THMC Modeling of Gas Hydrate Reservoirs

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Introduction

- Natural gas hydrates are solid, non-stoichiometric compounds of methane molecules and water. (Sloan 2003)
- Requires ambient conditions of high pressure and low temperature.
- Dense source of methane – 1 :164 at STP.
- Production - phase transition must be forced by changing the thermo-dynamic/chemical conditions.
- Common Methods - thermal stimulation, depressurization and chemical inhibition.

Fig.1 A sample of methane hydrate specimen under combustion

Motivation

- 3000 TCM worldwide in permafrost and marine setting (Chong et. al. 2016)
- Indian Scenario – 10% reserves gives 100 years of self-sufficiency. (K.Sain 2012)
- Complexity of production processes :

Phase change, fluid flow, heat transfer requires a complete **Thermo-Hydrological-Mechanical and Chemical (THMC)** approach to modeling for predicting cumulative gas production and rate of production.

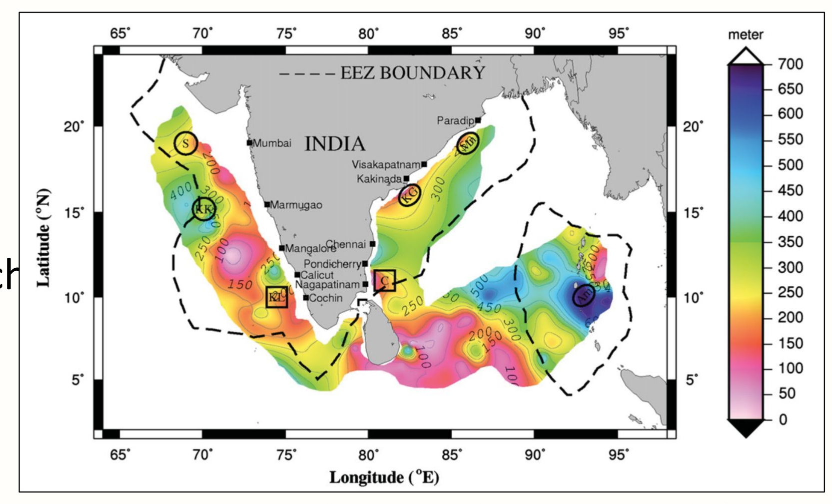

Fig. 2 Geographical distribution of methane hydrate reserves in India (Sain 2012)

Methodology

TOUGH+HYDRATE v1.5

- Coupled equations of mass and heat balance
- Integral finite difference method
- Non- isothermal gas release, phase behavior and flow
- Permafrost and in deep ocean
- Complex geological media
- Laboratory and Reservoir scale

$$\frac{d}{dt}\int_{V_n} M^{\kappa}\,dV = \int_{\Gamma_n} \mathbf{F}^{\kappa}\cdot\mathbf{n}\,d\tilde{A} + \int_{V_n} q^{\kappa}\,dV$$

$$M^{\kappa} = \sum_{\beta=1,\dots,N_\beta} \phi S_\beta \rho_\beta X^{\kappa}_{\beta}, \quad \kappa = 1,\dots,N_\kappa$$

$$M^{\theta} = (1-\phi)\rho_R C_R T + \sum_{\beta=1,\dots,N_\beta} \phi S_\beta \rho_\beta U_\beta$$

$$\mathbf{F}^{\kappa} = \sum_{\beta=1,\dots,N_{m\beta}} \mathbf{F}^{\kappa}_{\beta}$$

$$\mathbf{F}^{\theta} = -\bar{k}_\theta \nabla T + f_\sigma \sigma_0 \nabla T^4 + \sum_{\beta=1,\dots,N_{m\beta}} h_\beta \mathbf{F}_\beta$$

Fig.3 Equations representing the conservation of mass and energy along with the accumulation and flux terms

Model Parameters

- Equilibrium Model
- Uniform Cartesian Grid (25x25x25)
- Grid Spacing 1m
- Thermal injection of water at 45 °C at 1 kg/s at center-top location.
- Duration - 12 days
- Initial Temperature – 1.2 °C
- Initial Pressure – 4.0 Mpa

Model Parameter	Value
Gas Hydrate Saturation	0.5
Permeability	30mD
Porosity	0.30
Density	2600 kg/m^3
Formation Heat Conductivity	3.1 Wm^{-1}K^{-1}
Rock Grain Specific Heat	1000 Jkg^{-1}K^{-1}
Pore compressibility	10^{-8}Pa^{-1}
Pore expansivity	0.0 K^{-1}

Table 1. List of model parameters and their values used for simulation.

Production profile for base case

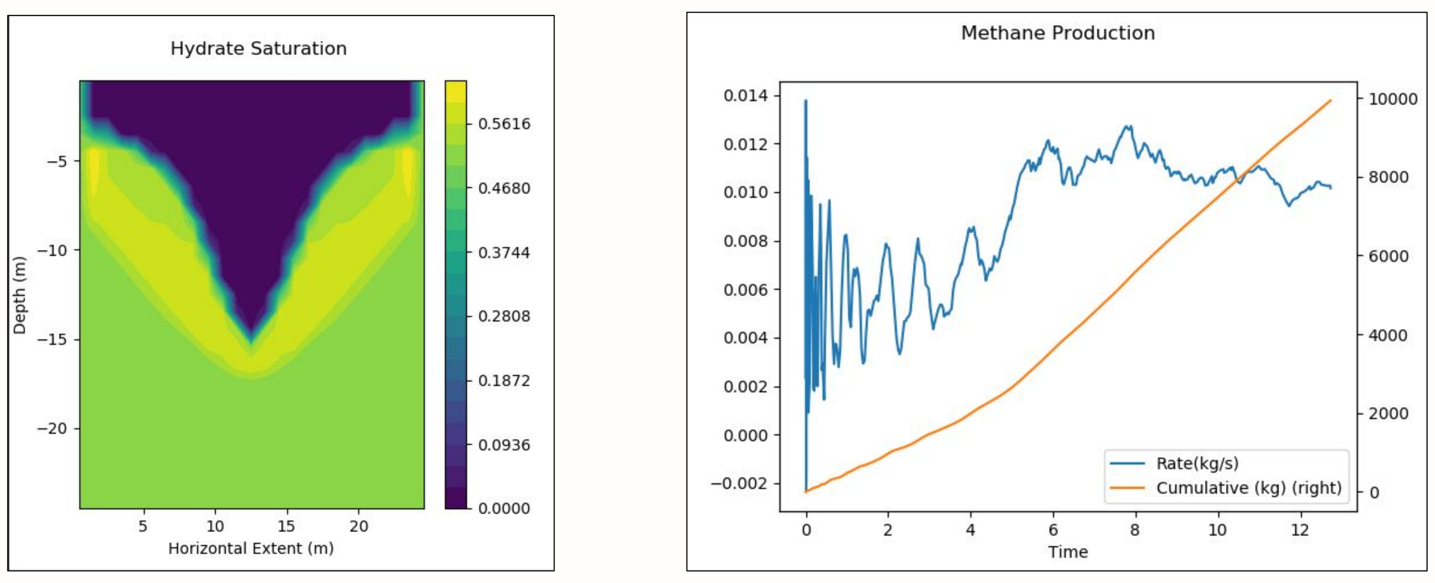

Fig 4. The hydrate saturation is displayed on the center lateral slice as a function of depth vs horizontal extent (left). The observed rate of methane production as well as the cumulative methane production is also shown(right).

Validation

The results were validated qualitatively against previously published works of Kowalsky et.al. (2007) which reported a similar zone of excess hydrate saturation.

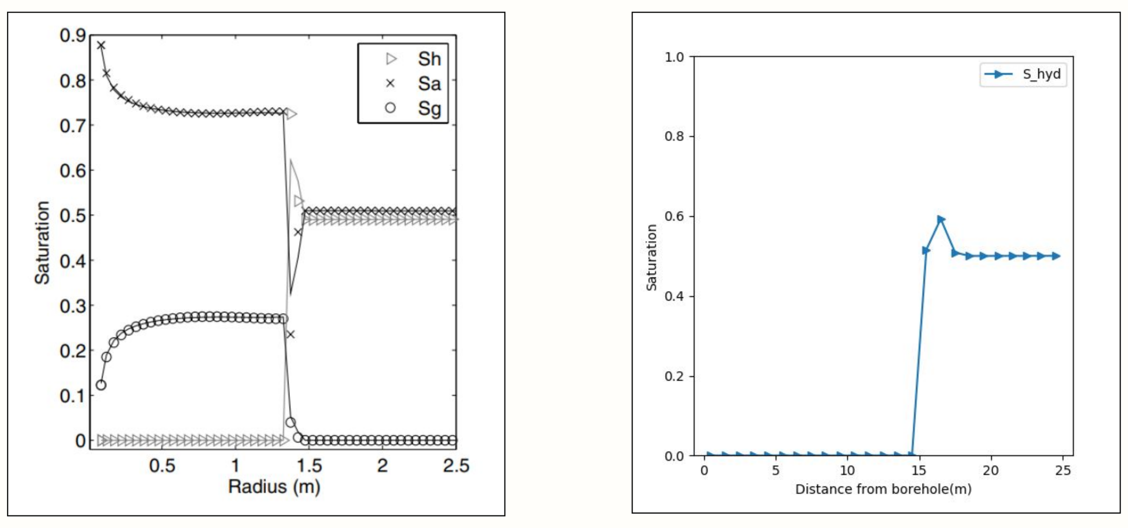

Fig. 5 Variation of saturation of gas, water and hydrate for a similar case (left) as reported by Kowalsky et.al.(2007)
Followed by variation of saturation of hydrate (right) as observed for the center slice in our 3D Numerical Simulation.

Salinity

The stronger bonds of salt ions with water result in the collapse of the clathrate structure of the hydrate promoting dissociation.
Increase in cumulative production by 128% was observed when salinity of the injection fluid was increased from 0% to 20% (w/w).

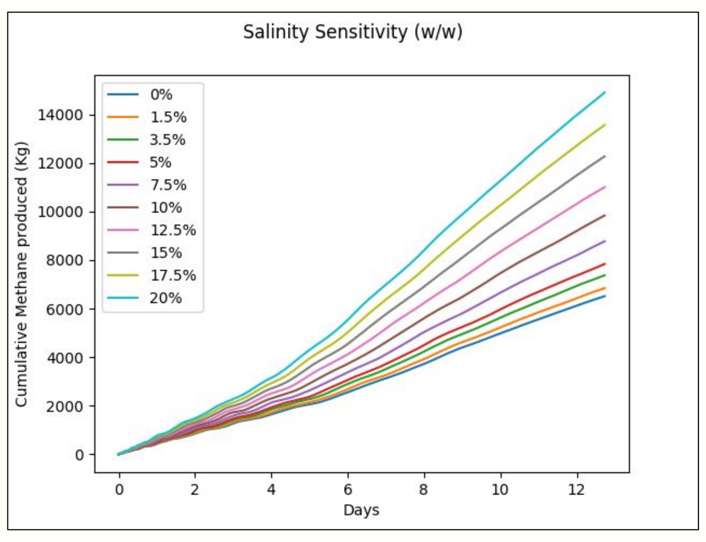

Fig. 6 Variation of cumulative gas production with injected fluid salinity.

Porosity

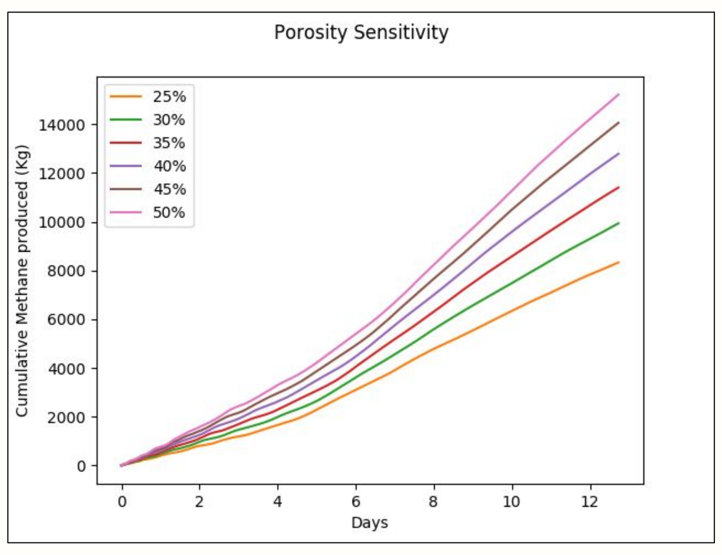

Fig. 7 Variation of cumulative gas production with saturation corrected porosity case.

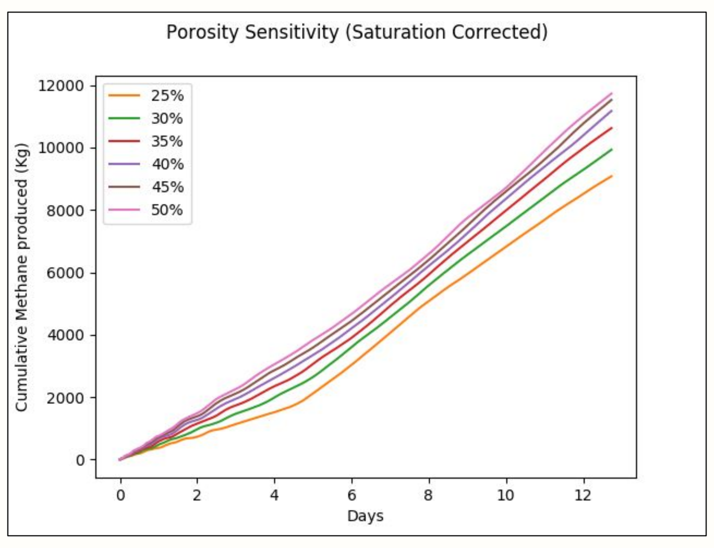

Fig. 8 Variation of cumulative gas production with saturation corrected porosity case.

Permeability

Permeability controls fluid migration through hydrate bearing sedimentary systems affect both dissolved gas and free gas transport. (Waite et al 2009). It is one of the most critical parameters since it contributes directly to both mass transfer and heat transfer processes. A total variation of 28% was observed in production levels when permeability was varied from 2mD to 100mD.

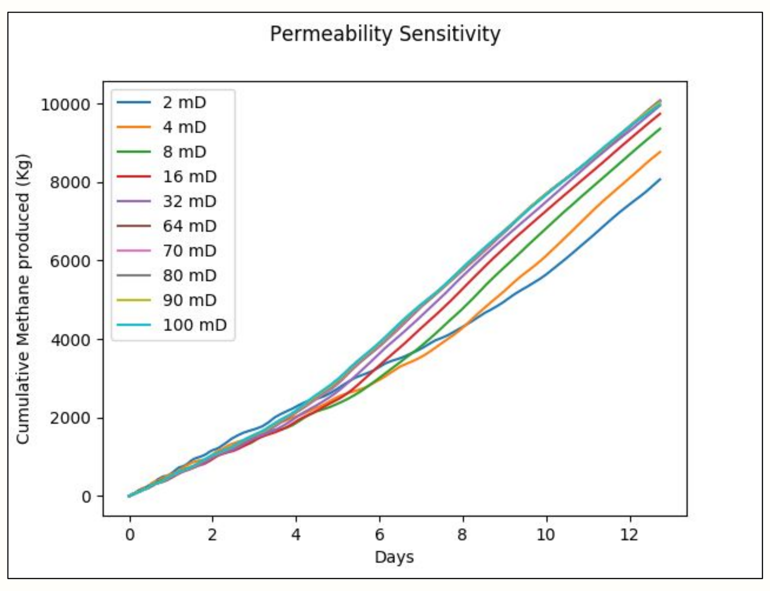

Fig. 9 Variation of cumulative gas production with absolute permeability

Conclusions

The numerical simulation was able to simultaneously solve the coupled equations and was successful in being validated against previously published work. Sensitivity analysis was conducted between permeability, porosity, porosity corrected for hydrate saturation and injected fluid salinity in order to determine the quantitative fluctuation in cumulative methane gas production. Increase in permeability and salinity both exhibited a significant increase of production.

Future Work

- Inclusion of coupling with geomechanical strength.
- Simulation of Class 1 and class 2 hydrate reservoir systems.
- Development of optimal wellbore configuration.
- Combination of thermal stimulation and depressurization.

References

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