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Analysis and Mitigation of High-Pressure and High-Temperature Well Completion Design of Elkin/Franklin Fields in the North Sea

Luay Hameed Shaheed

Drilling Department, North Oil Company.
Corresponding Author E-mail: luayh80@yahoo.com

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Abstract

The development of High-Pressure and High-Temperature (HP/HT) wells is accompanied by high risk, and still represents one of the greatest technological challenges for the oil and gas industry related to the equipments used and their ability to sustain these conditions. The results analysis of data is key to investigating reasons for bad performances and failures of well completion design and detecting at an early stage potential downhole events.

This paper applies machine learning to the results of real data analysis of deep and deviated well in the HP/HT environment. It presents techniques used to analyze design limits for the tubing string of the well with different rates of production and water injection, and predict pressure and temperature when multiple operations are applied to the tubular string during the well's lifetime. It also analyzes the most important parameters that impact the tubular string, such as temperature effect, safety factors, and tubing length change. A simulation model for a well has been developed to accomplish the objective of this work by using Wellcat™ software modules (Prod & Tube) based on real data from the Elgin/Franklin fields in the North Sea. Two designs of tubular string were used to analyze design limits; the first included a tubing size of 4 ½ in and a latched permanent packer, and the second was identical to the first one but included an expansion joint tool to allow free movement of the tubing, and it was used to mitigate the first well completion design failure. Based on the results of this paper, three load cases (produce-6 months, tubing leak, and water injection) failed in the first design when the rates of oil production and water injection were increased to 12000 bbl/d and 5000 bbl/d respectively, whilst all load cases fell into the triaxial envelope and met the axial criteria in the second design. Furthermore, the predicted results of pressure and temperature for the tubing and surroundings indicate the tubular string could be exposed to buckling problems and serious thermal expansion in the annulus. As well, tubing length can be changed (elongated or shortage) owing to thermal effects during multiple load cases.

Keywords: High pressure and high temperature wells, Completion design challenges, Completion design mitigation, Completion design analysis.

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1. Introduction

The growing demand for oil and gas around the world is driving the exploration and production industry to look for new resources. Some of these resources are located in deeper formations, which present extreme conditions of high pressure and high temperature (HP/HT) environment. Drilling into HP/HT wells is a new frontier for the oil and gas industry. The past decade has witnessed a marked increment in HP/HT projects and numerous HP/HT wells being drilled in several regions of the globe. The top 5 future HP/HT oil fields in the world all reside in the Middle East [1].

According to some studies, wells would be considered HP/HT when they have bottomhole pressures of approximately 10,000 psi and bottomhole temperatures in excess of 300^{o} F [2][3][4]. A very special completion operation is necessary to sufficiently complete and produce these wells. Hence, design conditions should be clearly identified and followed by a risk study to determine the various failure modes [5]. Therefore, companies are working on developing and using high techniques for designing and completing wells by using software to study and predict the future behavior of oil wells during their lifetime to reduce the risk and avoid any expected failure in the future.

Drilling and completion of wells in such high pressure and high temperature conditions is accompanied by high risk and numerous challenges, to cope with these challenges, need to find an appropriate completion design for tubular string, tubing and production packer, makes the well able to produce during its lifetime. In order to reduce production risk and overcome design challenges, we need to understand well behavior during different stages of well production, such as flowing and shut-in for short and long production periods, and that can be achieved by using good tools to predict the most effect parameters on the completion and to avoid possible failures in the tubing and production packers.

Drilling in HP/HT formations experiences the wells to severe stress due to an extreme combination of pressure and temperature. This represents the main effect on the well's completion integrity. So, finding the best well design is an important factor to cope with any possible future failure in the completion design during the well's lifetime.

1.1 HP/HT Well Classifications

There are ongoing efforts to establish standard HP/HT definitions [6]. In general, most companies categorize HP/HT operations into three tiers with different ranges of pressure

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and temperature, as shown in Figure (1) and Table (1). According to Courtesy of Schlumberger, the HP/HT operations are classified into three main tiers. Tier I, Tier II and Tier III, Extreme HPHT, which represents the greatest challenge of technology in HP/HT drilling.

Table (1) HP/HT Tiers, courtesy of Halliburton [1].

Category	Borehole Temperature	Borehole Pressure, psi
HP/HT	>300^{o} F - 350^{o} F	>10,000 psi -15,000 psi
Extreme HP/HT	>350^{o} F - 400^{o} F	>15,000 psi -20,000 psi
Ultra HP/HT	>400^{o} F and above	>20,000 psi and above

Whatever the differences in HP/HT definitions among various companies, there are still risks and challenges in such environments, and they need more advanced drilling operations and innovations, despite the fact that HP/HT wells constitute a small percentage of drilled wells compared with oil and gas wells that have been drilled today around the world.

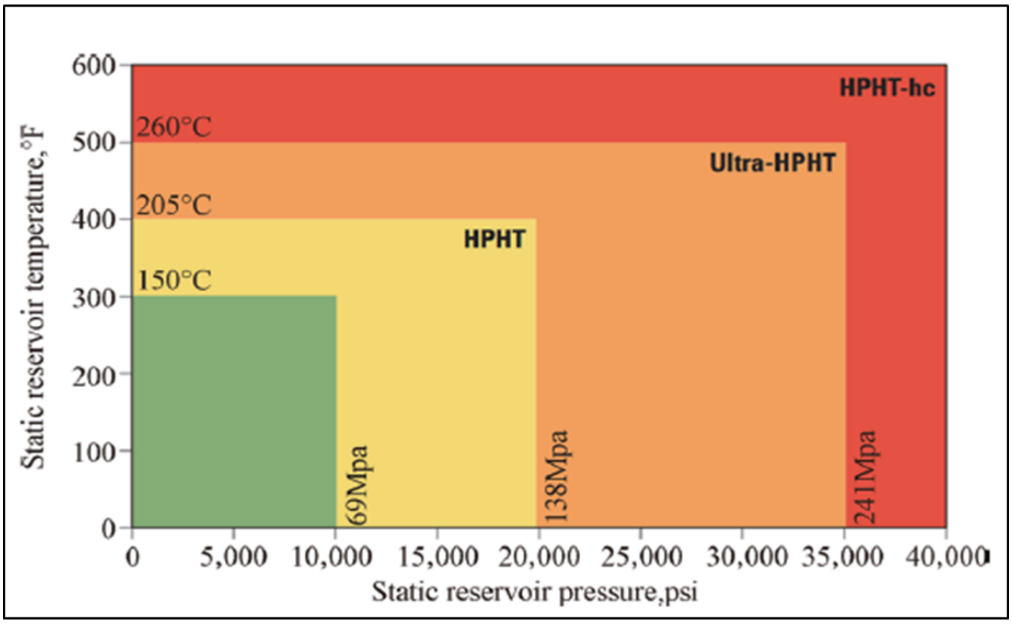

Fig. (1): HP/HT Tiers, courtesy of Schlumberger [7].

1.2 HP/HT well Challenges

The development of HP/HT wells still represents one of the greatest technological challenges for the oil and gas industry because of the difficulty of monitoring down- hole pressures and temperatures. According to some studies, the technological challenges

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associated with the completion and designing of wells at and above these conditions are diverse and continue to increase [8] [9].

Drilling and completion operations in HP/HT wells are accompanied by a number of risks and challenges, some are technical reasons related to the equipment used and their ability to afford the conditions of high pressure and high temperature and the other reasons are related to the problems that can be faced during drilling of the formations.

During well life production, complex loading conditions might happen due to different scenarios, such as warming tubing during production operations, or due to applying stimulation processes to enhance well production, for example, acidizing processes and steam- assisted gravity drainage (SAGD). Therefore, in possible complex loading conditions, the well design in HP/HT environments must be met with high integrity in order to carry under these diverse scenarios. If the well loading conditions exceed the design characteristics of the equipment, catastrophic consequences can ensue and the well could be lost [10]. The most common challenges during production operations will be discussed in detail in this study.

1.3 Elgin and Franklin Extreme-HP/HT Fields

Elgin and Franklin fields present HP/HT accumulations (15950 psi initial pressure and 390oF, respectively) and are considered the largest HP/HT fields developed in the UK sector of the North Sea. The fields are located approximately 200 km northeast of Aberdeen in the Central Graben area [11] as indicated in Appendix-Figure (1).

Franklin field was discovered in 1986 and Elgin field in 1992, Elgin/Franklin became the world's largest HP/HT development in the world. The Jurassic sand reservoir lies at 5300 m below sea level, at a water depth of 92 m [12]. The first oil production took place in 2001 and the reservoir pressure depletion was very quick initially (reduced to 1450 psi per six months).

2. Well Path and Tubular String Design

The well path, casing configuration, and completion design are based on real data available from the Elgin/Franklin exploration and appraisal drilling program to fulfill the necessary elements for designing an integrated production well. The Prod and Tube modules of Wellcat^{TM} from Landmark would be used to analyze tubular string design. Prod module is a thermal and pressure simulator [12]. It's been applied to simulate fluid

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flow and heat transfer in the tubular string and wellbore during production, and water injection processes. In this module, different operations are applied, such as; cleanup, pull work string/run tubing, initial production, multiple shut-in of the well, production for different time periods, and water injection in case the pressure is depleted in the well.

Tube module can be used to analyze differential pressure as a function of depth for one or different load cases. This feature is used to know which loads have the most effect on the burst and collapse criteria. Furthermore, the tube module is used to investigate tubing length change due to various factors, such as thermal, ballooning, Hook's law, buckling, and total length change [12].

The tubular string includes tubing and a production packer. The next discussion in this section will show the effects of different tubular string designs on the load cases that the well may be exposed to during its lifetime. In this project, two designs have been adopted for the tubular string, as indicated in the following:

- ***Design # 1:*** In this design, the well was completed without an expansion joint tool with a tubing size 4 ½ in (23.7 ppf, N-80) and a latched permanent packer, well schematic and tubing specifications as indicated in Appendix-Figures (2).
- ***Design #2:*** This design provides an expansion joint tool within the tubular string. The Expansion joint tool is located above the permanent production packer. It has significant importance in reducing tubing length changes during production and water injection operations. Design # 2 has the same size and configuration as design # 1, and the well schematic is as indicated in Appendix-Figure (3).

3. Design Limits of Tubular String

Based on the results of the tube module, two scenarios were used to analyze the effects of multiple operations on the tubular string of design #1, with different production rates and injection rates. The following discussion will outline the proposed scenarios:

- ***Scenario # 1:*** In this scenario, the initial oil production rate was 7000 bbl/d for the cleanup load (initial oil production) and 8000 bbl/d for produce - 6 months' load; both of these values were defined in the proud model loads menu. For the steady state production load of the tube module, the oil rate was 8000 bbl/d, and the water injection value was set at 4000 bbl/d. It's defined in the prod module and linked to the tube module.

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The Design limits plot with different loads for scenario # 1 is shown in Figure (2). The plot indicates that all load cases fall within the triaxial envelope and meet the applied criteria, except tubing leak, which fails the compression criteria, and water injection, which is the worst case because it fails both the triaxial and tension criteria.

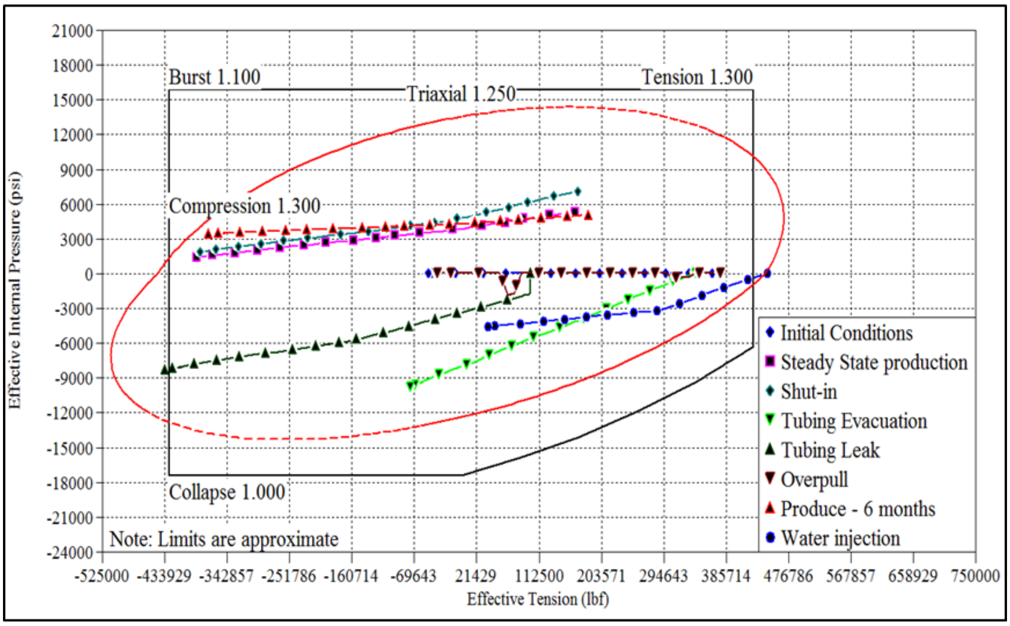

Fig. (2): Design limits with different loads, Scenario #1.

Scenario # 2: The same procedure as in scenario # 1 would be used for the input data of load cases. The production rate value was 10000 bbl/d for the cleanup load (initial oil production) and 12000 bbl/d for both produce-6 months' load and steady state production

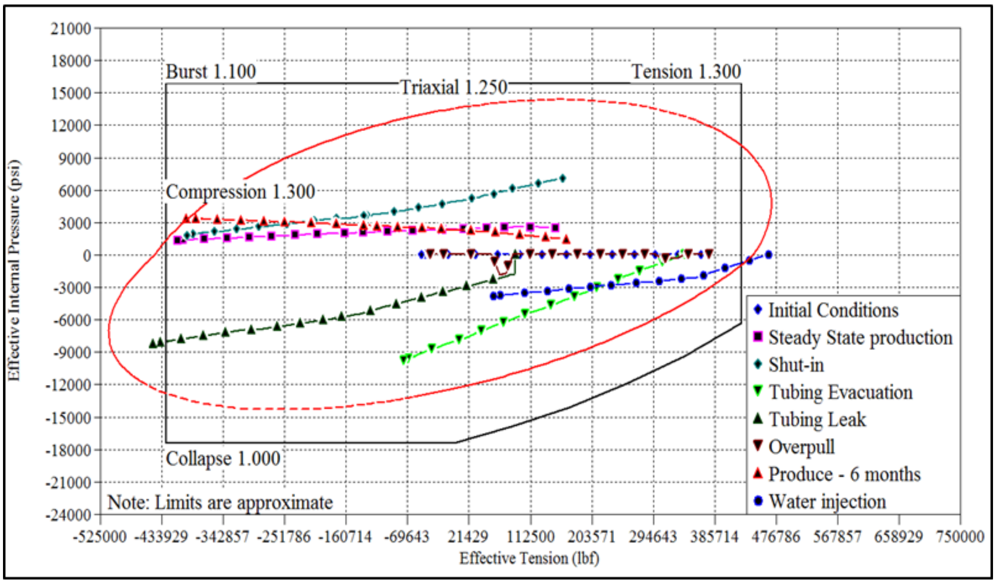

Fig. (3): Design limits with different loads, Scenario #2

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load. As for the water injection rate, it was 5000 bbl/d. Figure (3) shows the worst-case scenario, in which three of the load cases failed to meet the design limit criterion. Produce-6 months fails the triaxial criteria in this scenario, and the tubing leak exceeds the compression limit. This is the worst case tension for water injection because it fails the tension and triaxial criteria. Obviously, from the last two scenarios, the increase in production rate (> 8000 bbl/d) and water injection rate (> 3000 bbl/d) lead to failure of some operations at the tubular string's design limits.

4. Mitigation of Load Cases Failure

Based on the previous results, scenario # 2 was presented as the worst scenario because the tubular string design is no longer able to achieve the unaxial and triaxial criteria. In order to mitigate the load case failure, in the worst scenario, the tubular string of design # 2, expansion joint tools would be applied to scenario # 2 with the same input parameter which failed previously with design # 1.

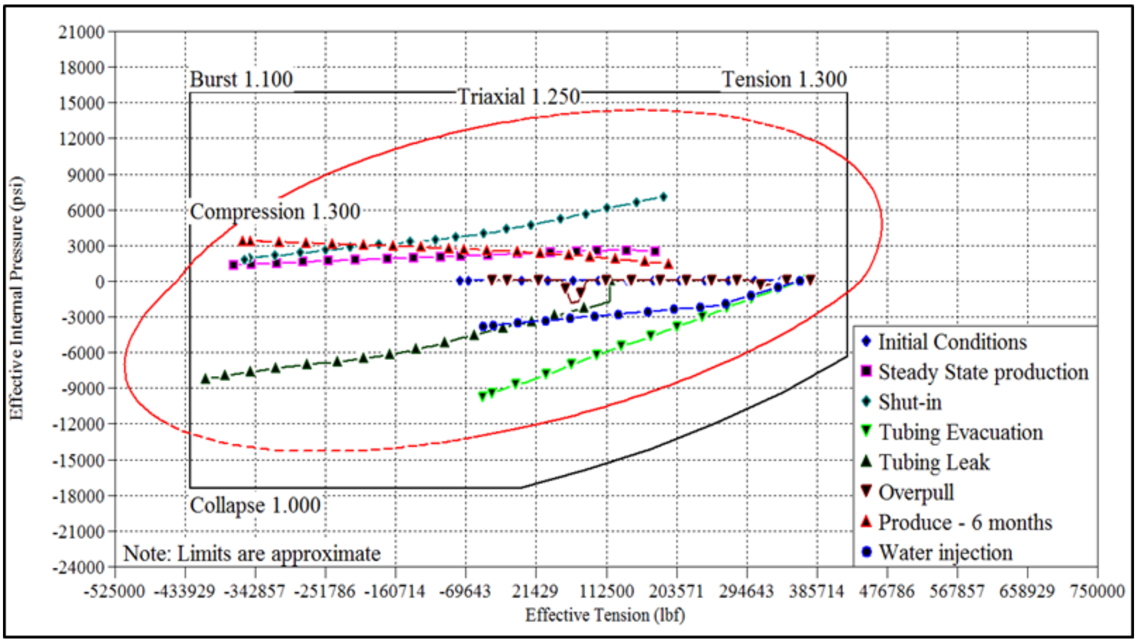

Fig. (4): Design limits for scenario #2 with Expansion Joint.

The results obtained in Figure (4) show the optimum scenario for load cases because all load cases fall within the triaxial envelope and meet the axial criteria. Furthermore, the use of the Expansion joint tool with design # 2 helps to give free movement to the tubing string, eliminating the impact of tubing length changes caused by production and water injection operations.

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5. Pressure and Temperature Prediction

Prod module would be used to predict pressure and temperature profiles with different load cases applied to the tubular string by using the worst scenario that was obtained previously, the worst load cases happened in scenario # 2, so this scenario would be used to analyze tubular string load cases and discuss in detail with graphs the failure reasons of the applied load cases in the design limits criteria. Results of prod module include the fluid temperature and wellbore temperature with measure depth for each load cases as indicated in the following.

5.1 Wellbore Temperature Analysis

The results of tubing temperature, all well casings, fluids of tubing and all casings annuli can be obtained from the tube module as indicated in Figure (5). At the end of 6 months' production, all the casings except the 30" casing at a depth of 3000 ft. were heated above 260° F. Buckling problems and serious thermal growth can take place due to a large increase in the temperature of the casing strings. Furthermore, incrementing the temperature of the trapped fluid in sealed annuli can lead to severe pressure increases for

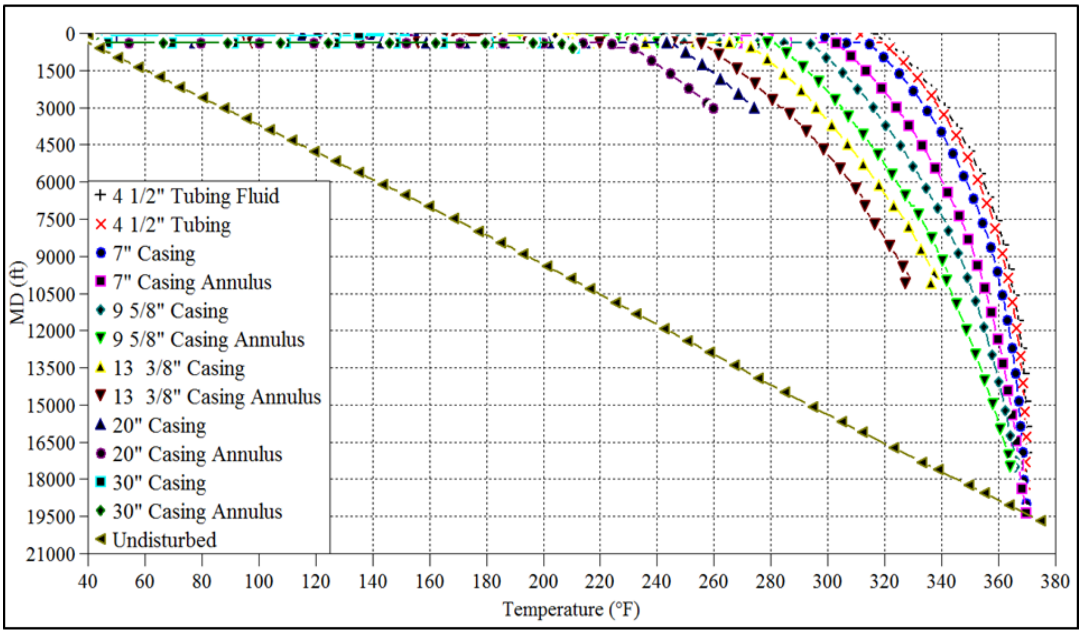

Fig. (5): Wellbore temperature for produce- 6 months' operation.

the trapped fluids, hence the annular volume is changed due to thermal expansion of the annulus fluids in the uncemented regions of the annuli and the compression of the inner casings. As a result, annular volume change due to thermal expansion of wellbore fluids

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can lead to undesirable consequences. In HP/HT wells, different strategies can be utilized to alleviate annular pressure effects, such as; allowing annular pressure to leak path to the weak formation by uncementing the previous casing shoe, using burst disks in the casing, or nitrogen based spacers (compressible gas), etc.

5.2 Fluid Temperature Analysis

Figure (6) shows a comparison of fluid temperatures inside the tubing for the production operations (cleanup and produce - 6 months), water injection, and displace to brine. It appears from the figure that, the fluid temperature for the fluid production operations is the same at the end of the tubing (near perforation), while there is a difference in the temperature of the fluid at the wellhead. Six months of production generates about 15^{o} F flowing wellhead temperature more than a cleanup operation (two days of production).

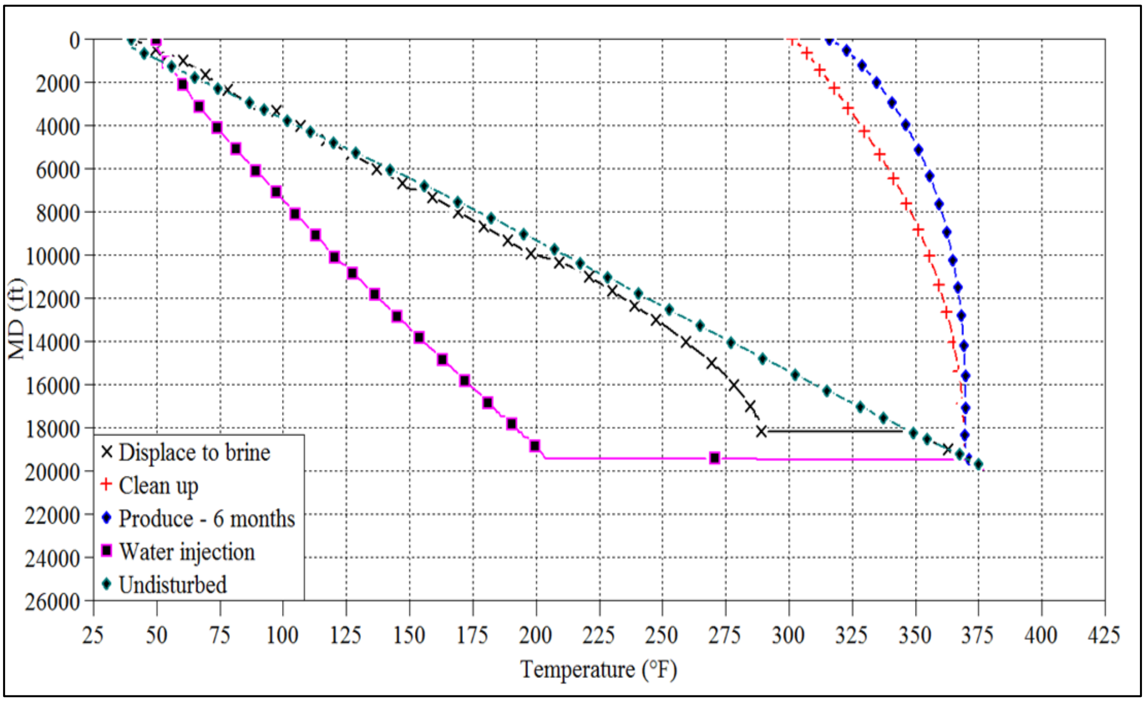

Fig. (6): Fluid temperature for production and injection operations.

As well, there is a significant decrease in wellbore temperature (> 180^{o} F) due to the water injection process, whereas there is less decrease (90^{o} F) with displace to brine. Although both the displacing to brine and water injection processes are considered cooling operations for the wellbore, you can notice from the plot that there is a significant difference in temperature at the end of the tubing because the displace to brine operation involves circulating seawater in the well to displace drilling mud and clean the wellbore from the remains of cutting, while the water injection operation involves injection of water into the formation and that significantly reduces the bottom wellbore temperature. For one day of the water injection process, a considerable decrease in wellbore temperature (> 180° F) occurred, and more decrease in wellbore temperature could occur if the water injection is continued for a longer period.

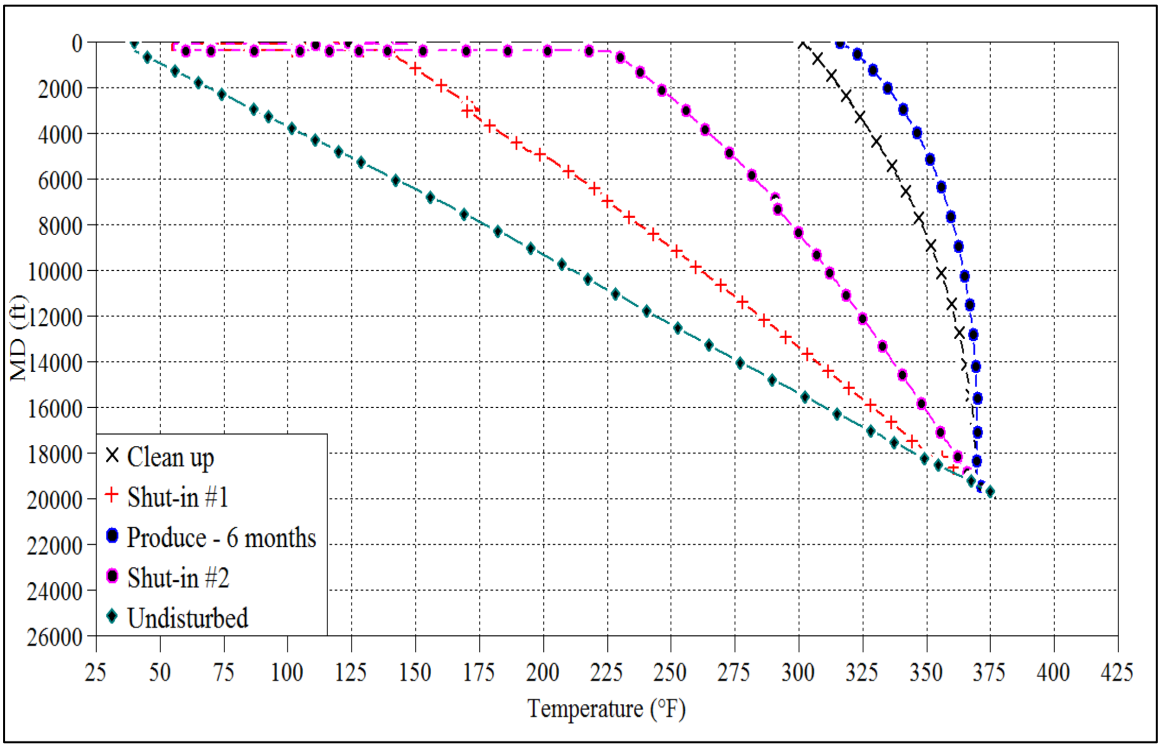

Fig. (7): Fluid temperature for production and shut-in operations.

Figure (7) displays a comparison of fluid temperature inside the tubing for shut-in # 1 after two days of production (cleanup operation), and shut-in # 2 after long-term production (produce- 6 months). It appears from the figure that the wellhead temperature in shut-in # 2 is about 90° F hotter than in shut-in # 1, due to 6 months of production before shut-in # 2, and the change in temperature decline at the wellhead between the cleanup operation and shut-in # 1 is 165° F, whereas the difference in temperature drops for a second production period (produce- 6 months) and shut-in # 2 is 85° F.

From the comparison between the two shut-in periods, we can see that the temperature drop after a short period of production (cleanup) is about double the temperature drops after a long time of production (produce - 6 months), even though the two shut-in periods

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are equal (for one day), and that means regardless of the wellhead temperature difference between the short and long production periods is 15° F, but still the difference between shut-in # 1 and shut-in # 2 is 90° F at the wellhead. During shut-in # 2, the production tubing string experiences high temperature at the wellhead (225°F), and hence the tubing string is exposed to the threat of buckling problems and serious thermal growth within this load case.

5.3 Safety Factors Analysis

Safety factor plots for the water injection process and tubing leaks will be analyzed because both of these two load cases failed in scenario # 2. The water injection process failed with tension and triaxial criteria, while the tubing leak load exceeded the compression limit. The absolute or normalized axial, burst, collapse, and triaxial as a function of depth are represented by the results of safety factors acquired from the tube module. During the water injection procedure, Figure (8) shows the applied and actual design factors for tubing string.

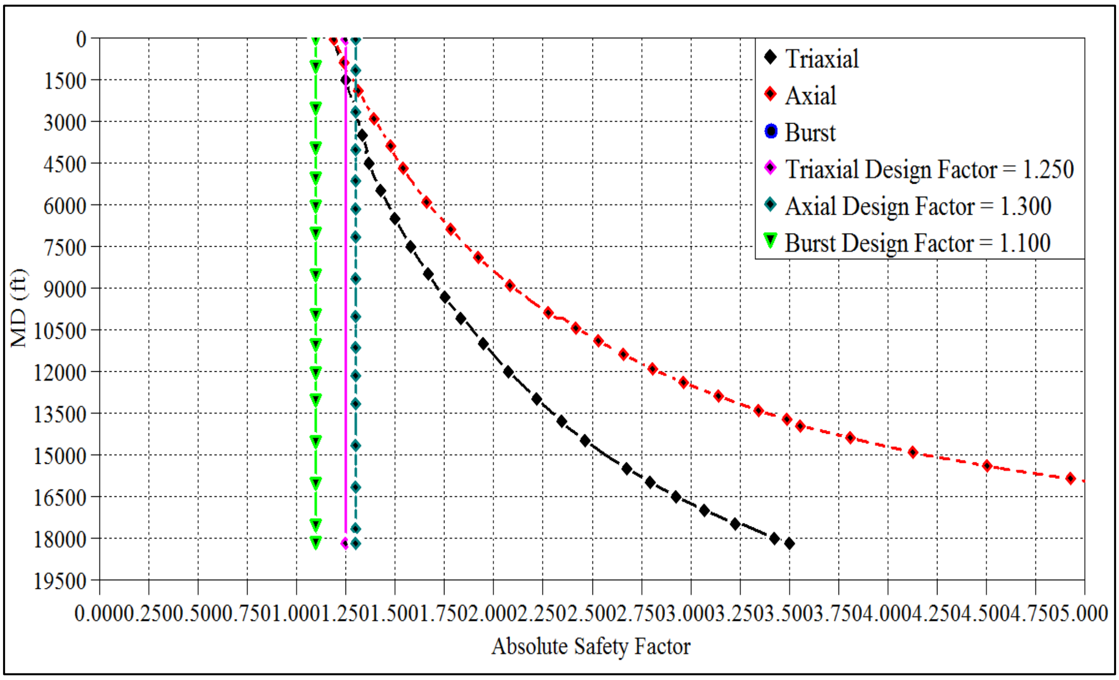

Fig. (8) Safety factors for water injection process.

The vertical lines represent the applied design factors and the value of them as shown in the legend of the plot, whilst the curves (red & black) represent the actual case for triaxial and axial criteria during the water injection process. It seems from the figure that the

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water injection operation fails the axial design factor beyond 2000 ft, and the triaxial design factor becomes less than the applied triaxial criteria for the water injection load above 1000 ft.

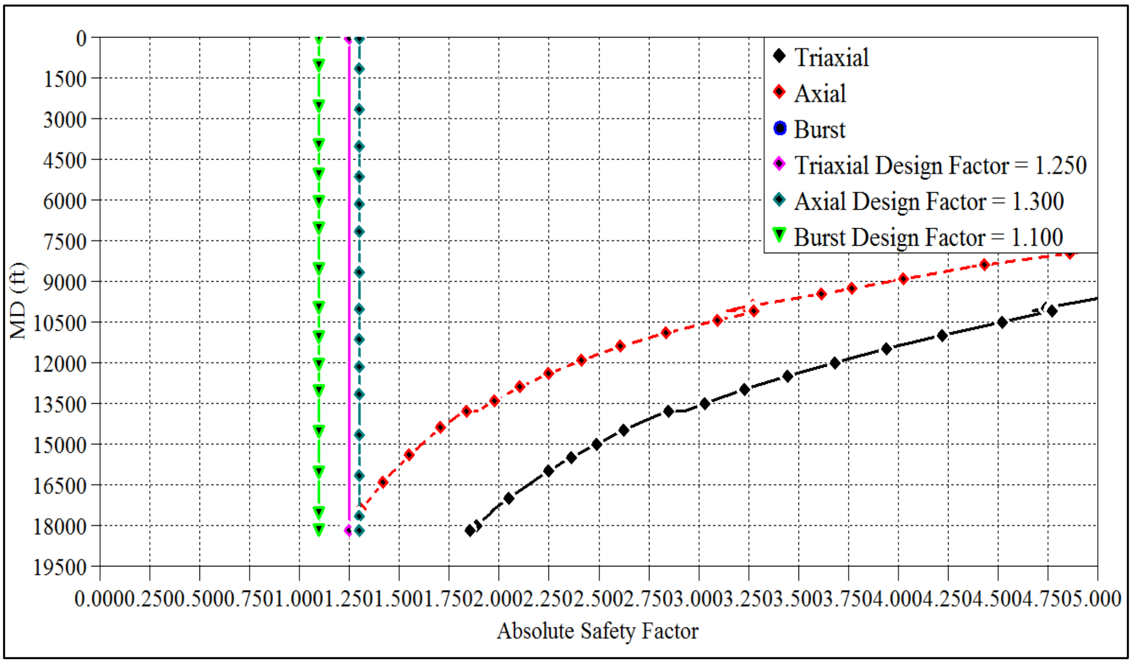

Fig. (9) Safety factors for tubing leak.

Figure (9) shows the safety factors for a tubing leak load case as a function of depth. It appears in the figure the axial design criteria for tubing leak fails the axial design factor below 18000 ft, and that means the expected tubing leak can be occurred at the packer (18200 ft) because the tubing leak load is linked to shut-in load and the pressure is 11000 psi near production packer in this case.

5.4 Tubing Length Change Analysis

The changing of tubing length can be obtained from the results menu of the tube module for multiple loads. The results of tubing length change represent variety of factors, such Hook's low, buckling, ballooning, thermal, and total length change for the tubing string. Figure 10 displays the tubing length change from the surface to the end of 4 ½ in. tubing (18200 ft.). The maximum tubing length change occurs during steady state production, shut-in, tubing leak, and produce - 6 months due to high temperature and high pressure of the hydrocarbon. During tubing evacuation and overpull/run tubing operations, the tubing length does not change because production fluids have not yet been started. The negative

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value, as seen in the figure, indicates to a reduction in the tubing length that occurs only during the water injection process due to tubing compression. However, the water injection operation cools the tubing, leading in a tubing length shortage.

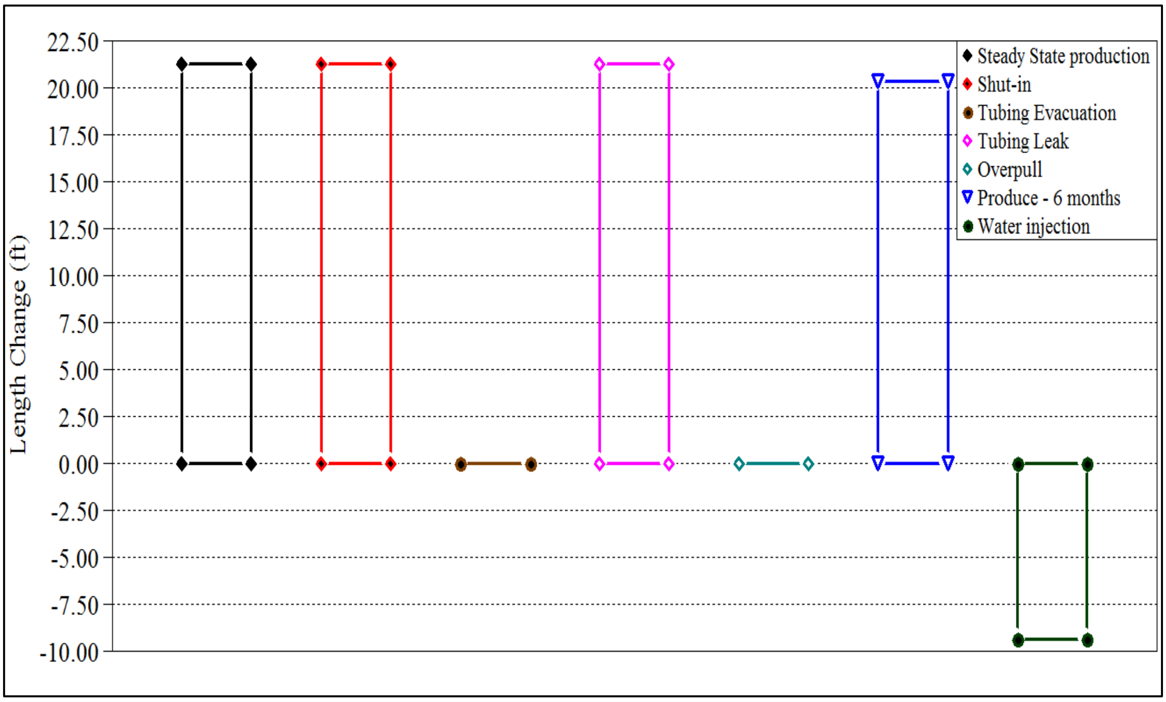

Fig. (10) Tubing length change bar for multiple load cases.

6. Conclusions

An overview of different operations that impact on the tubular string of a specific design for deep and deviated well in HP/HT conditions have been investigated by using Prod and Tube modules to analyze and mitigate well completion design. Based on the previous results and discussion, we can conclude that:

1. When the production rate and water injection rate are increased to 12000 bbl/d and 4000 bbl/d, respectively, the design limits of three applied operations (produce-6 months, tubing leak, and water injection) on the tubular string fail, and this failure can be mitigated by using an expansion joint tool with the tubular string design.
2. During produce-6 months operation, the tubing and most of the casing strings are heated above 260^{o} F at a depth of 3000 ft. As a result, buckling issues and serious

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thermal growth in the annulus could ensue due to a significant temperature increase.

3. The difference in temperature reduction at the wellhead from the short period of production (cleanup) to the shut-in # 1 is about 160^{o} F, double of the difference in temperature reduction in shut-in # 2 after produce-6 months (85^{o} F), i.e. at the same shut-in times but with different production periods, the temperature reduction is different. That means, even if the well is shut-in the effect of temperature on the tubular string after a long production period will continue.
4. The axial design limits of tubing leak load case are failed with axial design criteria below the depth of 18000 ft. Consequently, the expected tubing leak in the tubular string will be at the production packer.
5. Thermal effects of the produced fluids cause the most tubing elongation, while Hook's law causes the most tubing shortage. That means, the maximum tubing movement can occur due to these loads.

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APPENDIX

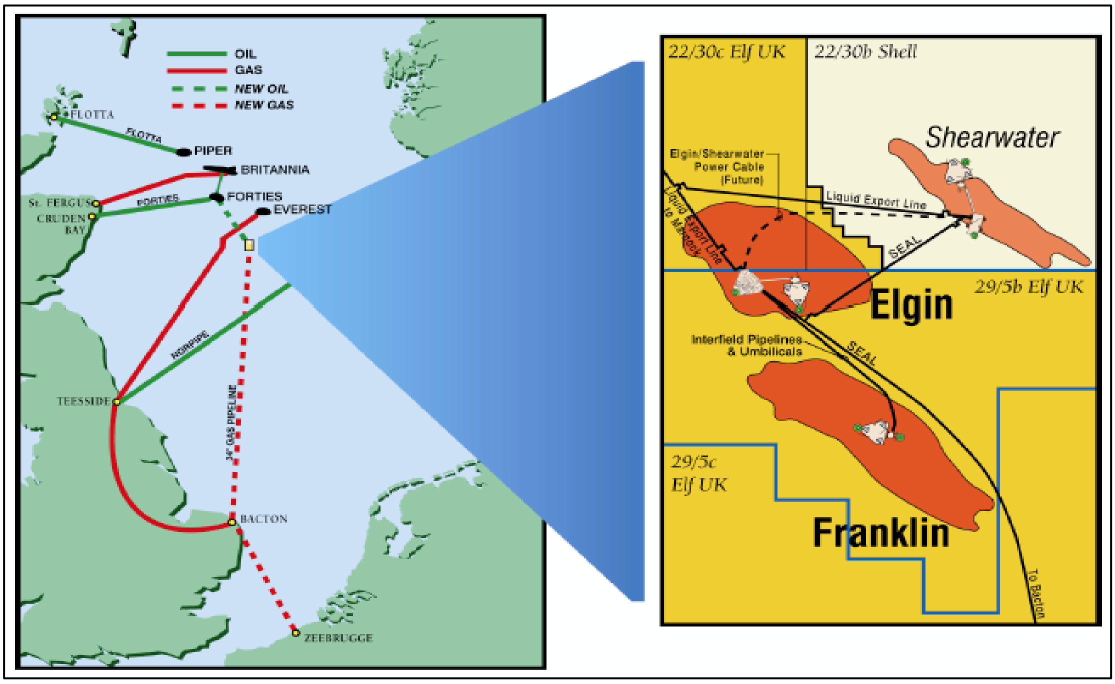

Fig. (1) Elgin and Franklin Fields locations [13].

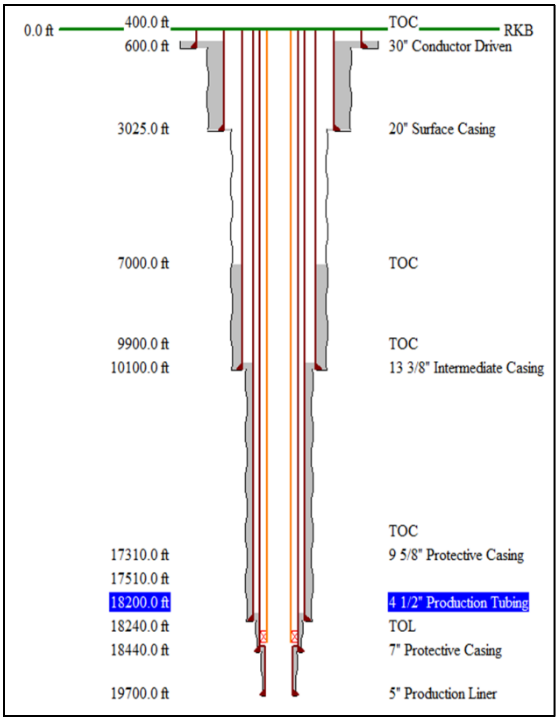

Fig. (2): Well schematic of design #1.

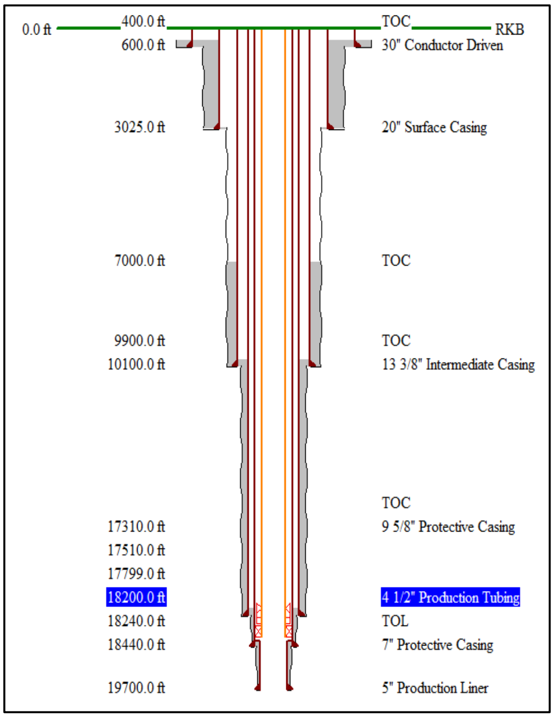

Fig. (3): Well schematic of design #2 (with Expansion Joint)