IV.3 Data and information that the first and the second offshore production test for methane hydrate provided

IV.3.1 Data of Well, Logging, the Core and the Reservoir

IV.3.1.1 Well Logging and Coring in First and Second Offshore Production Tests

(1) Summary

The logging while drilling (LWD) is a very effective tool to ascertain information about properties of methane hydrate (MH) reservoirs containing unconsolidated sediment. When you use LWD, you need to be careful about the positions of the sensor. A section between a drill bit and the sensor of the LWD is a no data section. The no data section will be long when LWD is connected. On the other hand, there is a risk that water will be produced when we drill into the free gas area where the water zone is below the methane hydrate reservoir section.

The production well did not drill below the depth of the MH stability lower limit to reduce the risk of water being drawn from a low-ranking layer in the gas production test zone. Other wells were drilled with a combination of LWD and wire line logging (WL) to shorten the non logging section as much as possible.

Information about well logging in the first and the second offshore production tests, as well as coring of the Second Atsumi Knoll are shown in Table 1.

Under room temperature and one atmospheric pressure conditions, MH will change into gas and water, so we developed a "the pressure coring tool system" that can keep the pressure of the core in-situ. Development of the device that can measure the sediment properties of the core under in-situ pressure advanced through phase 2 and 3. Various analyses of the acquisition core were also completed. In addition, information about analysis of the core is shown in another clause about.

(2) Summary of Well Investigation in Phase 3

In 2012, we carried out coring of the investigation well (geo-technique well) one year before the first offshore production test was carried out. The purpose of the geo-technique well is to investigate the properties of the shallow formation above the MH reservoir. The coring carried out at this time was implemented with a normal core tool that cannot maintain in-situ pressure. As a result, we were not able to recover core samples of semi-unconsolidated sediment or unconsolidated sediment, including MH. At the same well, a corn penetration test was carried out under in-situ conditions, however, well logging was not carried out.

The monitoring well was drilled the year before the first offshore production test was carried out. Various types of well logging were performed in the monitoring well during drilling and after completion. Logging while drilling (LWD), Open-Hole Wireline logging (OH-WL) and Cased-Hole Wireline logging (CH-WL) were performed in the AT1-MC well (see Table 2).

The coring in the first offshore production test was performed after these monitoring wells were drilled. We used both a normal coring tool of IODP, and a pressure coring tool. Both tools and related tasks were carried out in the MH reservoir section.

The acquisitioned core was subjected to a dynamics examination and a MH resolution examination, and various sediment properties of matter were measured after the density and P wave speed were measured. In order to gain an understanding of the geological properties after the gas production test was carried out, two wells, AT1-LWD1 and LWD2, were drilled, and OH-WL well logging was also carried out.

In the second offshore production test, a total of five wells were drilled comprising two production wells, two monitoring wells, and one prior investigation well. Drilling of the production well was stopped before the top of the production section was reached in the first year, and a reentry was carried out in the next year and drilling of a production section was completed. Therefore, drilling of the production well of the second offshore production test shown in Table 2 and well logging tools are different in each.

By the time the production well drilling took place in 2017, we had planned a large number of OH-WL well logging with LWD well logging, but we reviewed OH-WL well logging because a significant aperture diameter expansion was observed as a result of drilling in LWD. As a result, we did not carry out the saturated rate well logging using the pulse neutron generator of the P3 well. At the time mine abandonment work of the second offshore production test was carried out, AT1-CW1 and AT1-CW2 were drilled in order to ascertain formation properties. In AT1-CW1 and AT1-CW2, we carried out OH-WL well logging and implemented pressure coring using an improved pressure coring tool.

IV.3.1.2 Characteristics of MH Reservoir from Well Logging and Core Data

(1) Lithofacies Distribution

The wells that penetrated the MHCZ with LWD were AT1-MC, LWD1, LWD2, and MT2, UD. Of these, the three wells that enforced ratio resistance well logging and nuclear magnetic resonance well logging, and where the density was measured from pulse neutrons and saturated rate well logging, were AT1-MC, MT2, and UD. These three wells are located in the up dip in the order of MC, MT2, UD. In addition, in the CW1 and CW2 wells, well logging by OH-WL was carried out below the lower limit of the domain of the MH stability zone. Information about the formation continuity of the direction for sedimentation of the turbidite was provided from these wells (Fig. 1).

In wells AT1-MC, MT2, and UD, the lithofacies profile of the depth direction made it clear that it was possible to make comparisons using natural gamma rays in terms of a volume of less than 3ms of nuclear magnetic resonance well logging (Fig. 2). In addition, it was confirmed by natural gamma rays that wells AT1-MC, MT2, UD had good formation continuity. We can compare the CW2 well with the AT1-CW1 well equally in a depth profile (Fig. 3). From these well logging results gathered from the first and second marine production test locations, we were able to recognize the continuity of the formation and ascertain that there were few lithofacies changes.

We redivided the unit division that was built based on lithofacies information provided by research into wells drilled during phase 2 of the first and second offshore production tests because we recognized the lower part of Unit III leading to the thin sand mud layer (Unit IV). As a result, we revised the border depth of Unit III and Unit IV and associated it with lithofacies. From the result of drilling in the up dip location, we discovered that the thick sand of the lower part of the MH reservoir continued to the thick sand under the lower limit of the MH stable zone. We defined the section of thick sand again as Unit V and distinguished it from thin sand mud layers (Unit IV) that are the section of the upper part of the MH reservoir (Fig. 4).

(2) Resistivity of Wells and MH Saturation

We knew from the results of well logging and core analysis that the distribution of the MH saturation rate is heterogeneous at the location. The resistivity of well logging results made a big difference at each well (Fig.5). The section where low resistivity continued locally in the MH reservoir, was observed conspicuously in wells, MT2, UD, P2, and so on (low ratio resistance section: Low Resistivity Interval; LRI). It was confirmed that there was a sand layer in this low ratio resistance section, and the analysis of the core sample showed that the MH saturation rate was not regulated only by a lithofacies. Because the low MH saturation sand layer that has such low resistivity becomes the water production layer at the time of decompression, we need to pay more attention.

IV.3.1.3 Summary of MH Reservoir

From the thawing and re-freezing of MH through past changes in sea levels, it is thought that the characteristics of the MH reservoir of the Second Atsumi Knoll that were carried out during the first and second offshore production tests have become complicated.

The water production layer obstructs decompression, and there is an inherent risk due to its ability to cause sand to appear. The technique that detects a water layer in the MH reservoir is required in order to realize effective gas production without water.

From the viewpoint of natural resource quantities, it is considered that it is important that MH exists in the good sand layer with a high saturation rate, however, it is important for the initial water existence effect penetration rate that pressure that spreads during gas production due to decompression in the production well is not too low. From the production test results of the first and second tests, it was discovered that the sand layer with low MH saturation rates appears to contribute to gas production, and has the opposite nature to that which exists when there is a water layer. It will be necessary to note this as a result of a decision made by the production section.

Table 1. Well list of Second Atsumi Knoll

Year	Month	The survey names	Purpose	Well name	Drilling section
2011	Feb.～Mar.	The first offshore production test feasibility study	To understand the geological character of the upper section on the reservoir section	ATS, AT1-GT1, AT1-GT2, AT1-GT3	Unit Ⅰ, Unit Ⅱ, Unit Ⅲ
2012	Feb.～Mar.	The first offshore production test prior drilling	Monitoring well, production well drilling	AT1-MC, AT1-MT1, AT1-P	Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ
2012	Jun.～Jul.	The first offshore production test drilling	To understand the reservoir properties	AT1-C	Unit Ⅳ, Unit Ⅴ
2013	Aug.	The first offshore production test abandoned well logging	To understand the reservoir properties	AT1-LWD1, AT1-LWD2	Unit Ⅳ, Unit Ⅴ
2016	May	The second offshore production test prior drilling	Monitoring well, production well drilling	AT1-MT2, AT1-MT3, AT1-P2*, AT1-P3*, AT1-UD	Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ
2017	Apr.	The second offshore production test drilling	Production well drilling, and complation	AT1-P2*, AT1-P3*	Unit Ⅳ, Unit Ⅴ
2018	Mar.～Apr.	The second offshore production test abandoned well drilling	To understand the reservoir properties	AT1-CW1, AT1-CW2	Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ

*In the first year, "the AT1-P2 well" and "the AT1-P3 well" were drilled to above the reservoir section, and in the second year they was drilled to each TD and were completed.

Table 2. Loggings of Second Atsumi Knoll

Year・Month・The survey names・Well name (Logging)				LWD						Wireline Logging											Note
										Cased Hole								Open Hole			
Year	Month	The survey names	Well name	Ganmma Ray	Resistivity	NMR*	Density	MH Saturation**	Sonic	Ganmma Ray	Resistivity	NMR*	Density	MH Saturation**	Sonic	Dipmeter survey etc.	Formation Pressure	Ganmma Ray	MH Saturation**	Resistivility	
2012	Feb.～Mar.	The first offshore production test prior drilling	AT1-MC	○	○	○	○	○		○	○	○		○	○	○	○	○	○	○	Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ
			AT1-MT1	○	○																Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ
			AT1-P	○	○											○					We acquired data in some production section
2013	Aug.	The first offshore production test abandoned well logging	AT1-LWD1	○	○				○	○		○				○					Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ (In WL, we acquired data in some sections)
			AT1-LWD2	○	○				○	○		○				○					Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ (In WL, we acquired data in some sections)
2016	May	The second offshore production test prior drilling	AT1-UD	○	○	○	○	○	○	○											Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ
			AT1-MT2	○	○	○	○	○	○	○											Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ
			AT1-MT3	○	○					○											Unit Ⅰ, Unit Ⅱ, Unit Ⅲ, Unit Ⅳ, Unit Ⅴ
			AT1-P2	○	○					○											Unit Ⅱ, Unit Ⅲ and some of Unit Ⅳ
			AT1-P3	○	○					○											Unit Ⅱ, Unit Ⅲ and some of Unit Ⅳ
2017	Apr.	The second offshore production test drilling	AT1-P2	○	○					○		○		○	○	○					Production sections of Unit Ⅳ and Unit Ⅴ
			AT1-P3	○	○					○		○			○	○					Production sections of Unit Ⅳ and Unit Ⅴ
2018	Mar.～Apr.	The second offshore production test abandoned well drilling	AT1-CW1							○	○	○	○		○	○					Unit Ⅳ, Unit Ⅴ
			AT1-CW2							○	○	○	○		○	○					Unit Ⅳ, Unit Ⅴ

*NMR : nuclear magnetic resonance, **MH Saturation : well logging using the pulse neutron generator

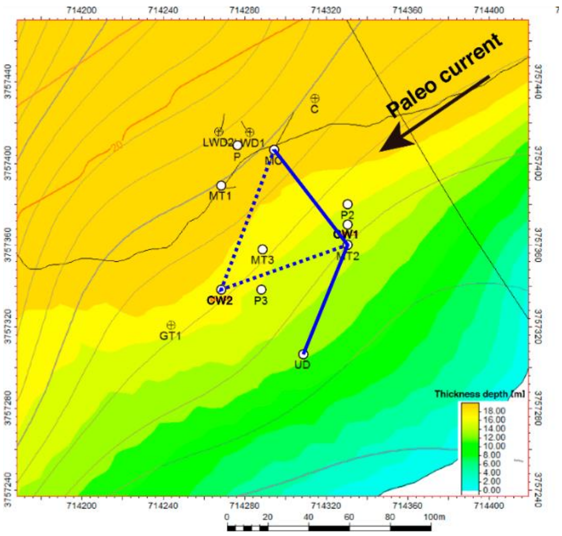

Fig. 1.　Main well location in Phase 3

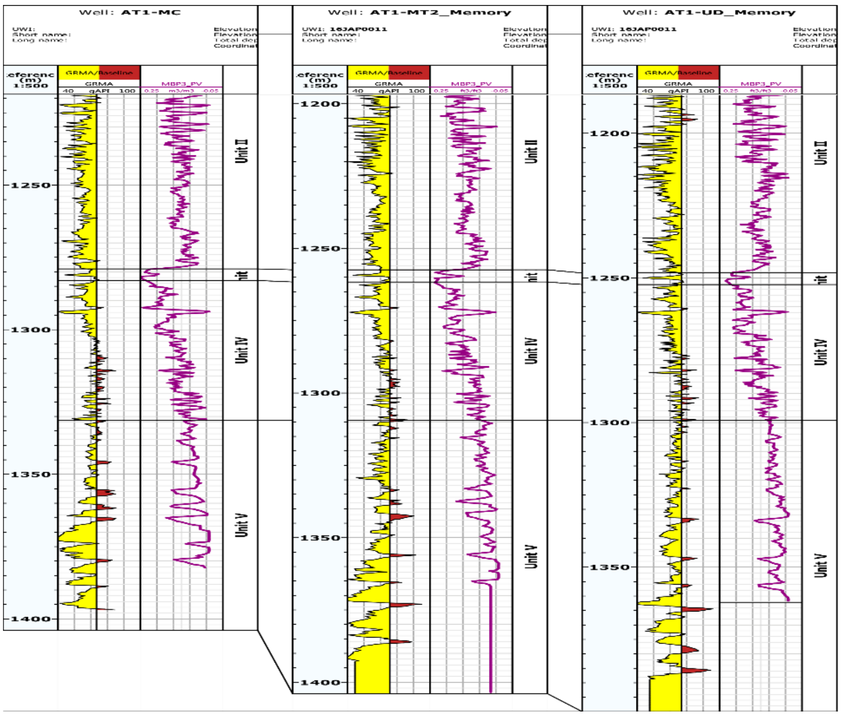

Fig. 2.　Well log correlation of AT1－MC, MT2, UD (Gamma Ray and NMR(less than 3ms))

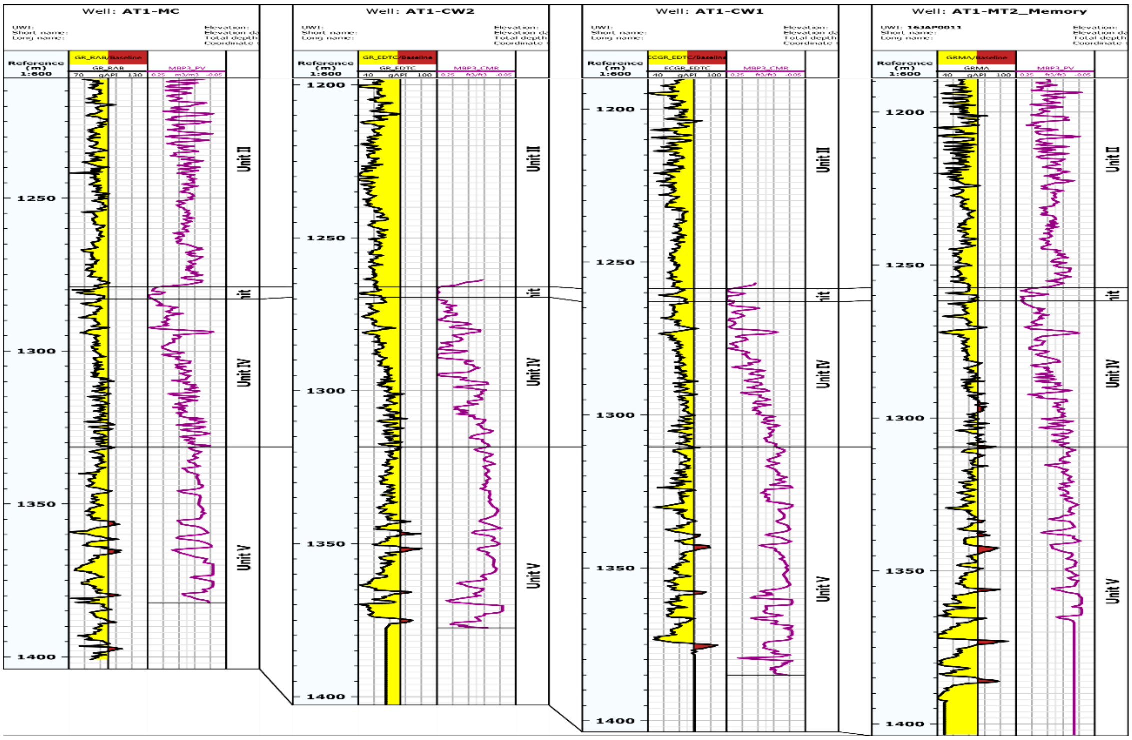

Fig. 3. Well log correlation of AT1－MC, CW1, CW2, MT2 (Gamma Ray and NMR(less than 3ms))

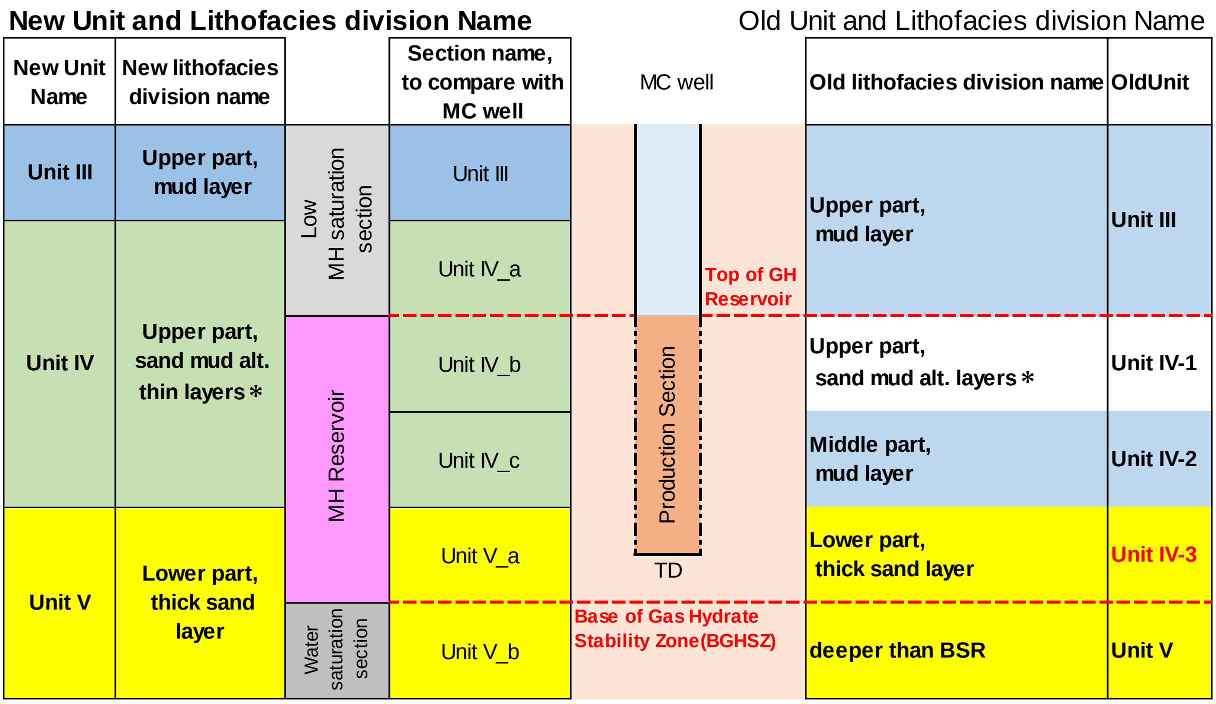

Fig. 4. New unit vs old unit of lithofacies

The new unit division sorts it in lithofacies based on findings. The low MH saturation sand layer as the water bearing layer in the lower old Unit III and old Unit IV-3 were sandwiched. So, we changed "the mud layers" to "sand mud alternated layers".

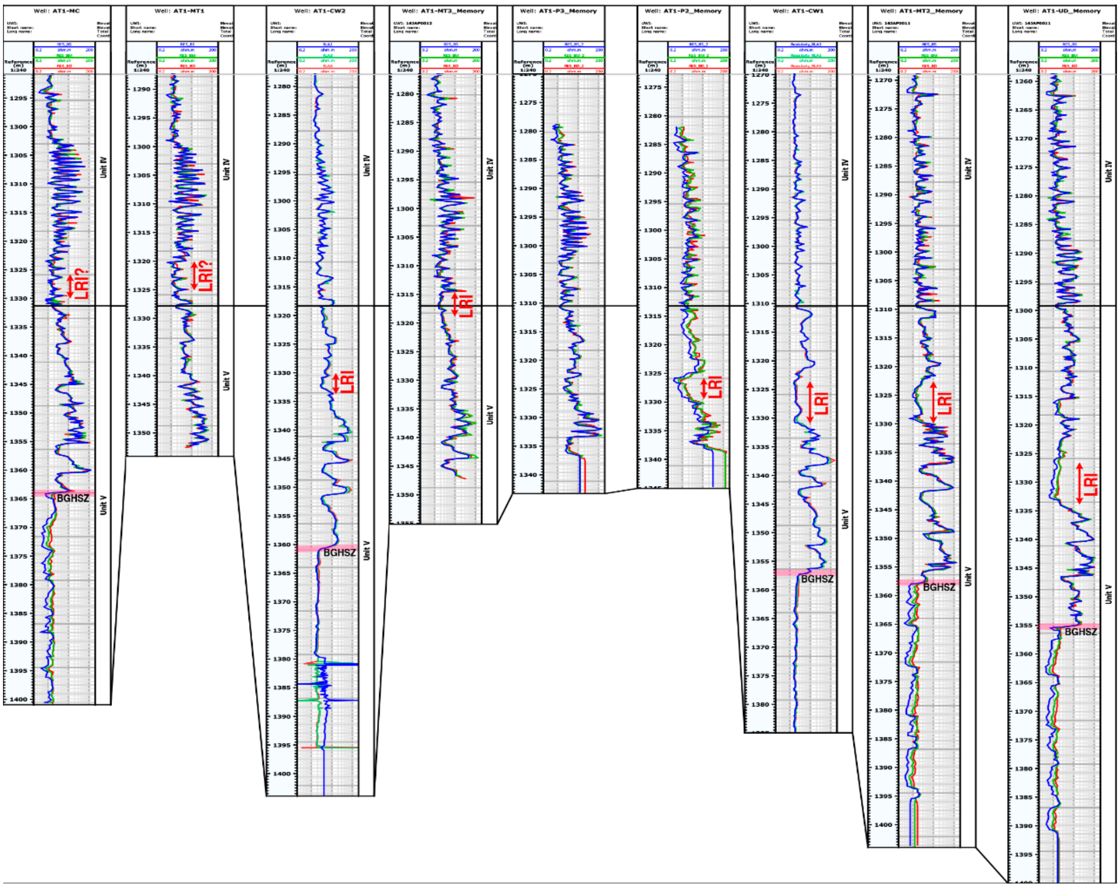

Fig. 5. A resistivity well logging result of each well. Even if we can compare the same horizon, the resistivity levels are different. LRI: Low Resistivity Interval, BGHSZ: Base Gas Hydrate Stability Zone.

IV.3.2 Gas/water Production and Gas Production Behaviors Interpreted from Monitoring Data

(1) Introduction

To evaluate the commercial value of MH, the main objectives of the two offshore production tests carried out in the Eastern Nankai Trough (2013 and 2017) were to identify how much gas and water can be extracted from a MH reservoir, and how MH dissociation regions were advanced temporally and spatially.

In past onshore tests (Mallik 2002, the Northwest Territories, Canada, Mallik 2007-2008, the Northwest Territories, Canada, Ignik Sikumi 2012, Alaska, U.S.), distribute acoustic sensor (DTS) and other devices were installed in boreholes to measure pressure and temperature changes, as well as to measure gas and water flow rates. Based on such experience, attempts were made to integrate monitoring data from producer wells and monitoring boreholes during the offshore production tests. Fig. 1 shows the configuration of boreholes in the two offshore tests.

(2) First Offshore Production Test

Fig. 2 shows the bottom-hole pressure and temperatures, and rates of produced gas and water measured during the first offshore test (2013). For this test, two monitoring holes (AT1-MT1; 20m from the producer hole, and AT1-MC, 30m from the producer hole) were drilled and DTS cable was installed into each hole. Measuring details are described in IV 2-5. Measuring continued after the test for more than 100 days and provided information about temperature recovery (Fig. 3).

During the first test, approximately 9 MPa of drawdown (from 13.5 MPa to 4.5 MPa in bottom hole flowing pressure) was achieved and lead to the realization of almost stable gas and water flow (20,000 m^3/day of gas and 200 m^3/day of water). The gas-to-water ratio (GWR) was approximately 100, which was almost half the theoretical value. This shows that approximately the same volume of original formation water was produced with gas hydrate dissociated water.

The following points were interpreted from the temperature data:

- Almost stable gas and water flow was realized with a gas-to-water ratio of approximately 100, however, no obvious increase in gas rate was observed. In the later stage, a slight increase in drawdown did not lead to an improved gas rate; rather a reduction in the GWR.
- In the producer hole, a temperature drop was observed in the sections of the upper thin-bed sand/silt alternation (0-20mBTMHCZ) and lower thick sand layer (30mBTMHCZ) as shown in Fig. 3. The temperature drop in the upper zone was also detected not only in the closer AT1-MT1 well, but also at the more distant AT1-MC. On the other hand, no temperature drop was measured in the lower zone.
- At the 20 mBTMHCZ of the AT1-MT1 well, a temperature drop was observed at the same time as drawdown began, however, the reduction trend slowed fairly soon after. This event could not be explained by dissociation of MH, and may indicate an influx of cooler formation water.
- At the same depth (20m BTMHCZ), anomalously strong water influx to the producer hole was interpreted by a detailed temperature analysis (Fig. 5).
- Moreover, this depth is interpreted as being the interval where sand production occurred. The temperature recovery trend for the depth also differed from that of the other interval.

An inferred situation in the reservoir used in the production test and related observations was summarized in Fig. 6. It seems that the gas/water production behavior and sand production were strongly affected by the anomalous water producing interval.

(3) Second Offshore Production Test (2017)

Fig. 7 shows the bottom-hole pressure and rates of produced gas and water measured in two producer boreholes (AT1-MT3 and AT1-MT2) of the second offshore test (2013). In spite of sand production events, 12 days of approximately 7MPa drawdown were realized in the AT1-P3 well, although no increase in gas rate was observed, and a slight decrease in gas and a slight increase in water rates were observed. Furthermore, although a relatively large drawdown occurred, the measured gas rate was 3,000-4,000 m^3/day, which was significantly smaller than the value from the 2013 test (AT1-P well). The water rate was approximately 80 ㎥/day, and GWR was 40-50.

The achieved stable drawdown in the AT1-P2 well was limited to approximately 5 MPa due to the excess water rate to be handled by the installed pump, however, the measured gas rate reached approximately 10,000 ㎥/day. The water rate exceeded 300 ㎥/day, and GWR was as low as 20-30. Under the situation, frequent flow assurance issues by MH re-association occurred, however, data sets of production behavior with different degrees of drawdown (3 and 5 MPa) were obtained.

No increase in gas rate was observed in either of the drawdown cases. When the degree of drawdown was increased, the gas rate was increased at once but decreased over time to approximately 10,000 ㎥/day. After the planned disconnection on the 21st day, no stable rates were achieved.

From the monitoring data, the following were observed.

- From the temperature and fluid density computed from pressure gradient (Fig. 8), the main gas production interval of AT1-P3 was interpreted as the deep section (40m or deeper below top of Unit-IVb). The upper thin-bed section, which was the main gas production zone in other wells, did not contribute to gas production. This might be caused by different reservoir characters (MH saturation, permeability, etc.) or any other reason that prevented propagation of depressurized conditions from the borehole to the reservoir.
- Meanwhile, the bottom part of the upper section seemed to be the main gas production zone in AT1-P2, and water was produced from the lower zone and the top of the upper zone.
- The temperature and pressure data shown in Fig. 9 indicated a MH dissociation-induced temperature drop, however, some sensors detected pressure recovery (lower sensor of AT1-MT2 during AT1-P2 production).
- By comparing data from producers and monitoring boreholes (Fig. 10), strong correspondence among wells were seen.

It should be noted that the production behavior of the early stage of AT1-P2 may have been influenced by the activation fluid, DE-acetate, or the sand control device (GeoFORM™).

(4) Summary

The data obtained from three boreholes highlighted a variety of production behaviors although the wells were drilled within a small area (within a circle with 50 m radius). The common observations were no increase in gas rate over time and degree of drawdown, and a decrease of GWR over time. The reasons for these observations should be considered critical knowledge to be utilized to improve productivity of MH reservoirs, and subsequently, further investigations are necessary.

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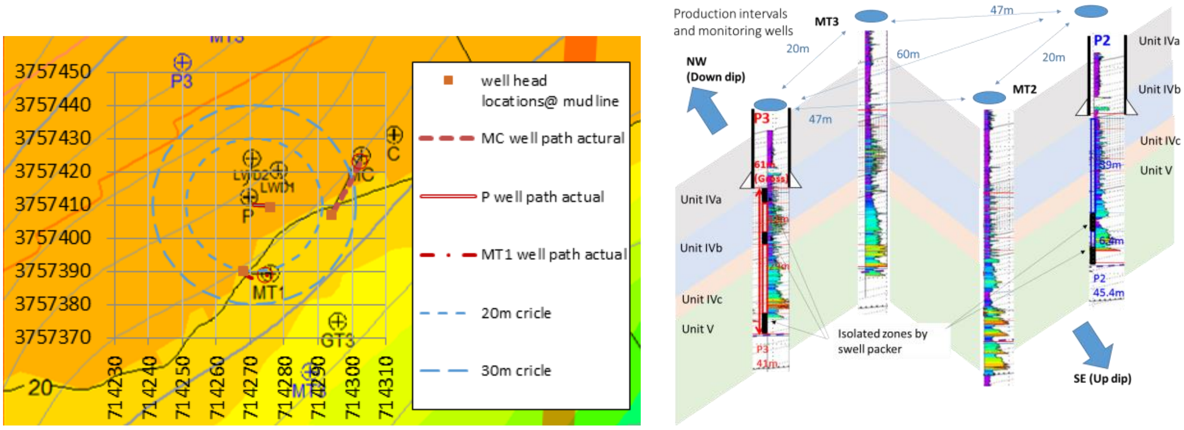


Fig. 1 Borehole configuration of first (left) and second (right) offshore production tests. In first test, some well inclination was observed, and projected well trajectories were drawn using red lines. As a result, production well was drilled in downdip direction. For second test, monitoring and producer boreholes were intentionally drilled at vertex points of a parallelogram to distinguish MH dissociation-induced temperature drop and influx of cool fluid.

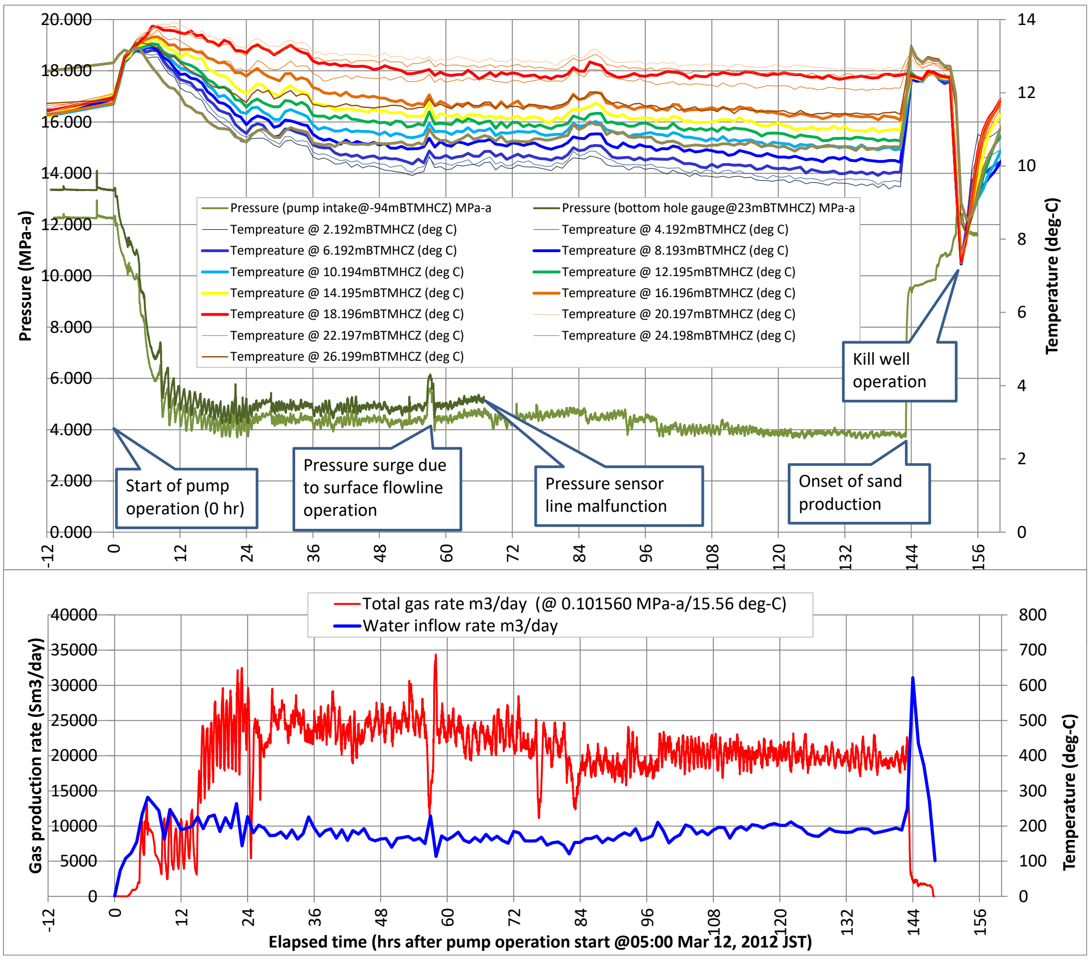


Fig. 2 Bottom-hole pressure and temperature, and gas and water rates of first production test (2013). Reference depth is top of MH concentrated zone (TMHCZ). Temperature data were taken by installed DTS. Pressure measurement at bottom of hole was interrupted by lost data communication, and pressure at ESP intake was added. Water production rate is converted to influx from reservoir to borehole by subtracting water displacement from wellbore to surface.

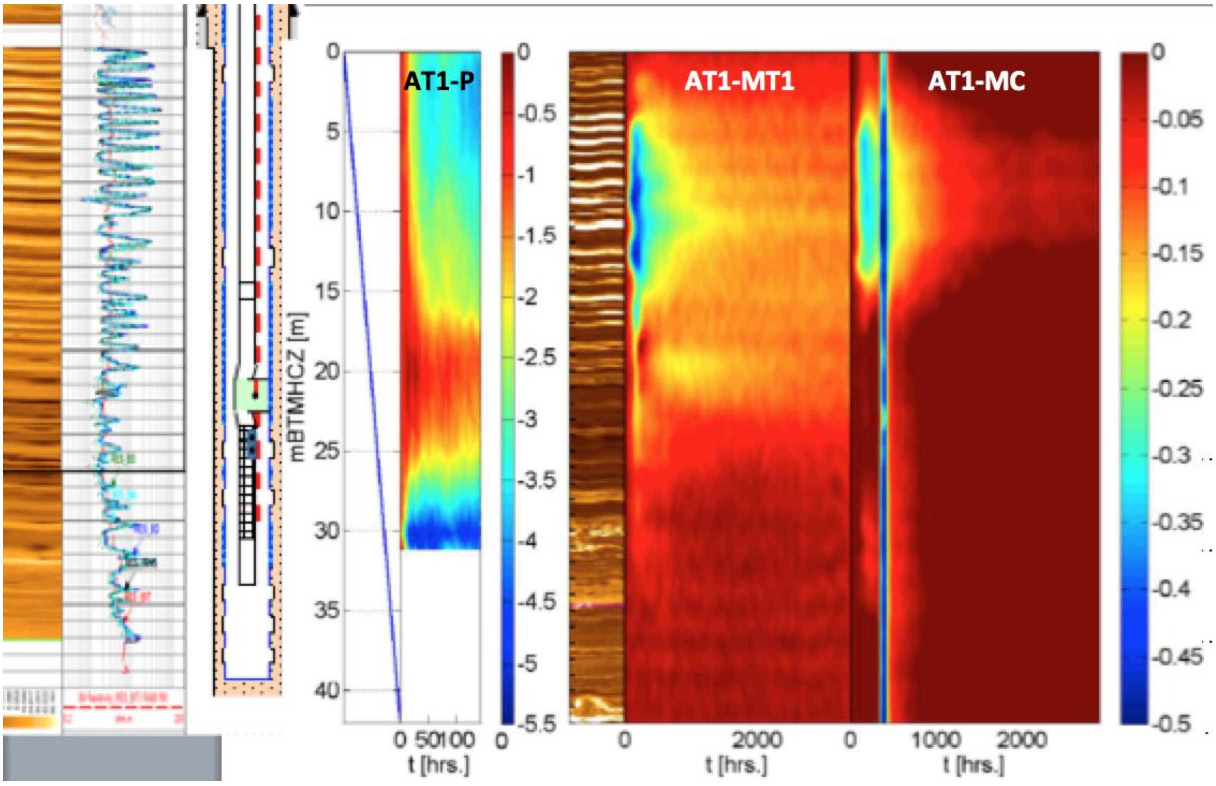


Fig. 3 Comparison of temperature drop data of producer (AT1-P), and monitoring wells (AT1-MT1 and MC). Monitoring well data also indicated temperature recovery term after test. AT1-MC well data was interfered with by circulation of water and running of logging tool after production test.

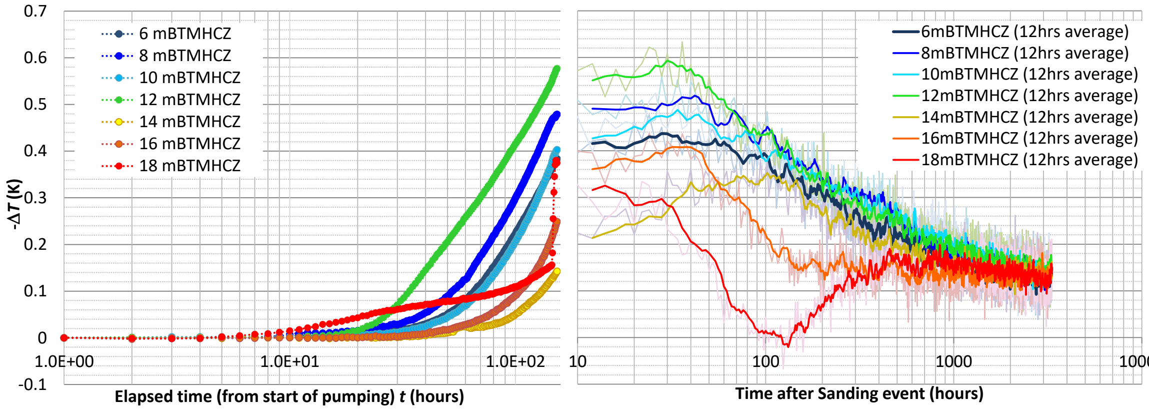


Fig. 4 Detailed temporal change of AT1-MT1 well during flow test (left) and recovery process (right). Data at 20 mBTMHCZ shows different trend flow from others and may indicate influx of low temperature formation fluid from up-dip direction. (Monitoring hole was drilled in up-dip direction of producer hole.)

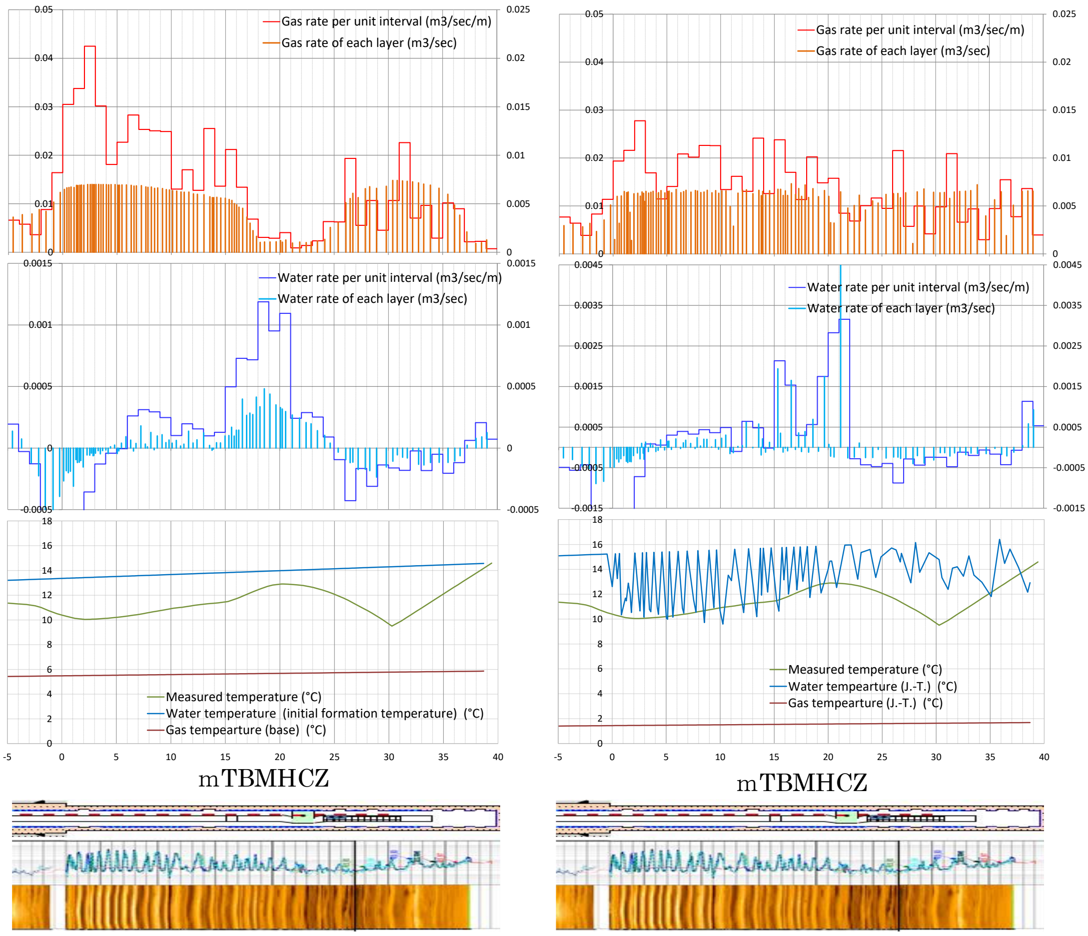


Fig. 5 Vertical gas and water production profiles calculated under assumption that produced gas was of MH dissociation origin then cool, but water was mixture of original formation water with MH dissociation origin, so slightly warm (Yamamoto et al., 2017). Image at left assumes that water temperature is original formation temperature, and image at right assumes that water temperature depends on MH saturation, and that both water and gas temperature are under influence of Joule-Thomoson effect. In both cases, strong water flux is expected around 20 mBTMHCZ.

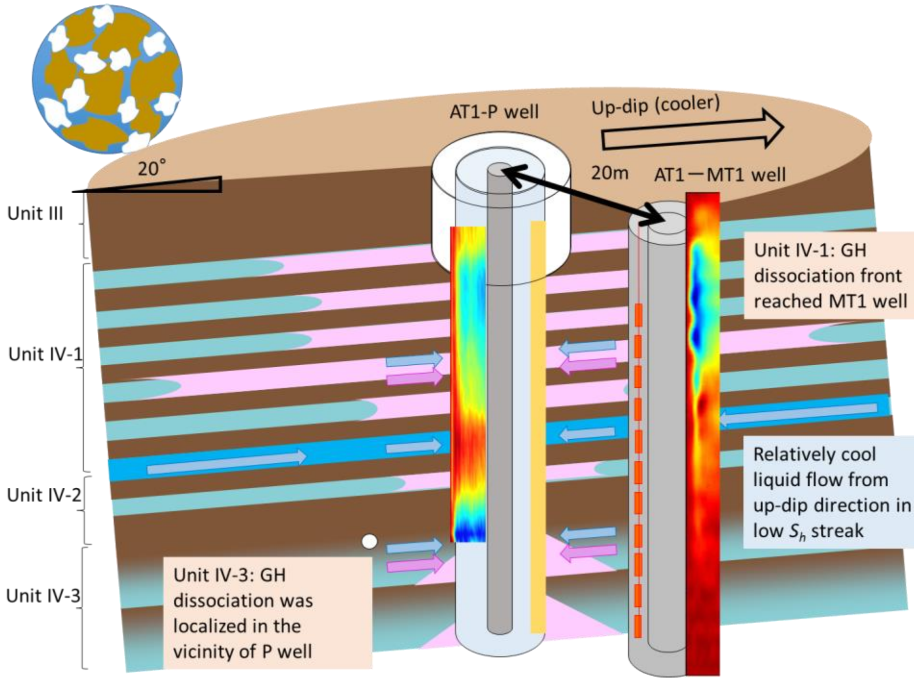
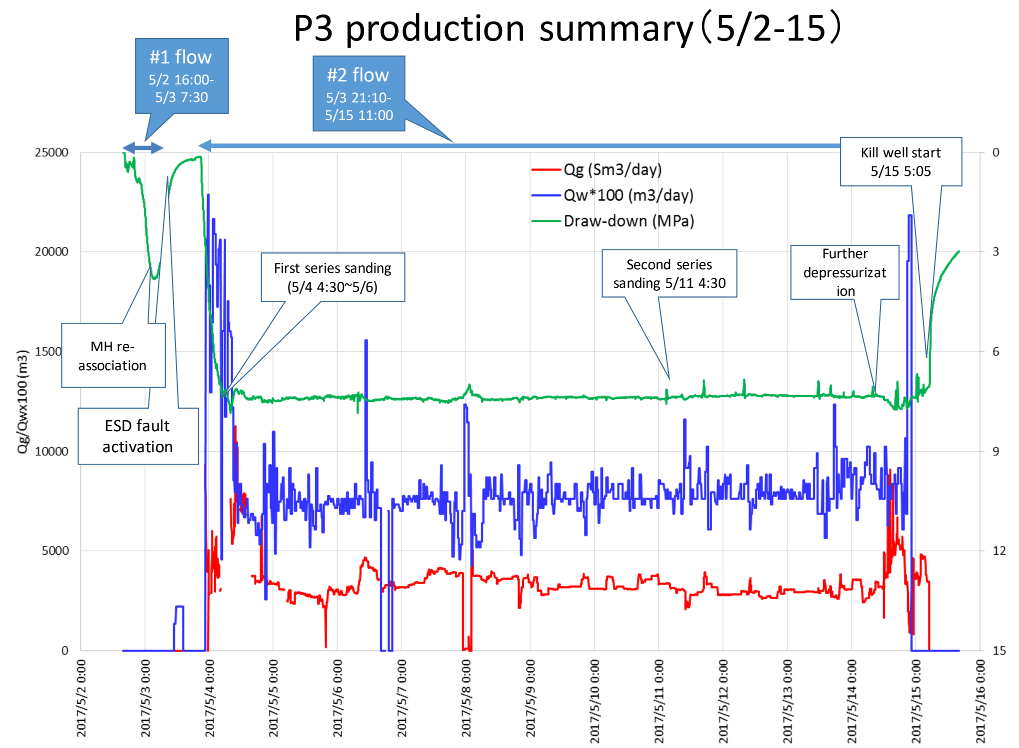


Fig. 6 Inferred phenomenological scheme of fluid motion and MH dissociation during first production test. Middle water bearing zone must be source of water and sand. Advance of MH dissociation front was fast in the upper zone.



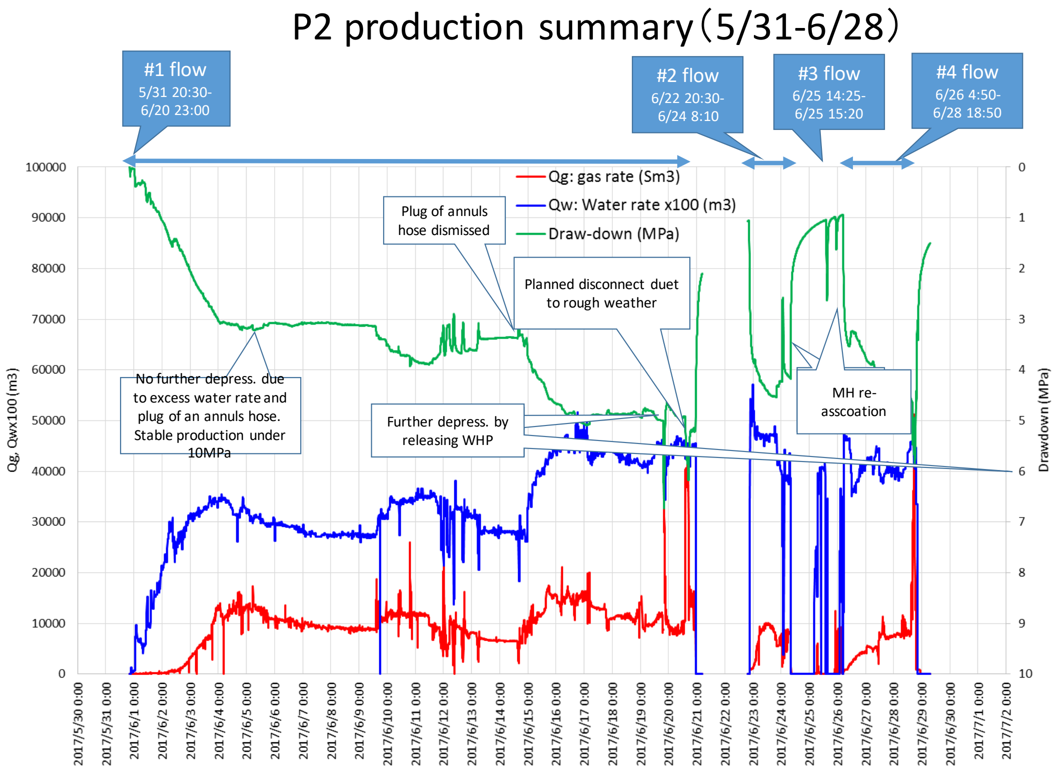


Fig. 7 Bottom-hole pressure, and gas and water rates of second production test (2017).

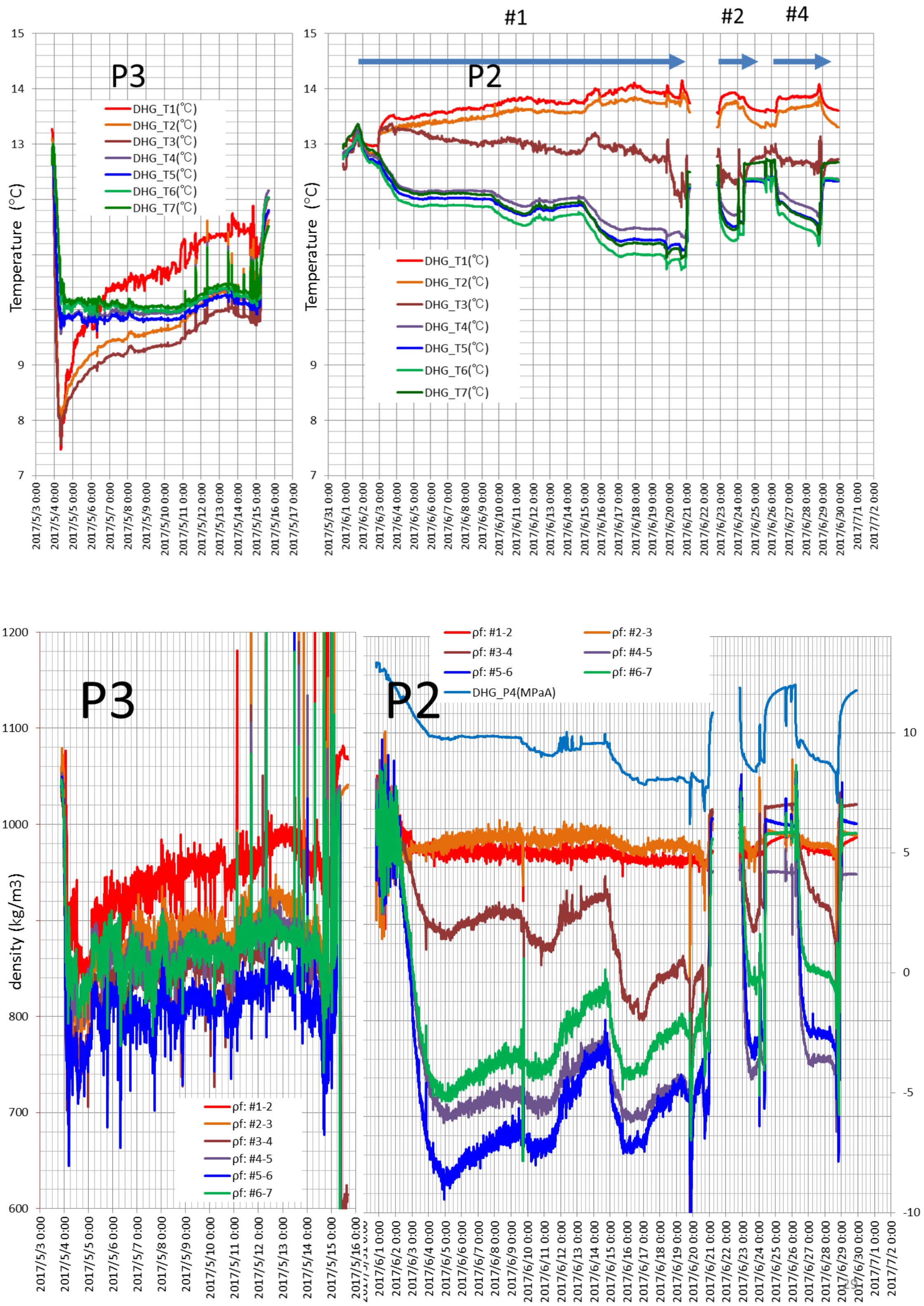


Fig. 8 Temperature and fluid density measured in production wells of second production test.

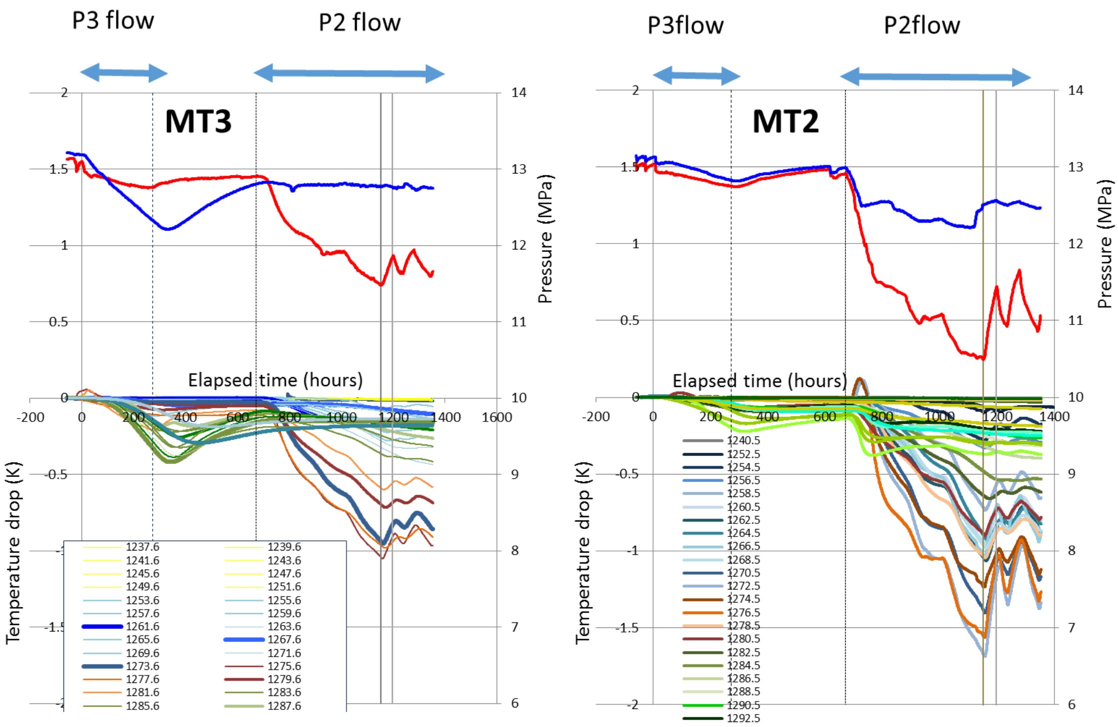
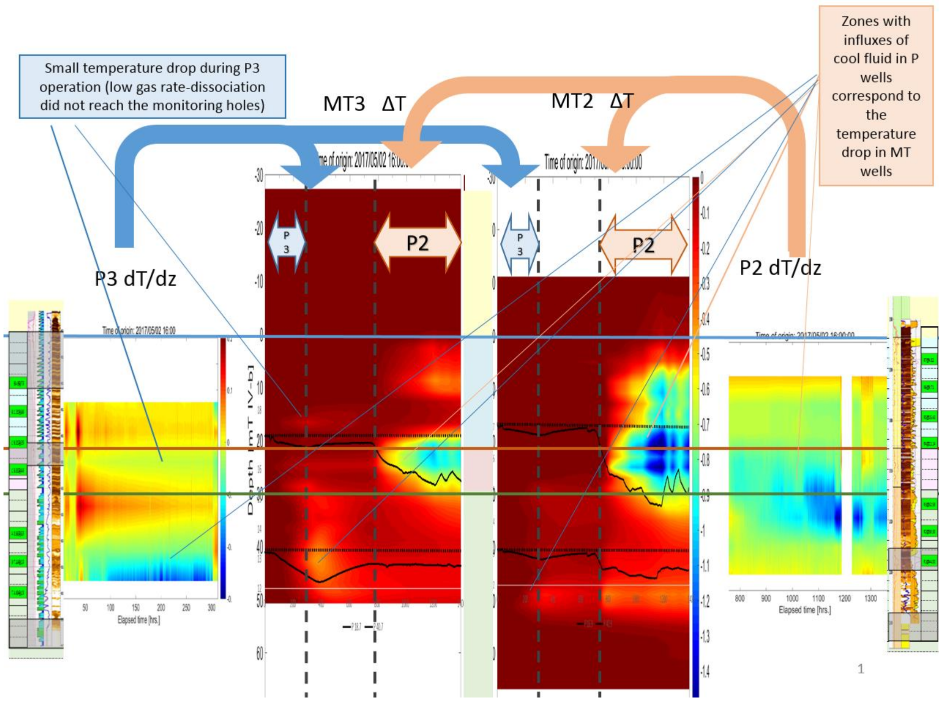
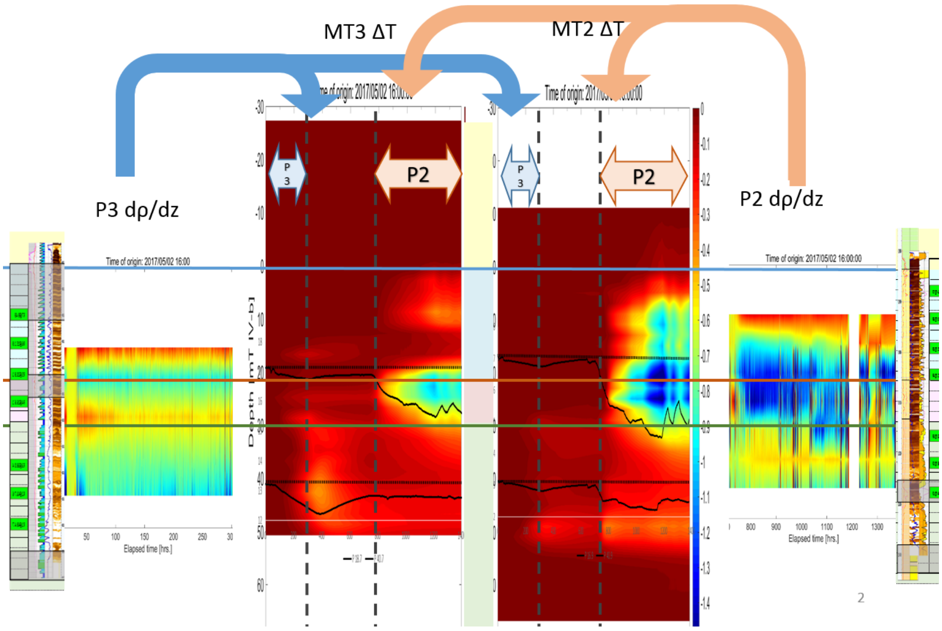


Fig. 9 Pressure and temperature data taken in monitoring boreholes of second production test. Depth is below mean sea level.



(1) Temperature gradient in P wells and temperature drop in MT wells



(2) Density gradient in P wells and temperature drop in MT wells

Fig. 10 Pressure and temperature data taken during second offshore production test. Negative temperature and pressure gradients indicate that something cool and low density flowed in, thus gas was produced. Such sections correspond to temperature drop zone in MT wells.

IV.3.3 Sample Analysis

At the time of the first and second offshore production tests, a sampling of production gas and production water was carried out. Many kinds of sample analysis were performed. Here, we will show some analysis results of production gas and production water when the first and second offshore production tests were carried out.

The following figures are: “Change in chloride ion concentration of production water during first offshore production test”, “Change in chloride ion concentration of production of P2 wells water during second offshore production test” and “Change in chloride ion concentration of production of P3 wells water during second offshore production test”.

IV.3.3.1 Summary of Production Gas Analysis

The production gas analysis was carried out to determine the composition of the gas and carbon isotope in order to determine the origin of the gas. The sample assayed O2, N2, CO2 and the hydrocarbon (CH4-C6H14) using a gas chromatograph at the Japan Petroleum Exploration Co., Ltd.(“JAPEX”) Research Center. The apparatus we used were a specific thermal conductivity type detector (TCD), and a flame ionization detector (FID) in GC 7,890A Valve System produced by Agilent Company. In addition, regarding the ingredient that separated into methane, ethane, propane, isobutane, and normal butane, each ingredient of carbon dioxide was analyzed using a gas chromatograph combustion i.w. analyzer (GC-C-IRMS). We analyzed the gas carbon isotope composition that was IsoPrime-GC) produced by GV Instruments Company (Table 1). Measurement accuracy is +-0.2 ‰ degree.

IV.3.3.2 Summary of Production Water Analysis

We acquired measurements of drawn production water during the production test, and the analysis of various elements and ions was accomplished for the purpose of handling this appropriately (Table 7). The analysis was carried out in the laboratory of the deep drilling ship “Chikyu” managed by Marine Work Japan (MWJ) Co., Ltd. In addition, we analyzed the production water that was refrigerated on land. As a result of these analyses, important information about the MH reservoir of the second Atsumi Knoll, including the chloride ion concentration abnormality of the crack water, was provided.

References

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Table 1. Production Gas Measuring Equipment Specifications

Equipment		Agilent, GC 7890A Valve System	
Detector		Thermal conductivity type detector(TCD)	
		Flame ionization detector(FID)	
Separation column	**TCD (O_2, N_2, CO_2, Separation)**	Column 1	HaySepQ 80/100 Mesh 0.5mm×1/8
		Column 2	HaySepQ 80/100 Mesh 6ft×1/8
		Column 3	Hmolecular Sive5A 60/80 Mesh 6ft×1/8
	FID (CH_4－C_5HI_4, Separation)	Column 4	HP-AL/S 25mm×0.32mm×8μm
Column flow quantity		Column 1	20 mi/min
		Column 2	25 mi/min
		Column 3	25 mi/min
		Column 4	1.8359 mi/min
Open temperature program		60˚C(2 min Hold), 60~80˚C(15˚C/min), 80~190˚C(20˚C/min), 190˚C(3min Hold9	
Data processor		Agilent ChemStation	

Table 2. First Offshore Production Test, Production Gas Composition Analysis

Sample number	Gas composition analysis value(vol.%)											Wetness
	O_2	N_2	C_1	C_2	C_3	i-C_4	n-C_4	i-C_5	n-C_5	n-C_6	CO_2	(%)
GT#9	5.54	24.16	70.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00
GT#24	8.01	31.94	60.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00
GT#27	9.10	37.16	53.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00
GT#31	20.52	79.22	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00
GT#36-a	0.31	2.14	97.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00
WT#11	11.07	42.88	46.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00
WT#24	11.10	43.47	45.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00
WT#27	15.68	60.86	23.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00
WT#31	20.72	79.02	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00
WT#36	0.38	1.99	97.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00
Wetness=(C_2+C_3+i-C_4+n-C_4)/(C_1+C_2+C_3+i-C_4+n-C_4)×100												

Table 3. First Offshore Production Test, Production Gas Carbon Isotope Analysis

Sample number	δ ^{13}C(‰)					
	C_1	C_2	C_3	i-C_4	n-C_4	CO_2
GT#9	-67.40					-6.70
GT#24	-67.60					-11.90
GT#27	-63.90					-12.20
GT#31	-66.80					-12.50
GT#36-a	-63.40					-4.10
WT#11	-62.20					-15.50
WT#24	-69.50					-5.60
WT#27	-68.10					-9.20
WT#31	-64.30					-11.50
WT#36	-67.20					-3.10

Table 4. Second Offshore Production Test, Production Gas Composition Analysis (On Board)

Sample ID		Sample 5	Sample 7	Sample 15	Sample 20	Sample 27
Date		2017/5/5	2017/5/6	2017/5/8	2017/5/11	2017/5/14
Time		18:15	5:00	17:00	5:00	17:00
GC-TCD	N2 (%)	0.4	1.1	-	-	-
	O_2+Ar (%)	0	0.22	-	-	-
GC-FID	Methane (%)	100.74	100.62	99.53	99.78	100.7

Table 5. Second Offshore Production Test, Production Gas Composition Analysis

Sample of P2 Well		Gas composition analysis value(vol.%)											Wetness	$C_1/(C_2+C_3)$	$i\text{-}C_4/n\text{-}C_4$	Gas specific gravity	Calculation heat capacity
Date	Time	O_2	N_2	C_1	C_2	C_3	$i\text{-}C_4$	$n\text{-}C_4$	$i\text{-}C_5$	$n\text{-}C_5$	$n\text{-}C_6$	CO_2	(%)				(MJ/m^3)
2017/6/4	5:30	0.08	0.66	99.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			0.56	39.6
2017/6/4	17:00	0.06	0.46	99.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00			0.56	39.7
2017/6/5	17:00	0.07	0.37	99.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00			0.56	39.7
2017/6/6	17:00	0.06	0.39	99.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00			0.56	39.7
2017/6/7	17:00	0.06	0.36	99.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00			0.56	39.8
2017/6/8	17:00	0.02	0.35	99.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00			0.56	39.8
2017/6/9	17:00	0.06	0.40	99.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00			0.56	39.7
2017/6/10	17:00	0.07	0.49	99.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00			0.56	39.7
2017/6/11	17:00	0.08	0.58	99.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00			0.56	39.7
2017/6/12	17:00	0.08	0.44	99.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.00			0.56	39.7
2017/6/13	17:00	0.08	0.50	99.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00			0.56	39.7
2017/6/14	17:00	0.07	0.50	99.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00			0.56	39.7
2017/6/15	17:00	0.06	0.60	99.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00			0.56	39.7
2017/6/16	17:00	0.05	0.66	99.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00			0.56	39.6
2017/6/17	17:00	0.04	0.69	99.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00			0.56	39.6
2017/6/18	17:00	0.05	0.67	99.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00			0.56	39.6
2017/6/19	17:00	0.06	0.79	99.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00			0.56	39.6
2017/6/20	17:00	0.08	0.74	99.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00			0.56	39.6
2017/6/23	17:00	0.05	0.52	99.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00			0.56	39.7
2017/6/26	17:00	0.05	0.46	99.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.00			0.56	39.7
2017/6/27	17:00	0.07	0.66	99.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00			0.56	39.6

Wetness=$(C_2+C_3+i\text{-}C_4+n\text{-}C_4)/(C_1+C_2+C_3+i\text{-}C_4+n\text{-}C_4)\times100$

Sample of P3 Well		Gas composition analysis value(vol.%)											Wetness	$C_1/(C_2+C_3)$	$i\text{-}C_4/n\text{-}C_4$	Gas specific gravity	Calculation heat capacity
Date	Time	O_2	N_2	C_1	C_2	C_3	$i\text{-}C_4$	$n\text{-}C_4$	$i\text{-}C_5$	$n\text{-}C_5$	$n\text{-}C_6$	CO_2	(%)				(MJ/m^3)
2017/5/4	2:40	0.19	0.51	99.25	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.01	6704		0.56	39.6
2017/5/5	1:00	0.11	0.38	99.46	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.02	5871		0.56	39.7
2017/5/5	18:15	0.04	0.39	99.54	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	9237		0.56	39.8
2017/5/6	5:05	0.15	0.56	99.25	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	7602		0.56	39.6
2017/5/6	17:00	0.06	0.39	99.51	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	13176	1.09	0.56	39.8
2017/5/7	17:00	0.04	0.35	99.58	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	19314	0.89	0.56	39.8
2017/5/8	17:00	0.06	0.42	99.48	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	9794	0.95	0.56	39.7
2017/5/9	17:00	0.07	0.41	99.49	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	19421	0.82	0.56	39.7
2017/5/10	17:00	0.08	0.38	99.50	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	21005	0.86	0.56	39.7
2017/5/11	17:00	0.04	0.33	99.60	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	8805	0.97	0.56	39.8
2017/5/12	17:00	0.07	0.38	99.51	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	9195	0.83	0.56	39.8
2017/5/13	17:00	0.03	0.37	99.59	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	10207	0.95	0.56	39.8
2017/5/14	5:00	0.07	0.36	99.53	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	11476	0.93	0.56	39.8
2017/5/14	17:00	0.09	0.40	99.47	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	8447	0.84	0.56	39.7
2017/5/15	2:00	0.07	0.40	99.49	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	8086	0.92	0.56	39.7

Wetness=$(C_2+C_3+i\text{-}C_4+n\text{-}C_4)/(C_1+C_2+C_3+i\text{-}C_4+n\text{-}C_4)\times100$

＊Bottle No.9～28：C3, i-C4, n-C4; 0.001%以下

Table 6. Second Offshore Production Test, Production Gas Carbon Isotope Analysis

Sample of P2 Well		$\delta^{13}C$(‰)					
Date	Time	C_1	C_2	C_3	i-C_4	n-C_4	CO_2
2017/6/4	5:30	-67.4					
2017/6/4	17:00	-68.4					-11.7
2017/6/5	17:00	-69.2					-3.8
2017/6/6	17:00	-68.0					-1.4
2017/6/7	17:00	-69.0					-3.2
2017/6/8	17:00	-67.7					-17.0
2017/6/9	17:00	-67.3					-6.2
2017/6/10	17:00	-69.1					-4.0
2017/6/11	17:00	-69.6					-0.3
2017/6/12	17:00	-68.8					-0.2
2017/6/13	17:00	-62.9					-4.3
2017/6/14	17:00	-68.1					-3.6
2017/6/15	17:00	-69.3					2.5
2017/6/16	17:00	-68.5					0.9
2017/6/17	17:00	-69.5					-4.7
2017/6/18	17:00	-68.1					-1.7
2017/6/19	17:00	-67.8					1.0
2017/6/20	17:00	-69.1					-4.1
2017/6/23	17:00	-68.7					-9.1
2017/6/26	17:00	-69.1					0.7
2017/6/27	17:00	-68.1					

Sample of P3 Well		δ13C(‰)					
Date	Time	C_1	C_2	C_3	i-C_4	n-C_4	CO_2
2017/5/4	2:40	-69.3	-42.1				-13.8
2017/5/5	1:00	-67.2	-41.3				-7.5
2017/5/5	18:15	-66.8	-42.4				-11.5
2017/5/6	5:05	-59.8	-27.3				8.8
2017/5/6	17:00	-66.6	-27.4				14.3
2017/5/7	17:00	-65.0	-31.1				12.4
2017/5/8	17:00	-57.5	-43.8				-1.1
2017/5/9	17:00	-67.0	-42.4				-1.6
2017/5/10	17:00	-66.5	-38.6				1.8
2017/5/11	17:00	-66.8	-43.0				0.6
2017/5/12	17:00	-66.6	-43.3				-0.2
2017/5/13	17:00	-65.6	-44.0				
2017/5/14	5:00	-66.3	-43.6				-0.2
2017/5/14	17:00	-66.7	-43.5				-4.4
2017/5/15	2:00	-65.8	-43.7				-3.5

Table 7. Analytical Instrument We Used In Production Water Analysis and Analysis Item

Analytical instrument	Analysis item
Quality of the water multi-sensor	water temperature, dissolved O2, turbidity
Digital camera	photography
Conductivity meter	conductivity
Specific gravity meter	Specific gravity
pH meter	pH
Titrator	COD_{Mn} Cl^-
Refractive index meter	refractive index
Discrete analyzer（DA）	PO_4^{3-}, NH_4^+, SiO_4^{4-}
Ion chromatograph - anion（IC-Anion）	NO_2^-, NO_3^-, Br^-, SO_4^{2-}
Ion chromatograph - cation（IC-Cation）	Na^+, K^+, Mg^{2+}, Ca^{2+}
Inductively coupled plasma mass spectrometry （ICP-MS）	V, Cr, Cu, Zn, As, Rb, Mo, Cd, Cs, Hg, Pb, U
Inductively coupled plasma atomic emission spectroscopy （ICP-AES）	Li, B, Si, Mn, Fe, Sr, Ba
Gas chromatograph-thermal conductivity detector（GC-TCD）	N_2, O_2

Table 8. First Offshore Production Test, Production Water Analysis (On Board)

sample name	The collection date and time		pH	EC	concentration (mg/L)									
				(mS/cm)	Na^+	K^+	Ca^{2+}	Mg^{2+}	Li^-	Sr	MH_4^+	Fe	Al	Si
Gas Train Water sample No.6	2013/3/13	0:00	7.85	43.9	11500	355	225	755	0.13	5.4	145	2.0	ND	15.0
Gas Train Water sample No.7	2013/3/13	7:00	7.90	43.6	11600	358	211	723	0.14	5.5	156	2.8	ND	16.1
Gas Train Water sample No.8	2013/3/14	0:00	8.00	44.0	11700	361	187	732	0.14	5.8	177	ND	ND	16.1
Gas Train Water sample No.9	2013/3/14	19:00	8.01	44.1	11700	364	179	730	0.14	6.2	174	ND	ND	16.2
Gas Train Water sample No.10	2013/3/15	1:00	8.06	44.3	11700	367	179	731	0.15	6.5	180	ND	ND	15.9
Gas Train Water sample No.11	2013/3/15	0:00	8.24	44.0	11700	363	171	731	0.14	6.1	180	ND	ND	15.1

sample name	The collection date and time		concentration (mg/L)										isotopic composition (‰)	
			B	Cl^-	Br^-	I^-	SO_4^{2-}	HCO_3^-	CO_3^{2-}	TDS	DOC		δD	$\delta^{18}O$
Gas Train Water sample No.6	2013/3/13	0:00	4.8	20100	85.1	43.1	350.0	804	2.3	36730	82		-19	2.0
Gas Train Water sample No.7	2013/3/13	7:00	4.6	20300	85.6	45.1	240.0	832	2.4	36790	85		-11	-0.3
Gas Train Water sample No.8	2013/3/14	0:00	4.4	20600	88.8	44.8	94.0	848	3.1	37880	59		-9	2.0
Gas Train Water sample No.9	2013/3/14	19:00	4.3	20600	90.0	45.7	52.0	896	3.3	37350	49		-14	-0.3
Gas Train Water sample No.10	2013/3/15	1:00	4.3	20700	90.5	45.2	45.0	839	3.9	38330	61		-13	0.5
Gas Train Water sample No.11	2013/3/15	0:00	4.3	20700	93.2	45.2	22.0	851	5.0	37760	53		-9	0.8

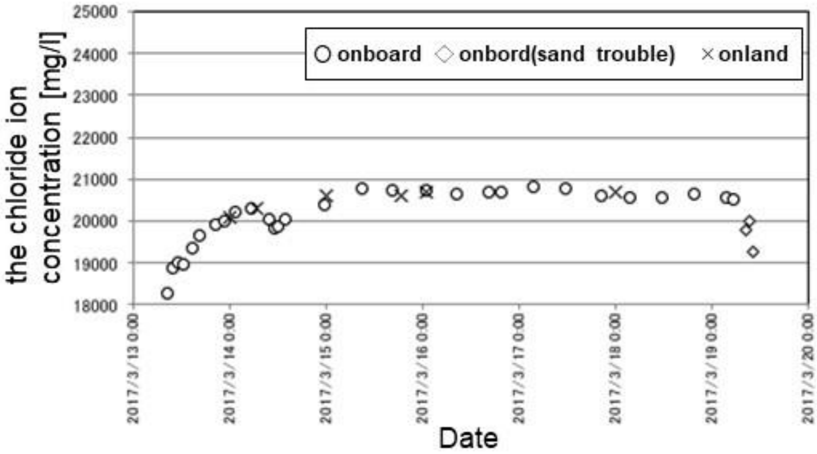

Fig. 1. Change in chloride ion concentration of production water of first offshore production test

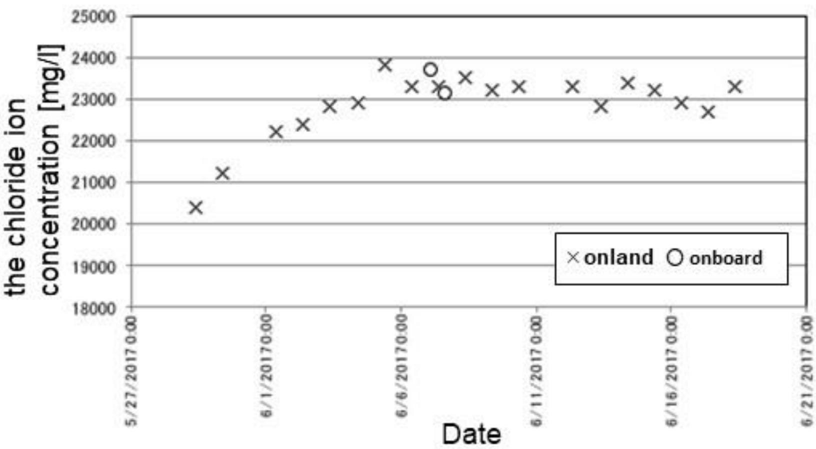

Fig. 2. Change in chloride ion concentration of production of P2 wells water of second offshore production test

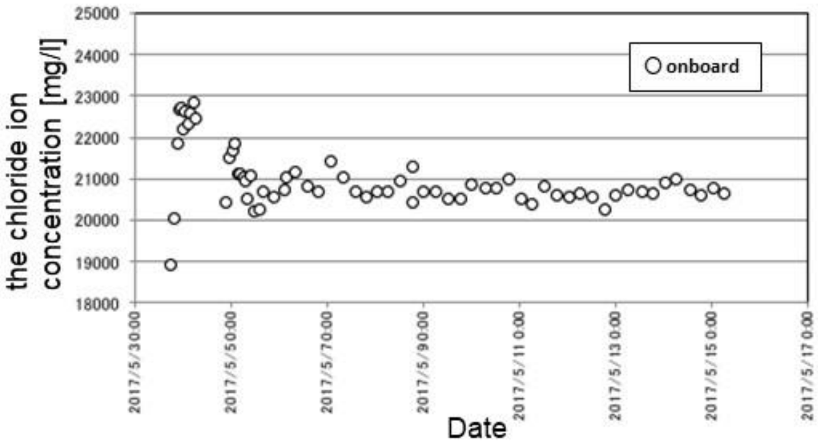

Fig. 3. Change in chloride ion concentration of production of P3 wells water of second offshore production test

IV.4 Major Findings from the Two Offshore Production Tests

The offshore production tests conducted in Phase 2 and 3 had two major objectives. One was a technical objective to realize the depressurized condition for a certain duration in a deepwater well. The other was to gain an understanding of reservoir responses to depressurized conditions. This section presents major achievements, findings, and remaining issues.

(1) Technical Issues

According to the fact that a total 36 days of depressurization was conducted during the second test, technologies that can realize a few months of continuous depressurization operations are supposed to be ready.

① Stability and Sustainability of the Operation

Both tests (the first test in 2013 and the second test in 2017) were conducted using D/V Chikyu, a Dynamic Positioning System (DPS) vessel. Because the production system using a drilling riser system and blow-out preventer (BOP) during the first test could allow a relatively small operation circle (r<14m), and due to the fact that we experienced difficulty reconnecting after the emergency disconnect sequence (EDS) was activated, an improved system featuring a workover riser was designed and implemented. The implemented system enabled a larger operation circle (r<30m) that drastically reduced the probability of EDS and capacity for reconnection. As a result, a total of 36 days of flow duration with borehole switching (from AT1-P3 to AT1-P2) and a planned disconnect operation were carried out, and a few months of continuous production was carried out during calm weather between April and June.

However, if it becomes necessary to ensure a flow over a period of several months, and in particular, if operations are required to be carried out during the typhoon season, the vessel should be moored. In such a case, mooring techniques considering subsea soil condition and interference with existing subsea communication cables should be employed.

② Sand Control System

Severe sand problems were encountered during the first test and the first well (AT1-P3) of the second test. However, despite high water and gas production rates, AT1-P2 well operation was completed without sand being produced. Moreover, it is believed to be likely that the AT1-P3 problem was not caused by a malfunction of the sand control device itself but by another element of the borehole taking into account various data and indications. Therefore, the sand control system used during the second test in 2017 was fully functional.

On the other hand, experience gained from two sand production events revealed the fact that MH bearing sediments are easily slurified after dissociation and tend to flow continuously into any weak point of the system. From another viewpoint, it is speculated that the relatively poor productivity of the AT1-P3 well may be influenced by the sand control device (a large pressure drop across the device may occur), and it is necessary to clarify the situation and improve the system.

③ Downhole Device Design

The downhole system employed during the second test effectively worked, although some unexpected situations such as sand production occurred. The degree of the drawdown in AT1-P2 did not reach the target, however, the main reason behind the failure was not a system design problem but inappropriate prediction of the water rate. The gas/water separation problem that occurred in the AT-P well (2013) was solved in the AT1-P3 well in which water and gas production rates were within the assumed basis of design. The problem occurred again in the AT1-P2 well, however, the main reason was also the excess water rate.

The AT1-P2 well operation encountered several instances of flow assurance problems due to MH re-association in the flow line, and this was a direct consequence of the insufficient degree of drawdown (pressure in the low temperature zone around the sea floor was kept within the boundaries of the hydrate stability conditions).

Such flow assurance issues and how to design the production device based on the prediction of production rates with low certainty will be remaining issues, and continuous studies are necessary.

④ Other Achievements and Remaining Issues

Well construction operations in shallow sections below deepwater, including casing and cementing of the boreholes, were successfully carried out without zonal isolation problems occurring (water influx from seafloor, leakage of produced gas to the seafloor, etc.).

Meanwhile, boreholes drilled during the first test had higher deviation angles than planned, which made it difficult to align production and monitoring boreholes. The problem was solved during the second test (2017) by using a rotary steerable drilling system by which vertical boreholes were drilled, however, a hole enlargement problem was surfaced. The enlarged hole might affect the isolation of water-bearing zones. The design of the production hole followed the safety standard for conventional petroleum wells, however, by considering the low pressure nature of gas hydrate operations, the design could be simplified, and there should be a room to reduce costs.

Several technical issues of the on-board production systems surfaced during the operation such as handling of the flare burner and the surface production system in combination with ship control, precision and reliability of production rate measurement, precise control of flow rate and pressure, continuation of the operating under unexpected conditions such as sand production, etc., however, these issues were mitigated through ship-board discussion and by improving devices and/or operations. This experience must be utilized in order to improve system design in the future.

The produced water from AT1-P and AT1-P3 could be disposed of at sea in accordance with the Water Pollution Controlling Act, however, water from AT1-P2 that was contained MH inhibitor and GeoFORM activation fluid was transported to shore for treatment. In the latter case, cost of water treatment may become an issue.

During the production test, the laboratory facility on the D/V Chikyu was effectively utilized to quickly analyze produced water and sand, and such analyses contributed to the continuation of the operation.

(2) Reservoir Responses

The gas production rate from each well was almost stable. In particular, the 24 day-long operation of the AT1-P2 well could produce data/information about reservoir responses to different degrees of drawdown from producer and monitoring boreholes. Such data are quite valuable in terms of improving reliability of predictions of long-term gas production. On the other hand, there were some discrepancies between model-predicted behaviors and reality. Some significant discrepancies are listed below:

① Different Production Behavior between Wells

It was discovered that there is a large variation in production behavior (gas and water rates to the degree of drawdown, and their vertical profiles) between three producer wells. There are three possible causes for this:

a. Differences in reservoir characteristics

Those wells are drilled within a 50 m radius and the geological and sedimentological settings are similar, however, a certain degree of hydrate concentration conditions and water bearing zones may exist. Such variety could cause differences in production behaviors.

b. Difference of borehole condition

Three boreholes each had specific sand control devices that could influence production behavior. Their effects on production had been investigated prior to the tests, however, the actual drilling conditions, such as hole enlargement, type of treatment fluid used to set the devices, etc., differed somewhat from the assumption, could change the situation, and may have a negative or positive effect as a result of a pressure drop across the devices or some well stimulation effect caused by chemical fluid used for GeoFORM™ activation.

In particular, the possibility cannot be ruled out that relatively poor production rates from the shallow section of the AT1-P3 well were caused by the sand control device.

c. Different production conditions

Different rates of drawdown (quick drawdown in AT1-P and P3 vs slow drawdown in AT1-P2) may affect the formation around wells differently as a result of mechanical processes.

A combination of the above may be the cause, however, the latter two factors are related to a pressure drop across the near wellbore region (positive or negative skin) and technical resolutions of them can be found. Furthermore, they may provide clues in how to improve productivity.

② Different productivity between reality and model-predicted

The most substantial difference between the model-predicted production behavior and the actual production behavior was the fact that a gradual increase in gas production rates was not observed in any borehole. The possible causes of this can be categorized into reservoir scale, and the near-wellbore phenomenon.

a. Reservoir scale phenomenon

<u>Anisotropy and Heterogeneity of Formations</u>

Numerical simulators cannot fully model the various scales of heterogeneity in an actual reservoir. The elements that are not reflected in the numerical model, such as heterogeneity and anisotropy in geological structure, hydrate occurrence, existence of water-bearing zones, fluid conduit, hydraulic discontinuity, etc., should affect actual production behavior. Each data for reservoir characterization, such as seismic survey, geophysical logging, core samples and in-situ testing, etc., has its own scale and limitation on information. It is necessary to integrate this information in order to interpret the obtained data.

Physical Process and Material Properties

In the case of the MH reservoir, many parameters such as hydraulic (permeability, etc.), thermal (thermal conductivity, etc.) and mechanical parameters (strength and elasticity, etc.) are affected by MH dissociation and pore fluid exchange, and other factors. Some physical theories employed during implementation of the model cannot sufficiently reflect the actual real-word status. Laboratory testing of cores should be combined with field data to improve understanding of physical processes.

Thermodynamic Processes

The monitoring data in the production test highlighted the motion of pressure and temperature conditions along the phase equilibrium curve, which meant a few percent points of MH gas in pore spaces was dissociated. However, comparing the modeling result with 2013 test data suggested that the heat was not sufficiently supplied to the MH around the sensor locations (Yamamoto et al., 2017).

b. Near wellbore situation

As described in ① b., the skin factor (pressure reduction across the near wellbore region due to fine migration, compaction, issues involving sand control devices, non-Darcy flow of gas-liquid mixed phase flow) may develop with time. If these phenomena are the main reason behind the model-reality discrepancy, the situation can be improved by implementing techniques such as hydraulic fracturing, acid treatment, etc.

(3) Conclusion

The two offshore gas production tests carried out in the Eastern Nankai Trough proved that the depressurization operation in a deepwater well and subsequent gas production from the well is possible. Although adequate information was not obtained during the first test (2013) due to a flow that was shortened by sanding, 36 days of flow were realized during the second test (2017) after the design of the systems was improved, and a large amount of data was obtained from producer and monitoring boreholes. This data contributed to understanding the long-term behavior of MH dissociation and gas production.

Meanwhile, the obtained data highlighted discrepancies between the model-predicted reservoir behavior and the actual response, and causes of those discrepancies should be investigated in order to improve reliability of the long-term production prediction and evaluate economics of the production more precisely, and also to clarify further R&D subjects to enable commercial production.

The data obtained in the tests gave us the information about temporal and spatial advances of hydrate dissociation, and we can make the stage of the study from theory and model based deductive one to the reality based inductive one.

The obtained data showed the complexity of real reservoirs and physical processes in the reservoir, and it is important to identify technical issues to be solved through the analyses of those data and to examine relevant countermeasures.

IV. 5 Study of Long-term Onshore Gas Hydrate Production Testing

(1) Introduction

Japan's methane hydrate (MH) resources exist below the deep-sea floor, while MH also exists underneath onshore permafrost in high latitude regions. The onshore MH fields have been utilized effectively for R&D primarily because the physical properties of onshore MH are similar to those of MH below the ocean floor, and easier access to the site makes data acquisition more economical.

The first onshore gas hydrate production test was conducted at the Mallik site, Canada, in 2002. It was the world’s first gas production test from a MH reservoir using the hot water circulation method, and also provided clues that the depressurization method could be more feasible. The second test at the same place in 2007-2008 saw successful continuation of production using the depressurization method, leading to the decision to attempt offshore production tests in Japan. In addition, the CO_2/CH_4 exchange method and subsequent depressurization method were tested at the Prudhoe Bay Unit, Alaska, USA in 2012. This test demonstrated that carbon dioxide could be exchanged in-situ with methane molecules (Schoderbek et al., 2013). In this way, the data and information acquired by these onshore production tests have significantly contributed to the progress of Japan’s MH research and development.

Although it was confirmed that gas can be produced from offshore MH reservoirs by using the depressurization method in production tests in 2013 and 2017 (see IV.1 and IV.2), it is necessary to understand the gas production behavior on an annual basis in order to establish reliable production methods. However, offshore production test facilities should be almost equivalent to permanent facilities in the case of production testing carried out throughout the year in such a severe marine environment as that around Japan, and taking into account the considerable budget that would be required for mid- or long-term production testing offshore.

Considering the above, and in order to proceed with MH R&D efforts in a reasonable and effective manner, the onshore production test is recognized as an effective way to understand the long-term production behavior before conducting mid- or long-term production tests off the coast of Japan.

On the other hand, the United States has also attempted long-term onshore production tests in Alaska (Collett and Boswell, 2009), and Japan and the U.S. have made ongoing efforts to determine a suitable location for long-term production test where existing infrastructure, such as permanent access roads, is available, in order to realize feasible and operable production test.

(2) Contents and Results

a. MOU for collaborations towards long-term production test in Alaska

The Memorandum of Understanding (MOU) for collaborations towards long-term production test in Alaska was signed on November 6, 2014, between JOGMEC and the National Energy Technology Laboratory (NETL), a U.S. Department of Energy (DOE) national laboratory.

Based on this MOU, the study had started to implement testing in a step-by-step manner as part of an international cooperative research and development program involving JOGMEC, NETL and the U.S. Geological Survey (USGS).

- Phase 1: Candidate sites screening and prioritization, preliminary planning of stratigraphic test well (STW), etc.
- Phase 2: Site Selection, overall planning and implementation, etc.
- Phase 3: Long-term production test implementation and data acquisition, etc.
- Phase 4: Post-production test analysis and interpretation, plug and abandonment, etc.

b. Phase 1

Three-dimensional seismic data for the area of set-aside-acreage (designated by State of Alaska) was purchased, analyzed and interpreted, and geological interpretation work was conducted by utilizing 11 log data provided by the USGS and mud log data, in order to identify candidate sites from the broad areas within North Slope. Based on these efforts, candidate sites were selected and prioritized. In addition, preliminary reservoir simulation models of each candidate site, based on available information and assumptions, were developed to forecast gas and water production profiles, and sensitivity analysis was conducted considering uncertainties of candidate sites.

In October 2015, a workshop was organized involving NETL, USGS, JOGMEC and Japan's National Institute of Advanced Industrial Science and Technology (AIST), in order to discuss and agree objectives of production testing, and outline of data items to be acquired.

Attending parties reached a consensus that the objectives of production tests would be to achieve production for as long a period as possible with a target of one year or longer using the depressurization method in order to understand the long-term response of MH reservoir during production. It was also agreed that application of enhanced recovery method(s) at the late stage of production would be included in the implementation plan.

JOGMEC intended to utilize its knowledge and experience obtained through both onshore and offshore production tests as well as vast amounts of studies performed so far, to contribute to the successful implementation of the production test, and continued its efforts in the areas of research and development. Further efforts include studies of sand control, artificial lift, downhole monitoring technology, and well design, to develop fit-for-purpose and feasible production technologies.

After the discussions between the U.S. members and JOGMEC about data acquisition items required to understand reservoir properties and reservoir behavior with MH dissociation, it was decided to begin studies and development of new technologies such as downhole sand detection technology with optical fiber acoustic measurement (Distributed Acoustic Sensing, DAS), Vertical Seismic Profile (VSP) using DAS, and reservoir deformation detection and measurement technology with optical fiber strain measurement (Distributed Strain Sensing, DSS), in addition to conventional logging, coring, downhole temperature and pressure sensing.

c. Phase 2

Kuparuk State 7-11-12 (**Fig. 1**), Prudhoe Bay Unit was selected as a promising candidate site based on the Phase 1 study result, because the existence of MH was confirmed by a near-by well, which meant its geological risk was relatively low, and temperature relatively high, which is suitable for the depressurization method. In addition, the site has an existing gravel pad and permanent access roads, which allow surface activities to be carried out, even during swampy summers. Then the specific target point was determined taking into account the estimated MH distribution and distance to main faults. However, the available log data is insufficient to estimate MH existence and reservoir properties. Therefore, it was decided to drill an exploratory well (STW), and started to develop the implementation plan.

It was presumed that multiple MH sand layers existed below the permafrost around the selected area. The main target would be B sand where the temperature is relatively high (850 mMSL, 8.5 MPa, 10 °C), and D sand would also be considered as a candidate testing reservoir (700 mMSL, 7.0 MPa, 5 °C). The approximate depths are quoted from R. Boswell (2016), the pressures are estimated based on K. A. Lewis et al. (2013) and M. E. Torres et al. (2011), and the temperatures are estimated using the data provided by T. S. Collett, USGS.

After the technical studies and operator selection, etc., the STW was drilled in December 2018. The acquired log data and pressure-retained sidewall cores are being analyzed by both Japan and the U.S.

In case this site is judged to be suitable for long-term production testing, it is planned that an additional two wells, a geo-data well (GDW, for obtaining detailed reservoir information by coring, etc., and downhole sensors are to be deployed) and a production test well (PTW) will be drilled.

It is also planned that the STW and the GDW will be converted to monitoring wells, and that all the three wells would be deviated wells with inclination angles of less than 30°.

JOGMEC is conducting planning work for system development of production testing, with support from Toyo Engineering Corporation (TOYO). This work includes preparing drafts for well completions, carrying out studies of monitoring equipment, sand control equipment, artificial lift considering the deep depressurization method, and combinations of bottomhole equipment in consideration of capabilities to test two sand layers separately and implement optimized workovers. **Fig. 2** shows the assumed wells and the monitoring equipment arrangements.

Investigation of currently available technologies and experiments regarding downhole monitoring equipment are ongoing. Joint research is conducted with the University of California, Barkley for DSS, and some experiments are performed and studied including feasibility study of sand detection utilizing DAS.

A preliminary reservoir simulation model has been developed for the selected testing site in order to determine the appropriate distance between the production well and monitoring wells where reservoir response is likely to be detected within the production test period, and also to forecast gas and water production profiles based on the depressurization method.

In addition the above, DAS-VSP was conducted in March 2019, by utilizing distributed acoustic sensing fiber optic cable as receiver, which was deployed at STW

(3) Conclusion

Based on the MOU concluded between JOGMEC and NETL in November 2014, Japan and the U.S. collaboratively conducted technical studies, candidate sites screening and prioritization, selection of testing site, planning of stratigraphic test well and preparation work for field activities, and then completed stratigraphic test well drilling.

In the case both Japan and the U.S. decide to conduct long-term onshore production test based on the analysis of STW data and related information, a detailed implementation plan would be developed accordingly

The acquired data and outcomes from various efforts to date should be effectively utilized for Japan's MH research and development, including future assessment of MH resources off the coast of Japan, and the development of production methods/ technologies.

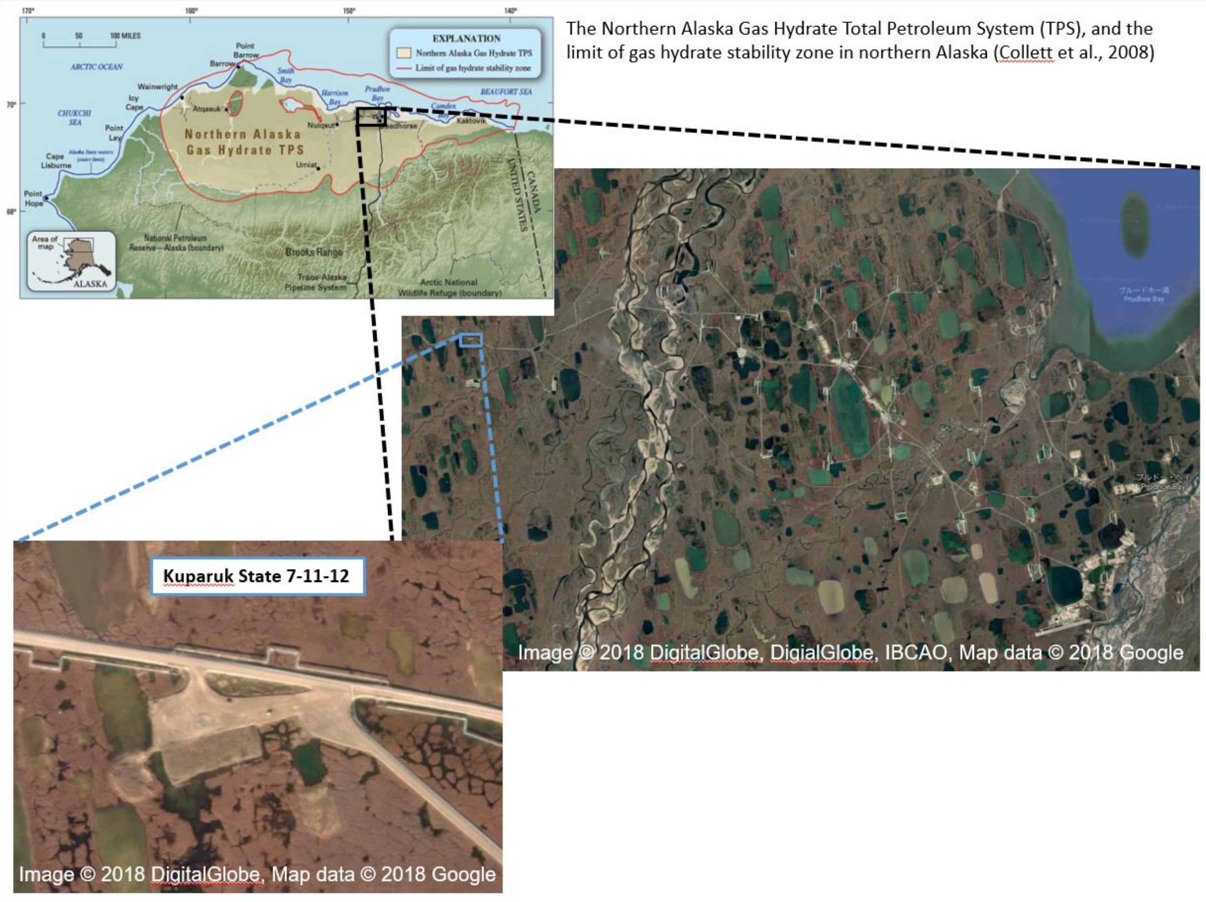

Fig.1: Location of the testing candidate site, Kuparuk State 7-11-12

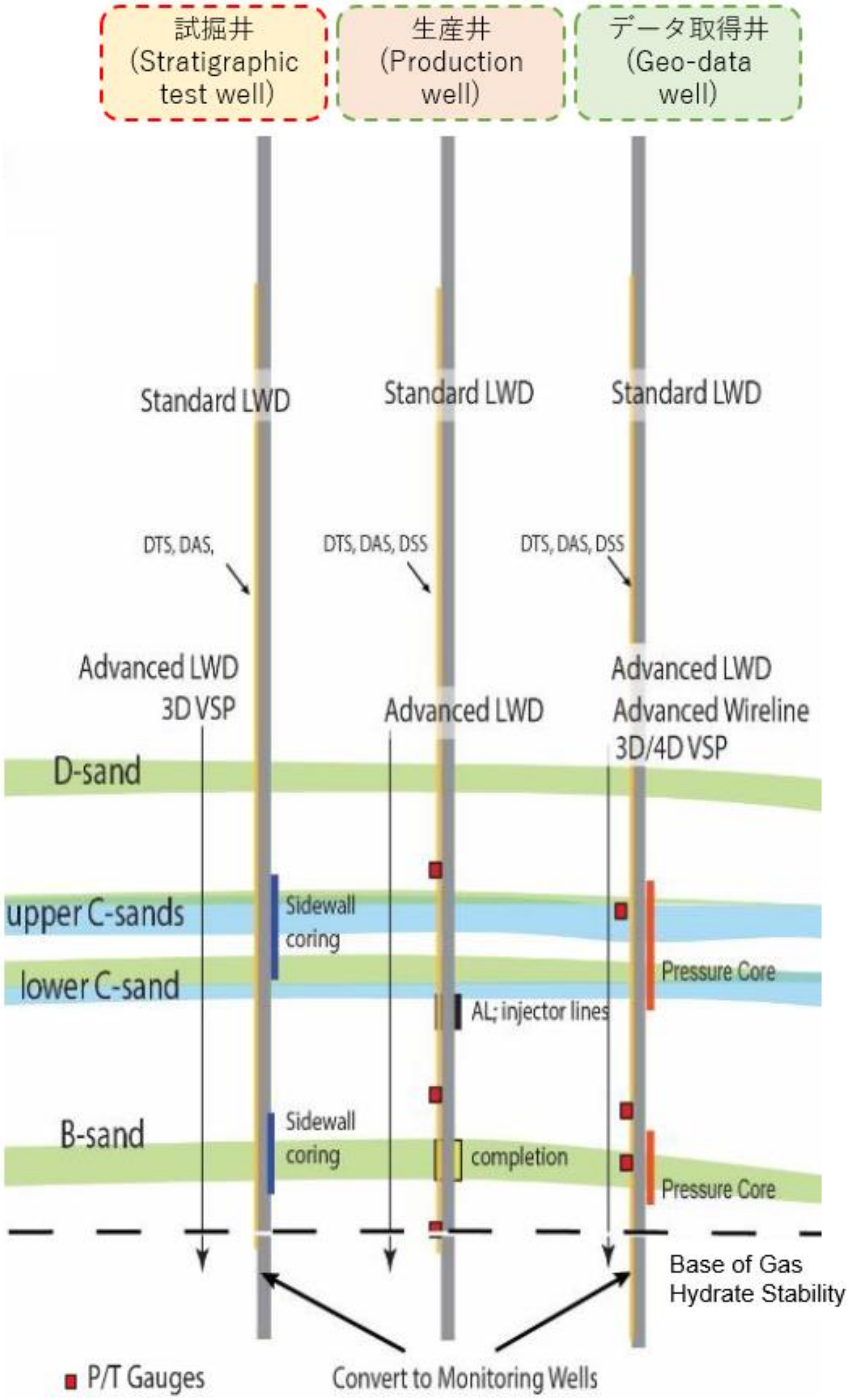

Fig.2: Assumed wells and the monitoring equipment arrangements

(R. Boswell, US DOE Methane hydrate advisory committee meeting, October 18-19, 2018, https://www.energy.gov/sites/prod/files/2018/11/f57/MHAC_Alaska%20Project%20Update%20Final.pdf)

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