Field-Scale Impact of Gas-Assisted Gravity Drainage EOR Process using CO2 and Flue Gas

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Acknowledgments

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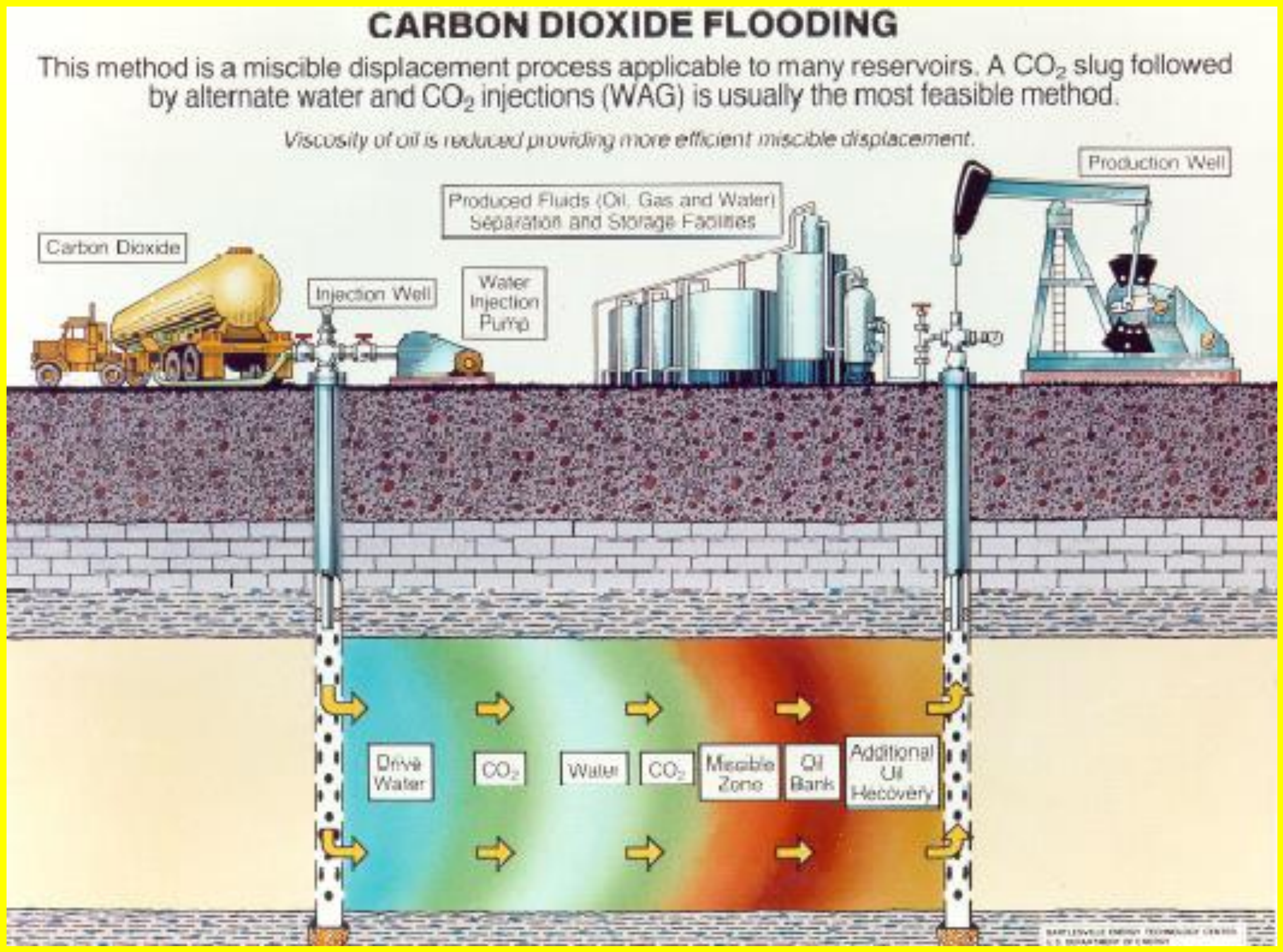
Present Industry Practice – Water Alternating Gas Floods



CARBON DIOXIDE FLOODING

This method is a miscible displacement process applicable to many reservoirs. A CO_2 slug followed by alternate water and CO_2 injections (WAG) is usually the most feasible method.

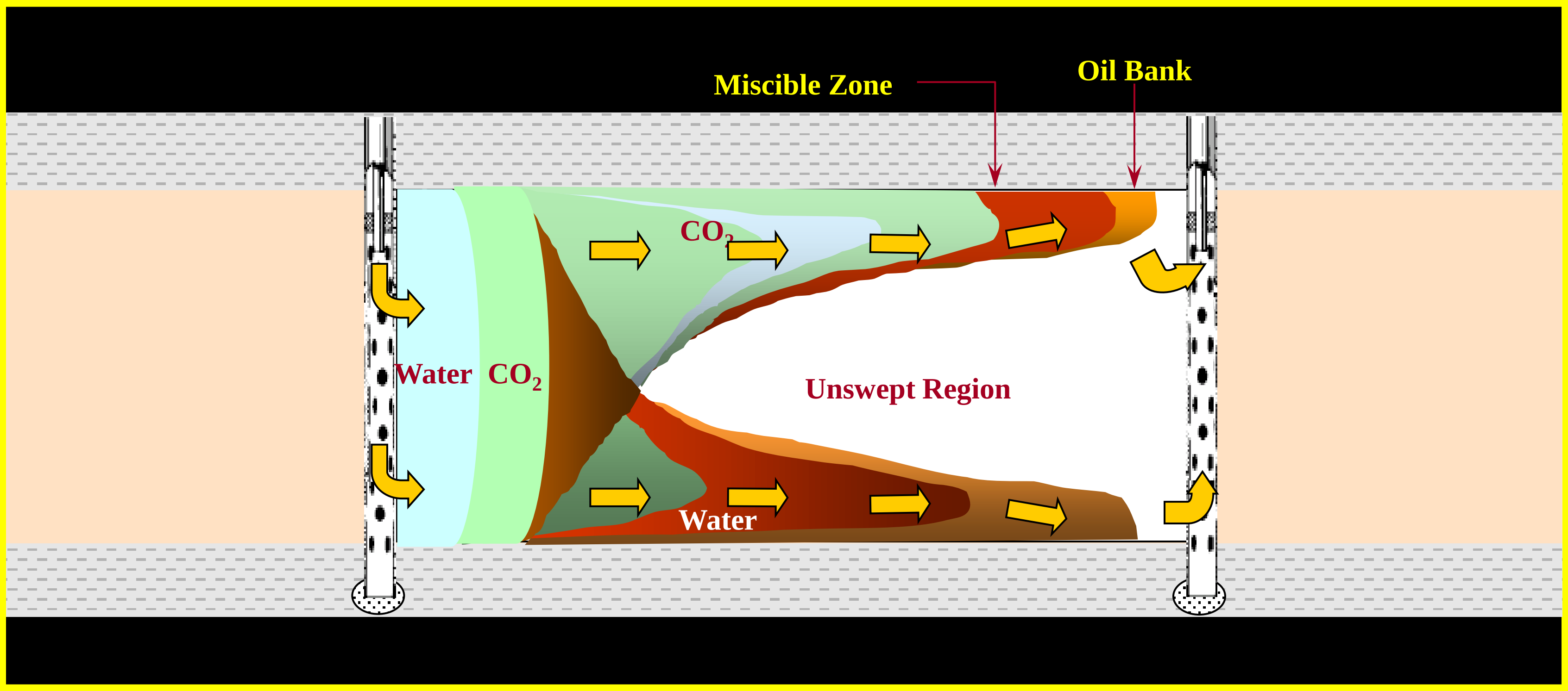
Viscosity of oil is reduced providing more efficient miscible displacement.

(Ref: US-DOE)

Water injected in WAG floods, blocks part of the oil from gas contact reducing displacement efficiency ($E_D < 1$).

Present Limitation of WAG

- **59 Field projects report recoveries from 5 to 10%!**
  - **A more realistic view of a WAG flood might be like this**



- **Gravity segregation of gas and water can be seen even in core level displacement tests**
- **To overcome these limitations of WAG process, we have developed the gas-assisted gravity drainage (GAGD) process in the EOR labs of LSU-Pet-Eng. Dept.**

Concept of GAGD

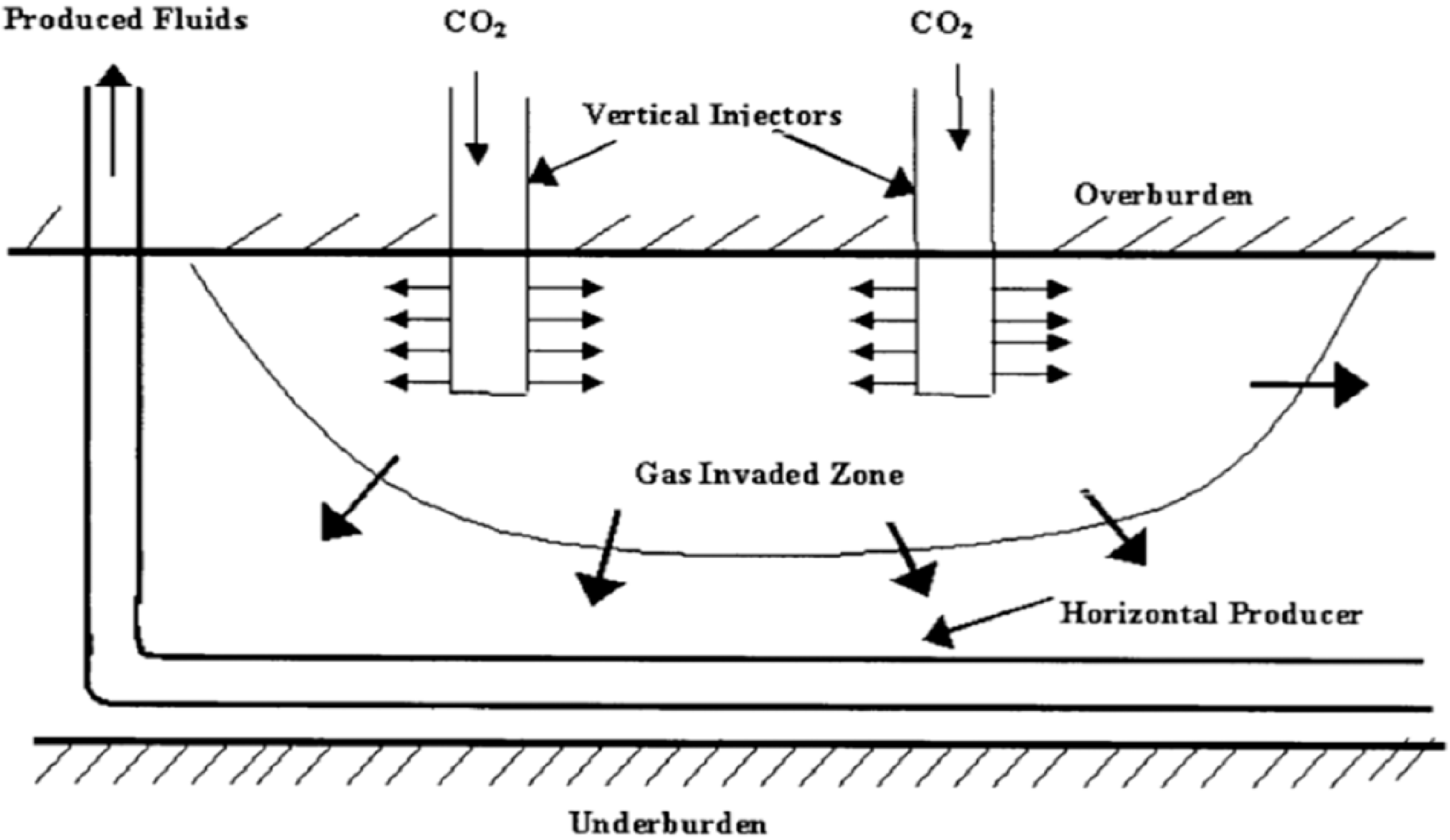


Figure 1: Schematic Drawing of GAGD process (Rao, 2012)

Advantages of the GAGD Process

- **Gas does not compete with oil for flow to producer - CO_2 segregates at the top – delaying gas breakthrough**
- **Horizontal wells can produce at very low drawdown and high rates**
- **No increase in water saturation, which mitigates water-shielding and increases gas injectivity**
- **Increased volumetric sweep as CO_2 chamber grows downward and sideways**
- **Utilizes existing vertical wells for gas injection - lowering cost**
- **Reservoir heterogeneities (fractures), while detrimental to WAG, may even be beneficial in GAGD**

Immiscible Secondary GAGD

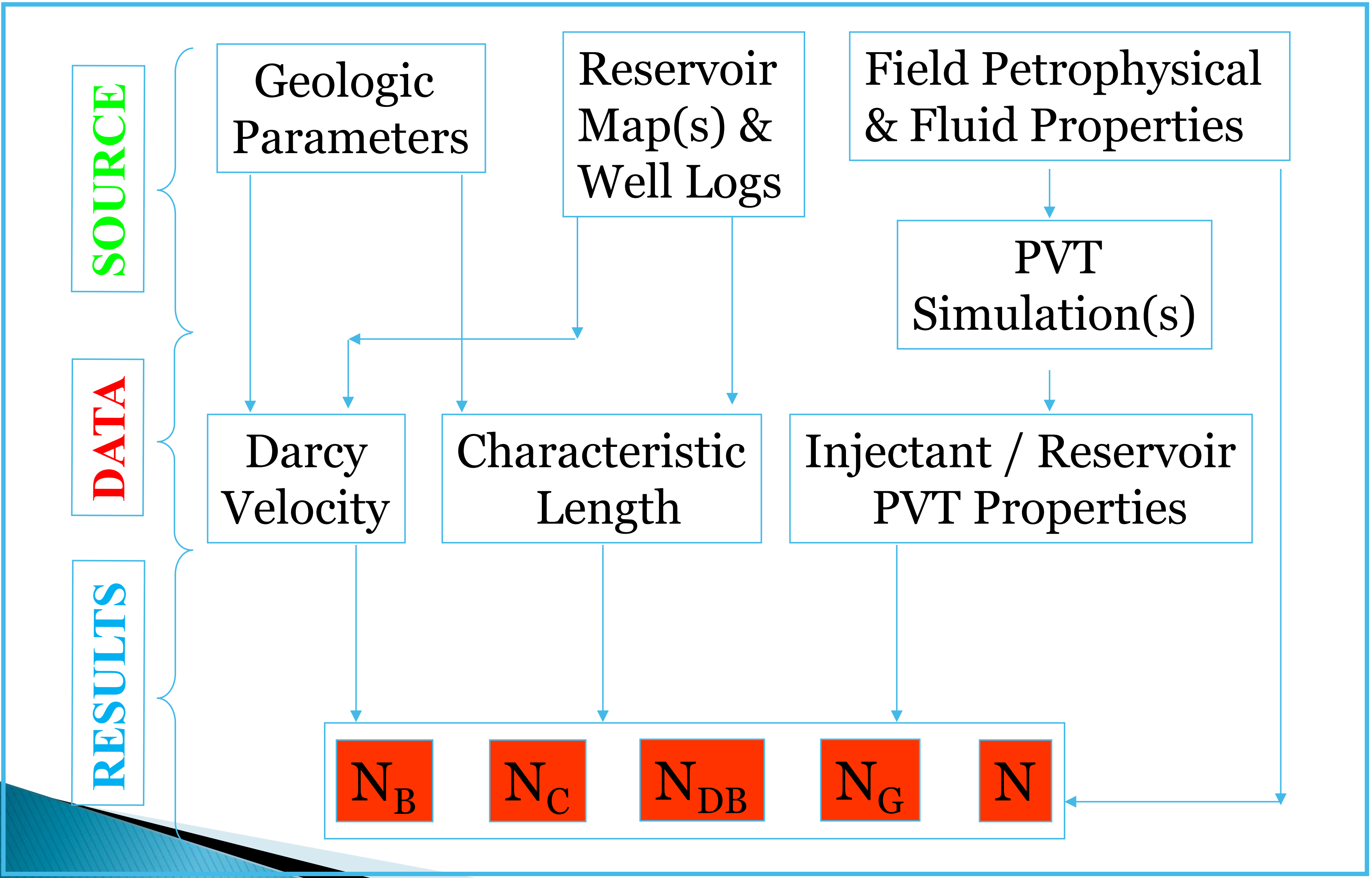
Miscible GAGD Process

Scaled-Model GAGD Tests

Dimensionless Variables Operating During Gravity Drainage

S. No:	Similarity Groups	Formulation	References
1.	Geometric Aspect Ratio (R_L)	$R_L = \frac{L}{H}\sqrt{\frac{K_V}{K_H}}$	Shook et al, 1992
2.	Capillary Number (N_c) Ratio of viscous forces to capillary forces	$\frac{v\mu}{\sigma}$	Grattoni et al, 2000
3.	Bond Number (N_B) Ratio of Gravity forces to capillary forces	$\frac{\Delta\rho g\left(\frac{K}{\phi}\right)}{\sigma}$	Grattoni et al, 2000
4.	Fluid property group (α)	$\frac{\sigma_{ow}(\rho_o - \rho_g)}{\sigma_{go}(\rho_w - \rho_o)}$	Kantzas et al, 1988 and Blunt et al, 1995.
5.	Gravity Number (N_G) Ratio of gravity forces to viscous forces	$N_G = \frac{\Delta\rho g\left(\frac{K}{\phi}\right)}{\mu_o v_d}$	Shook et al, 1992.
6.	Dimensionless Time (t_d)	$\frac{k k_{ro}^{o} \Delta\rho g / g_c}{h\phi\mu_o(1 - S_{or} - S_{wi})} t$	Miguel et al., 2004

Protocol Dimensional Analysis



SOURCE

Geologic Parameters

Reservoir Map(s) & Well Logs

Field Petrophysical & Fluid Properties

PVT Simulation(s)

DATA

Darcy Velocity

Characteristic Length

Injectant / Reservoir PVT Properties

RESULTS

N_B N_C N_{DB} N_G N

Research Objective

- The objective of this research are:-

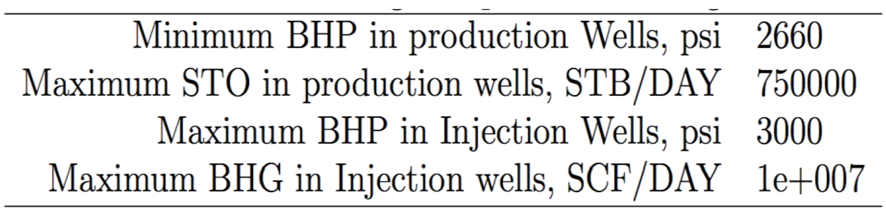
I. Investigate the feasibility of GAGD process to improve oil recovery in a Field-scale application.

II. Effective Comparison of GAGD process through CO2 and Flue Gas injection in terms of reservoir oil and gas flow responses.

GAGD Reservoir Simulation

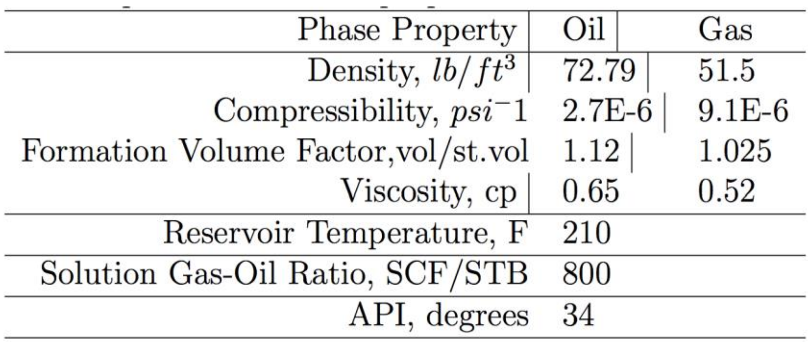
- Gridding: 69 in I-direction, 66 in J-direction, and 12 in K-direction.
- 20 vertical injector are installed at the top two layers & 10 horizontal producers are proposed at the middle zone above the oil water contact.
- The Immiscible GAGD-CO2 was conducted through EOS-Compositional reservoir simulator (CMG-GEM) and Peng-Robenson EOS was employed for phase equilibrium calculation in (CMG-WinProp).
- Horizontal producers of 3000 m length were placed through the reservoir at sand and shaly-sand lithology zones.
- The simulation period includes 61 yeas history (1954-2015) and the GAGD prediction period is 10 years (2016-2026).
- Initial reservoir pressure=5186 psi, Pb=2660 psi, and MMP=3500 psi.

Table: GAGD Base Case Setting of Operational Design Parameters



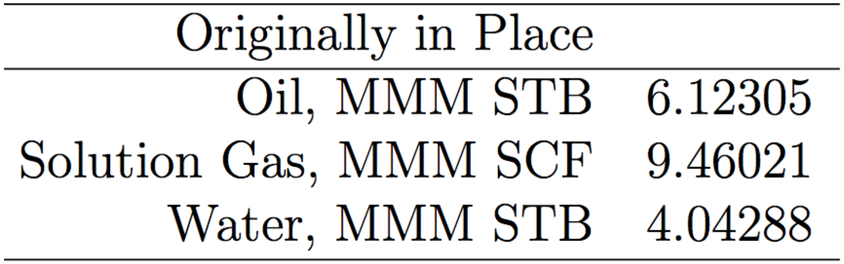
Minimum BHP in production Wells, psi	2660
Maximum STO in production wells, STB/DAY	750000
Maximum BHP in Injection Wells, psi	3000
Maximum BHG in Injection wells, SCF/DAY	1e+007

Table: Reservoir Fluid Properties

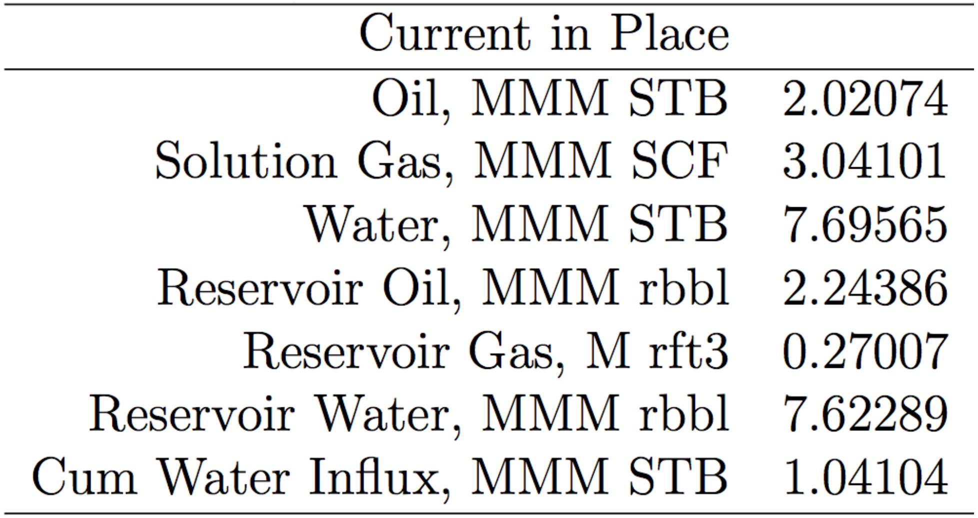


Phase Property	Oil	Gas
Density, lb/ft^3	72.79	51.5
Compressibility, psi^-1	2.7E-6	9.1E-6
Formation Volume Factor,vol/st.vol	1.12	1.025
Viscosity, cp	0.65	0.52
Reservoir Temperature, F	210	
Solution Gas-Oil Ratio, SCF/STB	800	
API, degrees	34	

Table: Initial & Current Fluid in Place in Main Sector



Originally in Place	
Oil, MMM STB	6.12305
Solution Gas, MMM SCF	9.46021
Water, MMM STB	4.04288



Current in Place	
Oil, MMM STB	2.02074
Solution Gas, MMM SCF	3.04101
Water, MMM STB	7.69565
Reservoir Oil, MMM rbbl	2.24386
Reservoir Gas, M rft3	0.27007
Reservoir Water, MMM rbbl	7.62289
Cum Water Influx, MMM STB	1.04104

Field & Reservoir Description

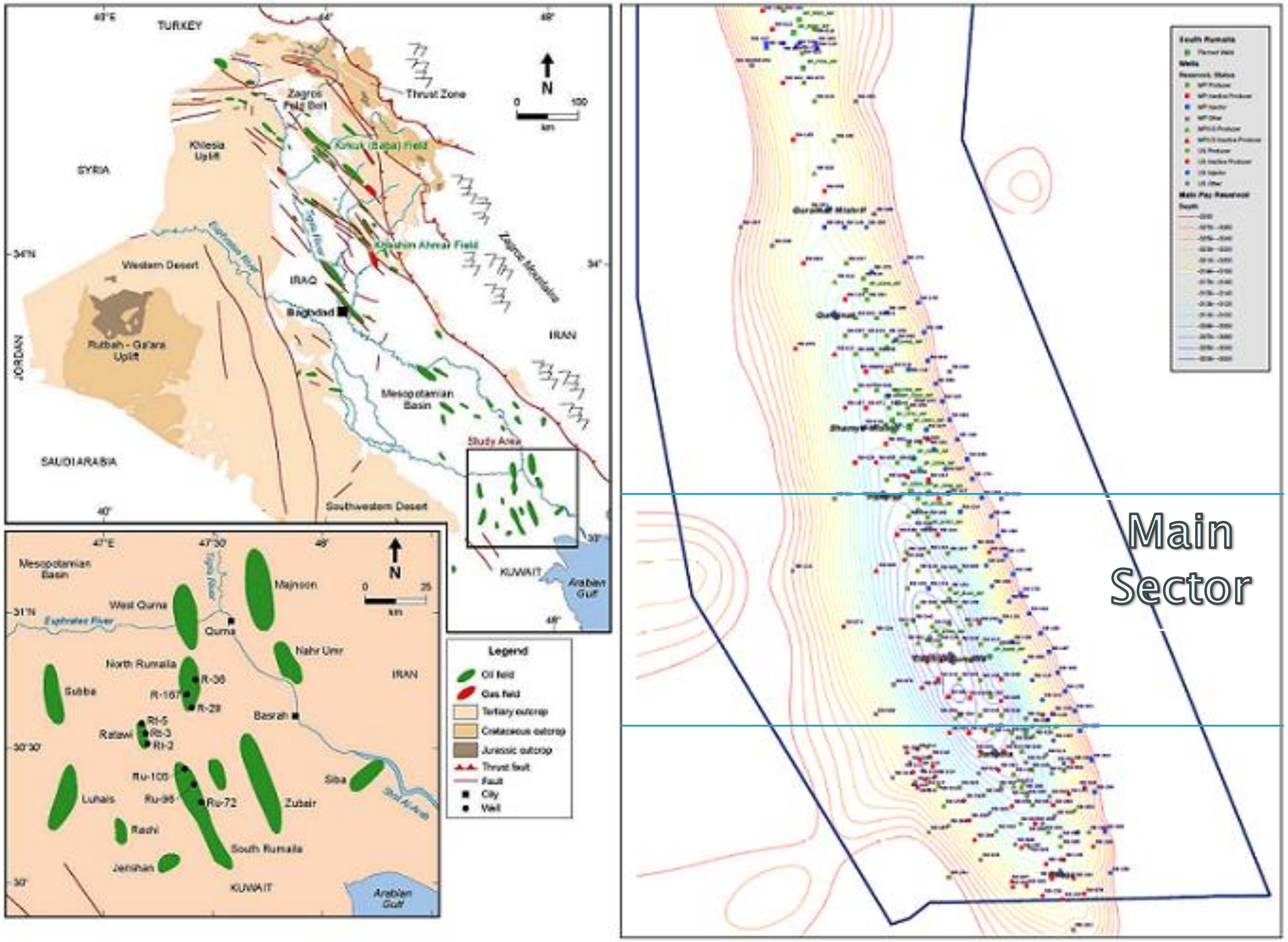


Figure 2 : Geographical Location of South Rumaila Field, **Al-Ameri, 2009**

Field & Reservoir Description

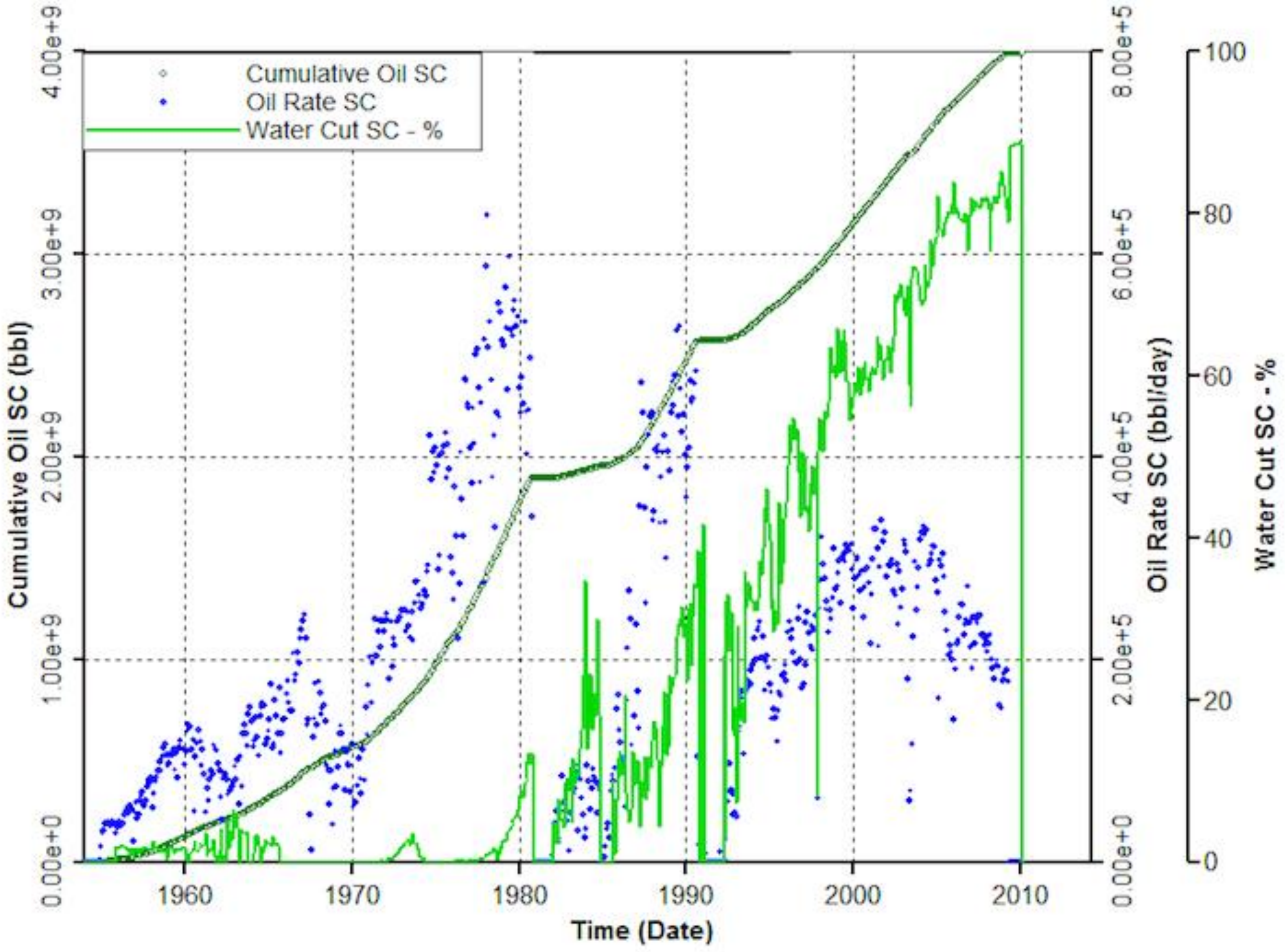
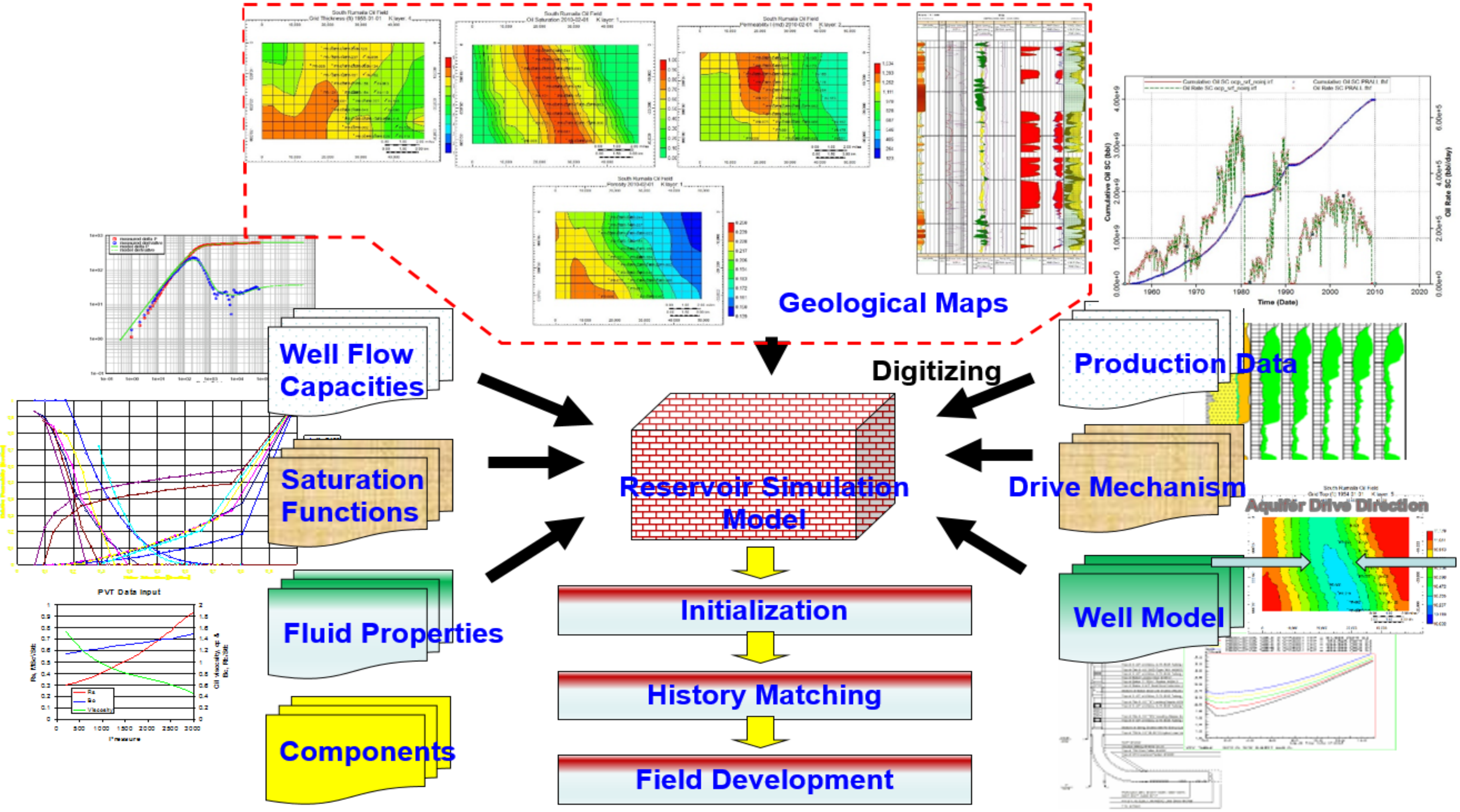


Figure 3 : Field Production History, **Al-Mudhafar, 2013**

3D Compositional Reservoir Simulation



Geological Maps

Digitizing

Well Flow Capacities

Saturation Functions

Fluid Properties

Components

Production Data

Drive Mechanism

Well Model

Reservoir Simulation Model

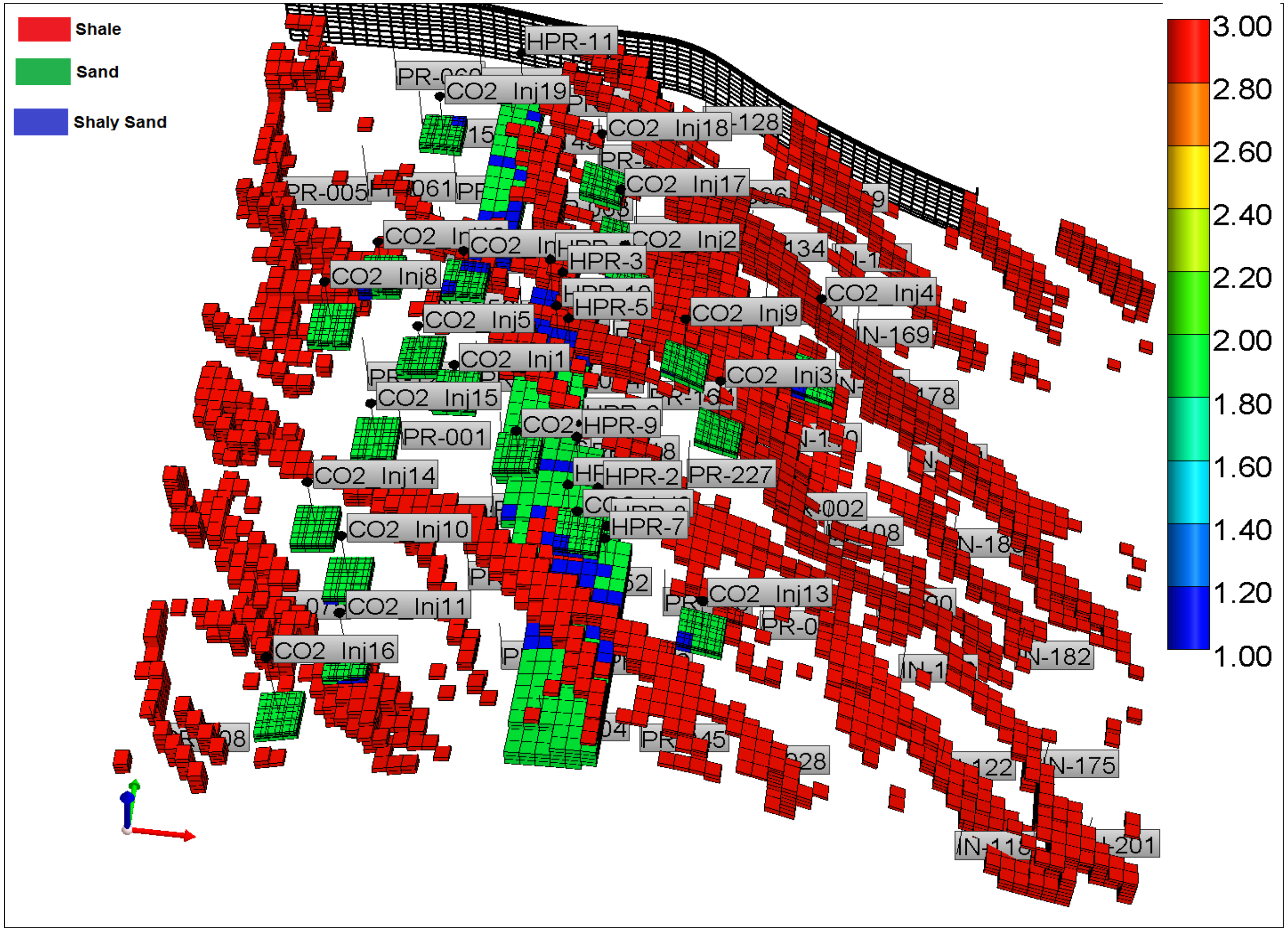
Initialization

History Matching

Field Development

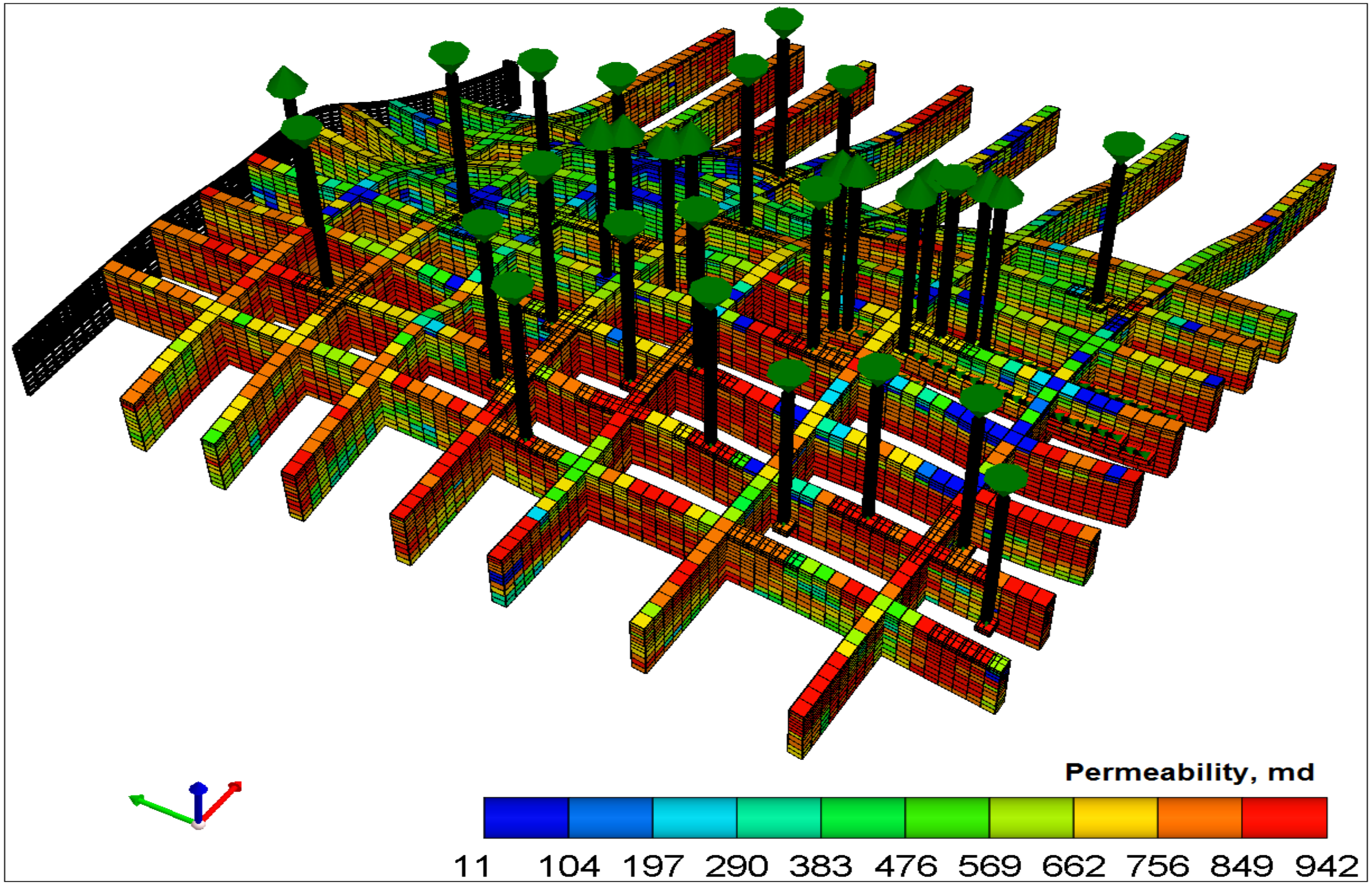
General Work Flow for Integrated Reservoir Studies, **Al-Mudhafar, 2014**

3D Compositional Reservoir Simulation



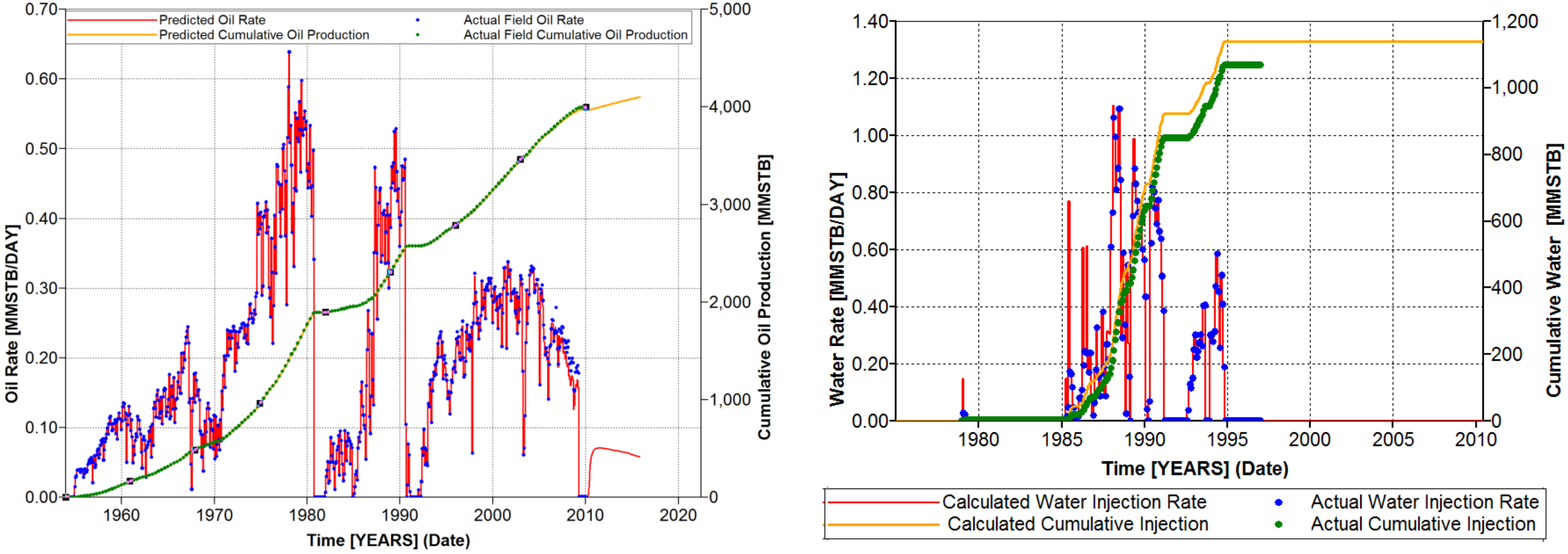
Production and Injection Well Locations in Sand and Shaly Sand Zones, **Al-Mudhafar, 2015**

3D Compositional Reservoir Simulation



Production and Injection Well Locations in High Permeable Zones, **Al-Mudhafar, 2015**

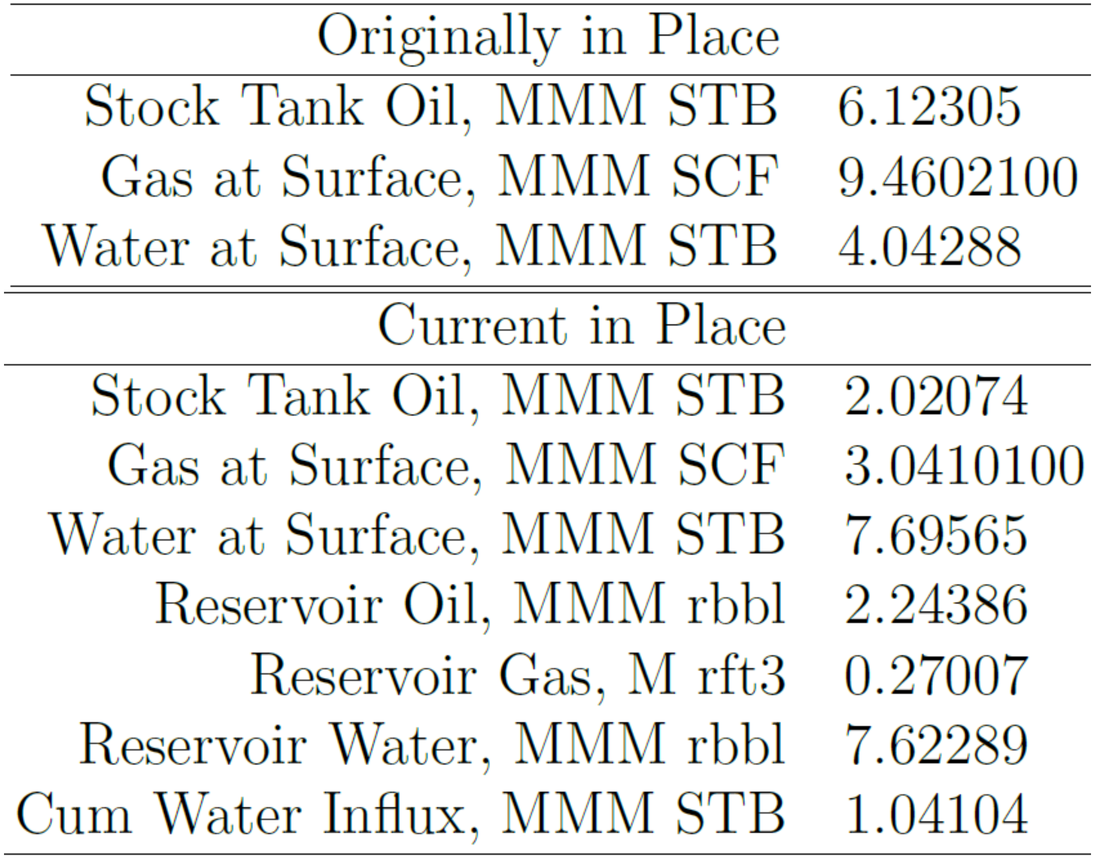
Reservoir History Matching



Production and Injection History Matching, **Al-Mudhafar, 2015**

Reservoir Initialization Results

Table 1: Initial & Current Fluid In Place of Rumaila Oil Field (Main Sector)



Originally in Place	
Stock Tank Oil, MMM STB	6.12305
Gas at Surface, MMM SCF	9.4602100
Water at Surface, MMM STB	4.04288
Current in Place	
Stock Tank Oil, MMM STB	2.02074
Gas at Surface, MMM SCF	3.0410100
Water at Surface, MMM STB	7.69565
Reservoir Oil, MMM rbbl	2.24386
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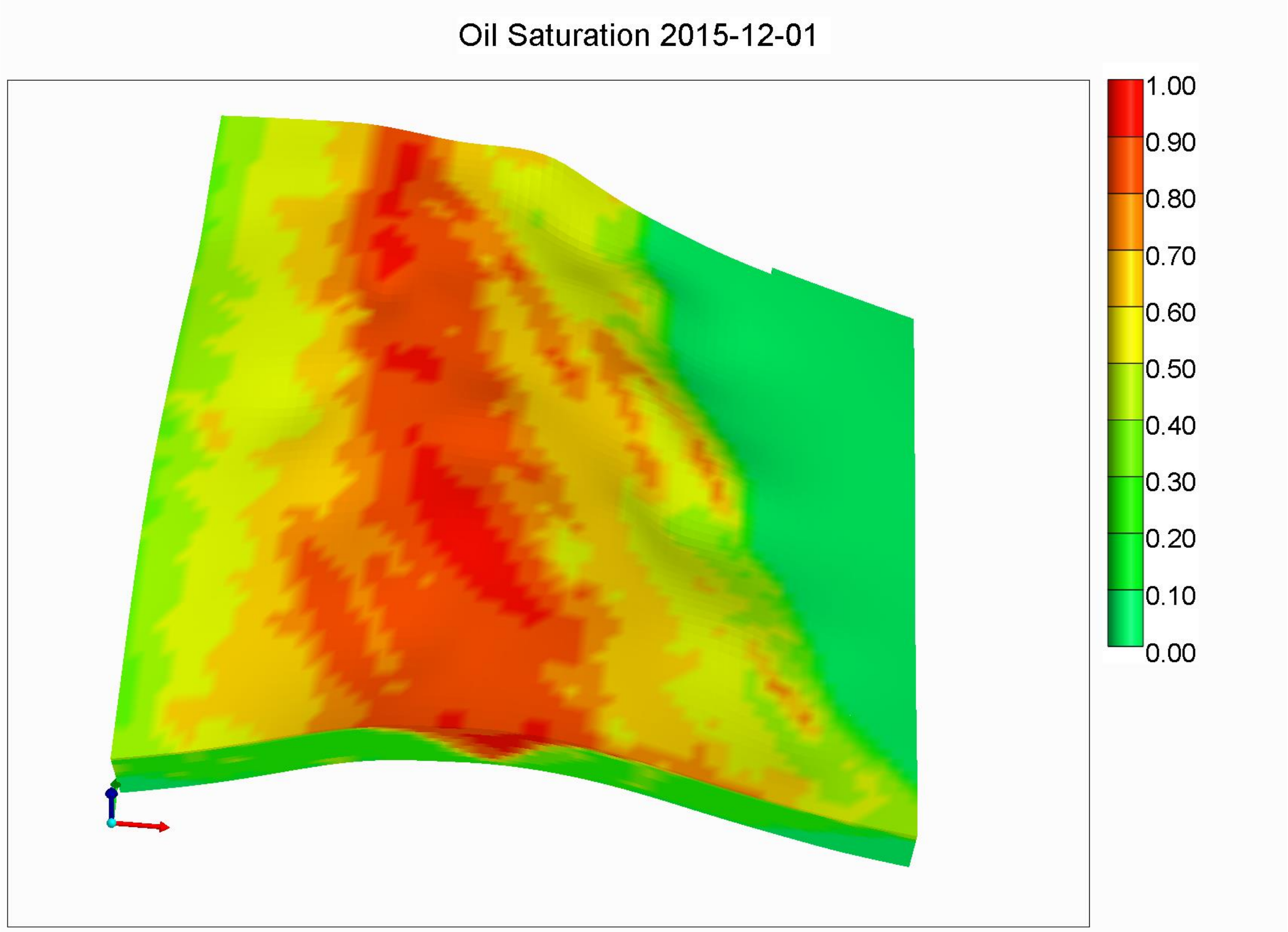
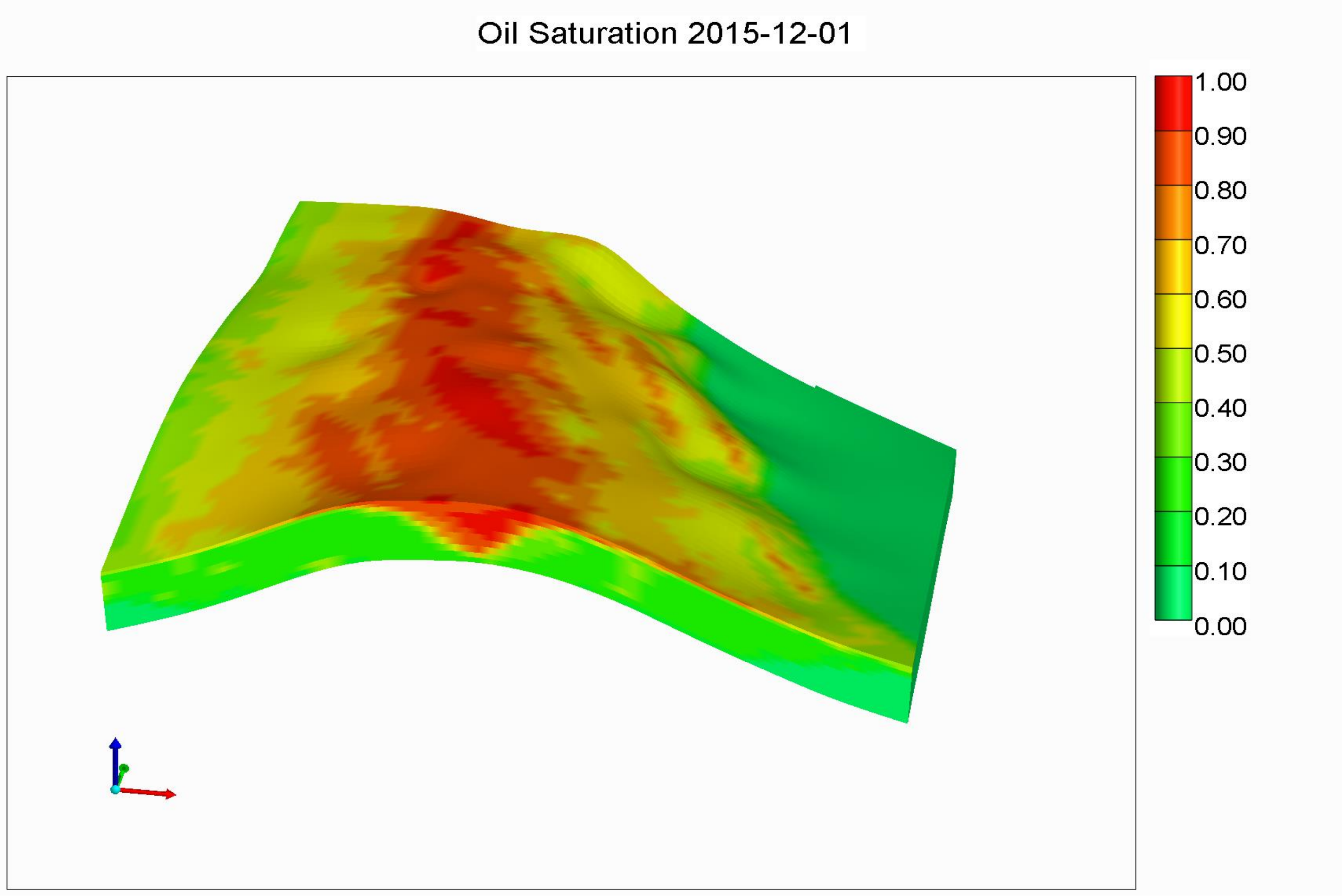
GAGD Process Results



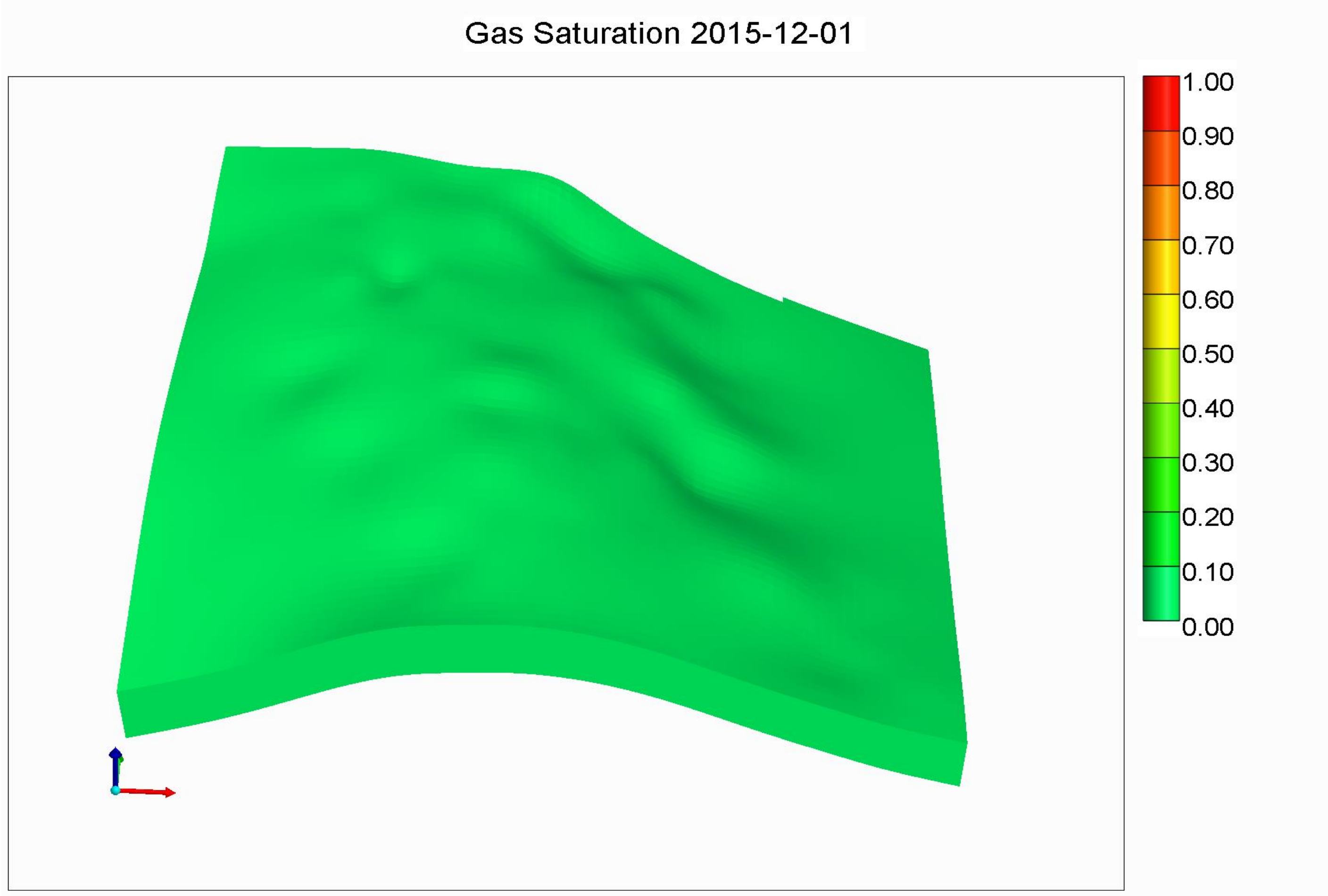
3D Spatial-Temporal Oil Saturation of GAGD CO2 Flooding

GAGD Process Results



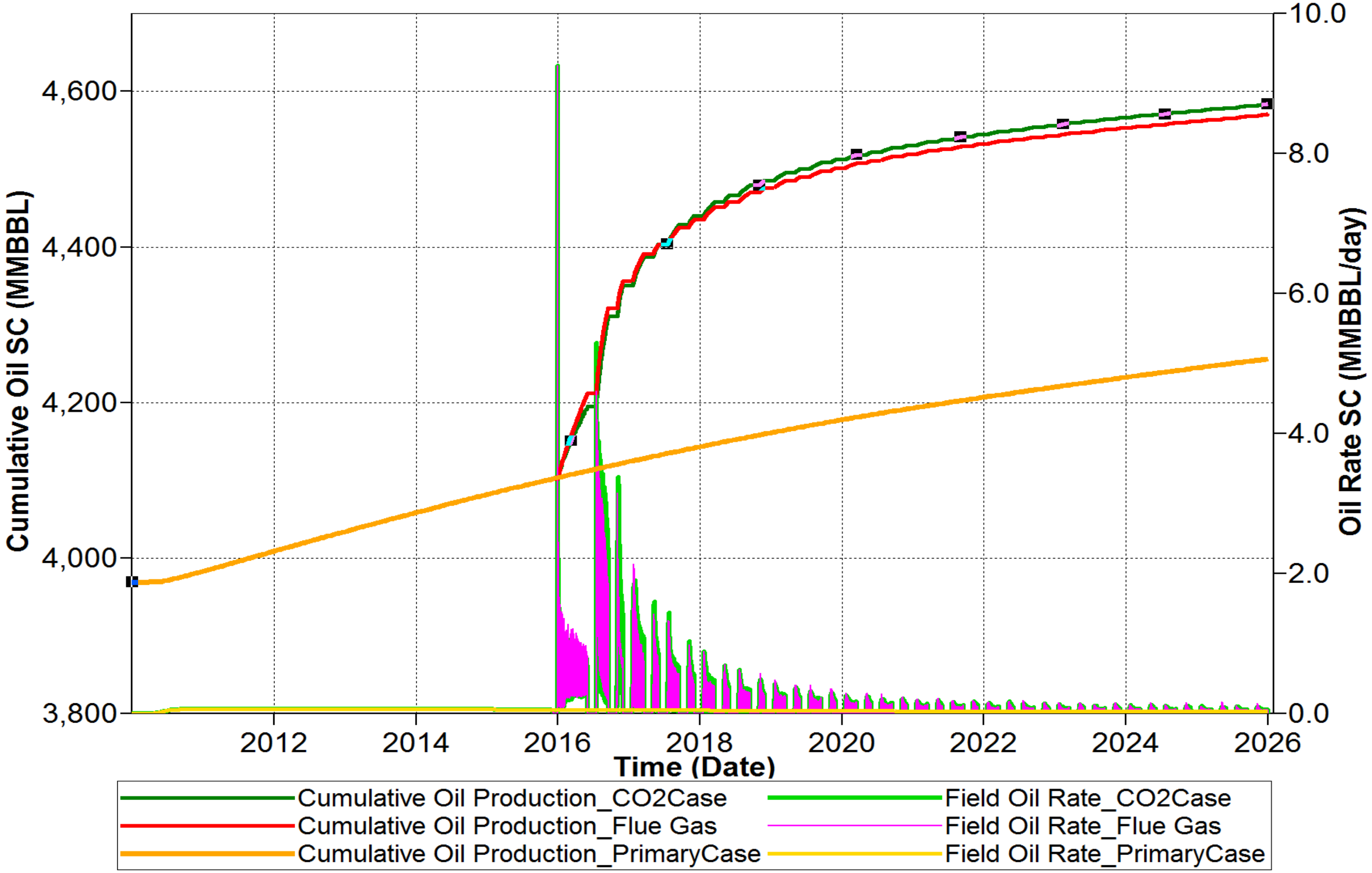
3D Spatial-Temporal Oil Saturation of GAGD Flue Flooding

GAGD Process Results



3D Spatial-Temporal Gas Saturation of GAGD CO2 Flooding

GAGD Process Results



Reservoir Oil Response Comparison between CO2 and Flue Gas Flooding

Net Present Value (NPV) of GAGD Process

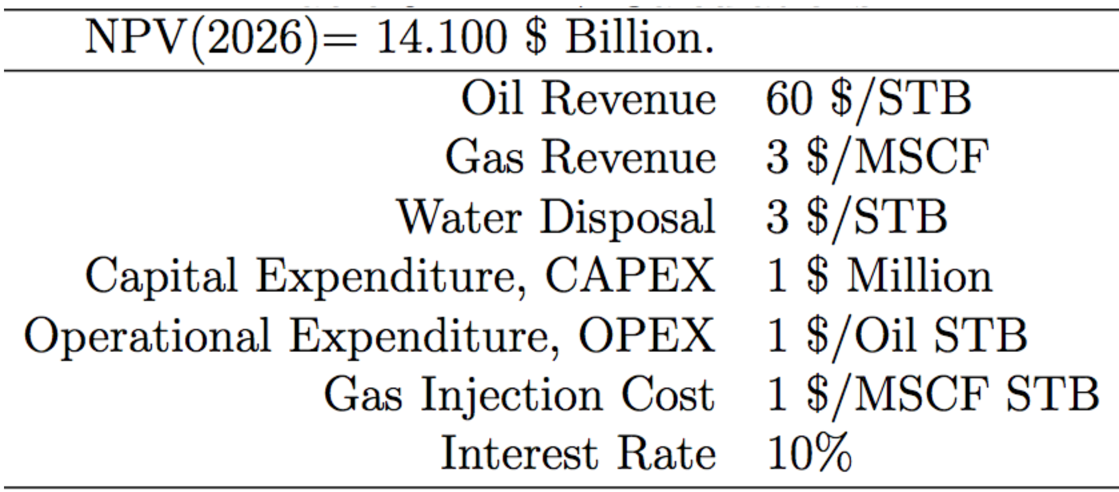
NPV is defined as the revenues from produced oil and gas sales, after subtracting the costs of disposing produced water and the cost of injecting water and the initial costs. The initial costs represent the capital expenditures. The result is the net cash flow:

Net Cash Flow (t) =Oil Production (t) Oil Price+ Gas Production (t) Gas Price -Water Production (t) Water Handling Cost- Water Injection (t) Water Injection Cost-OPEX-CAPEX

$$NPV = \sum_{t} \frac{NCF(t)}{(1+i)^{t}}$$

Oil price: ($ per STB).
Gas price: ($ per MSCf).
Water handling cost: ($ per bbl).
Water Injection Cost: ($ per bbl).
Where: -
NPV: net present value.
NCF: net cash flow.
FV: future income value.
PV: present income value.
i: interest rate.

Table: NPV Calculation of GAGD Process Evaluation



NPV(2026)= 14.100 $ Billion.	
Oil Revenue	60 $/STB
Gas Revenue	3 $/MSCF
Water Disposal	3 $/STB
Capital Expenditure, CAPEX	1 $ Million
Operational Expenditure, OPEX	1 $/Oil STB
Gas Injection Cost	1 $/MSCF STB
Interest Rate	10%

Summary & Conclusions

- GAGD EOR process was implemented in a well-characterized large reservoir (19.5 B bbl OOIP) using a compositional simulator.

- In the GAGD simulation, 20 vertical gas injectors were installed at the top along with 10 horizontal wells for production.

- The CO2-GAGD case led to significant incremental oil recovery of approximately 330 million STB more than the primary production to the end of the prediction period.

- FlueGas-GAGD performed almost on par with CO2-GAGD.