PROCEEDINGS, 50th Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 10-12, 2025
SGP-TR-229

Evaluation of Well Completion Configurations for Supercritical Geothermal Wells

Isabella OSORIO ACOSTA, Elvin ALLAHVERDIYEV, Eduardo Andres PABA VEGA, Khizar ABID, Catalin TEODORIU

Mewbourne School of Petroleum and Geological Engineering, The University of Oklahoma, Norman, OK, USA

cteodoriu@ou.edu

Keywords: geothermal energy, well completion design, supercritical, tubular integrity, steam production/injection.

ABSTRACT

As society moves toward a more sustainable future, geothermal energy emerges as a viable long-term solution with its strong potential to reduce the carbon footprint. Numerous studies focus on locating geothermal reservoirs and utilizing this energy as an alternative to fossil fuels. Simultaneously, the industry works toward standardizing high-temperature technologies crucial for downhole geothermal completions. The design of downhole completions for geothermal wells faces many challenges, especially regarding well integrity under high-pressure high-temperature (HPHT) conditions. These factors necessitate careful well planning and tubular design. A lack of tubular integrity can lead to serious personnel injuries, well integrity issues, high re-completion and workover costs, and environmental risks. Achieving a balance between well integrity throughout the life of the well and minimizing completion costs is essential. Proper selection of tubular strings, verification of connection integrity, and optimization of downhole completions are key components of completion design to avoid costly workovers.

Completing geothermal wells requires critical design considerations to optimize thermal energy extraction and maintain reservoir integrity. This study evaluates geothermal well completions in three different configurations using casing and tubing design software, i.e., tubing with packer, tubing with packer and expansion joint, and tubingless. The results of these sensitivity studies allow conclusions to be drawn about which completion configuration performs best for supercritical geothermal wells.

1. INTRODUCTION

Supercritical geothermal wells push the limits of engineering, using extreme underground conditions to produce renewable energy. Therefore, the completion of these wells tends to be challenging. This study compares the conceptual design employed in three supercritical geothermal well completion configurations. The purpose is to provide a deeper understanding of how engineering solutions are created for specific operational needs while addressing the demands of extreme thermal and mechanical conditions associated with each.

With the energy sector evolving, the environments where the wells need to operate evolve, too. Supercritical geothermal wells are constructed into one of the most extreme conditions on Earth, where temperatures exceed 406℃, and pressures are higher than 4,322 psi. Sometimes, even targeting volcanic reservoirs that exceed the conventional limits. These wells offer a vast, renewable energy potential. Still, they also demand that engineering challenges be resolved where severe thermal expansion, corrosive fluids such as H_2S, and long-term durability under repeated thermal cycling dominate. Supercritical geothermal wells require tubular materials that withstand corrosive and ultra-high temperature conditions.

This study explores tubular selection, thermal expansion, stress tolerance, and safety factors to show the innovative strategies that make these completions viable in their applications. The research tries to answer the question of which completion designs simulated for supercritical geothermal wells perform the best, how they differ, and what engineering principles are shared from these designs. The study contributes a clear understanding of operational challenges in extreme conditions by comparing the corresponding tubular designs. The results are relevant to these well types in particular and provide a base for improving thermal well completion practices, from geothermal exploration to unconventional oil recovery.

2. LITERATURE REVIEW

Typically, geothermal reservoirs are considered to be in HT (high-temperature) conditions. These conditions lead to problems during drilling and completion operations, including equipment failure and well construction material deterioration (Baena Velasquez et al., 2024). That is why conventional well construction is unsuitable for all geothermal projects in terms of safety and lifetime. Well design engineers must carefully select casing materials, tools, joints, and tubular thicknesses to withstand stress during drilling and production, ensuring optimal completion and a full well life cycle without integrity issues. (Hole 2008a).

The correct material selection is one of the most important aspects of designing a geothermal well. An incorrect selection of the material can have financial implications and has the potential to create well integrity issues due to string failure. (Zeringue, 2005). The main challenges of material selection include testing and qualification of high-strength carbon steels able to withstand pressures, temperatures, and harsh environments. Furthermore, challenges include designing the Ultra High-Pressure High-Temperature (UHPHT) connection for casing and tubing, managing the large differential pressures on casing, tubing, and packer, and high costs of alloys for UHPHT applications (Zeringue, 2005).

Corrosion in geothermal wells is another important challenge. It occurs when the casing, tubing, and couplings deteriorate due to the interaction with the geothermal fluids. Corrosion will depend on the fluid's chemical composition, temperature, pressure, and flow rate. Geothermal fluid is a multiphase mixture of several salt solutions and dissolved gas. These fluids may contain mercury, arsenic, and boron (Khasani et al., 2021).

According to API, the specified minimum yield strength (SMYS) is the amount of stress a material can withstand without suffering from plastic deformation and is used to classify the pipe. A reduction in the yield strength will directly impact the casing load ratings, such as burst, collapse, and tensile strength (Torres, 2014).

Another challenge faced by the downhole tool in the geothermal well is the HPHT condition. Nonetheless, some companies have designed downhole packers capable of working under HPHT conditions specific to the geothermal environment. For example, Welltec Inc. designed two downhole tools specially for HPHT conditions to be deployed in geothermal wells.

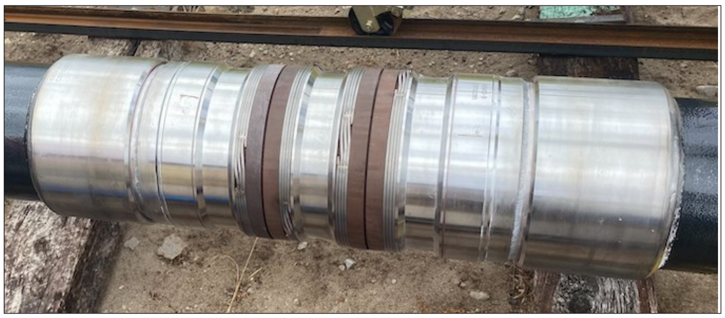


Figure 1. HPHT packer from Welltec Inc. Packer capable of withstanding 320℃ and designed to expand and set at 6,000 psi with a maximum run in hole ID of 8.42" (Álvarez et al., 2024).

Figure 2. Flow valve suitable for geothermal systems. Operating temperature of 260℃ and pressure of 6,000 psi (Baena Velasquez et al., 2024).

3. METHODOLOGY

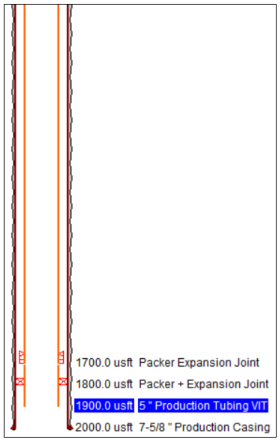
The methodology was based on producing high-temperature steam at 666°F from the supercritical geothermal well using a bottom-up approach and injecting steam at the same temperature to a SAGD (i.e., steam-assisted gravity drainage) well top-down for comparison purposes. The simulations were done using tubular design software.

Table 1 presents the design factors used for the geothermal well, although NZS 2403: 2015 suggests using a 1.8 design factor (DF) for the axial tension and compression in geothermal wells. However, these values can only be assumed when the tubulars are sourced from reputable manufacturers with tighter tolerances.

Table 1. Chosen DFs for the supercritical geothermal well.

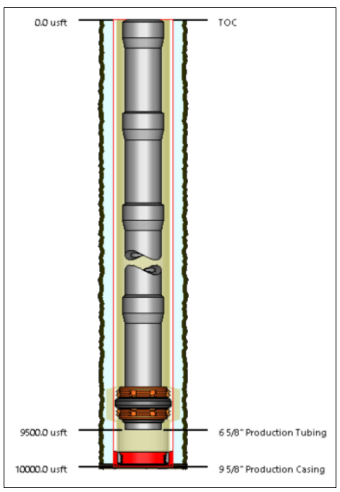
Design Factors	Pipe Body	Connection
Triaxial	1.25	
API Burst	1.5	1.5
API Collapse	1.2	
Axial Tension	1.6	1.6
Axial Compression	1.6	1.6

Detailed service-life operations for the SAGD and supercritical geothermal (SG) wells have been simulated and found in Figures 3 and 4. Fictitious data were used for these wells and operations. Production tubing with a packer and expansion joint was also adopted for the supercritical geothermal well, in addition to the tubingless completion. For the SAGD well, vacuum-insulated tubing (VIT) was simulated with a packer and expansion joint.



Operations	Inlet Temperature, °F	BHP, psi	Duration
Run Tubing	80		1 day
CH4 Production	125	3500	1 year
Post-Prod Shut-in		3500	1 day
Post-Prod FW Injection	125	1805	1 day
Post-Inj Shut-in		1864	1 day
DSteam TA Circulation Warm-up	533	1530	1 day
WSteam TA Circulation	533	928	1 day
Shut-in after WSteam Circulation		1687	1 day
WSteam T Injection	666	2643	1 day
Shut-in after WSteam Injection		1687	1 day
Heavy Oil Production	125	2000	1 year

Figure 3. SAGD well completion design (left) and assumed service-life loads (right).



Operations	Inlet Temperature, °F	BHP, psi	Duration
Run Tubing	80		1 day
Minifrac Pump-in	80	7500	1 hour
Minifrac Shut-in		7250	1 hour
Minifrac Flowback	666	4750	1 hour
DFIT Pump-in	80	8250	1 hour
DFIT Shut-in		7500	1 hour
DFIT Flowback	666	6000	1 hour
Stage Pump-in	80	9250	2 hours
Stage Shut-in		7750	1 hour
Stage Flowback	666	5000	1 hour
Hot Production	666	4750	1 month
Hot Shut-in		4750	30 minutes
Quenching	50	8250	8 hours
Cold Shut-in		7250	30 minutes

Figure 4. Supercritical geothermal well completion design (left) and assumed service-life loads (right).

4. RESULTS

4.1 Supercritical Geothermal with Tubing Completion

An expansion joint was incorporated into the tubing to manage the thermal expansion and contraction presented in geothermal wells. The expansion joint needs to be without elastomeric seals, as elastomers are unreliable under geothermal conditions due to their tendency to leak. They typically cannot work under extreme geothermal conditions.

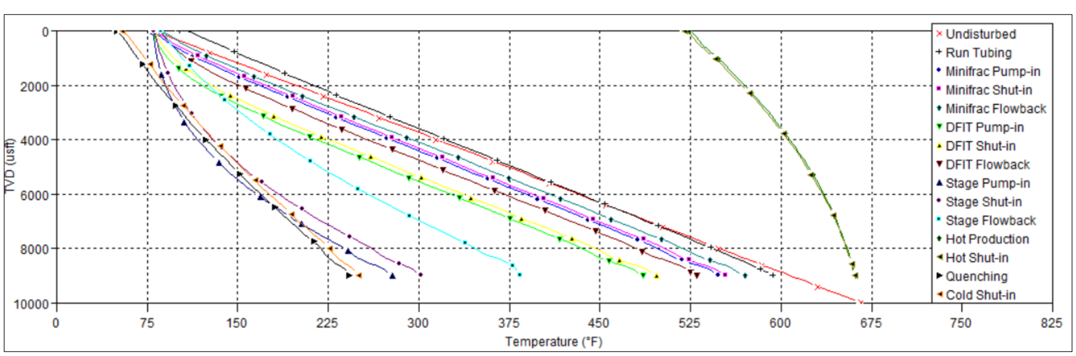
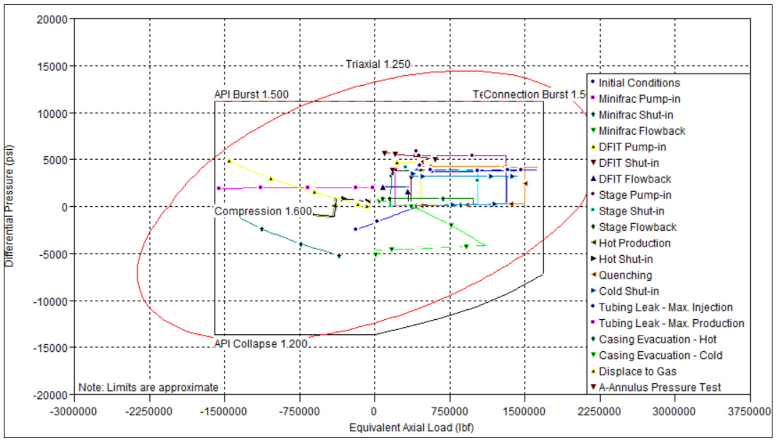


Figure 5. Tubing life-of-well temperature distribution in the supercritical geothermal well.

The temperature profile presented in Figure 5 belongs to the life-of-well scenario. It can be seen that the extreme temperatures belong to quenching or (stage pump-in) at the low end and hot production (or hot shut-in) at the high end. During hot production, the predicted temperature losses suggest that surface temperatures are around 525°F (i.e., reducing from 666 to 525°F near the surface due to wellbore heat losses). This is because there is no thermal insulation for this completion scenario, and the temperature profiles for the tubing and the A-annulus (i.e., the annulus between the tubing and production casing) are similar. Corrosion-resistant cladding was assumed to prevent potential metal loss. Additionally, the operational loads, including those from fracture stimulation, were carefully considered to achieve a life-of-well scenario.

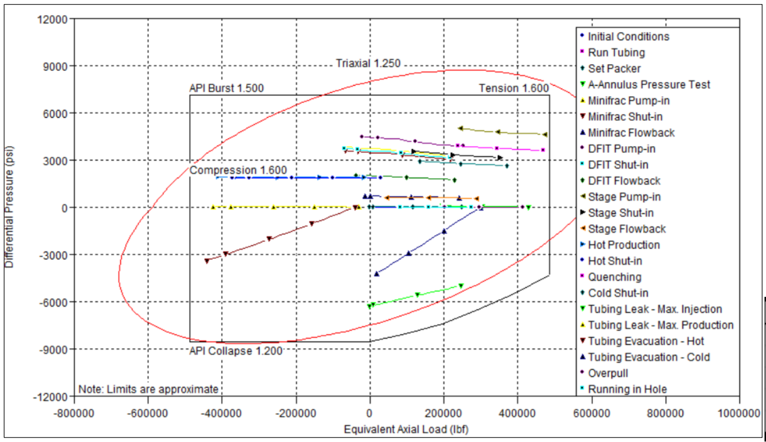


Design Factors	Pipe Body	Connection
Triaxial	1.25	
API Burst	1.5	1.5
API Collapse	1.2	
Axial Tension	1.6	1.6
Axial Compression	1.6	1.6

Figure 6. (Left) supercritical geothermal 9-5/8” with a nominal weight of 70.3 lbs/ft TN-125SS casing VME design limits plot (through tubing production). (Right) DFs used for the analysis.

Analyzing the left side of Figure 6, it can be seen that the well is loading under all four quadrants (i.e., burst-compression, compression-collapse, tension-collapse, and tension-burst). The most dominant loads are the tensile and compressive, while burst and collapse are moderate. It was identified that the maximum allowable quenching duration (orange line with left triangle) would be 8 hours without leading to any connection jump-outs. Otherwise, the safe tensile limit of the API envelope would be exceeded. Looking at Figure A-2 in the Appendix section, it can be seen that API BTC connections are not suitable and would not pass the design criteria. TenarisHydril Blue (rate to ISO 13679 CAL IV) connection was assumed because of its usage validation and rating for geothermal conditions with 100% tension and compression efficiency, in addition to reliable compression resistance in terms of its thread profile. Even for the case of tubing with packer completion, the production casing connection was decided to have a reliable metal-to-metal seal to prevent any H_2S leakage concerns. The main problem with the supercritical geothermal well completion was the criticality of the sour environment. The NZS 2403: 2015 recommends limiting API Spec. 5CT grades up to 95 ksi but allows higher proprietary grade steels with metallurgical properties suitable for sour gas service. Therefore, TN-125SS was justified by its improved resistance to sulfide stress cracking (SSC). Otherwise, it would be impossible to do the elasticity-based casing design.

In the 6-5/8” production tubing stress envelope, in addition to the previously mentioned loads, tubing running and overpull have been simulated. It can be seen from the left side of Figure 7 that all four quadrants of the VME envelope are occupied by the loads, with tension and compression being the dominant loading. This behavior was also observed for the production casing, another distinct aspect of supercritical geothermal well design. Although higher burst and collapse ratings would not necessarily be required for ordinary geothermal wells (i.e., relatively lower pressure and temperature), supercritical conditions limit the well designer’s ability to choose a suitable pipe. Another criticality of the supercritical geothermal production would be the high concentrations of H_2S, which could lead to a sour environment. Based on the NACE MR0175, NZS 2403: 2015, and IRP3-2012 standards, the metallurgy should not have a higher yield strength than 95 ksi if a sour environment downhole is possible. An expansion joint (i.e., travel joint) could eliminate the need for higher-grade tubing. The expansion joint was placed at a depth of 8,750 ft, while the packer was set at 9,250 ft. The connection chosen was TenarisHydril Wedge 563 (rate to ISO 13679 CAL IV), which has 100% pipe body tensile and compressive efficiency.



Design Factors	Pipe Body	Connection
Triaxial	1.25	
API Burst	1.5	1.5
API Collapse	1.2	
Axial Tension	1.6	1.6
Axial Compression	1.6	1.6

Figure 7. Supercritical geothermal 6-5/8” 30.2 lbs/ft L-80ICY tubing (section 1 above expansion joint) VME design limits plot with expansion joint.

Without focusing on the packer manufacturing details (hydraulic-set packer), the required performance envelope was predicted. Looking at Figures 8 and 9, it can be seen that all loads are within the assumed operating envelope with the help of an expansion joint. The operating envelope (i.e., red line) was an assumption. The expansion joint must at least have a 14 ft stroke with 7 ft upward and 7 ft downward movement limits. The details of how the loads would be induced on the packer without an expansion joint can be seen in Figure A-3 in the Appendix section.

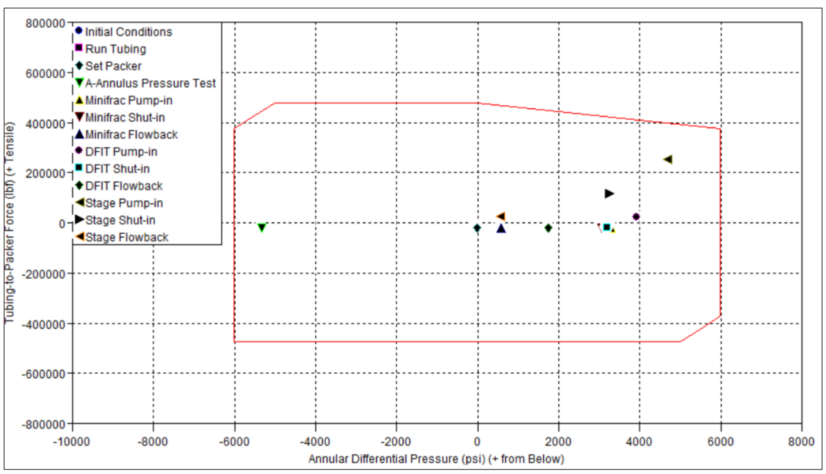


Figure 8. Supercritical geothermal 6-5/8” x 9-5/8” packer performance envelope with an expansion joint (1).

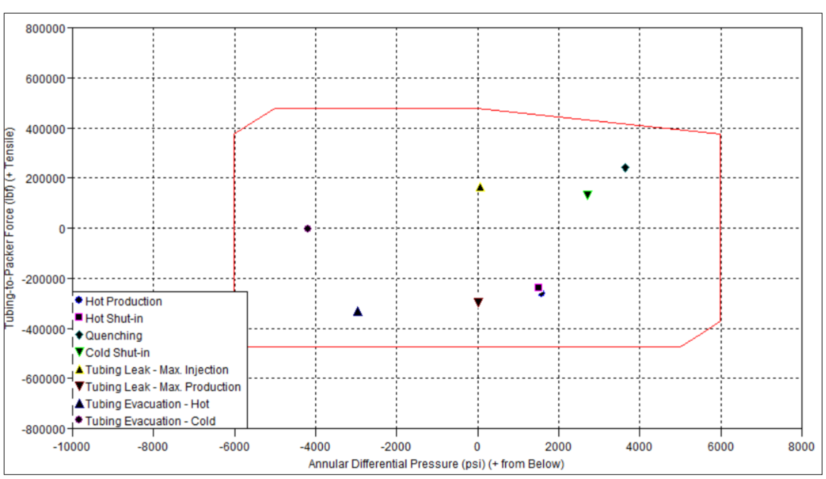
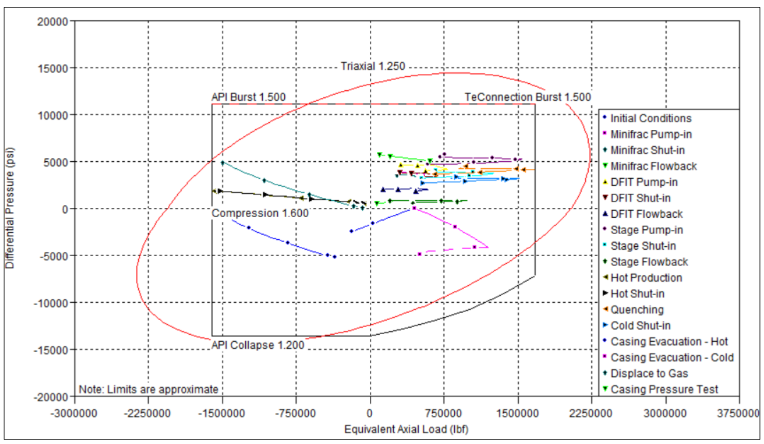


Figure 9. Supercritical geothermal 6-5/8” x 9-5/8” packer performance envelope with an expansion joint (2).

Considering the details of Figure 8, one of the most critical loads for the packer in terms of differential pressure was the A-annulus pressure test (i.e., green triangle) with 5,000 psi. This value was selected based on the maximum differential burst pressure that the production tubing and casing would undergo for the life of the well. It can also be seen that even with the expansion joint, there would still be considerable tensile tubing-to-packer forces (i.e., acting upwards on the packer/pulling upwards). These were observed during stage pump-in (i.e., khaki triangle) and stage shut-in (i.e., black triangle), with injection leading to a more significant effective upward force. Figure 9 shows the rest of the tubing loads the packer would undergo, which were more severe than the previous loads in Figure 8. It can be seen that cold operations like quenching (i.e., dark green rhombus), cold shut-in (i.e., green triangle), and tubing leak with maximum injection pressures (i.e., yellow triangle) led to effective upward forces on the packer (i.e., tensile tubing-to-packer). On the other hand, hot operations, namely, as production (i.e., blue asterisk), hot shut-in (i.e., pink square), tubing leak with maximum production pressures (i.e., dark brown triangle), and hot tubing evacuation (i.e., dark blue triangle), led to effective downward forces on the packer (i.e., compressive tubing-to-packer).

4.2 Supercritical Geothermal with Tubingless Completion

In addition to the tubing production with a packer, the tubingless production scenario was analyzed, where the production casing underwent the highest temperatures. As for this case, no insulation materials were considered for the tubing design, and the tubing and A-annulus temperatures were approximately the same. Although it was expected that there would be changes in terms of the design limits (i.e., safety factors) when the production was switched from tubing to tubingless completion, the results indicated otherwise. It can be seen that the left sides of Figures 6 and 10 are considerably similar in terms of maximum tensile and compressive loading. First, it was assumed that there would be some increase in the 9-5/8" casing temperature profile when switching from tubing to tubingless completion, which would deteriorate the casing selection. However, the increase in the temperature was not quite significant, as seen in Figure 11. The chosen casing could endure a maximum production temperature of 666°F at the bottom and 525°F near the surface (Figure 11).



Design Factors	Pipe Body	Connection
Triaxial	1.25	
API Burst	1.5	1.5
API Collapse	1.2	
Axial Tension	1.6	1.6
Axial Compression	1.6	1.6

Figure 10. Supercritical geothermal 9-5/8" 70.3 lbs/ft TN-125SS casing VME design limits plot (tubingless production).

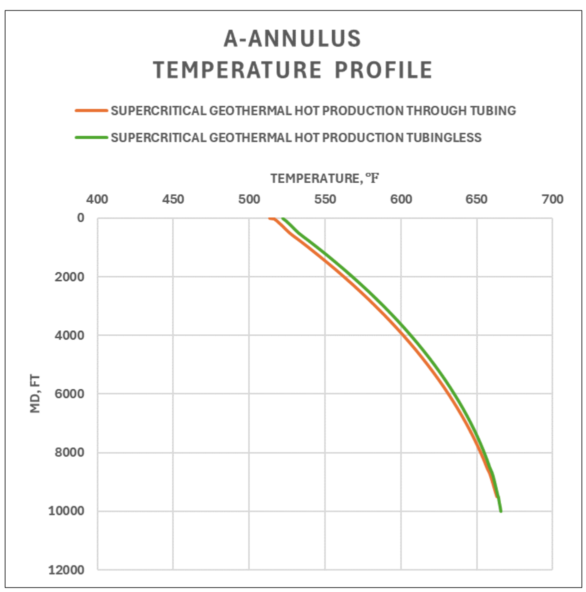


Figure 11. Tubing and tubingless A-annulus temperature comparison for the supercritical geothermal well.

4.3 Steam-Assisted Gravity Drainage with VIT Completion

Sometimes, it is claimed that the design of SAGD wells is more challenging than the geothermal well completion design. This section compares the temperature profiles of SAGD and supercritical geothermal wells. Looking at Figure 12, the two most extreme temperature profiles are undisturbed geothermal gradient (i.e., red line) and wet steam injection through 5” x 3-1/2” VIT tubing (i.e., dark violet line) corresponding to approximately 675°F downhole. Since the supercritical geothermal production temperature was assumed to be 666°F at the bottom of the well, the wet steam injection temperature at the surface had to be assumed the same.

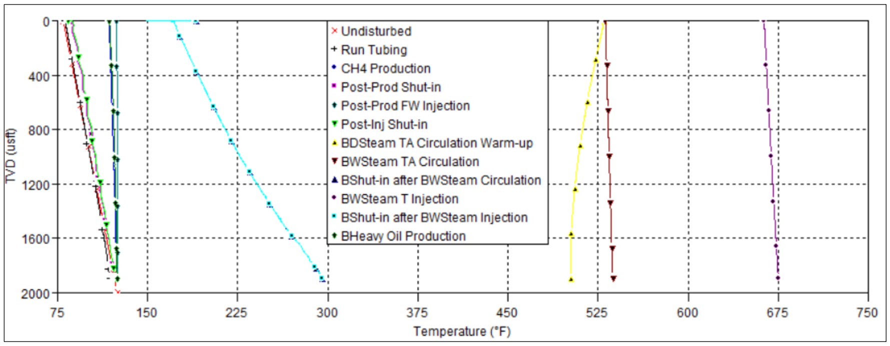


Figure 12. VIT tubing life-of-well temperature distribution in the SAGD well.

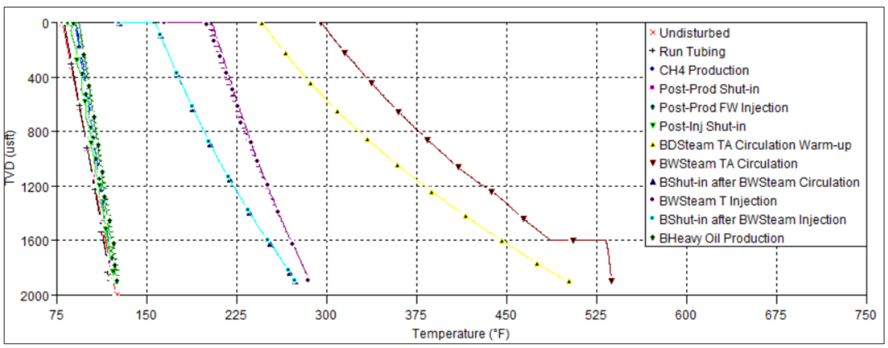


Figure 13. Casing (or A-annulus) life-of-well temperature distribution in the SAGD well.

Analyzing Figure 13, it is seen that the production casing would also undergo a maximum temperature just below 525°F downhole (i.e., around 525°F temperature was obtained in the supercritical geothermal well near the surface) as part of the completion program during wet steam tubing-annulus circulation. Using the corresponding temperature distributions, the idea was to compare the SAGD with the supercritical geothermal well completion (Figures 14 and 15).

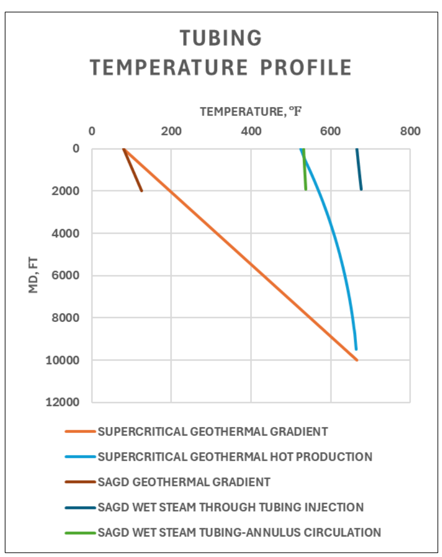


Figure 14. The comparison of tubing temperature distribution in SAGD and SG wells.

It was assumed that the temperature increases from the undisturbed geothermal (i.e., lithostatic) gradient would exert thermal expansion loading on the tubing string. Although the tubing string is not similar to a casing in terms of being fixed with cement, it would be restricted inside the well with the tubing hanger and a downhole production packer. If there were no seal movement allowance, increases in the temperature from the deployment conditions (i.e., assumed as the geothermal gradient) would exert thermal stress (i.e., compression) on the tubing. Figure 14 compares the tubing temperature profile between the supercritical geothermal and SAGD wells. The brown line refers to the geothermal gradient, and the dark blue line represents the wet steam through tubing injection temperatures in the SAGD well. On the other hand, the orange line represents the geothermal gradient, and the lighter blue line refers to the hot production temperatures in the supercritical geothermal well. It can be understood that the difference between the T_1 (geothermal gradient) and the T_2 (load condition) would play a major role in the so-called thermal expansion stress. This difference is higher in the SAGD than in the supercritical geothermal well if the load condition is the injection of wet steam for heavy oil production. There would be around a 400°F increase in the VIT tubing temperature along the SAGD wellbore for the case of wet steam circulation (i.e., 550°F for wet steam injection). Regarding the increases in the geothermal well, the temperature difference between the hot production load condition and the geothermal gradient in the supercritical geothermal well would be negligible at the bottom. However, this difference would reach as high as 400°F increase near the surface. This could indicate the relative ease of supercritical geothermal tubing design; however, one can argue that there are higher movement needs in the SG well due to longer tubing, which is also true.

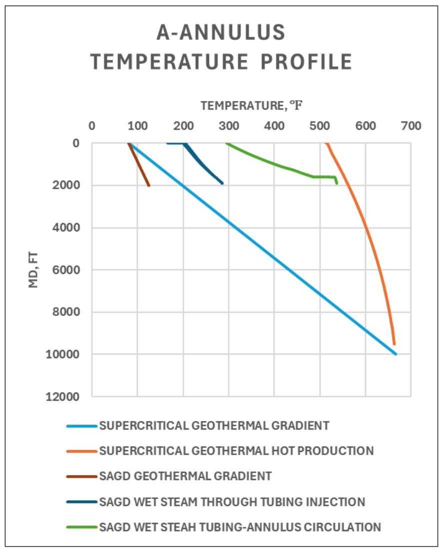


Figure 15. The comparison of A-annulus temperature distribution in SAGD and SG wells.

Since most geothermal wells are completed tubingless in reality, it would be worth looking at the A-annulus temperature profiles for both SAGD and SG wells. Adopting the same concept mentioned in Figure 14, it can be seen that similar loads have been simulated for the A-annulus in Figure 15. The figure depicts a relatively higher T_2-T_1 for the supercritical geothermal well casing string than the production casing in the SAGD well. Additionally, the length of the casing restricted with a full cement column in the SG well could limit the well designer's ability to choose a suitable grade and wall thickness. This result highlights the difficulties of supercritical geothermal well completions and the higher probability of well integrity issues. Generally, it is understood from Figure 15 that most failures would occur near the surface in SAGD but near the bottom of the SG well. The production casing in the SAGD well was 7-5/8" 26.4 lbs/ft P-110ICY, and the maximum A-annulus temperature to stay within the ellipse was 525°F (Figure A-5).

5. DISCUSSION

The supercritical geothermal well completion design highlights different challenges and engineering approaches required, emphasizing the need for elaborated solutions to meet operational well service demands. Table 2 shows the main differences in input information for the SG and SAGD wells. To be argued, one of the limitations of the SAGD wells in terms of injection/circulation temperatures is the pre-designed casing strings. Not all wells would be suitable candidates for the SAGD operations. For example, suppose the production casing designed for early CH_4 production and later heavy oil production has a moderate wall thickness and a lower grade. In that case, it may not endure the high-temperature (>500°F) steam injection loads. This could limit the ability to re-complete the well as a candidate for SAGD operations. On the other hand, fluid pressures were higher for the supercritical geothermal well because the well's depth (i.e., 10,000 ft) was 5 times deeper than that for the SAGD (i.e., 2000 ft) well.

Table 2. Input information for the SAGD and SG wells.

Input Information	
SAGD	**Supercritical Geothermal**
Lower geothermal gradient	Higher geothermal gradient
High surface temperature	High BHT
Cannot exert 666 ℉ thermal compressive force on the casing since the geothermal gradient is low	Can exert 666 ℉ thermal compressive force on the casing
Fluid pressure is up to 3,500 psi	Fluid pressure more than 9,000 psi

Table 3 compares the production casings, with one of the key differences being the number of thermal load cycles, which was more for the supercritical geothermal well. Notably, the number of load cycles was determined based on the switch between the compression and tension, and these were the minimum number of cycles. There could be other low cycles inducing higher stresses depending on the operational program. Regarding the nature of the loading, the supercritical geothermal conditions and stimulation program required performance under both tensile and compressive conditions.

Table 3. Production casing design for the SAGD and SG wells.

Production Casing Design	
SAGD	**Supercritical Geothermal**
2 severe load cycles	5 severe load cycles (4 for tubingless)
5 medium load cycles	5 medium load cycles (5 for tubingless)
Compressive loads dominant	Both compressive and tensile loads dominant
Lower DFs	Higher DFs
Can use TSH ICY grade	Cannot use TSH ICY grade due to SSC
Usually not very susceptible to SSC	Very susceptible to SSC due to H2S and thermal cycling, with higher tensile loads dominating
Can comfortably use >110 ksi	Cannot comfortably use 110 or 125 ksi (H2S max concentration limited to < 0.003%)
Gas-tight connection recommended, but not mandatory	Gas-tightness required due to H2S and steam
Critical SF # 4	Critical SF # 19
Burst domination	Burst & collapse domination

Considering the production tubing design in Table 4, the geothermal well conditions exerted more load cycles than the SAGD well. The same observation can be made about the nature of the VME stresses for the geothermal production casing. One advantage of using L-80 Type 1 casing for the geothermal production casing was its higher endurance for SSC (i.e., sulfide-stress cracking) even under a 5% H_2S concentration.

Table 4. Production tubing design for the SAGD and SG wells.

Production Tubing Design	
SAGD	**Supercritical Geothermal**
0 severe load cycles	1 severe load cycles
2 medium load cycles	8 medium load cycles
VIT	Cladding
Compression dominant	Tensile & Compressive dominant
Lower DFs	Higher DFs
Carbon steel OK	L-80 instead of CRA (ICY can be used)
Burst domination	Burst & collapse domination
Deviation: used larger tubing and changed casing to a larger size for that	Deviation: used smaller tubing for casing drift - connection coupling OD
Critical SF # 3	Critical SF # 20
	L-80 SSC not an issue even with 5% H2S concentration

Looking at Table 5, it is noted that the geothermal well required a higher stroke expansion joint. This was mainly due to the longer tubing string in the geothermal well, which resulted in higher effective tubing-to-packer forces.

Table 5. Packer and expansion joint for the SAGD and SG wells.

Expansion Joint & Packer	
SAGD	Supercritical Geothermal
5 ft up, 5 ft down (10 ft stroke)	7 ft up, 7 ft down (14 ft stroke)
Hot compressive loads lead to set down	Hot operation loads lead to set down; cold operation leads to tensile stress
<500 kip compression	>500 kip compression; <500 kip tension
4 ksi differential	6 ksi differential

It must be highlighted that these analyses have been done for sensitivity purposes, while in reality, well planning would require validated completion tools to be used under these environments. Knowing that elastomeric seal materials cannot endure high temperatures and corrosive environments of this nature, the industry still needs to research and develop thermal compensation tools, such as expansion joints. Welltec has already significantly improved the downhole packer elements to make the supercritical geothermal well completions achievable. However, a field-tested, proven, and validated expansion joint that incorporates non-elastomeric seals and effectively eliminates leakage issues in geothermal wells has not yet been developed.

6. CONCLUSIONS

The decades of experience designing thermal wells are insufficient to successfully plan, design, and execute supercritical geothermal well completions. Geothermal well conditions require high performance under both compressive and tensile quadrants, while for the SAGD wells, having high compressive efficiency can sometimes be enough. Further work should be done on the plasticity-based design theory to compare both well completions and understand the best design practices. Another main challenge of an elasticity-based design was increased loading as the tubular wall thickness was increased to eliminate axial failures. Since the wall thickness parameter is integral to the axial load formula, any increase in the cross-sectional area of the casing string leads to the same increase in tensile loading. This highlights the limitations of heavy-wall casing strings in thermal wells. Similarly, increasing the pipe yield strength is not always an effective solution. Even the highest grade and thickest wall pipes may not endure the cyclic thermal loading, and it may be necessary to analyze plastic deformation stability instead of spending excessive amounts of CAPEX (i.e., capital expenditure) to do elasticity-based design. Current limitations in the elastomeric expansion and contraction compensation tools and their leakage rate highlight the need for further research and development.

ACKNOWLEDGMENTS

The authors would like to thank the University of Oklahoma for offering amazing access to the computer lab and all the companies that provided incredible resources to OU students. Additionally, authors would like to thank Welltec for their support in the development of this paper.

REFERENCES

Khasani, Kusmono, Pri Utami, Rachmawan Budiarto; Corrosion in Geothermal Facilities: Their Causes, Effects, Mitigation, and Worldwide Cases. AIP Conf. Proc. 11 November 2021; 2338 (1): 020007. https://doi.org/10.1063/5.0066755.

VELÁSQUEZ, Andrés Felipe BAENA, Alberto TOLEDO VELAZCO, Jorge Andrés ÁLVAREZ ESCOBAR, Khizar ABID, Yosafat ESQUITIN, Ricardo REVES VASQUES, Leonardo ROCHA DE QUEIROZ, and Catalin TEODORIU. “Design and Experimental Validation of a Unique Geothermal Downhole Valve for FORGE Project.”

Kaya, T., & Hoshan, P. (2005, April). Corrosion and Material Selection for Geothermal Systems. In Proceedings World Geothermal Congress (Vol. 2005, pp. 24-29).

Hole, H. (2010). Geothermal Well Design – Casing and Wellhead. World Geothermal Congress 2010, June 1–28.

Torres, A. (2014). Challenges of Casing Design in Geothermal Wells. Society of Petroleum Engineers - IADC/SPE Asia Pacific Drilling Technology Conference 2014: Driving Sustainable Growth Through Technology and Innovation, 210–221. https://doi.org/10.2118/170480-ms.

Phi, T., Elgaddafi, R., Al Ramadan, M., Ahmed, R., & Teodoriu, C. (2019). Well Integrity Issues: Extreme High-Pressure High-Temperature Wells and Geothermal Wells A Review. Society of Petroleum Engineers - SPE Thermal Well Integrity and Design Symposium 2019, TWID 2019, 2, 198687. https://doi.org/10.2118/198687-ms.

Nganga, Anthony & Thórhallsson, Sverrir & Thorbjornsson, I.O. & Kaldal, Gunnar. (2021). Geothermal Well Design Using the New 2015 New Zealand Standard and 1991 Standard A Case of MW-20A in Menengai, Nakuru County, Kenya.

Alvarez Escobar, Jorge & Velazco, Alberto & Abid, Khizar & Esquitin, Yosafat & Vasques, Ricardo & Queiroz, Leonardo & Teodoriu, Catalin. (2024). Zonal Isolation Concept for FORGE Geothermal Wells.

Institute, A. P. (2018). Calculating Performance Properties of Pipe Used as Casing or Tubing (API TR 5C3: 2018). In: American Petroleum Institute.

ANSI/NACE MR 0175/ISO 15156:2009. Petroleum and Natural Gas Industries – Materials for Use in H2S-Containing Environments in Oil and Gas Production.

Zealand, S. N. (2015). Code of Practice for Deep Geothermal Wells (NZS 2403: 2015). In.

Appendix E of Industry Recommended Practice Volume IRP3-2012 (Enform Canada).

Olarte, P., Marquez, L., Landínez, G., & Amaya, R. (2009). Casing Collapse Study on Block VI Wells: Casabe Field. Latin American and Caribbean Petroleum Engineering Conference. https://doi.org/10.2118/122956-ms

Zeringue, R. (2005). HPHT Completion Challenges. SPE High-Pressure/High-Temperature Sour Well Design Applied Technology Workshop,

APPENDIX

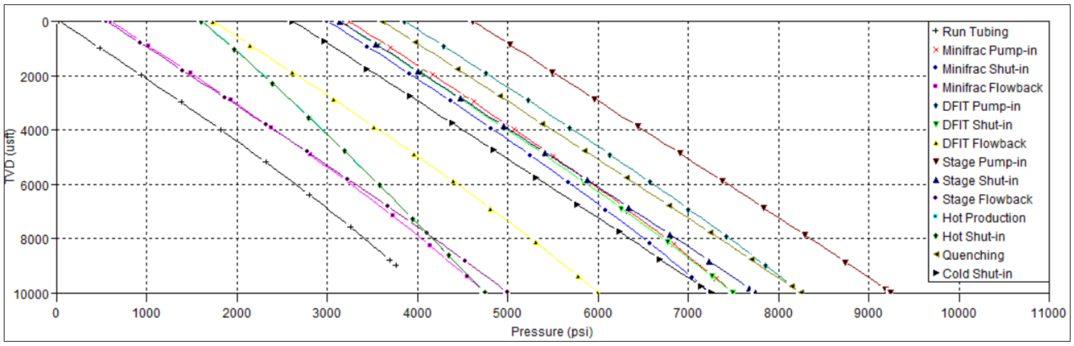


Figure A-1. Tubing life-of-well fluid pressure distribution in the supercritical geothermal well.

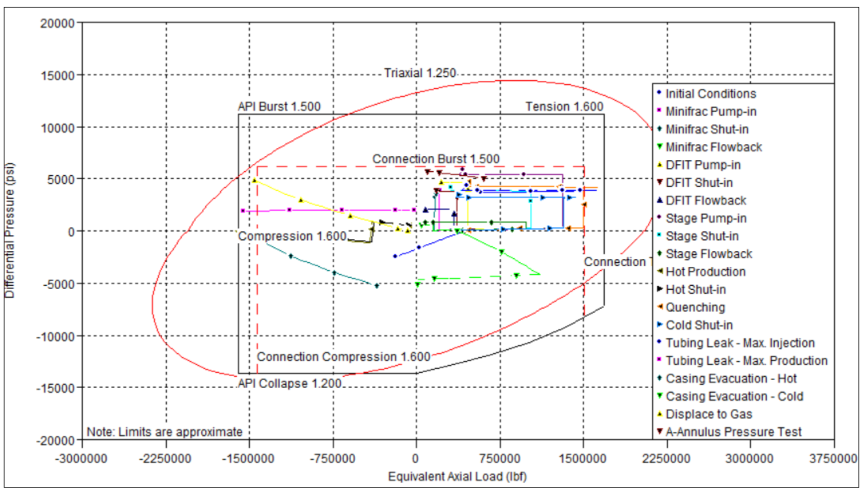


Figure A-2. Supercritical geothermal 9-5/8” 70.3 lbs/ft TN-125SS casing VME design limits plot (through tubing production) using API BTC connections.

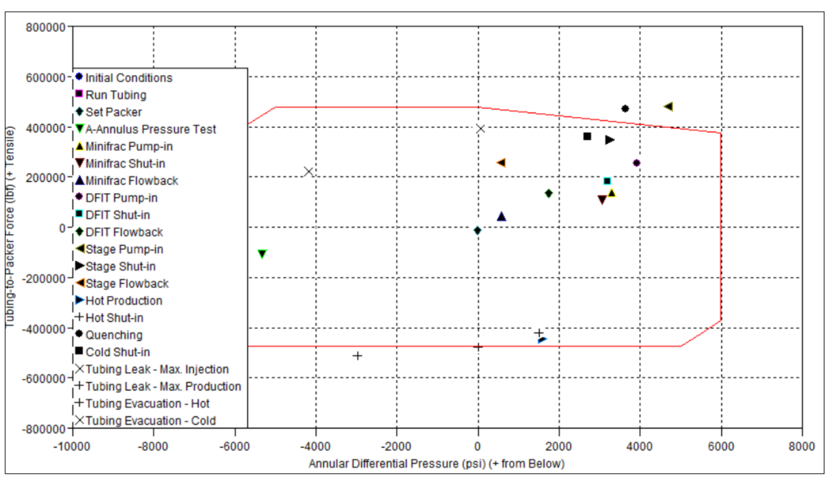


Figure A-3. Supercritical geothermal 6-5/8” x 9-5/8” packer performance envelope without an expansion joint.

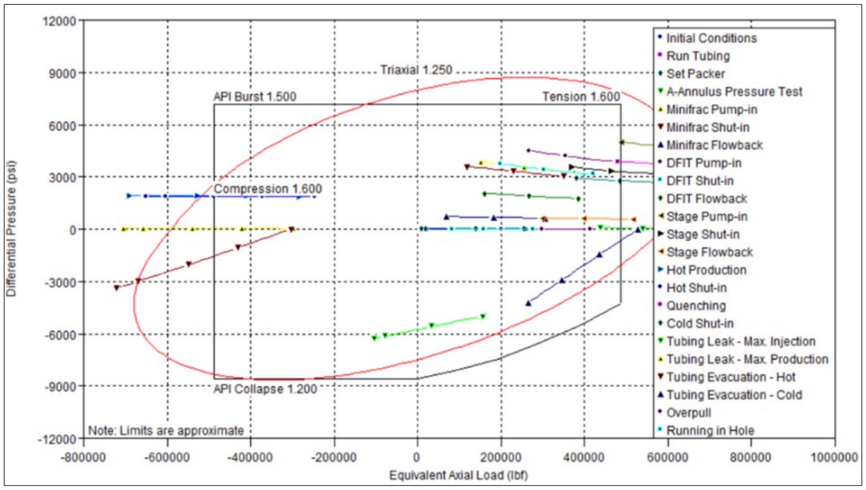


Figure A-4. Supercritical geothermal 6-5/8” 30.2 lbs/ft L-80ICY tubing VME design limits plot without an expansion joint.

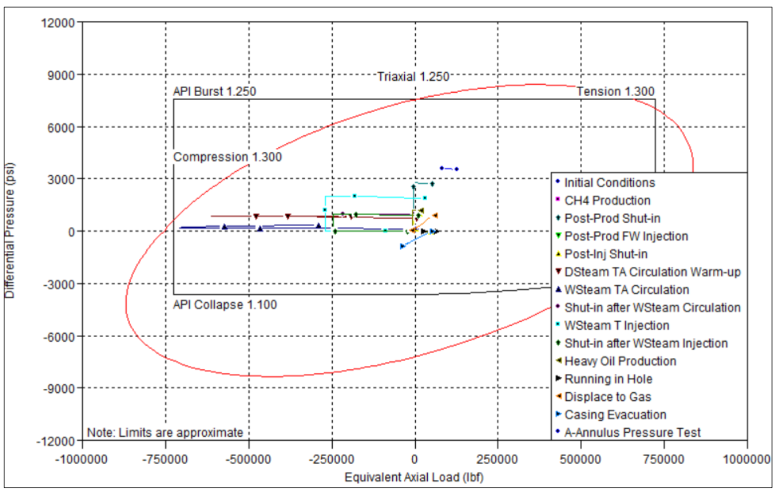


Figure A-5. SAGD 7-5/8” 26.4 lbs/ft P-110ICY casing VME design limits plot.