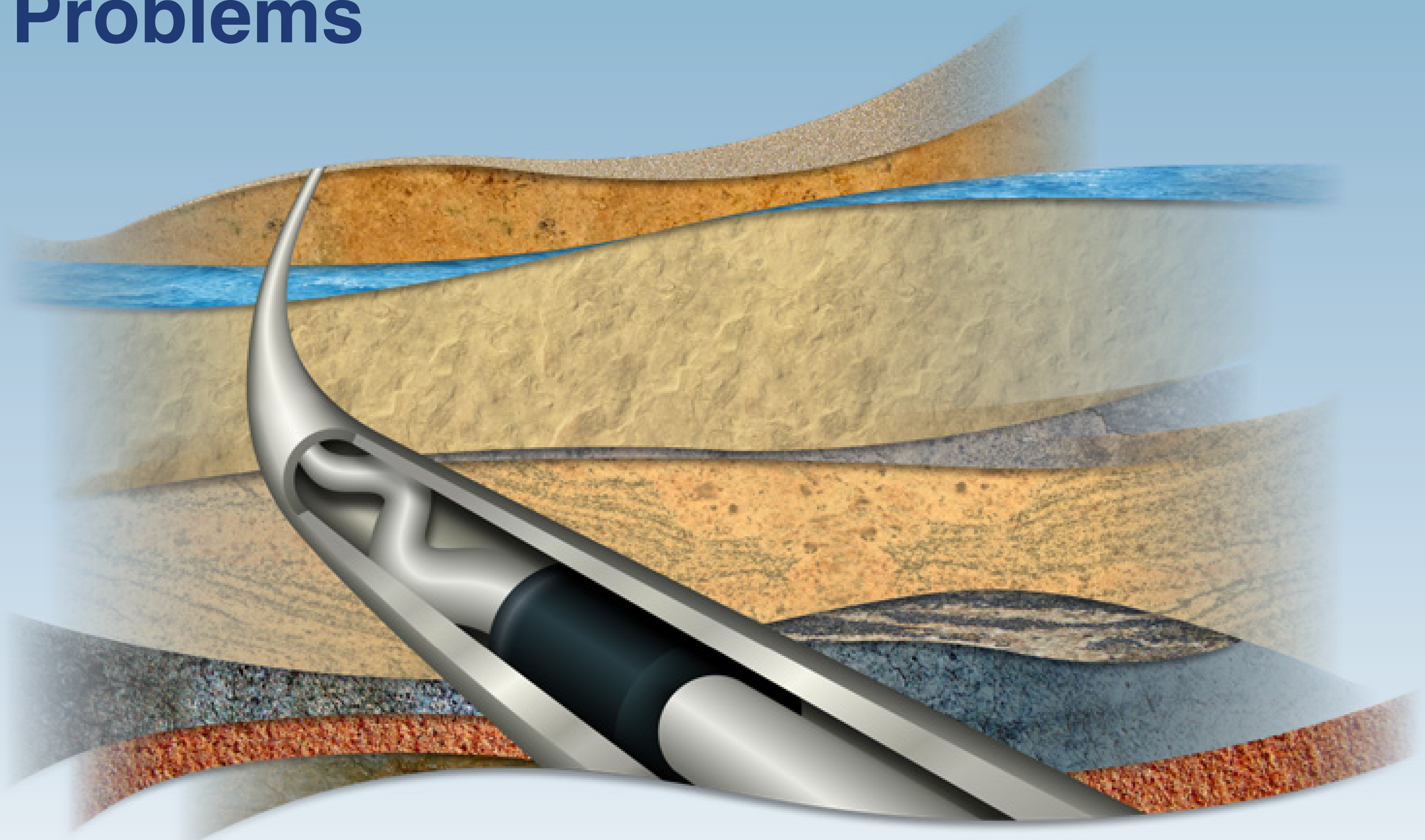
Pegasus Vertex, Inc.

Drilling Software | Sophisticated Yet Simple

WHITE PAPER

Solutions to Tubing and Packer Problems



CONTENTS

Many well completions and workovers require one or more tubing and packer systems. Changes in temperature and pressure inside or outside the tubing will either change the tubing length or induce force in the tubing and on the packer. The length and force changes can be considerable and cause enormous stresses in the tubing string and on the packer under certain conditions. The net result could reduce the effectiveness of the downhole tools and damage the tubing. Failure to consider length and force changes may result in costly non-productive time (NPT). This white paper discusses the cause of packer and tubing problems and how to predict and prevent tool failures using TMPRO.

I. Types of Packer

Packer is a downhole sealing equipment that isolates the fluid and pressure above and below the packer (Figure 1). It typically serves as a well barrier to protect the casing. Packer can be described by its setting mechanism, namely mechanical, hydraulic, and hydrostatic packers.

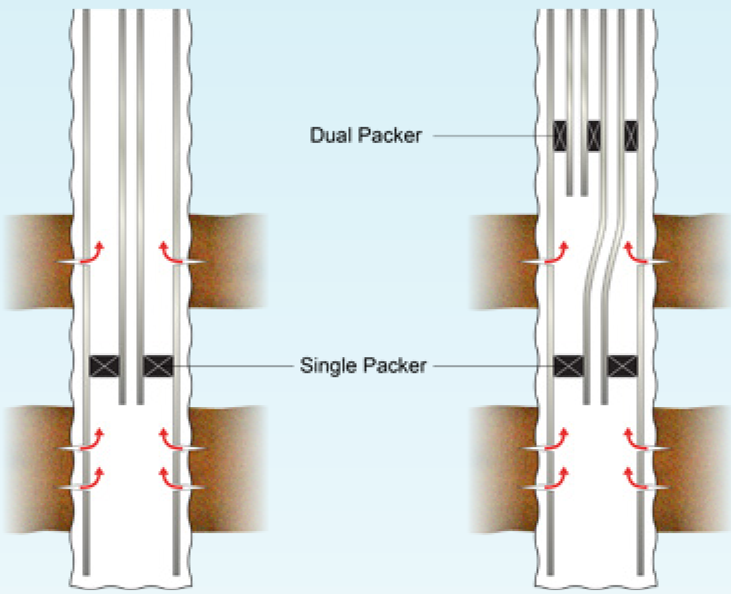


Figure 1: Illustration of packers in the well

Mechanical packers are set by applying pick-up or slack-off weight at the surface after the packer reaches the target depth. The applied force will be transferred to the packer location. The packer will be set if the applied force at the packer exceeds the required set force.

Hydraulic packers are set by pressuring up the tubing pressure when the tubing end is plugged. In this scenario, a downward piston force is applied to the tubing string which is countered by an upward ballooning force. The net force that will be locked at the packer is as follows:

$$F_{set} = P_{set} A_i (1-2\mu)$$

Where Ai is the tubing end's internal area, μ is Poisson's ratio, and P_{set} is the pressure difference between above and below the plug.

While hydraulic packers are set based on the difference between the tubing and annulus pressure, hydrostatic packers react to the absolute pressure. This allows the hydrostatic packers to be set without plugs. The force that will be locked after packer setting is as follows:

$$F_{set} = P_{set}\,(A_o - A_i)(2\mu - 1)$$

Where P_{set} is the hydrostatic tubing pressure and $A_o - A_i$ is the cross-section area of the tubing.

Packers can also be classified into three types based on the motion type: free motion, limited motion, and anchored. For the free motion packer, tubing is free to move upwards or downwards at the packer location. For the limited motion packer, tubing is only permitted to move in one direction, either upwards or downwards. For the anchored packer, tubing is anchored at the packer location and is not allowed to move upwards or downwards. Mechanical packers can have three types of motion, while hydraulic and hydrostatic packers are only anchored packers.

II. Tubing Movement and Packer to Tubing Force

According to Lubinski (1962), five factors can cause a change in the length or force in the tubing string: piston, ballooning, buckling, temperature, and packer setting.

Piston Effect: The length change induced by the piston effect is caused by a change in the actual axial force in the tubing. As illustrated in Figure 2, P_i and P_o are the fluid pressure applied inside and outside tubing, respectively.

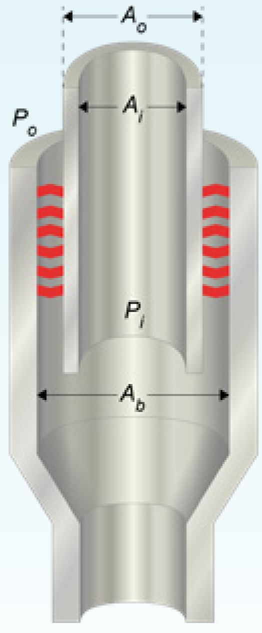


Figure 2: Cross section view of tubing at packer with seal bore

There is an actual end force acting on the tubing at the packer location. The force is determined from the following equation as:

$$F_a = P_i (A_p - A_i) - P_o(A_p - A_o)$$

Where A_p is the area with respect to the packer bore ID. The length change due to the piston effect is calculated based on Hooke's law as:

$$\Delta L_1 = -\frac{F_a \times L}{(A_o - A_i)E}$$

Where L is the total length of tubing and E is Young's modulus.

Balloon Effect: The ballooning effect is caused by the change of tubing and annulus pressure, which causes tubing size contraction or swelling. An increase in the tubing pressure balloons the tubing and causes it to shorten. On the other hand, an increase in the annulus pressure squeezes the tubing and causes it to elongate. The length change due to the ballooning effect is

$$\Delta L_2 = -\frac{2\mu L}{(A_o - A_i)E} \times (A_i \Delta P_i - A_o \Delta P_o)$$

Buckling Effect: The tubing string tends to buckle only when the tubing pressure exceeds the annulus pressure. Buckling always results in shortening the tubing string but the effect of buckling on the actual force is negligible. The diminishing length occurs because the tubing string is spiral rather than straight. The length change due to buckling is shown below as:

$$\Delta L_3 = -\frac{r^2 A_p^2 (\Delta P_i - \Delta P_o)^2}{8EI(w_s + w_i - w_o)}$$

Where I is the moment of inertia of tubing cross-section with respect to its diameter, w_s is the average weight of tubing per unit length, w_i is the weight of liquid in the tubing per unit length, and w_o is the weight of liquid in the casing per unit length.

Temperature Effect: The tubing length will increase when temperature increases and decrease when temperature decreases. The length change due to the temperature effect is defined as:

$$\Delta L_4 = L\alpha\Delta T$$

Where α is the thermal-expansion coefficient of the tubing material and ΔT is the change of temperature.

Packer Setting Effect: As described in the previous section, the tubing length will change during packer setting. The length change due to packer setting can be calculated based on the setting force as:

$$\Delta L_5 = - \frac{F \, x \, L}{(A_o - A_i)E}$$

Where F is the setting force.

The total tubing movement is the summation of the tubing movement length of the five effects. It is the actual length change of the tubing if it is free to move at the packer location. However, restriction of tubing movement will result in a packer to tubing force, which is the required force to move the tubing back to the original position in the packer. The tubing to packer force is tensile if the total length change is contraction and the force is compression if the total length change is elongating.

III. Software Solution

Pegasus Vertex, Inc. (PVI) has developed TMPRO to calculate tubing movement and to evaluate the tubing and packer integrity under various operational conditions. Based on the Lubinski (1962) and Hammerlindl theories (1977, 1980), TMPRO is a sophisticated yet easy-to-use software solution for identifying and avoiding potential tubing and packer failures.

TMPRO evaluates the tubing movement due to the total impact of five different effects: packer setting, piston, buckling, ballooning, and temperature. In addition, it calculates packer to tubing forces and buckling conditions. Stress along the tubing is also calculated and the tubing integrity is evaluated by comparing tubing forces and stresses with their corresponding limits. Figure 3 shows the results of tubing movement and packer to tubing forces in TMPRO.

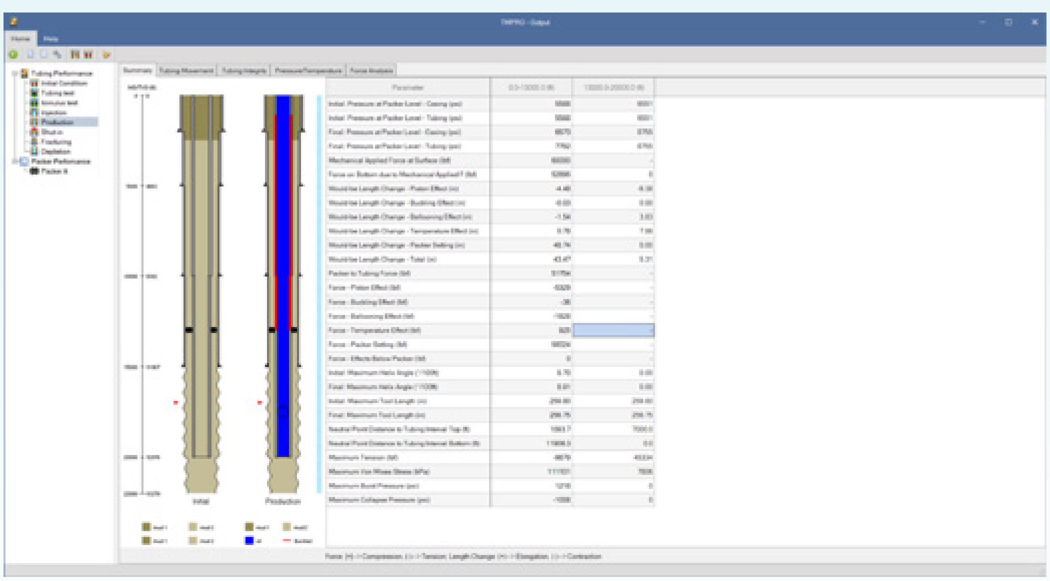


Figure 3: Illustration of tubing movement and packer to tubing forces

TMPRO can simulate both single and multiple packers. In the single-packer mode, the software can simulate mechanical, hydraulic, or hydrostatic packers. In the multiple-packer mode, it can simulate up to 15 hydraulic packers, each with a unique setting pressure. Every packer has a specific packer performance envelope, which describes that packer's safe operating condition. TMPRO evaluates packer failures by comparing the loading conditions with that packer's performance envelope. Figure 4 shows the evaluation of packer failure conditions.

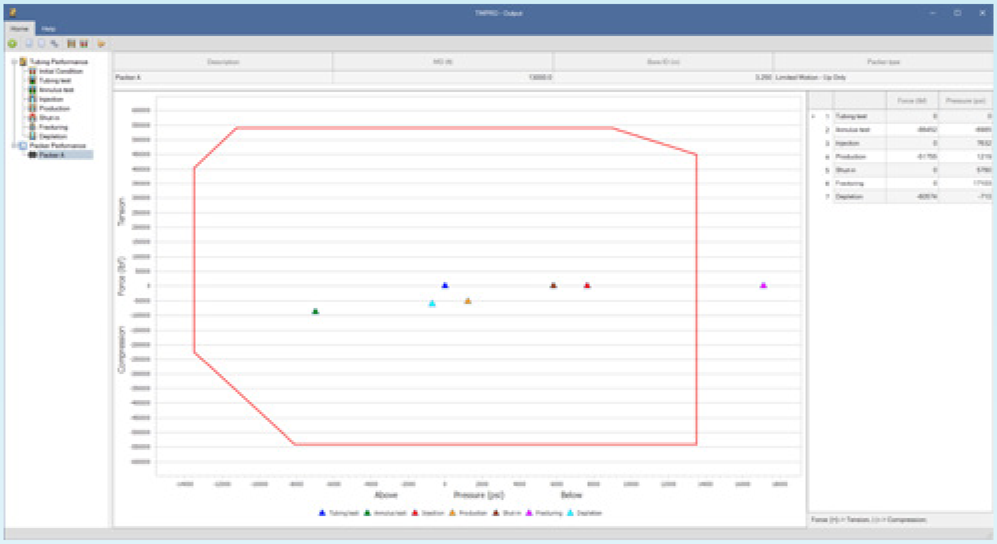


Figure 4: Evaluation of packer failure conditions in TMPRO

TMPRO can simulate tubing movement in seven types of operation, including tubing pressure test, annulus pressure test, shut-in, fracturing, injection, production, and depletion. Up to 20 operations can be simulated in one run. In addition, as illustrated in Figure 5, the operation design window in TMPRO allows the user to quickly predict the effect of setting forces and surface pressures on tubing and packer integrity in different operations.

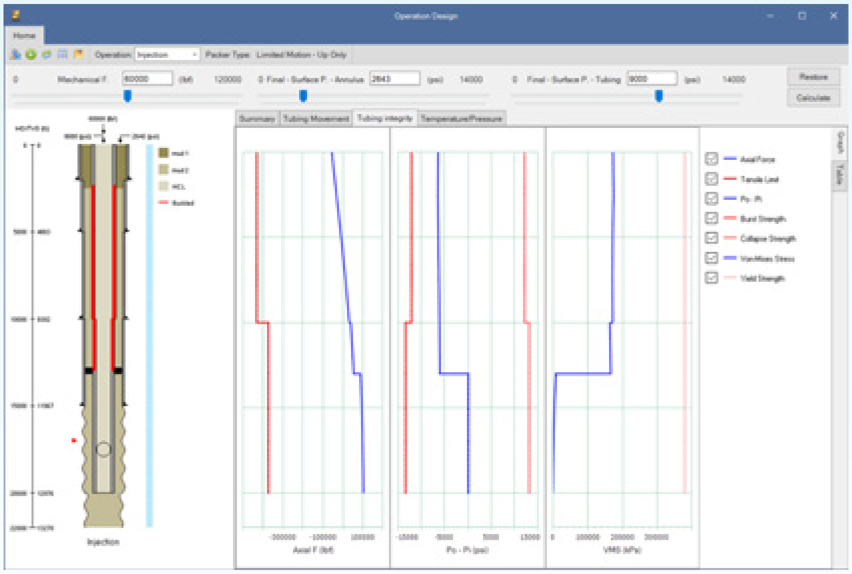


Figure 5: Operation design window in TMPRO

IV. Case Study

A case study was performed to evaluate tubing movement for a five-packer system using TMPRO. Figure 6 shows the well trajectory and Figure 7 shows the information of the tubing and packer. This study has two tubing sections: a 3.5-inch OD tubing from surface to MD = 14000 ft and a 2.8-inch OD tubing from MD = 14000 ft to MD = 20000 ft. In addition, this case study contains five packers at a depth of 10000, 16000, 17000, 18000, and 19000 ft, respectively. These hydraulic packers are set with different setting pressures and have different packer performance envelopes. An example of the packer performance envelope is illustrated in Figure 7.

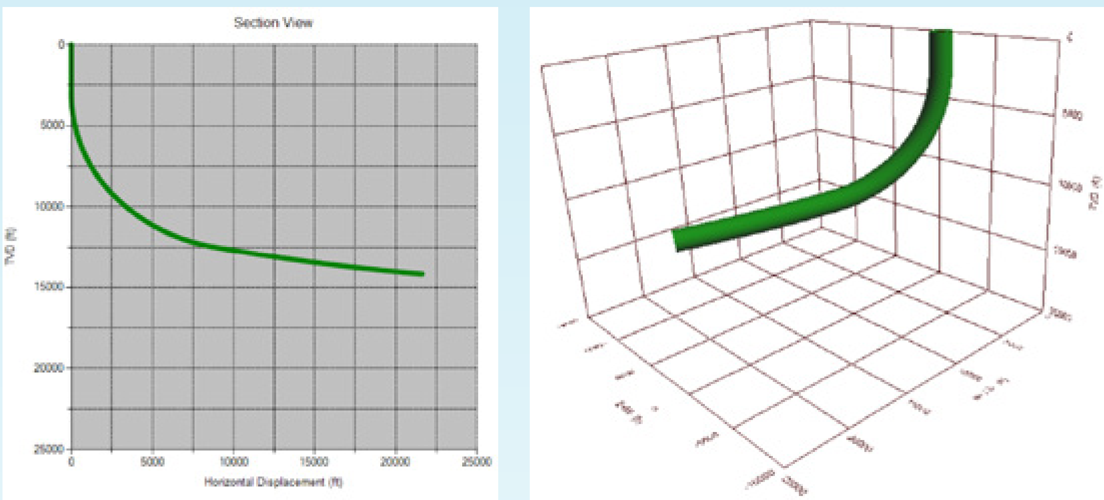
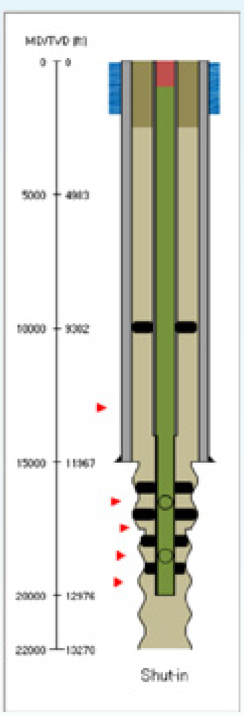


Figure 6: Well trajectory



	Description	MD (ft)	Bore ID (in)	Setting P. (psi)
1	top packer	10000.0	3.500	3000
2	inter 1 packer	16000.0	3.500	3000
3	inter 2 packer	17000.0	3.500	5000
4	inter 3 packer	18000.0	3.500	4000
5	bottom packer	19000.0	3.500	3000

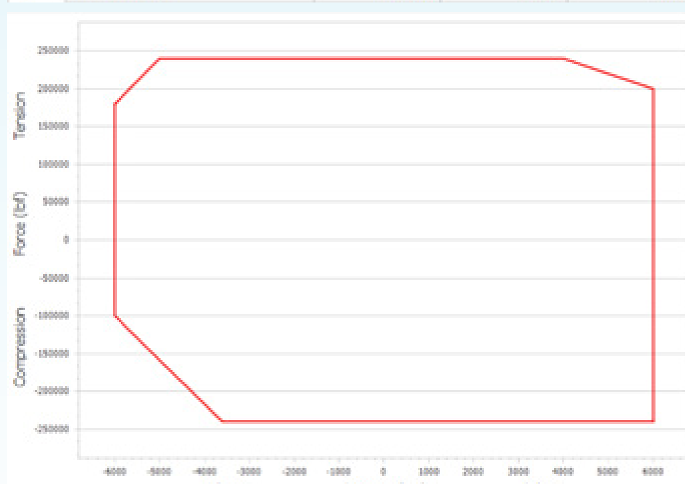


Figure 7: Illustration of tubing and packer information

This case study evaluates tubing failures at seven operations. Figure 8 shows a summary of tubing failure conditions at all operations. This summary table precisely tells whether the tubing section fails or not in the operation and which type of failure it fails. TMPRO evaluates tubing failure in four conditions: tensile, burst, collapse, and von Mises. The corresponding cell in the summary table is marked in red if the tubing section fails. The results show that the 1st tubing section (MD from 0 to 10000 ft) fails in production in the failure mode of burst and von Mises. This tubing section also fails in shut-in and fracturing in the burst failure mode, but it will not fail in other operations.

Other than the summary table for the quick analysis, TMPRO also presents detailed results of tubing movement. Figure 9 shows the tubing movement results for each tubing section and the tubing to packer force exerted on each packer. For instance, the results show that in the shut-in operation, the total tubing movement of the 1st tubing section is -25.251 ft (contraction), and a tensile force of 35431 lb is exerted on the top packer. However, a compressive force of 7856 lb is exerted on the 'inter 2 packer' at MD = 17000 ft.

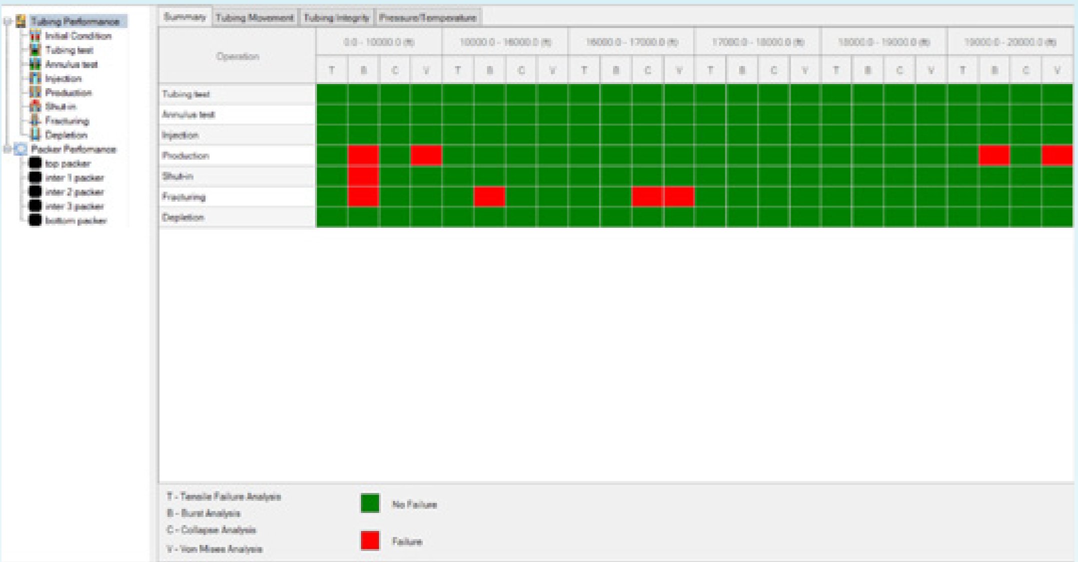


Figure 8: Summary of tubing failure conditions at all operations

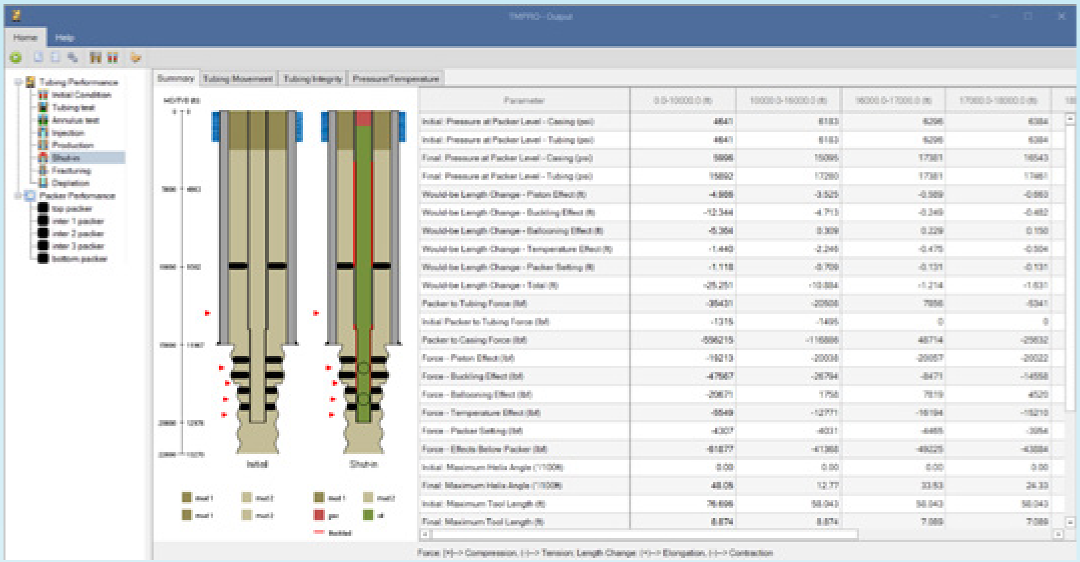


Figure 9: Illustration of tubing movement results in detail

TMPRO also evaluates the packer failure conditions. Figure 10 summarizes the failure conditions for all the packers in all the operations. It shows that the top packer fails in production, shut-in, and depletion, but the ‘inter 1 packer’ does not fail in any of the operations. Figure 11a shows the loading conditions for the top packer. The results show that the pressure differences are about 7500 psi in production, shut-in, and depletion, in which the loading conditions are outside the safe operating conditions, and thus failure occurs. The results suggest that the pressure difference between below and above the top packer is too high. The annulus surface pressure should be increased to prevent damage to the top packer. Figure 11b shows the updated packer loading conditions after the annulus surface pressures are increased from 1500 to 4500 psi in production, shut-in, and depletion. The results show that adjusting the operating conditions could avoid the potential packer and tubing failures.

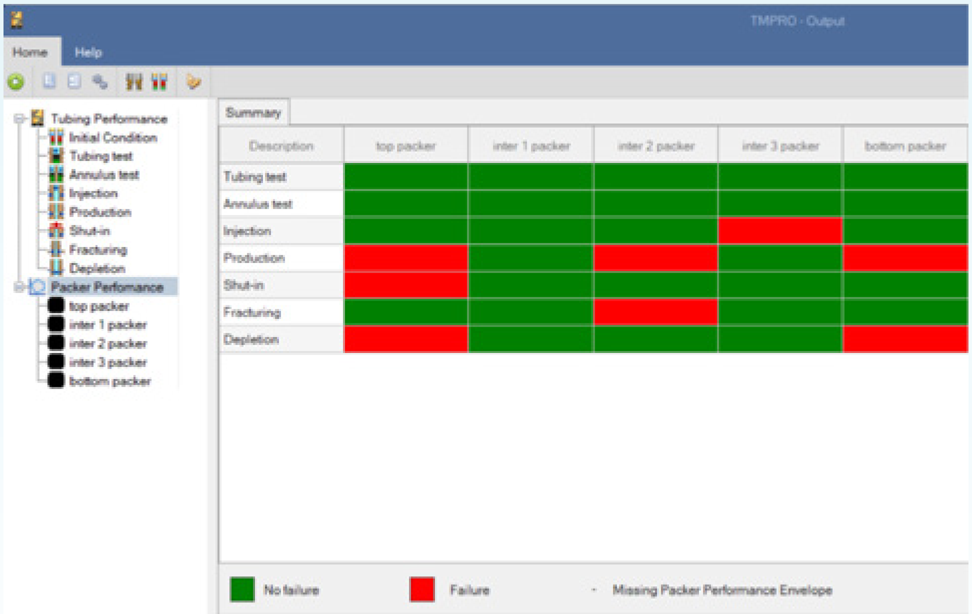
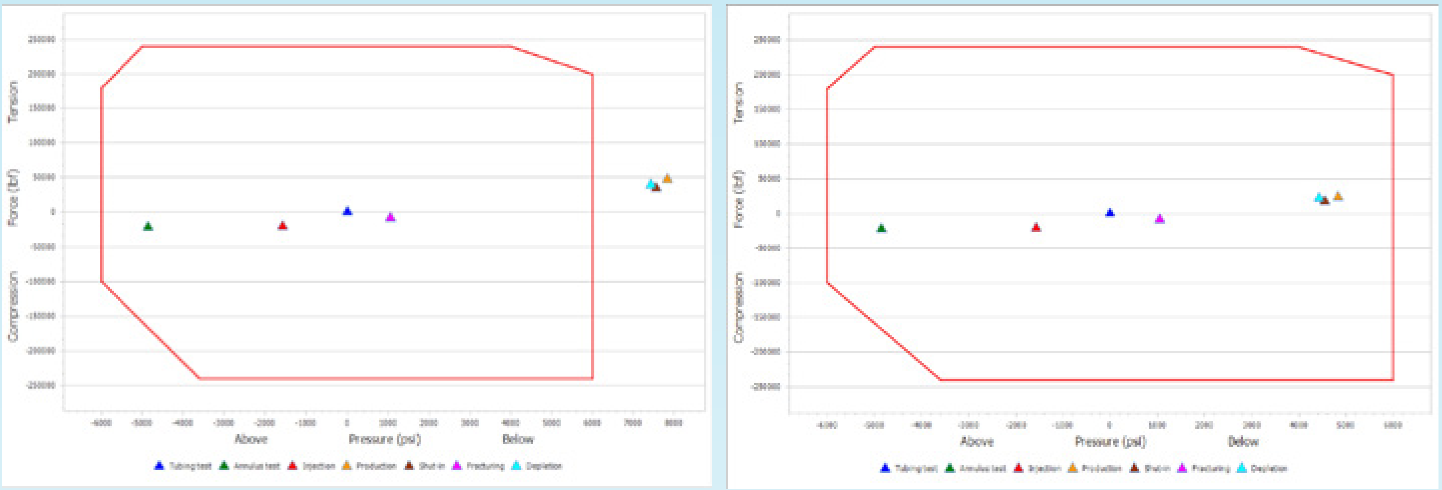


Figure 10: Summary view of packer failure conditions



(a) (b)

Figure 11: Illustration of loading conditions of the top packer: (a) in the initial condition and (b) after increasing the annulus surface pressure from 1500 to 4500 psi in production, shut-in, and depletion.

V. Conclusion

In this paper, we first discussed different types of packers and five effects related to tubing movement and packer to tubing forces. Then, we introduced TMPRO, which can be utilized to evaluate tubing movement and failure conditions of both tubing and packer. At the end of this paper, a case study is presented to show the capability of TMPRO. It shows that TMPRO can be utilized to evaluate tubing and packer failure conditions at various operations. It can simulate both single and multiple packers. In conclusion, TMPRO can be utilized to optimize packer and operation design to avoid potential failures in the field.

For more information on TMPRO or any PVI software models, please contact PVI at:
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