THE VERSATILITY OF HPGL

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Abstract:
Since its' introduction to the unconventional oil and gas realm in 2017, Single Point High Pressure Gas Lift (referred to as HPGL going forward) has emerged as one of the top artificial lift choices for operators in the Permian and MIDCON basins. It has become a proven technology with over 2,000 applications to date as more operators are choosing it as their primary form of artificial lift for their unconventional assets.

One of the primary advantages of HPGL is that its' performance is extremely predictable. Nodal analysis can be utilized to predict production performance and its cost are well defined given there are no mechanical downhole parts that can lead to unplanned, costly workover operations. Another primary advantage of HPGL is its versatility for handling various production regimes. The system is not constrained by tortuous wellbores or solids production, and it works exceptionally well across varying producing GLRs.

This paper will review several case studies that highlight the predictability and versatility of HPGL across the Permian basin.

Introduction:
High pressure gas lift (HPGL going forward) has been a popular choice for Permian and MIDCON operators' artificial lift needs. Its simplistic BHA design and deployment mitigates workover operations and the associated risk of complex pump systems. It is also extremely versatile and predictable. However, its versatility is not typically well understood.

There have been over 2,000 HPGL applications in North America since its introduction to the unconventional realm 6 years ago. I have spoken to many of these HPGL users over the last two years, and one of the more common discussion topics during these talks is how they select HPGL candidates. The answers vary greatly. Low GLR wells, high GLR wells, high tortuous wellbores, high sand cut, high water cut, wells that have high ESP failure rates, production acceleration cases, small casing applications, frac hit recovery, well unloading, unloading a well full of drilling mud, etc. However, I rarely heard where one engineer was using it across multiple applications.

Last year we introduced the four critical variables affecting your maximum outflow potential. The paper can be found via the SWPSC database. Our next step is to exemplify how you leverage each variable in certain producing environments. This paper will present various HPGL case studies with the hope that it broadens your thinking of HPGL applications across your asset portfolio.

Case 1: High Water Cut

Nearly all unconventional experience a period of high water cut (>75%) at some point in their life. In unconventional wells you deal with this scenario whether it is immediately following frac, a frac it, or just from producing a formation that has a high water cut component. Our Case 1 is a horizontal well that is producing from a high water cut formation. This well is located in the Delaware Basin and is producing from the Avalon formation. Well details as follows:

- Formation: Lower Avalon
- Pr = 3,800 psi
- Tr = 165 deg F
- Water Cut = 85%
- TFPD = 9,571
- FBHP = 3,000 psi
- Csg: 5-1/2" 20#
- TVD = 8,243'
- MD = 19,215'
- GOR = 3,035 scf/stb
- GLR = 455 scf/bbl
- Gas SG = 0.82
- Water SG = 1.07
- Oil API = 40
- Lateral Length = 9,900'

The equivalent produced fluid density is high due to the high water cut. We know that frictional pressure drop is directly related to fluid density and in fact with HPGL we can reduce the density of the produced fluid stream by lowering our injection point deep into the wellbore. Injecting gas at EOT with tubing set into the curve allows us to reduce the density of the entire vertical fluid column in the wellbore unlike conventional gas lift where your injection point varies based on compressor discharge max pressure, BHP drawdown, and valve injection set depths. So, reducing the density of the fluid stream is key, but what else can we do. As stated earlier, frictional pressure drop is a function of fluid density, but it is also a function of the flow path's cross-sectional area. Pairing a high water cut fluid with a small cross sectional flow area (i.e. flowing up the tubing) and you exacerbate the frictional pressure drop across the flow path. We can demonstrate the effects of both reducing fluid density and changing cross sectional flow area using Nodal Analysis.

We will first demonstrate the effect of increasing the cross-sectional flow area by utilizing annular flow (injecting gas down tubing at EOT with HPGL and flowing up the annulus) and running sensitivities against the tubing OD. Figure 1 below demonstrates these effects.

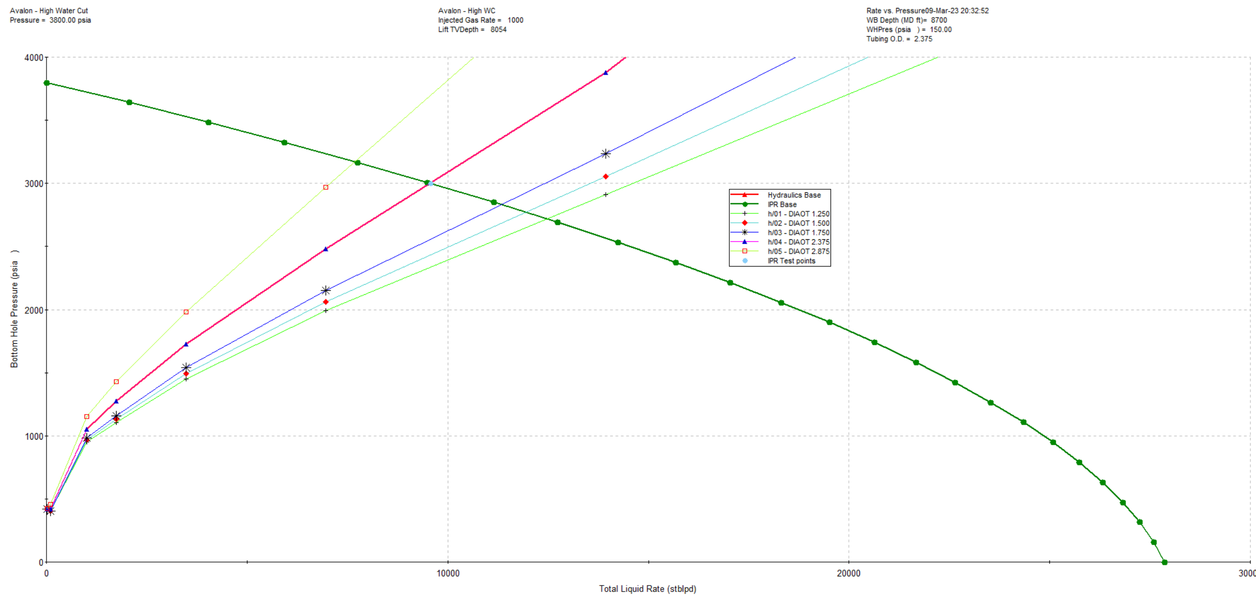

Fig. 1: Varying Tubing Sizes

Note the ever-increasing uplift opportunity by increasing the cross-sectional flow area via reducing the tubing OD. There is a delta of approximately 5,000 bfpd from the 2-7/8” case vs that of the 1.25” case (we have yet to see an operator use 1.25” but the potential is there!) A 1.25” string has complexity in itself, but you still can get a nice bump in production by running 2-3/8” instead of 2-7/8”.

Next, we will demonstrate how changing the density of the produced fluid stream by varying our injection rate affects your outflow potential. We will also go with the 2-3/8” tubing as our injection string. You can see the results in Figure 2 below.

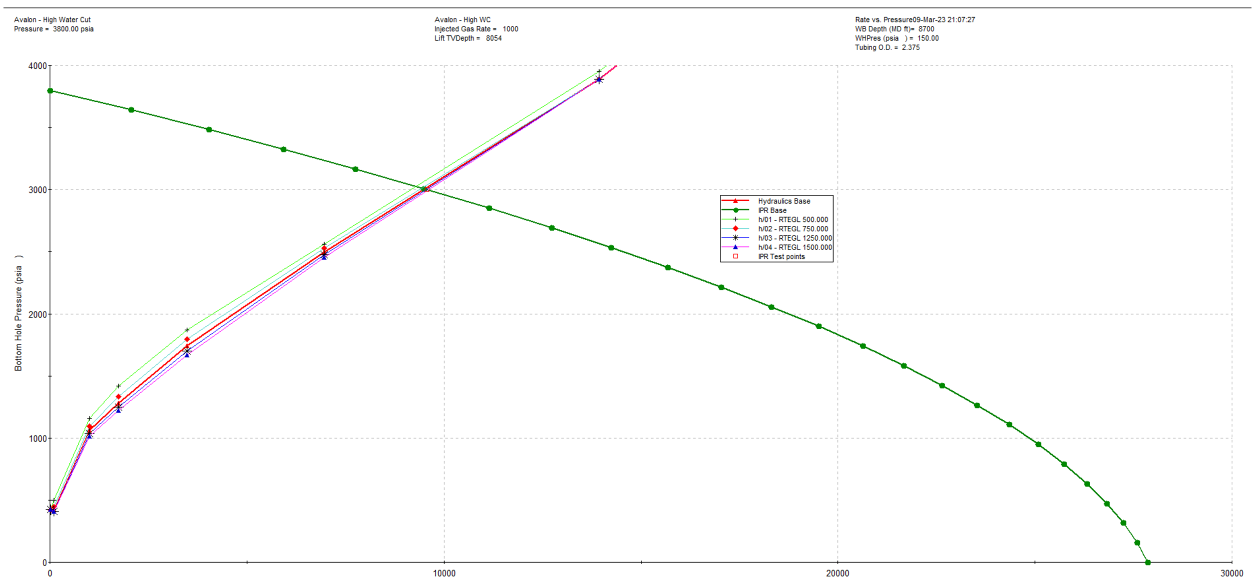

Fig. 2: Varying Injection Rates

Not quite the dramatic effect we saw with varying the tubing size, however it should be noted that your outflow potential increases approximately 400 bfpd when injecting 1500 mcfd versus that of injecting 500 mcfd.

Now for fun let's see if injection depth matters in high water-cut wells. The two previous models demonstrated the injection point at EOT, which will require an HPGL compressor. However, let's look at the outflow variance for injecting 1,500 mcfd with 2-3/8" at EOT versus that of 2000' which is the approximate depth of the top gas lift valve for a conventional gas lift design. Figure 3 demonstrates this affect.

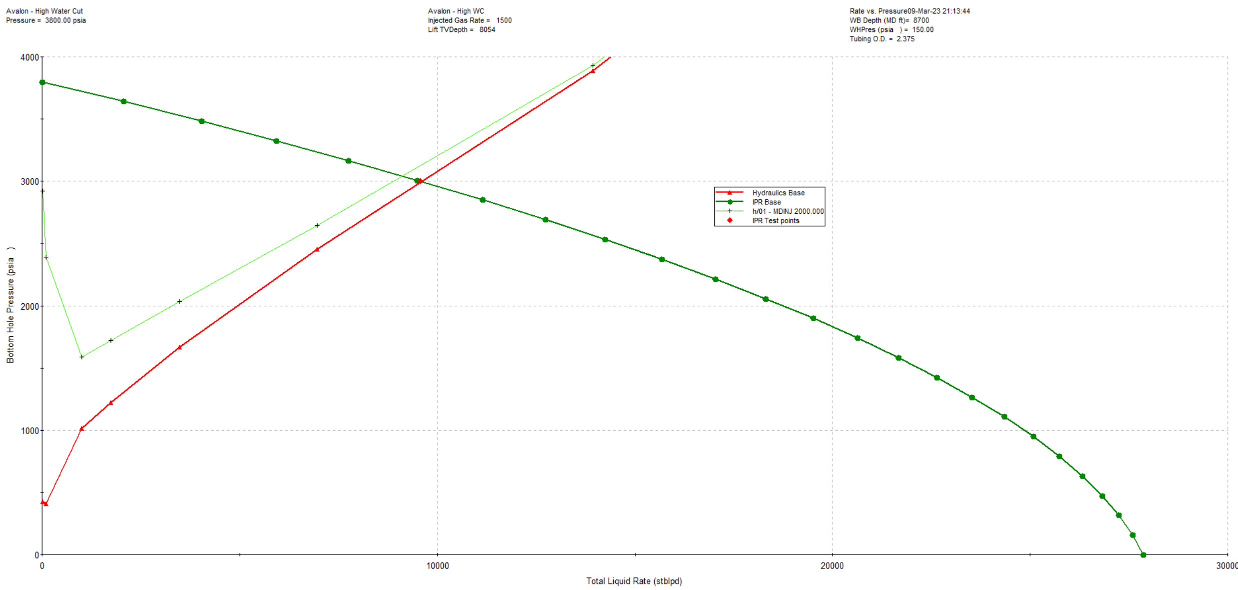

Figure 3: Varying injection depth

The outflow variance is approximately 600 bfpd, significantly better.

In conclusion we can rank the effects each critical variable had on the high-water cut's outflow potential. Increasing cross sectional flow area had the most dramatic effect. Lower injection depth to end-of-tubing took second with increasing injection rate coming in a close third. Pairing all 3 together by utilizing HPGL will allow you to maximize your outflow potential in this high water-cut well, which is what this operator achieved.

<u>Case 2: Replace ESP with HPGL due to Casing Patch</u>

Case 2 is a unique application of replacing an ESP with HPGL due to a casing patch. The operator experienced a casing leak and repaired it using a casing patch. This casing patch reduced the casing ID across the affected area. This restriction inhibited the operator's ability to use an ESP to produce the well, hence the desire to try HPGL in attempt to match the drawdown previously seen with the ESP.

Case 2's well is also located in the Delaware Basin. Well details as follows:

- Formation: 1st Bone Springs

- Pr = 3,275
- Tr = 175 deg F
- Water Cut = 69%
- TFPD = 790
- FBHP = 1,500 psi
- Csg: 5-1/2" 17#
- TVD = 9,869'
- MD = 20,008'
- GOR = 7,916 scf/stb
- GLR = 2,045 scf/bbl
- Gas SG = 0.82
- Water SG = 1.1
- Oil API = 40
- Lateral Length = 8,641'

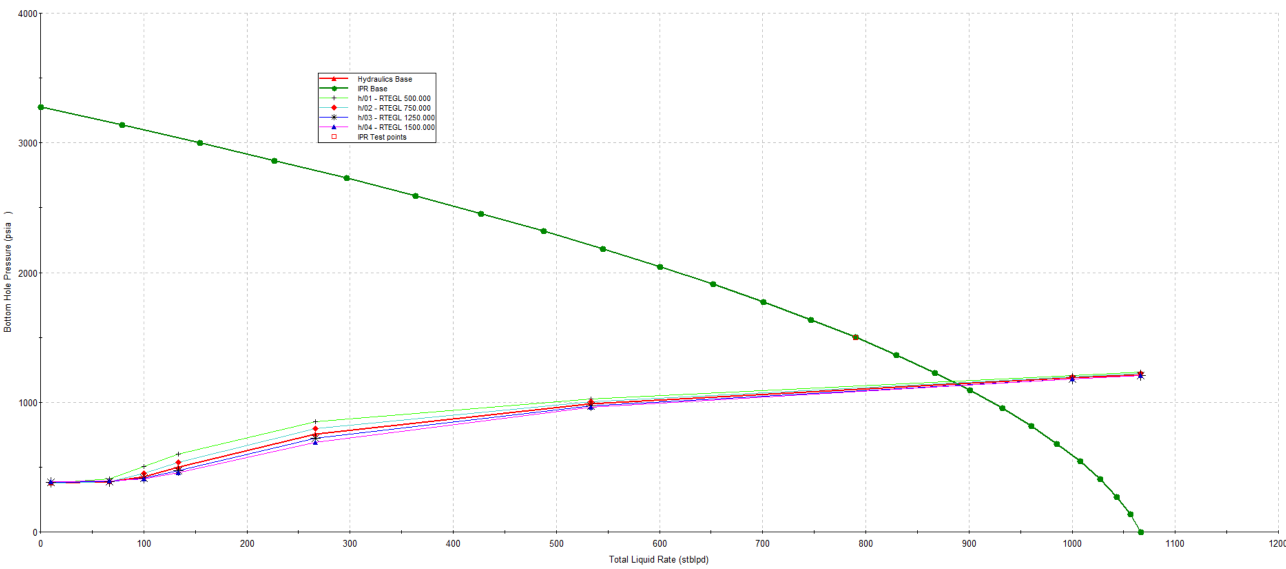

Fig 4: HPGL w/ 2-7/8" Tbg; EOT at 60 deg Dev; FWHP 150 psi; Varying Inj. Rates

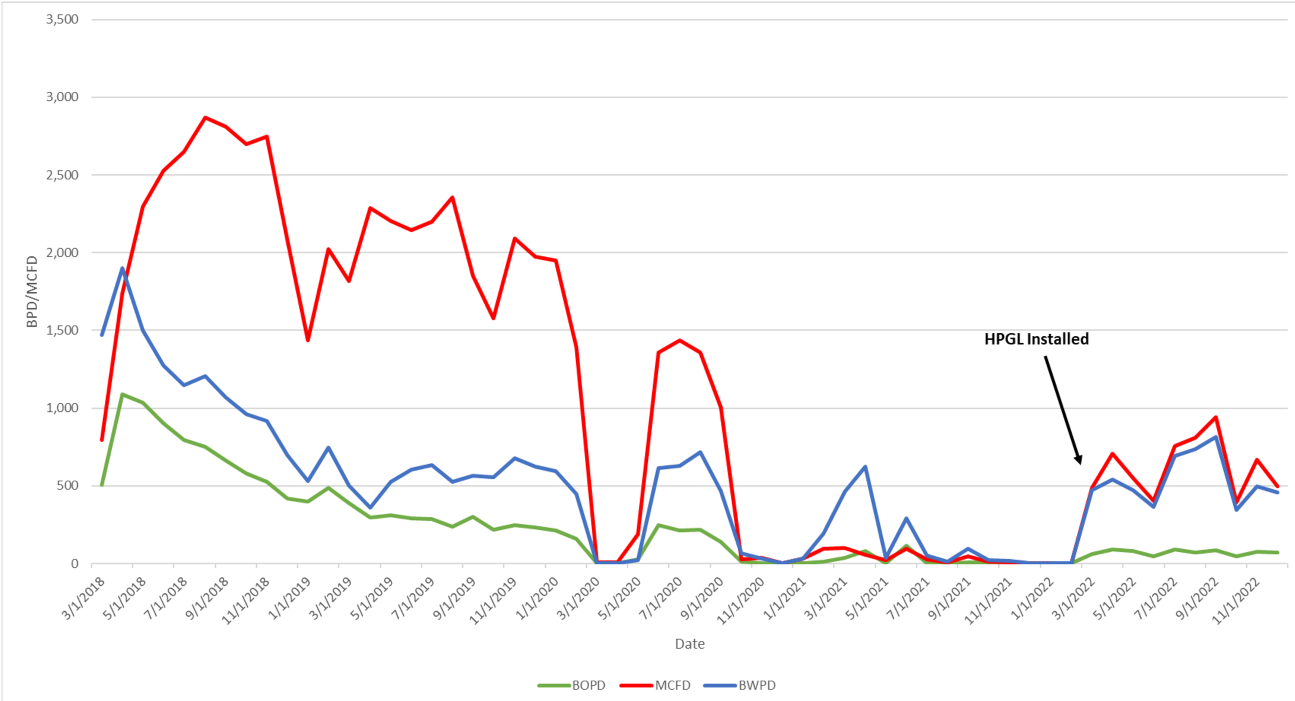

Fig 5: ESP to HPGL Conversion

The operator elected to go with HPGL. They stuck with their 2-7/8” tubing string and elected to go with a 205 hp feed compressor which limited their maximum injection rate to 900 mcfd. As you can see in Fig 4, the model demonstrates, from a hydraulics perspective, that little is gained from increasing the injection rate. Fig 5 demonstrates that the operator was able to sustain production rates once HPGL was installed. The increased reliability of the HPGL system allowed the operator to keep the well online while mitigating the risk of downhole equipment failure. It should be noted that this well is producing with an estimated flowing bottom hole pressure gradient of 0.15 psi/ft. It is reasonable to assume that this well is in the critical rate phase of gas lift. Therefore, the operator should ensure that their total gas rate (produced gas plus injection gas) is greater than the calculated critical rate. Using the Guo-Ghalambor method defined in SPE 94081, the calculated critical rate for this well is 2,175 mcfd. The operator was able to sustain an injection rate of 850 mcfd, however the well was only producing approximately 710 mcfd. This equates to a total gas rate of 1,560 mcfd, which is 615 mcfd below the critical rate and is one of the reasons we weren’t consistently seeing the modeled drawdown. It was recommended that the operator increase injection rate to keep the well unloaded.

<u>Case 3: Midland Basin Frac Hit Recovery</u>

Case 3 is a frac hit recovery application in the Midland Basin. The well was producing on annular gas lift prior to being hit by an offset frac. Post frac hit, the well remained on AGL though production rates were suppressed due to the increased water production. The operator wanted to test HPGL to accelerate frac hit recovery. Their target rate was 4,000 bfpd.

- Formation: Wolfcamp A
- Pr = 3,000
- Tr = 165 deg F
- Water Cut = 99%
- TFPD = 2,897
- FBHP = 2,500 psi
- Csg: 5.5” 17#
- TVD = 7,475’
- MD = 20,812’
- GOR = 970 scf/bo
- GLR = 634 scf/bbl
- Gas SG = 0.725
- Water SG = 1.08
- Oil API = 40
- Lateral Length = 12,000’

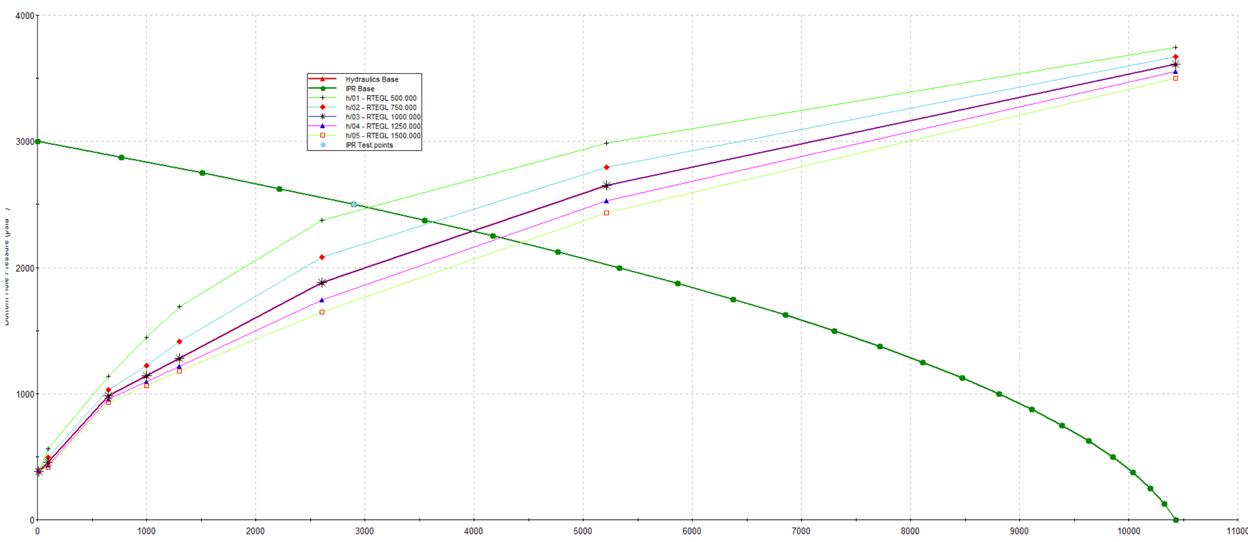

Fig 6: HPGL; 2-7/8” Tbg; EOT at 60 deg DEV; Varying Injection Rates

The model shows that the operator can achieve their desired production rates using HPGL with 2-7/8” tubing and injecting 1,000 mcfd. Being that this well was already on AGL, the operator only needed to trip tubing to remove the GLVs and run back in open ended and set the EOT at 60 deg DEV. The operator elected to move forward with this design and have seen very positive results in line with expectations.

<u>Conclusion:</u>

It is shown that HPGL is an extremely versatile form of artificial lift. It is important not to “pigeonhole” HPGL for specific applications. Instead, HPGL should be considered as a preferred method of artificial lift for all applications given its ability to give the user complete control over your drawdown potential. Remember the four critical variables affecting your outflow potential: cross sectional flow area, producing GLR, injection depth, and flowing wellhead pressure. HPGL allows the user to leverage these four variables to meet their desired outflow, and it does it without the associated risk of operating downhole equipment.