The NXT Data Model for Gas Lift Surveillance & Optimization

WHITEPAPER

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Abstract

Only 5% of the world's oil flows naturally and some sort of lifting methods need to be applied on the remaining production. On the offshore, 95% of the oil is gas lifted. Though gas lift is the major component in oil production, usually proper attention is not paid to and the poor performance of the system goes unnoticed. Reasons could be - only 10% of the world's production is metered, it continues to flow at reduced rates even if broken, unlike the other pumping systems which stop to produce.

Currently, there are no performance indicators for the gas lift system operations and this white paper is a small attempt in that direction. Saving of 1 psi at the bottomhole is equivalent to 10 barrels/day of production assuming a PI of 10 bbl/d/psi.

Each production well usually produces high frequency data recording many parameters, such as BHP, BHT, FTHP, FTHT, GL Rate, GL Valve Opening %, GL Annulus Pressure, Choke Size, etc. for every minute – if properly brought onto a data platform and analysed will tell many useful insights.

This white paper proposes a solution for the development of a gas lift surveillance tool and performance metric tool on a single well.

Introduction

Production of any well drops eventually even though the well would produce naturally in the beginning. When the natural reservoir pressure depletes the well requires some pressure support or an artificial lift to sustain the production or to increase the production. Gas lift is one of the oldest methods of artificial lift methods used to increase the production of the well. Gas lift employs the principle of reducing the density of the fluid in the tubing by injecting the optimum amount of gas. Reduced density results in lesser hydrostatic pressure thus reducing the pressure required at the bottomhole. Usually, lift gas flows in the annulus from the surface unto the pre-determined injection point.

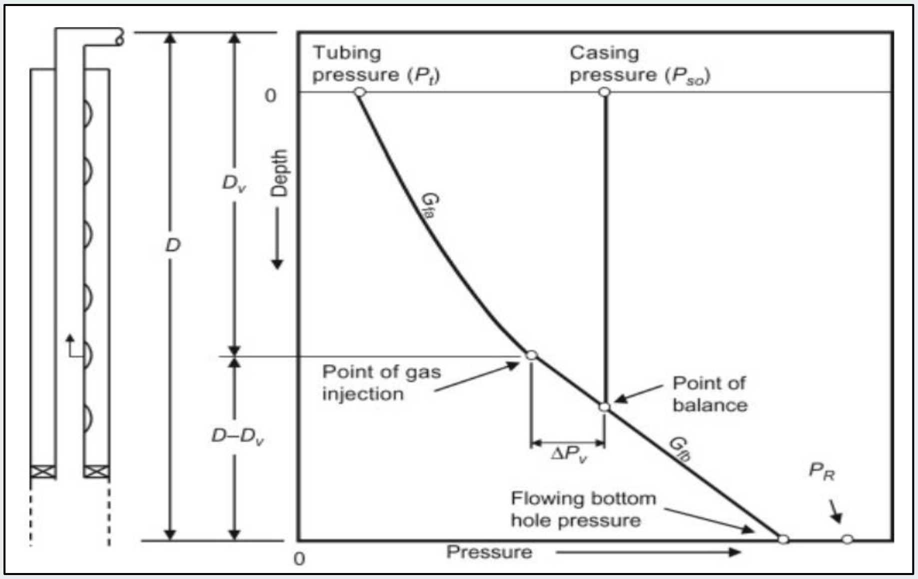

Figure 1: Flowing gradient curves above and below the injection point

For the slope of the gradient in Figure 1, the injection point is steeper (vs. depth) indicating the lower pressure drop compared to the gradient below the injection point

Continuous gas lift is usually employed in high flowing and high BHP wells, where the other lift methods encounter pumping issues. Gas lift makes a good application for wells producing from water flooded reservoirs, reservoirs with high water cut, high PI, and high GORs.

Aim of Design Practice

Two basic questions need to be answered during the design stage of a gas lifted well.

- Depth of Injection
- Rate of injection

Depth of Injection: It is obvious from the gradient curves in Figure 1 that the more the depth - less the pressure drops. Although higher depths of injection are recommended, the compressor discharge pressures at the surface limit the depth of the injection and hence an optimum depth needs to be selected at the design stage. Sometimes a very high depth of injection separates the gas and liquid phases as they rise to the top; the speeding gas thus slips from the liquid phase and hence allows the flow regime from the intended bubble flow to change to annular flow regime, which is undesirable. However, the depth of injection is not the primary focus of this white paper and hence let's stick to the fundamentally accepted principle of more depth better.

Rate of Injection: Though the injection of the gas lightens the liquid column, it also increases the velocity of the production fluid and hence the frictional pressure drop. There comes a point where the benefit gained by the lighter weight of the column gets offset by the increased frictional pressure drop – and further increasing the injection rate will be counterproductive. (See Figure 2.)

However, operating the gas lift at the max optimum rate of injection is subject to many other parameters such as the overall availability of injection gas in the network of wells rather than the focus being on a particular well and subject to the compressor discharge pressure.

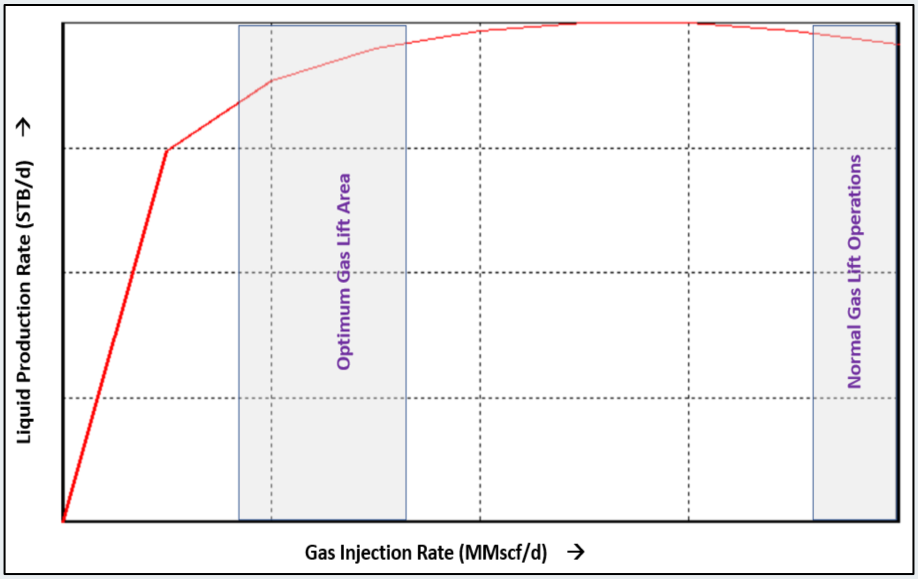

Figure 2: Optimum lift gas injection rate

Unloading of Casing

In a new well where the casing is filled with the kill fluid, it is practically impossible to inject at the designed/desired depth subject to the maximum designed casing pressure and the compressor discharge pressure on the surface. So, the concept of unloading has been introduced – where a series of unloading valves is deployed between the designed depth of injection and the wellhead. Instead of trying to inject at the deepest valve, the first attempt will be to inject at a shallower/topmost valve thus reducing the injection pressure at the surface (compressor discharge); the limitation on the maximum allowable casing pressure will also be automatically taken care of. The gas from the top percolates the casing liquid (kill fluid) and enters the topmost gas lift valve and thus injects the kill fluid along with the gas into the gas lift valve.

Once stabilized all the kill fluid above the valve would have gone and the liquid column in the tubing above the valve would be lighter. This procedure will benefit the overall operations in two ways –

1). The liquid column of the kill fluid in the casing above the unloading valve, that is gone now, will reduce the weight of the remaining column on top of the second injection valve – thus improving the ability to inject at a deeper depth for the same compressor discharge

2). Decreases the bottomhole pressure in the tubing for the same production rate and wellhead pressure – thus creating the drawdown.

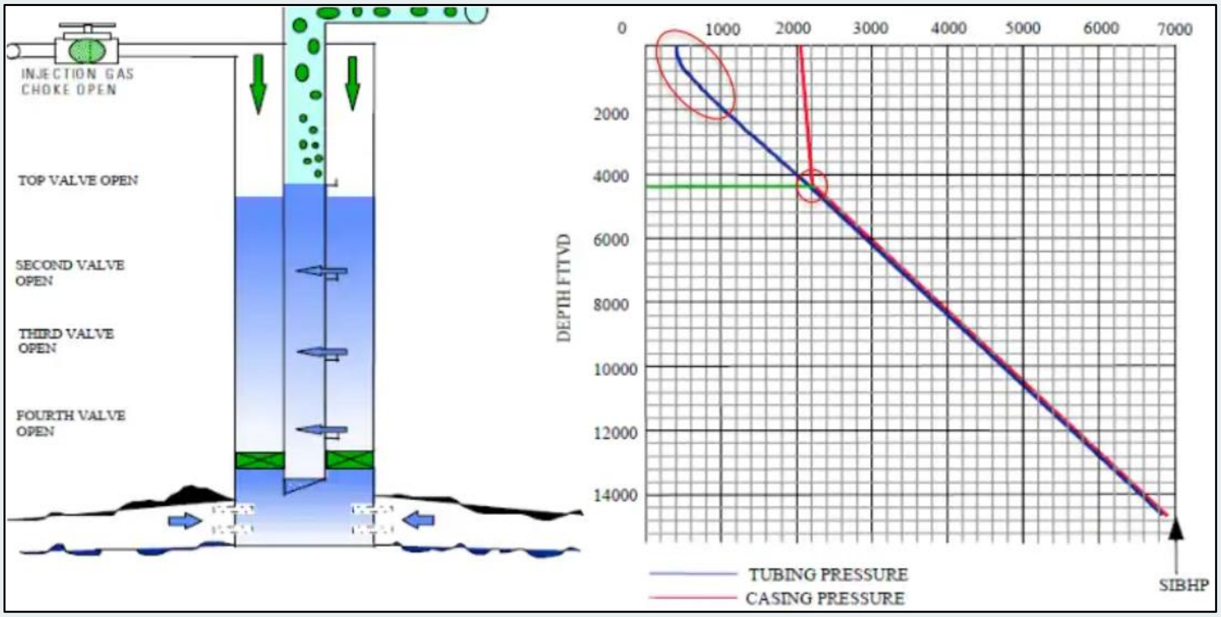

Figure 3: Injection being done at the top valve and production yet to start

Figure 3 shows the beginning of the injection from the topmost valve; "drawdown = 0" can also be observed in the pic, sometimes it may be negative as well.

Figure 4 shows that the injection passed over to the second valve and the gas percolation into the liquid column progressing towards the third valve. Two sidelights of this pic are 1). The top valve is closed and 2). Drawdown is created triggering the production fluid flow in the tubing.

This process continues until the injection is reached down to the deepest designed valve.

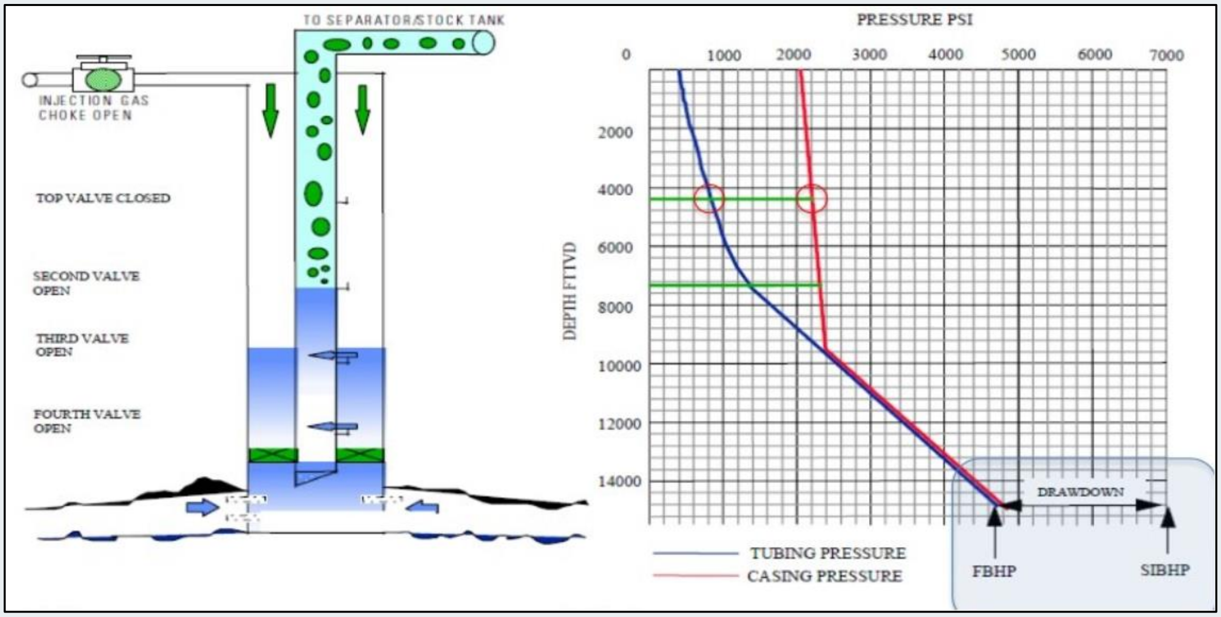

Figure 4: Injection being done at from the second valve and the gas percolation progressing towards third valve

Unloading Valves

In the case of the casing pressure operated unloading valves - once the unloading valve is open the tubing side of the pressure starts acting on the valve to keep it open; in this scenario closure of the unloading valve is achieved only by reducing the casing pressure. Once the casing pressure is reduced below a certain pressure, usually made in 25 psi steps, normally achieved when the next deeper valve starts injecting, the shallower unloading valve closes down automatically.

The dome pressures are carefully calibrated so that the top valve closes gradually, allowing the valve below to open and take over the injection job.

Source of Uncertainty

In the whole of the design process, the underlying assumption is stable and steady state operations where all the parameters such as wellhead pressure, injection pressure, production rate, gas injection rate, and the bottomhole pressure are constant (stable). But the operation of gas lift is highly dynamic that any small disturbance in any of the parameters on either side, be it the reservoir or the production operations, will trigger a dynamic response and unsettles all the three intertwining processes – reservoir inflow, vertical lift performance (VLP) in the tubing and injection gas pressure in the casing.

Once we are a few days into operations and many such small disturbances, it is enough for the small 25 psi of transfer pressure between the two consecutive unloading valves to go haywire and produce some random opening and closing responses from the unloading valves thus departing from the original design.

Missed Opportunity

Since the depth(s) of the injection is firmed up during the design stage itself by the time actual production operations would start, there would not be uncertainty regarding the injection depth, except for the random opening of unloading valves.

Injection rate is not generally measured at the well level but for a stable flowing well and the stable production data, it appears that the well is being injected at a desired depth and correct rate – but may not be true always. Unloading valves above the orifice may leak inject part of the injection gas supposed to be injected only from the designated orifice – but the production rate might still be stable.   This phenomenon is called multi-pointing.

Often it goes unnoticed as the well is stably producing, but that is a lost opportunity to produce more barrels if all of the gas is injected at the designated designed depth.

Problem Statement & Analysis

Based on the discussion so far, the statement of the problem can be made as follows:

1) If the well is behaving properly (no fluctuation in rate and pressure) and the injection is being done at the designated depth – the question to be asked is, "Can we produce more barrels by injecting a little higher amount of gas or lower for that matter?"

Sometimes the production (data) might be stable without any fluctuations, but the real time data could not be matched with the modelled gradient for the designated depth – thus pointing towards a multipoint scenario.

2). If the production rate and other parameters are fluctuating and not stable, the question to be asked is, "Did any of the unloading valves openup?"

Data Model

Industry standard packages like Prosper and PipeSim provide with the multipoint functionality where we can use multiple valves for injection simultaneously. But there will be multiple solutions to the same problem (one production data point) and hence one random VLP matching with an arbitrary split of total injection gas at different unloading valves will not confirm the correct & actual production scenario.

The solution to this problem lies in running many numbers of scenarios instead of depending on one random VLP match. Very few no. of such scenarios can be worked out with an offline manual VLP matching approach. Hence an online data model could be used to trigger multiple scenarios and validate them with other back up calculations.

For model development, data comes from three different areas of interest – reservoir data, production data from the tubing side, injection data from the casing side. But, for the sake of data model, it is classified into two categories.

1). Constant Data

Reservoir data such as shut-in bottomhole pressure (SBHP), reservoir temperature (T), and other reservoir parameters are measured only during the well test. Well inflow index (J) is calculated based on the acquired reservoir data during the well test.

Fluid property data such as gas oil ratio (GOR), water gas ratio (WGR), and API gravity are calculated based on the fluid analysis done during the well test.

All the data that is measured or calculated based on the well test can be treated as constant data until the new well test data arrives.

Tubing data such as inside diameter (ID), outside diameter (OD), roughness parameters, valve mandrel depths etc. is the constant data.

2). Real Time Measurable Data

Production data, such as wellhead pressure (WHP), wellhead temperature (WHT), bottomhole pressure (BHP), bottomhole temperature (BHT), are measured in real-time.

Casing side data such as lift gas pressure, lift gas temperature and lift gas rate are measurable at the wellhead in real-time.

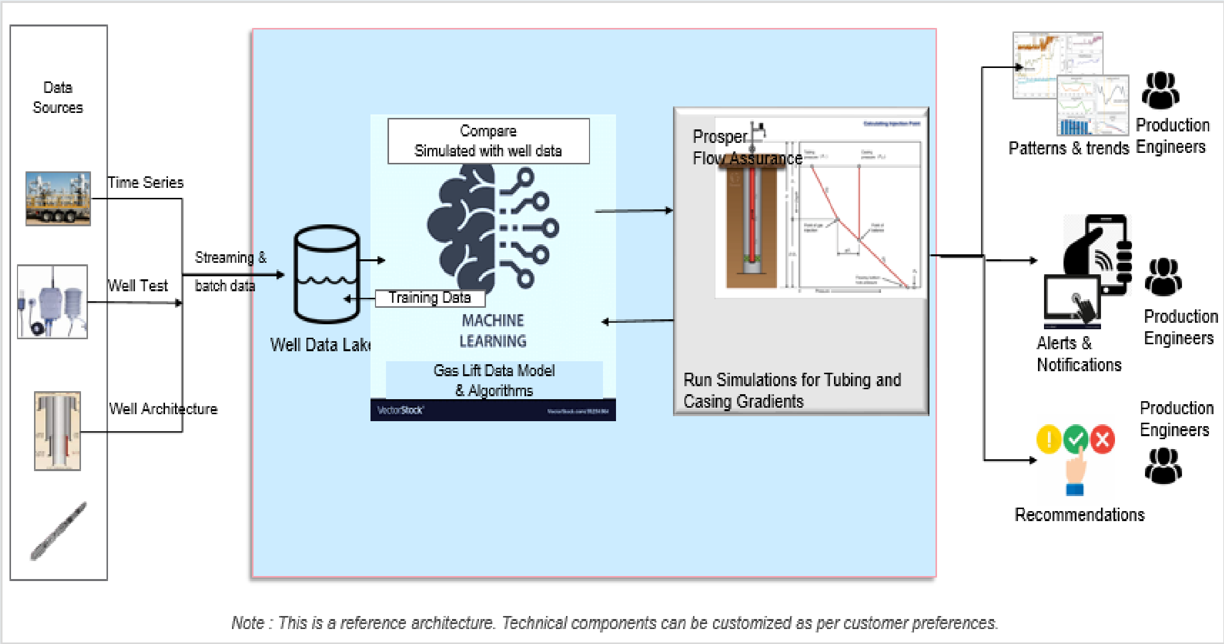

Figure 5: TechM Solution Architecture

The data model picks up the real time measured production data on to a data lake along with well test data and well architecture data. Algorithms in the data model pull the data from the data lake and trigger the simulation scenario(s) to be performed in industry standard package to verify if the pressure and temperature gradients fall between Fancher Brown and Duns and Ros Modified – and then tries to find a matching VLP. As long as the fluid parameters are not changed all the production points should match the same VLP. Those production points which could be matched will be saved in the data lake to be used for training the data model. This can be used as a digital twin and is useful in case of any measurement failure such as oil production rate, lift gas injection rate.

The Flow of control in the data model works broadly as in the schematic below.

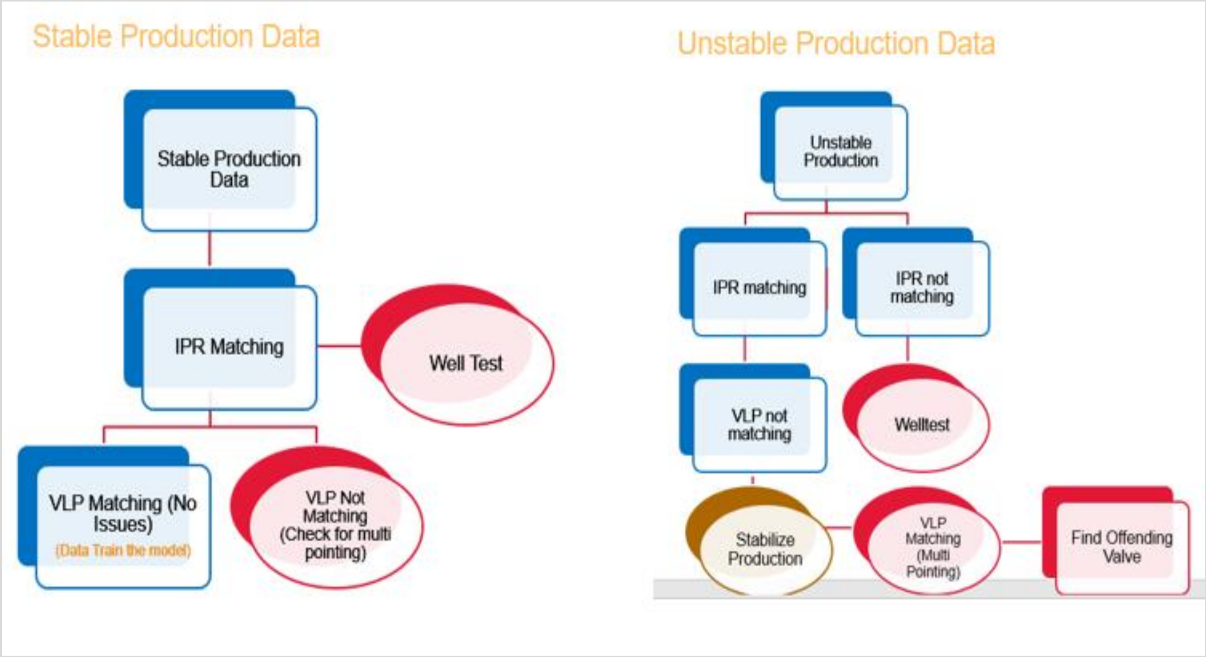

Figure 6: Flow Control Schematic of the Data Model

If the production is stable and no fluctuation is observed and if it comes out that the production data point is valid as per the expected design operational parameters, the system is supposed to be working fine – those data points will go for the training of the model.

If the production is not stable and/or the calculated gradients fall outside of Fancher Brown and Duns and Ros Modified, the data model triggers more simulation scenarios to verify if there it is multipoint. The data model takes the real-time production data and creates many no. of multipoint scenarios based on the total injection gas rate (random splits of injection data that sum up to the total measured injection rate). For each fictitious scenario, the calculated pressure and temperature gradients are verified against the measured data and checked if they are well within the gradients calculated using Fancher Brown and Duns and Ros Modified and match the previously selected VLP. In this event, it may very well happen that multiple scenarios will match the recorded data creating confusion which scenario to be believe.

To sort this problem of plenty, gradients on the casing side will be checked; while calculating the casing side gradients, gas injection flow rates in the unloading valves for the designed valve opening will also be checked and compared against the recorded production data and design data.

More real-time data points can be created by increasing the gas injection rate physically and validating the response by triggering more scenarios around it – a philosophy that is fundamental to reinforcement learning.

Sometimes the simulated production data point may very well fall within the acceptable limits thus misguiding to believe the correct working status of the gas lift system – capabilities of the data model to trigger more scenarios and further validation of the casing side data can be utilized to cross verify and thus to arrive at correct understanding.

Benefits

1) For a properly working gas lift system where multi-pointing is not observed, this model can be utilized to check if a small increase or decrease in the injection further increases the liquid production rate or not – thus pushing the gas lift system to always produce the maximum possible liquid production for the given operational conditions.

2) In case of an identified multi-pointing, it serves as an alert for the operations to go for pressure and temperature gradient survey to verify the GLMs and act accordingly.

3) According to notable industry magazines and journals, only 10% of the world's production is metered for non-availability of installed metering equipment. Since a lot of real time data is being captured, calculated, and cross verified on the well level – this data model can also be utilized as a virtual flow meter for measuring the oil, gas and water phase flow rates.

4). Data models can trigger alerts in case of any mismatch, recommend possible solution scenarios along with easily understandable plots and trends.

Caution

Though this approach can be used on the wells producing from both conventional and unconventional reservoirs, the number of unloading valves are very high in case of unconventional reservoirs thus complicating the calculation process.

This approach serves only as a surveillance tool for a single well and not as an optimization tool for a gas lift network.

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Authors

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