PROCEEDINGS, Thirty-Ninth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 24-26, 2014
SGP-TR-202

# Temperature Regime of Boreholes: Cementing of Production Liners

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**Keywords:** shut-in temperature, mud circulating temperature, liner cementing

## ABSTRACT

The effect of the borehole temperature recovery process effects (disturbed by drilling operations) the technology of the casing cementing operations. The design of cement slurries becomes more critical when a casing liner is used because the performance requirements should be simultaneously satisfied at the top and at the bottom of the liner. For these reasons it is logical to assume that the bottomhole shut-in temperature should be considered as parameter in the cement slurry design. In deep wells the actual downhole temperature during cement setting may significantly differ from the mud circulating or from the formation (undisturbed) temperatures. In this paper we suggest two methods (an empirical equation, the equivalent “API Wellbore” method). An early developed relationship can be used to determine the shut-in temperatures. A field example is presented to demonstrate the calculation procedure.

## 1. INTRODUCTION

In this paper we will consider the effect of the borehole temperature recovery process (disturbed by drilling operations) on the production liner cementing casing. Temperature and pressure are two basic influences on the downhole performance (Eppelbaum and Kutasov, 2006) of cement slurries. They affect how long the slurry will pump and how it develops the strength necessary to support the pipe. Temperature has the more pronounced influence. The downhole temperature controls the pace of chemical reactions during cement hydration resulting in cement setting and strength development. The shut-in temperature affects how long the slurry will pump and how well it develops the strength to support the pipe. As the formation temperature increases, the cement slurry hydrates and sets faster and develops strength more rapidly. Cement slurries must be designed with sufficient pumping time to provide safe placement in the well. At the same time the cement slurry cannot be overly retarded as this will prevent the development of satisfactory compressive strength. The thickening time of cement is the time that the slurry remains pumpable under set conditions. The specifications of circulation temperature in the design of thickening times for oil well cement are very important. While retarders can extend thickening times, the thickening time for a given concentration of retarder is still very sensitive to changes in temperature. Slurries designed for erroneously high circulating temperatures can have unacceptably long setting times at lower temperatures. A compressive strength of 500 psi (in 24 hours) is usually considered acceptable for casing support (Romero and Loizzo, 2000). From Figure 1 follows that a temperature difference of only 6 $^{o}$F (3.3$^{o}$C) significantly affects the compressive strength development of the cement. To reduce the wait on cement we recommend increasing the outlet mud temperature. Earlier we suggested this technique to reduce wait on cement at surface casing for wells in permafrost regions (Kutasov, 1999). This may reduce the cost associated with cementing of the conductor and surface casing.

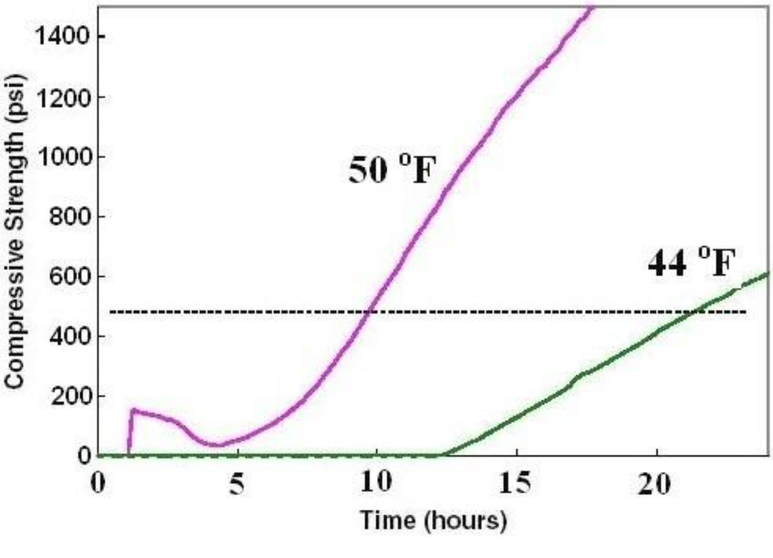

**Figure 1: Compressive strength development for a deep-water**

The design of cement slurries becomes more critical when a casing liner is used because the performance requirements should be simultaneously satisfied at the top and at the bottom of the liner. Formation (undisturbed) temperatures and fluid circulation temperatures at the top of the liner may be much lower than those at the bottom of the liner. Thus, in designing the cement slurry knowledge of the actual temperature to which it is exposed is an important factor. In deep wells the actual downhole temperature during cement setting may significantly differ from the formation temperature. It should be also taken into account that a time lapse exists between the end of mud circulation and placement of the cement.

## 2. BOTTOMHOLE CIRCULATING TEMPERATURE

### 2.1. An empirical equation

It was found that the bottomhole circulating temperature ($T_{mb}$) can be approximated with sufficient accuracy as a function of two independent variables: the geothermal gradient ($\Gamma$) and the bottomhole static (undisturbed) temperature ($T_{fb}$). Assuming that for deep wells $T_{mb}$ is a linear function of $T_{fb}$, we found that the following empirical expression can be used for predicting bottomhole circulating temperature

$$T_{mb} = d_1 + d_2 + (d_3 - d_4\Gamma)T_{fb}. \tag{1}$$

For 79 field measurements (Kutasov and Targhi, 1987; Kutasov, 1999), a multiple regression analysis computer program was used to obtain the coefficients of the formula.

$d_1$ = -50.64 °C (-102.1°F), $d_2$ = 804.9 m (3354 ft),

$d_3$ = 1.342, $d_4$ = 12.22 m/°C (22.28 ft/°F).

These coefficients are obtained for

$$74.4^{\circ}\text{C } (166\ ^{\circ}\text{F}) \le T_{fb} \le 212.2\ ^{\circ}\text{C } (414^{\circ}\text{F}),$$

$$1.51^{\circ}\text{C/100m } (0.83\ ^{\circ}\text{F/100ft}) \le \Gamma \le 4.45\ ^{\circ}\text{C/100m } (2.44\ ^{\circ}\text{F/100ft}).$$

Therefore, the Eq. (1) should be used with caution for extrapolated values of $T_{fb}$ and $\Gamma$. The accuracy of the results (Eq. (1)) is 4.6°C, and was estimated from the sum of squared residuals.

### 2.2 The equivalent “API Wellbore” method

American Petroleum Institute (API), Sub-committee 10 (Well Cements) has developed new temperature correlations for estimating circulating temperatures for cementing (Covan and Sabins, 1995). To use the current API bottom-hole temperature circulation (BHCT) correlations (schedules) for designing the thickening time of cement slurries (for a given depth) the knowledge of the averaged static temperature gradient is required. The surface formation temperature (SFT) for the current API test schedules is assumed to be 80 °F. Thus to calculate the static temperature gradient the static (undisturbed) temperature profile of formations should be determined with a reasonable accuracy. The value of SFT (the undisturbed formation temperature at the depth of approximately of 50 ft, where the temperature is practically constant) of about 80°F is typical only for wells in Southern U.S. and some other regions. For this reason the API test schedules cannot be used for determination values of BHCT for cementing in wells drilled in deep waters, in areas remote from the tropics, or in Arctic regions. For example, the equivalent parameter of SFT for offshore wells is the temperature of sea bottom sediments (mud line) that is close to 40 °F. In Arctic areas the value of SFT is well below the freezing point of water. Many drilling operators came to a conclusion that computer temperature simulation models (instead of the API schedules) should be used to estimate the cementing temperatures (Honore et. al, 1993; Guillot et. al, 1993; Calvert and Griffin, 1998). It is logical to assume that for wells with $T_0$ = 80 °F a good agreement between measured and estimated from API correlations values of BHCT should be expected. Therefore we suggested to “transform” a real wellbore to an “Equivalent API Wellbore” (Kutasov, 2002**)**. As an example let us consider a well with following parameters: $H$ = 20,000 ft, $\Gamma$ = 0.020 °F /ft and $T_0$ = 60 °F. Then the depth of the 80 °F isotherm is: (80-60)/0.020 = 1,000 (ft). Thus the vertical depth of the “Equivalent API Wellbore” is

$$H^* = 20{,}000 - 1{,}000 = 19{,}000 \text{ (ft)}.$$

Similarly, for a well with $T_0$ = 100°F,

$$H^* = 20{,}000 + 1{,}000 = 21{,}000 \text{ (ft)}.$$

Below we present simple equations for estimation of the equivalent vertical depth ($H^*$). For on land well,

$$H^* = H + \frac{T_0 - 80}{\Gamma}. \tag{2}$$

For an offshore well,

$$H^* = (H - H_w) + \frac{T_0 - 80}{\Gamma}, \tag{3}$$

where $T_0$ is the temperature of bottom sediments (mud line) and Γ is the average temperature gradient in the $H – H_w$ section of the wellbore.

$$\Gamma = \frac{T_{fb} - T_0}{H - H_w}. \tag{4}$$

### 2.3 Examples

Below we present two examples of determination bottom-hole circulating temperatures (BHCT) by the API-EW Method.

Example 1 – on land well A (Figure 2). The surface temperature $T_0$ = 50 °F, vertical depth $H$ = 20,000 ft, and the static temperature gradient Γ = 0.015 °F/ft, and the bottom-hole static temperature is 350 °F.

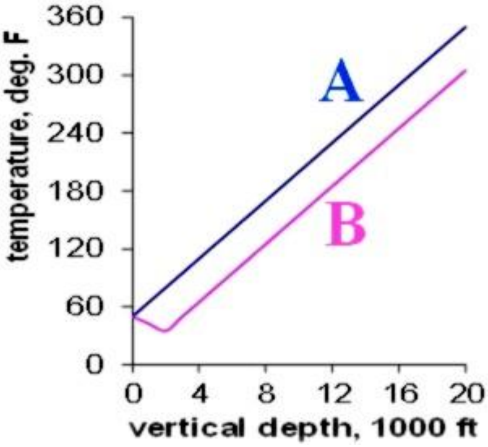

**Figure 2: Temperature profiles: A – on land well, B – offshore well**

From Eq. (3) we obtain

$$H^* = 20,000 + (50 - 80)/0.015 = 18,000 \text{ (ft)}.$$

Using the new API BHCT correlations (Covan and Sabins, 1995) for $H^*$ = 18,000 ft and Γ = 0.015 °F/ft we estimate that BHCT = 291 °F and this is in a fairly good agreement with value of 301 °F determined from Eq. (2) (note that the averaged accuracy of the Eq. (1) is 8.2 °F).

Example 2 – offshore well B (Figure 2). The water surface temperature is 50 °F, the temperature of bottom sediments a $T_0$ = 35 °F, $H$ = 20,000 ft, Γ = 0.015 °F/ft, water depth $H_w$ = 2,000 ft, and the bottom-hole static temperature is 305 °F. From Eq. (2) we obtain

$$H^* = (20{,}000 - 2{,}000) + \frac{35 - 80}{0.015} = 15{,}000\,(\text{ft}).$$

From new API correlations (Covan and Sabins, 1995) for $H^*$ = 15,000 ft and Γ = 0.015 °F/ft we determined that BHCT = 244 °F and this is in a satisfactory agreement with value of 256 °F determined from Eq. (1).

### 3. THE SHUT-IN TEMPERATURE

By using the adjusted drilling mud circulation time concept we obtained an equation for dimensionless shut-in temperature (Kutasov, 1999).

$$T_{sD} = \frac{T_s(t_s) - T_f}{T_c - T_f}, \tag{5}$$

$$\left\{ T_{sD} = 1 - \frac{Ei\left[-\beta\left(1 + t_D^* / t_{sD}\right)\right]}{Ei\,(-\beta)}, \quad t_{sD} = \frac{a t_s}{r_w^2} \right\}, \tag{6}$$

$$t_D = \frac{a t_c}{r_w^2}, \qquad \beta = \frac{1}{4 t_D^*}, \qquad t_D^* = G t_D, \tag{7}$$

where $T_s$ is the shut-in temperature, $t_s$ is the shut-in time, $T_c$ is the drilling fluid circulation temperature (at a given depth), $t_c$ is drilling fluid circulation time, $T_f$ is the formation (undisturbed) temperature.

The values of the function $G$ can be calculated from Eqs. (7) and (8):

$$\left\{\begin{matrix} G = 1 + \dfrac{1}{1+AF}, & t_D \le 10, & \\ F = \left[\ln\left(1+t_D\right)\right]^n, & n = 2/3, & A = 7/8 \end{matrix}\right\}, \qquad (7) \qquad \left\{ G = \frac{\ln t_D - \exp\left(-0.236\sqrt{t_D}\right)}{\ln t_{cD} - 1}, \quad t_D > 10 \right\}. \qquad (8)$$

The correlation coefficient $G(t_D)$ varies in the narrow limits: $G(0) = 2$ and $G(\infty) = 1$.

## 4. FIELD EXAMPLE

Well #4 (Venezuela) is a vertical wellbore. The total depth was 12,900 ft the bottomhole static temperature at 12,600 ft was 244°F. The casing size of this well is $5^{1/2}$ in. And the hole size was 8 1/2-in.=0.354 ft the 14.0 ppg composite blend cement slurry was used (Dillenbeck et al., 2002). We assumed that the surrounding formation is oil-bearing sandstone with thermal conductivity 1.46 kcal/(m·hr·°C) and thermal diffusivity -0.0041m²/hr. Let us assume that a production liner was set at a depth of 10,000 to 12,600 ft. A period of 30 days was needed to drill this interval. In addition to this, 36 hours were needed to clean up the well and pump the cement slurry; therefore, the duration of the thermal disturbance of the formation at depth of 10,000 ft was 756 hrs (30·24+36) days and at depth of 12,600 ft was 36 hours. Let us assume that the geothermal gradient $\Gamma = 0.013$ °F/ft. Then the formation temperature is

$$T_f\left({}^{\circ}\mathrm{F}\right) = 80\left({}^{\circ}\mathrm{F}\right) + 0.013\left({}^{\circ}\mathrm{F/ft}\right)\cdot H\,.$$

The drilling mud circulating temperatures were estimated from Eq. (1): for $H$ = 12,600 ft, $T_{mb}$ = 199 °F, and for $H$ = 10,000 ft, $T_{mb}$ = 162.5 °F.

The results of calculations after Eq. (5) are presented in Figure 3 and Table 1.

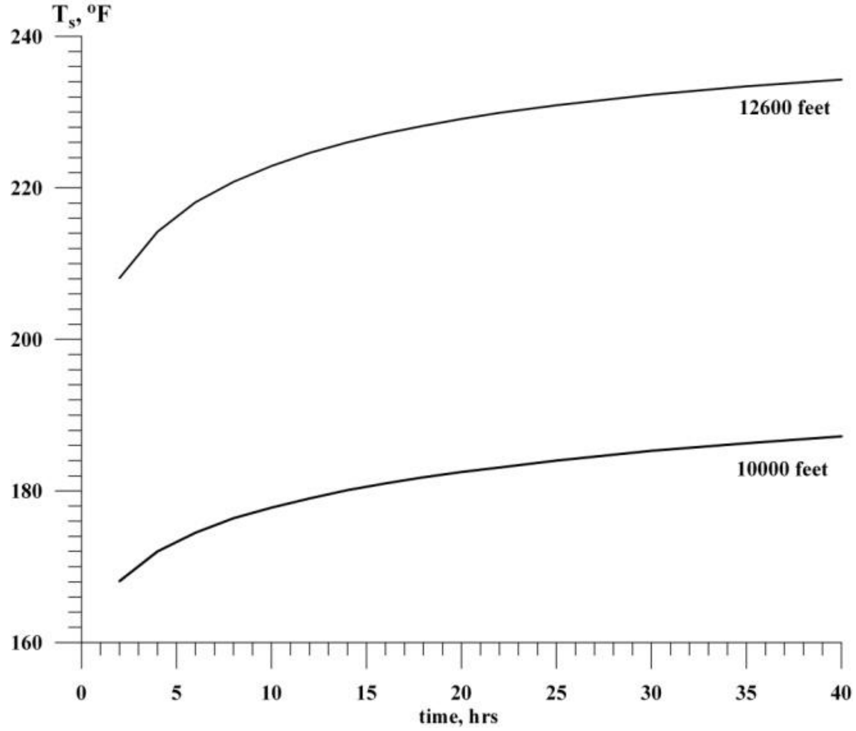

**Figure 3: Shut-in temperatures for two depths**

The temperature variation (Table 1 and Figure 1) depends on the time of the cement slurry placement and can have a significant effect on the performance of a cement system and has to be taken into account. For example, the temperature at depth of 10,000 ft after 6 hours is not 162.5 °F (circulation temperature), but 174.5 °F. Also, the temperature at the depth 12,600 ft after 6 hours of shut-in is not 199 °F (circulation temperature), but 218.1°F. The difference of 12-19 °F can have a substantial impact on the cement slurry design. For both depths the difference of $T_f - T_s$ after 6 hours of shut-in is 25.9 and 35.5 °F (Table 1).

**Table 1: The difference $T_f - T_s$ for two depths and values of $\gamma$**

| | $h$ = 12,600 ft<br>$t_c$ = 36 hrs<br>$T_f$ = 244 °F<br>$T_c$ = 199 °F | | $h$ = 10,000 ft<br>$t_c$ = 756 hrs<br>$T_f$ = 210 °F<br>$T_c$ = 162.5 °F | |
|---|---|---|---|---|
| $t_s$, hrs | $T_f - T_s$, °F | $\gamma$ | $T_f - T_s$, °F | $\Gamma$ |
| 2.0 | 35.9 | 0.798 | 41.9 | 0.881 |
| 4.0 | 29.8 | 0.662 | 38.0 | 0.800 |
| 6.0 | 25.9 | 0.576 | 35.5 | 0.747 |
| 8.0 | 23.2 | 0.515 | 33.6 | 0.708 |
| 10.0 | 21.1 | 0.468 | 32.2 | 0.677 |
| 14.0 | 18.0 | 0.400 | 29.9 | 0.630 |
| 18.0 | 15.8 | 0.351 | 28.2 | 0.594 |
| 20.0 | 14.9 | 0.331 | 27.5 | 0.579 |
| 30.0 | 11.7 | 0.260 | 24.7 | 0.521 |
| 40.0 | 9.7 | 0.216 | 22.8 | 0.480 |

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