1 Problem 1: Cooling of a Logging Tool by Drilling Mud Circulation

The most commonly used setup in oilfield drilling operations consists of a drillbit, a bottomhole assembly (which sometimes includes devices such as logging and steering tools, stabilizers, etc.) which are connected to the surface via a drillpipe. In order to remove the detritus generated during the drilling operation, and to cool down the bit and the assembly (as well as to ensure the stability of the wellbore until casing is installed), a very viscous fluid called the "drilling mud" is pumped down through the drilling pipe, enters the wellbore via nozzles located at the bit, and returns to the surface through the annulus between the borehole walls and the drillpipe (see Figure 1).

Occasionally, the drilling operation has to stop due to mechanical or logistic problems. During those "dead times", the operators usually let the mud circulate at a much slower rate than during active drilling. However, the electronic components of the bottomhole assembly must be maintained below a given threshold temperature, to keep them from "frying". Assuming that the rock temperature, the fluid temperature at a certain depth, the thermal properties of the rock, fluid and pipes, and all the dimensions are known, the question is what should be the minimum rate that should be kept to avoid the temperature at the bottomhole assembly to raise above such threshold temperature.

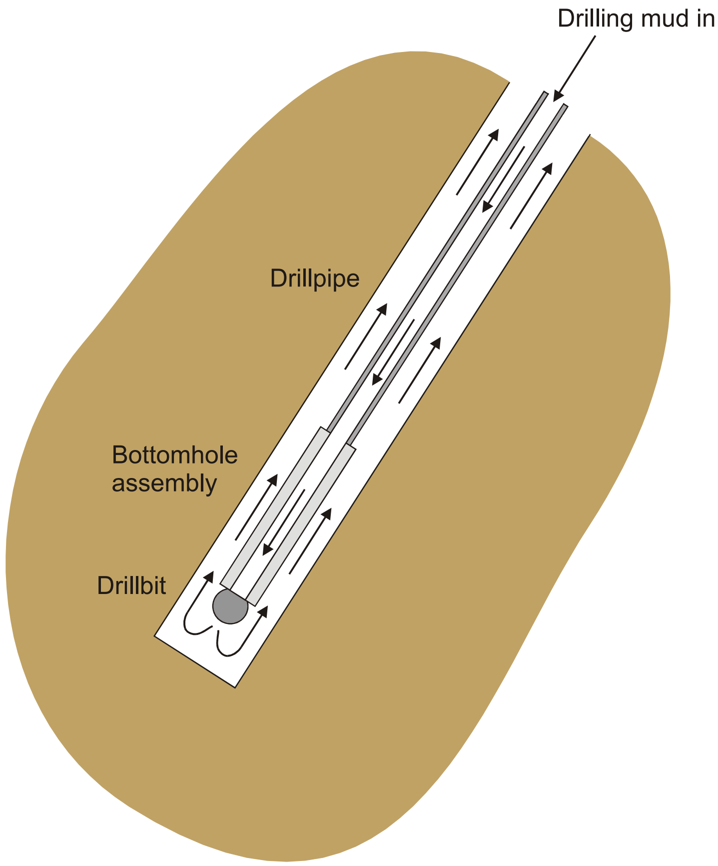

Figure 1: Schematic for Problem 1.

2 Problem 2: Release of Encapsulated Breaker During a Laboratory Experiment

Hydraulic fracturing (HF) is the most commonly used technique for stimulation of hydrocarbon reservoirs. In a conventional HF treatment, a fracture is created in the reservoir layer by injection of a viscous fluid from the wellbore (see Fig. 2). The fluids used in these treatments consist basically on a high-density polymer (guar is the most commonly used) and a crosslinker agent to promote the entanglement of the polymer chains, thus increasing the fluid viscosity. The need for high viscosity is basically driven for the fact that the fracturing fluid is followed by a slurry of fluid carrying propping materials (the "proppant"). The proppant is a granular phase (e.g., coarse sand), whose function is to keep the fracture open after the treatment is over, so as to provide a high-permeability channel for the hydrocarbons. A fluid with high viscosity can carry the proppant farther, delaying the gravity-induced settling, and helps to create a wider fracturing, preventing the bridging or lodging of proppant particles in the fracture.

Once the treatment is completed, the long, entangled polymer chains must be broken so that the hydrocarbons can flow towards the well. Chemical agents called "breakers" must be used for this purpose, the most commonly used being an ammonia salt called ammonium persulfate (APS). However, under normal conditions of pressure and temperature, APS acts very fast, so it cannot be injected freely during the treatment. Also, it cannot be injected only at the end of the treatment, because it is desirable for the APS to be uniformly distributed in the fracture, ensuring a uniform "cleaning".

The obvious solution is to inject the APS in the form of encapsulated particles mixed with the proppant. The idea is for the APS to be protected by the encapsulation, and to be released only at the end of the treatment, specially when the fluid pressure is released and the fracture starts to close on top of the proppant. The high level of compressive stress should be enough to break the encapsulation, with the consequent release of the APS. This technology was introduced in the late 1990s, and consists of pellets of APS coated with a mixture of vinylidene chloride and methylacrylate (a plastic with similar properties to PVC). The thickness of the coating is about 20 μm, and the average diameter of the particles is 0.6 mm.

In 2002, Lo, Miller and Li published a paper with results of experiments performed at Schlumberger's Sugar Land facilities. The interest of the authors was to study the effect of temperature and confining pressure on the release of APS from the encapsulation. The experimental setup is described in Fig. 3: a batch of encapsulated APS particles was put into a reactor (a steel tubing of 1/2 in inner diameter) contained in a pressure vessel, and submerged into a thermal bath. Once pressure and temperature were equilibrated, distilled water was circulated through the particles in an open circuit. Samples of the outflow were collected and the concentration of APS was measured in each sample. The results of the experiments were published in the aforementioned paper, without any modeling attempt. An example of the results is illustrated in Fig. 4.

In late 2005, "someone" had the bright idea of plotting the results of the experiments of Lo et al. in log-log scale, as shown in Fig. 5. Plotting the results in log-log scale revealed the presence of at least three well-defined regimes: the first regime is characterized by a $\sim t^{1/2}$ release of APS, which is strong evidence that the release of APS is diffusion-controlled. The second regime shows a much faster release, proportional to $\sim t^{\alpha}$ with $\alpha > 1$ (values of $\alpha \simeq 3/2$ and even $\alpha \simeq 5/2$ have been measured from the experimental curves). A third regime corresponds to the depletion of APS, as shown by the decline in the release rate.

There are two things that are particularly intriguing about these observations: first of all, the presence of the $\sim t^{1/2}$ regime. Considering the relatively high rate at which distilled water is pumped through the pressure vessel, it would be expected that the release of APS should be controlled by convection, and not by diffusion. The hypothesis is that diffusion is happening **inside** the encapsulation. The second intriguing point is the sharp and pronounced acceleration of the release, which would indicate the presence of another mechanism, such as damage to the encapsulation.

The aim of this problem is to try to construct a mathematical model that would show the presence of these three regimes.

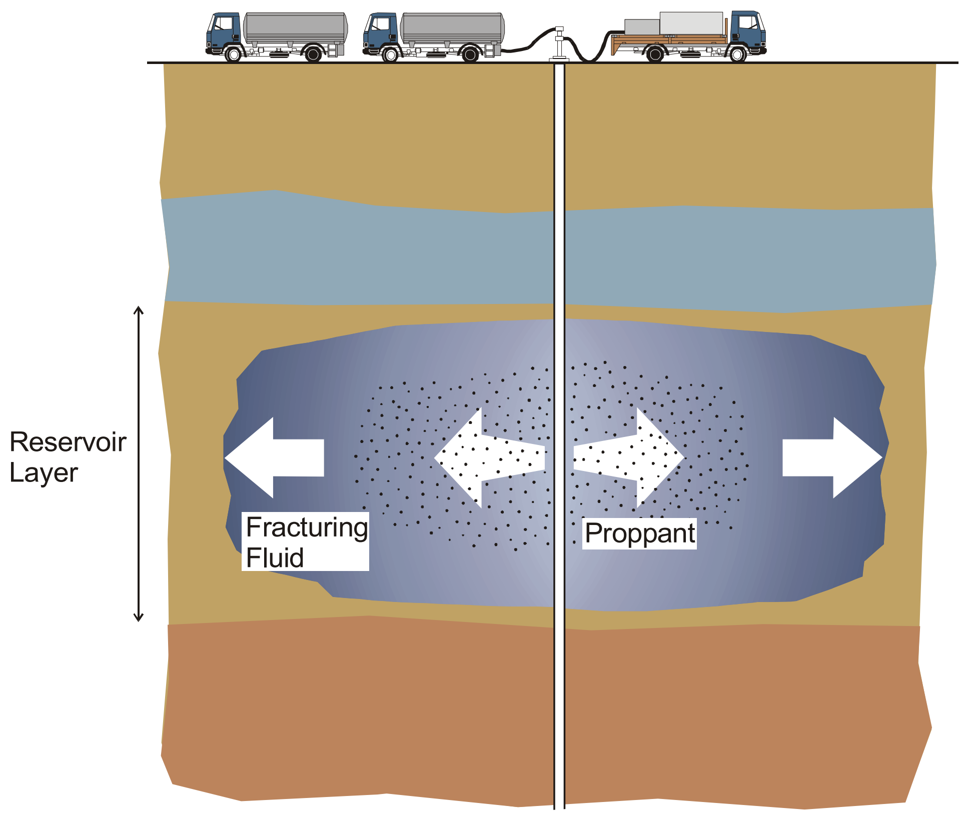

Figure 2: Schematic of typical hydraulic fracturing treatment.

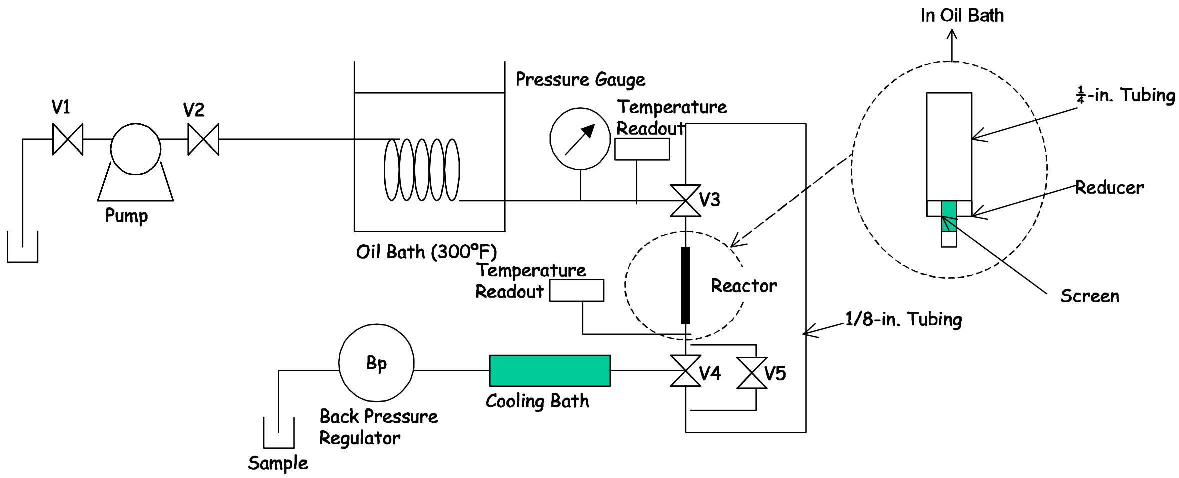

Figure 3: Description of experimental setup used by Lo et al. (2002).

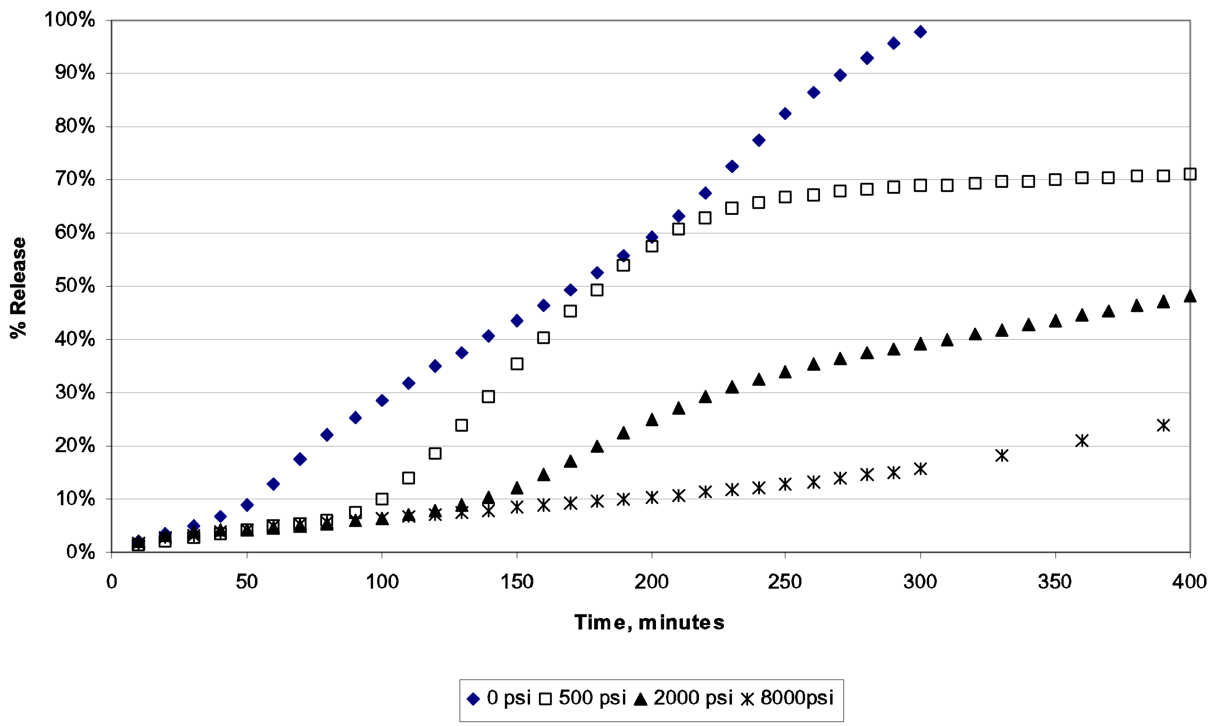

Figure 4: Example of experimental results obtained by Lo et al. (2002): plot of percentage of APS available that has been released versus time, for a fluid temperature of 150°F and four given confining pressures.

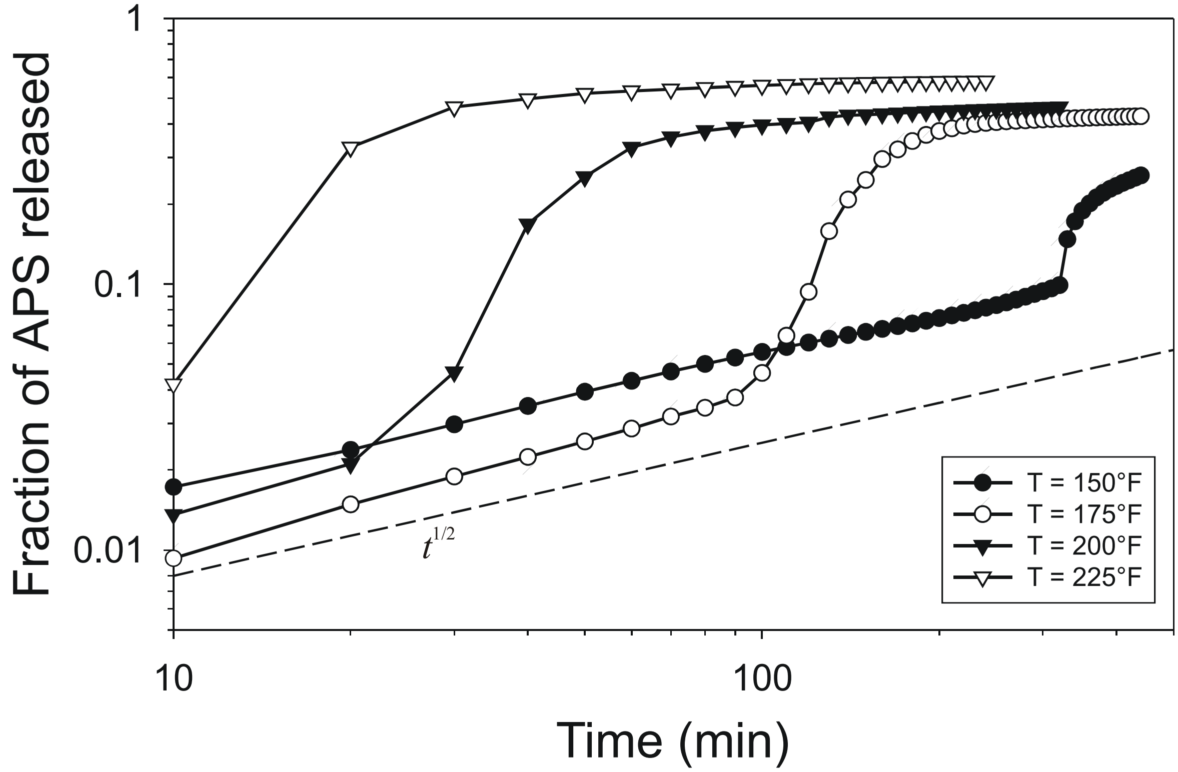

Figure 5: Experimental results of Lo et al. (2002) plotted in log-log scales (experiments performed with a confining pressure of 150 psi and at different temperatures). The curve $t^{1/2}$ is shown as a dashed line.

References

[1] Lo, S.-W., Miller, M. J. and Li, J. (2002). Encapsulated breaker release rate at hydrostatic pressure and elevated temperatures. In *Proc. SPE Annual Technical Conf. and Exhibition, San Antonio, Sept. 29 - Oct. 2*. (SPE 77744).