream becomes a transient performance test

ESP Sand Slurry Flow Loop: Case 3

- Liquid/solid slurry erosion testing conducted on ESP assembly
- Pump tested vertically in casing section with downhole drive motor
- Slurry composed of 1% sand by volume and water viscosified using a polymer agent
- Pump performance monitored as a function of erosion exposure time



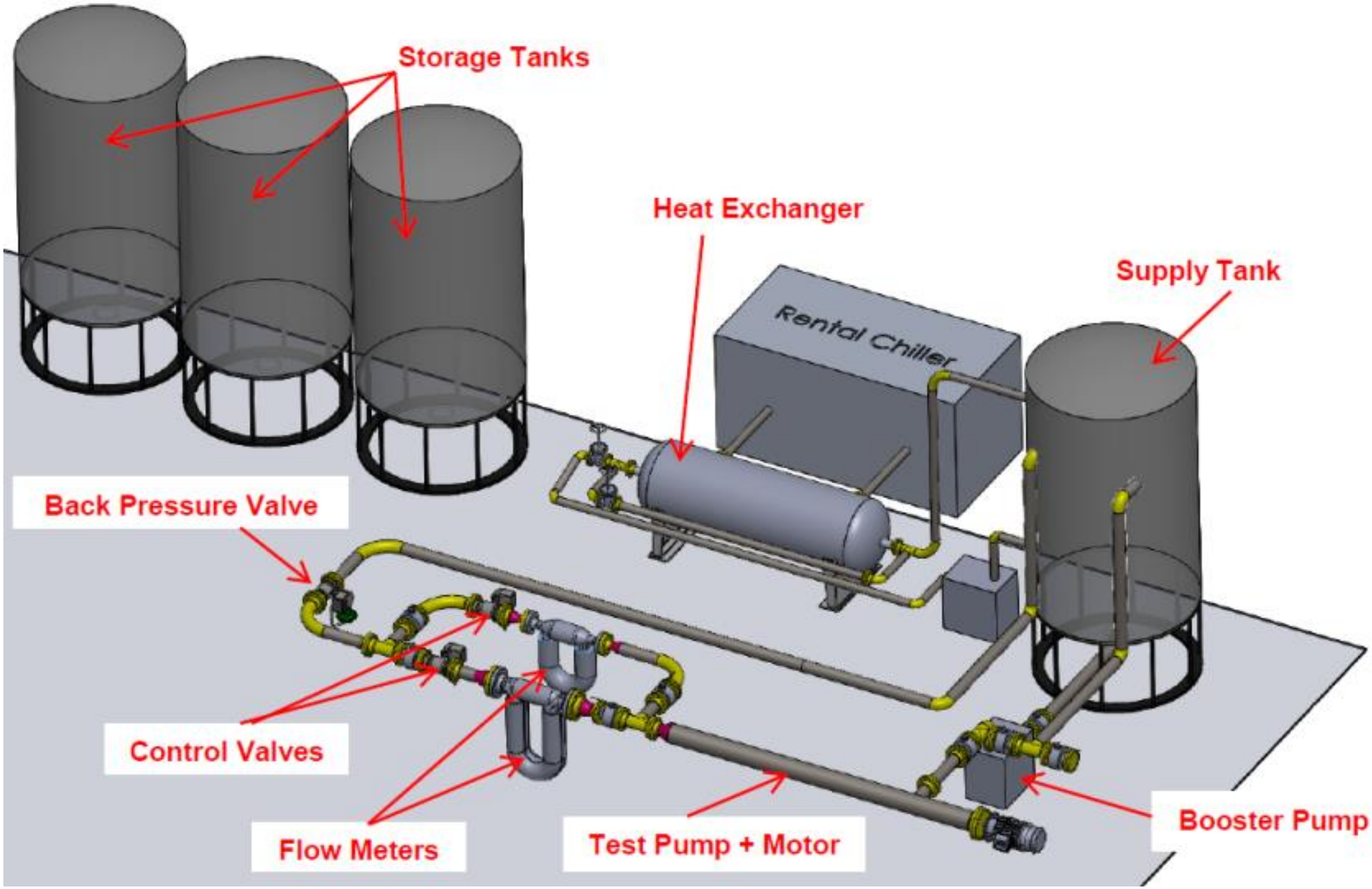
Viscosity Effects

- Normal high viscosity culprits: heavy oil and emulsions
- Some companies perform stage-by-stage performance calculations, correcting for pressure and temperature at each stage
- ANSI/HI 9.6.7, *Effects of Liquid Viscosity on Rotodynamic (Centrifugal and Vertical) Pump Performance – B131*, 2010
  - Method for calculation of correction factors, including speed effect
  - Single stage volute pumps within specific speed range and viscosity up to 3,000 cSt
  - Error margins over 40% shown comparing ESP field data with predictions (Sheth & Wilson, 2015)

High Viscosity Flow Loop: Case 4

- Viscosities up to 4,500 cP (4,000 gallons of four different oils to be kept on-hand to cover entire viscosity range)
- ESP inlet temperatures up to 110˚F
- ESP inlet pressures up to 100 psi, discharge pressures up to 400 psi
- Flow rates up to 22,600 bpd

High Viscosity ESP Test Facility



Challenges to ESP Testing at "Downhole" Conditions

- High pressure (material and safety issues)
- High temperature (material and safety issues)
- Avoiding unmeasurable free gas
- Defining surging
  - Oscillating differential pressure drop across pump (threshold variable)
  - Oscillations in motor amplitude
  - Define curve relating DP vs. GVF for fixed total flow and suction pressure. GVF causing DP to undergo sharp drop defines surging
- Flammable gas/combustible fluids
- High viscosity (power and thermal requirements)

Questions?