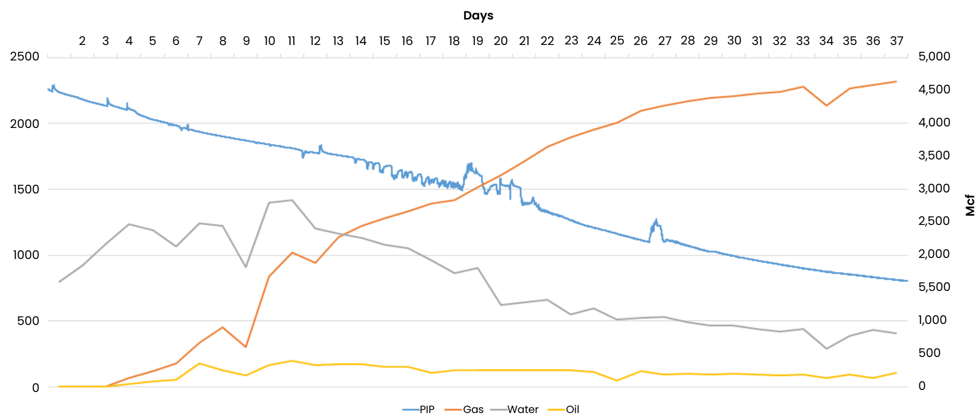
Baker Hughes

Case study: Texas Panhandle

CENesis PHASE production solution increased gas/fluids production 126% and 123% respectively



Production data showing steady draw down and increased gas production.

Baker Hughes was approached by a major operator in the Texas Panhandle to help deliquefy a natural gas well. The challenge was to quickly unload completion fluids and to lower the bottomhole pressure in the well with an electrical submersible pumping (ESP) system to enable production of up to 4,500 MMcf/d and 396 BOPD.

The operator had been using gas lift, but this form of artificial lift was unable to sufficiently lower bottomhole pressure. The well had a wide flow range from 3,000 BFPD to 200 BFPD and a high gas-to-liquid ratio of >4,500 scf/stb. Typically, such large volumes of gas create gas locking conditions in ESP systems as well as motor overheating when the gas displaces fluid flowing past the system—both of which negatively impact the reliability of a standard ESP system.

The Baker Hughes Artificial Lift Systems applications engineering team devised a solution that, based on the operator's production requirements of 3,000 to 200 BFPD, could quickly draw down the well and start producing gas. The team recommended the **CENesis PHASE™ multiphase encapsulated production solution** for wells with 7-in. casing. This solution has proved successful in more than 750 installations in the U.S., but never at these high gas and liquid rates. However, with only minor modifications, the system was able to accommodate the large gas and liquid volumes.

The encapsulated CENesis PHASE system is designed to improve overall ESP reliability by naturally separating gas from the production stream, before it enters the ESP system; by allowing the pump to continue operating during gas slug events; and by continuously diverting fluid past the motor to prevent overheating.

Within days of installing the CENesis PHASE system, the operator was selling nearly 4,500 MMcf/d, an increase of 126%. Oil production also increased from 177 BOPD to 396 BOPD. The technology also extended ESP run life by over 200 days in an application typically outside the operating parameters of traditional systems.

Challenges

- High gas-to-liquid ratios (>4,500 scf/stb)
- Gas slugging
- Potential for motor overheating and pump gas locking
- Wide flow range (3,000 down to 200 BFPD)
- Fluctuating fluid density
- Remote location with inconsistent electrical generation
- Lack of three-phase power to the wellsite

Results

- Removed fluids quickly to increase gas production from 1,900 MMcf/d to 4,500 MMcf/d and to increase oil production from 177 BOPD to 396 BOPD
- Extended ESP run life by 200+ days or 73% compared to the average ESP run life in similar applications
- Lowered bottomhole pressure significantly compared to gas lift