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Identifying Important Reservoir Characteristics Using Calibrated Wellbore Hydraulic Models in the Salak Geothermal Field, Indonesia

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ABSTRACT

The performance of production wells in the Salak geothermal field is routinely evaluated using wellbore hydraulic models that have been calibrated to match the 15 year production history of each well. The calibrated models accurately represent well geometry, the location and productivity index of each permeable zone, and the historical evolution of pressure and enthalpy at each zone. The models are normally used to forecast the deliverability of individual wells as reservoir conditions continue to evolve. However, during the calibration process it is also possible to identify well and reservoir characteristics that are not apparent in production trends or downhole surveys. For example, evidences of scale deposition, the influx of cooler fluids, and interzonal flow were identified during calibration. In several wells; these phenomena were subsequently confirmed through more detailed well surveillance. The calibrated wellbore models were found to be accurate tools for forecasting steam and brine production over the medium term and powerful tools for diagnosing well performance issues and focusing surveillance efforts.

1. INTRODUCTION

WELLHIST is a Chevron's in-house application for running a wellbore simulator as many times as required to produce a series of well deliverability calculations for different reservoir conditions. The first step of the course is to develop an initial wellbore hydraulic model for individual production using information of wellbore geometry and the pressure-temperature-spinner (PTS) data. Construction of the initial wellbore model is done by matching simulated wellbore fluid velocity, wellbore pressure, and total mass flow rate to the measured data to identify the productivity index (PI) and enthalpy of each feed zone.

In the second step, the wellbore hydraulic model is then calibrated by history matching its output to the historical data of wellhead steam mass flow rate and enthalpy. Most production wells in Salak are two-phase wells. Conventional inflow performance relationship (IPR) that merely derived from a mass balance equation is not applicable for this system (Acuna, 1996). For a two-phase system, change in pressure is not only related to the change in mass flow rate but also to change in enthalpy. To address this concern, the PI parameter used in history matching process with the WELLHIST is the mobility and enthalpy normalized PI (PI', Appendix A). Besides PI', the other input for the WELLHIST is the measured pressure and temperature history data at each feed zone obtained from the shut-in pressure and temperature surveys.

During the calibration process, it is assumed that permeability is unchanged throughout the entire period of well production. With this assumption, PI' distribution for a well with more than one feedzone is constant. The calibrated wellbore hydraulic model mainly obtained by trial and error the PI' value until the calculated steam mass flow rate and enthalpy histories agrees well with the measured data. The initial estimate of PI value obtained from PTS interpretation. On several production wells, adjusting PI magnitude did not result in a good match with historical production data. Further evaluation of these wells suggests that scale development in the wellbore, cold fluid influx into the wellbore and the presence of interzonal flow are the sources of deviation. This paper describes how the development processes of wellbore hydraulic model address several well and reservoir characteristic that are not apparent in the production trend or standard surveillance works.

2. IDENTIFICATION OF SCALE DEPOSITION

Well #1 was drilled in December 2002 and completed with total depth (TD) of 5120 ft-md in the steam cap part of East Awibengkok reservoir in the Salak geothermal field. As can be seen on Figure 1, the initial production of the well was 280 kilo-pound per hour (kph) with production decline rate of 8%. In early 2005, the performance of the well considerably decreased as its production decline rate increased to 23%. Around this period, one new production well was drilled into the same reservoir sector and put online. Also, a production well near to Well#1 evolved from a two-phase well into a dry steam well. The increase in total extraction from East Salak steam cap was believed to increase the production interference and resulted in an increased decline rate at Well #1.

In late 2006, production performance of Well #1 was dropped further. Its steam production dropped from 190 to 90 kph at decline rate of 237% even though there was no change in steam extraction rate from the neighboring wells.

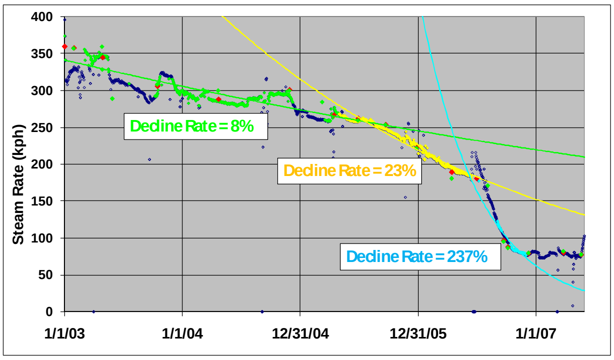

Figure 1: Historical Well #1 production and its decline rate evolution.

An Initial hydraulic model of Well #1 was constructed and calibrated using an injection PTS survey data. Further characterization and observation revealed that the well produced dry steam without entrained water. Variation of wellhead steam mass rate and enthalpy on a dry-steam well such as Well #1 is merely driven by changes in the reservoir pressure since fluid enthalpies of the feed zones are unchanged. The reservoir steam cap pressure is regularly measured and used to produce well production history predictions. In the case of Well#1, a good match between the wellbore model's output and the actual historical production at the wellhead was obtained only during the early production period (Figure 2). After late 2006, a large deviation between the model's predictions and historical data was observed. A better match can be obtained from either reducing the wellbore diameter or feedzones PI by 60% (Figure 3). However, Well #1 record shows that the wellbore geometry had not been intentionally changed.

Based on the information above, a more-detailed surveillance program was run to assess the possibility of anomalous changes in reservoir pressure, effective wellbore diameter and the feed zones PI'. During evaluation of reservoir pressure, it was found that the change in the shut in wellhead pressure of Well #1 was consistent with pressure evolution of East Salak steam cap reservoir.

Evaluation of the change in wellbore diameter was performed by running the sinker bar tool with 2.25" diameter. The survey suggested the presence of a blockage at around 3730 ft-md. The subsequent down-hole solid catcher run successfully recovered scale samples from the obstruction point. Based on the petrographic analysis, the scale consisted of 80% amorphous silica.

Well #1 was worked over in June 2007 in order to recover its production performance. The work over program consisted of mechanically clean out the scale inside the wellbore were successfully recovered steam production. After the work over, the production profile of Well #1 was consistent with the hydraulic model (Figure 4). This suggested that the excessive production decline at Well #1 was caused exclusively by scale development inside the wellbore. Silica scale development did not extend to the formation. Exercise with the hydraulic model on Well #1 has advantageously provided additional information about the problem in the wellbore and insight into the reservoir processes that leaded to scale development.

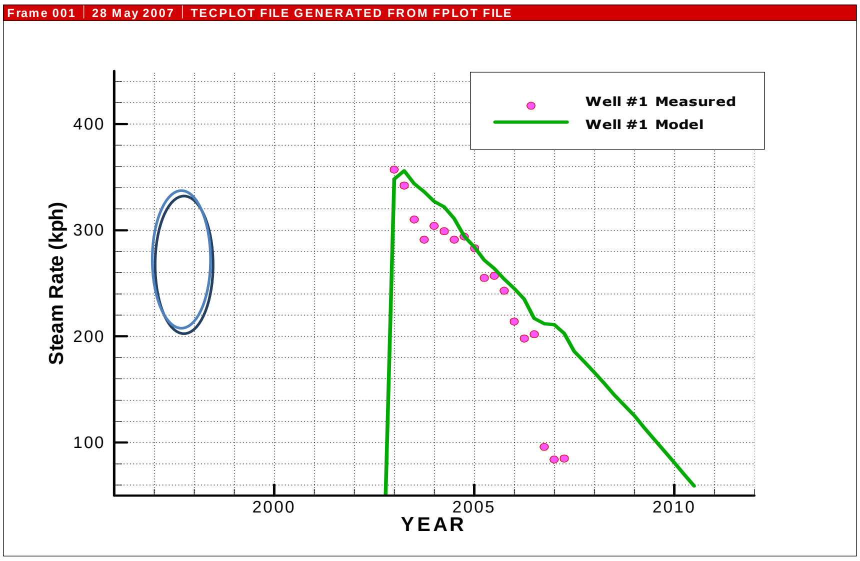

Figure 2: Plots of Well #1 Production Prediction from the WELLHIST and Historical Production data at the wellhead.

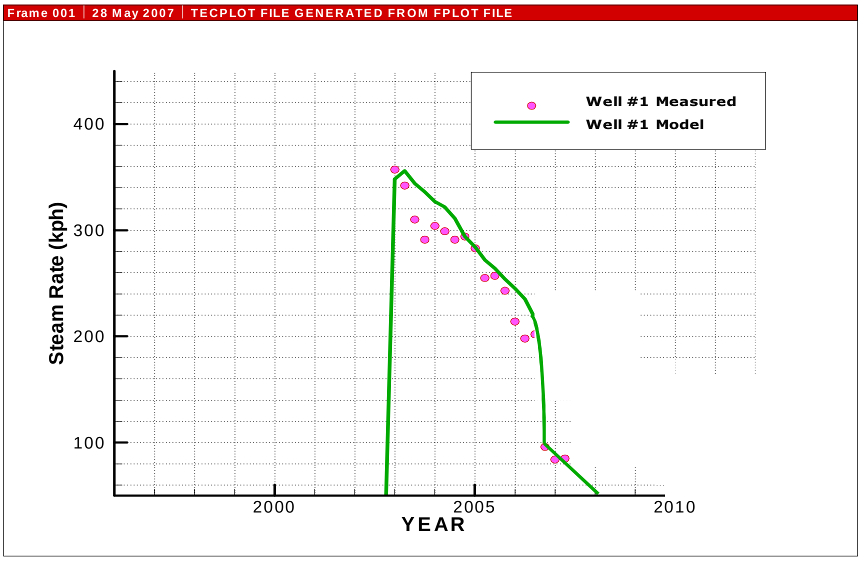

Figure 3: A matched model obtained from modifying inside wellbore diameter

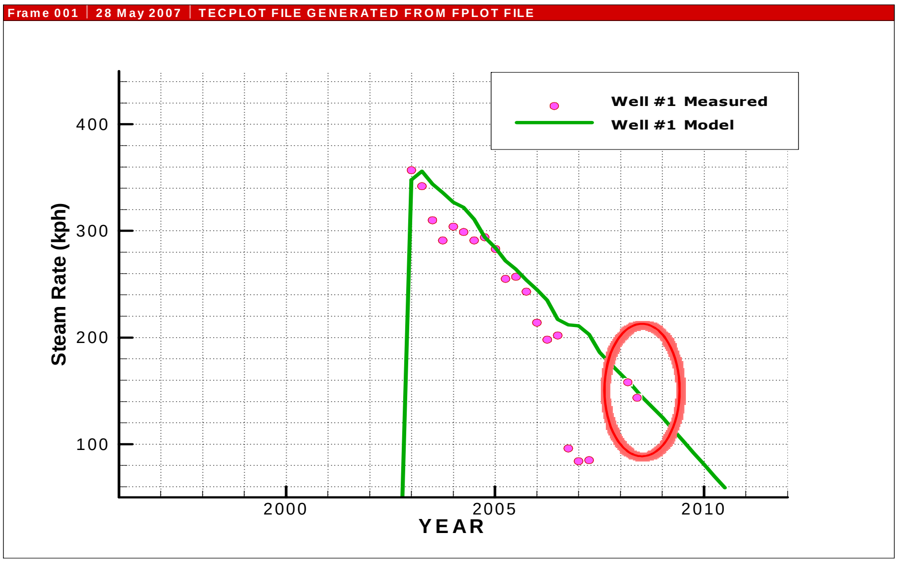

Figure 4: Extended production history of Well #1. Production performance recovered in mid 2007 after the work over.

3. IDENTIFICATION OF COLD FLUID INFLUX

3.1 Pressure-Temperature-Spinner (PTS) Interpretation on Well #2

Well #2 was drilled during the 2006 drilling program to a total depth of 7483 ft-md. Initial analysis of injection pressure-temperature-spinner (PTS) data provided information about the location of the permeable zones and the amount of liquid accepted by each zone. The PTS analysis identified 5 permeable zones and also suggests that the uppermost feed zone of Well #2 is located at the steam cap reservoir and the rest are located at the liquid reservoir.

An injecting wellbore model was then constructed by matching simulated wellbore fluid velocity, wellbore pressure, and total injection rate to the measured data (Figure-5). The injecting wellbore simulation was performed to identify the individual injectivity index (II, in kph/psi) value of each permeable zone and then convert it into PI’.

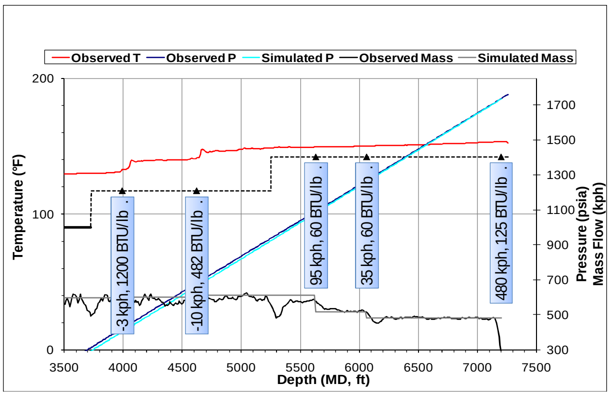

Figure 5: Wellbore simulator match of injection pressure, fluid mass and velocity on Well #2

3.2 Well #2 History Matching

Prior to proceeding with historical matching of the well head steam mass flow rate and enthalpy, it was necessary to estimate the fluid pressure and enthalpy histories at the feed zones between 2006 and 2007. For liquid wells such as Well #2, this information is normally inferred from the wellbore pressure and temperature (PT) profiles measured while the well is shut in. For a measured temperature, the saturation pressure is determined. If the measured pressure is higher than the saturation pressure, then the fluid is in liquid state and enthalpy is determined from measured temperature and a steam quality of zero. If the measured pressure is lower than the saturation pressure, then the fluid is in the vapor state and enthalpy is determined from pressure and steam quality of 1. If the measured pressure and saturation pressure are the same, then the fluid could be either in the liquid or steam phase and enthalpy is determined respectively. In the Salak field, there are three observation wells than provide real time liquid pressure data information at three different reservoir compartments. Interpolation of liquid phase pressure of production wells is carried out using normalized observation of well pressure history. Interpolation of steam phase pressure is achieved using the normalized steam cap pressure. Figures 6a and 6b show the fluid pressure and enthalpy histories at the steam feed zone and a liquid feed zone respectively estimated using the described practices.

Estimated PI’ obtained from PTS analysis, fluid pressure and enthalpy histories inferred from shut-in PT surveys and the well geometry becomes the input for the WELLHIST application to produce the calculated wellhead steam mass rate and discharge enthalpy profiles. In most cases, the application of this practice provides a good match between the model’s output and production history. However, in several wells a good match cannot be obtained. In the case of Well #2, the model gives overestimated discharge enthalpy and steam production (Figure 7). Trial and error attempts by freely modifying PI’ values and distribution were unsuccessful in improving the match.

Despite the above mismatches, it is believed that the shut-in pressure and temperature were accurately measured and recorded. Potentially, there are some reservoir and wellbore mechanisms that are not apparent from the injection PTS and shut in PT surveys that leads to some differences. Consequently, a pressure and temperature survey was then carried out when the well under flowing condition. Temperature profiles from this survey together with profiles from shut-in surveys were plotted against depth (elevation) and these are shown in Figure 8. A reversal temperature at around -2340 ft elevation is observed from surveys under both, shut in and flowing conditions which suggests the presence of lower fluid enthalpy inflow compared to the enthalpy from the deeper sections. As the well flows, the back pressure in the wellbore decreases and triggers a higher inflow of low enthalpy fluid. As a result, the fluid enthalpy above -2340 ft is lower than that under shut in conditions and is reflected by 20 °F lower temperature curve. Based on this information, the temperature data from shut in surveys used for inferring enthalpy history was systematically corrected by -20 °F. Output of wellhead production characteristics resulting from running the wellbore hydraulic model of Well #2 run using the corrected enthalpies are in good agreement with the historical data (Figure 9).

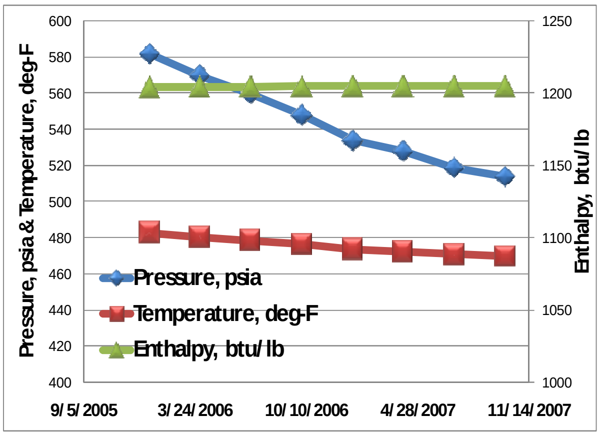

Figure 6a: Fluid pressure and enthalpy evolution at steam entry on Well #2 inferred from the normalized steam cap pressure

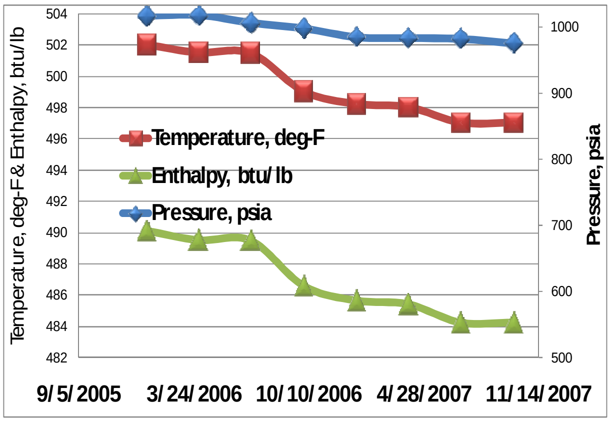

Figure 6b: Fluid pressure and enthalpy evolution at a liquid feed zone (-1928 ft-elevation) Inferred from shut-in PT surveys.

4. IDENTIFICATION OF INTERZONAL FLOW

Most geothermal wells will adjust to a stable pressure and temperature state if they are left shut in sufficiently long (Grant et al, 1982). However some wells never stabilize and host the interzonal flow. Interzonal flow occurs when a well acts as a short circuit in the flow system, creating fluid movement under shut-in conditions. This phenomenon could occur naturally from upflow and outflow of reservoir fluid or could occur as a result of changing reservoir pressure distribution due to fluid withdrawal, injection and recharge. The use of shut in pressure and temperature data to produce production history predictions for wells that host interzonal flow is not a correct practice. Therefore, the model's output will not be in good agreement with the historical production data. Well #3 in Salak geothermal field is an example.

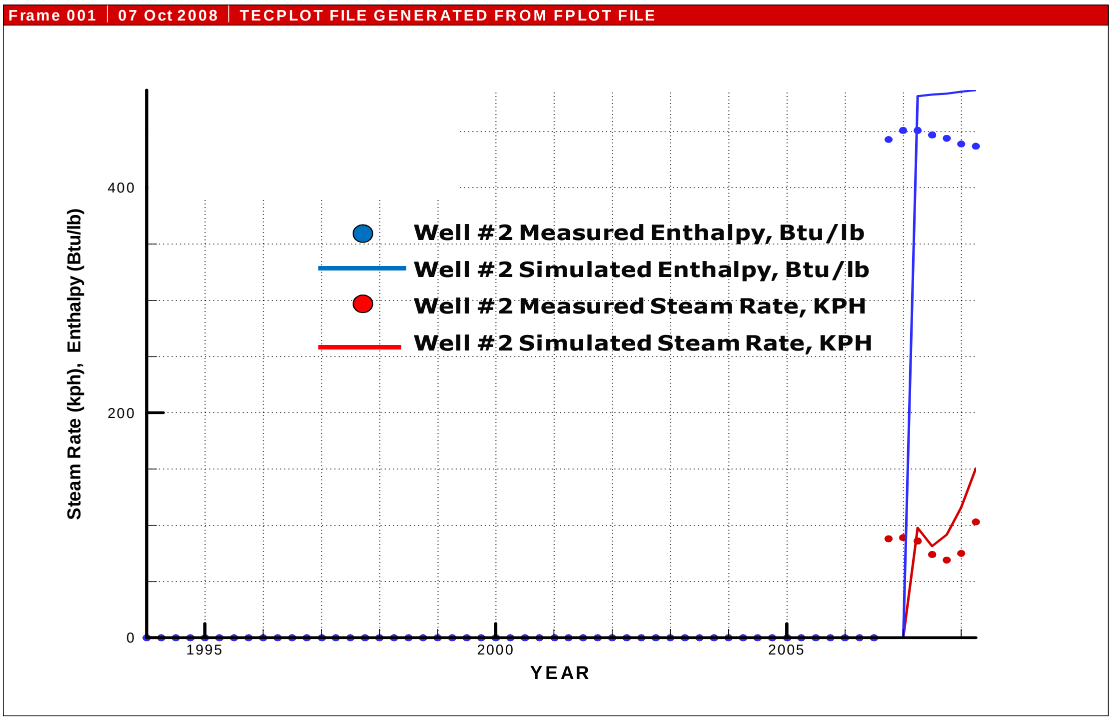

Figure 7: Comparison of hydraulic model and historical records of enthalpy and steam production of Well #2.

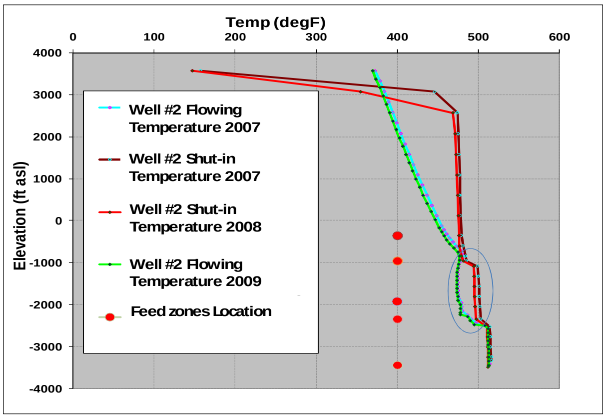

Figure 8: Plot of flowing and shut in temperature profiles on Well #2

Well #3 is an old well which was drilled in 1985 to the West Awibengkok liquid reservoir with the total depth of 4857 ft-md.. Three liquid feed zones and their PI' values were identified from the flowing PTS survey run in 2007 (Figure 10). The wellbore hydraulic model was then calibrated using historical steam production and discharge enthalpy at the wellhead. Similar to history match processes of other liquid wells, the wellbore model used PI' from the PTS analysis and the inferred feed zones pressure and enthalpy from shut in PT data as the inputs. In Figure 11, Well #3 wellbore models that run using this practice can provides a good match with the first 5 years of production data. After mid 2003, the model provides lower steam production and discharge enthalpy than those of actual. Regular down hole surveys on Well #3 did not indicate the presence of scale development. Also, the PT data from shut in and flowing surveys did not suggest that inflow of colder fluid was the source of deviation (Figure 12).

A more thorough analysis on the shut in PT data suggests that the interzonal flow appeared on Well #3 starting in 2003. These analyses included the evaluation of a pressure gradient relative to the hydrostatic and vapor static pressure. One footprint from the presence of interzonal flow is that the measured pressure gradient lies between the hydrostatic and vapor static pressure gradient as a result of fluid movement inside the wellbore. This profile was observed in Well #3 in 2005 (Figure 13). In 2002, interzonal flow did not occur since the measured pressure gradient from the shut in PT survey lies on the hydrostatic pressure gradient.

Inaccuracy will be generated from using the measured shut in pressure of well which hosts interzonal flow such as Well #3. Correction to the formation pressure is required. The basic assumption used is that the fluid enthalpy is unchanged as a result of fluid movement in the wellbore. The first step in the correction process is calculation of the minimum fluid enthalpy, which is determined from the pressure and steam quality. Feed zone pressure is obtained from measured data while steam quality can be computed using the following equation:

$$Q = (V_{mix} - V_L)/(V_S - V_L) \quad (1)$$

Where Q is the steam quality, V_{mix}, V_L, and V_S is the specific volume of mixture, liquid, and steam in cu-ft/lb respectively. The true formation pressure is then determined from the calculated minimum enthalpy with steam quality of zero.

Utilization of the true formation pressure on Well #3 hydraulic models had improved the match significantly. After mid 2003, the model outputs are in good agreement with the historical production profiles.

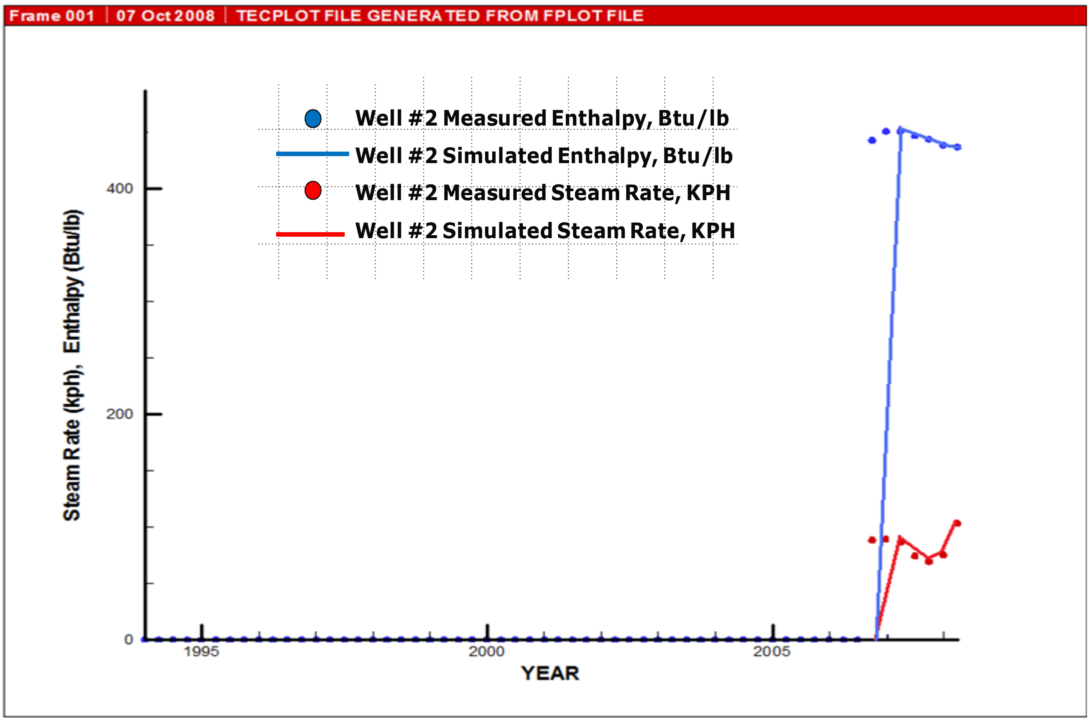

Figure 9: A better history match obtained from running Well #2 hydraulic models with the corrected enthalpies.

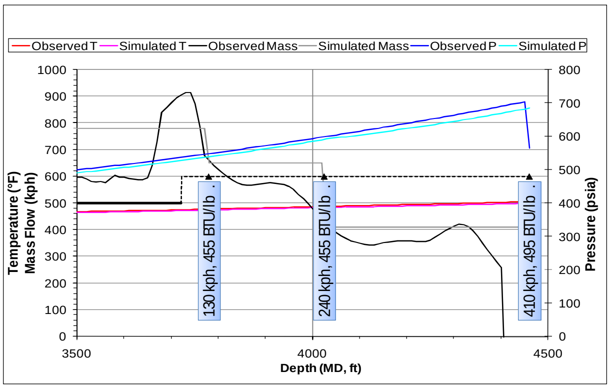

Figure 10: Wellbore simulator match of flowing pressure, temperature and flow rate on Well #3

5. SUMMARY AND CONCLUSION

Three special wellbore and reservoir characteristics have been successfully addressed during the calibration processes of the wellbore hydraulic models: scale development in the wellbore, the inflow of low enthalpy fluid and the presence of interzonal flow in the wellbore. Additional insights on reservoir and well characteristic from this practice will benefit the reservoir management processes.

Once the reservoir processes of the wells are well understood, the inputs for wellbore hydraulic model can be corrected accordingly and effectively matched with the production history. Therefore, a more reliable production forecast can be produced. This will provide benefit to the production management.

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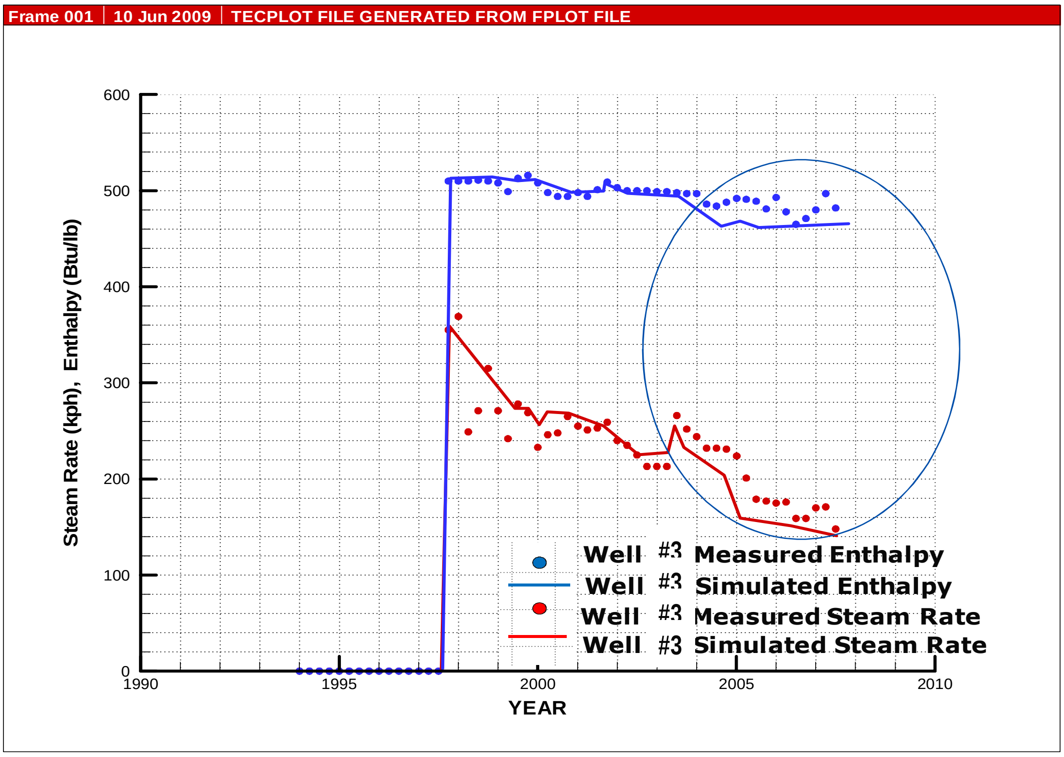

Figure 11: Plots of Well #3 Production Prediction from the WELLHIST and Historical Production data at the wellhead.

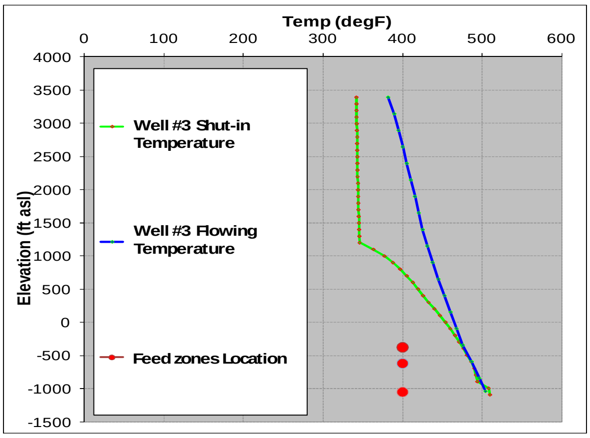

Figure 12: Comparison between shut-in and flowing temperature Profiles of Well #3.

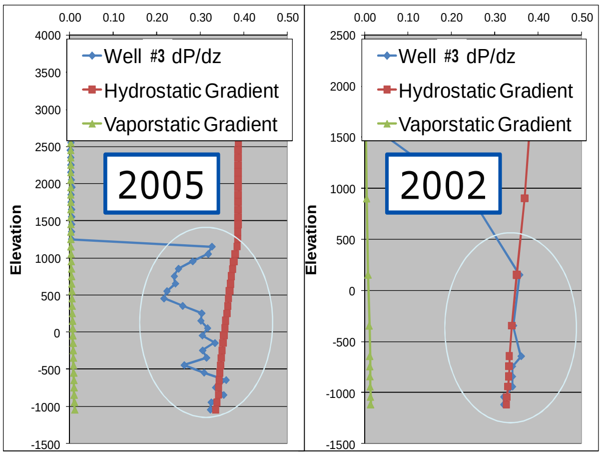

Figure 13: Evidence of Interzonal flow occurrence in Well #3 based on 2005 measured shut-in pressure data.

APPENDIX A

PI' is the part of the productivity index (PI) that does not depends on fluid properties. Constant PI obtained from a pressure-temperature-spinner survey need to be corrected by mobility and enthalpy correction factor (ECF) for wellbore hydraulic modeling purposes since it will be used to calculate a series of well steam production and enthalpy using historic records of pressure and enthalpy for each feedzone which evolve from time to time thus affecting the fluid properties.

Constant PI (in kph/psi) can be defined as:

$$W = PI(P^* - P_{wf}) \tag{A1}$$

Where W is mass flow rate in kph; P* is the formation pressure in psi, and Pwf is wellbore flowing pressure in psi.

PI'(in (kph-cuft-cp)/(lb-psi)) is obtained by multiplying PI with the mobility (MOB) and enthalpy correction factor (ECF).

$$PI = PI'\frac{1}{\nu_T * ECF} \tag{A2}$$

ν_T (kinematic viscosity of mixture, in Cuft-cp/lb) is calculated as:

Assuming $k_{rs} + k_{rw} = 1$

$$MOB = \frac{1}{\nu_T} = k_{rs}\frac{\rho_s}{\mu_s} + k_{rw}\frac{\rho_L}{\mu_L} \tag{A3}$$

In the wellbore simulator it is further assumed that $k_{rw} \sim S_w$ to obtain:

$$\nu_T = X\frac{\mu_S}{\rho_S} + (1 - X)\frac{\mu_L}{\rho_L} \tag{A4}$$

Where X is steam quality, k_{rs} is relative permeability of steam, k_{rw} is relative permeability of liquid, S_w is water saturation, ρ_s, ρ_L, μ_s, μ_L are steam density in lb/cuft, liquid density in lb/cuft, steam dynamic viscosity in cp, and liquid dynamic viscosity in cp respectively.

ECF comes from solving energy conservation equation rather than mass conservation for radial flow

$$ECF = \frac{1}{H}\frac{\partial(\rho H)}{\partial \rho}$$

Equals 1 for liquid and for two phases is

$$ECF \sim 94.68\frac{p^{0.244}}{H}$$

Where p is the formation pressure in psia and H is the formation enthalpy in btu/lb.

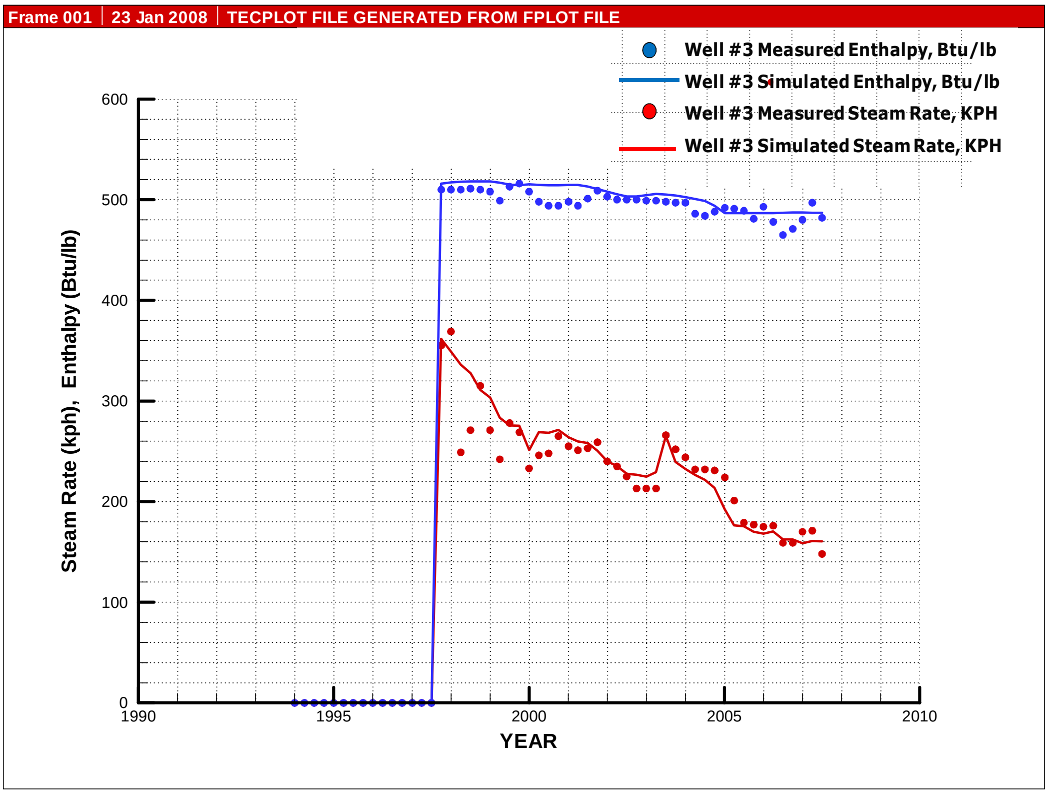

Figure 14: The use of true formation pressure after mid 2003 successfully improves the match.