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Near wellbore thermal effects in a tight gas reservoir: Impact of different reservoir and fluid parameters

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ABSTRACT

Temperature changes in and around the wellbore could lead to significant well performance and flow assurance issues. Despite its importance, near wellbore temperature change due to gas production and its importance on well performance is not well understood. Reduction of temperature in the near well bore section, could potentially lead to hydrate formation and as a result reduction of well performance.

This work is aimed at evaluating the thermal behaviour in the near wellbore region of a low to tight permeability gas reservoir (ranging between 0.02 and 10 mD) during its natural depletion. The study is conducted by using a thermal-compositional simulator. The process required to simulate such thermal behaviour in a numerical simulator is outlined in this paper. This study is focused on analysing the impacts of different parameters such as reservoir and fluid properties, well trajectories and draw down magnitudes have been studied. Such parameters have an impact on JTE or conductive/convective heat transfer and therefore will affect the reservoir temperature. In addition the near wellbore temperature responses to varying production and well configurations are reviewed to identify the contributing parameter and their impact on reservoir temperature.

The results of a grid sensitivity analysis showed that the choice of grid size will have a significant impact on calculated temperatures. In addition, the results reveal that significant temperature reduction could occur around the wellbore due to Joule-Thomson expansion and heat transfer in form of conduction and convention. It is also shown that size of the affected area depends on the magnitude of cooling due to Joule-Thomson expansion as well as reservoir properties such as skin and permeability. This study showed that the most influential parameter is the wellbore inflow rate due to draw down. In addition, parameters such as pressure profile along the well trajectory, inflow area along the well and reservoir quality along the wellbore will play a vital role in cooling process as well as radius of the impacted zone. The results also showed that absolute initial reservoir temperature have no significant impact on the magnitude of temperature change.

Introduction

Historically, reservoir temperature and more specifically the wellbore flowing temperature have been used to understand the layer flow contribution as well as reservoir permeability (App and Yoshioka, 2013; Brown et al., 2007; Yoshioka et al., 2007). Johnson et al. (2006) showed a successful example of flow profiling for a multi-layered gas reservoir using distributed temperature sensing (DST). In addition reduction of temperature in the well bore or near the wellbore is associated with some of the flow assurance problems or production anomalies. These issues tend to occur within the wellbore itself and therefore traditionally wellbore modelling has received a lot of attention. For example, Charles and Igbokoyi (2012) developed a temperature prediction model for fluid flowing in the wellbore. Their model considers the JTE as a function of mass flow rate of different present phases. Despite its importance and potential impacts, change in reservoir temperature near the wellbore has received less attention.

The change in temperature in the areas next to the wellbore are mainly associated with the Joule-Thomson expansion of the reservoir fluid. The temperature change of the flowing gas is triggered through the JTE, as a result of gas expansion. A strive for local thermal equilibrium within the pore structure will force the surrounding rock matrix to adjust to this temperature (Gamal and Furmanski, 1997). The time dependency of heat rate will result

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Nomenclature

c	Heat capacity, J.kg^{-1}.K^{-1}
G	Gravitational coefficient, m.s^{-2}
h	Height, m
k	Permeability, mD
Q	Production rate sm^3.day^{-1}
P	Pressure, kPa
T	Temperature, °C
κ	Compressibility, kPa^{-1}
ΔT	Temperature change, °C
ΔP	Pressure change, kPa
V	Volume, m^3

Greek

λ	Thermal conductivity, J.m^{-1}.s^{-1}.K^{-1}
β_T	Thermal expansion coefficient, K^{-1}
ϕ	Porosity of formation

Subscript

c	Critical
f	Fluid
g	Gas
i	Initial condition at time 0
m	Rock matrix
s	Specific
Res	Reservoir

in a continuous temperature change, under steady-state conditions at continuous production. Baker and Price (1990) reported about 14 °F change in temperature for a high pressure drill stem test in the North Sea. They believed that such change is due to the JTE of the produced gas. Non-isothermal behaviour due to Joule-Thomson expansion are provided by App (2009, 2010) for oil and gas fields which experienced significant temperature changes under high draw down conditions. The results of that study showed that under a high pressure oil production case 10 °F in temperature was observed. In addition and as a result of a low pressure gas production test, a temperature reduction of 38 °F has been reported by App (2009, 2010). This study also showed that temperature variations closely follow the pressure changes. Kabir et al. (2014) studied a deepwater asset in Western Australia and showed that temperature variations follow the gas production rate. They further used these data to conduct a temperature-rate transient analysis.

In tight gas reservoirs as well as shale gas reservoirs, hydraulic fracturing is the most routine form of well stimulation. Slick water is one of the dominant fluids used to create the hydraulic fractures. This is due to complexity involved in application of other types of fluids such as CO2, N2 and foam (Wanniarachchi et al., 2015; Li et al., 2016). Li et al. (2016) showed that not only creating fractures with CO2 increases the fracturing pattern complexity, but also returns higher break down pressure. Ribeiro and Horne (2013) studied the impact of temperature variation for a hydraulically fractured well. They studied the temperature and pressure responses during and immediately after a hydraulic fracturing. Their study showed that, even though that different permeability may not significantly change the temperature in a wellbore, it will lead to significant temperature change in the fractured zone and around the wellbore. App (2013) studied the influence of hydraulic fractures on wellbore and sandface temperatures. The result of this study showed that the Joule-Thomson expansion thermal effect is proportional to the square of the local pressure gradients. This study also showed that change in flow regime due to the presence of hydraulic fractures, will impact the magnitude of the Joule-Thomson expansion effect.

Beside the JTE, other parameters that impact heat transfer condition, will impact the temperature of the near wellbore area. Thermal conduction and convention are the two different ways heat transfer occurs in this area. Adivarahan (1962) first gave a detailed account on thermal conductivity of plug experiments under various flow conditions. He concluded that the total thermal conductivity of a rock and fluid is a function of fluid properties and flow

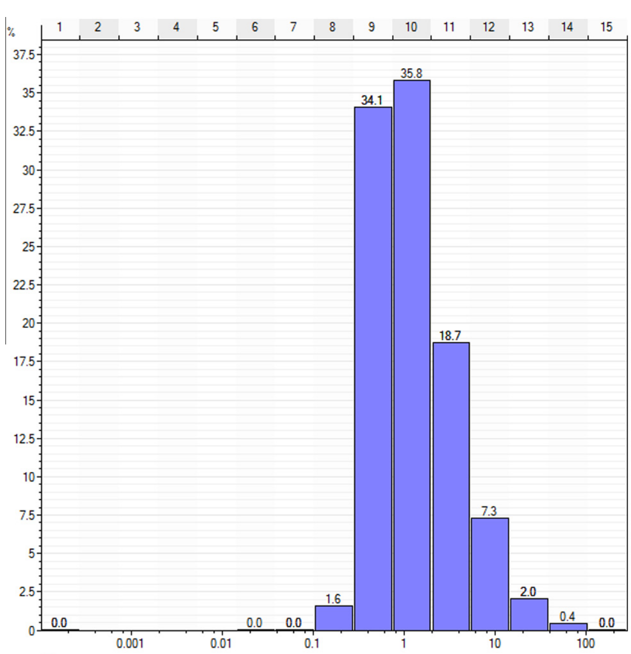

Fig. 1. Reservoir permeability distribution ($k_i = k_j = 10 \times k_k$).

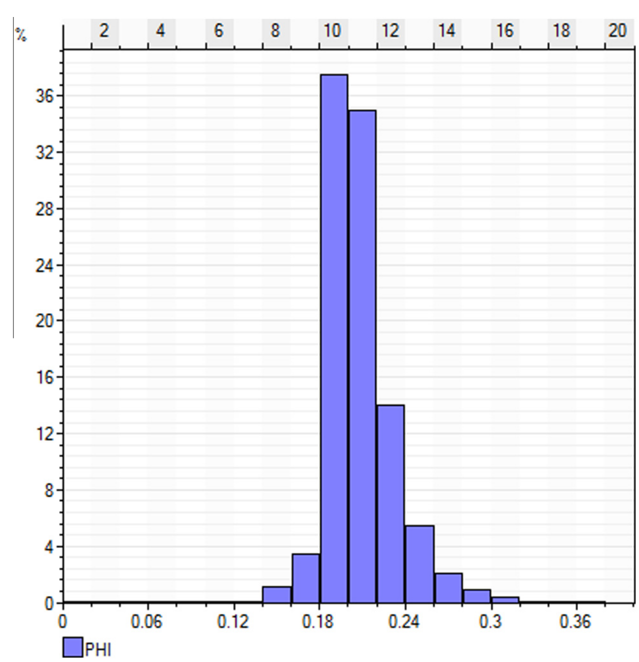

Fig. 2. Reservoir porosity distribution.