Journal of Petroleum Science and Engineering 112 (2013) 290–295

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Improvement of wellbore stability in shale using nanoparticles

S. Akhtarmanesh [a,*], M.J. Ameri Shahrabi [a], A. Atashnezhad [b,1]

[a] Petroleum Engineering Department, Amirkabir University of Technology, Tehran, Iran
[b] National Iranian South Oil Company, Ahvaz, Iran

ARTICLE INFO

Article history:
Received 2 April 2013
Accepted 1 November 2013
Available online 12 November 2013

Keywords:
shale
osmosis phenomenon
physical plugging

ABSTRACT

Wellbore instability causes many difficulties including costly drilling operation. Many wellbore instabilities occur due to sloughing or swelling shales and abnormal pressured shale formations. Showing different degrees of influence, pore pressure transmission and chemical osmosis are the main mechanisms in shale instabilities, with regard to physical and chemical properties of shale and thermodynamics condition. Both of these mechanisms are investigated in this paper to evaluate their significance in wellbore stability consideration. For wellbore stability maintenance, a logical approach to prevent pressure increase at near wellbore is pore throat physical plugging. Nano-particles have been used for this intent. To evaluate performance of different water based drilling fluids on pore pressure; Membrane Efficiency Screening Equipment (MESE) set up has been used. Three different drilling fluids, containing different additives, in contact with Gurpi formation were studied with and without the addition of nano-particles. Gurpi formation is located in sedimentary basins of western and southwestern regions of Iran. Much better physical plugging was achieved by using nano-particles which caused reduction in permeability and pressure increment. One of the mud formulations using nano-particles reduced pressure increment in near wellbore, up to 97%.

1. Introduction

In the drilling industry, there is a consensus that shales are the most troublesome formations to deal with, due to instability during drilling when water-based drilling fluids are used. Shale formations cause many problems such as partial or huge slump which cause poor hole conditioning or stuck pipe, Drill bit balling up, Bit Floundering, low quality logging and cementing, and drilling fluid contamination due to its mixing with dispersed active clay particles. Clays are the basic constituent of shales and some clay minerals such as Smectite and Illite have chemically active nature. They are hydrated easily when they come in contact with water.

The main cause of shale instability for both soft and hard shales is water absorption and subsequent swelling and sloughing of the wellbore. Water adsorption by shale causes reduction in compressive strength and leads to ultimate shale failure (Chenevert, 1970). Shales behaved as non-ideal semipermeable membranes (Fritz and Marine, 1983). They defined “Reflection Coefficient” to explain non-ideality of shale membrane systems. The “Pressure Transmission” test was used to measure the membrane efficiency of the shale–fluid systems (Van Oort et al., 1995). They specified initial pressure decrease is due to osmosis phenomenon and subsequent pressure increase is caused by diffusion phenomenon. Shale water content has determinant impact on the shale properties especially its strength (Hale and Mody, 1996). Shale stability is related to osmotic pressure and membrane efficiency of shale (Schlemmer et al., 2002). They concluded that silicate-based drilling fluids provide high membrane efficiency and optimum osmotic effects. Shale borehole stability can be achieved through using relevant additives in drilling fluids to develop appropriate osmotic forces.

Oil based muds are more effective in maintaining shale stability by preventing near wellbore pressure increase due to their high entry capillary pressure toward shale pores (Ewy and Morton, 2008). These types of drilling fluids have functional advantages for shale formations drilling operation and they are also a desired option for directional well drilling (AL-Bazali et al., 2006). It is noticeable that because of environmental limits, these drilling fluids require high cost due to treatment of drilling fluid wastes and cuttings before disposal procedure.

The other choice is the improved water based drilling fluids which have necessary properties to lower wellbore instability while being environmentally acceptable. Because of very low permeability (~10 nD), mud cake will not be created on shale surface. Therefore, to prevent filtration into shale, fluid loss standard materials are useless, but nanoparticles may be useful for physical plugging which prevents pressure penetrating

* Corresponding author. Tel.: +98 9171343148.
E-mail addresses: akhtarmanesh@gmail.com (S. Akhtarmanesh), atashnezhad1@gmail.com (A. Atashnezhad).
[1] Tel.: +98 9369451125.

0920-4105/$ - see front matter © 2013 Elsevier B.V. All rights reserved.
http://dx.doi.org/10.1016/j.petrol.2013.11.017

Nomenclature

$a_{w,mud}$	water activity of test fluid, dimensionless
$a_{w,shale}$	water activity of shale, dimensionless
P_π	osmotic pressure difference accounting for membrane efficiency, psi
R	gas constant, mL^2/t^2-mol-deg
T	absolute temperature, deg
v	molar volume of water, m^3/mol
ΔP_{i1}	initial hydraulic differential pressure in test 1, psi
ΔP_{f1}	final hydraulic differential pressure in test 1, psi
ΔP_{i2}	initial hydraulic differential pressure in test 2, psi
ΔP_{f2}	final hydraulic differential pressure in test 2, psi
α	the fractional reduction in top and bottom pressures at the end of test
β	comparative reduction in fluid invasion in two tests

(Chenevert and Sharma, 2008; Sensoy et al., 2008; Cai et al., 2011). They showed the positive impact of adding nanoparticles to water-based drilling muds and their effect on fluid penetration into Atoka and Gulf of Mexico (GOM) shales.

2. Experimental

2.1. Apparatus

There are several methods and apparatuses to accomplish "membrane efficiency" tests. In our study, we used MESE designed by CSIRO in which we were able to exert confining pressure on shale sample. Membrane Efficiency Screening Equipment (MESE) was used to simulate downhole stresses distribution and monitor downstream pressure which deputizes near wellbore pressure. Pressure difference between upstream and downstream is recorded during the test. The apparatus and its experimental set up are illustrated in Figs. 1 and 2. A schematic of the test cell of the membrane efficiency screening equipment is shown in Fig. 3.

2.2. Methods and test procedures

2.2.1. Chemical potential test

Positive aspect of chemical osmosis mechanism is used in mud engineering. When shale is in contact with water based mud, if mud filtrate water activity is lower than pore fluid water activity, this causes a flow of water from shale into well. Downstream line is filled by shale pore fluid and pressure in downstream line is initially zero. Confining pressure is increased to (20 MPa) 2940 psi. The test starts by raising downstream pressure to 1480 psi approximately. If there is no sudden increment in upstream pressure, upstream pressure will be increased to 1480 psi. This section will be terminated by stabilizing sample's upstream and downstream pressures. Then upstream pressure will be increased to 2200 psi for the purpose of pressure penetration from upstream to downstream. After downstream pressure builds up, we must change the upstream fluid to desired mud filtrate, and its pressure will be increased to 2200 psi. The new filtrate is circulated through upstream. The drilling fluid filtrate is circulated slowly with the intention to ensure that its chemical contents remain constant at upstream. A pressure transducer is located in downstream line recording pressure continuously. By measuring the activity of the pore fluid and the activity of the filtrate, we were able to convert osmotic pressure to membrane efficiency. As presented in several references such as Fritz and Marine (1983) and Van Oort et al. (1995), the membrane efficiency (σ) is defined by

Fig. 1. Apparatus (MESE) and other auxiliary equipments.

$$\Delta\pi = \frac{RT}{v}\ln\left(\frac{a_{w,shale}}{a_{w,filtrate}}\right) \tag{1}$$

$$\sigma = \frac{\Delta P}{\Delta\pi} \tag{2}$$

where ΔP is the measured osmotic pressure (maximum pressure difference is usually used to measure membrane efficiency), $\Delta\pi$ is the theoretical osmotic pressure, R is the gas constant, T is the absolute temperature, V is the partial molar volume of water, $a_{w,shale}$ is the water activity of the shale and $a_{w,filtrate}$ is the water activity of the filtrate.

2.2.2. Pore plugging test

Downstream line is filled by shale pore fluid and pressure in downstream is initially zero. Confining pressure is increased to (10 MPa) 1470 psi. The test starts by raising upstream pressure by an amount 900 psi in excess of the pore pressure and monitoring the downstream pressure build up using a pressure transducer. Drilling fluid filtrate, which is in contact with the bottom face of shale sample, is circulated through upstream line. The drilling fluid filtrate is circulated slowly with intent to ensure that its chemical contents remain constant at upstream. A pressure transducer is located in downstream line recording pressure continuously. At the end of the test, when downstream pressure remains stable for a while, we will be able to compare two formulations in pressure increasing rate or their difference in total pore plugging and ultimate permeability. The fractional reduction in top and bottom pressures at the end of Tests 1 and 2 (α_j) are calculated using

$$\alpha_j = \frac{\Delta P_{ij} - \Delta P_{fj}}{\Delta P_{ij}}, \quad j = 1, 2 \tag{3}$$

Then the reduction in fluid invasion by comparison (β) is obtained by using the equation

$$\beta = \frac{\alpha_1 - \alpha_2}{\alpha_1} \tag{4}$$

where ΔP_{ij} is the initial hydraulic differential pressure in test j, ΔP_{fj} is the final hydraulic differential pressure in test j, α_j is the fractional reduction in top and bottom pressures at the end of test j, β is the comparative reduction in fluid invasion in two tests. The tests are conducted at 25 °C and may last several days.