Effect of Heat Loss on Pressure Falloff Tests

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Abstract *Analysis of pressure falloff tests gives initial estimates of swept volume, essential for the evaluation of a thermal recovery process. The analysis is conventionally based on a two-zone composite reservoir model with highly contrasting fluid mobilities where the swept zone is assumed to behave as a closed reservoir for a short period exhibiting pseudo steady state behavior. The upward buckling of the pressure derivative curves at late times in some cases could not be explained using the conventional composite models. This issue and some of the errors associated with the estimation of swept volume may possibly be related to heat loss which could have significant effects on the pressure behavior and dominate the pseudo steady state flow. A few models were suggested for the analysis of falloff tests with significant heat loss, however they are limited in application. Moreover, permeability should be known in advance for further analysis. In this paper, a modified method of analysis considering heat loss is discussed which makes the flow regime identification easier and removes some of the practical limitations. Results of the analysis show improvement over the estimates obtained by other methods.*

Keywords— *pressure falloff test, thermal methods, composite reservoir, heat loss*

I. Introduction

Swept volume together with the cumulative steam injected provide an estimate of the heat loss and efficiency of a thermal project. Among other methods used in field operations, well test analysis provides a quick and inexpensive way to obtain an initial estimate of the swept volume. It can also provide estimates of flow capacity and skin factor and is used as a reservoir characterization tool. Falloff tests are mostly analysed in thermal projects assuming a composite reservoir model with two regions of highly contrasting fluid mobilities [1]. The boundary between the inner and outer regions acts as a closed one. Therefore, pseudo steady state (PSS) flow regime is observed for a short period and is used for the analysis.

Some inconsistent, even opposing results in the literature motivated further analysis and application of thermal well testing method for steam injection wells in previous studies ([2]-[4]) using vertical and horizontal wells considering effects of several operating parameters on well test results. It was concluded that some trends seen on the pressure plots cannot be explained correctly using the existing models and there are errors associated with the results that could be related to the simplifying assumptions of the methods of analysis. One of these assumptions is neglecting the heat loss effect.

Stanislav et al. [5] performed studies to improve the estimation of swept volume based on the PSS concept. Steam condensation was included in the flow model by adding heat loss from steam zone to the formation. They modified the original solution to the composite reservoir model by including a term which accounts for the heat loss. They carried out a sensitivity study of the solution to this term. It was concluded that under certain conditions, heat loss could have a significant effect on the pressure falloff behavior and dominate the PSS behavior. Consequently, they proposed a new procedure for falloff data interpretation when heat loss effect is significant.

Sheng and Ambastha [6] investigated the applicability of a new approach. They stated that Stanislav et al. approach is limited in practical well tests where the pressure changes are typically small during the test. In addition, the value of permeability should be known in advance. They tried to modify the approach to expand the applicability by removing some limitations. Recently, Duong [7] analyzed heat loss effect on pressure behavior using real field data. He proposed a method of analysis based on the data he observed in the field, and is not general.

The methods considered have some drawbacks and assumptions and cannot be generally applied. In this study, it is tried to analyze some examples in the literature and also a few synthetic falloff tests affected by heat loss using different methods and to correct and comment on some of these methods. A general procedure will be described to analyze the data affected by heat loss.

II. Method of Analysis

Different methods are first briefly discussed here. The conventional thermal well test analysis method for the estimation of permeability and swept volume is based on the Miller-Dyes-Hutchinson (MDH) method for the analysis of falloff data since the shut in time is much less than the injection time in practical steam injection. The pressure analysis technique should suffice for all practical purposes, and real gas analysis is in fact unnecessary because of the relatively small pressure changes common for steam pressure falloff tests.

Based on the material balance with the inclusion of the steam condensation effect induced by heat loss to the surroundings, neglecting capillary effects and expressing the velocities in terms of Darcy's law, Stanislav et al. [5] summed up the immiscible flow equations for flow in the inner (steam) zone as:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p}{\partial r}\right)=\frac{\phi c_t}{0.000264\lambda_t}\left(\frac{\partial p}{\partial t}\right)+\frac{(F_\rho-1)G}{0.000264\lambda_t} \qquad 1$$

G is the volume of liquid water generated by steam condensation per unit reservoir volume and time or simply the rate of condensation per unit volume in terms of the rate of heat loss given by [8]:

$$G=\frac{2k_h(T_s-T_i)}{\sqrt{\pi\alpha\, t}\,L_v\rho_w h} \qquad 2$$

This represents the case in which temperature assumes the constant value T_s as soon as steam injection begins. A two-region composite reservoir model is assumed with heat loss from the inner hot region. Using dimensionless parameters and the definition of G, equation 1 can be written as:

$$\frac{\partial^2 p_D}{\partial r_D{}^2}+\frac{1}{r_D}\frac{\partial p_D}{\partial r_D}=\frac{\partial p_D}{\partial t_D}-\beta\frac{1}{\sqrt{t_D}} \qquad 3$$

Where

$$\beta=\frac{4\pi(F_\rho-1)k_h(T_s-T_i)r_w}{L_v\rho_w qB}\sqrt{\frac{k}{\pi\alpha\,\phi\,\mu\, c_t}} \qquad 4$$

The short-time approximation to the solution of equation 3 is:

$$p_{wD}=\frac{1}{2}(\ln t_D+0.81)+2\beta\sqrt{t_D}+s \qquad 5$$

The PSS solution (Assuming the inner zone acting like a closed reservoir) is:

$$p_{wD}=\frac{1}{2}\ln\left(\frac{2.24A}{C_A r_w{}^2}\right)+2\pi\, t_D\left(\frac{r_w{}^2}{A}\right)+2\beta\sqrt{t_D}+s \qquad 6$$

The dimensional equivalents of equations 5 and 6 can be written, respectively as:

$$\Delta p-(\gamma/2)\ln\Delta t=2\beta\,\gamma\,\delta^{1/2}\Delta t^{1/2}+$$
$$(\gamma/2)\ln(\delta+0.81+2s) \qquad 7$$

and

$$\Delta p-2\beta\,\gamma\,\delta^{1/2}\Delta t^{1/2}=2\pi\,\gamma\,\delta\left(\frac{r_w{}^2}{A}\right)\Delta t+$$
$$(\gamma/2)\ln\left(\frac{2.24A}{C_A r_w{}^2}\right)+\gamma\, s \qquad 8$$

Where

$$\gamma=\frac{141.2qB\mu}{kh} \qquad 9$$

and

$$\delta=\frac{0.000264k}{\phi\,\mu\, c_t r_w{}^2} \qquad 10$$

Reference [5] suggested (based on equation 7) that a plot of Δp - (γ/2) ln Δt vs. $\Delta t^{1/2}$ should yield a straight line with slope:

$$m=2\beta\,\gamma\,\delta^{1/2} \qquad 11$$

From equation 11, the heat loss coefficient (β) can be readily obtained and skin factor can be computed:

$$s=[\Delta p^{(1)}/\gamma]-2\beta\ \delta^{1/2}-(1/2)\ln(\delta+0.81) \qquad 12$$

Where $\Delta p^{(1)}$ is the pressure difference at the test time of one hour, determined from the linear plot of Δp - (γ/2) ln Δt vs. $\Delta t^{1/2}$.

From equation 8, a plot of Δp - $2\beta\gamma\delta^{1/2}\Delta t^{1/2}$ vs. Δt yields a straight line with slope:

$$m^*=\frac{(5.615)\,qB}{(24)Ah\phi\, c_t} \qquad 13$$

It can be solved for the swept volume. Before the above approach can be used, γ and δ must be calculated. However, permeability is not known before well tests. If due to a wrong permeability estimate a negative β is estimated, as [6] reported, the analysis is of no importance. They investigated the applicability of heat loss coefficient calculation to evaluate steam condensation effect during falloff test. They reported that the calculated values of β (using equation 4) were different from the values obtained by well test analysis, either bigger or smaller and suggested a condition to obtain positive volume for late-time pressure data as:

$$\frac{d(\Delta p)}{d\Delta t}>\beta\,\gamma\,\delta^{1/2}\,\Delta t^{-1/2} \qquad 14$$

In the same way, a positive value for β is obtained, if the following condition is valid for the early-time:

$$\frac{d(\Delta p)}{d\Delta t}>\frac{\gamma}{2\Delta t} \qquad 15$$

This is not likely to happen before t=1 hr since the pressure function is governed by the logarithmic term if Δp is not large (which is common). Then, the pressure function could be a decreasing function of time for a while which results in negative β.

Because of the shortcomings of the approach of [5] discussed, the method was reconsidered by Sheng and Ambastha in [6] assuming that the following product (named steam condensation constant) could be correctly estimated from the available data:

$$C_G=2\beta\,\gamma\,\delta^{1/2} \qquad 16$$

or

$$C_G=\frac{57.63(F_\rho-1)k_h(T_s-T_i)}{L_v\rho_w\phi c_t h\sqrt{\pi\alpha}} \qquad 17$$

Although the parameters γ and δ depend on k, the constant itself is independent of the value of permeability. It does not depend on wellbore radius and flow rate either. In the case of horizontal wells, *L*, the horizontal length of the steam chamber will be used instead of reservoir thickness (*h*) in the equation. Rearrangement of equation 7 yields a straight line on the plot of Δp - $C_G \Delta t^{1/2}$ vs. log Δt for the early-time data with slope:

$$m' = \frac{162.6 qB\mu}{kh} \quad 18$$

It can be used in the determination of permeability. The skin factor can also be estimated:

$$s = 1.1513\left((\frac{\Delta p^{(1)}}{m'}) - \log(\frac{k}{\phi \mu c_t r_w^{\ 2}}) + 3.23 \right) \quad 19$$

Where $\Delta p^{(1)}$ is the value of the pressure function (Δp - C_G $\Delta t^{1/2}$) at the test time of one hour, determined from the straight line on the plot. Heat loss coefficient can then be obtained as:

$$\beta = \frac{C_G}{2\gamma\, \delta^{1/2}} \quad 20$$

For the late-time data, a plot of Δp - $C_G \Delta t^{1/2}$ vs. Δt yields a straight line with slope:

$$m^* = \frac{(5.615)\, qB}{(24) V \phi\, c_t} \quad 21$$

Swept volume can then be estimated. Reference [6] suggested that even if C_G could not be estimated from the available information, a trial and error approach for determination of C_G can be used to ensure having the radial and PSS flow regimes. Several guesses of C_G may be tried until the desired linear plots for early and late-time data are achieved. They also stated that the two conditions of equations 14 and 15 can be reduced to one using their modified approach as:

$$0 < C_G < 2\frac{d(\Delta p)}{d\Delta t}\Delta t^{1/2} \quad 22$$

This condition (valid for both early and late-time analysis) was supposed to make the C_G guess more reliable and flow regime identification easier. Another method ([7]) suggests using a linear plot of pressure and pressure derivative data of the period influenced by heat loss versus square root of time. Slopes and intercepts of these plots and also analysing the semi-log plot of the late radial flow can give estimates of reservoir parameters.

III. Results and Discussion

Stanislav et al. [5] showed that low values of β (0-0.1) will have just marginal effect on the pressure behavior where a PSS flow regime is dominant for over two log cycles. This can possibly explain why the application of the PSS method in many cases turned successful. In such systems, possibly having very small heat loss, the PSS flow regime is not distorted and a quite long set of data is used for volume calculations and therefore can be analysed by the conventional PSS method assuming no heat loss. At higher values of β (1-5), the early-time radial flow and PSS flow are masked by a kind of linear flow characterized by half-slope line on log-log plots of both pressure and pressure derivative versus time. This can be confirmed by investigating equations 7 and 8. Unlike the cases with small values of β for early-time period, at higher β values the weight of the $\Delta t^{1/2}$ term in the pressure drop expression increases and will dominate the logarithmic term. The same thing happens to the PSS equation where at high values of β, the $\Delta t^{1/2}$ term will dominate the PSS behavior. So, the effect of huge heat loss shows up as a linear flow.

In this section, some comments on different methods are given and some of the examples considered in previous works are analysed. Some simulated test data are also considered to further investigate the applicability of heat loss analysis. Data of [5] is a good example to analyse and discuss using different methods. Fig. 1 shows the pressure and derivative data for this example. As indicated by the half-slope line, early and late-time data are influenced by heat loss effects.

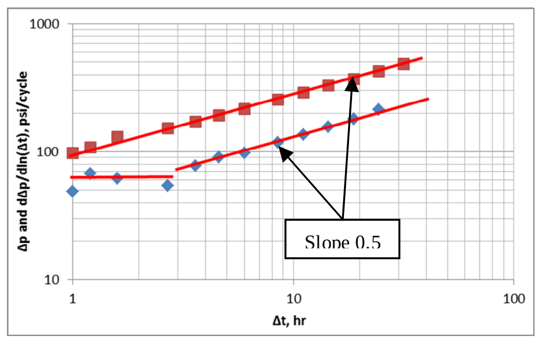

Fig. 1 Example pressure and pressure derivative plot [5]

This example was analysed by the method of [5] (Table 1). Results are different from the original paper [5] since we used the value of the slope (C_G) from plots in the calculations while in the original paper, the calculated value using equation 17 was used.

Table 1 Results of the analysis of example of [5]

Method of analysis	β	C_G (psi/hr$^{1/2}$)	γ (psia)	δ (hr^{-1})
Method of [5]	0.49	75.27	8.15	87.6
Method of [6]	0.53	76.29	7.34	97.3
This study with no *k* or C_G	0.61	81.16	6.56	109

Reference [6] claimed that if the calculated values of β using equation 4 were used, the pressure function and the slope (and hence volume) would be negative. Values of β obtained from plots were also reported small or negative in some cases. It is very important to estimate β correctly as it may result in negative swept volume. For early-time data before one hour, based on equation 7, the logarithmic term may be very large and may govern the pressure function and result in negative β. Overestimation of β may also result in negative pressure function and hence wrong estimates since pressure drop is typically small in steam injection. Reference [6] suggested further investigation of equation 4 and steam condensation rate, G, for steam injection processes. They mentioned that for the example of [5], all data points fall on the same straight line (plotted against $\Delta t^{1/2}$) which makes flow regime identification impossible. This is obviously due to heat loss They also mentioned that almost all the data points fall on the same Cartesian straight line indicating too long PSS flow regime which is not practical in their opinion and they mentioned this example is not typical of a thermal falloff test. Again, this happens due to the heat loss effect. This example was therefore analysed by method of [6]. Based on the available data, the value of C_G is first calculated. The pressure function (Δp - C_G $\Delta t^{1/2}$) and its derivative are then plotted. As can be observed from Fig. 2, when the effect of heat loss (or $C_G \Delta t^{1/2}$) is removed from the data, flow regime identification is made easier, as reported in [6]. Radial flow (zero slope) and PSS flow (unit slope) are visible on the derivative plot.

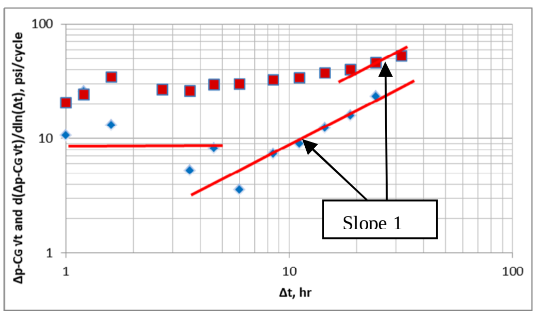

Fig. 2 Pressure function (Δp - C_G $\sqrt{t}$) and derivative plots

Reference [6] provided other examples with negligible heat loss and that is why they reported no improvement over the conventional well testing method by application of Stanislav et al. or their modified method and obtained even worse estimates of permeability and volume.

It is suggested to first calculate C_G or estimate it from plot of pressure versus $\Delta t^{1/2}$ instead of guessing. If the calculated value of C_G from equation 17 is used, the semi-log (early-time) and Cartesian (late-time) plots can be obtained. Using the slopes, properties can be calculated (as shown in Table 1), using the formulas presented earlier.

The inequality 22 was almost satisfied in this example, as the calculated values of C_G (Table 1) are below the limit for most of the data points, and quite reasonable results are obtained in agreement with Stanislav et al. method. It is important to notice that the inequality 22 should be satisfied over the period influenced by heat loss and not necessarily over the whole data set.

If the value of C_G cannot be obtained using the available information, it can be roughly estimated from the pressure or derivative plots (either early or late-time data if influenced by heat loss) versus $\Delta t^{1/2}$. Again, using the value of C_G, semi-log and Cartesian plots are obtained. The C_G obtained from the plots is probably not as accurate as the calculated value (equation 17) since the slope of the plots contains a combination of condensation effect and radial (early-time) or PSS (late-time) flow that makes it slightly larger than the actual value.

Reference [7] used the intercepts of pressure and derivative plots for parameter estimation. The application of this method is basically the same as the method suggested in the analysis of the example discussed. From the corresponding plots, values of C_G and then k (γ and δ) and skin factor are estimated. The only difference is in the calculation of swept volume where [7] used the equations for intercepts instead of the Cartesian plot.

Plot of the late-time pressure derivative data versus $\Delta t^{1/2}$ is used. Using the linear expression of this plot and the derivative of PSS late-time solution (equation 8) written as:

$$\Delta p' = \frac{C_G}{2}\sqrt{\Delta t} + 2\pi\gamma\delta\left(\frac{r_w^{\,2}}{A}\right)\Delta t \qquad 23$$

And evaluating the expressions at one hour, results in negative value of area which may possibly be due to the wrong estimate of C_G as discussed before. Instead of derivative, using Δp of late-time (PSS flow) versus $\Delta t^{1/2}$ and its intercept in the following equation (equation 8 evaluated at Δt =0):

$$\Delta p_{at\ \Delta t=0} = (\gamma/2)\ln\left(\frac{2.24A}{C_A r_w^{\,2}}\right) + \gamma\, s \qquad 24$$

The volume is 2730 ft^3 which is far away from the values estimated before by other methods. The value of C_G used for the analysis (81.16, exceeding the limit for most of the data points) did not obtain good volume estimates, because the condition of inequality 22 is not met and this makes the analysis unreliable. So, it is very important to accurately estimate the value of C_G to ensure reasonable estimates.

The value of β calculated by equation 4 (0.45) is close to the values obtained by different methods in Table 1. This shows that equation 4 is appropriate for the estimation of heat loss coefficient and qualitative heat loss analysis when the required information is available.

Reference [7] mentioned that the early radial flow and late-time boundary dominated flow regimes cannot be observed in their field data and are masked by relatively long linear flow regime which was attributed to steam condensation during shut in period as a result of heat loss. It was claimed that the analysis of the linear flow and late-time data gives estimates of skin, condensation factor, swept zone, effective bitumen drainage area and initial formation permeability. In this paper, some modifications to the application of the original equations are considered to modify the suggested method.

It is important to notice that equations presented in [5] were developed assuming conduction heat loss to the formation. Therefore, in contrary to [7], the heat loss caused by live steam production (through the producer) or leakage should not be accounted for. It was stated in [7] that the results obtained by many investigators do not apply to a steam assisted gravity drainage (SAGD) process because these studies assumed a single injector with negligible heat loss. However, [9] and [10] and others (including SAGD studies such as [3] and [4]) analysed real and simulated data and effect of producer was added to the observations showing the heat loss (if huge).

In addition to the steam zone radial flow and the initial PSS flow regime, based on the mobility difference with the hot water zone, radial flow in this zone and also late PSS flow regime may be dominated by the $\Delta t^{1/2}$ term (heat loss) and show up as linear flow or at least distort the trend towards linear flow. The late radial flow (in outer zone) is however most probably not masked due to the high value of mobility difference (λ, the dominant term). The late-time solution proposed by [5] is:

$$p_{wD} = \frac{\lambda}{2}\ln t_D + \ln\frac{2}{F_\eta^{\lambda/2}} + 0.5772\left(\frac{\lambda}{2}-1\right) + \ln\left(R_D^{\,1-\lambda}\right) + \beta\sqrt{t_D} + s \qquad 25$$

Heat loss is assumed to happen from the inner hot zone to the formation and therefore at late time (describing flow in the outer cold zone), the value of β does not matter. In equation 25, the mobility contrast between zones is very high and for values of λ bigger than 1000 (which is common), effect of the heat loss term becomes almost negligible. Reference [7] reported λ values of around 2000 at the steam chamber wall region to over 20000 far inside the unswept zone for Surmont.

Based on equation 25 (dimensional form), for the cases with significant heat loss, since mobility term dominates the condensation term, for radial flow in the outer zone, a plot of Δp - λ (γ/2) ln Δt versus $\Delta t^{1/2}$ results in slope of C_G /2 while Δp versus $\Delta t^{1/2}$ for radial flow in the steam zone results in slope of C_G. Based on the same equation, for flow in the hot water zone, if the mobility contrast between steam zone and this zone is not too big, a plot of Δp versus $\Delta t^{1/2}$ results in slope of C_G /2. This can be used as an indication of flow in different zones. It can be applied to the example of [7] to ensure the late-time data is related to the radial flow in the outer zone. In the example of [5], slope is maintained at C_G, and this reveals that radial flow in the hot water zone is not yet reached or it is masked.

Reference [7] mentioned that the linear flow they observed is present for over a log cycle up to 100 hours and is not the same as the linear flow described by [3] and [11] that lasted only during the first hours of shut in. He claimed that it represents the condensation dominant period. However, still there is the possibility that this linear flow is because of the lateral boundaries of the reservoir in the shape of a channel known as the late linear flow in horizontal wells. As shown in Fig. 3, for long injection time (here 160 days), after the early radial flow and before the PSS flow regime, some early linear flow can be observed due to the boundaries. This is also seen in the case of 80 days injection. The characteristic of the linear flow regime on derivative plot is the presence of half-slope line.

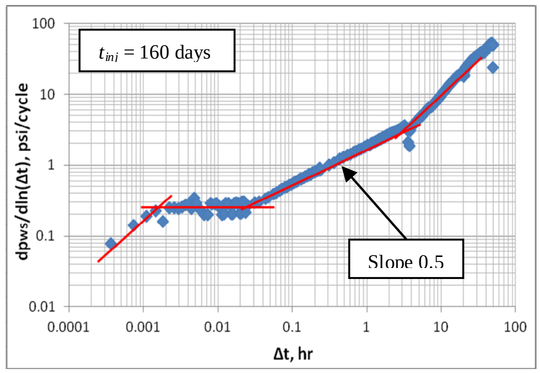

Fig. 3 Example pressure derivative plot for long injection time [3]

Linear flow calculation should be done by a plot of pressure data (not the derivative) versus $\Delta t^{1/2}$ to estimate C_G. Reference [7] stated that since this is the PSS flow affected by heat loss showing linear flow trend based on equation 8, the slope is a summation of C_G and another term. The intercept of derivative was used; however, in the formula for the logarithmic derivative, there are two time dependent terms, so the intercept should be zero at zero time and cannot be used for parameter estimation. However, the value of derivative at one hour may yield the value of A if C_G is calculated. The equation given in [7] for the intercept of derivative of pseudo pressure (ψ) should therefore be corrected to:

$$\Delta\psi'_{3\,at\,\Delta t=1} = \frac{C_G}{2} + \frac{2.36qT_s}{\phi\mu c_t LA} \qquad 26$$

Pressure (or pseudo pressure) plots are usually used for parameter estimation (not the derivative plots). Therefore, the intercept of pseudo pressure plot may be used, relating A and s:

$$\Delta\psi_{3\,at\,\Delta t=0} = 1422\frac{qT_s}{kL}\left[\frac{1}{2}\ln\left(\frac{2.24LA}{C_A r_w^{\,2}}\right) + s + Dq\right] \qquad 27$$

For the late radial flow observed in [7]:

$$\Delta\psi_{4\,at\,\Delta t=1} = \frac{1422}{2}\frac{qT_s}{kL}\left[\ln\left(\frac{4.61\times10^{-4}k\pi}{\phi\mu c_t A}\right) + 2(s + Dq)\right] \quad 28$$

Using either equation 26 or 27 together with equation 28, having two equations and two unknowns, *A* and *s* can be determined. Properties of the unswept zone should be used in equation 28. Table 2 shows the results obtained for the example of [7]. The same C_G and β as calculated by [7] were used.

Table 2 Results of the analysis of example of [7]

Method	***A*** **(ft²)**	β	C_G **(MMpsi²/cp/hr$^{1/2}$)**
Duong [7]	3801	1.3	0.55
This study using eq. 26	2720	-	-
This study using eq. 27	1345	-	-

The value of $\Delta\psi'_{3@\Delta t=1}$ used in equation 26 was assumed to be 1.3×10^6, found from the expression ($\Delta\psi'_3$=0.524 $\Delta t^{1/2}$ + 0.772) suggested for derivative. However, this expression seems not accurate enough as the intercept should be zero (as discussed above), and also based on the value of C_G=0.55, the slope should be about 0.27 since the slope of the derivative plot is C_G / 2 when heat loss is huge. However, this difference may possibly be accounted for by the fact that slope contains a combination of condensation and PSS flow effects. Using the value of 0.6×10^6 in equation 26 will result in: *A*=8578 ft² and s = -0.15.

There is not a close agreement among the results obtained in Table 2, but note that derivative data of [7] are very noisy, so maybe it is better to comment about flow regimes more carefully. And maybe, the linear trend is a combination of flow regimes. When [7] found the last radial flow regime not reliable because of non-consistent semi-log plots showing smaller slopes with higher injection rates, he related this to the steam condensation due to heat loss, chamber non-conformance and non-Darcy effects. The conformance and the value of effective well length were reported to be the most important causes. However, this flow regime is probably happening in the hot water zone that can still being distorted by heat loss and rate effects.

The analysis method of [7] relied on the existence of the late radial flow regime representing the flow in the cold oil zone. Normally, the test is not run long enough to see this radial flow or the radial flow is not obvious. Furthermore, permeability should be known in advance and this is a drawback. Initial estimates of permeability can be obtained from conventional method of falloff pressure data analysis.

A general procedure is proposed here to ensure reliable falloff test analysis even if huge heat loss occurs. It is suggested to choose the method of analysis based on the flow regimes observed during a test. Pressure derivative plot should be analysed first for flow regime identification. It is not easy to see the late radial flow unless long shut in times are considered. Based on the equations presented for the possible individual flow regimes, reservoir parameters can be estimated. If any radial flow is recognized, a semi-log plot will give the value of mobility (or permeability) or mobility ratio. For any PSS flow, a Cartesian plot will give estimates of swept volume or reservoir volume. Any linear flow may result in the estimation of heat loss coefficient if huge heat loss happens. If the calculated coefficient is not large, the linear flow can be due to the effect of the boundaries.

For the periods affected by huge heat loss, the corresponding term should be removed from the pressure data. This defines the new pressure function (Δp - C_G $\Delta t^{1/2}$). Derivative of the pressure function is then generated and plotted. This plot should exhibit the radial and PSS flow regimes with the characteristic slopes (zero and one, respectively) if correct value of C_G is used. Semi-log and Cartesian plots of the pressure function can then yield permeability and swept volume. This is when the value of C_G can be calculated from the available information. Otherwise, it is suggested to obtain an estimate from the slope of the plot of (Δp) vs. $\Delta t^{1/2}$. Reading the value of C_G, special plots are then generated and analysed. This procedure was described for the analysis of an example before. In addition to the slopes of characteristic straight lines on special plots, their intercepts also contain some useful information. The intercepts of different plots (each including unknowns) will form a system of equations that can be solved for the unknown parameters.

The method of analysis proposed in this study uses the original model of [5] and rearrangement by [6] and will simply correct the method proposed by [7]. To further investigate and confirm the applicability of the method, a few cases with significant heat loss are considered. A numerical thermal simulator is used to simulate the falloff tests. Basic details of the models, input data for simulator and other test conditions can be found in [2]-[4]. Briefly, for the vertical well base-case, steam is injected (at rate of 500 STB/D) into reservoir models until appreciable rock volumes are swept (here 30 days). Pressure falloff tests are then simulated by shutting in the injection well (for one day) and reading the wellbore gridblock pressures as a function of time. For the horizontal well base-case, rate of injection is 200 STB/D for 20 days and shut in time is 50 hours. The base-cases are then modified to allow more heat loss from steam zone to the formation. Some of the test results are shown in Table 3.

Table 3 Results of the analysis of some simulated falloff tests

Case No.	V_s (ft^3)	β	C_G (psi/hr$^{1/2}$)	Heat loss (%)
1	220577	1.6	10	35
2	240900	-	-	48
3	390651	-	-	68
4	233707	-	-	16
5	-	2.9	17	31
6	-	1.3	7	43

For case 4 in Table 3, heat loss is not significant. In case 3, the same model is used with higher values of formation heat capacity and thermal conductivity which results in huge heat loss. For case 2, finer gridblocks are used and less heat loss compared to case 3 is observed. The linear flow trend characteristic of heat loss was not seen for cases 2 and 3. For case 1 (with very fine grids), the effect of heat loss is obvious in Fig. 4 by late-time half-slope line. For further analysis, pressure function and its derivative are plotted and analysed. Parameters listed in Table 3 are calculated using the approach suggested in this study. Since there was no indication of heat loss for the last 3 cases, conventional analysis was used. Also, since the early-time data of case 1 are not masked by heat loss, permeability was obtained by conventional analysis. Fine grids allows better observation of the heat loss effects on pressure plots (the half-slope).

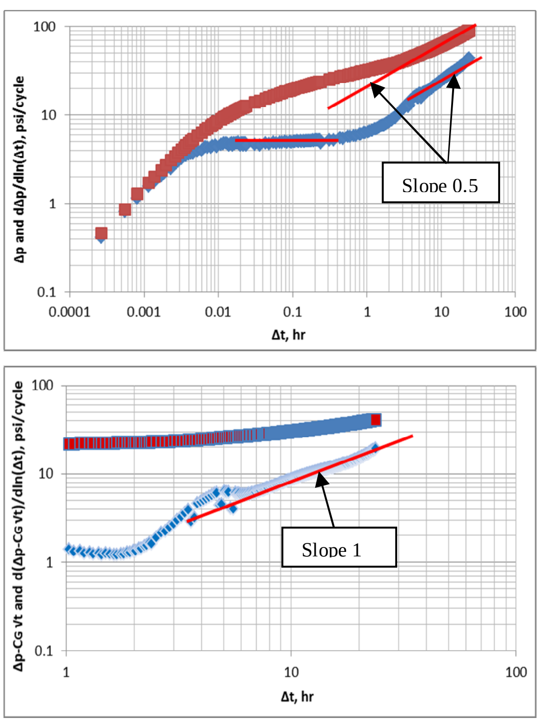

Fig. 4 Pressure and pressure function with derivative plots for case 1

The calculated values of swept volume can be compared with 224651 ft^3 for the base-case. Case 5, uses a fine grid model with increased hydraulic diffusivity and temperature difference that affect the value of heat loss coefficient to allow more heat loss. The observed linear flow trend (Fig. 5) was analysed by pressure function plots.

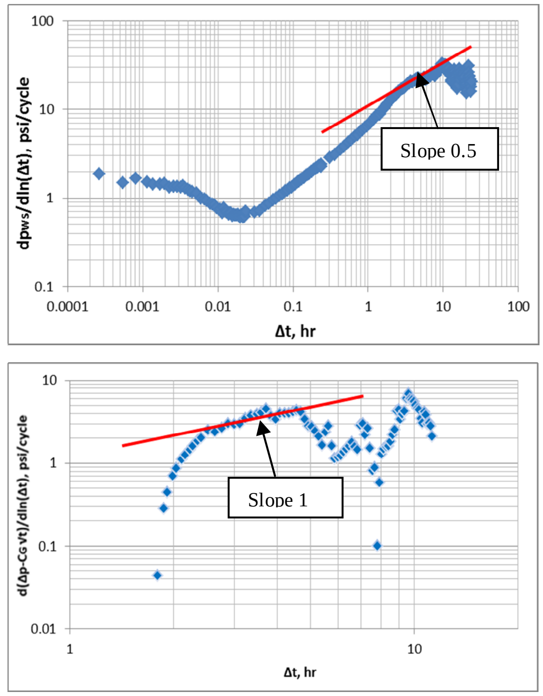

Fig. 5 Pressure derivative and pressure function derivative plots for case 5

Based on equation 4, heat loss coefficient (β) decreases with injection rate. Therefore, it is expected that the half-slope line on derivative plot disappears as the flow rate increases. The observed half-slope line turns into unit-slope line with increased rate. This has been investigated for a very fine grid model of SAGD with horizontal well pair. Based on the operating conditions, increased rate may however result in huge heat loss in SAGD process. In the case shown in Fig. 6, heat loss to the formation may be small (6.27%) with low heat loss coefficient, but overally almost all the heat was produced (total 92% loss) at rate of 800 STB/D. This is in contrary to the result of [7] with higher values of heat loss coefficient in the case of heat production through producer or leaking to surface. It is very important to notice that the original model including the condensation effect only considers heat loss through formation and therefore heat loss coefficient does not reflect other types of heat loss. The case shown in Fig. 6 may happen after a certain rate due to the presence of a producer. Huge heat loss may occur while just a small portion is conducted to the surroundings and just a part of the derivative plot may be affected showing the half-slope line with no effect on the late-time data.

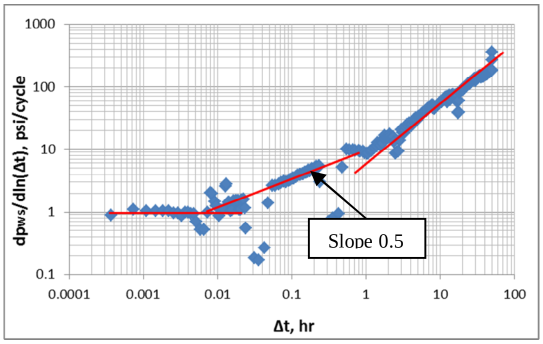

Fig. 6 Pressure derivative plot for a case with huge overall heat loss

Effects of other parameters such as temperature difference and diffusivity term on the value of heat loss coefficient were considered. With increased diffusivity and temperature difference, obvious gas override and formation of different zones with mobility contrast happens. With low injection rate, data are too scattered to show any heat loss effect. In Fig. 7, it is seen that the late-time PSS flow may be masked by half-slope line indicative of heat loss.

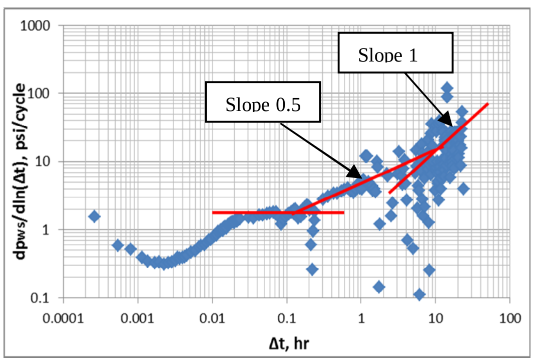

Fig. 7 Pressure derivative plot for case 6

The test may then be analysed by the suggested method. The derivative of the pressure function (Fig. 8) shows the unit-slope line for the period affected by heat loss (indicated in Fig. 7 by half-slope line).

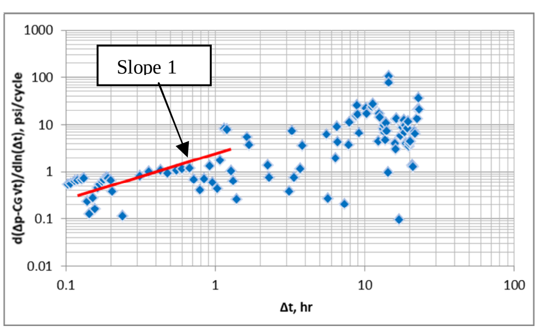

Fig. 8 Pressure function derivative plot for case 6

In cases with negligible heat loss, the errors associated with estimates of swept volume should be related to other simplifying assumptions in the conventional models. For example, the method of analysis is based on a two-zone composite reservoir model. In reality and in most of the cases studied, three zones are formed: steam zone, hot water zone and the oil zone. Better accuracy and identification of different flow regimes may result if a three or multi-region composite reservoir model with gradual changes of properties is applied for the analysis. Furthermore, if the model assumes tilted fronts, effect of gravity segregation can be included. Recently, new models have been proposed ([12]-[14]) to include these conditions for better analysis.

IV. Conclusions

Better results are expected if the effect of steam condensation as heat loss to the surroundings can be included in thermal well test analysis. Several examples were investigated in this study considering the effects of heat loss on the results. The following conclusions can be drawn:

- A general method of falloff test analysis was proposed in this study that works well when significant heat loss happens.
- The method gives the swept volume even if the PSS flow regime has been distorted by steam condensation effect. It makes the flow regime identification easier and removes some of the practical limitations of other methods.
- Heat loss analysis is only advised when the effect is significant (typically for β >1). Otherwise, conventional well test analysis suffices for all practical purposes.
- It is very important to notice that the original model including the condensation effect considers only the heat loss through formation and heat loss coefficient does not reflect other types of heat loss.
- It is crucial to accurately estimate the value of C_G to ensure reasonable estimates.
- Some comments were given to modify and correct some of the methods in the literature with emphasis on their drawbacks.

Nomenclature

A = swept area, ft^2
B = fluid formation volume factor, bbl/STB or res. ft^3/scf
c = isothermal coefficient of compressibility, psia^{-1}
C = heat capacity, BTU/lbm-°F
C_A = shape factor, dimensionless
C_G = steam condensation constant, psi/hr$^{1/2}$
D = Non-Darcy flow coefficient, (Mscf/day)$^{-1}$
F_η = hydraulic diffusivity ratio, dimensionless

F_ρ = density ratio of water to steam, dimensionless
G = rate of steam condensation, $ft^3/(hr.ft^3)$
h = formation thickness, ft
k = permeability, md
k_h = thermal conductivity, BTU/(ft.day.°F)
L = effective horizontal well length, ft
L_v = latent heat of vaporization, BTU/lbm
m = slope of pressure plots
p = pressure, psia
p_{ws} = shut in wellbore pressure, psia
q = flow rate, STB/D
r = radius, ft
R = steam chamber radius, ft
s = skin factor, dimensionless
t = time, hr
T = temperature, °R
V_s = swept (steam chamber) volume, ft^3

Greek symbols

α = thermal diffusivity, ft^2/day
β = steam condensation coefficient, dimensionless
γ = inverse of coefficient for dimensionless pressure, psia
δ = coefficient for dimensionless time, hr^{-1}
Δt = shut in time, hr
λ = mobility ratio, dimensionless
λ_t = total mobility, md/cp
μ = viscosity, cp
ρ = density, lbm/ft^3
ϕ = porosity, fraction
ψ = pseudo pressure, $psia^2$/cp

Subscripts

f = formation
g = gas (steam)
i = initial
s = steam
sc = standard conditions
t = total
w = water or wellbore

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