

Novel Fluids for Gas Productivity Enhancement in Tight Formations

**Duc Le
The University of Tulsa**

**Ken McQueen
Williams Exploration and Production**

**Jagan Mahadevan
The University of Tulsa**

Outline

- **Introduction and Past Work**
- **Objectives**
- **Experimental Methods**
- **Results and Discussion**
- **Conclusions and Future Work**

Technical Overview of Project

- **A combination of both experimental and modeling studies to develop cheap and novel treatment fluids for fracturing liquid damage**
- **Experimental studies to remediate gel damaged gas well by dry gas injection and solvent treatment**
- **Development of mathematical model to simulate the experimental clean-up of gel, both by displacement and evaporation**
- **Field test of the process will be carried out on a non-performing well in Merna Field, Wyoming**

Project Timing and Participants

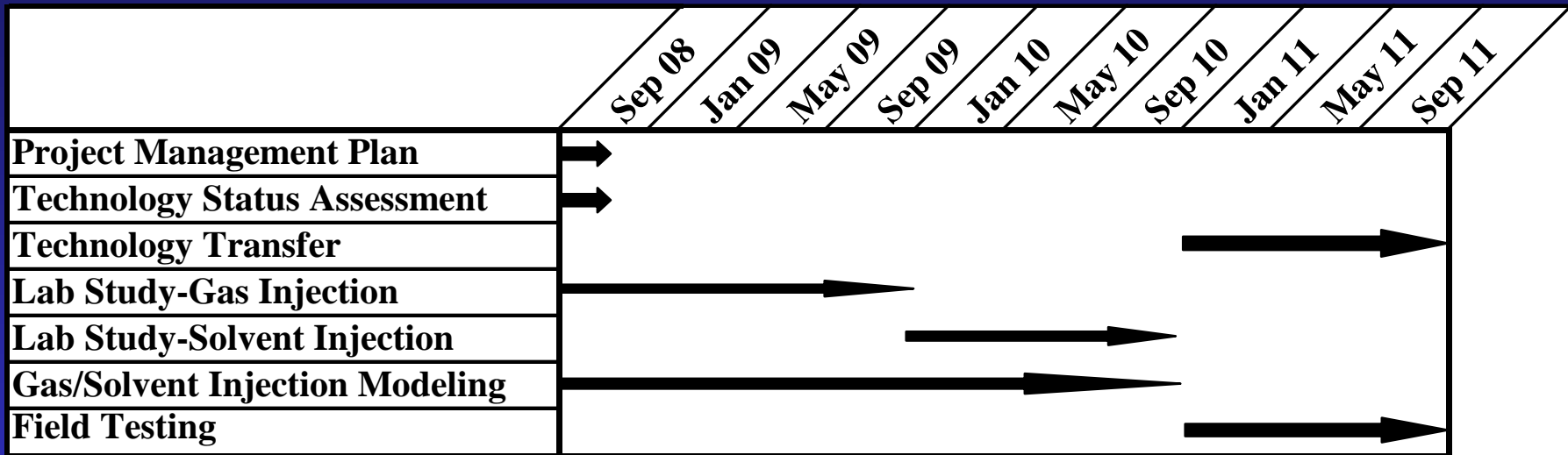
- **Project duration is 3 years from the date of award; Started - Sep 2008 and expect to be completed by Sep 2011.**
- **Participants:**
 - **Principal Investigator: Jagan Mahadevan (TU)**
 - **Graduate Student: Duc Le (TU)**
 - **Company Participant: Ken McQueen (Williams)**

Project Value

Application of results to improve production from Merna Field, Wyoming operated by Williams E&P

- **With expected fracture length of upto ~300ft the well is producing almost 9 times below potential (currently at 100 Mscf/D comparison to expected 900 Mscf/D)**
- **If the remedial treatment procedure is successful, the gas production from damaged Merna well can increase 9 times and hence the reserves**
- **Better understanding of gel damage clean-up mechanism can be used to design better fracturing fluids**

Milestones and Schedule



Status of Tasks

- **Project Management Plan-Completed**
- **Technology Status Assessment-Completed**
- **Technology Transfer – Ongoing**
- **Gas Injection Studies – Completed**
- **Solvent Treatment Studies – Completed**
- **Mathematical Modeling – Ongoing**
- **Field Testing – Planned for 2010/2011**

Introduction

- **Production from tight gas formation is uneconomical without hydraulic fracturing**
- **The injected fracturing fluid, most often polymeric gels, may be trapped in the fracture or near fracture region**
- **The focus of this work is to study the fundamental processes of remediation of the gas well by removal of trapped liquids**
- **A better understanding of the process of removal will provide greater benefits in formulating improved fracturing fluids with the right additives**

Gel Removal Mechanism

- Trapped liquid saturation is reduced in two steps: first by viscous displacement, which lasts for a short time, followed by evaporation.
- Gas flow rate recovers due to relative permeability effects as water is evaporated.



Flowing gas carries the vapors through the porous medium

Past Work

- Most attempts to remove the gel block focus on improving the effectiveness of the displacement process by reduction of viscosity (Ayoub *et al.* 2006)
- Penny *et al.* (2005, 2006) suggest using microemulsion additives to reduce the interfacial tension and the capillary pressure
- The reduction in capillary pressure leads to a reduction in the trapped liquid saturation, although it is not clear as to whether the capillary effects will be important in the case of gelled fluids

Past Work (cont.)

- Gel removal experiments from proppant packs (Penny, 1987, Ayoub *et al.*, 2006) show that the clean up by displacement is also dependent on the polymer concentration due to leak-off.
- Recent study by Marpaung *et al.* (2008) shows gel clean-up by displacement improves with greater gas flux in the fracture (in the presence of breakers the clean-up efficiency is as high as 60% but only upto ~10% otherwise)
- Studies on water blocking (McCleod and Coulter, 1966, Tannich, 1975, Kamath and Laroche, 2003) show that addition of alcohols can help reduce interfacial tension and also increase volatility.

Evaporative Removal

- **Evaporation can be a significant mechanism of liquid block removal**
- **Evaporative methods do not depend on reduction of viscosity and hence do not require high gas flow rates or reservoir pressures**
- **It is here that the alcohol solvents prove useful as an additive-to increase the evaporation rate and also to influence gel-alcohol phase behavior**

Objectives

- **Experimentally investigate the improvement of gas flowrate in sandpacks and fracture-packs using dry gas treatment and alcohol treatment methods.**
- **Determine optimum treatment fluid composition and procedure based on laboratory results**
- **Conduct field treatments to improve gas productivity from a non-performing well**

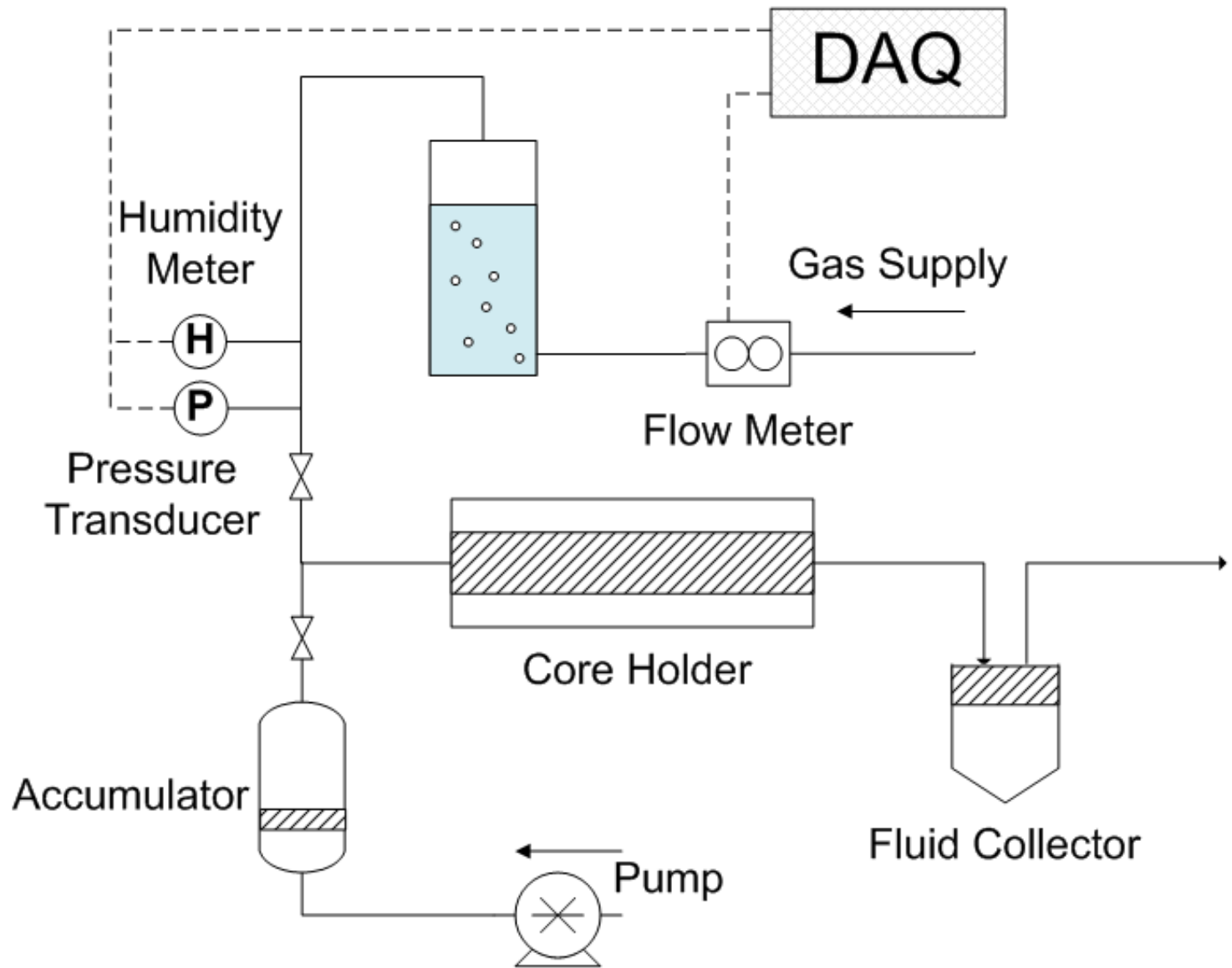
Dry Gas Treatment

- **Dry sandpack/fracture-pack is first subjected to invasion by aqueous fracturing fluids**
- **Part of the invaded gel is removed by wet gas flowback at ~65psi pressure drop**
- **The water content of the remaining gel is removed by dry gas injection at ~10 psi pressure drop**

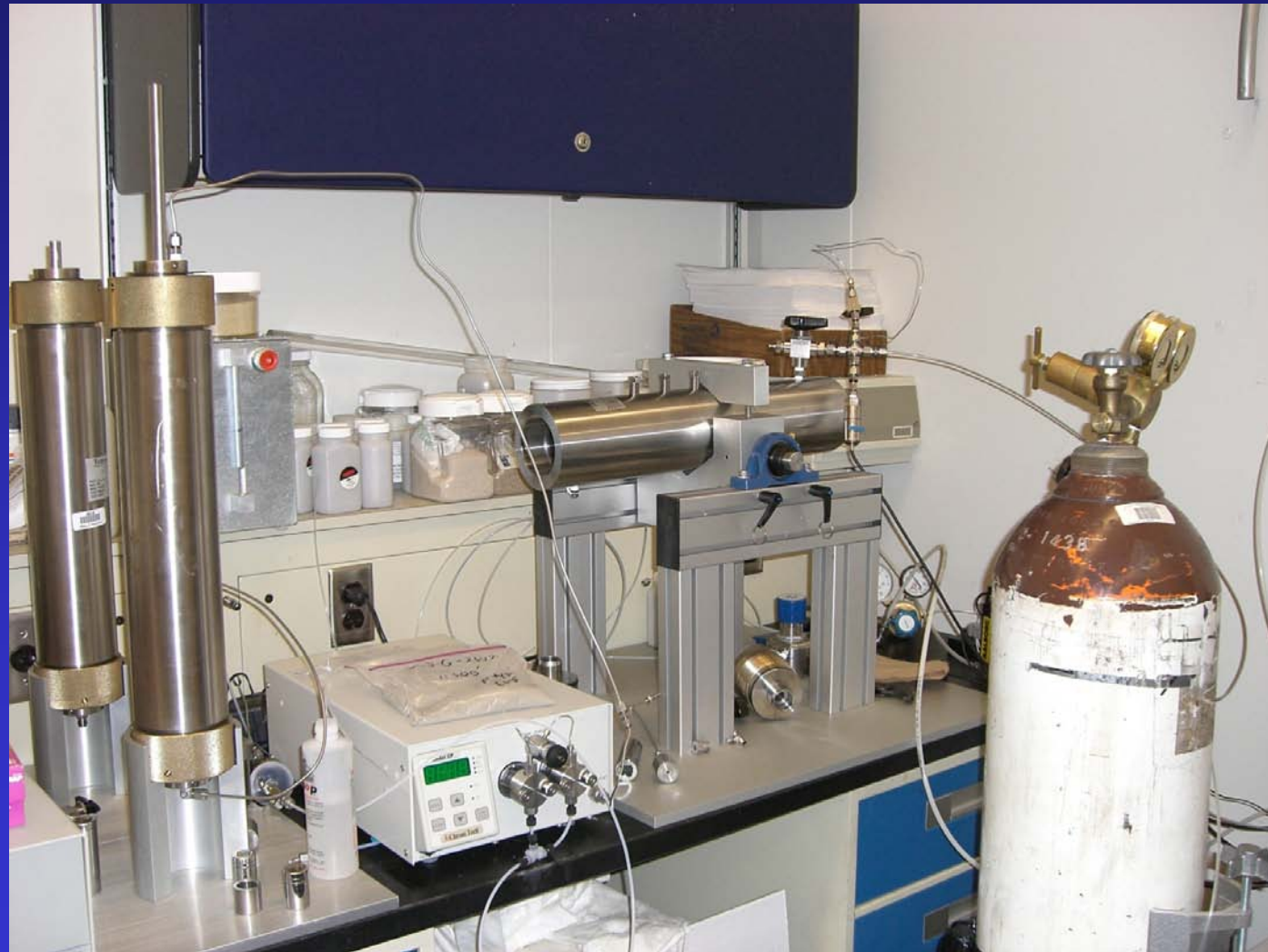
Alcohol Treatment

- **After fracturing fluid invasion and displacement processes are complete, 2 solvent treatment scenarios are considered:**
 - 1. Solvent treatment alone immediately following gas flow-back**
 - 2. Solvent treatment in combination with dry gas treatment after gas flow-back**
- **We considered Iso-propyl alcohol for treatment in this study (due to its relatively non-hazardous nature)**

Schematic of Experimental Set-up



Experimental Setup



Fracture-pack Preparation (Tight Gas Core from Merna Field, Wyoming)



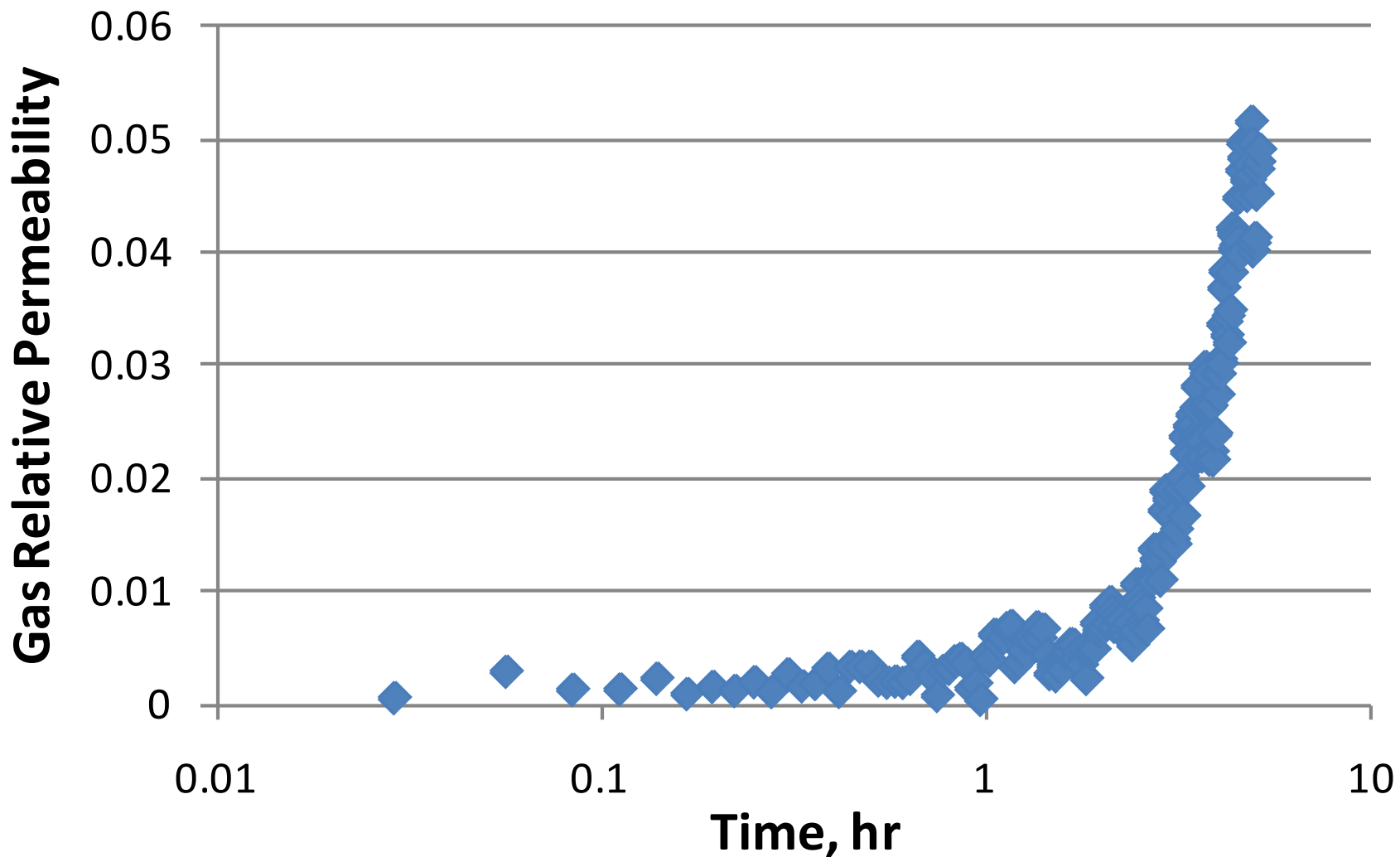
Fracturing Fluid Preparation

- **Slowly add 3.0 grams WG-35 Guar Polymer (obtained from Halliburton) to 1 liter of water.**
- **Stir at moderate speed in Waring® Blender for 30 minutes.**
- **Add 1.75 ml BC-140 – Cross-linker (obtained from Halliburton) to the solution. Crosslinking takes place immediately.**

Experimental Results

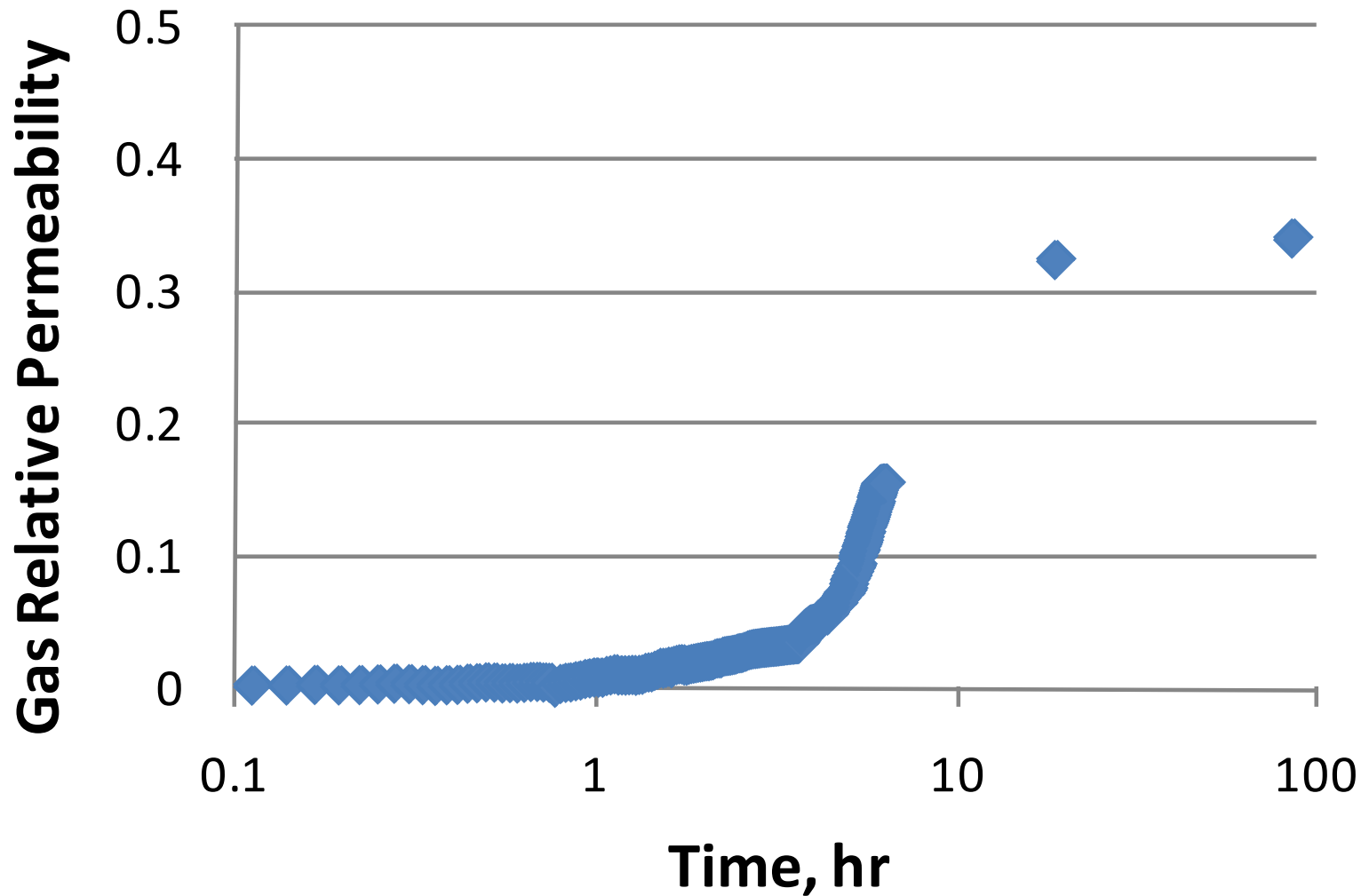
Fracture-pack: Wet Gas Flow-back

(16/40 mesh size, permeability=40 D, $\Delta P=65$ psi)



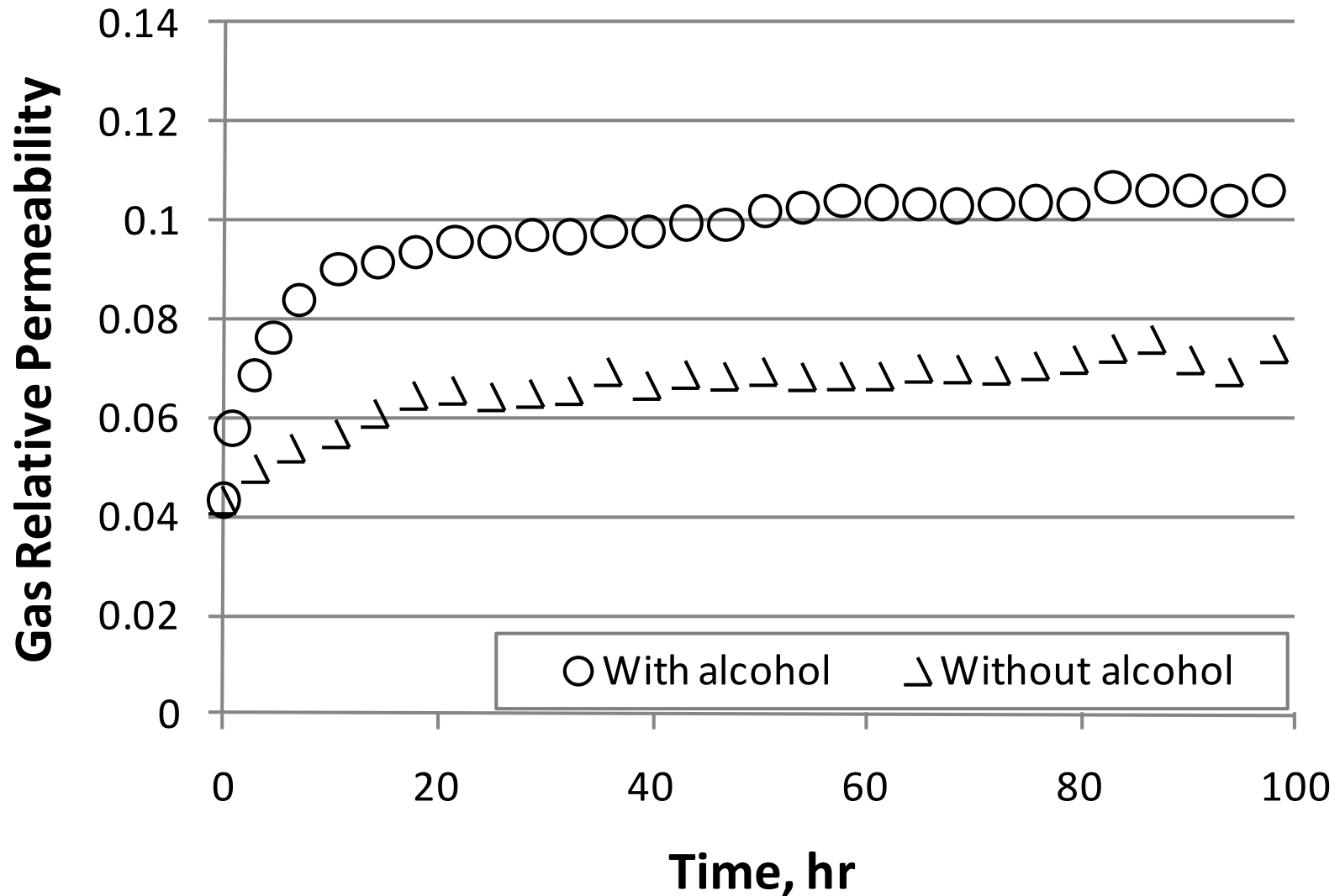
Fracture-pack: Dry Gas Treatment

(16/40 mesh size, permeability=40 D, $\Delta P=10$ psi)

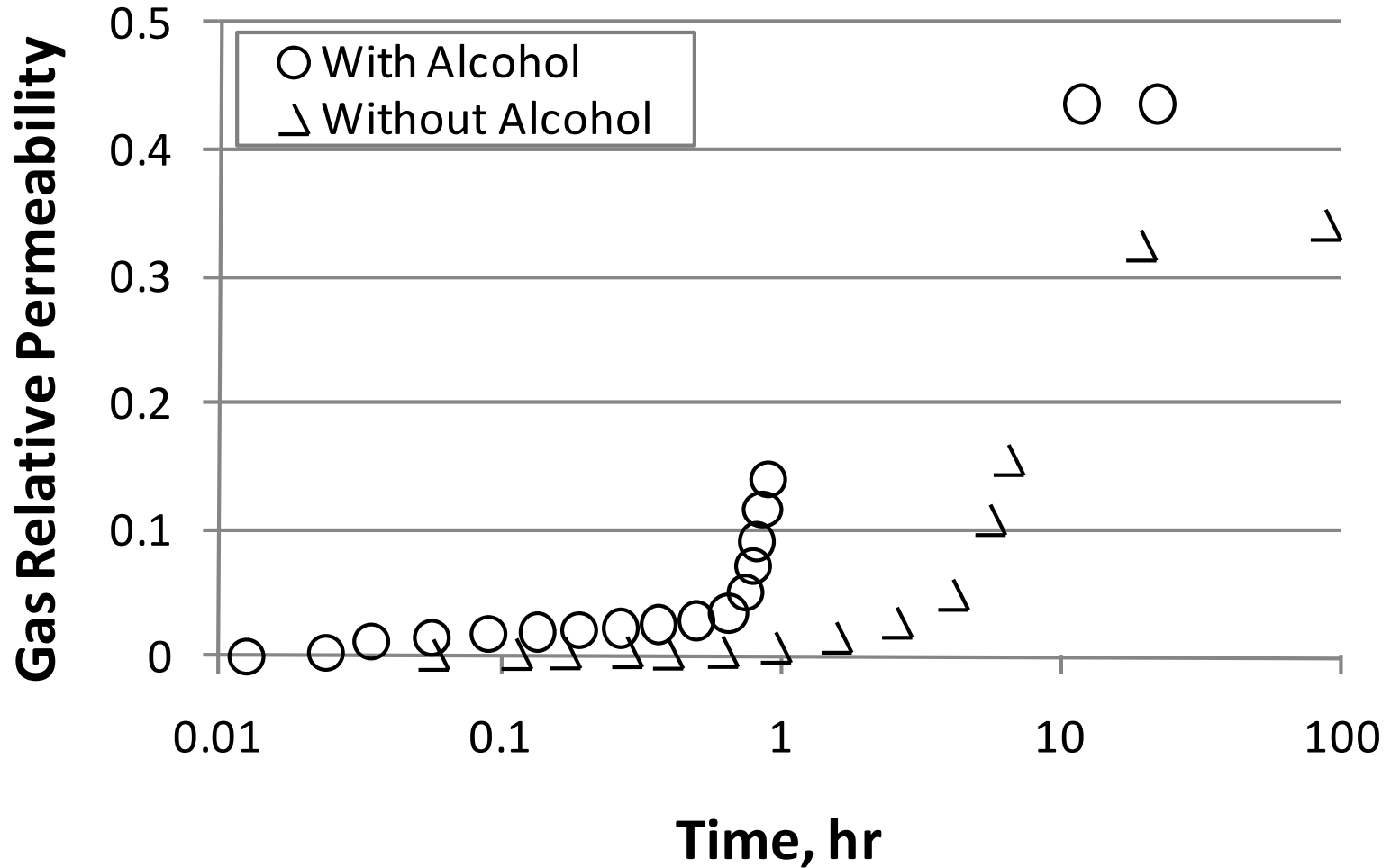


Solvent Treatment W/O Soak

(16/40 mesh size, permeability=40 D, $\Delta P=10$ psi)



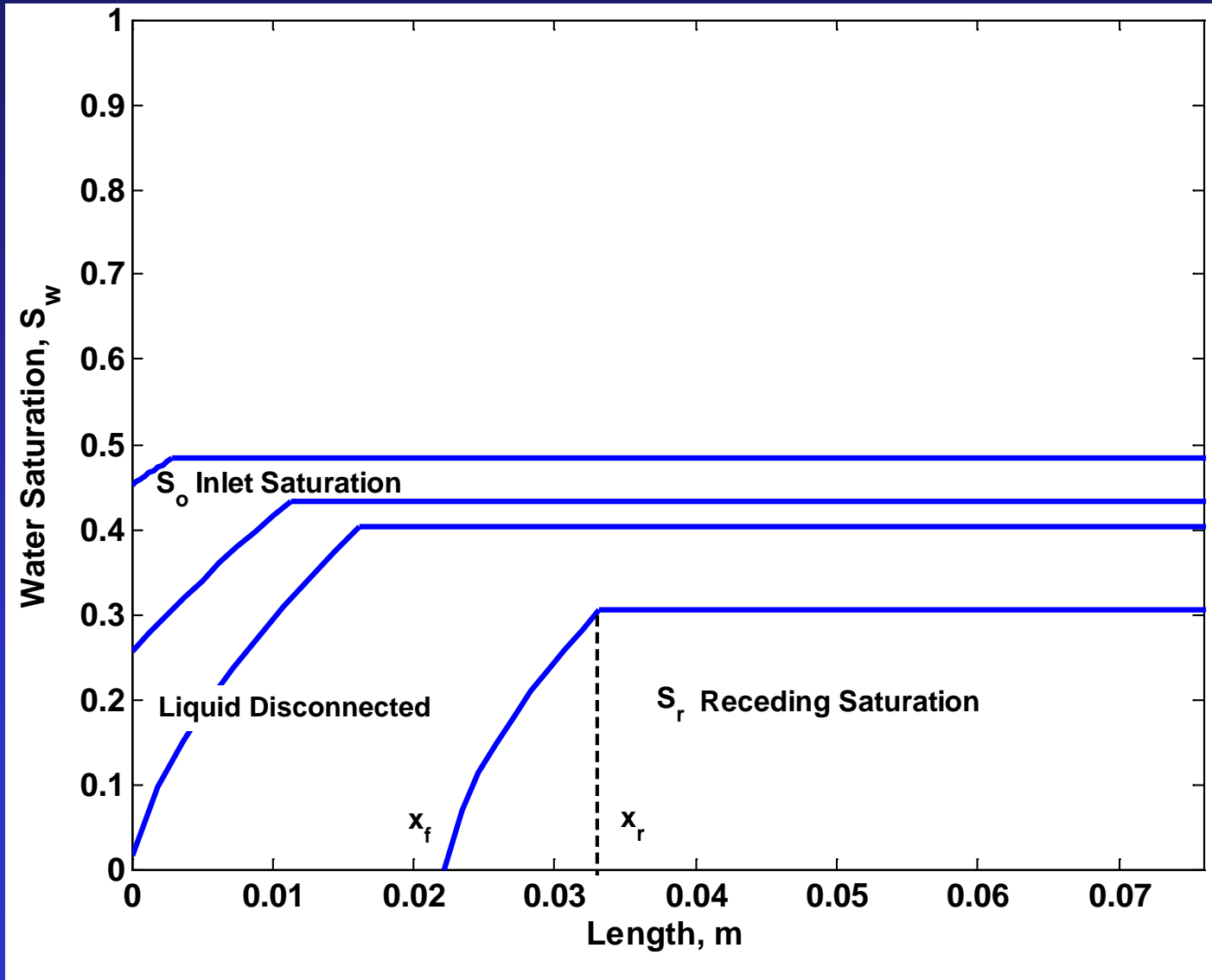
Solvent Treatment With 3 Hour Soak Followed by Dry Gas Treatment (16/40 mesh size, permeability=40 D, $\Delta P=10$ psi)



Model Development

- **Based on drying front propagation which was originally developed by Mahadevan *et. al* 2006**
- **Assumptions:**
 - 1D (linear, homogeneous) system
 - Joule-Thompson cooling is negligible
 - Phase behavior is described by Raoult's Law (acceptable at low gel concentrations)
 - The gas obeys ideal gas law
 - Local thermodynamic equilibrium exists
 - Mass transfer is dominated by convection
 - Liquid flow is negligible

Schematic of Water Saturation Profile during Dry Gas Injection



Conservation Equations

Mass Balance for Liquid

$$\phi \frac{\partial}{\partial t} (\alpha_w S_g + \beta'_w S_l) = - \frac{\partial}{\partial x} (\beta'_w u_T f_l' + \alpha_w u_T f_g')$$

$$\alpha_w = \frac{y_w P_g}{R_g T}$$

Mass Balance for Gas

$$\phi \frac{\partial}{\partial t} (P_g S_g (1 - y_w)) + \frac{\partial}{\partial x} (P_g (1 - y_w) f_g' u_T) = 0$$

$$\beta'_w = \frac{\rho_l x_w}{M_l}$$

Model for Evaporation By Dry Gas Injection (cont.)

Integrating from x_r to 1:

$$(1 - x_r) \frac{1}{\varepsilon} \frac{dS_r}{dt_D} = -u_D(1) + u_D(x_r)$$

Integrating from 0 to 1:

$$S_r \frac{1}{\varepsilon} \frac{dx_r}{dt_D} = u_D(x_r)$$

By solving the above equations assuming $x_f \approx x_r$, we can obtain the saturation profile at any time during dry gas injection.

Model for Evaporation By Dry Gas Injection (cont.)

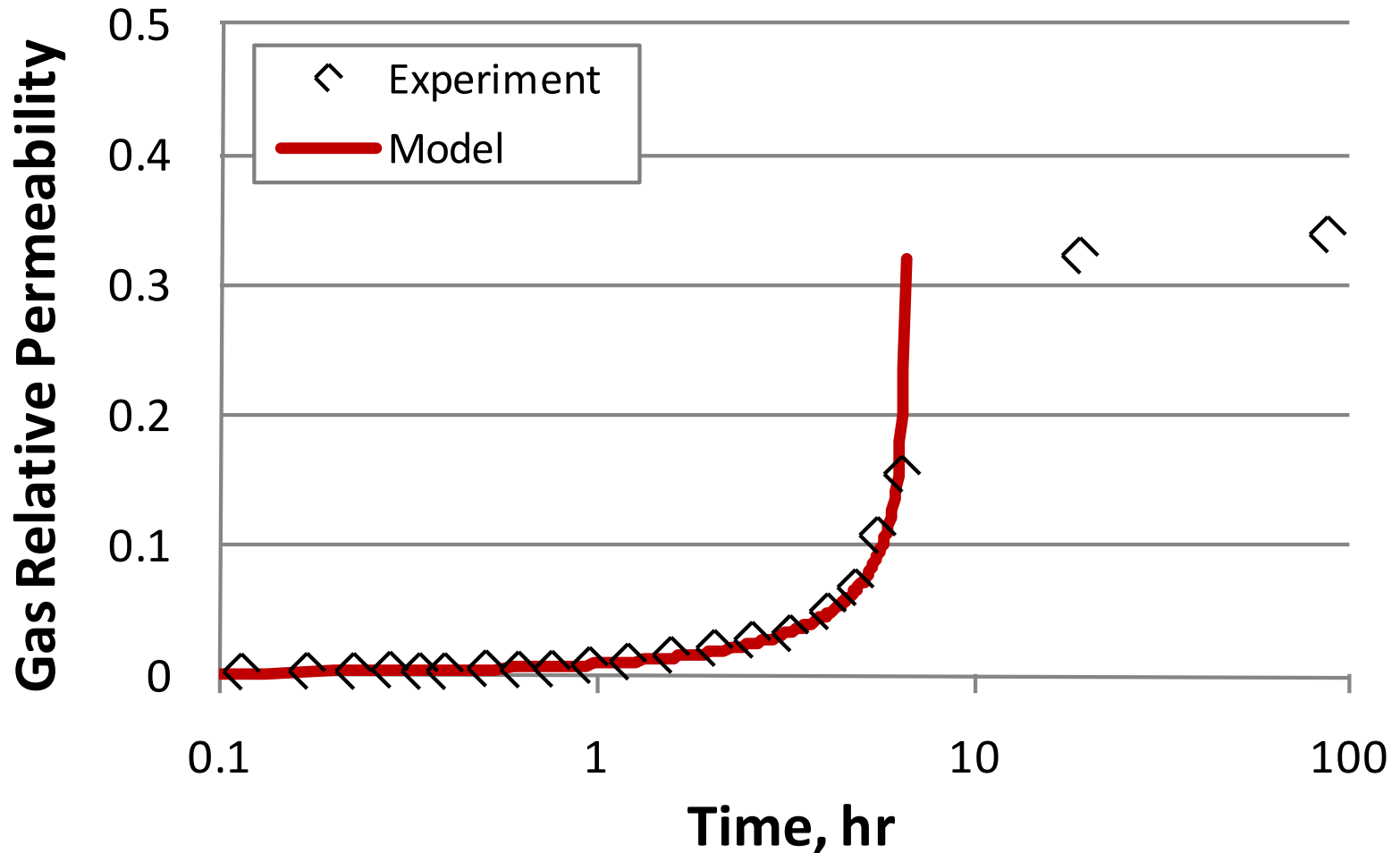
Effective gas relative permeability is obtained by taking the pore volume average of the local gas permeabilities over the entire length of the core:

$$k_{rg,eff} = \frac{\int_0^L k_{rg,local} dx}{L}$$

Relative permeability curves are determined from experiments.

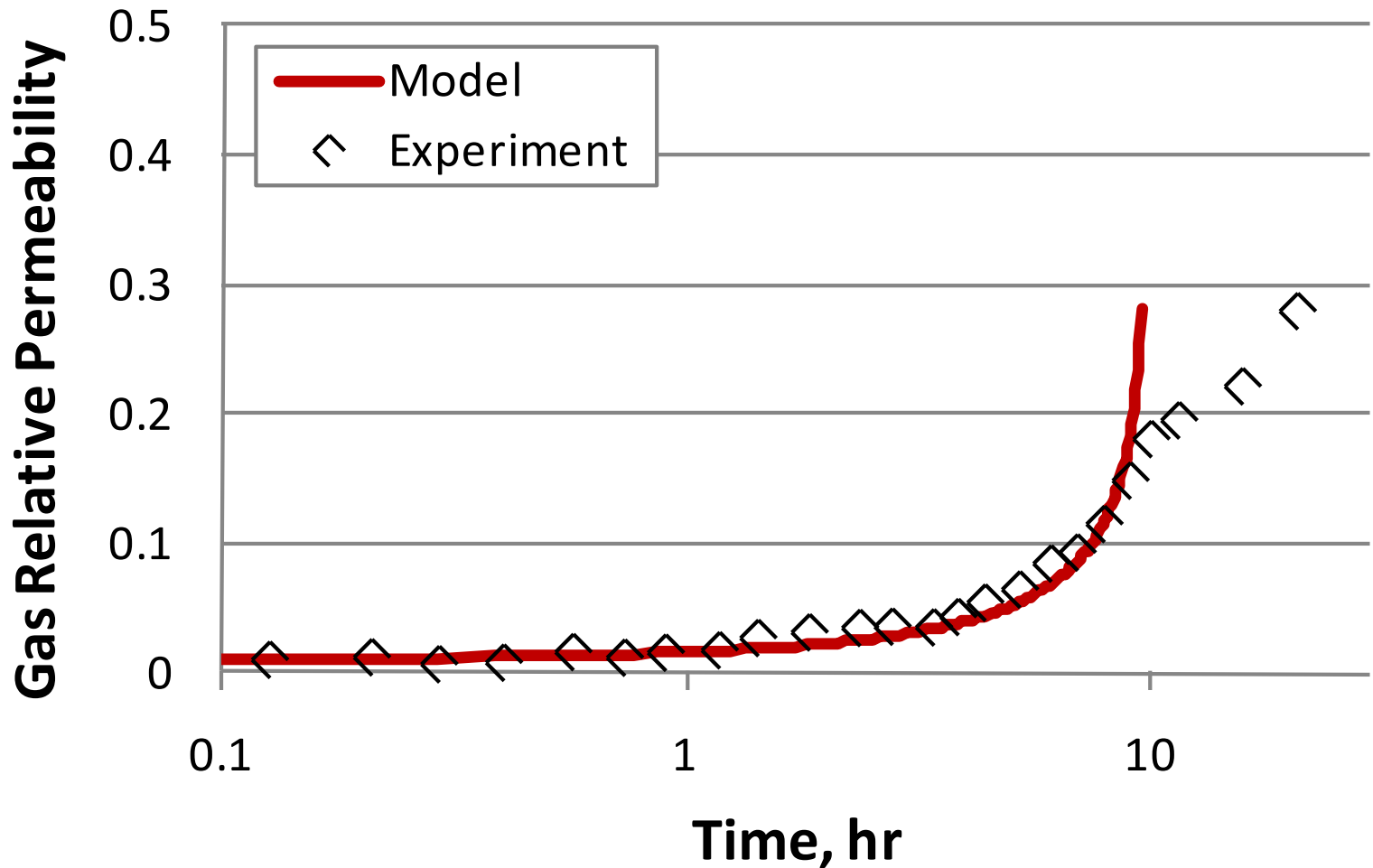
Fracture-pack: Model Comparison with Experiments

(permeability=40 D)

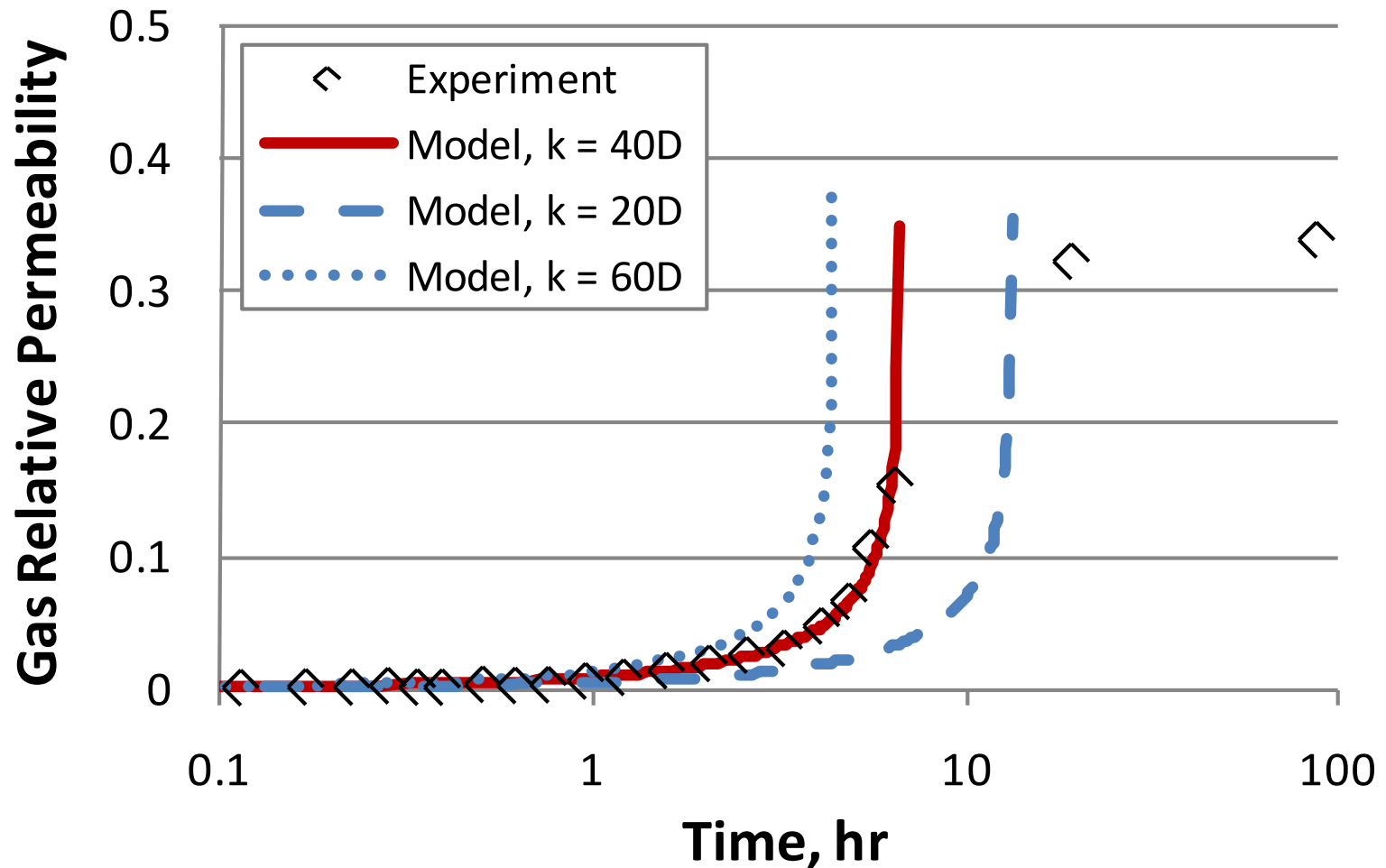


Sandpack: Model Comparison with Experiments

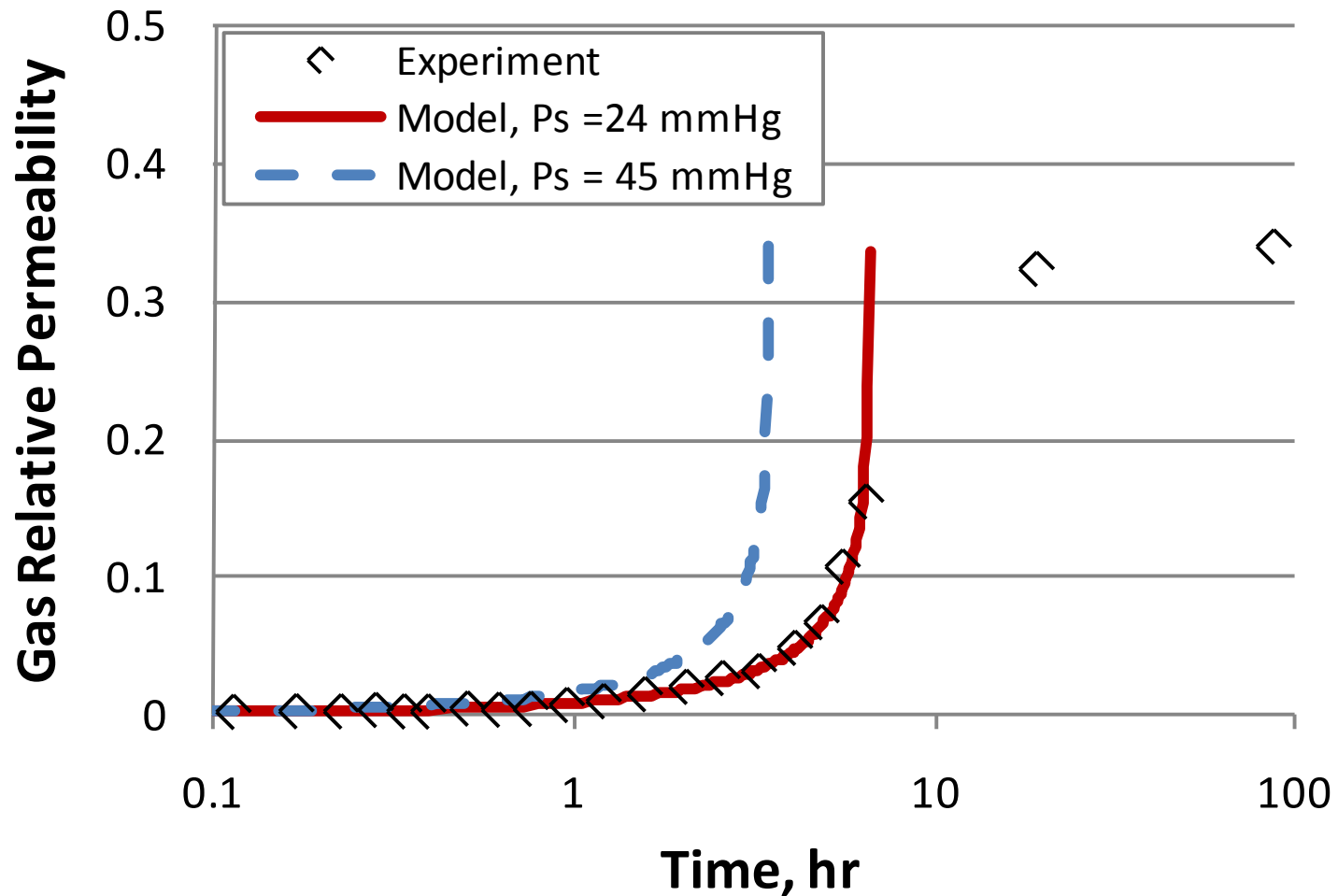
(permeability=10 D, $\Delta P=10$ psi)



Effect of Permeability on Flowrate Improvement (permeability=40 D, $\Delta P=10$ psi)



Effect of Solvent Vapor Pressure on Flowrate Improvement (permeability=40 D, $\Delta P=10$ psi)



Conclusions

- Experiments on sandpacks and fracture-packs show that dry gas treatment leads to clean-up of gel damage by removing the water content of the gel through evaporation process, thus reducing gel saturation.
- The improvement in ultimate gas flowrate during flow-back in sandpacks and fracture-packs due to dry gas treatment is several times (>6) higher than that obtained by the viscous displacement method alone.

Conclusions..

- **When the alcohol treatment is combined with a dry gas treatment, gas flowrate recovers faster and to greater values compared to dry gas treatment alone.**
- **A model based on drying front propagation is able to predict gas flowrate recovery during dry gas treatment and the predictions compare well with experimental observations.**

Future Work

- **Well testing on Merna MF-74 well to determine the fracture characteristics more accurately**
 - **Post-fracture build-up test: the well has been flowing at near constant rates for the last 4 months;**
- **Development of model for**
 - **calculation of gas rates when solvent is used (compositional model to include the effect of soak time)**
 - **field scale prediction of treatment volumes of gas/solvent**
- **Field treatment – planned for summer of 2011; Dry gas and solvent treatment**

Accomplishments

- **Website containing details and results of the study is available through The University of Tulsa departmental portal.**
- **This is accessible to all web surfers and especially to local operating companies who are already evincing interest.**
- **Paper SPE 132605 accepted at the SPE Western Regional Meeting in California, May 27-29 2010 in Anaheim. Manuscript submitted with all results.**

Acknowledgements

- **Financial support for the study was provided by RPSEA (Contract # DOE-07122-36).**
- **Kent Perry, Gas Technology Institute, Denver, Colorado**
- **Christy Allen, Williams E&P Company**