Insights and Managing CO₂ WAG Injectivity

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Outline

• Introduction
• Theory on WAG Injectivity
• Core Studies
• Field Approach
  – Near wellbore effects
  – Far wellbore effects
• BHI Well Treatment Case History
• Summary
Introduction: Injection Approaches

1. The Injection-Production Ratio “voidage ratio” of 1
   1. Maintain pressure for MMP
   2. Pressure differential for production

2. Alternate Injection Phases “Water Alternating Gas” (WAG)
   1. Reduce gravity over-ride
   2. Improve sweep efficiency

Proper Voidage ratio may be difficult to maintain when injectivity is limited
Injection Schemes for Miscible Displacement

- Continuous Injection
- Continuous Injection, Chase Water
- Water Alternating Gas (WAG)
- Tapered/Hybrid (WAG) (WAG) chase gas and chase water
WAG Injectivity

• In the Literature
  – Water injectivity has been reported to be <, > and = pre CO₂ injection
  – CO₂ injectivity has been reported to <, > equivalent injection pre WAG

• WAG Injection Character Has Been Studied in Core, Simulation and Field Studies

• Many Working Hypothesis have Been Developed

• Phenomena Seems to be Field and Pattern Specific
**Character Around CO\(_2\) Injectors**

- Can “dry out” Rock, Reducing the \(S_w\) Below Irreducible Saturation
- Acidify Water Which Reduces Water Wettability
- Multi Contact Miscibility can Strip-out Lighter Hydrocarbons
  - Leave residue sludge
  - Causes 3 phase saturation oil, water, CO\(_2\)
- **WAG Produces Trapped CO\(_2\)/oil**
  - Lowers attainable SW on water cycle
  - 3 phase permeability
General WAG Information

- WAG is a 3 phase Displacement Mechanism
- The Cyclic Nature of the Process Creates a Combination of Imbibition and Drainage
- CO₂ Floods Controlled by Viscous Fingering Display Maximum Recovery at WAG ratio of about 1:1. (more oil wet)
- CO₂ Floods Dominated by Gravity Tonguing Display maximum recovery with the continuous CO₂ slug process. (more water wet)
- The Optimum WAG Design is Different for each Reservoir and Patterns within a Reservoir
WAG Injectivity Characteristics

• Injectivity Behavior Is Due To:
  – Interaction of fluid properties
  – Displacement geometries
    • radial vs linear flow
  – Interaction between slugs

• Effective Wellbore Radius
  – Reduction results in less absolute injectivity for both $H_2O$ and $CO_2$
  – Increases $CO_2$ injectivity relative to $H_2O$ injectivity

Christman and Claridge 1990, SPE #17335
Relative Permeability and Hysteresis

- Relative permeability directly affects the fluid-bank mobility.
- The trapped water reduces the water relative permeability on secondary drainage.

**Fig. 3**—Imbibition and secondary-drainage relative permeabilities for Wasson.
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WAG Core Flood Results

• The corresponding residual oil saturations after CO₂ miscible displacements ranged from about 14 to 17% PV
• Significantly reduced (35-40% lower) CO₂ injection rates
• Simulator predicted water injection rates during WAG cycle operations were about 30 % lower than the water injection rates during water-flooding

Wegener and Harpole, 1996, PSE # 35429
MWAG Core Flood Results

- Trapped Gas Saturation Was 20-25% PV
- Trapped Gas Was Rich In CO\textsubscript{2} and not Pure CO\textsubscript{2}.
- CO\textsubscript{2} Relative Permeability was Significantly lower than Oil
- Water Relative Permeability was Significantly Lower Post WAG
WAG Core Flood Results

Wegener and Harpole, 1996, SPE# 35429
WAG Core Flooding Experiments

• Endpoint $K_{rom}$ in the Miscible Zone Was Higher Than That of Oil-endpoint $K_{ro}$
  – Thus miscible zones could be more mobile than oil bank
• Water Endpoint Permeabilities were greater than the Values of the Supercritical CO$_2$ Injection

This work seems to indicate that rel perm endpoints changed between injection cycles.

Zhou, Al-Otaibi and Kokal, 2013 2013 SPE # 167646
• Injectivity of the Chase Water Was:
  – Comparable to the initial waterflood injectivity
  – Increased as the trapped CO$_2$ dissolved

• Injectivity of the CO$_2$-Rich Zone was Significantly Higher than the Initial Waterflood Injectivity
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Water Injectivity loss in WAG Application

• On Average 20% loss in water injectivity after CO$_2$
  – Hadlow, 1992 SPE # 24928

• Lower Injectivity is not Necessarily a Near-Wellbore Effect

• Lower Mobility of the Tertiary Oil Bank

• Salinity and pH may Change Wettability
  – Lower water pH causes less water-wet conditions
Water Injectivity loss in WAG Application

• Trapped and Bypassing of Gas
  – 3-phase rel perm reduces injectivity
  – Trapping and water-shielding of oil is significant in water-wet rock

• Multiphase saturations lower max water saturation reducing water mobility
WAG Water Injectivity Reduction, Hypothesis

• Near Wellbore Effects
  – Organic matter precipitation
    • Asphaltenes
    • Paraffin
  – Emulsion Block
    – Water Relative Permeability Reduction

• Far Wellbore Effects
  – Lower mobility of the tertiary oil bank
  – Water relative permeability reduction
Approaches to Understanding WAG Injectivity Character

• Determine if the Injectivity is an Near Wellbore or Far Wellbore Reservoir Problem
  – Study paraffin and asphaltene precipitation charter
  – Determine if fluids and near wellbore environment suggest:
    • Wettability change
    • Trapped gas
    • Relative perm alteration
    • and/or organic deposits

• Near Wellbore Problem
  – Design chemical treatments

• Far Wellbore Problem
  – Do additional rock-fluid studies combined with simulation studies
  – Optimize WAG process
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Water Injectivity Problems, West Texas Experience

• San Andres Carbonate CO$_2$ WAG
• Depth 4,500 ft Vertical Wells
• Problem
  – 5 – 10 days lag time before the well would accept water at designed rates
• Solution
  – Applied ASOL Chemistry H-9867
  – Shut in over night
  – Return to water injection next day at designed rates
Oil Bank Influences on WAG Injectivity

- Oil Bank is the Least Mobile Slug
- The Well Pattern and Flow Type Effects Injectivity
  - The Influence of the oil bank grows before breakthrough for linear displacement
  - Oil bank is felt instantly for radial displacement and remains unchanged.

Christman and Claridge 1990, SPE #17335
Water Injectivity Loss in Far Wellbore

• Relative permeability in miscible gas-injection systems are dependent on the saturation of that phase only.
• Increasing the capillary number has been suggested to reduce hysteresis effects in the relative permeability curve.
• Mitigation techniques include:
  – Decreasing WAG ratio thus decreasing mobility control
  – Increasing the injection pressure
  – Adding additional wells
  – Using horizontal wells
Summary

• WAG Water Injectivity Reduction Occurs From
  – Near Wellbore Effects
  – Far Wellbore Effects

• Near Wellbore Effects Include:
  – Wettability change
  – Trapped gas, 3 phase relative permeability
  – Organic deposits

• Near Wellbore Effects Can Be Treated By:
  – Chemical injection to:
    • change rel perm, wettability, remove deposits
Summary

• Far Wellbore Effects
  – Lower mobility of the tertiary oil bank
  – Water relative permeability reduction
  – Linear vs Radial flow

• Far Wellbore Effects Treated By:
  – Controlling WAG strategy
    • Decreasing WAG ratio thus decreasing mobility control
  – Increasing the injection pressure
  – Adding additional wells
  – Using horizontal wells
Back up slides
Production Chemicals and Field Services

• Flow Assurance
  – Mineral scale (esp. for CO₂ flood in carbonates and certain ASP floods)
  – Organic deposits (paraffin & asphaltene, esp. in CO₂ floods)

• Fluids Separation
  – Breakers tuned for thermal/heavy oil emulsions
  – Breakers tuned for certain CO₂ flood emulsions
  – Breakers and clarifiers tuned for chemical floods

• Integrity Management
  – High CO₂ level inhibitors (that allow use of mild steel)
  – Under-deposit corrosion in water-EOR injection system

Continual field and lab service to respond to changing production conditions.
References Studied

- Rampersad, et. Al, 1995, SPE# 29563
- Wegener and Harpole, 1996, PSE # 35429
- Rodgers and Grigg, 2001, SPE 73830
- Harvey Shelton and Kelm, 1997, SPE # 4738
- Christman and Claridge 1990, SPE #17335
- Zhou, Al-Otaibi amd Kokal, 2013 2013 SPE # 167646
- Kamath, Nakagawa, Boyer and Edwards,1996 SPE# 39791
Water Injectivity/Production General Solutions

• **RESTORE Wellbore Remediation Program**
• **Deep Diversion Systems**
  – Preformed particle gel: PPG
• **Relative Permeability Modifier (RPM)**
  – Oil productivity is selectively increased
  – Water productivity is decreased or remains constant
Boots on the Ground

• Daily Service Capability – not ‘here, then gone’
• Field Service Monitoring
  – Chemical injection system inspection and light maintenance
  – Injection chemical field QA/QC
  – Manual or fully automated chemical usage and metering
  – Instrumentation and data management QC
  – Production chemistry monitoring and rapid response
Increase of Water Injectivity, Oil and Gas Production in Germany

- Gas and Oil production in Germany
  - EXXON (EMPG), GdF, RWE DEA, Wintershall
  - Zechstein Carbonat / Rotliegend / Wustrow / Carbon
  - Application in gas and oil wells

- Products
  - PAO30001 (nonyl phenol) in gas and oil wells
  - CLW85890 is green replacement of PAO30001 applied in gas wells
  - CLW85932 is green replacement of PAO30001, in lab phase of testing, application in oil wells
Increase of Water Injectivity, Oil and Gas Production in Germany - Selection of Treatment Liquid

- Regular sampling
- Monitoring by applying microscopy work
- Quantify the amount of paraffin crystals
- Kind of emulsion (linked or not)
- Quantify the amount of inorganic material (sand, clay FeS, scales, etc.)
- Preparation of treatment liquid
Increase of Water Injectivity, Oil and Gas Production in Germany - Treatment Liquid

- Mixing of 0.1-2 Vol.-% of PAO 30001 (its replacement products) in hot water
- Possible additional treatments as combination or follow up are foamer, EDTA, citric acid, SRW85778
- Prepare sufficient mixing by adding the product in front of suction line of pump
- Max. 15 to 20 m³ of product water mixture required
- Stop production
- Pump the product water mixture into the tubing or casing
- Wait a suitable shut in period (max 1 day)
- Start and monitor the production
West Texas Treatment for Water Injectivity

- **Pre-flush**
  - PEP3 220 gal,
    - mixture of aliphatic, aromatic, and polar solvents,
  - PEP24 55 gal, Asphaltene Dispersant
  - PFR -83 220 gal

- **Treatment**
  - WAW 5202 55 gal 15 % HCl

- **Overflush**
  - WAW5202 2% KCl

- **Soak 2- 4 hours**
West Texas Examples., Poor Effect

- Hydrocarbon cleanup, 500 b/d to 130 b/d
  - Xylene
  - Matrix acid treatment follow up
  - Propane follow up
- CO₂ treatment
  - Theory to increase water relative permeability
  - CO₂ would dissolve in to water
- Lease crude injection
  - Reestablish pre injection saturations
- Acid Treatments
  - 5,000 gal acid, 2 bbl/min, w/o improvement

Factor of 3 reduction in H₂O injection

Harvey, et., al, 1977, SPE # 4738
West Texas Examples., Poor Effect

• Acid Treatments
  – High volume, high rate with fracing
  – Fracing help only for the immediate next cycle

• Operating Changes
  – Switch 0.25 % HCPV gas slug
  – Water injection rate declined as cumulative solvent injection increased

• Water Salinity Change
  – High salinity vs fresh water showed on injection change

• Reduction of Rich Gas Injection Rate
  – Produce lower pressure, mobilizing oil into main pores

Conclusions: wellbore treatment may temporarily help but problem reoccurs after next cycle

Harvey, et., al, 1977, SPE # 4738
WAG Injectivity Characteristics

• A small effective wellbore radius results in less absolute injectivity for both brine and CO2 injection, it has the effect of increasing CO2 injectivity relative to brine injectivity

• Denver Unit vs South Pine Pilot Performance Differences
  – Relative differences in the fluid-bank mobility's,
    • Function of relative perm character
    • Fluid viscosities
  – Differences in effective wellbore radius
  – Differences in rock heterogeneity

Injectivity Behavior is due to:

  Interaction of fluid properties
  Displacement geometries, radial vs linear flow, interaction between slugs

Christman and Claridge 1990, SPE #17335
What causes the unexpectedly low injectivity during gas injection

- Crossflow or convective mixing can increase CO2 injectivity substantially
- CO2 injectivity is an increasing function of increased transport in high-permeability layers near the injection face.

Rodgers and Grigg, 2001, SPE 73830
WAG Core Flood Results

Figure 7 - South Cowden Unit Water-Oil Relative Permeability Data

Figure 8 - Effect of Krw Hysteresis on Incremental Oil Production

Wegener and Harpole, 1996, PSE # 35429
Residual Oil Trapping

• Reservoir Mobile Water can shield the in-place oil from being contacted by the injected solvent

• Optimum WAG Ratio is Fairly Insensitive to any Assumed level of Trapping of Oil phase

• Dispersion and Mass Transfer are Important Factors that Affect the Injected Solvent Propagation Characteristics

Rampersad, et. al, 1995, SPE# 29563