

DESIGNING A RESERVOIR FLOW RATE EXPERIMENT FOR THE GOM HYDRATE JIP LEG II LWD DRILLING

Irene Gullapalli*, Chevron Energy Technology Company, **George Moridis**,
Lawrence Berkeley National Laboratories, **Suntichai Silpngarm**, **Barry Reik**,
Medhat Kamal, **Emrys Jones**, Chevron Energy Technology Company, **Timothy**
Collett, US Geological Survey

ABSTRACT

The Deep Water Gulf of Mexico (GOM) may contain a large hydrate resource. Short term production profiles (from modeling) for a hydrate deposit that was logged in the GOM are presented along with the feasibility of using traditional well test analysis tool to obtain production parameters that can be used to further refine the reservoir model estimates. The presence of the solid hydrate phase in hydrate reservoir not only poses challenges in production but also in designing flow tests. Unlike conventional well flow tests, the time scale needed to produce methane gas from hydrate formation may take longer time. This is because the effective permeability in hydrate formation is initially very low. Hence, there is a need to establish a flow path as a result of hydrate dissociation with change in pressure and temperature. In this paper, we attempted to determine the type and duration of a well test that could provide the needed information to support and validate production modeling of gas hydrate deposits. The investigated parameters in this study included the effects of permeability and hydrate saturation as a function of the duration of the flow test. These parameters, initial hydrate saturation and absolute permeability, appear to be most influential in gas production from hydrate formation based on experimental design. The results also indicate that production using a constant bottom hole pressure is the most appropriate method to impact hydrate dissociation by depressurization for flow testing because of the relatively rapid response and early release of gas. Reasonable values for water and gas effective permeability were obtained from short term flow tests (3 to 15 days) but was not possible to recognize changes in transient pressure plots to identify regions of varying saturations in the studied system. Furthermore, it was not feasible to calculate absolute permeability values for the studied system as the range of fluid saturation was in an area of high relative permeability uncertainty. This may be due to the fact that the conventional well test analysis tool does not capture underlying physics describing hydrate systems. Hence, for proper analysis, history matching using the well test data and a proper hydrate simulator are recommended.

Keywords: gas hydrates, depressurization, flow test, buildup, GOM

NOMENCLATURE

k Absolute permeability [mD]
 k_{eff} Effective permeability [mD]
 P Pressure [Psi]
 P_w Bottom hole pressure [Psi]
 Q_M Mass rate [kg/s]
 S_H Hydrate saturation [fraction]

T Temperature [°C]
 ϕ Porosity

INTRODUCTION

Hydrate deposits have recently begun receiving attention as an emerging energy resource because of continuously increasing energy demand and

* Corresponding author: Phone: +1 925 842 6249 Fax +1 925 842 6281 E-mail: olee@chevron.com
6001 Bollinger Canyon Road, San Ramon, CA 94583

overtaxed conventional resources. Hydrate reservoirs are considered unconventional resources, in which the hydrocarbon gas is trapped inside ice-like cage. Proper manipulation of its pressure and/or temperature is needed in order to induce dissociation of the solid hydrate phase, leading to the release of gas to be produced [1] and water (in aqueous or ice state). Assuming that the energy demand is likely to continue to rise during the 21st century, research organizations with various backgrounds and missions need to begin thinking about how to develop and commercialize gas production from hydrate accumulations to meet the future energy needs. Generally, after an energy asset is identified through seismic and other exploration tools, the next step involves a series of short-term flow tests to determine reservoir properties (such as permeability k or porosity ϕ) prior to beginning long-term production.

The main challenges in designing a flow test in hydrate-bearing media is the lack of any previous experience and expertise on the subject, and a practically non-existence body of literature. Because there have been hardly any field activities related to gas production from hydrate deposits to date, it is necessary to use numerical simulation to understand and design such flow tests. Some numerical simulation studies have been conducted to determine the gas production potential from the various classes of hydrate deposits in the oceans and in the permafrost [2,3,4].

One of the major challenges with hydrate reservoir is how to quickly transform the solid hydrate into fluid phases that can be produced. This becomes particularly challenging when it comes to the design of short term flow test because the expectation of practitioners of such test (involving durations on the order of several days) is in conflict with the behavior of hydrates (which require much longer times before the dissociation-induced increase in effective permeability can register as a change in the flow behavior of the tested system). Hence, hydrate reservoirs that are desirable production targets (characterized by large porosity, absolute permeability and hydrate saturation) pose extra challenges compared to oil and gas reservoirs because of generally very low effective permeability to fluid flow.

This challenge is even greater in Class 3 deposits, where there is no mobile phase underneath the hydrate interval that could allow the easy withdrawal of reservoir fluids. For such reservoirs, attaining gas production at commercially viable rates involves a depressurization method that consists of an early stage of constant-pressure production, followed by a longer stage of constant-rate production [5]. This indicates that a typical flow test in hydrate deposits is likely to take longer than one in a conventional oil and gas reservoir.

The main objective of this study is to determine a test duration that is appropriately long to yield reliable estimates of important flow parameters such as k . The effort involves analysis of pressure transients obtained from numerical simulations of various well test designs in a GOM hydrate deposit. The simulations were conducted using the TOUGH+HYDRATE numerical code [6].

GEOLOGICAL MODEL DESCRIPTION

The geologic model of the hydrate deposit under study (Figure 1) is based on a reservoir located in the Deep Water Gulf of Mexico (GOM) of a 9000+ ft of water depth. The 60-ft-thick reservoir is situated on the top of an anticline structure at a depth of 10,530 ft, where the thermal gradient is about 0.0186 °F/ft. The hydrates are trapped in the amalgamated, high net-to-gross, deep-water channels and lobe and/or sheet sands. The brine concentration is about 35,000 ppm, i.e., typical of an oceanic environment.

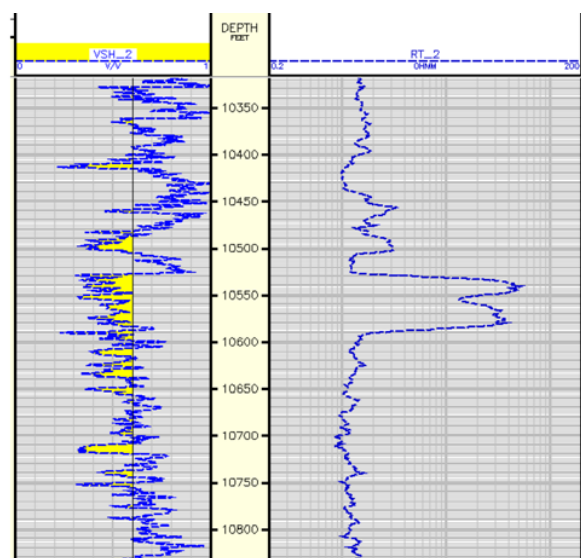


Figure 1: Well log display

PRELIMINARY INVESTIGATIONS

Rationale and description of approach

Because of the dearth of data on the behavior of hydrate-bearing media under production, it was necessary to conduct a series of preliminary simulations. These provided critical information of the system sensitivity to various initial conditions and flow parameters, and supplied sufficient data to provide a basis for the expected system response during both short-term well tests and longer-term production regimes.

The domain in the single-well preliminary studies involved a cylindrical deposit with a 1/2 mile drainage radius, and was representative of the GOM hydrate field, with approximately 100 BCF/sq mile of total methane-in-place at standard conditions. The domain was discretized in $100 \times 100 = 10,000$ elements in (r,z) . Fine vertical discretization was used to properly capture the fluid and heat transport processes.

In the preliminary studies, we treated the system as a Class 2 deposit, in which a constant mass rate of fluid withdrawal $Q_M = 19$ kg/s (= 10,000 BPD) was produced through a perforated interval that intruded deeply into the water zone underneath the hydrate. The resulting depressurization caused the hydrate to dissociate and gas to be released. We made the assumption (a valid one, supported by geophysical indications) that the bottom of the hydrate interval is close to or coincides with the bottom of the hydrate stability zone (BHZ). Such accumulations are the easiest to destabilize, and, consequently, are the most appealing candidates for gas production.

In both the preliminary and the well test series of simulations, the hydrate-forming gas was assumed to be 100% CH₄, and hydrate dissociation was treated as an equilibrium reaction with the phase behavior illustrated in Figure 2. The initial T and P in the reservoir were assumed to follow the geothermal and hydrostatic gradients, respectively, with the T at the base of the hydrate being very close to the equilibrium T corresponding to P at that elevation. This relatively high T provides significant sensible heat to fuel the strongly endothermic dissociation reaction during depressurization. The irreducible water and gas saturations were 15% and 2%, respectively.

Uncertainty parameters and system response

Subsurface uncertainties are an unavoidable reality in the study of any reservoir (conventional or hydrate). Therefore, the rationale behind the preliminary tests was obtaining an insight into the production behavior of a hydrate reservoir and determining the relative importance of key uncertainty parameters prior to designing the flow test.

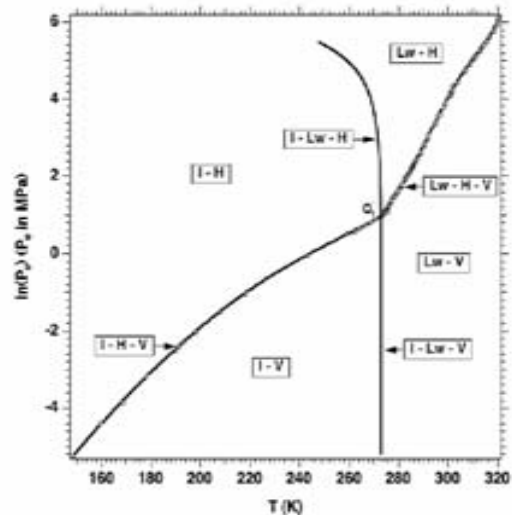


Figure 2: Pressure-temperature equilibrium relationship phase diagram of water-methane-hydrate system [6]

Among the many uncertainties, the authors decided to focus on parameters that appeared to be most relevant in short-term production. We identified 5 such parameters: absolute permeability k , porosity ϕ , saturation of the hydrate interval S_H , T and P at the bottom of the hydrate interval, and aquifer size (strength). The range of these 5 uncertainty parameters are illustrated in Table 1.

A Folded Plackett-Burmann (FPB) design [7] was employed to set up the appropriate combinations or parameters needed to assess the uncertainty in Cumulative Gas Production (GPC). This is a compact design that assumes a linear relationship between the GPC and the input parameters. It doesn't capture the interaction effects between parameters but it provides an efficient way of estimating the main effects. This resulted in 16 runs plus the center point run, as shown in Table 2.

“Heavy hitters”

The analysis of the PB design runs are shown in Figure 3. Pareto chart displays the order of parameters that most influenced the cumulative

gas production in 180 days. Among the 5 parameters, hydrate saturation had most impact on cumulative gas production (GPC) in 180 days. The vertical red line corresponds to 95% confidence interval. This means the hydrate saturation effect on gas production is statistically significant with 95% confidence. The curvature in the response was assessed with the center-point run and was deemed negligible compared to the effects of the parameters, hence validating the hypothesis of linearity in the system.

Parameter	Low	Mid	High
Hydrate Permeability	500	1500	2500
Hydrate Porosity	0.2	0.25	0.3
Hydrate Saturation	0.5	0.63	0.75
Aquifer Size	97	165	234
Temperature At BHZ	18.5	20.3	22.5

Table 1. Subsurface uncertainty parameters.

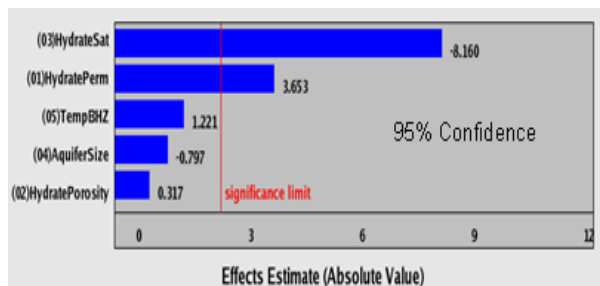


Figure 3: Pareto chart of Folded Plackett-Burmann Design based on 180-day production

The negative number on hydrate saturation and aquifer size indicate that the smaller the values, the better the production. Hence, smaller saturation helps initially in production. On the other hand, the positive values on permeability, temperature at BHZ, and porosity indicate that higher values will result in higher cumulative gas recovery.

Based on the results of Figure 3, cumulative gas production is expected to increase with:

- Decreasing hydrate saturations
- Increasing permeability
- Increasing T at the BHZ
- Increasing porosity
- Decreasing aquifer strength

It is important, however, to indicate that these results and conclusions are a direct function of time frame of observation, and reflect conditions within the 180-day-long period of initial production. This is a rather short time compared to the multi-year process of production from hydrates, and some of the corresponding observations are almost certain to not apply to the entire production period. Thus, the results indicate sensitivity to gas production during the initial stages of production only. As such, they are directly applicable to the design of the short-term flow test.

Run	Perm	Pogo	HySat	Aqu	Temp
1	High	Low	Low	High	Low
2	High	High	Low	Low	High
3	High	High	High	Low	Low
4	Low	High	High	High	Low
5	High	Low	High	High	High
6	Low	High	Low	High	High
7	Low	Low	High	Low	High
8	Low	Low	Low	Low	Low
9	Low	High	High	Low	High
10	Low	Low	High	High	Low
11	Low	Low	Low	High	High
12	High	Low	Low	Low	High
13	Low	High	Low	Low	Low
14	High	Low	High	Low	Low
15	High	High	Low	High	Low
16	High	High	High	High	High
Ctr	Mid	Mid	Mid	Mid	Mid

Table 2. Folded Plackett-Burmann Design

The production period was then doubled to test whether the order of ranking may change. The outcome in Figure 4 suggests that there were essentially no change in the ranking between 180-day and 365-day production. For the reason previously discussed, this does not indicate that the ranking will remain unaltered throughout the multi-year life of the reservoir. This remains to be seen as methane production from hydrate reservoirs involves reaction as well as right temperature and pressure.

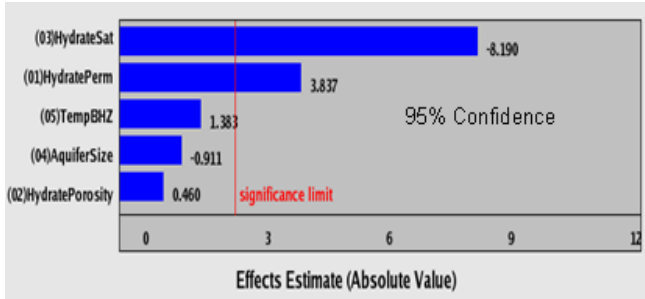


Figure 4: Pareto chart of Folded Plackett-Burmann Design based on 365-days production

WELL TEST DESIGN - CLASS 2 DEPOSITS

The objective of this set of simulations was to understand the effect of k and S_H on gas production when a constant pressure $P_w = 1740$ psia (12 MPa) was imposed at the producing well. The initial pressure at the bottom of the hydrate interval was 4495 psia (31 MPa) and the corresponding temperature $T = 68^\circ\text{F}$ (20°C). Note that the model assumed that the BHZ was close to 3-phase equilibrium line, as shown in Figure 2. Only the top 14 ft at of the 60-ft hydrate interval were completed for production in order to minimize the aquifer influx during the constant- P production. A schematic of a sample homogenous hydrate reservoir is shown in Figure 5.

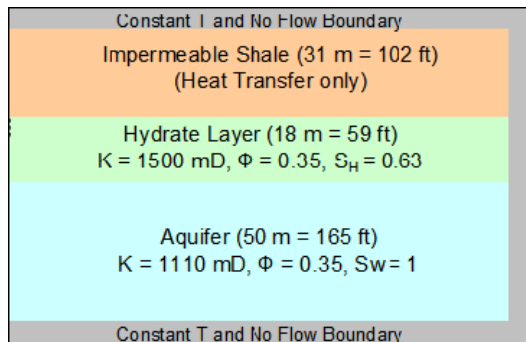


Figure 5: Schematic of the Class 2 hydrate reservoir

Hydrate Saturation Effect

The effect of initial S_H is investigated because it was ranked as the most important parameter to gas production. For this study, the permeability was kept at 1500 mD whereas the saturations were varied as follows: 0.5, 0.63 and 0.75. Figure 6 confirms that the deposit with the lower $S_H = 0.5$ responded faster (by releasing gas) than the $S_H = 0.75$

case. In the latter case, the system has essentially only 10% mobile water, thus significantly reducing the likelihood of rapid dissociation. Figure 7 shows that at $t = 2.5$ days, gas formed a gas bank with a radius of more than 15 m (50 ft) in the $S_H = 0.5$ case. Conversely, a much smaller bank is formed in the $S_H = 0.75$ case.

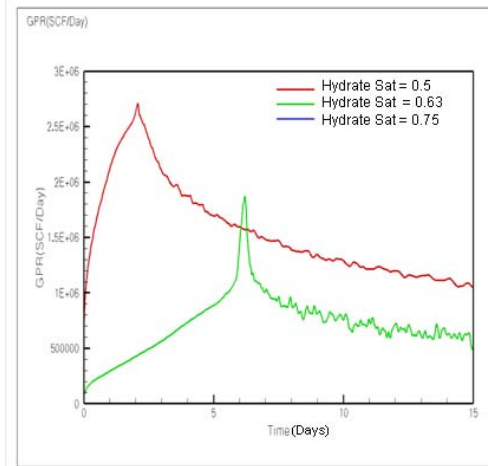
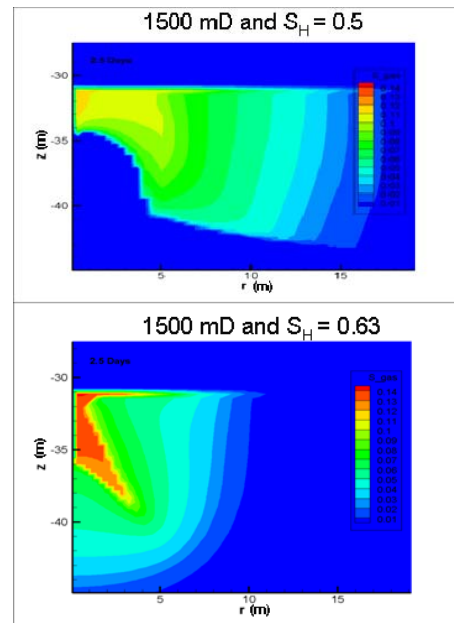


Figure 6. Effect of hydrate saturation on instantaneous gas production rate



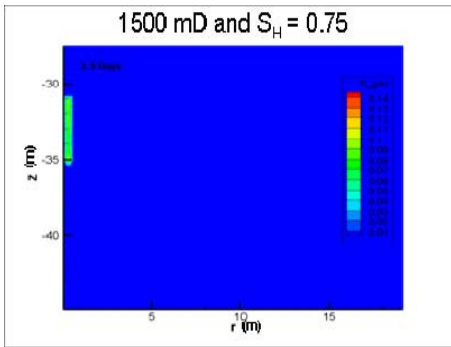


Figure 7. Gas saturation maps at 2.5 Days Into production ($K = 1500$ mD)

Hydrate Permeability Effect

The earlier ranking study had indicated absolute permeability to be the next most important parameter. The effect of k on gas production was investigated for $S_H = 0.63$. The k values were 300 mD, 1000 mD, 1500 mD, and 3000 mD. Figure 8 shows that gas production increases with k . The results also indicate that a system with low permeability (e.g., the $k = 300$ mD, $S_H = 0.63$ case) will take a long time to reach the sufficiently low pressure and high k_{eff} needed to attain a high production rate.

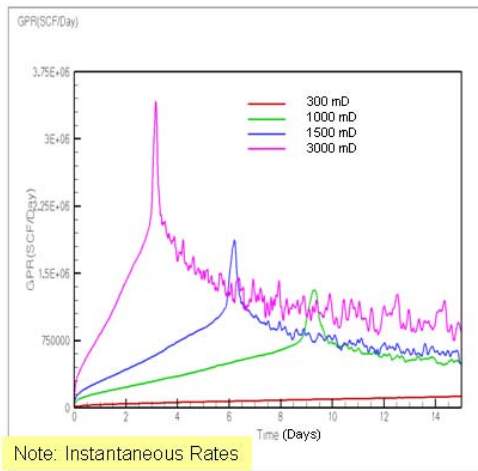


Figure 8: Effect of absolute permeability on instantaneous gas production rate

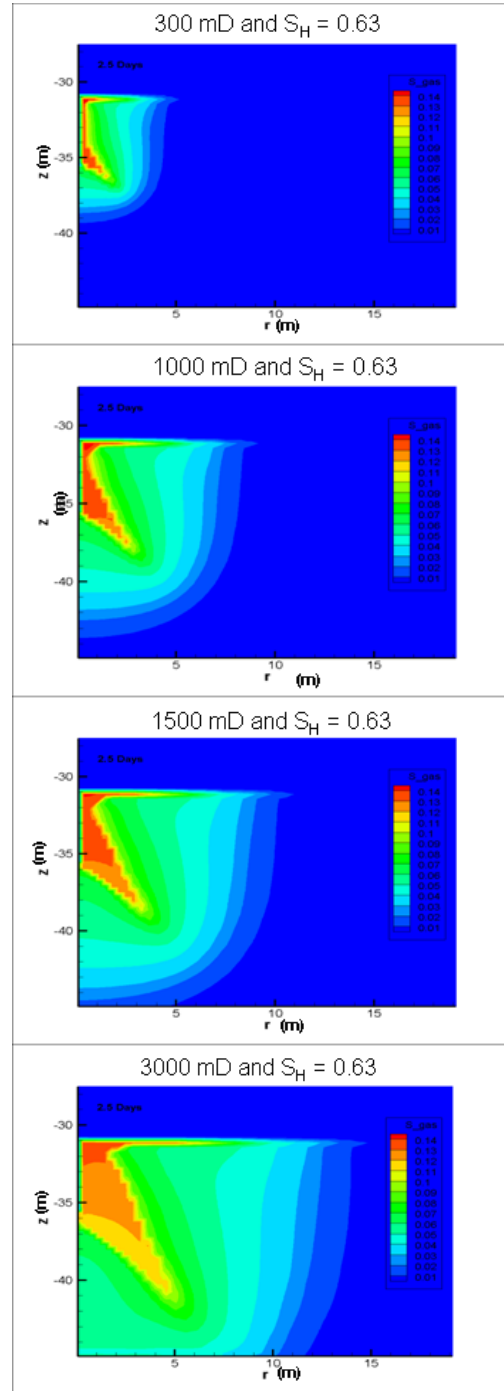


Figure 9: Gas saturation maps of 300 mD, 1000 mD, 1500 mD, 3000 mD at 2.5 days into production ($S_H = 0.63$)

Saturation maps illustrated in Figure 9 suggest that as early as $t = 2.5$ days, a large gas bank with high S_G is already formed for $k > 1000$ mD. These observations are consistent with those from the PB runs.

WELL TEST DESIGN - CLASS 3 DEPOSITS

The Class 3 deposit used in this study is depicted in Figure 10. The production interval covered the entire thickness of the hydrate zone. Gas was produced by applying a constant bottom hole pressure $P_w = 1740$ psia (12 MPa) at the well. The initial reservoir pressure at the bottom of the hydrate interval was 4527 psia (31.22 MPa) and the corresponding temperature was 68.8 °F (20.45 °C).

The four cases considered were as follows:

Case 1: 3-day production at constant pressure followed by 15-day buildup

Case 2: 5-day production at constant pressure followed by 15-day buildup

Case 3: 10-day production at constant pressure followed by 15-day buildup

Case 4: 15-day production at constant pressure followed by 15-day buildup

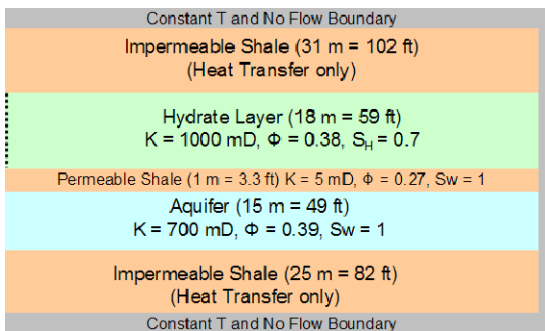


Figure 10: Schematic diagram of Class 3 hydrate reservoir.

Flow and Buildup Results

The result of the 15-day flow test is depicted in Figure 11 to illustrate the early gas production profile observed from Class 3 deposit. The oscillations in this figure are an inevitable result of the endothermic nature of hydrate dissociation. As k_{eff} increases, dissociation increases until it reaches a peak. The resulting lower temperature (and locally higher pressure resulting from the gas release) slows the release of more gas, a fact reflected in the decline in the gas release until more heat from the surrounding reaches the dissociation front. This is marked by the valley in

the oscillations and marks the onset of increase in gas release. This cyclical process is repeated.

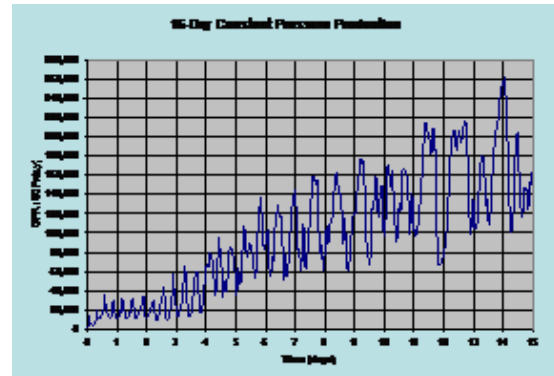


Figure 11: 15-day gas production rate (instantaneous)

The 15-day buildup results followed by 3-day, 5-day, 10-day, and 15-day productions are illustrated in figures 12 – 15. Comparison plot of all cases is shown in Figure 16.

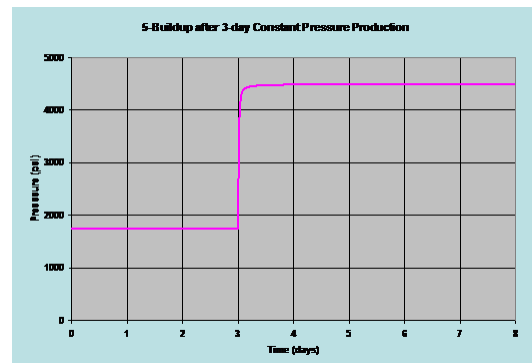


Figure 12: 3-day pressure buildup (Case 1)

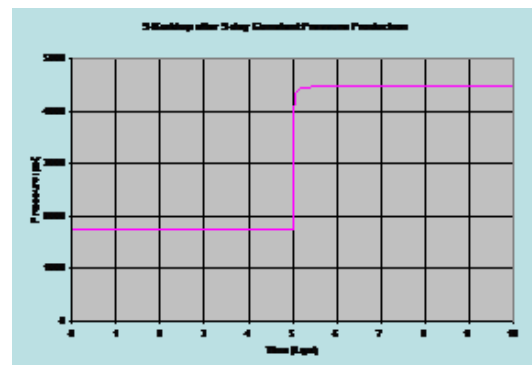


Figure 13: 5-day pressure buildup (Case 2)

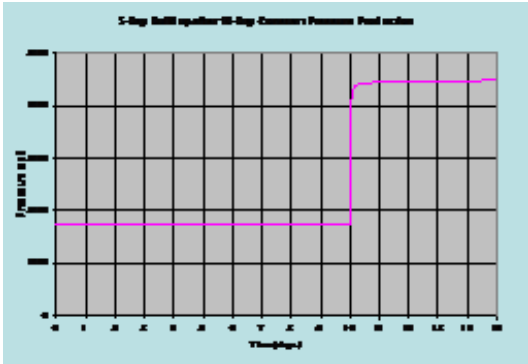


Figure 14: 10-day pressure buildup (Case 3)

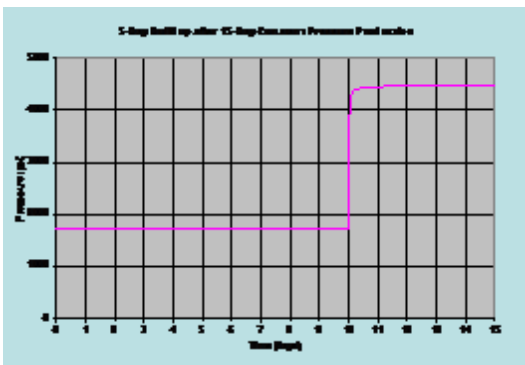


Figure 15: 15-day pressure buildup (Case 4)

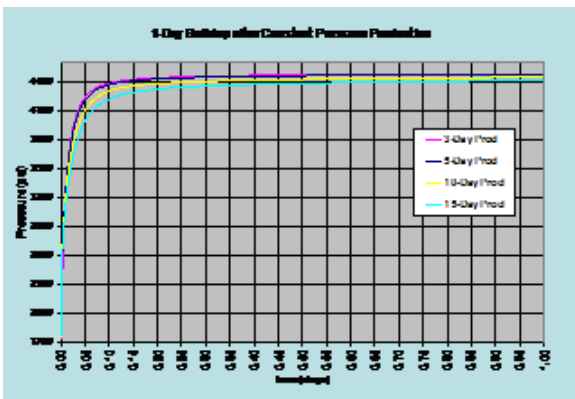


Figure 16: Comparison of 4 cases at 1-day buildup

Figure 17 is the gas saturation maps of 4 cases investigated. The gas accumulation that is a result of hydrate dissociation is shown nicely along the well. Furthermore, it is evident that the longer the production period, the larger the dissociation area and the higher the gas saturation. However, the radius over which dissociation and gas accumulation are observed appears to be no more than 3.3 ft (1 m).

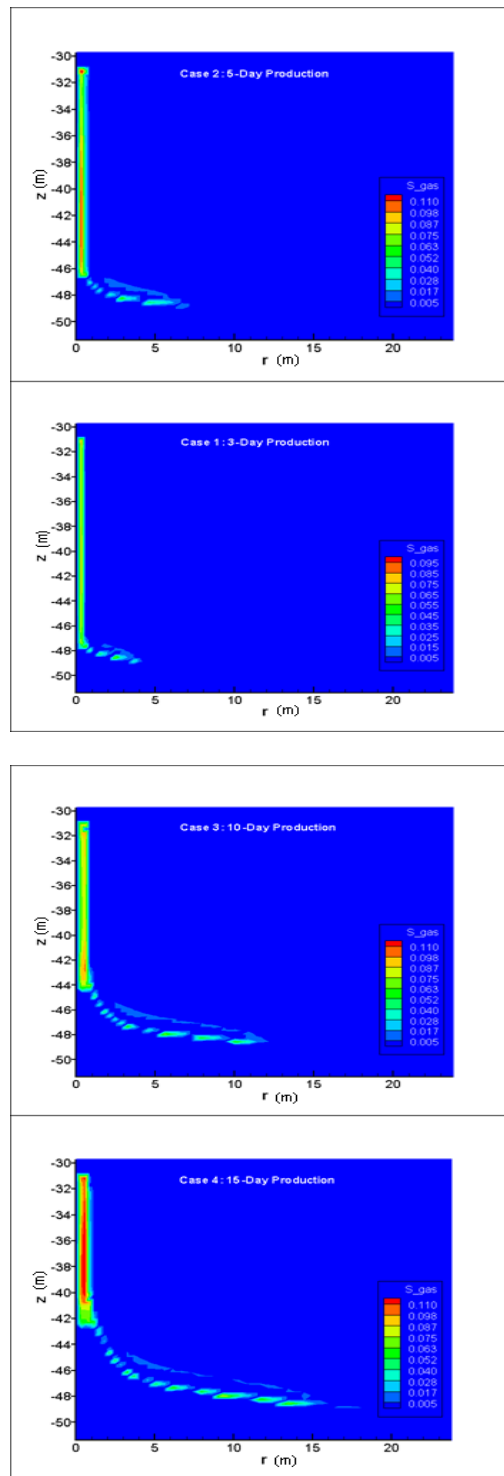


Figure 17: Gas saturation during 3-day, 5-day, 10-day, and 15-day production periods

Notice that there is significant difference in the dissociation and gas accumulation patterns between Class 2 and 3 (Figures 9 and 17). The reason is the permeability of the underlying

aquifer in the Class 2 deposit, which is reached within a relatively short time (marked by the peak in gas production) as the dissociation front advances rapidly downward. The resulting larger k_{eff} leads to the larger dissociation evident in Figure 9. The corresponding gas and water relative permeability maps of 15-day production are illustrated in Figure 18 and 19, respectively.

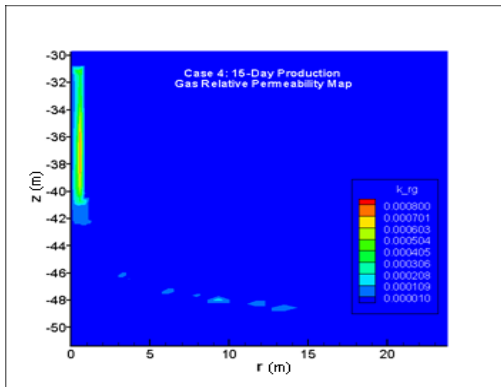


Figure 18: Gas relative permeability (k_{rg}) map of 15-day production test (Case 4)

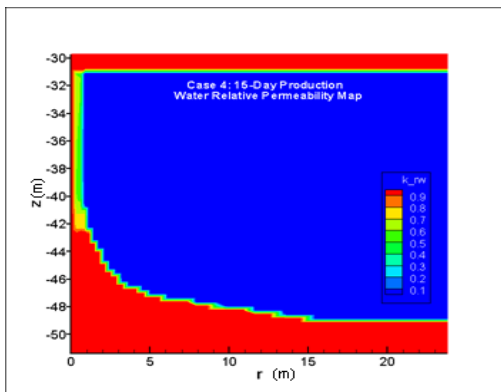


Figure 19: Water relative permeability (k_{rw}) map of 15-day production test (Case 4)

The range of gas relative permeability near the well ranges between $1E-5$ to $1E-4$ which corresponds to gas effective permeability between 0.01 to 0.1 mD for 1000 mD sand.

TRANSIENT TESTING

Approach

The objectives were to determine the feasibility of using transient tests to estimate the properties of a hydrate reservoir following a production (flow) test of an exploration well and determine properties that can be obtained with a production test of practical duration. The approach involved

using rate and pressure results from simulation studies to mimic pressure buildup tests with Saphir® to calculate effective permeabilities of gas and water. Multi Phase Testing method [8] was used to attempt to calculate absolute permeability. The model consists of 3 layers (hydrate – thin shale – aquifer) where it is consistent with the schematic presented in Figure 10. The cases considered for this study is tabulated in Table 3.

Case	Production Time (Days)	Shut-in Time (Days)
1	3	15
2	5	15
3	10	15
4	15	15

Table 3. Transient test cases.

Results and Discussions

The daily average rate of water and gas flow rates of 15-day production test are shown in figures 20 and 21, respectively. The daily average rate was calculated based on cumulative gas and water production results from simulation runs.

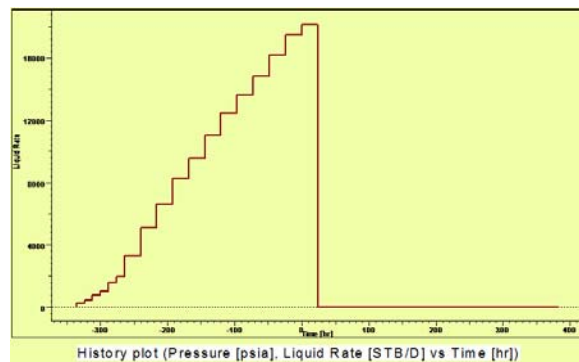


Figure 20: 15-day water flow rate

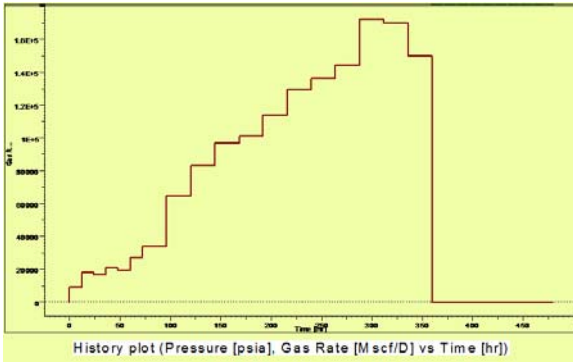


Figure 21: 15-day gas flow rate

The results of the log-log diagnostic plots of pressure vs. time for these 4 cases are illustrated in figures 22 – 25. The results of all cases are also shown in Figure 26 to help them compare to one another. The green curve is the pressure buildup points obtained from simulation run and the red curve is the derivative of the buildup data. Briefly, the derivative of the pressure buildup shows both wellbore storage effects and reservoir effect. The tail or latter portion of the line designates the reservoir effect.

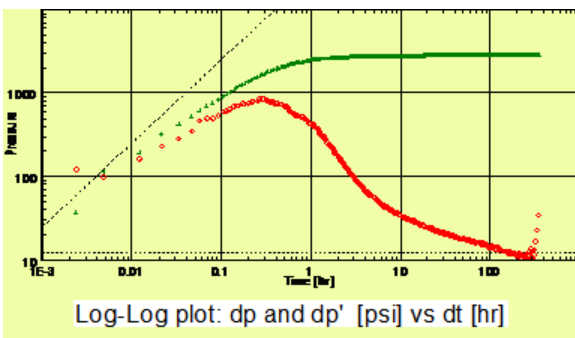


Figure 22: Diagnostic plot of Case 1

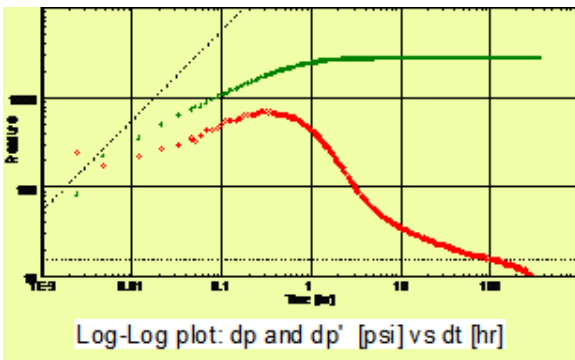


Figure 23: Diagnostic Plot of Case 2

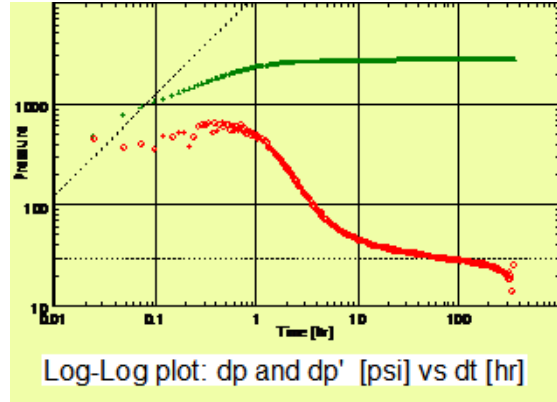


Figure 24: Diagnostic plot of Case 3.

The derivative curves of all cases towards the end of the buildup tests suggest that the aquifer support was pronounced with the increase of the duration of the production, indicating that the reservoir was beginning to act like a dual porosity system. Likewise, the change in effective reservoir properties with the change in the duration of the production is nicely reflected by the end time of the derivative of the buildup.

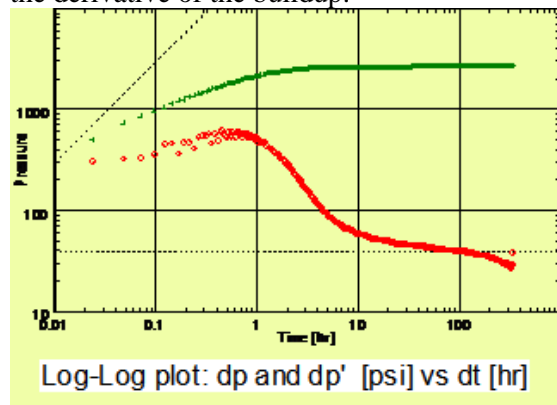


Figure 25: Diagnostic plot of Case 4

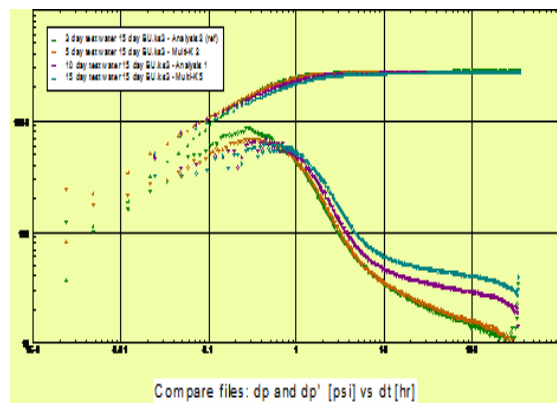


Figure 26: Diagnostic plot of all 4 cases

Based on these diagnostic plots, following observation can be made:

- Data does not show enough character to identify different regions around the well. Most probably due to the relatively short production durations.
- Data trends indicate increasing values of effective water and gas permeability as the saturation of both phases increase with production time.
- The geometry of the reservoir (three layers; one only producing) affects the late time behavior. In this case, aquifer influx is evident and if there was impermeable shale, the response would have been different.

Figure 27 is an example of history matching the pressure from simulation runs by using results from the well test analysis. Figure 28 is a history match of a diagnostic plot where a good match is obtained for late time data indicating reasonable reservoir properties being used. On the other hand, poor match at the middle range was due to the saturation change around the well. Additional work to match the middle range would require the use of a numerical reservoir simulator to describe the multi composite effect resulting from saturation changes in both layers.

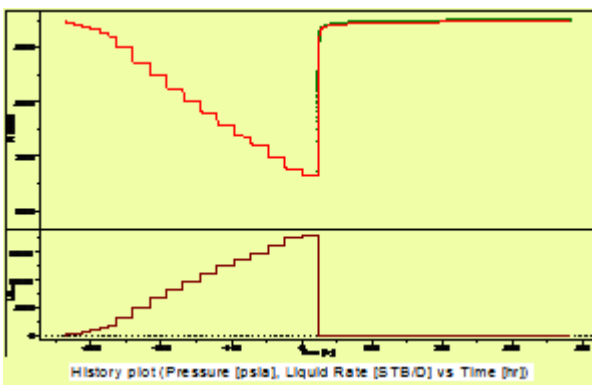


Figure 27: Example match of history plot

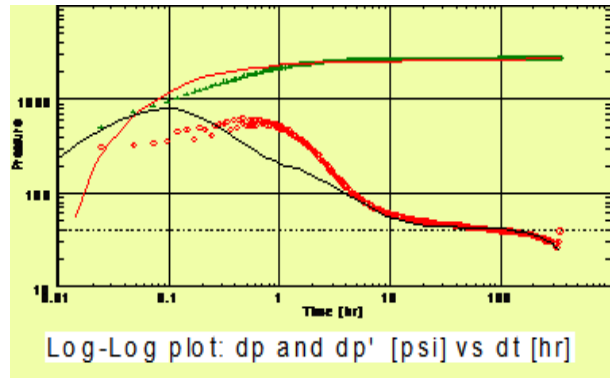


Figure 28: Example match of diagnostic plot

Based on diagnostic plots, Saphir® analysis obtained following effective permeabilities for each cases. The results are tabulated in Table 4. Briefly, the effective permeability of each phase was calculated based on the thickness of the hydrate layer.

Case	Effective Water Permeability (md)	Effective Gas Permeability (md)
1	171	0.0345
2	230	0.0513
3	315	0.0532
4	345	0.0576

Table 4. Summary of effective permeabilities of 4 cases.

The following observation can be made:

- Ratio of k (effective water) to k (effective gas) is much higher than what could be obtained from relative permeability relations due to low gas saturations (e.g., ~6000 to ~3000).
- Regions of fluid saturation after producing for short durations (3 to 15 days) are in areas of low confidence in relative permeability curves.
- It is not possible to calculate the absolute permeability of the reservoir for this system with short production periods.

Although the transient analysis of Class 2 system (Figure 5) was not performed, one can project that the late time behavior will resemble more like 15-day production rather than 3-day production due to aquifer support which reduces the pressure change. Likewise, with systems with higher pore compressibility (e.g. gas reservoir), one would expect longer test duration.

SUMMARY

Reasonable values for water and gas effective permeability could be obtained for the studied system with short production duration (3 to 15 days). Under the constraint of production time not exceeding 15 days, it is not possible to recognize changes in transient pressure plots to identify regions of varying saturations in the studied system. Furthermore, it is not feasible to calculate absolute permeability values for the studied system as the range of fluid saturation is in an area of high relative permeability uncertainty.

RECOMMENDATIONS

The commercial well test package used for this analysis lacks the necessary underlying physics describing hydrate systems. Thus, it can only be useful to the determination of the effective permeability if no dissociation is involved, and its usefulness is doubtful after dissociation begins. For proper analysis, history matching using the well test data and a proper hydrate simulator are recommended.

As more than 15-day production followed by another 15-day buildup test did not provide absolute permeability information that one would like to obtain from transient test, an alternative may be to put the well on production for several months and perform transient test where the pressure information is constantly recorded by the permanent downhole gauge during the buildup stage.

ACKNOWLEDGEMENT

This paper was prepared with the support of the U.S. Department of Energy, under Award No. DE-FC26-01NT41330. However, any opinions, findings, conclusions, or recommendations expressed herein are those of the authors and do not necessarily reflect the views of the DOE. Also the author expresses gratitude to Alex Castellini at Chevron Energy Technology Company for discussion on Experimental Design.

REFERENCES

- [1] Sloan, E.D., Kop, C.A. *Clathrate Hydrates of Natural Gases*. 3rd edition, New York: CRC Press, 2008.
- [2] Moridis, G.J. *Depressurization-Induced Gas Production From Class 1 Hydrate Deposits*. SPEREE 2007; 10(5): 458-481.
- [3] Moridis, G.J. Reagan, M.T. *Gas Production From Oceanic Class 2 Hydrate Accumulations*. OTC 18866, Houston, TX, April 30 – May 3, 2007.
- [4] Moridis, G.J. Reagan, M.T. *Gas Production From Class 2 Hydrate Accumulations in the Permafrost*. SPE 110858, Anaheim, CA, November 11 -14, 2007.
- [5] Gullapalli, I, Jones, E, Moridis, G. *Methods for Gas production From Gas Hydrate Reservoirs*. US Patent Application No. 11/852,833.
- [6] Moridis, G.J., Kowalsky, M.B., Pruess, K. TOUGH+HYDRATE v1.0 User's Manual: A code for the simulation of system behavior in hydrate-bearing geologic media, Report LBNL-149E, Berkeley, CA: Lawrence Berkeley National Laboratory, 2008.
- [7] Montgomery, D.C. *Design and Analysis of Experiments*. Ed. Wiley & Sons, 1995.
- [8] Kamal, M. M. and Pan, Y. *Use of Transient Data to Calculate Absolute Permeability and Average Fluid Saturations*. SPE113903. Presented at the Western Regional Meeting, Bakersfield, CA, March 31-April 2, 2008.