INCREASING PRODUCTION ON ROD PUMPING WELLS

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In the present state of the oil and gas economy, operators have been searching for ways to increase production and cash flow with no gamble and with an AFE expenditure that gives their money back and a good return on their investment the first year.

Operators are finding that one sure way to increase production and cash flow on producing wells is to relieve the **RESTRICTING BACK PRESSURE** on the producing formation on wells which respond to this technique. This restricting back pressure is caused by a combination of several things; a direct result of the **sales line** pressure; the pressure required to operate the **separator;** the **line friction** from the separator back to the well head. These flow lines vary in length and the longer the flow line and the terrain they follow, the more back pressure you will find at the well head. The final results of this back pressure translates all the way down to the face of the formation and restricts its ability to give up oil and gas. Pressure requirements to operate an individual lease may vary, but the negative effect of production is the same - **IT IS RESTRICTED.**

FORMATIONS AND PRODUCTIVITY INDEX

Now lets talk about formations and bottom hole pressures. Each formation is different in its response to back pressure or a reduction of back pressure. The producing formations that have good porosity and a good productivity index (PI) will give the best results when the back pressure is reduced. The **PRODUCTIVITY INDEX** is defined as **the increased fluid the well will give up for each pound of drawdown at the face of the formation.** In other words, if a well has a "PI of one (1), then for each pound of pressure relieved from the face of the formation, the well will give up one (1) barrel of fluid. So, when looking for an increase in production, we look at wells that have a high "PI". For example, a well with a "PI" of 0.5 and a wellhead back pressure of 50 psi will increase 25 barrels per day when the wellhead pressure is reduced to "0" psi.

PRODUCTION DECLINE

When a well is first drilled and placed into the production stream, it normally has a **good bottom hole pressure** and will often times **flow,** provided the bottom hole pressure is high enough to overcome the surface pressure and fluid gradient.

As the well continues to produce and the bottom hole pressure declines, the surface pressure becomes a factor and the well will ultimately be placed on some type of artificial lift. The most common type of artificial lift is the rod pump. As a well continues to produce on rod pump, **the bottom hole pressure continues to decline until the surface back pressure requires a greater percentage of the energy available from the formation to produce the well.** This is when the operator should look at how his well is being produced and consider alternatives that will relieve the back pressure.
(See fig. 1)

WELL BORE

Take a look at how the well is completed and where the tubing is in relation to the perforations. When the well was first completed or placed on rod pump, the tubing may have been set above the perfs for some reason and that reason may no longer exist. **REMEMBER, THE FORMATION RECOGNISES PRESSURE AS A RESTRICTION** and does not differentiate between **gas pressure, line pressure, back pressure valves,** or in this case, **FLUID WEIGHT.** If the well has declined in bottom hole pressure, acolumn of fluid standing above the perfs will have the same effect as back pressure at the well head.
(See fig. 2)

WELL HEAD HOOK UP

Care should be taken to **plumb** the well head **with** as **little restriction** as possible. Examine the plumbing and see if the flow line can be positioned to a more **direct route** to the production facility. Ninety degree turns provide a restriction and the more turns you make the more restriction you have.

One tool that is sometimes utilized at the well head is a **back pressure valve** placed on the flow line. This valve is used to hold pressure on the tubing to help prevent **gas locking** or **gas interference** in the down hole pump. In some cased I have seen where the casing line is tied into the flow line so the back pressure valve is placing pressure on the casing as well as the tubing. **THIS PRACTICE RESTRICTS PRODUCTION.**
(See fig. 3)

LINE FRICTION

Long flow lines feeding to the production facility or **trunk lines** that are too small for the number of wells feeding it will cause line friction and will **result in greater pressure at the well head.** The greater the distance the well is from

the production facility the more back pressure you will see. Depending on the situation, an additional trunk line or an additional production facility closer to the higher pressure wells could show to be a good investment.
(See fig. 4)

PRODUCTION FACILITY

The separator or heater treater can be another source of back pressure. Again, the plumbing should be arranged so there is a minimum of restriction due to turns. **There should be no excess pressure on these vessels,** Any pressure on a separator over what it takes to dump it, is placing unnecessary back pressure on the formation on all the wells using the facility.
(See fig. 5)

WELL HEAD COMPRESSION WITH THE BEAM GAS COMPRESSOR

Well head compression is the next step. After you have looked at all the alternatives, it is time to evaluate the economics of removing the balance of the well head back pressure with some method of compression.

THE (BGC)

One sure way to **remove back pressure** on a rod pumping well is **with a beam mounted gas compressor.** This tool mounts on the walking beam of the pump jack and incorporates a cylinder with a piston inside. The suction line to the BGC comes from the casing through a check valve and the discharge goes through a check valve back to the flow line or to operate other lease equipment. The energy already on location (the pump jack) is used to draw the pressure and gas from the well and little additional energy is required. Most of the the **BEAM GAS COMPRESSORS** have been **INSTALLED** on **LOW BOTTOM HOLE PRESSURE WELLS** that are considered low producers, so most pumping units were on time cycles. In the case of a pumping unit operating an a time cycle, the **BGC** was simply sized to compress the volume of gas the well makes, using the existing time cycle. In some cases, when the pressure is removed and the well gives up more fluid and gas, the time cycles have been extended. **The by - pass or recycle line allows the casing to remain at the operators desired pressure.**
(See fig. 6)

Another method used to relieve back pressure is with a **SKID MOUNTED COMPRESSOR.** The skid mounted compressors are excellent machines to remove back pressure where there is no pumping unit available to drive the BGC. The skid mounted compressors are used in cases where the volumes of gas are larger than the pumping unit mounted systems can move. While both the skid mounted and beam mounted gas compressors have their application, the **BEAM GAS COMPRESSOR** installation is usually **less costly** to the operator and with the **addition of energy savings, the payout is much quicker.**

In some applications the operator is producing against a line pressure greater than 40 to 50 psig. **The BGC will take the casing down to 0 psig and push gas directly into a line pressure of up to 100 psig with one stage or one stroke of the piston.** This equates to a compression ratio of approximately eight (8). The skid mounted system would require a minimum of a two (2) stage system which would increase the cost and extend the payout time for the operator. There are some cases where the BGC system is taking gas from the casing at 150 psig and discharging into a 700 psig flow line. Other operators are using them to boost gas from 50 psig into a 400 psig flow line. The application for both the skid mounted and the beam mounted compressor systems is determined by the well conditions and the pumping unit operation already on location.

PROBLEMS WITH WET GAS AND CORROSIVE GAS

Both the skid mounted and beam mounted systems will handle wet gas **(most casing head gas is heavily saturated with liquids)**, however the **skid** types require a **liquid scrubber** with an **electric pump** to discharge the liquids into the flow line or tank, where the **BGC does not.** Both systems can be protected from corrosive gas, however when a reciprocating type skid mounted unit is used, care must be taken to keep condensates and water away from the crank case. These components will reduce the lubricating properties of the crank case oil, thereby reducing the life of the system. **THE BGC HAS NO CRANK CASE.**

CASING GAS GATHERING SYSTEMS

In some cases, where several wells are producing to the same tank battery, it is more economical to run gathering lines to the casings and draw the pressure down with one or two compression units. The skid mounted system is the most widely used for this practice. However, where pumping units are available, the **BGC system has been used with great success.** I know of one field where **one BGC is being used to keep 20 wells drawn to 0 psig** on the casing discharging into a 50 psig flow line and it is very **common to see two to five wells being placed**

on just one BGC SYSTEM. When casing gathering systems are used for multiple well applications, care should be taken to assure that the wells in the back of the field do not end up with positive pressure due to line friction. As an example, I know of one field where thousands of dollars were spent to relieve back pressure with a skid mounted compressor, where the suction pressure at the compressor at the tank battery was 0 psig and the wells at the back of the field still had as much as 20 psig back pressure on the casings. These wells were tested by venting off the 20 psig still on the casings and they showed as much as additional 18 BOPD increase. **One major oil company overcame this type of situation by installing BGC systems throughout the field and in effect had several small gas gathering systems.** They were able to maintain 0 psig at each well by producing through a manifold to regulate the back pressure on each well thereby maximizing production on each well.

APPLICATIONS FOR THE "BGC"

1. **TO REDUCE BACK PRESSURE** on the formation **TO INCREASE OIL AND GAS PRODUCTION.** on rod pumping wells.

2. **TO CAPTURE AND SELL GAS** being vented to increase oil production. Pushing vented gas into the sales line means **MORE CASH FLOW** and **LESS PROBLEMS** with the **REGULATORY AGENCIES.**

3. **TO OPERATE LEASE EQUIPMENT** like gas engines and heater treaters by **DRAWING MORE GAS FROM THE WELL.**

4. **TO ELIMINATE "GAS LOCK"** or gas interference in the down hole pump. Drawing gas and reducing the casing pressure on the casing will cause more gas to break out of solution in the well bore where it will flow up the casing and discharged by the **BGC** into the flow line. **THIS WILL CREATE A MORE efficient PUMPING STROKE IN THE DOWN HOLE PUMP.**

5. **TO SELL LOW PRESSURE GAS** by boosting it into the sales line. Some wells have such a low bottom hole pressure that the gas will not pass into the sales line without a little help.

6. **TO KEEP A WELL ON PRODUCTION** when the gas sales line goes up due to downstream compressor problems or because new wells are being put on stream causing older wells to be restricted.

DETERMINING IF COMPRESSION WILL HELP YOUR PRODUCTION

Most state regulatory agencies will issue temporary permits to vent test your well for a few days. While the vent test is being done, simply gauge your increased production and the

economics are simple to compute. This system of testing takes all the gamble out of the project, since you will know for certain what the payout time will be. If venting is not possible, then contact a manufacturer or distributor of the **BEAM GAS COMPRESSOR** (if a rod pump is available) or a **SKID MOUNTED** unit to arrange for a test in your field.

CONCLUSION

We have installed the **BEAM GAS COMPRESSORS** on wells that were scheduled to be plugged producing against as little as 20 psig line pressure. These wells were able to maintain an additional two to three years of profitable life due to a reduction in back pressure. The objective is to keep those wells producing at a higher profit for a longer period of time. The average well producing in the UNITED STATES today produces around 14 BOPD. So, **NO WELL IS SUCH A LOW PRODUCER THAT IT SHOULD NOT BE CONSIDERED AS A "SUSPECT" FOR WELL HEAD COMPRESSION.**

REFERENCES

1. Al-Khatib, Ali M., "Improving Oil and Gas Production with the Beam-Mounted Gas Compressor" Journal of Petroleum Technology, February 1984, pp.276.

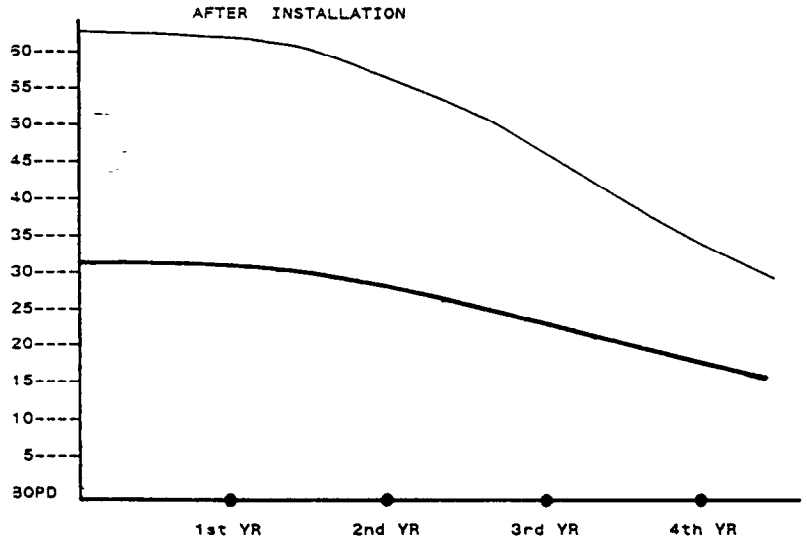
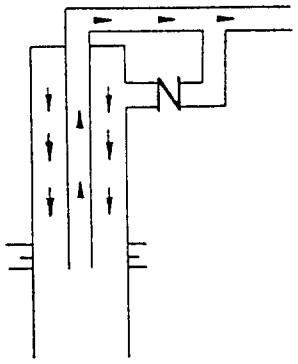


Figure 1

WITH BACK PRESSURE



Restricting back pressure holds back the flow of hydrocarbons into the well bore.

WITHOUT BACK PRESSURE

Back pressure is relieved from the face of the formation, allowing more hydrocarbons to flow into the well bore.

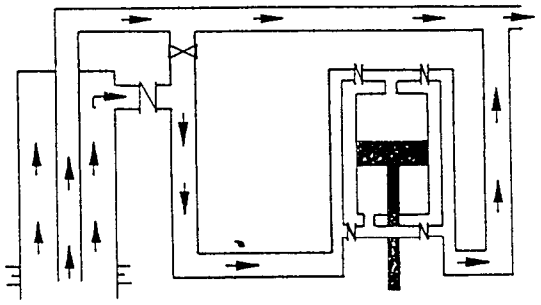
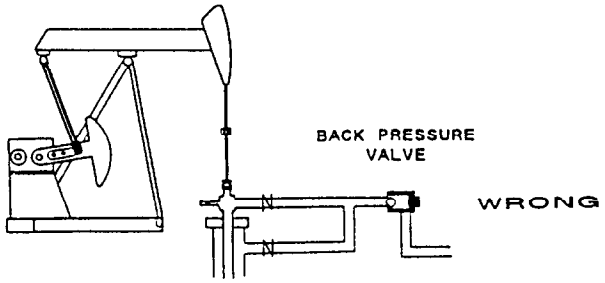


Figure 2



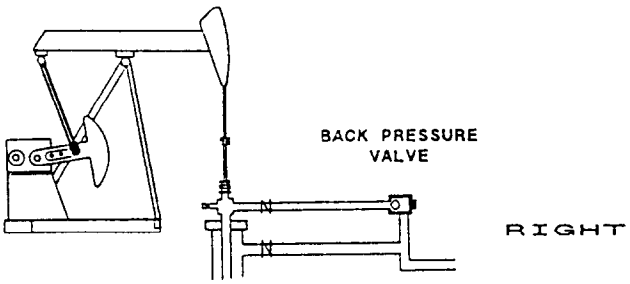


Figure 3

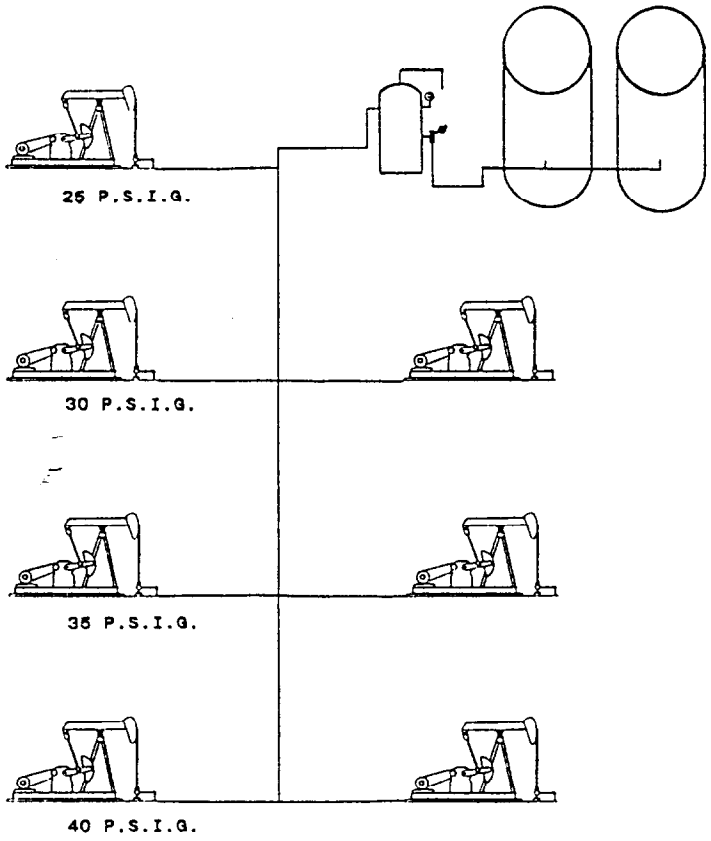


Figure 4

INCREASED BACK PRESSURE AT THE TANK BATTERY

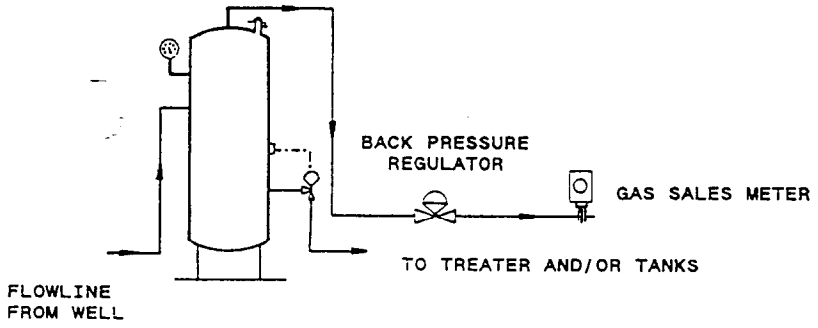


Figure 5

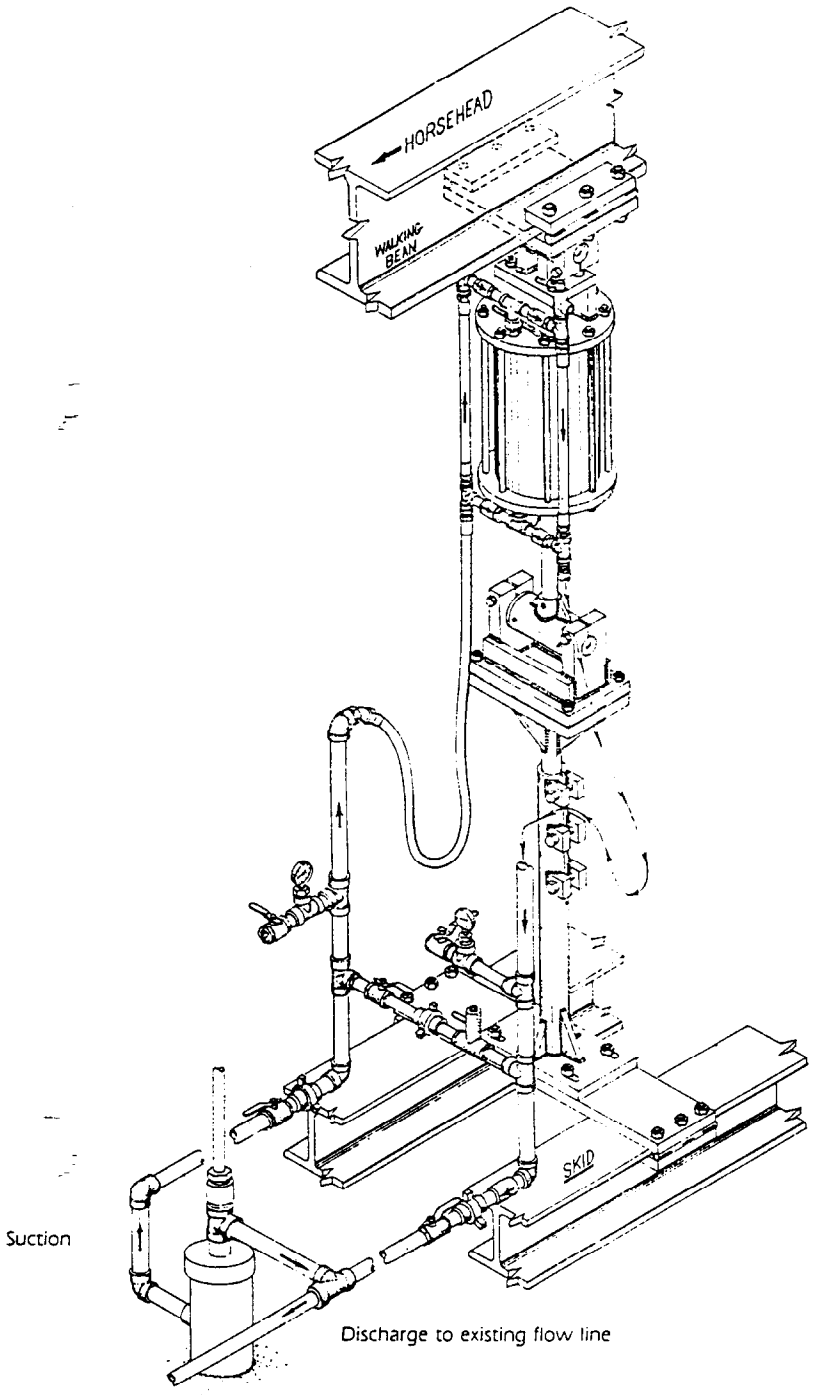

HORSEHEAD
WALKING BEAM
SKID
Suction
Discharge to existing flow line

Figure 6