WHOC15-359

Vacuum-Insulated Tubing Behavior during Cyclic Steam Injection in the San Tome District of the Orinoco Heavy Oil Belt in Eastern Venezuela

F. Armas, PDVSA; A. López, Petropiar; R. Mago, PDVSA; J. Rodriguez, PDVSA; J. Cadena, Petropiar; J. Houghton, Petropiar; P. Arellano, Petropiar

ABSTRACT

The San Tome District, located in the Orinoco Heavy Oil Belt of Eastern Venezuela, frequently performs cyclic steam injection and has considered this the stimulation method of choice for its recovery of extra-heavy crude oil. This process consists of pumping a predetermined volume of steam in the reservoir with the main objective of reducing oil viscosity to enhance fluid mobility.

Different completion techniques for steam injection have been evaluated in the San Tome District including the use of conventional tubing, isolated tubing, and insulated tubing, the last one being the most efficient technique based on field results in hot fluid injection. The efficiency of insulated tubing is based on the total absence of matter (vacuum) between two strings of pipe. This vacuum space significantly lowers heat transfer from convection and conduction and leaving only the effect of radiation.

The primary objective of this paper is to evaluate the thermal behavior of the insulated tubing based on real field data and using this as supporting data to validate the observed exterior wellhead temperature while injecting saturated steam at 560°F. Also, to demonstrate that as steam injection continued, downhole temperature outside of the insulated tubing was maintained below the hot-yield point that would cause plastic deformation of the 9-5/8" casing.

The heat loss during steam injection was simulated using Halliburton's WellCat™ software program and the simulated temperature profile outside the pre-insulated tubing (casing-tubing annulus) was compared to the temperature profile obtained from downhole fiber optic readings during steam injection in the Bare field, San Tome District, in the Ayacucho Division. By calibrating the model with this actual information, we can better estimate the downhole temperature during steam injection that affects casing deformation and potential damage.

KEY WORDS

Cyclic Steam Stimulation, Insulated Tubing, Vacuum-Insulated Tubing, Thermal Conductivity, Casing Stress Analysis, DTS Fiber-Optic

INTRODUCTION

Recovery of Heavy and Extra Heavy crude oil contained in the Orinoco Heavy Oil Belt in Eastern Venezuela is challenging due to its physical and chemical properties. The high viscosity of the crude oil makes it a candidate for thermal recovery techniques that can reduce the viscosity and dramatically improve the oil mobility.

Steam injection is the most commonly used process to transmit heat to the formation. The disadvantage of this process is that only part of the heat generated reaches the target formation due to heat losses at the surface and to downhole formations. But for many years in the oil industry, steam injection has been the application of choice as a thermal enhanced recovery method.

INJECTION OF HEATED FLUIDS

The process where thermal energy is supplied to the reservoir in order to increase oil recovery factor is known as heated fluid injection (See Figure 1). The main objective of this hot fluid injection is to reduce oil viscosity in order to improve its mobility; this being particularly suitable for heavy (<22° API) and extra-heavy (<10° API) crude oils. Other benefits of this thermal method, in addition to viscosity reduction, is the reduction of residual oil saturation as a result of thermal expansion, increased areal efficiency due to the improved mobility, distillation with steam and thermal cracking, among others.

One of the key challenges in this recovery scheme is to deliver the injected steam to the reservoir with minimal heat losses by reducing transfer of energy to undesired areas. The type of injection completion installed can play an important role in the efficiency of the heat delivery process.

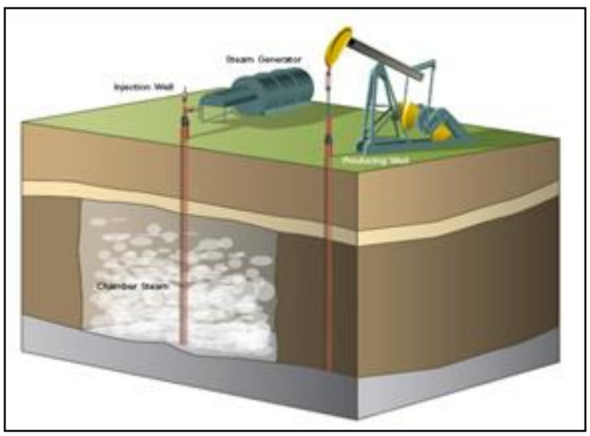

Figure 1: Heated Fluid Injection Diagram (Steam)

CYCLIC STEAM STIMULATION (CSS)

There are two techniques for steam injection in heavy crude reservoirs - cyclic steam stimulation and continuous steam injection. The main differences between these two methods lies in the volume of steam injected, exposure time of heat in the reservoir, and the affected reservoir areal extent. In Cyclic Steam Stimulation (CSS), also known as huff-and-puff, the fluid is injected and produced by the same producer well but sometimes requires a downhole completion change.

The Continuous Steam Injection (CSI) technique typically involves separate injection and production wells, but can be done with a single well as in the case of Single-Well Steam Assisted Gravity Drainage (SW-SAGD), where a single well has a dual completion and is used as an injector and producer simultaneously. For the purpose of this data analysis, it is important to mention that the CSS method was used for data evaluation and well modeling.

The Cyclic Steam Stimulation technique consists of three phases: first, the phase of steam injection; second, the soaking time while the well is shut-in; and last, when the well is placed on production. See Figure 2 for a visual schematic of the three CSS phases.

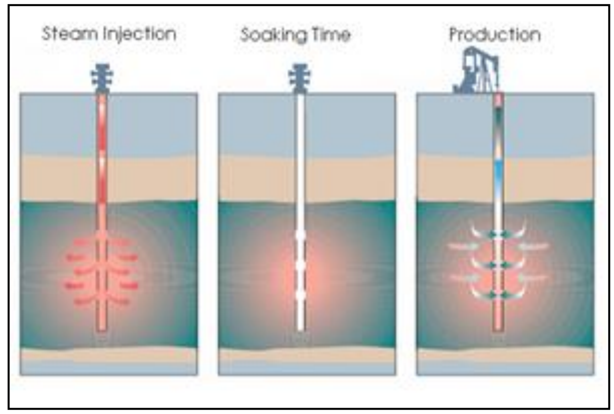

Figure 2: Three Phases for Cyclic Steam Stimulation

The steam injection phase is the period when thermal energy (heat) is being supplied to the reservoir and injection variables such as daily rate, total volume injected, and injection saturation parameters vary depending on reservoir properties. The soaking period starts after shutting-in steam injection and is used to allow energy dissipation into the reservoir. In Bare the soak time is usually approximately 5 days (Armas & Mago 2012). The last stage is when the well is producing fluids from the reservoir to the surface through an artificial lift system suitable for high downhole temperatures. Reservoir injection temperatures using appropriate completion materials in the Orinoco Heavy Oil Belt can reach 500°F or more. This large amount of energy carried out by steam is certainly transmitted to the reservoir by heat transfer and thus achieving insulated tubing function of increasing temperature in the reservoir vicinity.

WELL INTEGRITY UNDER STEAM INJECTION

The wellbore is an important element that provides the physical connection between the reservoir and the surface as wells as the means through which the removal of hydrocarbons is achieved. The efficiency and reliability of this surface-subsurface linkage depends on the selection of components used.

The proper selection and design of well completion assemblies are an important part of the operational and productive performance of a field under thermal recovery.

The amount of crude oil recovered from reservoirs under CSS is directly related to the completion of the well. Reducing heat losses will improve the heat delivered to the reservoir which will impact recovery per volume of steam injected.

Two types of well completions are often used for cyclic steam injection in the Orinoco Belt (Armas *et al* 2012): One is using conventional tubing with nitrogen in the annulus, and the other is using insulated tubing with in-situ fluid and water in the annulus. Both completions are designed to slow the loss of heat from the injection tubing, which can reduce wellbore mechanical damage and increase heat supplied to the reservoir.

During steam injection, there are two heat flow paths within the insulated tubing: heat flow through the un-insulated connections and heat flow through the vacuum-insulated body of the tubing. At the connections a higher heat loss transfer is experienced to the annulus via conduction and it generally flows axially from between the welded areas. In the body of the tubing a smaller amount of heat flows from the inner tubing to the outer tubing by the effect of radiation as shown in Figure 3.

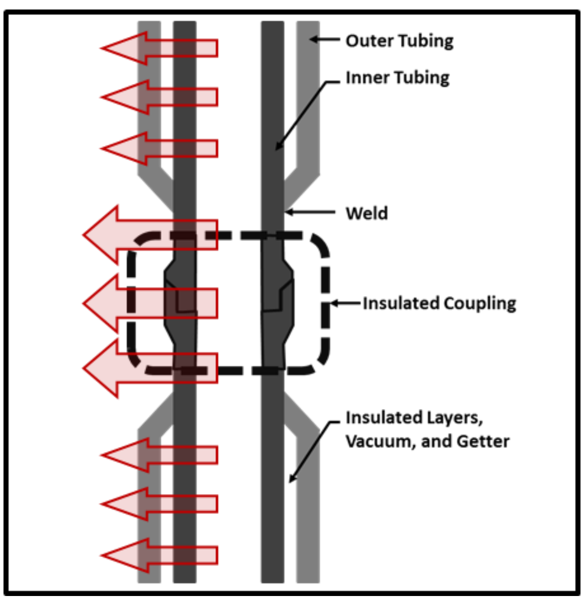

Figure 3: Heat flow paths along the insulated tubing

The magnitude of this second flow direction depends on the thermal conductivity of the completion system (material) and the heat transfer coefficient of the fluid in the tubing-casing annulus. For this reason, it is important for the insulated tubing to provide a low thermal conductivity (k) which in conjunction with its surroundings, such as annular fluid properties, insulating tubing collars, well geometry, and geothermal gradient (GG), can lead to a low overall heat transfer coefficient (U).

In the case of a thermal well completion using insulated tubing, its isolation principle is based on the very low thermal conductivity obtained from its internal vacuum system. Heat transfer is considerably reduced since heat flow is almost exclusively by radiation in such systems. Radiation is the phenomenon of heat transfer which occurs when there is no contact between bodies and/or fluids.

High-performance insulated tubing is a double concentric tubing separated internally by a vacuum "annular space". The quality of the internal vacuum is key to the insulating properties of the tubing. The insulated tubing typically has three elements that contribute to this temperature insulation: a "multi-layered" insulation sheet, a getter or scavenger, and the absolute vacuum system (See Figure 4).

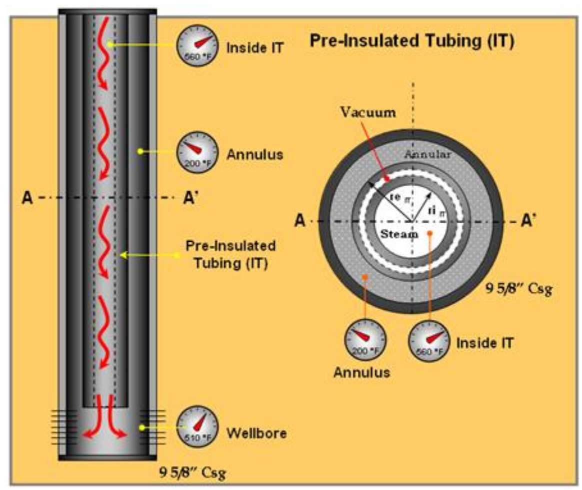

Figure 4: Insulated Tubing Completion and Cross-Sectional Diagrams

As an example, Figure 4 shows a cross-section of the insulated tubing (IT) inside a 9-5/8" casing. In this example, at a hypothetical time "X", the steam being injected at a saturation temperature of 560°F only raises the annular temperature to 200°F. This high difference in temperature represents a low heat exchange between the hot fluids inside the insulated tubing and the tubing-annular space. Reducing the heat loss from the tubing results not only in an efficient delivery of heat to the reservoir but also a mechanical protection system to the casing.

ACTUAL TEMPERATURE DATA USING INSULATED TUBING

In a well completed with insulated tubing for its first cyclic steam stimulation, a fiber-optic line was installed with special clamps strapped to the outside of the insulated tubing (annular temperature) to acquire temperature profiles during the thermal stimulation process. Figure 5 represents the temperature profile with time measured by the fiber-optic line at the wellhead during steam injection. Recorded temperatures were in the range of 140°F to 221°F. For this case, steam temperature was 560°F which showed an efficient well protection starting at the wellhead level.

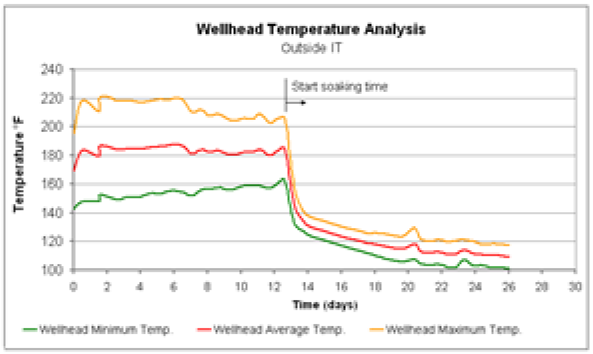

Figure 5: Wellhead Minimum/Average/Maximum Temperatures (Outer Wall of Insulated Tubing)

The average wellhead temperature was observed to be 183°F using an insulated tubing completion. This low thermal heat loss prevents casing deformation and reduces the movement and elongation of the casing.

According to previous failure analysis published by the San Tome District in the heavy crude department of the Orinoco Belt (Quintero & Armas 2012), the primary failures in cyclic steam injection obtained from field statistics are based on well completion problems. High induced casing temperatures, well sanding, and collapsed casing are all strongly related to the elevated temperatures in the well, resulting in some cases in premature well abandonment.

GEOTHERMAL GRADIENT IMPACT

It is particularly important for engineers to understand geothermal temperature values when analyzing downhole thermal profiles. Geothermal Gradient (GG) is the rate of temperature increase per unit of depth in the existing subsurface. Temperature gradients vary widely and at times increase considerably around volcanic areas. In any case, the downhole temperature can be calculated by adding the surface temperature to the product of the geothermal gradient and the depth. Figure 6 shows the recorded temperature data observed from the geothermal gradient behavior by depth in the location of this study.

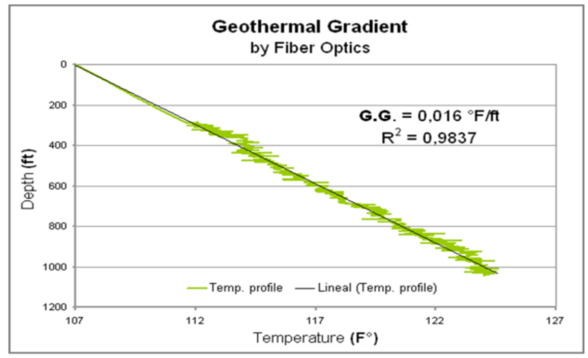

Figure 6: Recorded Geothermal Gradient Used

When temperature profiles are taken from a well under hot fluid injection the Geothermal Gradient (GG) plays an important role in interpreting the data. Since the fiber-optic line not only captures temperature changes caused by heat loss from the tubing, but also the changes in GG. The GG needs to be taken into account when evaluating the readings to avoid misleading interpretations.

Figure 7 shows three temperature profiles acquired from a well in the Orinoco Belt during cyclic steam injection. The green curve is the raw data from fiber-optic, while the orange curve has the GG subtracted. These temperature profiles are results of data obtained from a fiber-optic line located on the outside of the insulated tubing.

The reference line "B-A-C" in Figure 7 shows three points to indicate each profile: Point "A" indicates the cold temperature profile without steam injection, this being the true Geothermal Gradient (GG); Point "B" indicates the temperature profile during steam injection considering GG; and Point "C" represents the temperature profile during steam injection without GG.

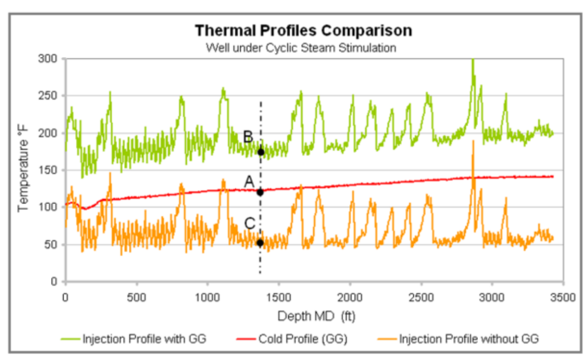

Figure 7: Downhole Thermal Profiles.

The annulus temperature profile shown by the green curve during steam injection in Figure 7 has an average positive slope as the temperature behavior reflects the effect of the geothermal gradient; in addition, over time this profile is affected by the energy transferred from the heated fluid and increases in magnitude until it reaches equilibrium.

On the other hand, after subtracting the geothermal gradient, the annulus temperature profile shown by the orange curve has an average negative slope. This is due to the fact that the pressure is decreasing along the wellbore because of friction, which reduces the temperature of the saturated steam.

This study focused on the analysis of the temperature difference (based on fiber-optic temperature readings) between the injected fluid and the annulus to validate the heat loss behavior (k-factor) of the insulated tubing.

HEAT-LOSS BEHAVIOR BASED ON INSULATED TUBING

Field data collected for 22 consecutive days from a well under steam stimulation using insulated tubing was used to evaluate the performance of the insulated tubing. During this period, steam was injected for 13 days at an average rate of 616 BSPD (98 metric tons/day) and the remaining 9 days represented the soaking phase. Figure 8 shows the historical steam injection rate and steam saturation temperatures at the surface during the injection and soaking periods.

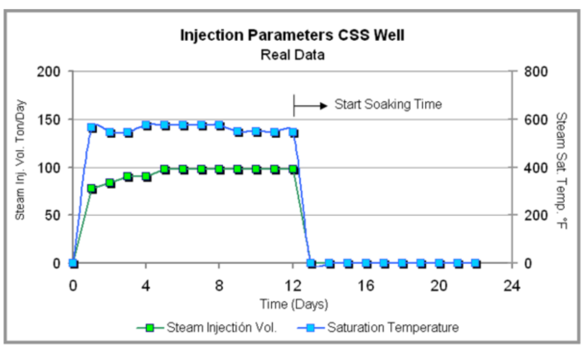

Figure 8: Injection Parameters for Actual CSS Well

The scope of this study was not to evaluate the operational parameters but to use the thermal data extracted by fiber-optic DTS to develop an understanding of heat-loss behavior in the well and validate the effective thermal conductivity of the insulated tubing.

Figure 9 compares the temperature profiles at different times from the wellhead (on the left) to the 9-5/8" casing shoe (on the right), calculated from fiber-optics values located on the external surface of the insulated tubing after subtracting the geothermal gradient effect.

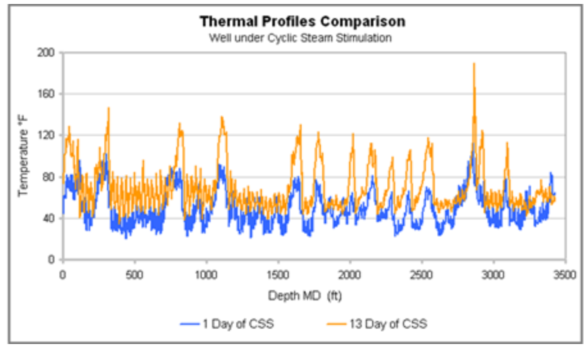

Figure 9: Comparison of temperature profiles at different steam injection times

Also, Figure 9 shows a temperature variation of 10-40°F in each data set as a result of not having complete thermal protection at each tubing connection, despite using insulated couplings. The connections affect the fiber-optic reading which is in direct contact with the external surface of the tubing. On the other hand, the temperature peaks above 100°F are not part of the scope of this paper but could be caused by one or more of the following:

a) Fiber optic problems (poor calibration, adjustments, etc.)
b) Damage to joints or insulated couplings while running in hole.
c) Property changes in adjacent formations (Shale/sand).
d) Fluid variation in the tubing/casing annulus.

In addition, a slight temperature increase is observed between the selected temperature profiles in Figure 9. As a result, the slight temperature difference made it difficult to determine the variation behavior in magnitude. For this reason, Figure 10 was created to measure the change in temperature with respect to injection time for various constant depths using temperature readings without subtracting geothermal gradient (GG).

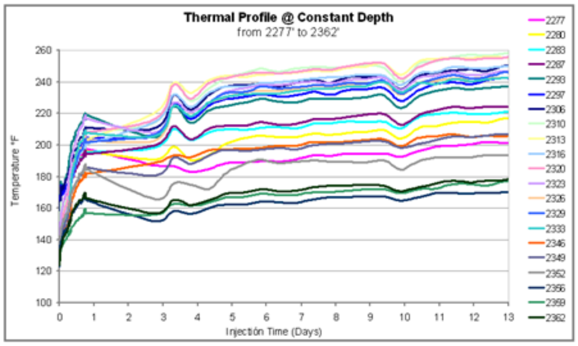

Figure 10: Temperature profiles at various constant depths with respect to injection time.

As shown in Figure 10, temperature increases 35-50°F in the first 24 hours as the cold system is heated. After the first day of injection, temperature continues to increase at an average rate of 1.25°F per day. This linear behavior was observed at a representative depth between 2277' to 2362' MD. This field data was obtained at a steam injection rate of 600 BSPD. The slope would be expected to change for different injection rates.

The maximum compressive hot-yield temperature for N-80 casing is 397°F and according to the data shown in Figures 7 and 10 the actual temperature outside the insulated tubing ranged from 180-260°F during steam injection at an average steam temperature of 560°F. This is a significant mechanical benefit provided by the insulated tubing as severe thermal casing stresses where avoided.

The objective of this study is to use existing field data to corroborate modeled results so that the validated results can be used on other similar applications. The simulation model used for this exercise was Halliburton's WellCat™ software.

THERMAL SIMULATION USING WELLCAT™

WellCat™ was used to simulate annulus temperature using various tubing thermal conductivities (k-factors). The objective was to obtain a good match between the temperature profile obtained from using the assumed thermal conductivity and the measured fiber optic temperature data. The effective thermal conductivity of the system can then be inferred by the best fit to the data that takes into account the couplings that are not protected by the vacuum insulation.

WellCat™ is a tubular stress analysis software that considers fluid property changes based on downhole and wellbore conditions. The software takes into account pressure and temperature losses along the injection or production tubing to simulate expected temperature profiles in the tubing, annulus and casing. These temperatures are important to simulate the axial and tri-axial casing forces. For this exercise, the temperature profile in the annulus was matched to the field data obtained from fiber optic by changing the insulated tubing k-factor in order to estimate an effective thermal conductivity.

WELL DATA INFORMATION

The well data used in order to validate the injection tubing k-factor was obtained from an actual steam injector used for a thermal project in the Bare field, San Tome District, Ayacucho Division of the Orinoco Oil Belt. The WellCat™ model was loaded with the same horizontal well trajectory and wellbore conditions as the Bare well including well inclination, measured and true-vertical depths. This horizontal well design is common in the Orinoco Belt. The well trajectories are shown in Figure 11 with total depths of 2975-ft TVD and 5522-ft MD.

The injection and bottomhole conditions in the Bare well were also considered as input data in WellCat™. The fiber-optic temperature correlating data was obtained when the selected well injected steam at an average rate of 616 BSPD and surface wellhead steam temperature of 560°F. The reservoir pressure and temperature before the steam injection period were 780 psi and 140°F, respectively.

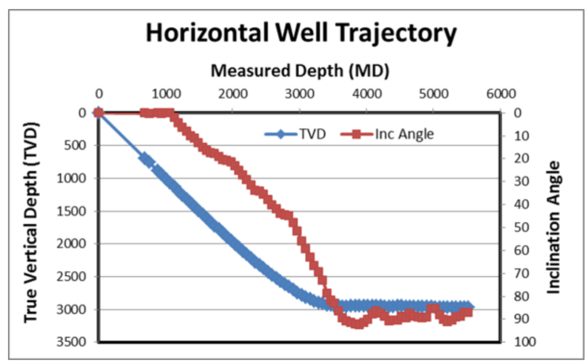

Figure 11: Offset Horizontal Well Trajectory

As shown in Figure 12, the analogous fiber-optic data for this analysis was obtained from an insulated tubing completion in a horizontal well with a 13-3/8" surface casing set at 666-ft MD, 9-5/8" production casing set at 3472-ft MD, and 7" slotted liner set at 5516-ft MD (5522-ft TD). The injection completion consisted of 2-7/8" x 2-1/16" insulated tubing set inside the 7" slotted liner with the high-temperature DTS fiber-optic cable clamped to the insulated tubing down to 5237-ft MD.

Even though this fiber optic data was obtained in 2006, it is still useful to evaluate temperature loss behaviors with well injection temperature of 560°F and reservoir pressure of 780 psi.

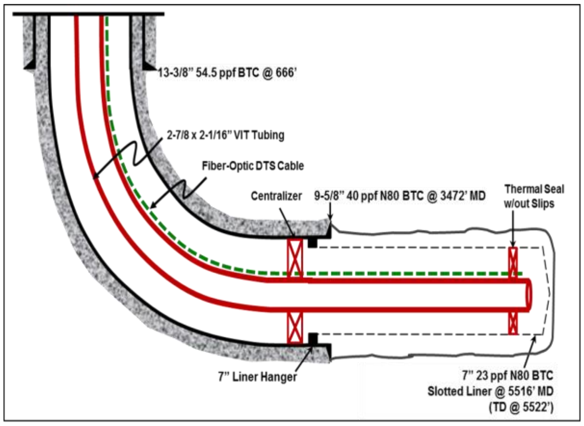

Figure 12: Wellbore Model Diagram

COMPARISON OF ACTUAL AND SIMULATED TEMPERATURE DATA

Figure 13 compares the results from the actual fiber-optic field data to the WellCat™ model results. The actual field data is shown in blue and the other curves represent three different assumed values of k-factor for the tubing. The k-factors for 2-7/8" insulated tubing that were chosen were 0.03, 0.04, and 0.05 BTU/hr-ft-°F shown by the red, green and yellow lines in Figure 13.

The actual fiber-optic temperature data was recorded after 13 days of continuous steam injection at an average injection temperature of 560 °F. Both the actual fiber-optic temperature profile and the WellCat™ model results, considered the geothermal gradient and maintained the same well conditions such as wellbore geometry, injection rates, and saturated steam conditions.

All three simulated profiles maintained the same upward trend in temperature with respect to the measured depth. Based on this data correlation, the red curve, representing a thermal conductivity (k) of 0.03 BTU/hr-ft-°F, is the best fit to the actual data obtained from the Bare steam injection well.

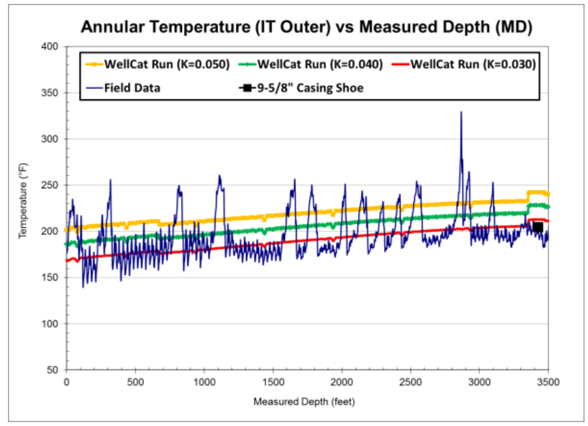

Figure 13: Field Data vs Model Annular Temperature

CASING THERMAL STRESS RESULTS

Once a thermal conductivity factor (0.03 BTU/hr-ft-°F) for insulated tubing was obtained and validated using real field data, a casing stress analysis was performed to identify thermal stress behavior on the 9-5/8" N-80 casing. This risk-case was run using the same steam and wellbore conditions to understand the impact of the temperature on casing stress.

The von Mises casing stress results shown in Figure 14, are from the actual Bare wellbore and operating conditions after 13 days of injection at an average steam temperature of 560°F (1132 psi), average steam injection rate of 616 BSPD (95.4 Tons/day), insulated tubing size of 2-7/8" x 2-1/16", and production casing size of 9-5/8" 40# N-80. Based on these inputs, the tri-axial load results for the 9-5/8" casing fell within the von Mises ellipse and therefore was not expected to result in casing damage. The compression axial force was expected to reach near -40,000 lbf - within the casing hot-yield limits. This result also corroborates with the fact that the annulus temperature during steam injection was below the compressive hot-yield temperature for N-80 casing of 397 °F.

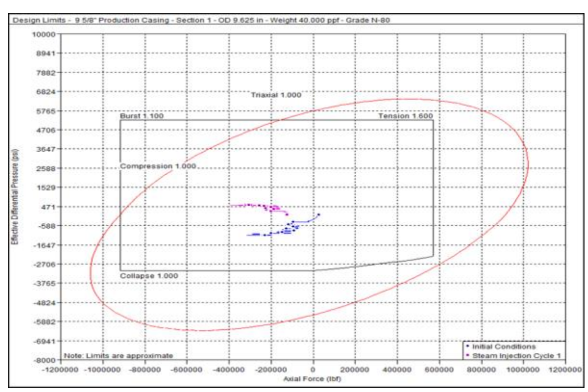

Figure 14: 9-5/8" N-80 Casing Tri-axial Stresses within the von Mises Envelope

CONCLUSION

There are three principle conclusions obtained from this analysis:

First, the temperature profile in the annulus outside of the insulated tubing decreases slightly from the surface to the casing point when the effect of the geothermal gradient (GG) is subtracted.

Second, after the first day of heating from injection, temperature increases linearly at a rate of about 1.25 °F per day at any given depth for the injection system modeled.

Finally, based on the particular system that was modeled, the effective thermal conductivity k-factor of insulated tubing was found to be 0.030 BTU/hr-ft-°F.

These results can be used to estimate heat losses for insulated tubing designs in similar conditions to evaluate not only annular temperature behavior but also casing stress analysis.

ACKNOWLEDGMENT

The authors would like to express their gratitude to PDVSA for their approval to use and publish the data included in this work and also to the PDVSA San Tome and Petropiar EOR engineers in the Ayacucho Division for their valuable team work.

NOMENCLATURE

BFPD – Barrels of Fluid per Day
BSPD – Barrels of Steam per Day
BTU – British Thermal Unit
CSS – Cyclic Steam Stimulation
DTS – Distributed Temperature Sensing
°F – Degrees Fahrenheit
GG - Geothermal Gradient
HC – Heating cable
IT – Insulated Tubing
Lbf - Pounds force
k - Thermal Conductivity Factor (BTU/hr-ft-°F)
MD – Measured Depth
MI Cable – Mineral Insulated Cable
Tons/D – Tons per Day
Faja - Orinoco Oil Belt
ppf - Pounds per Foot
psi – Pound per Square Inch
TVD – True Vertical Depth
U - Overall Heat Transfer Coefficient
VDL – Variable Density Log

REFERENCES

1. Armas, F., Mago, R., 2012, *“Quantification of the soaking time in a reservoir subjected to Cyclic Steam Stimulation, based on real data, Orinoco Oil Belt, Venezuela”*, WHOC12-215

2. Armas, F., St Bernard, J., Mago, R., 2012 *“Thermal analysis of completions for Cyclic Steam Injection used in San Tomé District. Orinoco Oil Belt”*, WHOC12-216

3. Avik S., M.D. Deo, 1993, *“Comparison of Thermal EOR Processes Using Combinations of Vertical and Horizontal Wells”,* SPE 25793

4. Birrel, G., 2003, *“Heat Transfer Ahead of a SAGD Steam Chamber: A Study of Thermocouple Data from Phase B of the Underground Test Facility (Dover Project)”*, Volume 42, N°. 3

5. Brown G. A., Kennedy B., Meling T., 2000, *“Using Fibre-Optic Distributed Temperature Measurements to Provide Real-Time Reservoir Surveillance Data on Wytch Farm Field Horizontal Extended-Reach Wells”*, SPE 62952

6. Joshi, S. D., Mutalik, P. N., Godbaole, S. P., 1968, *“Effect of drainage area shapes on the productivity of horizontal wells”*

7. Nars, T. N., Ayodele, O. R., 2005, *“Thermal techniques for recovery of heavy oil and bitumen”*, SPE 97488

8. Quintero C., Armas F., 2012 *“Cyclic Steam Injection Statistical Analysis in San Tomé District, Orinoco Oil Belt”,* WHOC12-214

9. Smith, J., Van Ness, H., Abbott, M., 1996, *“Introduction to Chemical Engineering Thermodynamics”,* Mc Graw Hill Book Company

10. Willhite G. P., 1967, *“Over-all Heat Transfer Coefficients in Steam And Hot Water Injection Wells”*, SPE-1449-PA