ABSTRACT

Cairn India has a number of permeability challenged (1 mD – 10 μD) oil and gas reservoirs in Barmer and Krishna-Godavari basins in India. The work programs on these permeability challenged reservoirs are in exploration/appraisal/development planning stages. An understanding of permeability challenged reservoirs is very important to optimize the development of such fields that have a huge potential to become game-changers.

The permeability challenged reservoirs are developed through hydraulic fractures whereby the permeability of the system is increased multifold in the vicinity of the wellbore. In hydraulically fractured system the hydrocarbon flows from reservoir matrix to fracture and then from fracture to wellbore. The key job of reservoir engineering is to represent the hydraulic fracture in the numerical simulation model enabling the high confidence in production forecast.

Tight reservoirs are produced with high drawdowns leading to multiphase flow scenarios near the wellbore. In addition, a typical production profile starts with a peak initial rate followed by rapid decline and stabilizing to a pseudo-steady state rate for long term. Thus capturing the near wellbore pressure transient is very important to understand the reservoir dynamics for accurate prediction of hydrocarbon flow.

There are several methods available in the literature to represent hydraulic fracture performance in the numerical simulation.

- Negative Skin Modeling
- Productivity Index/Local matrix Permeability Modification
- Transmissibility modification
- Stimulated Rock Volume Modeling (Local Grid Refinements)

The above methods work efficiently in single wellbore modeling but have several advantages and disadvantages on the full field numerical simulation to achieve accurate near wellbore flow representation. The selection of hydraulic fracture modeling method depends upon the tradeoff between the model accuracy and simulation run time. This paper presents a good comparison of various hydraulic fracturing numerical simulation models in tight reservoir application.

INTRODUCTION

The commonly used phrase “Tight Oil and Gas” is a misnomer, as gas or oil is not tight but can be contained in low permeability rocks.

The definition of a tight gas (or tight oil) reservoir is: “A reservoir that cannot be produced at economic flow rates nor recover economic volumes of gas (oil) unless the well is stimulated by a large hydraulic fracture(s), or is produced by use of a horizontal wellbore(s) which normally also contains multiple fractures (by Holditch)”

The Concept of Resource triangle was used by Masters and Grey (1979) to find a large gas field. The concept considers that all natural resources are distributed lognormally in nature (Figure-1). As we go down in the oil and gas resource triangle, the reservoirs are lower grade, which usually means the reservoir permeability is decreasing. These low permeability reservoir however are much larger in size than high quality reservoirs. Truly unconventional reservoirs have permeability in order of nano-Darcy e.g. in organic shales and salts. Reservoirs being developed with hydraulic fracturing as referred to in this paper are commonly referred to as ‘tight’ or ‘low-perm’ reservoirs with matrix permeability in order of 1 mD to 10 μD (Figure-2).