RPSEA
Research Partnership to Secure Energy for America

Onshore Production Conference: Technological Keys to Unlocking Additional Reserves

Bakersfield, CA
October 11, 2011

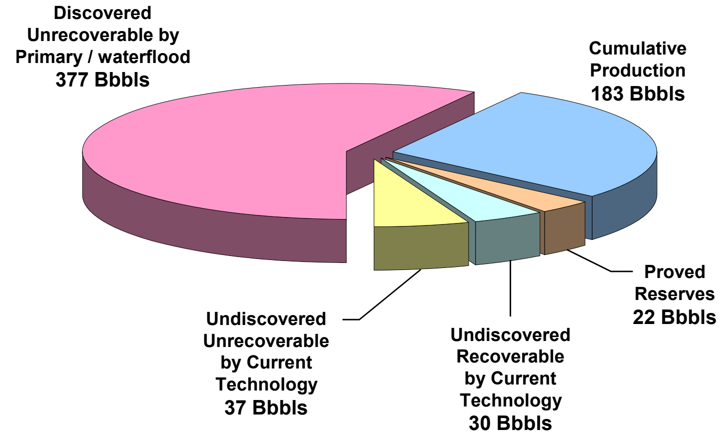
Project 08123-02

Field Demonstration of Alkaline Surfactant Polymer Floods in Mature Oil Reservoirs Brookshire Dome, Texas

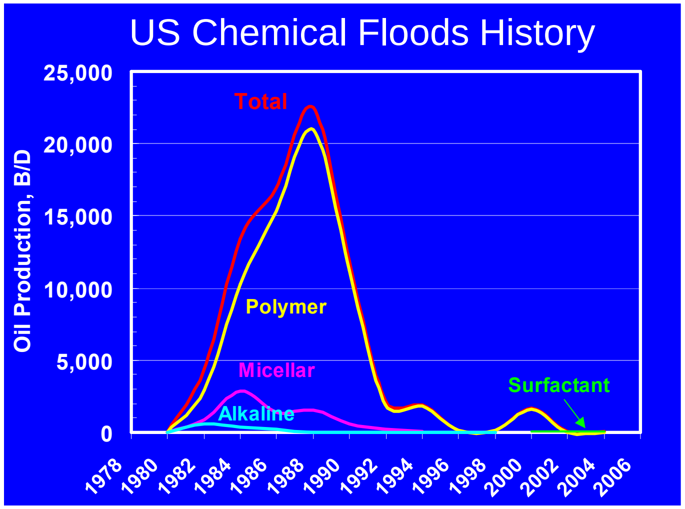
Bo Gao, The University of Texas
Mukul M. Sharma, The University of Texas
Chris Lewis, Layline Petroleum
Tom Burghardt, Tom Waldman, Vic Baginski, TIORCO

Chemical EOR 101

- **Promising technologies for mature field development**
- **Intricate interplay of all chemicals involved**
  - **Surfactants to lower interfacial tension**
  - **Polymer to maintain mobility control**
  - **Alkali to reduce adsorption / form soap**
- **Challenges**
  - **Chemical cost & oil price**
  - **Unforgiving geology**
  - **Complicated design process**
- **Recent Advancement in Chemical EOR**
  - **New generation of chemicals**
  - **Rigorous laboratory protocols**
  - **Tailorability to various conditions**



Onshore Oil Resource in US, DOE Website



Source: SPE website

Project Summary

- **Systematic Laboratory Design for Brookshire Dome ASP Flood**
  - **Optimal formulation screened from phase behavior study**
  - **Over 90% oil recovery from coreflood experiment**
- **Injection Plan Optimization using Numerical Simulation**
  - **5-layer model built upon tracer test and cum. production**
  - **Different chemical injection scenarios studied**
- **Field Implementation and Progress**
  - **Pilot chemical injection initiated earlier last month (Sept. 2nd, 0211)**
  - **Polymer pre-flush completed; surfactant slug injection underway**
- **Ongoing work**
  - **Pilot support and production monitoring**
  - **Data collection and results analysis**

Location of Brookshire Dome Field

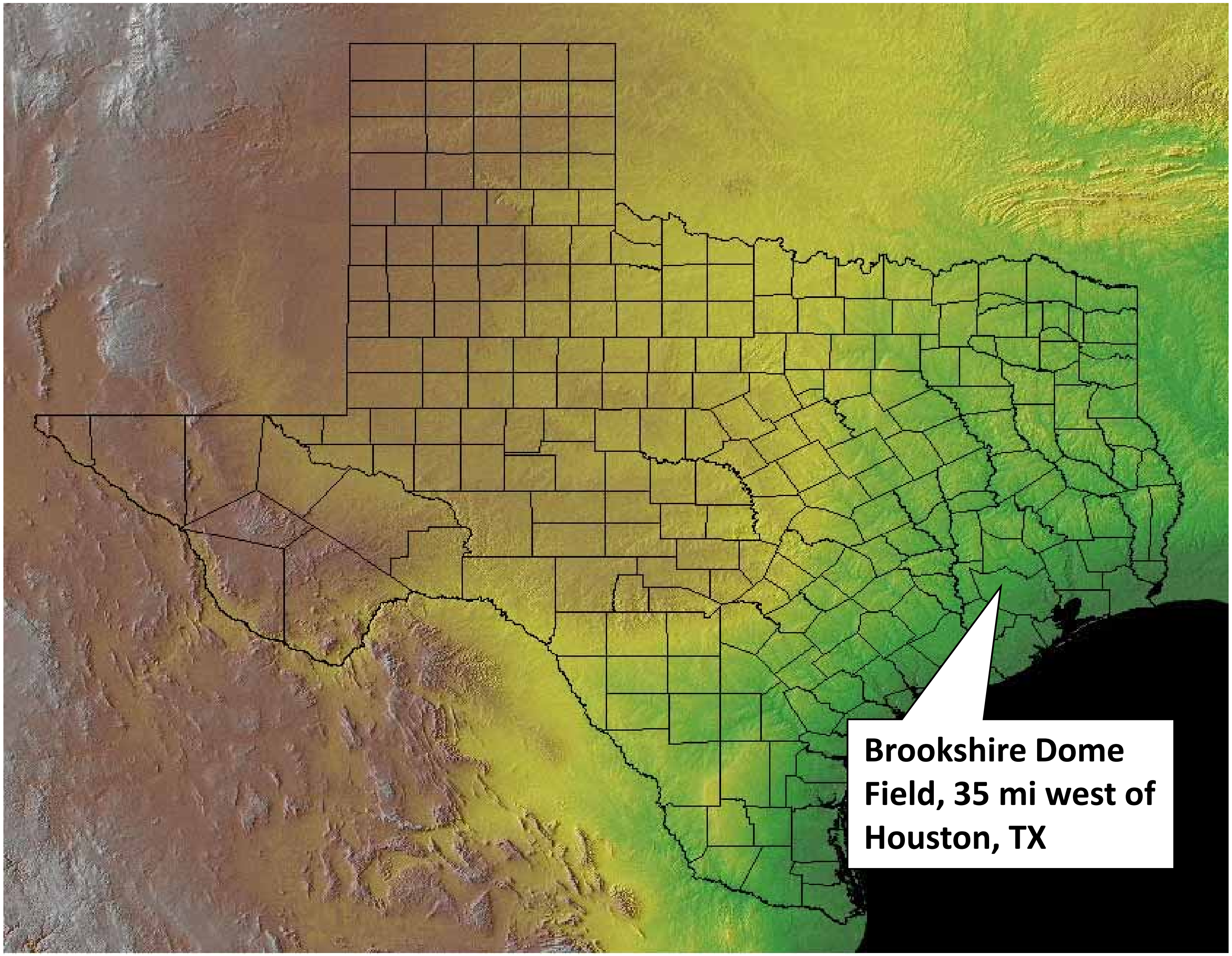


Chart 4

Brookshire Dome, Martin lease

- 2.0 MMBO produced (Martin lease)
- Piercement salt dome, discovered in 1996
- 2 main sands (Catahoula and Plunk sands)
- 2 to 5 acre well spacing
- Oil found in the caprock above the salt dome (3500 ft)
- Monthly cash flow $ net of operating costs and taxes
- Catahoula sand is 70 to 80 ft thick
- Sand is full to base
- Salinity of reservoir brine is 8000 ppm
- Reservoir T = 130 ºF (55 ºC)
- Viscous oil (28 cp)
- Very active water drive

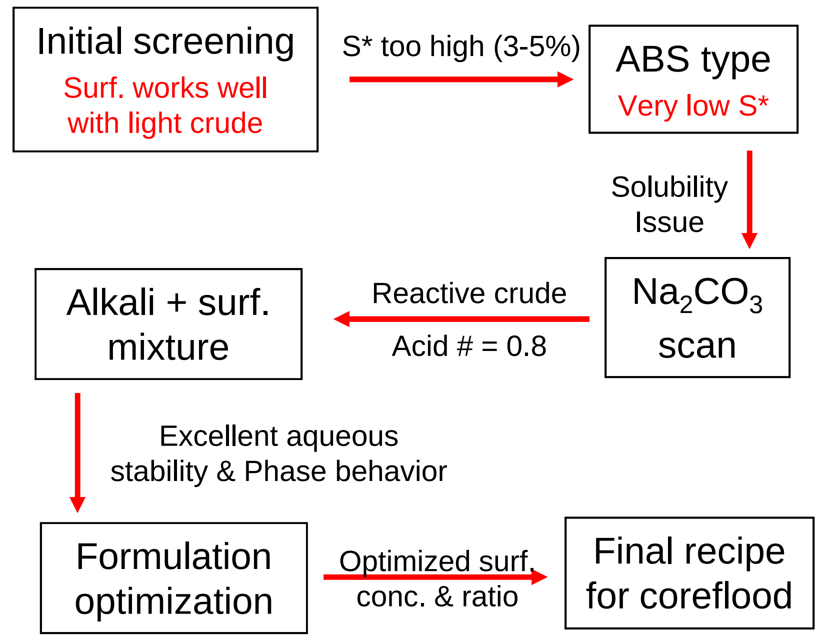
Outline

- **Alkaline/Surfactant/Polymer Flood Laboratory Design**
  - **Phase behavior test**
  - **Coreflood experiment**
- **Pilot Simulation Study**
  - **Field tracer test**
  - **Injection plan optimization**
- **Field Implementation and Progress**
  - **Pilot design and field installation**
  - **Field chemical injection update**
- **Conclusions**
- **Acknowledgements**

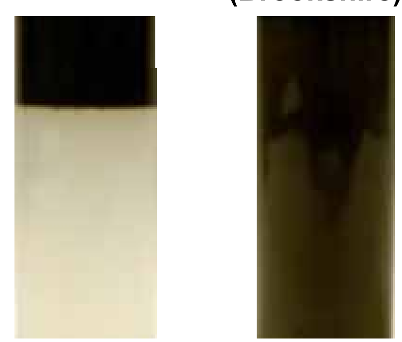
ASP Formulation Design

- **Objective: identify optimal chemical formulation subject to reservoir conditions**
- **Reservoir specifics**
  - **Moderate temperature ~ 55ºC (131ºF)**
  - **Live oil viscosity ~ 28cp at 55ºC**
  - **Oil cut in the field < 1.5%**
  - **Reservoir brine analysis**
    - **< 8,000 ppm TDS**
    - **< 60 ppm Ca^{++}, Mg^{++}**
  - **Challenge for formulation design**
    - **Available surfactants offer either too high (3 – 4wt% NaCl) or too low (< 5000 ppm) optimal salinity**
  - **Solution: reactive crude oil**
    - **In-situ soap formed upon alkali addition**
    - **Synergy between soap and synthetic surfactant**

Screening Workflow

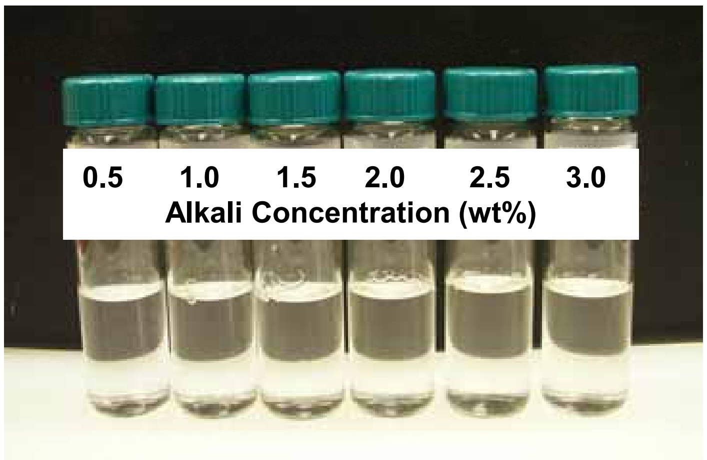


Crude Oil: (w/ Na2CO3) **non-reactive** **reactive (Brookshire)**



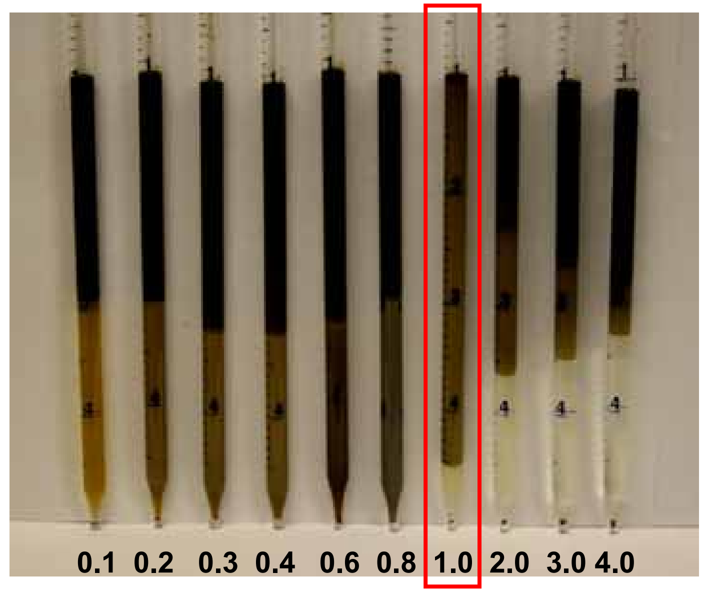
Aqueous Phase Behavior

- **Optimal formulation:**
  - 1 wt% alkali in synthetic brine
  - 0.3 wt% primary surfactant
  - 0.1 wt% co-solvent
  - 2000 ppm polymer A



Na2CO3 Scan (wt%) in SFB									
0.5	1	1.5	2	2.5	3	3.5	4	4.5	5

clear	
hazy	
phase separation	



Na_2CO_3 wt%

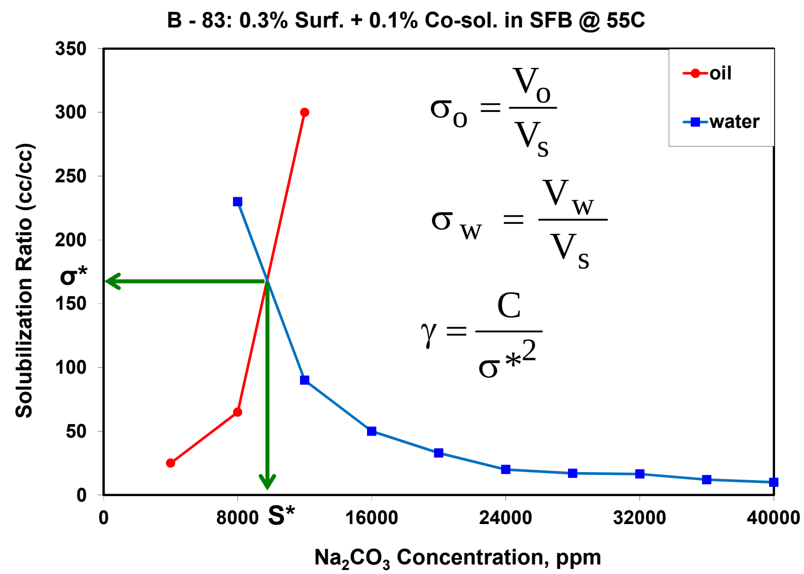
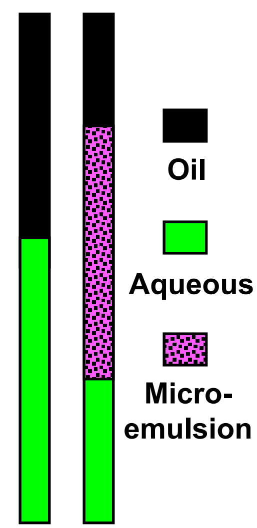
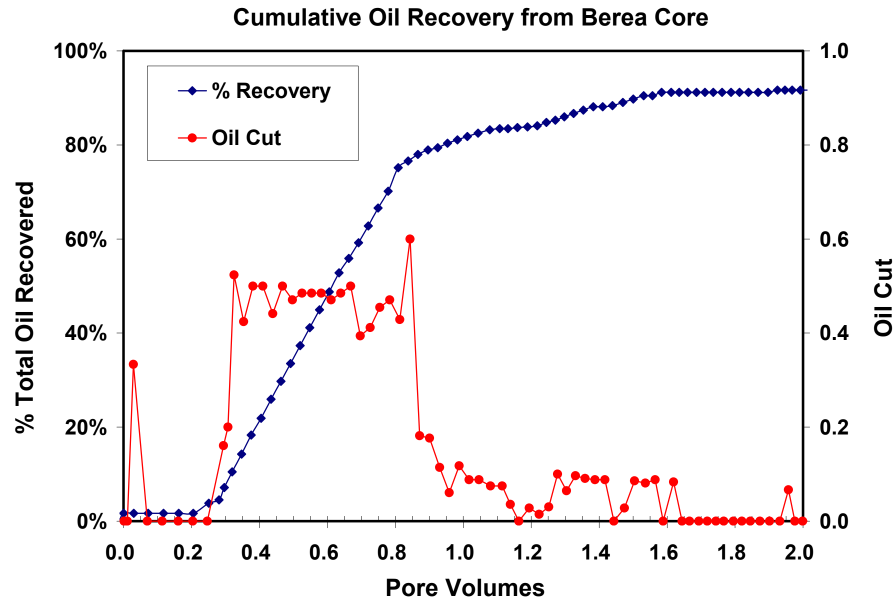


Chart 8



Coreflood Results

- **Berea sandstone core**
- **0.3 PV surfactant slug (ASP)**
  - **0.4 wt% surfactant + co-solvent**
  - **2000 ppm polymer A**
  - **1 wt% Na_2CO_3 in synthetic brine**
- **2 PV polymer drive (ASP)**
  - **2000 ppm polymer A**
  - **Synthetic formation brine**
- **Successfully recovered over 90% residual oil after waterflood**



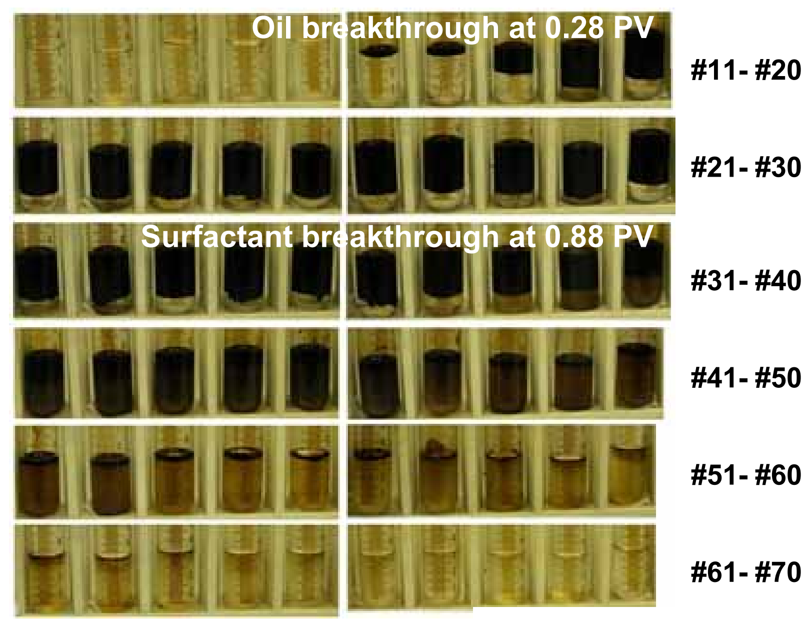


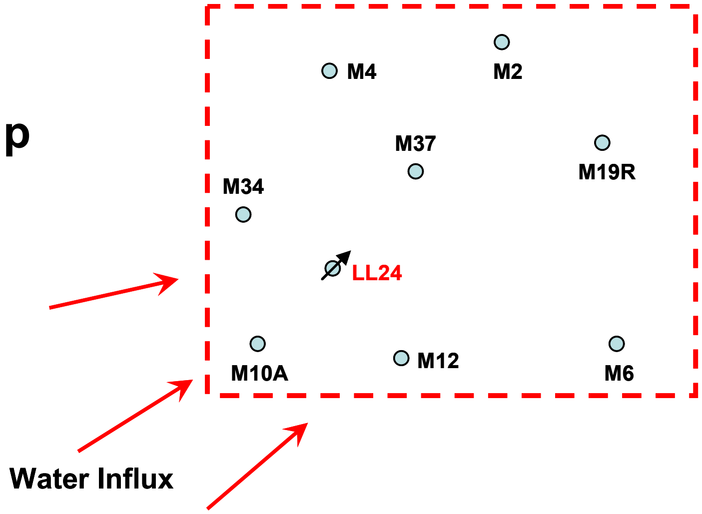
Chart 9

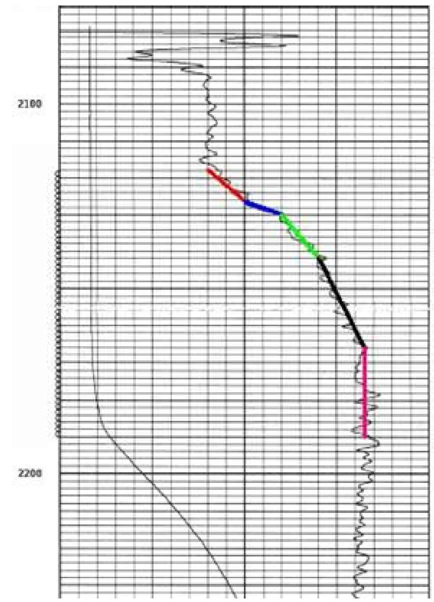
Outline

- Alkaline/Surfactant/Polymer Flood Laboratory Design
  - Phase behavior test
  - Coreflood experiment
- **Pilot Simulation Study**
  - **Field tracer test**
  - **Injection plan optimization**
- **Field Implementation and Progress**
  - **Pilot design and field installation**
  - **Field chemical injection update**
- **Conclusions**
- **Acknowledgements**

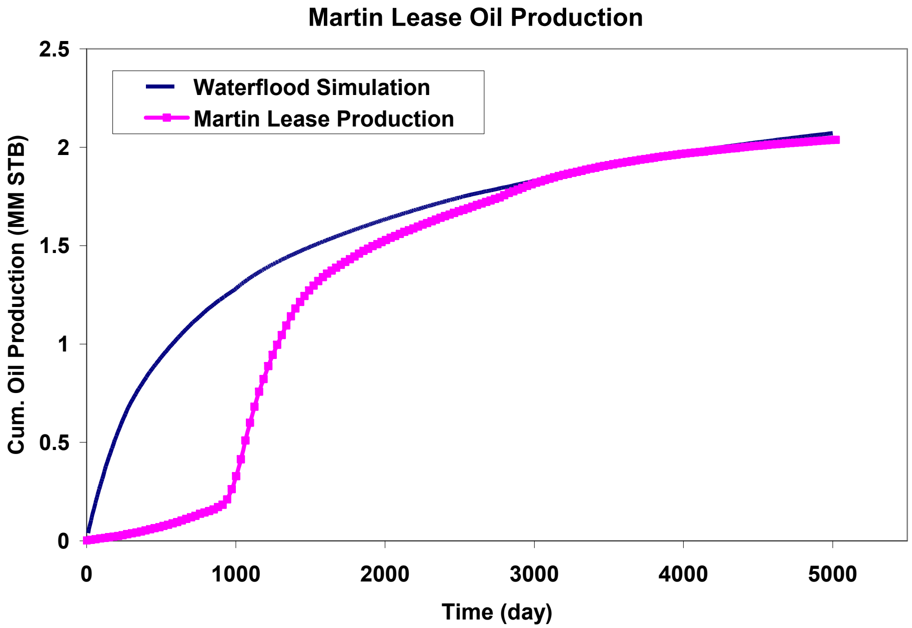
Simulation Model

- **Inverted 5-spot pattern**
  - **Peripheral producers up-dip**
  - **Active aquifer charge**
- **Layer cake model based on**
  - **Spinner survey**
  - **Water injectivity**





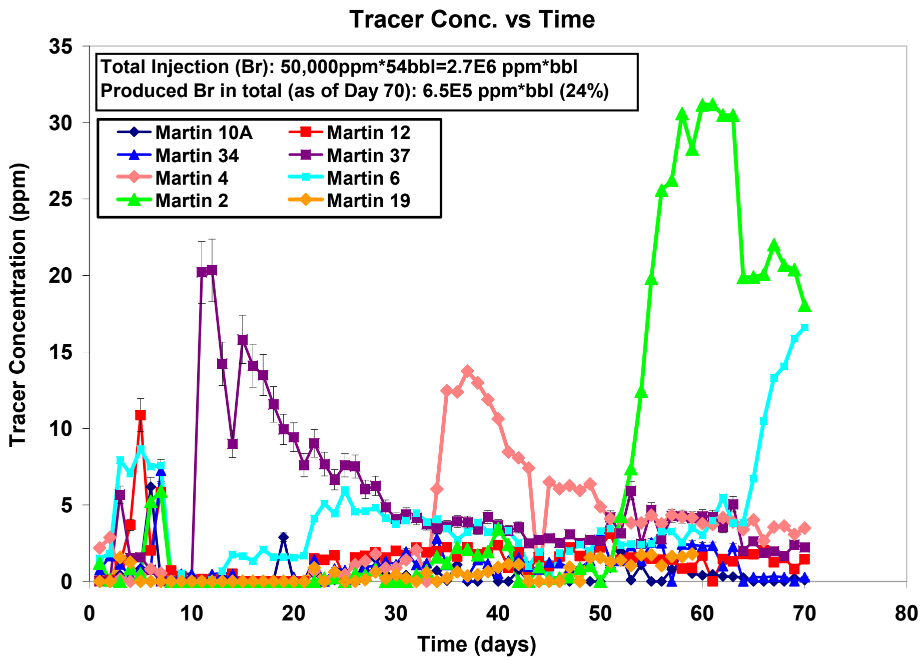
Spinner Survey

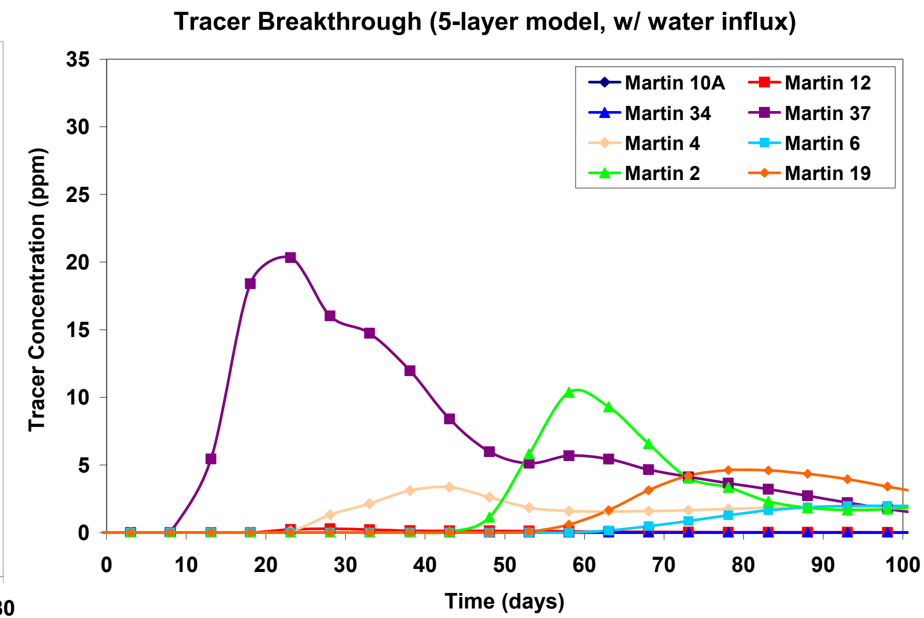


- **Model validated by matching cum. oil production**
  - **2 MM barrel produced**
  - **Avg. oil saturation ~ 0.4**
  - **All wells at < 1.5% oil cut**

Chart 11

Field Tracer Test



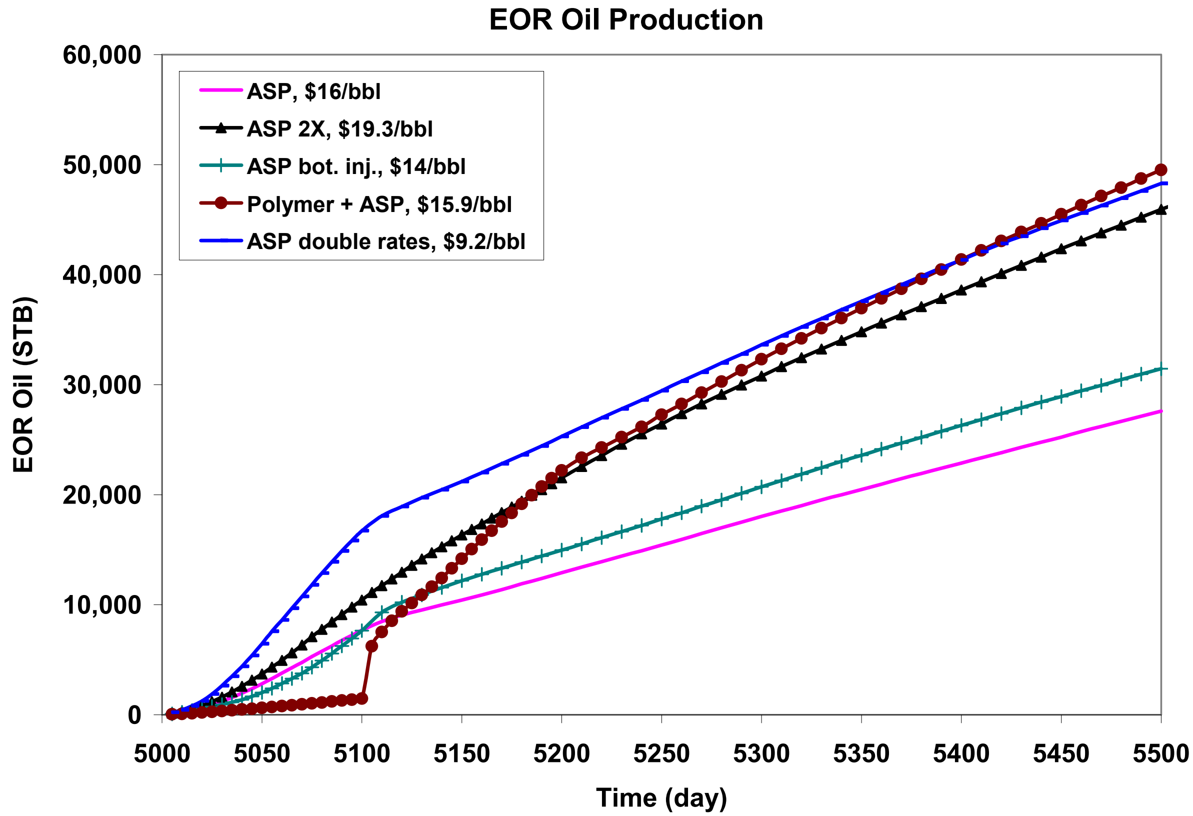


- **Complicated field responses**
- **General observations**
  - **M37 first to response**
  - **Tracer recovery: 24%**
  - **Strong SW to NE water influx (M2, M4, M6)**
- **Over-simplified model**
  - **Probably best we can do with given information**
- **Focus on M37 response**
  - **Time and concentration matched**

Injection Plan Optimization

- **Chemical compositional simulator UTCHEM**
  - **Polymer rheology**
  - **In situ generation of soap**
  - **Phase behavior & IFT from soap & surf. conc.**
- **Various operating strategies studied**
  - **ASP 1X (0.3PV surf. slug + 0.9PV polymer drive)**
  - **ASP 2X (double the size of slug and drive)**
  - **ASP bottom injection (injection into bottom layer)**
  - **Polymer + ASP (pre-flush for conformance control)**
  - **ASP double rates (double rates on all producers)**
- **Key metric: chemical cost per incremental barrel**

EOR Oil Production



- **Practical concerns**
  - Injection pressure permit
  - Pumping capacity on producer
- **Final strategy**
  - Polymer pre-flush first for conformance control
  - Followed by ASP injection
  - Further action based on performance

Outline

- Alkaline/Surfactant/Polymer Flood Laboratory Design
  - Phase behavior test
  - Coreflood experiment
- Pilot Simulation Study
  - Field tracer test
  - Injection plan optimization
- **Field Implementation and Progress**
  - **Field facility installation**
  - **Chemical injection update**
- **Conclusions**
- **Acknowledgements**

Field Facility Installation

Injector (M24) wellhead

Chemical injection calibration

Polymer hopper

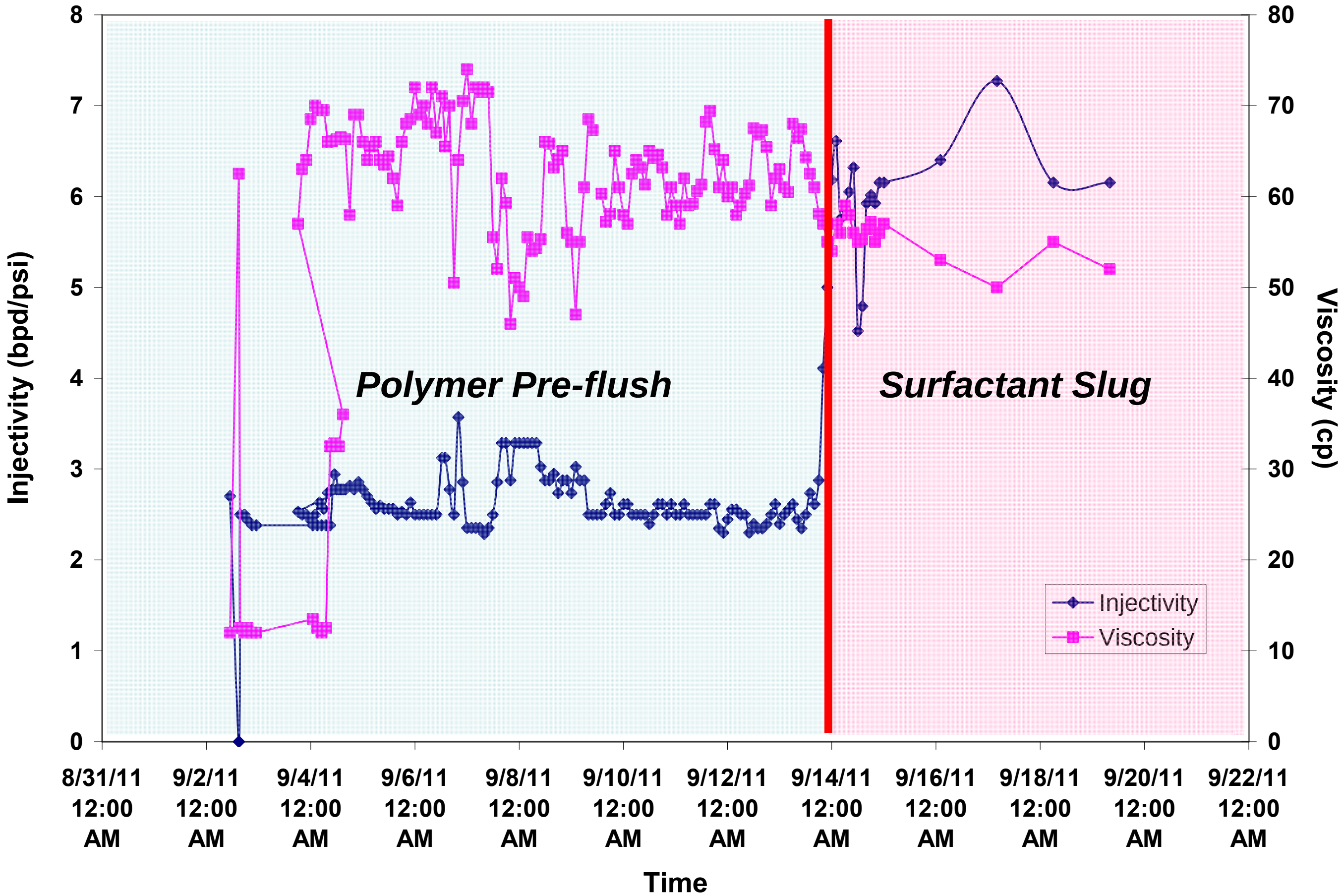
Triplex pump

Chemical storage, mixing, filtering & pumping

Control panel

Chemical Injection Summary

- **Polymer Injection on Sept. 2nd, 2011**
- **11 days of polymer pre-flush (~6000 bbl injected)**
- **Surfactant slug started on Sept. 13th, 2011**



- **Polymer injectivity stays steady**
- **Injectivity increase**
  - **Viscosity Relative perm. (oil mobilization)**

Chart 17

Current status

- Surfactant formulation completed (Feb. 2011)
- Core flooding tests completed (April 2011)
- Field tracer test completed (June 2011)
- Field preparation completed (July 2011)
- EOR equipment delivered (August 2011)
- Chemicals received in the field (August 2011)
- Polymer injection started (Sept. 2, 2011)
- ASP injection started (Sept. 13, 2011)
- Initial EOR response expected (November 2011)

Conclusions

- **Systematic Laboratory Design for Brookshire Dome ASP Flood**
  - **Optimal formulation screened from phase behavior study**
  - **Over 90% oil recovery from coreflood experiment**
- **Injection Plan Optimization using Numerical Simulation**
  - **5-layer model built upon tracer test and cum. production**
  - **Different chemical injection scenarios studied**
- **Field Implementation and Progress**
  - **Pilot chemical injection initiated earlier last month (Sept. 2nd, 2011)**
  - **Polymer pre-flush completed; surfactant slug injection underway**
- **Ongoing work**
  - **Pilot support and production monitoring**
  - **Data collection and results analysis**

Acknowledgements

We wish to thank the following companies for their support throughout this project:

- **RPSEA for the financial support**
- **Layline for their unwavering support of this project and for providing financial support, field data and excellent field personnel**
- **Fabtech for helping with the equipment design and fabrication**
- **TIORCO for help with project coordination**
- **Stepan (for surfactant supply)**
- **Nalco for their expertise in demulsification**

Back-up Slides

ASP/SP Basics

After waterflood, oil remains trapped in reservoirs because of capillary trapping at S_{or}

Capillary Trapping

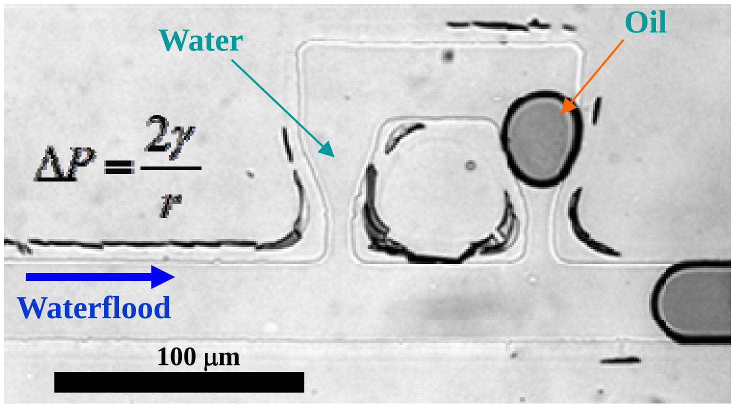
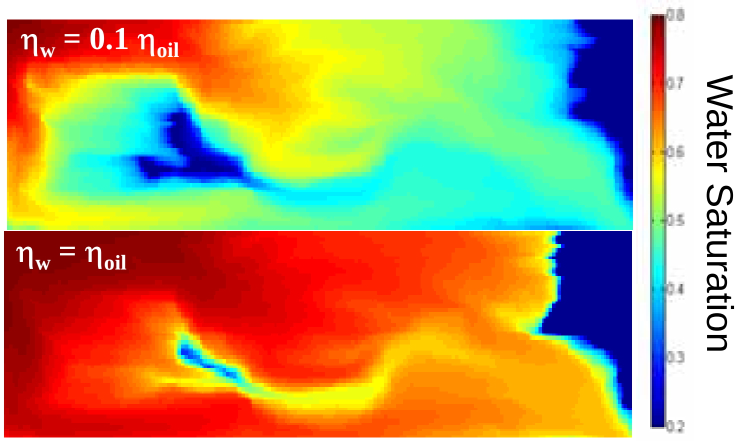


Illustration of **capillary trapping in micromodels**

The only realistic way is to **drastically decrease** the **interfacial tension** (γ) → **Optimized surfactant formulations**

Mobility control to drive the surfactant slug and bank the oil to the production well



Surfactant slug integrity is secured by controlling **mobility ratio** → **Polymer**

Laboratory Design Process

Reservoir characteristics

- Temperature: 55°C
- Production brine: 7400ppm TDS
- Injection brine: produced water
- Rock: sandstone
- Permeability: medium

Process & material selection

- Process: ASP
- Alkali: Sodium carbonate
- Surfactants: Sulfates
- Polymer: HPAM

Formulation Screening

Formulation design

- Surfactant: Alkyl Propylene Sulfate
- Cosolvent: Alkyl Ether
- Alkali: Na_2CO_3 (10,000ppm)
- Polymer: HPAM (MW ~ 8 million)

Formulation performance

- Ultra-low interfacial tension
- Good solubility

Cross Section of Catahoula Sand
Brookshire Dome, Texas

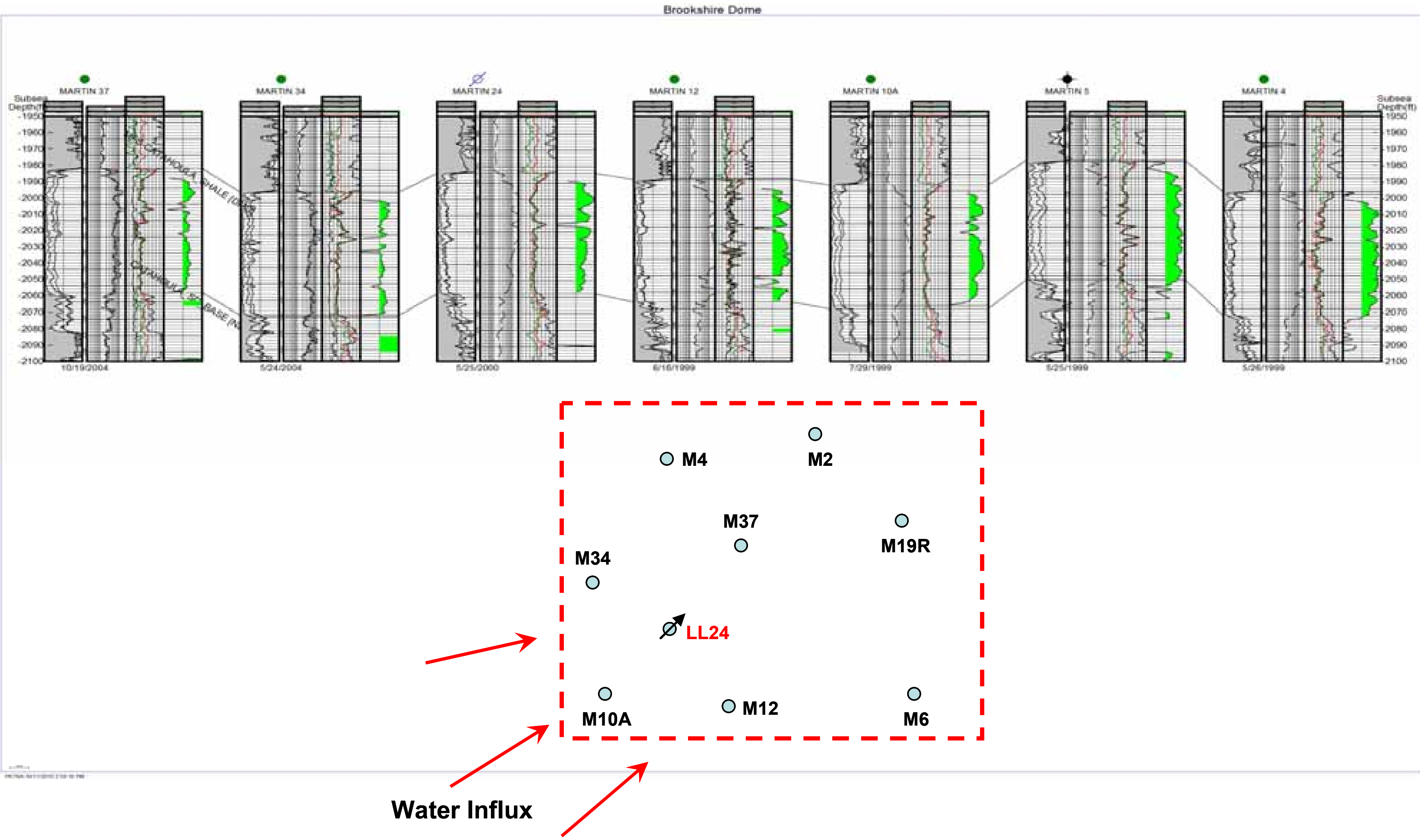


Chart 24

Poor Sweep due to Heterogeneity

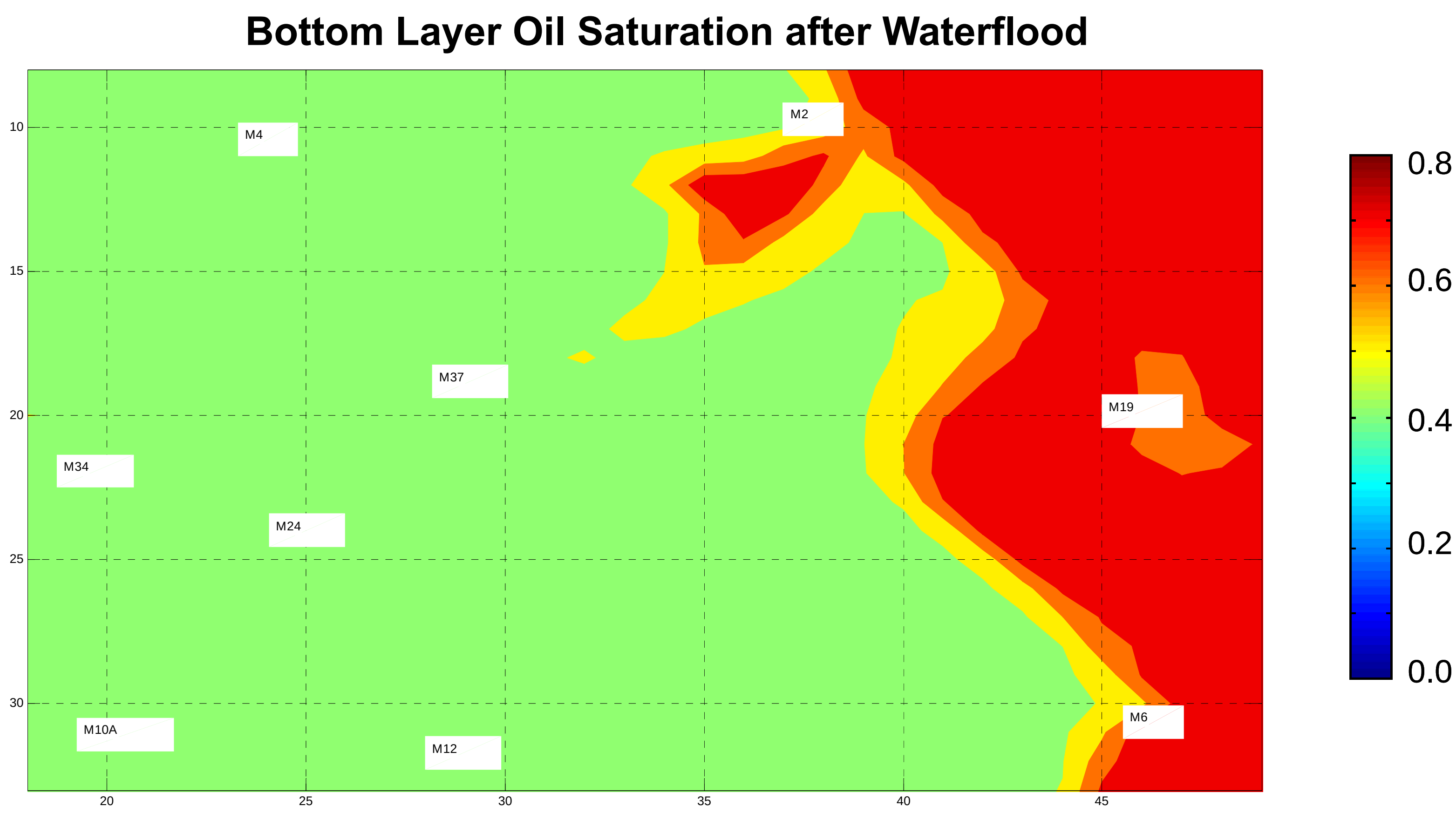


Chart 25

ASP Base Case Inputs

Base case starts from uniform oil saturation of Sor = 0.4

Base Case Design Variables	
Injector	Rate constraint = 1,500 bbl/day
Producer	Rate constraint (same as tracer test)
Surfactant slug	25 days (~0.3PV of five-spot) 0.4 % surf. + co-sol. mixture 2,000 ppm polymer 7,000 ppm NaCl + 8000 Na2CO3
Polymer drive	75 days 2,000 ppm polymer 7,000 ppm NaCl
Water postflush	400 days 7,000 ppm NaCl

Base Case Design Assumptions	
Vertical permeability	k_v/k_h = 0.2
Average horizontal permeability	123.4 md
Polymer adsorption	10 mg polymer/g rock
Surfactant adsorption	0.1 mg surfactant/g rock

Field Operation Summary

- **Polymer Injection on Sept. 2nd, 2011**
- **11 days of polymer pre-flush (~6000 bbl injected)**
- **Surfactant slug started on Sept. 13th, 2011**

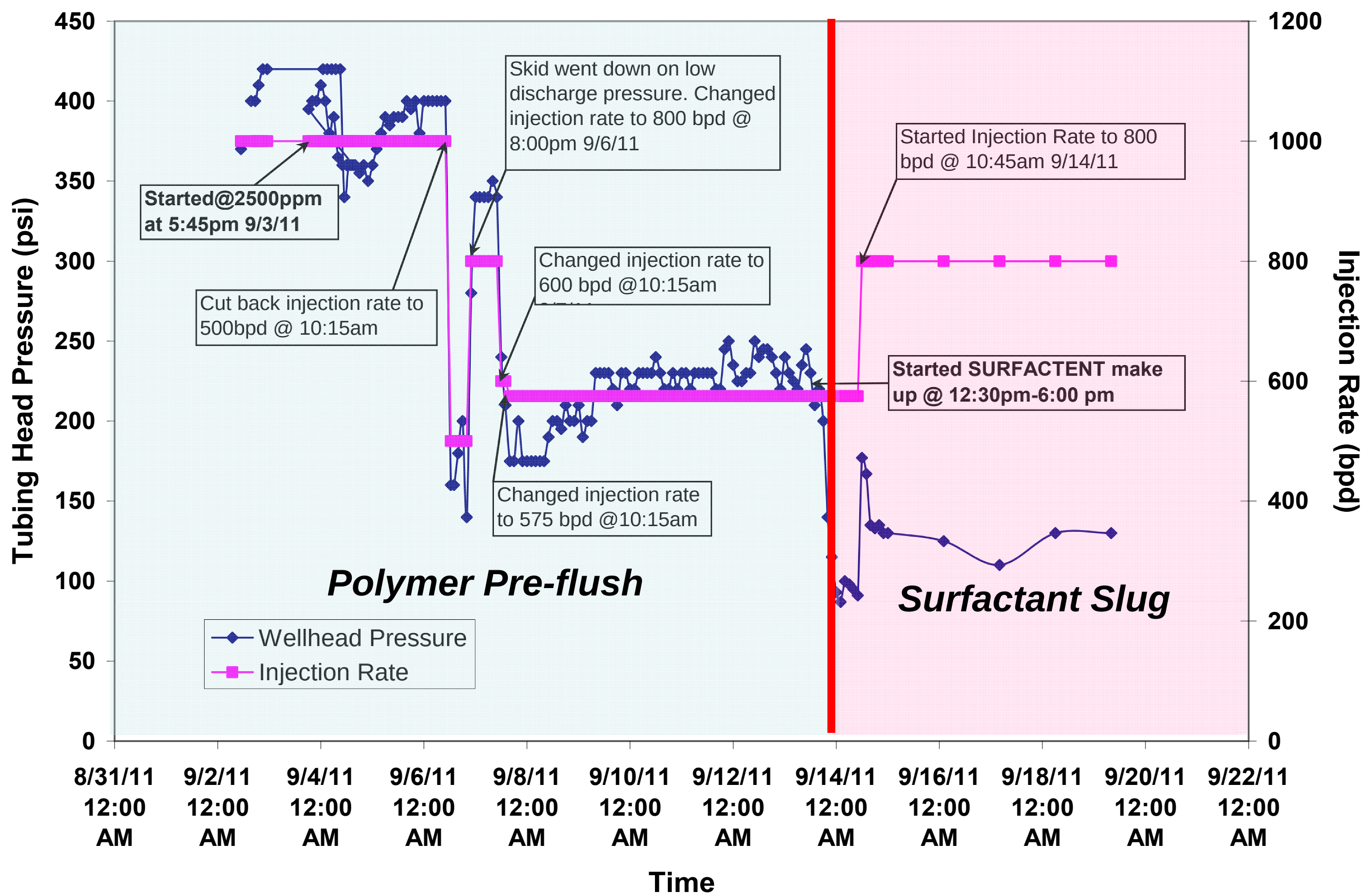
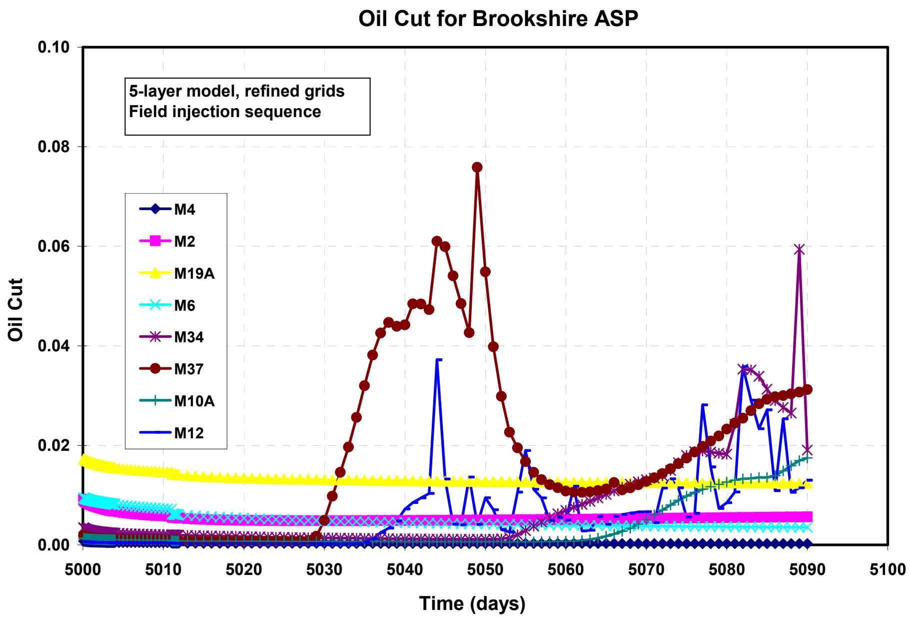


Chart 27

Results for Field Execution Plan



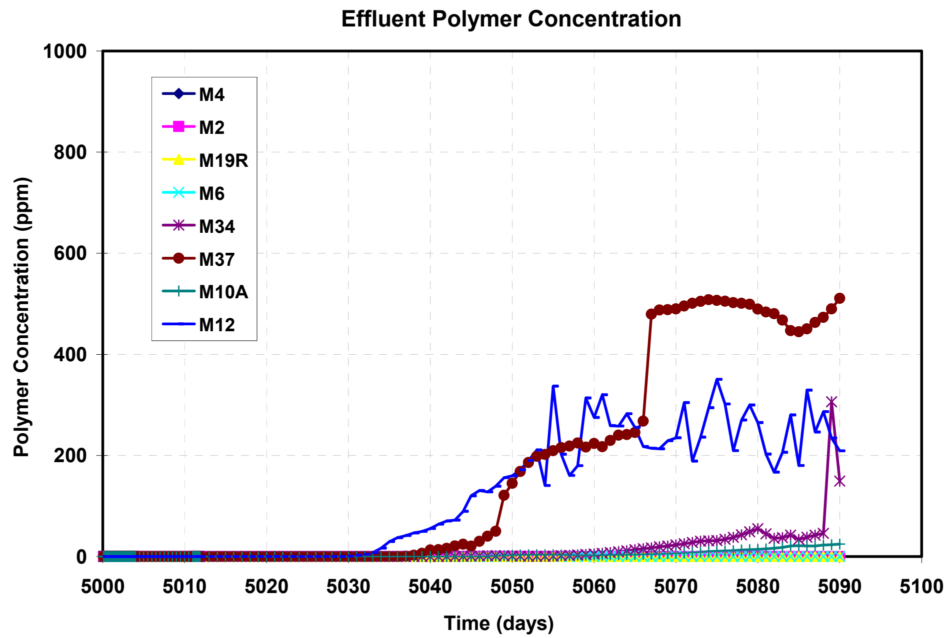


Chart 28