SELECTION AND EVALUATION OF PLUNGER LIFT SYSTEMS

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ABSTRACT

The selection of a plunger can be as critical as the surface equipment to optimize a plunger lift well. When considering plunger lift, a candidate's decline, IPR, velocity, fluid and pressure are used to achieve proper evaluation. The necessity for proper plunger lift choice in completely optimizing a plunger well can result in incremental production from an existing plunger system by as much as 500 Mcf/day by changing from a conventional plunger lift system to a high-speed bypass plunger. However, a bypass plunger in a well with the wrong conditions will not result in a successful increase and may in fact hurt production.

For proper well evaluation, it is necessary to first consider the velocity and the fluid rates for high-speed bypass, and subsequently to consider more conventional methods. This paper will discuss types of plungers most commonly used, in addition to the well evaluation and selection process as it pertains to plunger lift applications.

INTRODUCTION

Plunger lift can essentially be categorized into two major divisions - continuous flow and conventional plunger lift. Continuous flow can be defined as any well that does not require down (or off) time to build pressure in order to cycle the plunger. In such cases the plunger can fall against flow to the bottom of the well, reset, and then return to surface using only the velocity of the flowing gas. Good examples of this include the Pacemaker[1] (Fig 1.), the padded RapidFlo™ (Fig 2.) the FreeCycle™[2] and the RapidFlo™ (Fig 1). Alternatively, conventional plunger lift can be defined as any form of plunger lift that requires that the well be shut in to build pressure in order to acquire the necessary velocity to cycle the plunger. While this includes both solid plungers (no bypass) as well as plungers with bypass (Fig 3.), they still require a minimal fall time to reach the bottom in order to reset themselves. These two major divisions can be evaluated in one complete process rather than multiple separate evaluations for each different scenario.

CONTINUOUS FLOW PLUNGER LIFT

Continuous flow plunger lift is based on the concept that if gas can maintain a minimal velocity necessary to make a turbulent seal, then a plunger should travel to surface once it has closed its bypass method. For example, some plungers require that a valve be reset upon arrival on a solid contact (usually a bumper spring) while others will be reset once the ball and sleeve make contact and seal. The turbulent seal that is developed will only occur if the gas is moving with enough velocity to make this seal.

Types of Continuous Flow Plungers

Continuous flow plungers can be divided into solid ring type and more efficient solid contact plungers (padded or brush). Depending on tubing conditions and plunger conditions, it is usually necessary for over 15 ft/s velocity to ensure a solid ring arrival and a minimal of 10 ft/s velocity for a padded plunger or new brush. The lower velocity is a result of the better metal-on-metal or metal-on-brush seal that is acquired in a brush or padded plunger.

Solid Ring (High-Speed Continuous Flow): In general, high-speed continuous flow plungers are a ring type plunger with some form of valve on the bottom of the plunger. Some examples of this are the *Pacemaker* and the solid ring *RapidFlo*. Advantages to these plungers include reduced down time (no fall time necessary), minimal amounts of moving parts, relatively low cost and overall operating simplicity. The largest benefit for operators is the speed of travel (both up and down), which results in the maximum number of trips in a day. Since there are fewer moving parts they are able to travel

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[1] The *Pacemaker* is a patented product built by MGM Well Service.
[2] The *FreeCycle* plunger is a trademark of Integrated Production Services.

with minimal fluid loads above the spring without causing damage. Disadvantages to solid ring plungers are the necessity of the 15 ft/s gas velocity and the requirement of some moving parts to operate valves. These plungers are especially effective in low line pressure/high velocity applications, especially in single well compression where down time can be critical to compressor operation. High-speed continuous flow plungers also have great application in winter conditions where continually moving plungers can reduce hydrate problems.

Solid Contact (Padded and Brush): Continuous flow plungers are generally a brush, pad or any combination of the two and typically have some form of valve system. Some are mounted on the bottom, similar to the padded *RapidFlo*, while others contain an internal valve system. The advantages to these plungers are similar to those of the solid ring plungers (above), including the reduction of down time. Depending on the seal, however, these plungers have the potential to travel with as little as 10 ft/s velocity. The primary disadvantage of solid contact plungers is the possibility of damage due to added moving parts.

CONVENTIONAL PLUNGER LIFT

Conventional plunger lift requires a build-up pressure in order to cycle a plunger and can generally be categorized into padded, solid ring, brush or any combination of the three. In some instances it is necessary to have a valve bypass for quicker fall times, although the concept remains the same. The plunger falls to bottom and once enough build-up pressure is acquired the plunger can cycle to surface. Padded plungers generally provide the best seal for extended periods of time but require maintenance to avoid breakage. Solid ring plungers provide the least efficient seal but require very little maintenance to maintain. Primarily used in sand inflow wells, brush plungers provide the best initial seal but tend to wear out very quickly. Conventional plungers can also come in combinations and with a variety of sealing capabilities.

EVALUATION PROCESS

The evaluation process is extremely critical to a successful plunger lift program. When evaluating for a plunger lift application, the first step is to gather data in order to decide whether the well is an appropriate plunger lift candidate.

Data Gathering

There are several factors to consider during the data gathering process:

- The more data the better, as this will allow accurate estimates of well potential using decline curves.
- The more recent the data the better, in order to give the most current possible picture of the well's potential.
- Producing pressure data can help indicate other potential problems and conditions.
- Downhole and surface details can be used to identify potential problems as a plunger candidate.

Data can be divided into the following four categories:

- **Past production data**, such as flowing and static pressure data, and producing pressure data (casing, tubing, line pressures)

- **Current production data and pressure,** such as flowing and static pressure data, and producing pressure data (casing, tubing, line pressures)

- **Downhole details,** such as tubing detail and perforation depths

- **Surface information** including wellhead, facility and gathering system info

Past production data (uses)

1) Establish a decline curve. This may be difficult due to lack of information.
2) Establish what the current flowing rate and pressures should be if the well were following this decline.
3) Establish potential economics (use production data versus the actual current production).
4) Attempt to identify the point at which the well had liquid loading issues and back this up to the wells critical velocity.
5) Establish what the wells current fluid rates should be.

6) Establish the velocity of gas. It is very important that the rates used are the unloaded state conditions so that proper velocity is calculated. Graphs of flow versus pressure can be used to estimate which velocity range the well falls into. These graphs will change when all well data is entered including all reservoir properties (Fig. 4-6).

Current production data and pressure

Current flowing data can give indications of the magnitude of the liquid loading problem.

1) Casing to tubing differential (when open-ended) can indicate the amount of liquid currently held in tubing, and therefore additional backpressure.
2) Flowing gradient can indicate fluid presence as well as FBHP in packer completions.
3) Varying LGR can indicate either erratic fluid entry or liquid loading.
4) Minute-by-minute flowing data (if available) can indicate sweeping, which is recognized on flow charts as a "painting" effect.
5) Operator input can be used to indicate what is being done to keep the well producing. Operators can also provide potential losses (e.g. losses of blowing well to atmosphere or shutting in for build).

Downhole details

1) Tubing depth
    a. Ideally this will be far enough into the perforations so that the most prolific perforations will be completely unloaded (tubing down to this point).
    b. A consistent ID of tubing from top to bottom (not tight spots that can't be broached out).
    c. One nipple on the bottom of the tubing (or with just a short pup below).
2) Packer/packer-less completion
    a. A packer in the hole makes conventional plunger lift more difficult because it depends on the casing energy.
    b. Packers will not necessarily result in problems if the well is a potential continuous flow candidate.
3) Perforations
    a. Clear (no fill)
    b. No skin damage or blockage

Surface information

1) Can the surface facility handle the fluid as it arrives in a slug?
    a. Can the gathering system handle the manner in which the gas is going to be delivered (ups and downs in conventional application)?
2) Is the wellhead sizing correct (do the ID's match the tubing)?

Process of Elimination

Once this data is gathered, a step-by-step process of elimination should be used to conclude whether the well is a good plunger lift candidate.

1) Consider the downhole and surface data gathered above. This may be a key to project cost if there are major problems. In some cases rig work may be required to change downhole configurations or major piping changes to modify surface equipment. Keep this in mind as the evaluation continues.
2) Establish a decline curve, if possible, and establish what current potential flowing rates and actual rates are. This will be important for establishing economics as well as calculating velocity (see next step). If no decline can be established due to the well always flowing below critical, an IPR may be used if a current static pressure as well as flowing bottom hole pressure with rates are available. This may also be used to estimate potential due to the decrease in flowing bottom hole pressure that should occur with a plunger lift installation.
3) Use the potential rates and the current surface pressures to establish a velocity of the gas. Estimate a bottom hole velocity using an unloaded condition. This can be done using either a velocity equation or a graph of flow rate versus pressure with velocities plotted and can be used to estimate into which bucket a well fits (Fig. 4-6).

    a. +15 ft/s wells can flow as continuous flow with a high-speed solid ring plunger. The amount over the 15 ft/s will determine how much tolerance the well will have to run in this kind of a system, as well as how much the wear and tear on the plunger will effect the well. Wells that barely meet this criterion may be better candidates for a padded continuous flow plunger.

b. 10-15 ft/s wells can flow as continuous flow; however these wells will usually require a better seal than the solid ring plunger will provide. In this case a padded continuous flow plunger should be considered. A conventional plunger should be considered for wells that barely meet these criteria.
c. <10 ft/s wells should be considered for conventional plunger lift because they are going to require a build up pressure to establish the necessary velocity to bring a plunger up.

DECIDING WHICH TYPE OF PLUNGER TO USE

The above process and information should contribute to the decision as to which type of plunger is best suited for the well. Once the bucket is established (using information above) fluid rates and amount of fluid per load should be evaluated to ensure proper running conditions.

Solid Ring Continuous Flow Plungers

Solid ring continuous flow plungers are used when flowing conditions require the maximum number of cycles due to fluid intake, and the velocity is readily available.
While calculating the maximum number of cycles can be difficult, it is possible to make estimates. Using the velocity of the gas the rise time can be estimated quite accurately. Depending on the bypass area, the fall time can also be calculated; however, fluid gradients, plunger condition, tubing condition, and changing conditions make it difficult to match exactly. A common rule of thumb is that the fastest they will fall with flow velocity over 15 ft/s is the same as half of the rise time. Meanwhile, the slowest they will fall may be up to three times the rise time. Any slower than three times the rise time may indicate that the plunger is being dropped against flow rates above critical velocity and is therefore unnecessary. For example, a 9,900 ft well with 15 ft/s velocity would be five minutes fall and ten minutes rise leading to 15- minute cycles - four per hour, 96 per day.

Ideally, an attempt should be made to maintain a minimum of 100 ft cushion of fluid. For example, in 2 3/8" tubing this would be around one quarter of a barrel per run, or a minimum of 24 barrels per day of fluid if continuously cycling. The well may be able to produce more based on the wells' flowing capabilities. If the well makes less fluid it will require after-flow time in between cycles to acquire a fluid load.

Padded Continuous Flow Plungers

Padded continuous flow plungers are used when fewer cycles are required and 15 ft/s velocity is not available. A padded continuous flow plunger will provide the better seal necessary to travel at lower velocity. They usually have some method of slowing them down on the fall to bottom in order to avoid damage to bottom hole equipment (some form of orifice assembly). This will usually result in less cycles being possible.

The rise time can still be estimated by velocity, but the restriction should be changed in order to keep the fall time below 10 ft/second. For example, in an application in a 12,000 ft well where there will only be 100 ft of fluid and the gas is moving with a velocity of 10 ft/s, the rise time will be around 20 minutes and the fall time should be no less than 20 minutes, which makes the maximum number of cycles per day 36. With ¼ barrel per run a minimum of nine barrels a day is needed to run a continuous flow plunger. However, if that is not the amount being produced either after-flow can be added or a smaller orifice may be added to slow the fall time down further.

Conventional Systems

When establishing how much fluid a conventional system can move, there are many good methods from which to choose. The classic Foss and Gaul method, developed in the 60's, gives a very mechanical approach to plunger lift.[1] This method can generally be used to establish whether a well can operate a plunger and estimates can be made from the decline to show potential rates. Slightly more complex is the Hacksma method, which includes a reference to the IPR and therefore with enough data can give more information on daily rates. This method uses the Foss and Gaul method to calculate the average casing pressure then considers the gradient and uses this on the IPR to calculate potential uplift.[2] If an understanding of the well dynamics as well as the reservoir characteristics is substantial enough, something more complex like the Dynamic method of Jim Lea can be used. This method is substantially more complete and includes instantaneous velocity and acceleration as well as inflow capability.[3] Ultimately, the Dynamic method should produce the most accurate results but any model must be matched to the actual results in the field.[4]

The next step is to apply actual physical results, including accurate plunger fall times, with one of these methods. A padded plunger with high spring tension or a new brush can produce fall times as slow as 250 ft/min, while a bypass plunger used in a conventional method can have fall times as fast as 1,800 ft/min. This makes it possible for a 9,000-foot well that is producing 15 ft/s velocity during the on cycle to rise in 10 minutes. Depending on the plunger type it would have the potential to reach bottom in as little as five minutes or as long as one hour. What must be considered in a conventional plunger system, however, is the speed at which the well will build the pressure to cycle the plunger against the system pressures with the fluid loads. The importance of the seal, as well as how much fluid the plunger will be falling into must also be considered in order to avoid damage. These pieces of information can be added into the evaluation and help estimate uplift.

Once a well has been evaluated both economically and mechanically, it may be evaluated for other forms of lift. Or, in many cases a well may have better adaptability to compression. One thing to note is that in many cases compression will result in better operating conditions down the road, including both liquid-loading conditions and potential plunger lift conditions (Fig. 4-6). Typically, but depending on conditions, it is much easier to establish velocity to run plungers at lower system pressures (<250 psi).

CONCLUSION

The major issues involving plunger lift selection and evaluation need to be carefully investigated in order to successfully find a plunger lift candidate. The past production, current production, down hole details, and surface information all are extremely important when evaluating wells. This data needs to be built into the evaluation procedure and used to establish which type of plunger is necessary for the most successful program.

REFERENCES

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3. Lea J.F. "Dynamic Analysis of Plunger Lift Operations," Paper SPE 10253 presented at the 56th annual Fall Technical Conference and Exhibition, San Antonio, TX October 5-7, 1981.
4. Avery D.J. and Evans R.D, University of Oklahoma "Design Optimization of Plunger Lift Systems" Paper SPE 17585, presented for presentation at the SPE international meeting on Petroleum Engineering held in Jinjin, China November 1-4, 1988.

Figure 1 – Solid Ring Continuous Flow Plungers
Pacemaker (Left) and RapidFlo (Right)

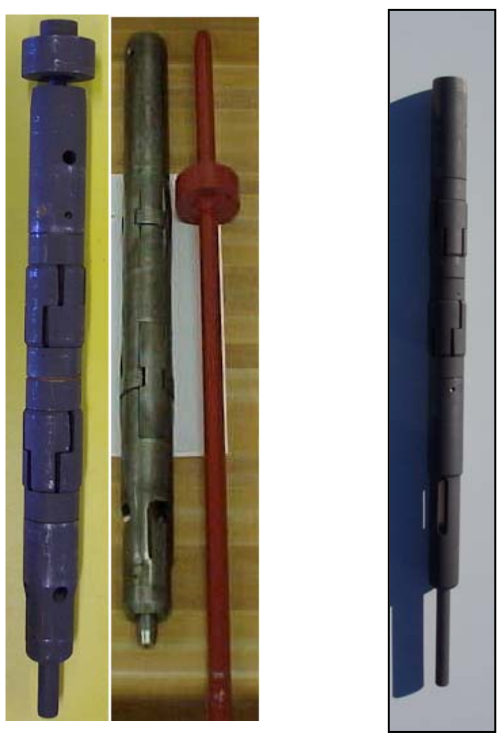

Figure 2- Padded Continuous Flow Plungers
Left to Right Weatherford Bypass Plunger McClain Plunger and Weatherford Padded Rapid Flow

Figure 3 - Example of Conventional Pad, Spiral and Brush Plunger

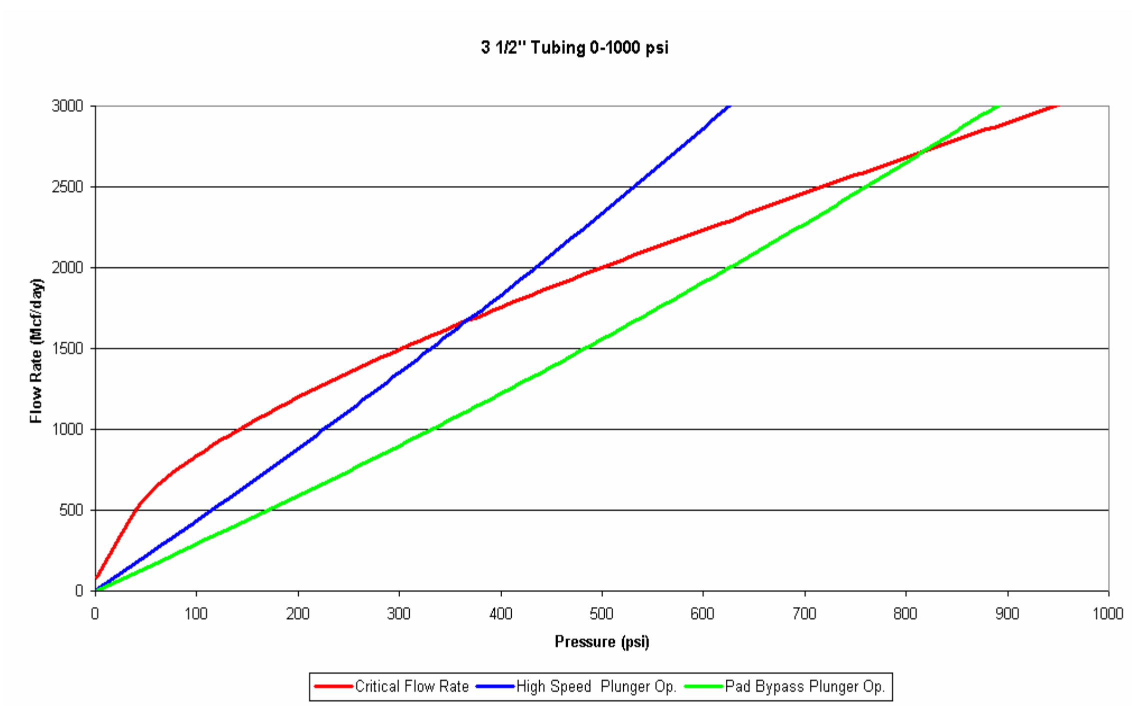

Figure 4 - Velocity and Liquid Loading Curves for 3 1/2" Standard Tubing

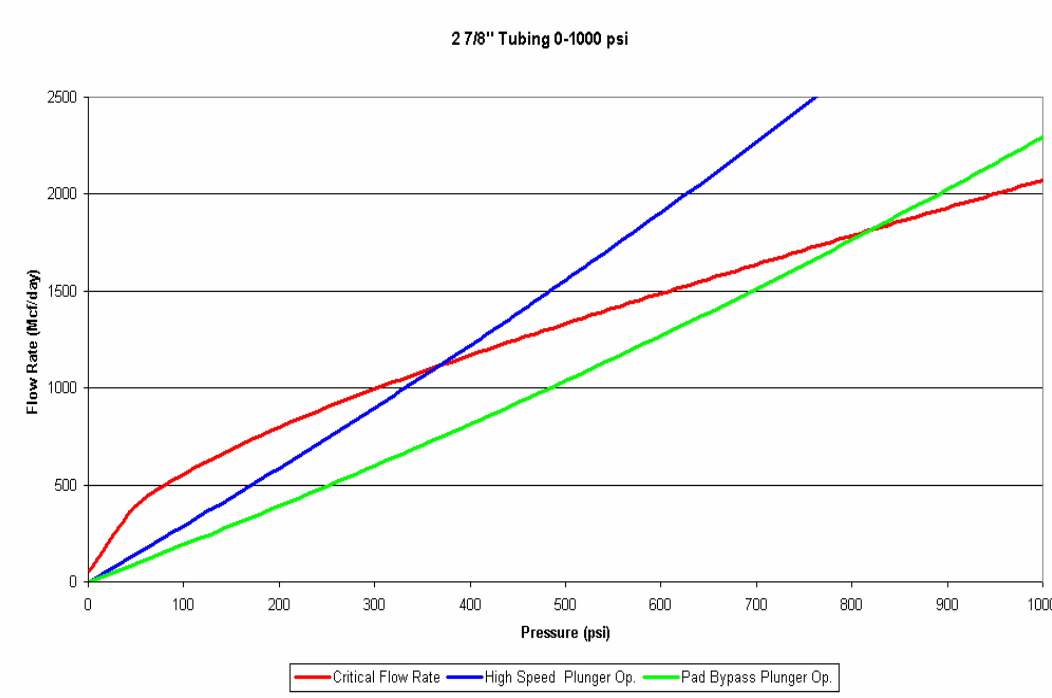

Figure 5 - Velocity and Liquid Loading Curves for 2 7/8" Standard Tubing

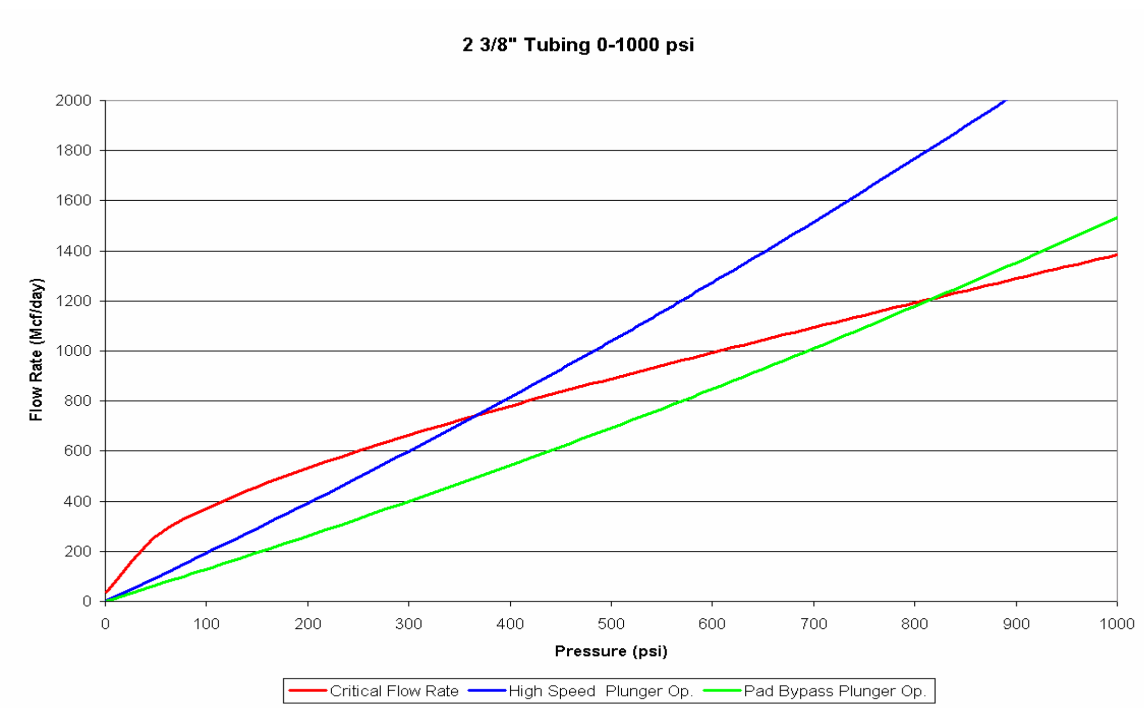

Figure 6 - Velocity and Liquid Loading Curves for 2 3/8" Standard Tubing