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# Integration of Geomechanics and Numerical Fracturing model for optimization of hydro-frac stages: A case study from the V&V field, Barmer basin, NW India


## Abstract

Successful commercial development of low permeability reservoirs relies on establishing connectivity between the pay intervals. To achieve this objective, an understanding of the geomechanical characters of the host rock its and fraccability need to be established. Low permeability Barmer Hill reservoirs in the V&V field contains approximately a billion barrel of STOIIP. Discrete pay zones over a gross thickness >500m pose challenges in achieving sustained commercial oil rates from individual zones. Connecting maximum Kh against pay with multiple stages of hydraulic fracturing is proved to be instrumental in achieving improved rates. Rate transient analysis carried out on the data acquired till date indicate ~1000 bbl/d oil production potential per well, as a result of effective Kh connect through optimized hydraulic fracturing from a connected well drainage radius of 200-250 metres. Evolving geomechanical understanding in the field extensively helped in optimizing the hydro-frac stages and evaluating the geometry of the fracs created.


## Introduction

The Vijaya and Vandana (V&V) field, located in the central part of Barmer basin and discovered in 2005 contains approximately a billion barrel of in-place resources (Figure-1). The V&V reservoirs comprise sediment gravity flow deposits in form of turbidite sands and pay-zone consists of packages of 5-10 meters thickness dispersed over gross thickness of ~500m landing Net-to-Gross in the range of ~20% (Figure-1). Sandstone lithofacies is the main reservoir rock, but with permeability vastly impaired by cementation (Majumdar et. Al, 2017). The porosity of these sandstones ranges 10-20% and show permeability variation of 0.01-200mD (average <1mD). Twelve wells, drilled through exploration and appraisal drilling programs have confirmed seven oil pools, in tight low permeability turbidite sands (Konar et. Al, 2018). These reservoirs, named from top to bottom as BHT1, 2, 10, 20, 30, 40 and 50 contain significant volumes of stratigraphically entrapped oil (Figure-1). Among these BHT10 is the key zone of interest holding ~60% of the total in place volume. Initial testing results in exploratory stage had shown sub-commercial production rates through perforations (~25-50 bbl/d). The challenge in developing this resource is to produce commercial rates from discrete sand layers and to formulate a commercial development plan.

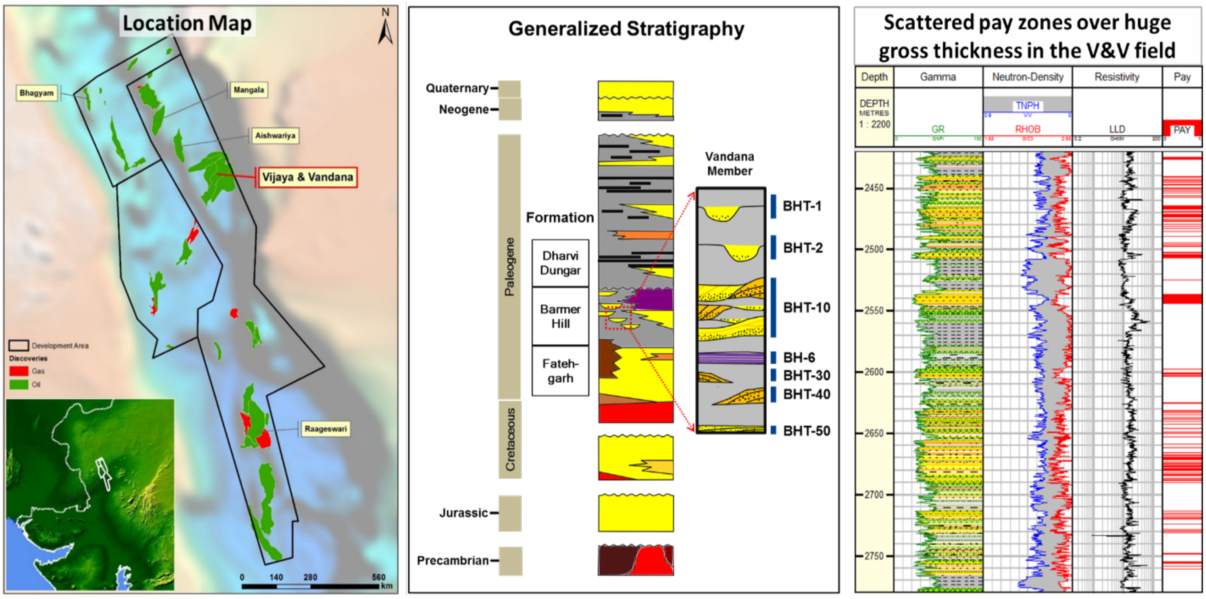


Figure-1: Location map and generalized stratigraphy of the V&V field. Tight reservoirs in the BHT-10 unit in the Barmer Hill Formation is the key zone of interest. (Bora et. Al, 2017)

Well testing campaign-1 in this field was planned with five fracs in two wells (against selected intervals) to evaluate the incremental gain after stimulation. On frac maximum production rate achieved was ~200 bbl/d proving the concept of 'Kh connect'. However, post frac observations did not fully support the existing geomechanical model and stress profiles with limited calibrations. Frac simulation model results were found to be quite deviating from actual frac growth as observed from temperature logs prior to having a well calibrated geomechanical model (Figure-2).

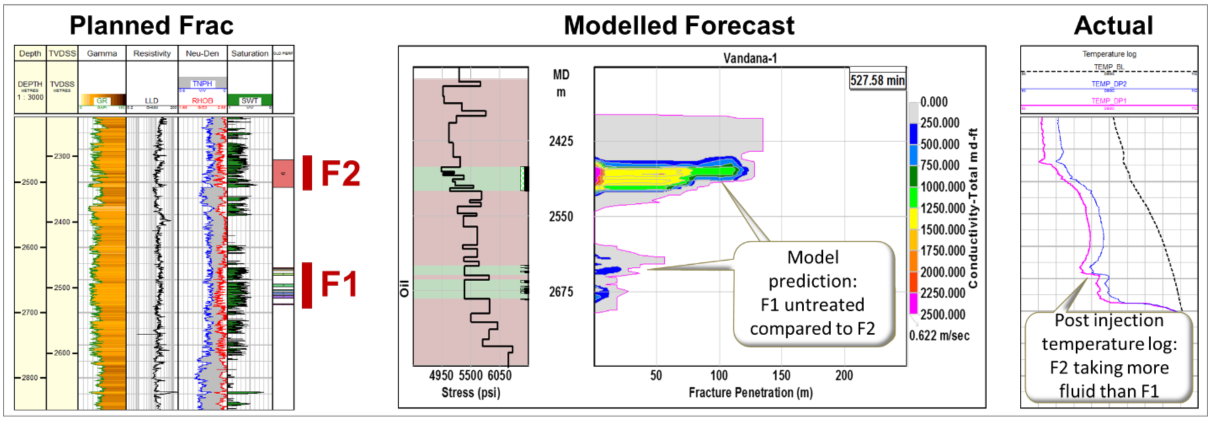


Figure-2: Frac simulation model failed to predict actual frac growth as observed from cooling in post injection temperature logs.

A systematic data acquisition plan was designed for the campaign-2 comprising 12 fracs in two wells. This campaign aimed at connecting 100% available Kh in two wells to establish full flow potential. Sustained rate of 500+ bbl/d was achieved on execution of multi stage hydraulic fracs. Good amount of injection tests and temperature logs were acquired in this campaign that helped us in: 1) optimizing frac stages in real time to ensure the targeted coverage of net pay; 2) validating the geomechanical and frac simulation model for better optimization and sizing of future frac jobs.

In this case study, we demonstrate how through systematic data acquisition, full use of available data and cross discipline integration, we could build a useful geomechanical model for robust hydraulic fracture characterization in the field.

## Methodology

Basic petrophysical logs with dipole sonic data, rock mechanical tests on core, processed image logs and injection tests such as diagnostic fluid injectivity test (DFIT) and step rate test (SRT)/mini frac formed the foundation of creating a robust 1-D geomechanical model in the V&V field. The key steps followed are summarized below:

**Rock mechanical property estimation**

A highly focused set of core geomechanical test data were performed in core samples for measuring Young's modulus, Poisson's ratio, Uniaxial compressive strength, Tensile strength and internal friction angle which are typical indicators of rock strength. Available measurements were thoroughly quality checked prior to use for calibration. Dynamic Young's modulus and Poisson's ratio were calculated using sonic and density logs (Fjaer et al. 2004). Needful gains (~ 0.85) have been applied to the log estimated dynamic moduli to convert to static domain for tying in the core measured results.

YMD=ρDTS2*3DTC2-4DTS21DTC2-1DTS2 ............................. **(1)**

PR=12*1DTC2-2DTS21DTC2-1DTS2 .................................... **(2)**

Where, ρ = bulk density; DTC = Compressional sonic; DTS = Shear sonic.

Uniaxial compressive strength (UCS) has been estimated as a function of DTC with a relationship established from the measured Triaxial Mohr-Coulomb Failure Analysis data. Tensile strength (TS) is then estimated as a linear function of UCS honoring the core Brazilian tensile strength data.

UCS=49453exp(-0.024*DTC) .................... **(3)**

TS=0.0217*UCS+125.05 ............................. **(4)**

Estimated rock strength indicators are found to be in fair agreement with the core test results (Figure-3).

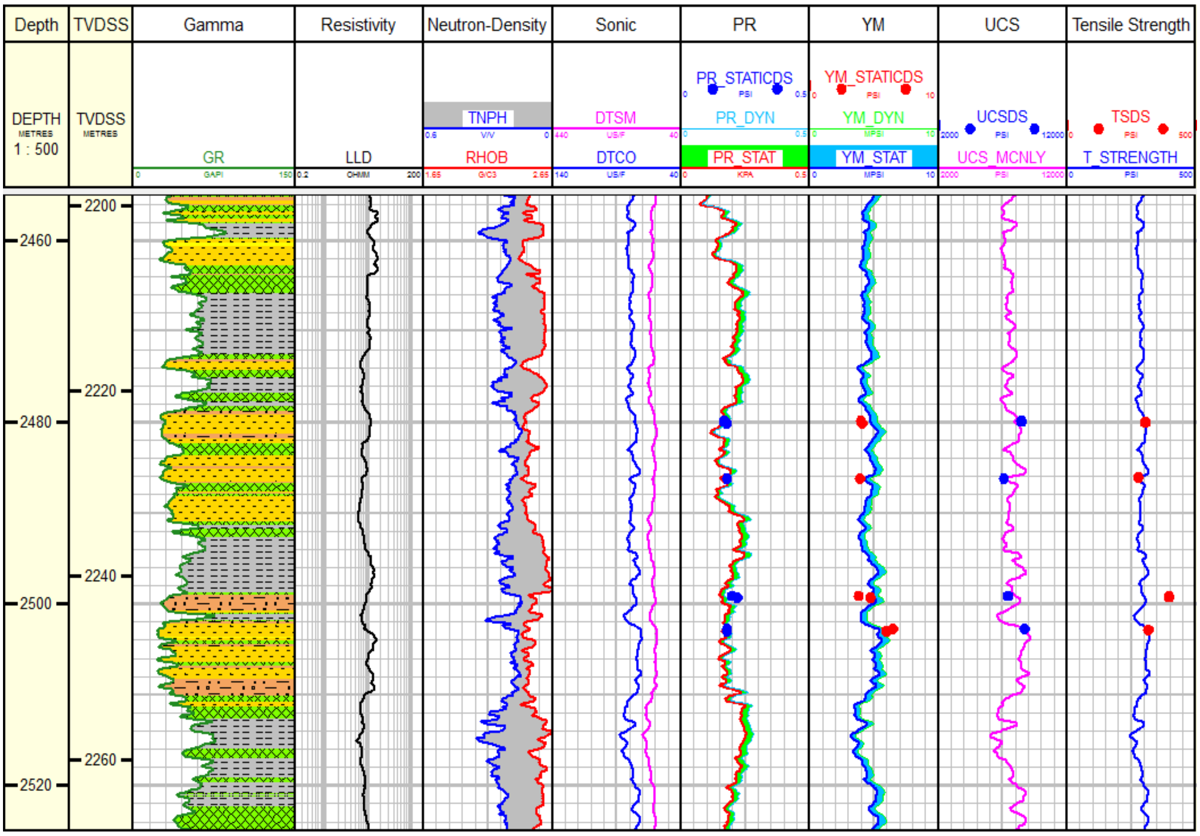


Figure-3: Rock mechanical property estimation and its calibration in the cored well.

**Estimation of stress magnitude and direction**

Estimation of stresses involved assessment of over burden stress, pore pressure, followed by horizontal stress (both maximum and minimum). Overburden gradient (OBG) in the V&V field has been well constrained with bulk density logs in 12 wells (with 2 wells logged up to surface). More than 200 formation pressures points acquired through wire line formation tester were used to tie in the sonic predicted pore pressure profiles in the field.

Uniaxial transverse isotropic model was implemented to calculate the minimum horizontal stress (Shmin) (Thiercelin and Plumb, 1994).

Shmin=PR1-PRSv-αPP+αPP+YMS1-PR2ϵHmax+YMS*PR1-PR2ϵHmin …… **(5)**

Where PR is Poisson's ratio, YMS is the static Young's modulus, Sv is overburden pressure, PP is pore pressure, α is the Biot's co-efficient, $\epsilon_{Hmax}$ is the maximum horizontal strain and $\epsilon_{Hmin}$ is the minimum horizontal strain. The first two terms of the equation represent poro-elastic components which can be obtained from sonic data. However, the last two terms of the equation represent tectonic contributions to the stress and cannot be established with any direct measurement. In case of V&V, the strain parameters were iteratively adjusted for the field, so that estimated Shmin ties well with all available closure pressure data. Biot's constant is assumed to be 0.98 for the calculations. Prior to this, when closure pressures were not acquired, initial geomechanical model involved leak off test (LOT) data from the formation above to calibrate the Shmin estimation. Figure-4 shows the close agreement between estimated Shmin and closure pressures from injection tests.

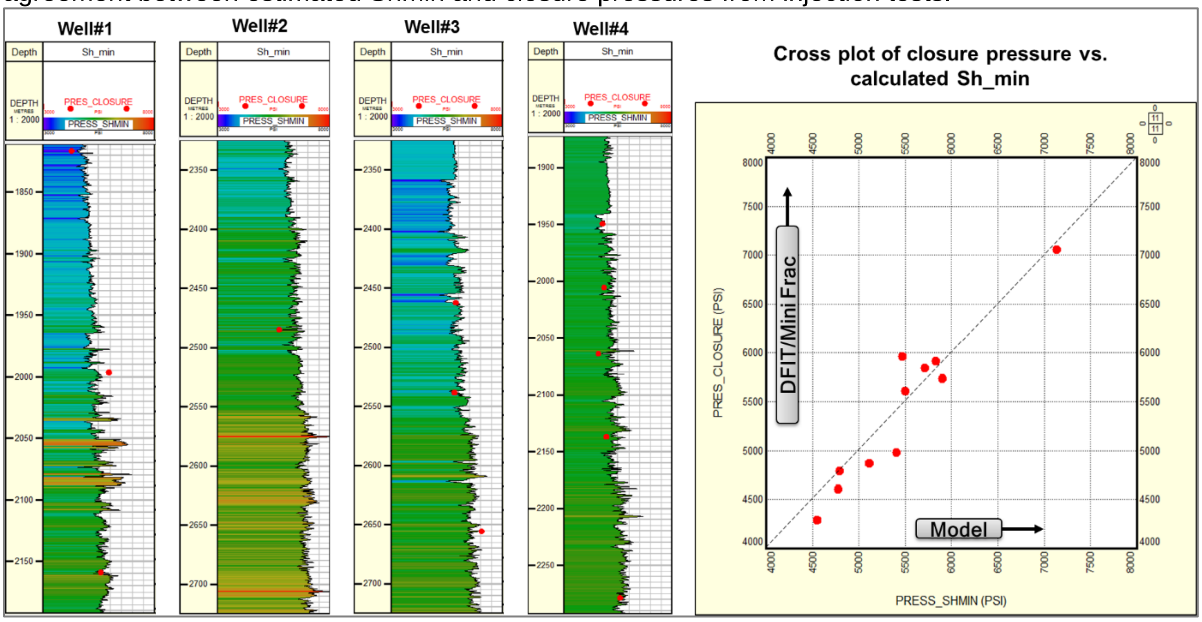


Figure-4: Estimated minimum horizontal stress matches well with available closure pressures in different wells in the V&V field.

Compressive shear failure is characterized by symmetrical borehole enlargements (i.e. breakouts) that are aligned along the minimum horizontal stress, while drilling induced tensile fractures, if developed, are aligned in the maximum horizontal stress direction. Breakouts and drilling induced fractures in the V&V field were identified in the available image log data that confirmed the maximum horizontal stress direction to be NNW-SSE (Figure-5).

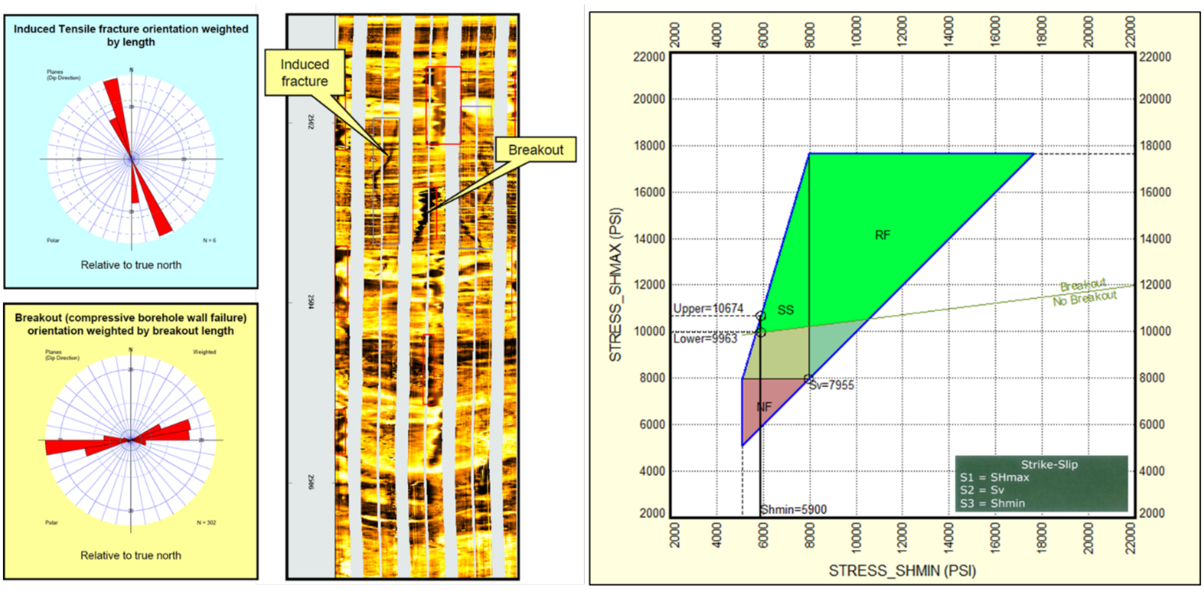


Figure-5: Breakouts and tensile fractures observed from image log confirm the SHmax direction to be NNW-SSE. Calibrated Shmin log along with breakout azimuth was used to find out the possible range of SHmax presented in the form of stress polygon. Stress regime is found to be strike-slip in this example.

Maximum horizontal stress magnitude (SHmax) was constrained using the borehole breakout and tensile fracture criteria. Following failure criteria were used to constrain the SHmax (Zoback, 2010):

SHmax=Ceff+2P+ΔP+σΔP-Shmin(1+2cos2θb)(1-2cos2θb)........................ **(6)** [Wellbore breakout criterion]

SHmax=3Shmin-2P-ΔP+T0-σΔP........................ **(7)** [Tensile wall failure criterion]

Where, $C_{eff}$ is the effective compressive strength, P is pore pressure, ΔP is excess mud weight, $\sigma^{\Delta P}$ is cooling stress, $T_0$ is tensile strength and $\theta_b$= (π-breakout angle). Cooling stress is assumed to be 0 in our case. Both the equation can be simultaneously solved to constrain the SHmax magnitude. The same can also be visualized in the form of stress polygon with upper and lower bound of SHmax (Figure-5).

**Frac model simulation and history match**

Surface pressures and declines observed during all injections carried out in the field have been history matched using the calibrated 1-D geomechanical models for the respective wells. Rock strength properties, calibrated stress profile, permeability and leak off co-efficient are some of the key inputs used in these simulation models. A porosity based leak off correlation established for the field has been used to control the leak off co-efficient during the simulation exercise. Fracture height and width profiles were then generated using the history matched model. Temperature log cool downs were used to validate the predicted frac geometry from the model.

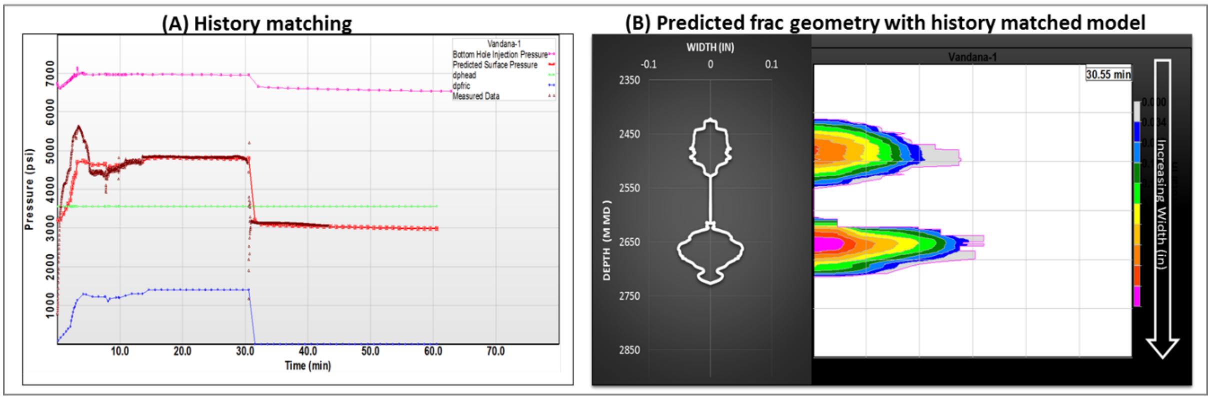

Figure-6: Post frac history match of the injection pressures with calibrated geomechanical model outputs.

## Results and Discussion

Robust geomechanical model is an essential component in optimum planning of hydro frac jobs giving consideration to both rock property as well as stress profiles. However, every geomechanical model has its own inherent assumptions. Without proper validation and check points these models may lead to unrealistic estimation and sub optimal frac design. In case of V&V field, similar situations were experienced. Preliminary geomechanical understanding of the field failed to deliver workable frac geometry predictions. Rock strength and stress profiles created using standard equations didn't really help to deliver a useful model. Moreover, at initial field life stage, calibrations were limited for tailor made workflow. Reasonable amount of core geomechanical tests, injection tests and temperature log data acquired throughout the appraisal life of the field aided to get hold of a useful geomechanical model. The interlayered shales in BHT10 reservoirs were initially envisaged to be good stress barriers that may contain the hydraulic fractures. However the actual frac height observed from temperature logs during frac jobs showed uncontained growth of fractures. At few instances consecutive frac stages were clubbed into single stage with no significant net pressure development while pumping bigger than the initially planned volume of proppant. Updated 1D geomechanical model revealed these shale layers to have insignificant stress contrast in comparison to pay zones, thus allowing the fracs to propagate through it. Frac simulation models created with calibrated geomechanical inputs provided convincing picture similar as observed in the field. Robustness of the frac model was ascertained on obtaining reasonable accuracy in predicted frac tops while comparing to the temperature log measurements against already executed fracs (Figure-7). This study established the effectiveness of future usage of these models with greater confidence to plan bigger jobs with optimum stages, for monetizing these tight reservoirs.

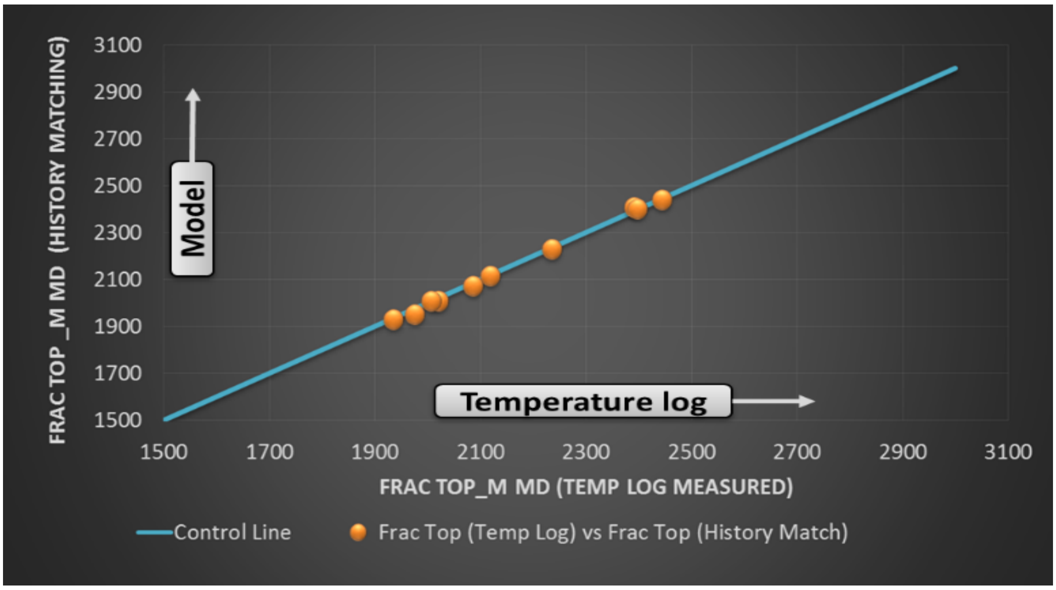


Figure-7: Validation of the frac model using a cross plot of frac tops predicted from simulation vs. the temperature log measurements.

## Conclusions

Robust 1D-Geomechanical model has been developed for the V&V fields, calibrated to field observed pressures and core geomechanical tests. Integration of calibrated geomechanical model helped in achieving a predictive frac simulation model in the field. Implementation of these models will be pivotal in saving of well fracturing cost through optimization of frac stages and to bring down the overall capital expenditure of the project. Post frac analysis of each stage calls for continuous update and improvement of the model addressing local variation in in-situ stresses and variation in geomechanical properties.

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