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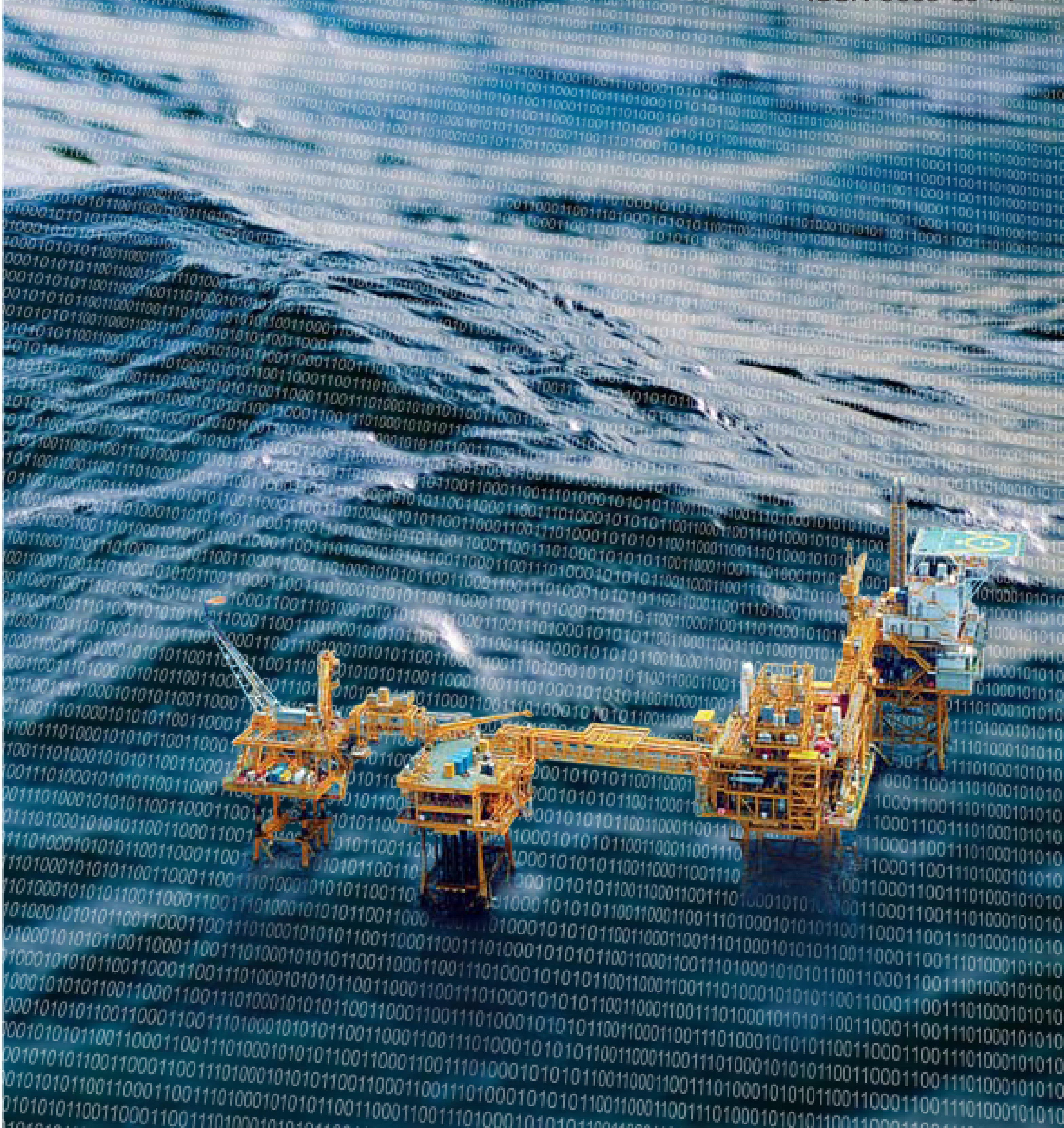

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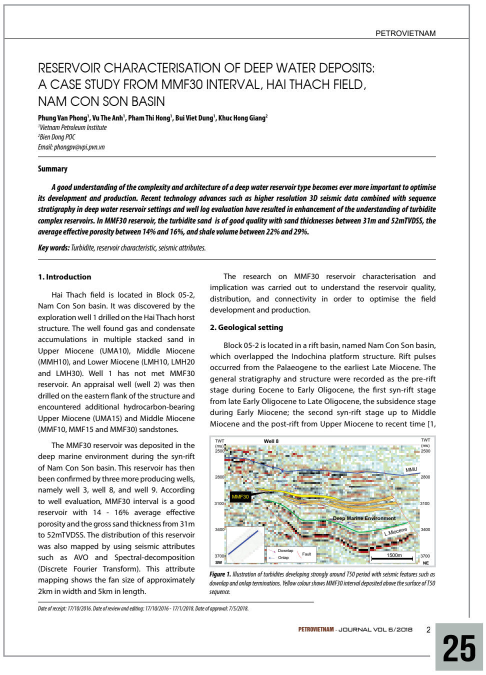
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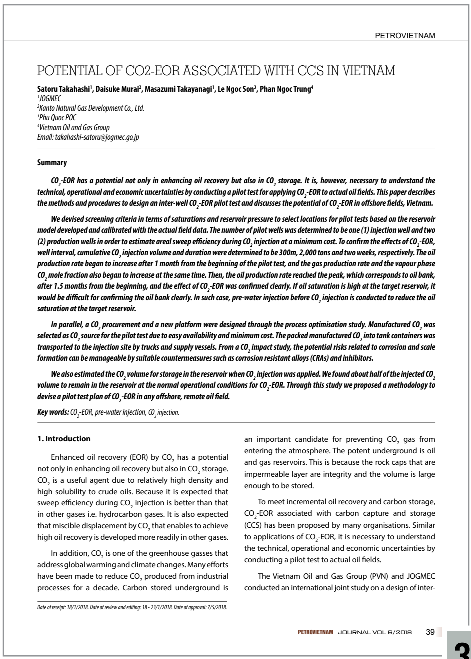
PETROVIETNAM

POTENTIAL OF CO2-EOR ASSOCIATED WITH CCS IN VIETNAM

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Summary

CO_2-EOR has a potential not only in enhancing oil recovery but also in CO_2 storage. It is, however, necessary to understand the technical, operational and economic uncertainties by conducting a pilot test for applying CO_2-EOR to actual oil fields. This paper describes the methods and procedures to design an inter-well CO_2-EOR pilot test and discusses the potential of CO_2-EOR in offshore fields, Vietnam.

We devised screening criteria in terms of saturations and reservoir pressure to select locations for pilot tests based on the reservoir model developed and calibrated with the actual field data. The number of pilot wells was determined to be one (1) injection well and two (2) production wells in order to estimate areal sweep efficiency during CO_2 injection at a minimum cost. To confirm the effects of CO_2-EOR, well interval, cumulative CO_2 injection volume and duration were determined to be 300m, 2,000 tons and two weeks, respectively. The oil production rate began to increase after 1 month from the beginning of the pilot test, and the gas production rate and the vapour phase CO_2 mole fraction also began to increase at the same time. Then, the oil production rate reached the peak, which corresponds to oil bank, after 1.5 months from the beginning, and the effect of CO_2-EOR was confirmed clearly. If oil saturation is high at the target reservoir, it would be difficult for confirming the oil bank clearly. In such case, pre-water injection before CO_2 injection is conducted to reduce the oil saturation at the target reservoir.

In parallel, a CO_2 procurement and a new platform were designed through the process optimisation study. Manufactured CO_2 was selected as CO_2 source for the pilot test due to easy availability and minimum cost. The packed manufactured CO_2 into tank containers was transported to the injection site by trucks and supply vessels. From a CO_2 impact study, the potential risks related to corrosion and scale formation can be manageable by suitable countermeasures such as corrosion resistant alloys (CRAs) and inhibitors.

We also estimated the CO_2 volume for storage in the reservoir when CO_2 injection was applied. We found about half of the injected CO_2 volume to remain in the reservoir at the normal operational conditions for CO_2-EOR. Through this study we proposed a methodology to devise a pilot test plan of CO_2-EOR in any offshore, remote oil field.

Key words: *CO_2-EOR, pre-water injection, CO_2 injection.*

1. Introduction

Enhanced oil recovery (EOR) by CO_2 has a potential not only in enhancing oil recovery but also in CO_2 storage. CO_2 is a useful agent due to relatively high density and high solubility to crude oils. Because it is expected that sweep efficiency during CO_2 injection is better than that in other gases i.e. hydrocarbon gases. It is also expected that miscible displacement by CO_2 that enables to achieve high oil recovery is developed more readily in other gases.

In addition, CO_2 is one of the greenhouse gasses that address global warming and climate changes. Many efforts have been made to reduce CO_2 produced from industrial processes for a decade. Carbon stored underground is an important candidate for preventing CO_2 gas from entering the atmosphere. The potent underground is oil and gas reservoirs. This is because the rock caps that are impermeable layer are integrity and the volume is large enough to be stored.

To meet incremental oil recovery and carbon storage, CO_2-EOR associated with carbon capture and storage (CCS) has been proposed by many organisations. Similar to applications of CO_2-EOR, it is necessary to understand the technical, operational and economic uncertainties by conducting a pilot test to actual oil fields.

The Vietnam Oil and Gas Group (PVN) and JOGMEC conducted an international joint study on a design of inter-

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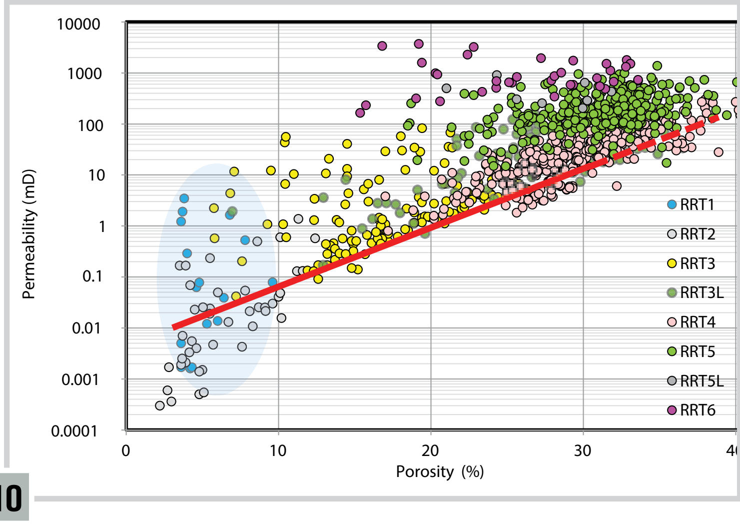

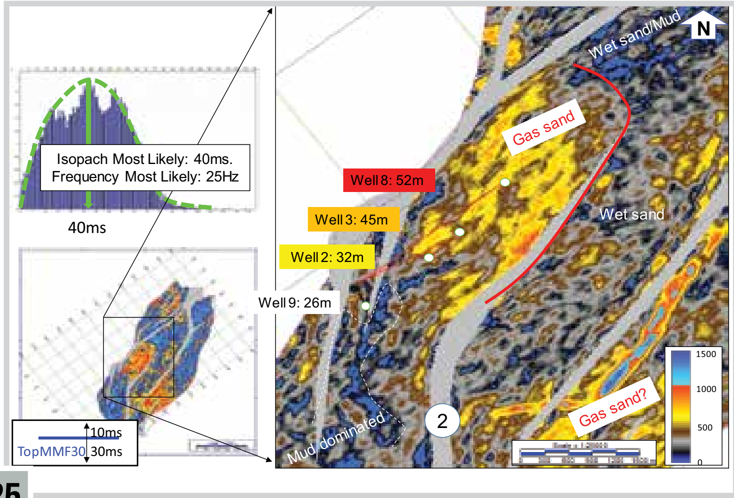

VPI CONFERENCE - MORE EFFICIENCY, TOWARD SUSTAINABILITY

MORE EFFICIENCY, TOWARD SUSTAINABILITY FOR VIETNAM'S OIL AND GAS RESOURCES

Petroleum is an industry which involves a lot of risks and requires great capital investment and high technology. In the context of the Fourth Industrial Revolution (Industry 4.0) rapidly taking place on a global scale, creativity and technology innovation are the key to improve the productivity, the quality of growth and the sustainable development of enterprises. On the sidelines of the Scientific Conference on "More Efficiency, Toward Sustainability" organised by the Vietnam Petroleum Institute, the Petrovietnam Journal (PVJ) had an interview with Mr. Tran Viet Hoa, Director of the Science and Technology Department, Ministry of Industry and Trade (MOIT) on the orientation of scientific research and technological development to successfully implement the Development Strategy of the Vietnam Oil and Gas Group.

PVJ: How do you assess the role of science and technology in the development of the oil and gas industry in Vietnam?

Mr. Tran Viet Hoa: Petroleum is an industry which involves a lot of risks and requires great capital investment and high technology. To overcome these specific challenges, the Development Strategy of the Vietnam oil and gas industry/Vietnam Oil and Gas Group has clearly defined the important role of science and technology and considered them one of the breakthrough measures to improve the productivity, quality, production and business efficiency and sustainable development of the Vietnam Oil and Gas Group in particular and the Vietnam oil and gas industry in general.

PVJ: Working with the Vietnam Oil and Gas Group, Prime Minister Nguyen Xuan Phuc emphasised "Undertaking major tasks of the country in the context of tough international competition without giving priority to new science and technology would mean failure". How do you think the global development trend of science and technology will affect the development of the oil and gas industry of Vietnam?

Mr. Tran Viet Hoa: The global development trend of science and technology is greatly affecting the development of the oil and gas industry in Vietnam. The cost of shale oil production decreases, the production output continues to increase; the application of 3D, 4D analysis and new geophysical techniques helps improve the reliability and accuracy of calculations; the combination of fast development and optimal production plans to achieve the highest oil and gas recovery rate; offshore CNG and GTL technologies will help convert gas into valuable liquid products with high economic efficiency.

The development trend in the seismic exploration sector will be application of the advances in physics and information technology to improve the quality of received signals; increase the resolution of small size exploration targets in the great depth and in complex geological conditions; exploit the special attributes of seismic waves to predict the petrophysical properties of the target in question; develop hardware and software that enable real-time visualisation of targets in 3 and 4 dimensions; and develop research on seismic acquisition towards multi-target in great depths and seismic microsystem technology in order to increase the level of details and the resolution of the target (the US has successfully applied for tight reservoirs).

Mr. Tran Viet Hoa, Director of the Science and Technology Department, Ministry of Industry and Trade

The technological trend in the borehole geophysics sector is based on advances in physics, mechanics, electronics and software that enable acquisition of more reliable

Ca Mau Gas Processing Plant. Photo: PV GAS

petrophysical properties in real-time (logging while drilling); reduce non-production time; increase the number of physical parameters per run; meet various services (small-diameter borehole, opened hole and cased hole) as well as the environmental conditions surrounding borehole walls. Furthermore, advances in well log interpretation that integrate relevant logging curves and other available data using artificial neural network (ANN) also help increase the reliability of algorithms predicting the petrophysical characteristics of reservoirs.

Modern drilling technologies recently applied around the world aim at minimising drilling cost, enabling drilling operations in deep water and drilling reservoir targets at great depth. Current drilling technologies include casing drilling, single diameter well drilling, slim hole or micro hole, seismic imaging while drilling in real-time, drilling mud in high temperature and high pressure, drilling under balanced pressure, multi-well drilling, horizontal drilling, and drilling in deep water and great depth.

New production technologies currently applied around the world include improvement of water injection efficiency; improved oil recovery (IOR); production technologies for very small to small permeability such as tight oil and shale gas requiring well completion by hydraulic fracturing; production in vuggy and fractured carbonate reservoirs; production in deep water and reservoir at great depth; digital oil field (DOF) enabling more efficient management and production monitoring (automatic measurement, real-time monitoring); production in unconventional reservoirs, enhanced oil recovery (EOR): mixture technology (hydrocarbon, CO_2, N_2), chemistry, temperature; microbial enhanced oil recovery (MEOR); oil recovery by water alternating gas (WAG). Among those, the most developed is chemical method (surfactants, polymer, alkane, alkali - polymer (AP), alkaline - surfactant - polymer (ASP), surfactant - alkaline - polymer (SAP), and nanomaterials).

In the material technology, the trend is application of new generation of materials which are super durable, corrosion and abrasion resistant, and have high mechanical strength in harsh operating conditions such as corrosive environment, high temperature and pressure, etc. Many plants are studying the application of composite materials, special alloys based on Al (aluminum),

MR. TRAN SY THANH - CHAIRMAN OF VIETNAM OIL AND GAS GROUP

The important tasks set out for current scientific and technological activities are continuing to renovate the mechanism of operation, improving the efficiency of management in line with the innovative spirit of the Science and Technology Law; effectively using the Science and Technology Development Fund; encouraging and boosting research, application and transfer of technology for sustainable development and enhancement of PVN's competitiveness; conducting research and development (R&D) in keeping with market demands and PVN's requirements; further strengthening the scientific and technological capacity of PVN, and building a contingent of scientific and technological staff with leading specialists who are highly qualified and capable of guiding and orientating the research activities of PVN.

With such urgent and difficult tasks, in an era where the Fourth Industrial Revolution is taking place extremely rapidly, more than anyone else, scientists, technicians, and scientific and technological managers of PVN should be the most active, taking the lead in the quest, research, and application of science and technology, with the ambition and desire of true and respectable scientists to excel and dedicate oneself.

nano materials (carbon nano tube, nanofibre, etc).

In order to improve the economic efficiency of refining and petrochemical projects, companies around the world have been focusing on research and development of technologies to increase the efficiency of energy use: thermal energy and electricity. The improvement of technologies for energy saving operation is included in the designing phase with proper conversion cycles to maximise the use of excess energy and reduce energy consumption.

For refining technologies, researches have been focusing on reducing the limitation of raw materials and improving the quality of products. Technically, the current main trend in the refining sector is to improve and upgrade the refining technology so that it can process heavy crude oil having high content of sulfur and impurities to produce products containing less harmful substances to the environment (impurities containing sulfur, olefin, and aromatics). The technology group which is expected to grow rapidly in the coming years to meet the demand for both materials and products is the hydrogen-related technologies: hydrotreating, hydrocracking and hydrogen production technologies. In order to lengthen the value chain, reduce risks and increase profitability, the current and future trend for construction of refineries is maximum integration of refining and petrochemical technologies.

For petrochemical technologies, the new technological trend is to convert methane into high-value intermediate products such as olefins or aromatics and then produce petrochemical products. To reduce CO_2 emissions to the environment, the use of bio-based materials such as ethanol to produce intermediate products (ethylene) and other petrochemical products in the chain such as bio-PE, bio-PET is also a growing trend.

Bach Ho field. Photo: Minh Tri

DR. NGUYEN QUOC THAP - VICE PRESIDENT, VIETNAM OIL AND GAS GROUP

Science and technology contribute to improving labour productivity, reducing production costs, and increasing the rate of grey matter in the composition of products. Considering science and technology as an important tool for enhancing competitiveness and successfully implementing the Development Strategy, the Vietnam Oil and Gas Group has been continuously researching, developing, applying and transferring new technologies, optimising operations and saving energy to improve production efficiency. Oil and gas scientific and technological activities should be implemented on the basis of promoting internal resources, in combination with domestic and international co-operation, linking research, training and production, and constantly raising the quality of scientific and technological human resources to create synergy and improve competitiveness.

Being the unit playing a central role in implementing this measure, the Vietnam Petroleum Institute (VPI) needs to strengthen research activities and provide more useful scientific, technological and management solutions to the Group as well as to oil and gas companies and contractors, with the aim to increase oil and gas reserves, optimise production and enhance oil recovery, raise the efficiency of production and business as well as invest in the production of new products with high added value.

These new technologies will open many opportunities for the oil and gas industry, namely the ability to exploit and use resources efficiently to create high quality and added value products. But on the other hand, it also creates a huge competitive pressure among enterprises in the oil and gas industry, and only companies that have the ability to acquire, apply and even create new and breakthrough technologies can survive and develop in such an increasingly fierce competitive environment.

PVJ: In the context of unpredictable crude oil prices, increasingly difficult conditions for deployment of oil and gas projects and huge pressure on capital arrangement, which key measures should the Vietnam Oil and Gas Group focus on in order to achieve the goal of improving productivity, quality and efficiency?

Mr. Tran Viet Hoa: The Vietnam Oil and Gas Group and its units should continue to closely follow oil price fluctuations in order to have timely response; review the tasks of exploration, appraisal, and development of new fields, arrange the tasks in order of priority and devise their implementation plans. New seismic acquisition and processing technologies should be applied to improve the quality and resolution of 3D seismic data for exploration of small structures and non-structural traps, and for additional exploration and production.

Efforts should be made to promote focused research, international co-operation in research, application of advanced technology to directly facilitate and orient prospecting and exploration activities, especially to identify the targets and locations of exploration and appraisal wells; to closely manage and supervise field development projects in order to put new fields/structures into operation on schedule; and to update the results of drilling wells for optimum adjustment of the exploration plan, ensuring the adequate increase of reserves in order to prepare the fields

for production in 2019, 2020 and the following years.

Units in the refining and petrochemical sector should proactively forecast and calculate the appropriate structure of product types of each plant in each period based on the fluctuations of oil prices and the market, ensure the efficiency of production and business, and cut down 5 to 10% of variable costs in the production cost structure.

I think that in the current difficult situation, cost optimisation is imperative. The Vietnam Oil and Gas Group should continue to promote research, development, application and transfer of new technologies, and at the same time boost initiatives, inventions, technical improvement, and rationalisation of production to optimise operations and save costs and energy.

PVJ: The views on comprehensive restructuring of the Vietnam Oil and Gas Group during the 2017 - 2025 period is to focus on developing strong linkages between oil and gas exploration and production - gas - oil and gas processing to maximise the strength and advantages of the industry, increasing the competitiveness in the country in order to participate in overseas investment. To achieve these objectives, what are the requirements for scientific research in the coming period?

Mr. Tran Viet Hoa: I think that the Vietnam Oil and Gas Group needs to build a contingent of leading scientific and technological staff who are highly qualified and capable of orientating researches, gather and train the contingent of successor scientists, dedicate efforts and enthusiasm to the key scientific and technological fields of the sector; promote research, application and transfer of technologies, and

Dung Quat refinery. Photo: BSR

DR. NGUYEN ANH DUC - GENERAL DIRECTOR, VIETNAM PETROLEUM INSTITUTE

Peter F.Drucker, the father of the modern management, once said "The best way to predict the future is to create it". For the last 40 years, VPI has been supporting Petrovietnam and the Vietnamese petroleum industry to create a competitive and sustainable future by getting the most out of their assets and researching for major breakthroughs. The former includes realising oil and gas potential in the entire continental shelf and territorial sea, maintaining a safe, stable and controllable operation, optimising operating costs, and increasing/enhancing oil recovery while the latter has been finding oil in fractured granitoid basement, studying alternative energies such as biofuels and gas hydrates, planning and implementing mega-scale, game-changing projects, and last but not least, embracing digital.

While the 1st industrial revolution replaced human muscles by steam engines, the 4th revolution is replacing human brains by artificial intelligence. Embracing digital will surely help PVN become sustainably competitive for the years to come. With its large database of all oil and gas activities in Vietnam, its experienced, ambitious and skillful people, and its modern infrastructure, VPI will help PVN successfully implement digital transformation by formulating a data-analytical decision-making process and setting up a system to collect and process large amount of data in real-time.

Through collaborations with various institutes, universities and companies all around the world, VPI has been actively researching and applying technologies in 04 directions: (1) Effective exploration in a low oil-price environment; (2) Facilitating IOR/EOR in Vietnam; (3) Treatment and processing of CO_2-rich gas in Vietnam; (4) Risk management in the volatile oil and gas world.

Those long-term R&D directions will surely benefit not only PVN but also the petroleum industry by maximising the values of Vietnamese natural oil and gas resources.

strengthen the linkage between scientific research, training and application.

The operation mechanism should be reformed, with the management efficiency to be enhanced in line with the innovative spirit of the Science and Technology Law, the market demand and the requirements of the oil and gas industry to be closely followed; awareness and mindset to be innovated whilst boosting training and utilisation of the contingent of scientific and technological staff; developing and completing incentive and investment policies for scientific research activities and innovation in the sector.

It is necessary to evaluate technologies and build a suitable technology roadmap for the oil and gas industry; to determine the technologies to be acquired in each specific area; to conduct step by step research, application and transfer of technologies to meet the technological trend of the Fourth Industrial Revolution; to promote research, application and transfer of technologies in order to enhance the competitiveness of the oil and gas industry, creating national products of the industry in the direction of sustainable development and protection of natural resources and environment.

A roadmap should be built for investment and development of the scientific and technological research infrastructure. In the immediate future, a number of priority domains should be selected for investment in improving the research capability and equipment to meet the regional and world level in some domains.

PVJ: Thank you very much.

RESERVOIR CHARACTERISATION OF THE MIDDLE MIOCENE CA VOI XANH ISOLATED CARBONATE PLATFORM

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Summary

The Ca Voi Xanh field is located offshore Vietnam in the southern Song Hong basin. Tertiary carbonates of Middle Miocene (Langhian and Serravallian) age form an isolated carbonate platform on top of the Triton Horst structural high. Shallow water corals and large and small benthic foraminifera are the main constituents of the older Langhian carbonates, whereas the overlying Serravallian carbonates are dominated by deeper water coralline red algae (rhodolith) and large benthic foraminifera (LBF).

Sequence stratigraphic interpretation is based on detailed sedimentolological core description tied to well-log character. A sequence stratigraphic framework was established for the Serravallian carbonates, displaying three third-order depositional sequences (Ser1, Ser2, and Ser3).

Langhian carbonates can be described by one lithofacies: coral-LBF-foraminifera grainstone-packstone/rudstone. Depending on the presence of mud in the samples, two lithofacies types are characteristic for the Serravallian: LBF-rhodolith packstone to mud-lean packstone and rhodolith-LBF grainstone to mud-lean packstone.

Two well-developed exposure surfaces can be identified on top of the Langhian (Serravallian sequence boundary Ser1_SB) and on top of the Serravallian (Tortonian sequence boundary Tor1_SB). Serravallian carbonates show an overall shallowing-upward trend from more horizontally-oriented coralline red algae (encrusted and bored pavements/hardgrounds) at the lower part of the section to large, roundish, irregular rhodoliths towards the upper part of the section. Petrographic thin section, stable isotope (oxygen and carbon), and fluid inclusion analyses confirm a freshwater (vadose and phreatic) diagenetic overprint of the carbonates below the exposure surfaces (sequence boundaries).

Partial dolomitisation observed at Well-2 and Well-3 might be related to CO_2 and hydrocarbon charging, causing secondary leaching of the Mg-rich coralline red algae and LBFs; leading to an enrichment of the water with Mg-ions and thus favouring downward dolomitisation of the Serravallian carbonates.

A reproducible reservoir rock type (RRT) scheme was developed for the described carbonates, using a combination of depositional environment, diagenetic overprint, and reservoir parameters (porosity and permeability). The Langhian is characterised by two RRTs, depending on the degree of cementation (RRT-3L) and dissolution (RRT-5L). The Serravallian RRTs are separated into dominantly packstone (RRT1) and dominantly grainstone textures (RRT-2, RRT-3, RRT-5, and RRT-6). RRTs with grainstone texture show varying degrees of cementation (RRT-2 and RRT-3) and dissolution (RRT-5 and RRT-6). Early diagenetic dolomitisation (RRT-4) preferentially effects packstone (RRT-1), but also grainstone textures (RRT-3 and RRT-5). The vertical and lateral distribution of RRTs, supported by seismically-derived paleo-reconstruction of the carbonate platform, adequately describes the reservoir.

The geologic (static) model consists of both, matrix and non-matrix components. Seismically-derived probablitiy maps for each of the six Seravallian RRTs, based on 3D seismic paleo-structure mapping, were used as input to the matrix component of the geologic model. Different karst geometries and features consistent with known hydro-geologic processes are identified in the seismic discontinuity (variance) cube and are used to interpret karst regions with different degrees and/or types of karst/fractures. These karst regions are used to populate the non-matrix component of the geologic model along the identified two major sequence boundaries (Ser1_SB and Tor1_SB).

Key words: *Reservoir characterisation, carbonate platform, Ca Voi Xanh field.*

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1. Introduction

The Ca Voi Xanh field is located offshore Vietnam in the southern part of the Song Hong basin, between the Qiongdongnan basin in the north and the Phu Khanh basin in the south [1, 2]. The greater East Sea area has a relatively simple tectonic history. In the Eocene to Early Oligocene, extension (rifting) was initiated, followed by movements along the Red River/East Vietnam Boundary Fault Zone approximately 45 million years ago. The Red River Fault is a major left-lateral strike-slip fault system caused by the collision of the India and Asia tectonic plates. Motion on the Red River Fault System continued into the Early Miocene, and marine conditions, triggering carbonate platform growth, were established East of the fault zone on top of structural highs. Carbonate growth was widespread on structural highs offshore Central Vietnam throughout the Early and Middle Miocene. Regional uplift of the mainland resulted in increased influx of siliciclastics from the West; leading to stressed carbonate growth and finally to the drowning of the Tri Ton horst carbonate platform during the Late Miocene [1, 2].

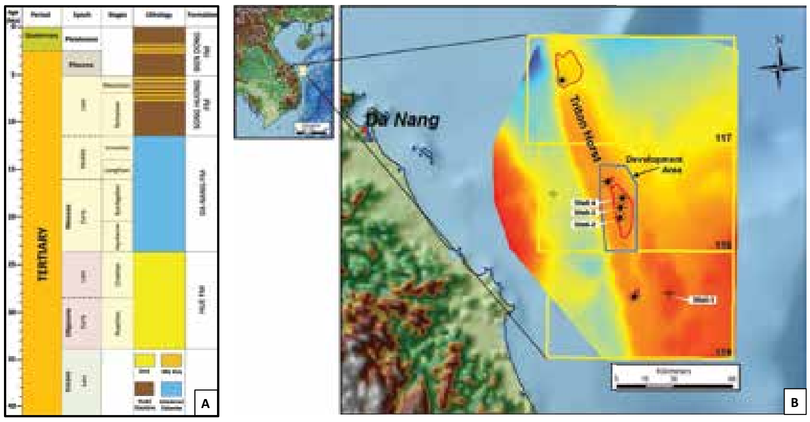

Figure 1. *Generalised stratigraphic column for the Tri Ton horst area (a). Regional top carbonate depth map showing Tri Ton horst high (bright red colors), Blocks 117 through 119 (yellow outlines), and the location of the four exploration wells. Also shown are the offshore Ca Voi Xanh field area (red outline) and the remaining development area (blue outline) (b).*

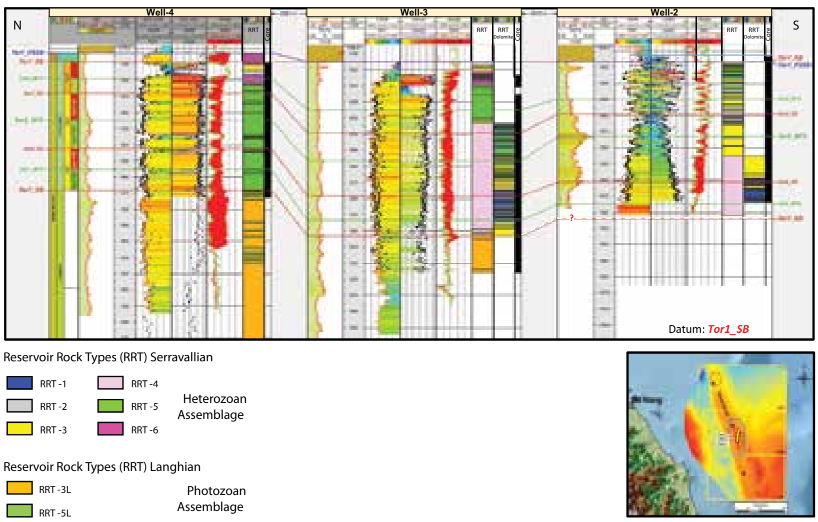

Figure 2. *Serravallian sequence stratigraphic framework showing sequence boundaries (SB) in red, flooding surface/sequence boundary (FSSB) in blue, and maximum flooding surfaces (MFS) in green. The logs displayed for each well are Gamma Ray (Track 1), Porosity (Track 2), Permeability (Track 3), and Neutron-Density (Track 4). Vertical reservoir rock type (RRT), and pre-dolomite rervoir rock type (RRT Dolomite) distribution, as well as the cored interval (Core) is displayed for each well.*

The generalised stratigraphy of the region is shown on Figure 1a. Middle Miocene age carbonate platforms of the Da Nang Formation nucleated on older, remnant syn-rift highs. The Ca Voi Xanh platform is an isolated carbonate platform that was established on the Tri Ton horst structural high (Figure 1b). The horst is a positive feature separated in the West from land by a deep trough that trapped time-equivalent clastics and allowed deposition of carbonates on the Tri Ton horst structural high. Carbonate deposition ended when clastics filled the trough and prograded over the carbonate platform.

2. Sequence stratigraphy

The complete carbonate interval at Ca Voi Xanh and south of Ca Voi Xanh was penetrated by two wells, where it is approximately 600 to 800m thick. The well penetrations in the main Ca Voi Xanh platform (Well-2, Well-3, and Well-4) only penetrated the upper portion (less than 200m) of the carbonate platform. Well-3 and Well-4 were cored across the Serravalian sequence boundary Ser1_SB into the Langhian section. The core obtained from the Well-2 only covers the Serravallian interval (Figure 2).

Sequence stratigraphic correlation between Well-2, Well-3, and Well-4 is based on observed facies distribution, biostratigraphic interpretation, and well-log character. Conventional core was recovered from all three wells, in addition to sidewall cores from Well-2 and Well-4. A sequence stratigraphic framework was established for the Serravallian carbonates. The Serravallian interval can be described by one third-order composite sequence [3], comprising three third-order depositional sequences: Ser1, Ser2, and Ser3 (Figure 2). Four major regionally correlative surfaces can be carried across the Ca Voi Xanh platform: Serravallian sequence boundary Ser1_SB (identified on well-logs, core, and seismic), Serravallian maximum flooding surface Ser2_MFS (identified on well-logs and core only), Tortonian sequence boundary Tor1_SB (identified on well-logs, core, and seismic), and Tortonian flooding surface/sequence boundary Tor1_FSSB (identified on well-logs and core only), merging with the Tor1_SB at Well-2 and Well-3. The Ser2_MFS (Serravallian third-order composite maximum flooding surface) correlates with a zone of bioturbated hardgrounds with platy corals observed in core material of all three wells and is closely associated with an elevated gamma ray response (Figure 2). Generally, above the third-order composite Ser2_MFS, Serravallian carbonates show decreasing (lower) GR-log values, compared to Serravallian carbonates below the Ser2_MFS (Figure 2).

Langhian carbonates, directly underlying the Serravallian third-order sequence boundary Ser1_SB display root marks filled with detrital quartz grains, indicative of an exposure surface [4] (Figure 3). Serravallian carbonates show a cemented interval of varying thickness, interpreted to be the result of exposure, directly below the third-order Tortonian sequence boundary Tor1_SB (Figure 4a). Glossifungites burrows, as well as fluid inclusion (brackish to fresh water inclusions) and stable isotopes (typical “inverted J” trend of oxygen and carbon isotopes [5, 6]; Figure 4b) analyses support the interpretation of an exposure surface, related to a sea-level lowstand at the end of Serravallian time.

The Tor1_SB at Well-4 (top of cemented zone, approximately 10m below the top carbonate) is correlated with the top carbonate picks at Well-2 and Well-3 (Figure 2). The interpreted Tor1_FSSB, marking the top carbonate at Well-4, merges with the Tor1_SB in the other wells (absence of uppermost, approximately 10m thick carbonate succession; Figure 2).

Figure 2 shows the above described integrated stratigraphic framework on a North-South oriented well cross-section.

3. Environment of deposition

The Environment of Deposition (EOD) interpretation is based on the integrated sequence stratigraphic framework, the antecedent topography, and biostratigraphic analyses, mostly done on large benthic foraminifera (LBF) and coralline red algae (rhodoliths).

Langhian-age deposits are interpreted to inherit a broad central platform morphology based on core-interpreted facies and seismic facies analysis across the platform. Serravallian deposits are interpreted to occupy a wide facies belt associated with a central platform high. The depositional style changes between Langhian (rimmed platform) and Serravallian (carbonate ramp) time. Both, Langhian and Serravallian carbonates were exposed during sea-level lowstands at the end of Langhian and Serravallian times.

During the Langhian, the common presence of hermatypic coral rudstones, interlayered with packstones, and grainstones, rich in large benthic (Miogypsina) and, predomminantly, small benthic foraminifera, including miliolids, soritids, and alveolinids point to a warm, shallow marine, inner shelf environment of deposition [7]. Coral-rich patch reefs can be found forming today in many platform-interior, shallow, warm, well-lit settings [8, 9]. Langhian carbonates represent a typical photozoan association of organisms [9].

The Serravallian third-order composite sequence is interpreted to represent a deeper open marine, proximal to distal middle ramp environment [11]. The carbonates are rich in large benthic foraminifera (LBF) like Cycloclypeus, Katacycloclypeus, Amphistegina, and Lepidocyclina, coralline red algae with encrusting foraminifera (Acervulina inhaerens), and minor small benthic and planktonic foraminifera. In contrast to the Langhian, Serravallian carbonates represent a typical heterozoan association of organisms [10].

Coralline red algae (Corallinales, Halidiales and Sporolithales, Rhodophyta) are common and are represented by members of the subfamilies Neogoniolithoideae, Mastophoroideae, Melobesioideae, and Lithophylloideae (family Corallinaceae), and members of the families Hapalidiaceae and Sporolithaceae. Six non-geniculate genera (seven species) of coralline red algae were recognised. Neogoniolithoideae: Neogoniolithon and Spongites; Mastophoroideae: Lithoporella; Lithophylloideae: Lithophyllum; Melobesioideae: Mesophyllum and undetermined melobesioids; Sporolithaceae: Sporolithon [11].

Coralline red algae occur as encrusting thalli floating in the sediment matrix, rhodoliths, as well as thallial fragments. Rhodolith shapes range from sub-spheroidal

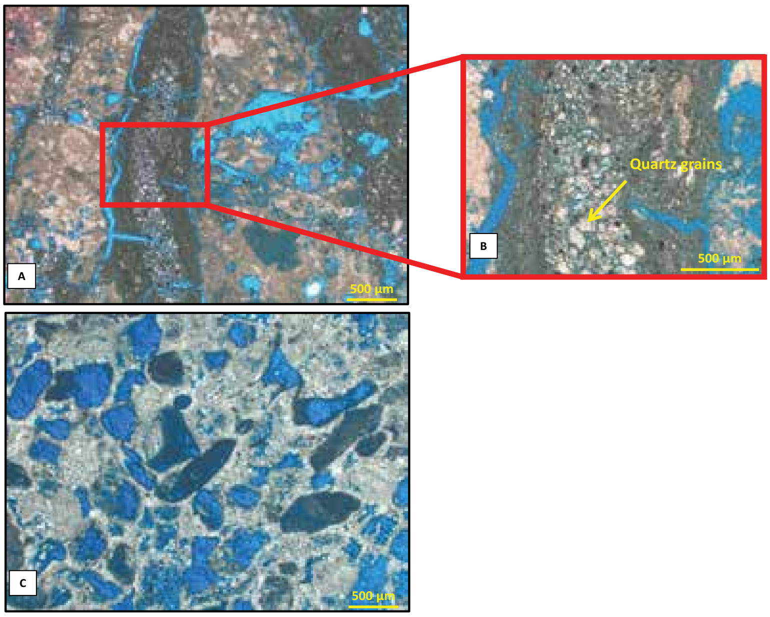

Figure 3. Thin section photomicrograph (below Serravallian sequence boundary Ser1_SB) showing probable root traces filled with quartz grains (pedogenic overprint) (a). Close-up of Figure 3a (b). Thin section photomicrograph (below Serravallian sequence boundary Ser1_SB) showing dissolution of less-stable bioclasts and cementation of original interparticle pore space (porosity inversion) (c).

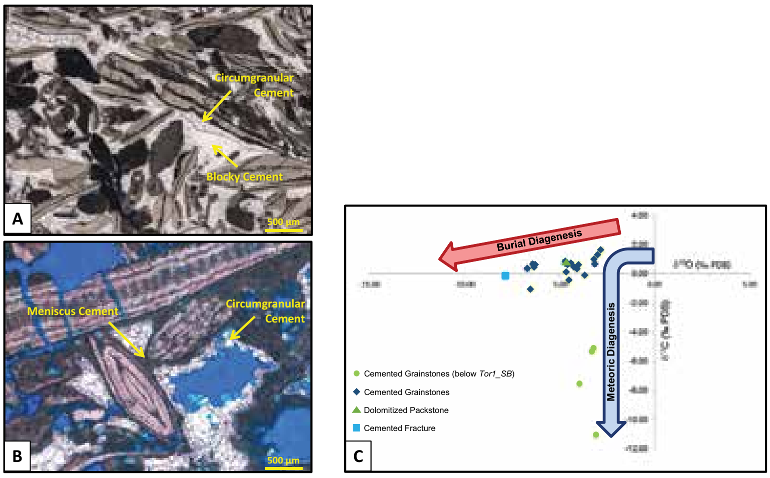

Figure 4. Thin section photomicrograph (below Tortonian sequence boundary Tor1_SB) showing meteoric phreatic circumgranular and blocky cement (a). Thin section photomicrograph (below Tortonian sequence boundary Tor1_SB) showing vadose cryptocrystalline meniscus cement, overgrown by meteoric phreatic circumgranular cement (b). Stable isotope analyses ($\delta^{18}O$ and $\delta^{13}C$) confirm the interpreted meteoric origin of cement types displayed on Figure 4a (green dots; blue, "inverted J" trend). Most samples show the burial (red) trend (c).

to flat shapes. Inner and outer parts of the rhodolith do not show different growth-forms. Encrusting growth-forms are very common in the outer parts of the rhodoliths. Rare warty morphologies are also present. Encrusting foraminifera are represented by acervulinids which, together with the coralline red algae, make up rhodoliths and the encrusting coralline framework (i.e., crustose pavement). Acervulinids can be dominating and often alternate with coralline red algae making superimposed successions of coralline thalli/acervulinid shells [11].

Coralline algae can be common in both tropical and non-tropical settings, though they seem to be more prevalent as facies dominating components in the latter. In the studied thin sections, reef-building corals and dasycladalean green algae are missing; suggesting that these deposits may represent a tropical/warm temperate water transitional area. Non-tropical heterozoan carbonates do not form carbonate platforms with steep, wave-resistant rims, but can accumulate hydrodynamically as carbonate ramps.

The coralline red algal and larger foraminiferal assemblages suggest deposition in environments between (below) fair-weather wave base (FWWB) and storm wave base (SWB), or what is referred to as the middle ramp setting [12 - 15]. This setting was further differentiated based on gradient ranging from: (1) the proximal middle ramp or shallowest part close to the FWWB and characterised by higher coralline taxonomic diversity and abundant larger nummulitid foraminifera to (2) the distal middle ramp, representing the transition to the outer ramp, characterised by lower coralline taxonomic diversity, dominated by melobesioids, and larger orbitoidiform foraminifera [11].

The dominance of Neogoniolithoideae in shallow water settings with an increase in the presence of Melobesioideae with depth has been observed in many areas including the Hawaiian Islands [16], Ryukyu Islands [17 - 19], Papua New Guinea [20], Gulf of Mexico [21, 22], Rio de Janeiro [23], and South Pacific reefs [22]. The sporolithacean Sporolithon occurs from tropical to temperate areas [25 - 27] from sea-level down to 80m water depth [16, 25, 28 - 30].

Middle Miocene sediments with abundant rhodoliths (composed of Lithothamnion and Sporolithon) from the Queensland Plateau and Marion Plateau are believed to be deposited in water depths between 30 and 80m [14, 15, 31].

On the Kikai-jima shelf (Central Ryukyu Islands, Japan), at water depths of 61 to 105m, sandy and gravelly carbonate sediments are characterised by macroid pavements

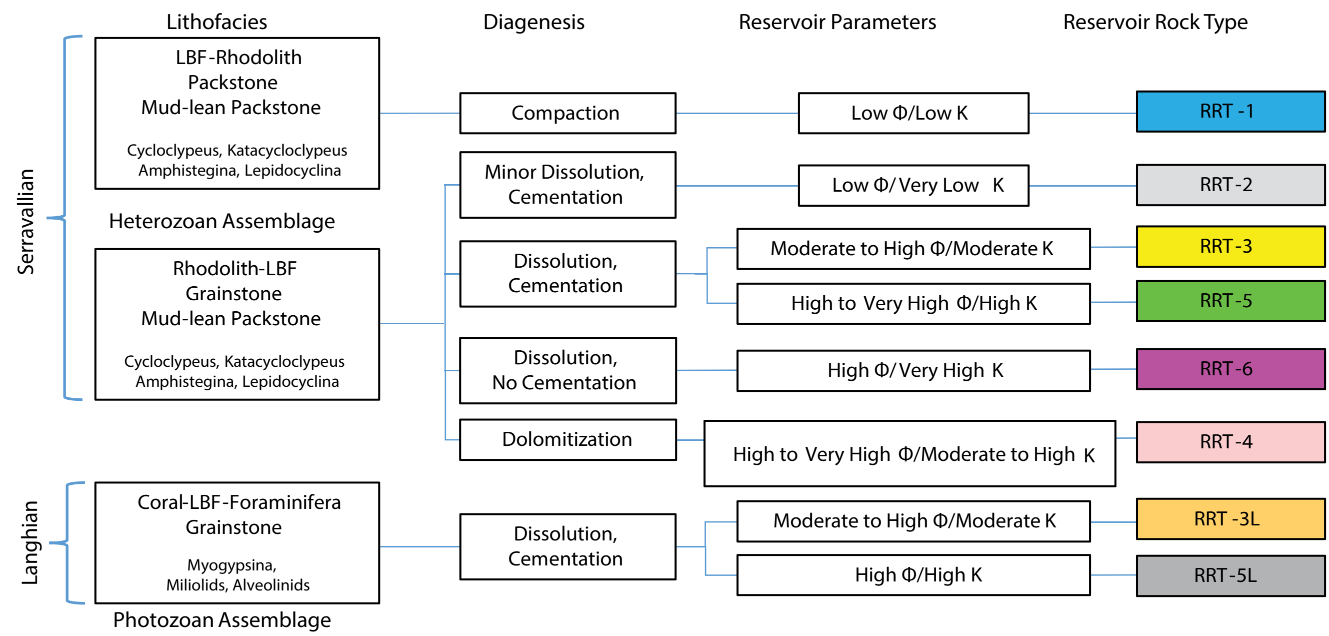

***Figure 5.** Langhian and Serravallian Reservoir Rock Types tied to lithofacies, diagenesis, and resulting reservoir parameter.*

[32]. Macroids, ranging in size from ca. 25 to 130mm in diameter, are spheroidal and sub-spheroidal in shape and consist mainly of the encrusting foraminifera Acervulina inhaerens and subordinate thin encrusting and lumpy coralline algae. The macroid pavements are forming under low sedimentation rates and occasional movement due to current action. Similar environmental characteristics can be argued for the studied material. The occurrence of the ichnotaxa Gastrochaenolites and Entobia confirm a low sedimentation rate of the setting.

Crustose pavements consist of coralline algal bindstone made up of thin encrusting coralline thalli, superimposed onto each other. The framework points to low turbulence interpreted to be in the distal portion of the middle ramp. Somewhat contradicting, the pavement is also characterised by Neogoniolithon.

Also Rhodolith beds are sites of biodiversity, they are habitats hampering the occurrence of larger foraminifera. The dominance of acervulinids and melobesioids can be indicative of a middle ramp, below 50m water depth (a similar setting in which the Kikai-jima macroids grow; low sedimentation rate, occasional overturning [32]). However, the occurrence of Neogoniolithon suggests a shallower setting. The occurrence of Neogoniolithon both in the crustose pavement and in rhodolith beds could correlate to two settings, located not very far from each other. Within the proximal to distal middle ramp, the crustose pavement occur in a low energy, deeper water area, whilst the rhodolith beds in an occasionally turbulent, somewhat shallower setting.

The depositional system of the analysed thin-section material is interpreted as a ramp. The environment of deposition ranges from a proximal middle ramp, relatively shallow-water setting below the FWWB, to a distal middle ramp, realtively deeper-water setting with occasional high water motion (storms) causing rhodolith overturning. An inner ramp setting is ruled out due to (1) the absence of very shallow-water coralline taxonomic assemblage and components such as hermatypic corals, abundant larger porcellaneous foraminifera and dasycladaleans green algae, and (2) the abundant occurrence of orbitoidiform larger foraminifera (typical of middle-outer ramp environment).

A summary of the rhodoliths identified and their general paleogeographic setting [11] are:

Proximal Middle Ramp

- Dominated by Mastophoroideae (Lithoporella) and Neogoniolithoideae (Neogoniolithon, Spongites)
- Subordinate corallines such as Melobesioideae (Mesophyllum), Lithophylloideae (Lithophyllum) and Sporolithaceae (Sporolithon)
- Higher coralline taxonomic diversity
- Occurrence of nummulitid larger foraminifera
- Occurrence of larger porcellaneous foraminifera (Orbitolites, Neoplanorbulinella)

Distal Middle Ramp

- Dominated by Melobesioideae (Mesophyllum)

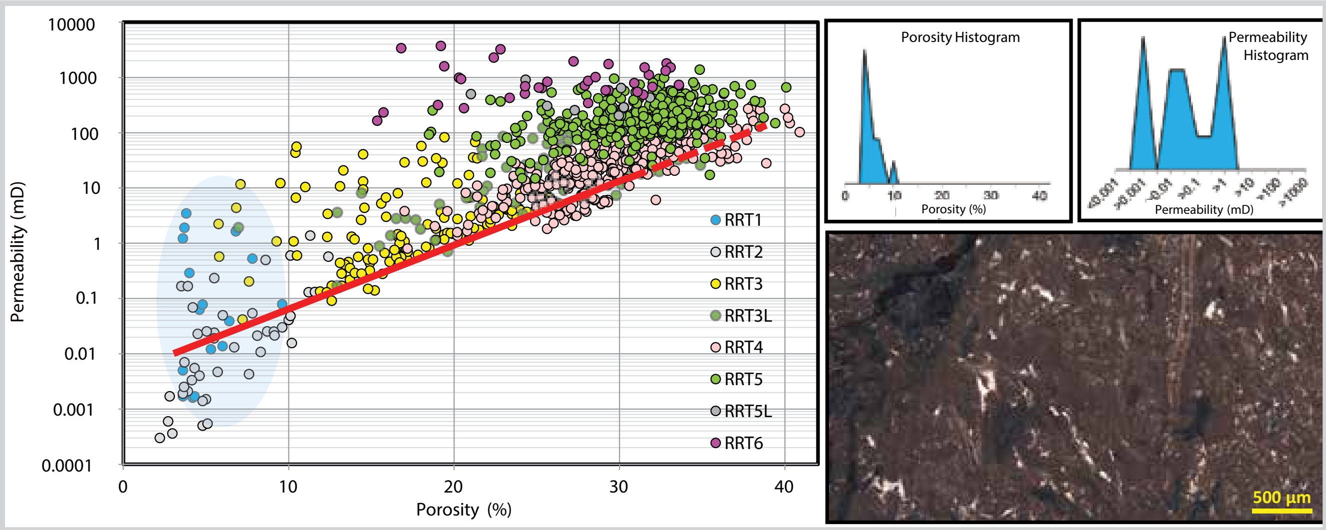

Figure 6. *Reservoir rock type 1. Displayed are permeability/porosity cross-plot (left) and porosity and permeability histograms, as well as thin section photomicrograph (right). Microporosity line (red), showing microporosity-dominated (below the red micro porosity line) and non-microporosity-dominated (above the red microporosity line) samples [40, 41].*

- Subordinate corallines such as Mastophoroideae (Lithoporella), Neogoniolithoideae (Neogoniolithon, Spongites), and undetermined melobesioids

- Lower coralline taxonomic diversity

- Bioerosion by boring sponges (Entobia) and bivalves (Gastrochaenolites)

A likely average paleo-water depth for the Serravallian sediments is interpreted to be between 50 and 80m (distal middle ramp) below Ser2_MFS, and < 80m, shallowing-upward to approximately 30m above Ser2_MFS; towards the top of the reservoir (Tor1_SB).

The Serravallian carbonate section is overlain by Tortonian, deeper marine, outer ramp, marls or claystones with > 90% planktonic foraminifera.

4. Diagenesis

Detailed analysis of core and thin section material has led to an understanding of the paragenetic sequence for the Serravallian carbonate reservoir that highlights the importance of diagenetic overprint rather than primary deposition on reservoir parameter trends.

Alteration of Ca Voi Xanh carbonate sediments began in the marine realm soon after deposition (both in Langhian and Serravallian times). Early seafloor alteration of sediments is apparent in most thin sections in the form of grain micritisation and micritic envelope formation. These alterations occur through the activity of bacteria and algae borings into grains. Thin isopachous fibrous, marine cements (neomorphosed aragonite cement) are present in some Ca Voi Xanh thin sections, but are volumetrically insignificant. More common are isopachous bladed, marine cements (neomorphosed high-Mg calcite cement). Neither grain micritisation nor seafloor cementation has a major impact on reservoir quality. Notably missing in the Serravallian sequence are large numbers of original aragonitic allochems (green algae, molluscs, and corals). Importantly, the Serravallian fossil assemblage is rich in Mg-calcite, as both the rhodoliths [10] and the large benthic foraminifers such as Amphistegina [33] are composed of this mineral.

Meteoric diagenesis (both vadose and phreatic) follows early sediment alteration (Figure 4). There are two important aspects to this alteration with respect to reservoir impact: dissolution of allochems and precipitation of calcite cements. Most dissolution is fabric-selective with allochems such as coral fragments, benthic foraminifera, and red algal grains commonly leached. Partial leaching of grains results in microporous textures, whereas complete leaching results in mold formation. Non-fabric-selective dissolution is commonly observed below interpreted exposure surfaces [4]. The dissolution/cementation below sequence boundaries is interpreted to be meteoric as it is associated with meteoric cement fabrics (cryptocrystalline meniscus, circumgranular, dog tooth, and blocky cements), and occurs prior to compaction. Fluid inclusion (brackish to fresh water inclusions) and stable isotopes (carbon and oxygen), following the meteoric or "inverted J" trend [5, 6], demonstrate that these cements have been formed by meteoric early diagenesis.

Most of the data points follow the burial trend whereby variations in ^{13}C are minor compared to the overall variations in ^{18}O [34]. Later diagenetic dissolution of allochems rich in Mg-calcite (red algae and large benthic foraminifera) in the process of porosity inversion, might be driven by acidification of connate marine waters by CO_2 diffusion from the hydrocarbon reservoir down into the aquifer [35]. With the beginning of CO_2 and hydrocarbon charging the reservoir, the gas water contact and hence the dissolution of Mg-calcite-rich allochems moved downward, causing the amount of Ca^{2+}, CO_3^{2-}, and also Mg^{2+} (mainly derived from dissolved corraline red algae) to increase in the underlying aquifer [36].

Partial dolomitisation, observed in the Serravallian section of both Well-2 and Well-3, is rare to non-existent in Well-4. Dolomitisation appears to post-date meteoric cement and pre-date deep burial-realm diagenesis. It is challenging to predict the extent of dolomitisation across the platform, given the limited number of well penetrations. Onset of clastic deposition occurred during the Tor1 sequence, constraining the initiation of dolomitisation to Early Tortonian time. Dolomitisation may continue to take place after initiation of burial by shales and marls, as tested in reactive transport modelling [37]. The observed partial dolomitisation at Well-2 and Well-3 might be related to CO_2 and hydrocarbon charging, causing secondary leaching of the Mg-rich coraline red algae and LBFs (see above). Enrichment of the water with Mg-ions might have favoured downward dolomitisation, driven by gas displacement, of the Serravallian carbonates [36]. This interpretation is supported by the fact that dolomitised sections of Well-2 and Well-3 are overlain by porous (leached) carbonates. It is important to note, that only Serravallian carbonates are dolomitised. Dolomitisation does not cross the Serravallian to Langhian boundary (Serravallian sequence boundary Ser1_SB). This argues for an internal and very local Mg source but might also be caused by the different grain composition of the Serravallian compared with the Langhian. The Langhian is dominated by aragonitic bioclasts like corals, whereas the Serravallian is dominated by bioclasts built by Mg-calcite, like coralline red algae. One might argue, that dolomitisation needs high-Mg calcite seeds or nucleation sites (missing in the Langhian) to trigger ("jump-start") dolomitisation [38, 39].

5. Reservoir rock types (RRT) and geologic controls on reservoir architecture

Reservoir rock typing was done in an effort to model varying reservoir quality, tied to different environments of deposition (EOD) across the Ca Voi Xanh platform. Reservoir rock types (RRT) were identified based on lithofacies, diagenesis, and reservoir parameters. Eight RRTs were identified: six in the Serravallian (RRT-1, RRT-2, RRT-3, RRT-4, RRT-5, and RRT-6; described in detail below) and two in the Langhian (RRT-3L and RRT-5L; Figure 5).

5.1. Reservoir rock type 1 (RRT-1)

RRT-1 (Figure 6) is limited to Well-2 core material (Figure 2). However, it also occurs as pre-dolomitised RRT-1 within the dolomitised part of Well-3 core material (Figure 2). This RRT is characterised by large benthic foraminifera (LBF), encrusting coralline red algae, and, often horizontally aligned, rhodoliths and platy corals. RRT-1 is the only

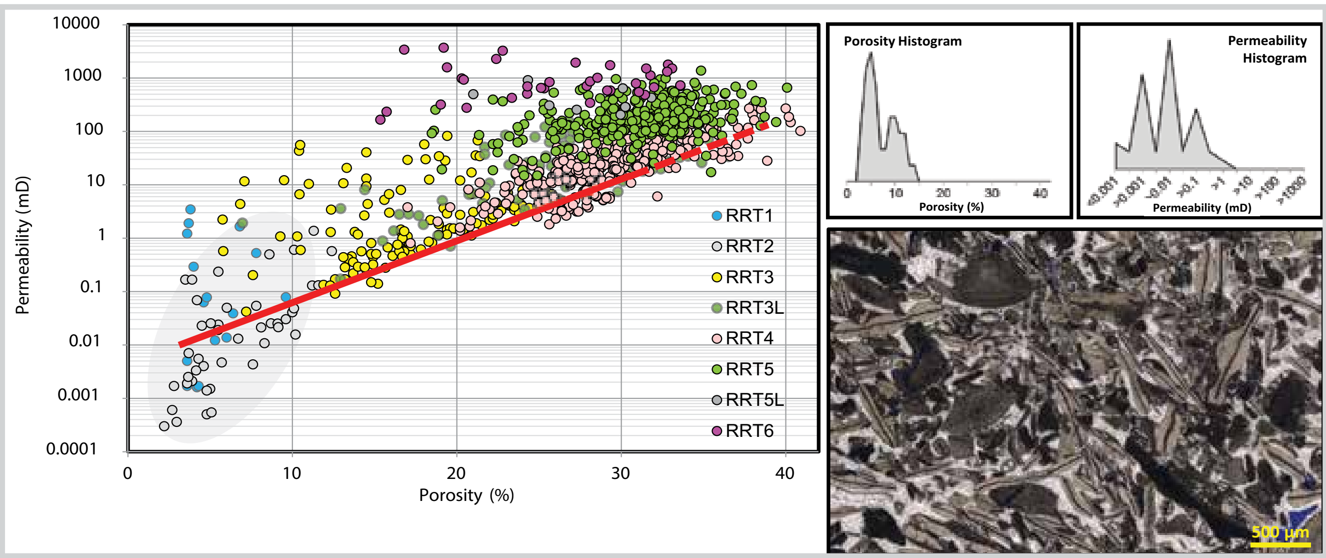

Figure 7. Reservoir rock type 2. Displayed are permeability/porosity cross-plot (left) and porosity and permeability histograms, as well as thin section photomicrograph (right). Microporosity line (red), showing microporosity-dominated (below the red micro porosity line) and non-microporosity-dominated (above the red microporosity line) samples [40, 41].

RRT that shows considerable amounts of mud, giving it a packstone to mud-lean packstone texture (LBF-rhodolith packstone to mud-lean-packstone). Compaction features like horizontal stylolites and solution seams are common.

RRT-1 is interpreted to represent a low-energy, deeper marine, distal middle shelf environment); most likely in an estimated 50 to 100m water depth range.

Throughout the Serravallian section at Well-2 and Well-3 (pre-dolomite RRT-1), intervals representing RRT-1 occur commonly around interpreted maximum flooding surfaces (MFS). This interpretation is further supported by biostratigraphy.

The pore system is dominated by microporosity [40, 41]. Subordinate partial moldic and between particle porosity is partly occluded by blocky calcite cement. RRT-1 is preferentially dolomitized (see RRT-4).

5.2. Reservoir rock type 2 (RRT-2)

RRT-2 (Figure 7) is present in core material of all three wells studied (Figure 2). It is made up of similar allochems characteristic for RRT-1 (but lacks considerable amounts of mud) and RRT-3. RRT-2 is described as rhodolith-LBF grainstone.

The graistone texture indicates elevated to high water-energy conditions. Environment of deposition (EOD) ranges from proximal to mid middle shelf, most probably representing rather shallow water depth of around 30m.

Cementation with circumgranular and blocky cement has considerably reduced between particle, partial moldic, and moldic pore space. Apparent microporosity (Figure 7) is within the grains. RRT-2 represents a strongly cemented version (strong diagenetic overprint) of RRT-3 (see below).

The presence of RRT-2 near interpreted sequence boundaries suggests that cementation most likely is related to exposure. This interpretation is further supported by the presence of cryptocristalline meniscus, circumgranular (but not isopachous), dog tooth, syntaxial, and blocky cements, as well as $\delta^{18}O$ and $\delta^{13}C$ isotope, and optical fluid inclusions (OFI) analyses; all indicating that cementation took place early in the meteoric phreatic diagenetic environment (Figure 4).

5.3. Reservoir rock type 3 (RRT-3)

RRT-3 (Figure 8) dominates the Seravallian section at Well-1, but it is also present, although to a lesser degree, at Well-3 and Well-4 (Figure 2). Similar to RRT-2, RRT-3 is described as rhodolith-LBF grainstone to mud-lean packstone.

Like RRT-2, RRT-3 is characterised by LBF (Cycloclypeus, Katacycloclypeus, Amphistegina, Lepidocyclina) and rhodoliths, interpreted to have been deposited throughout the proximal to distal middle shelf under moderate to high water-energy conditions. An absolute water depth is difficult to assign to this type of rhodolith-dominated carbonates. However, LBF assemblages, the occurrence of smaller benthic foraminifera, and rhodolith morphologies suggest that it may vary between 30 to 80m.

The pore system is dominated by between particle, partial moldic, and moldic porosity. Cement is present

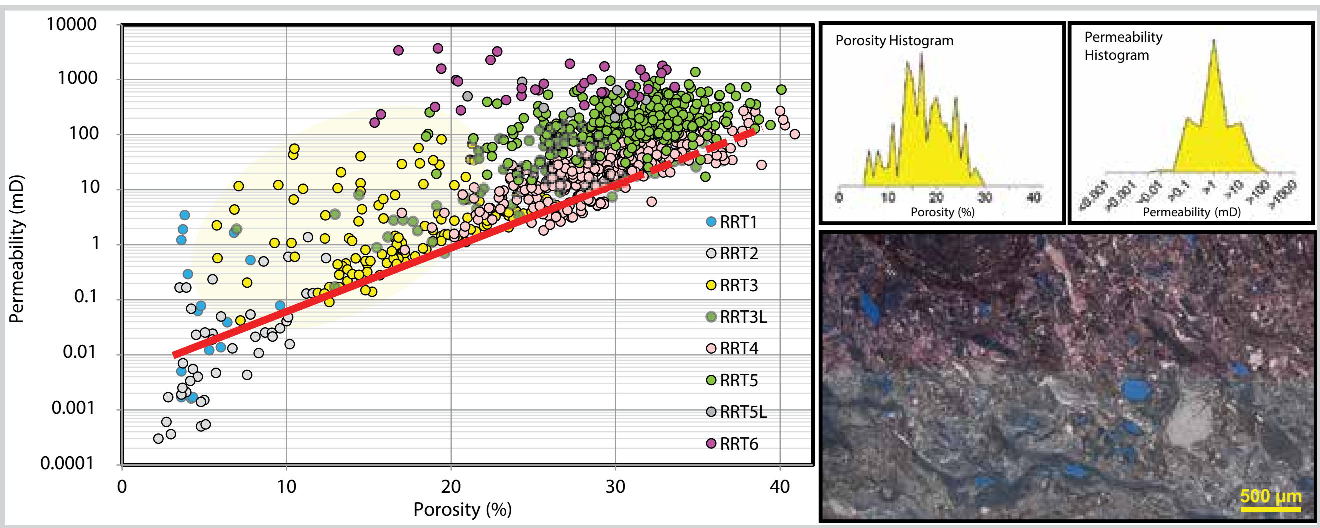

Figure 8. *Reservoir rock type 3. Displayed are permeability/porosity cross-plot (left) and porosity and permeability histograms, as well as thin section photomicrograph (right). Microporosity line (red), showing microporosity-dominated (below the red micro porosity line) and non-microporosity-dominated (above the red microporosity line) samples [40, 41].*

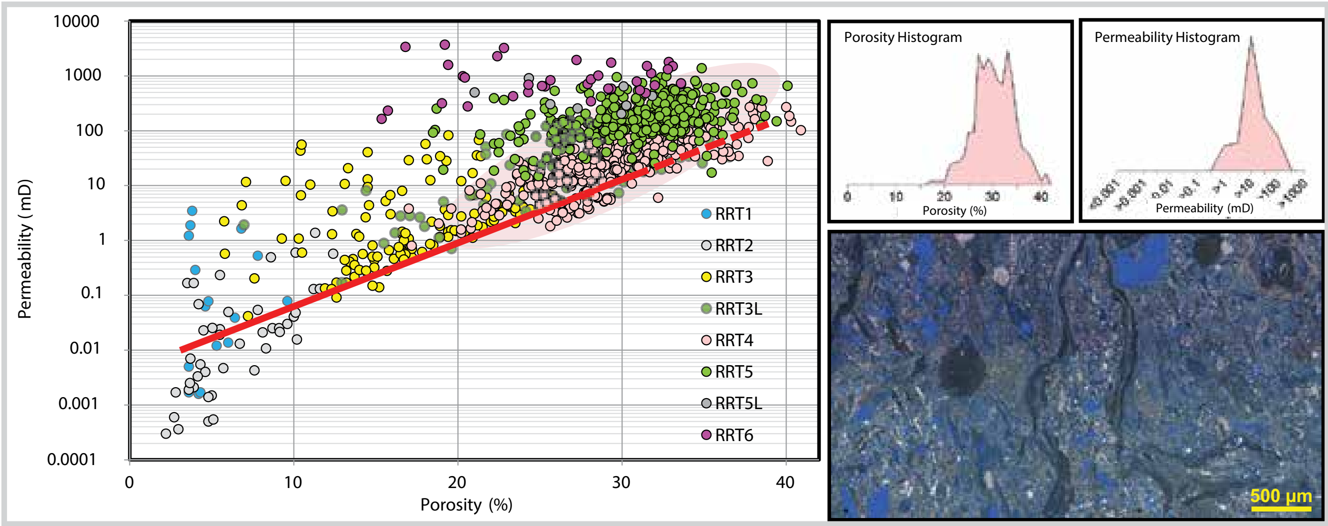

***Figure 9.** Reservoir rock type 4. Displayed are permeability/porosity cross-plot (left) and porosity and permeability histograms, as well as thin section photomicrograph (right). Dolomite content is 87%. Microporosity line (red), showing microporosity-dominated (below the red micro porosity line) and non-microporosity-dominated (above the red microporosity line) samples [40, 41].*

(cryptocrystalline meniscus, circumgranular, isopachous, syntaxial, and blocky), but it does not occlude all pore space. Cement types represent marine vadose (cryptocrystalline meniscus cement), phreatic (isopachous, neomorphosed acicular aragonite, and bladed and high-Mg calcite cements), meteoric vadose (cryptocrystalline meniscus cement), phreatic (circumgranular, dog tooth and blocky, as well as syntaxial cements), and/or burial (syntaxial and blocky to drusy mosaic cements) diagenetic environments.

RRT-3 represents a depositional, minor diagenetically altered, reservoir rock type.

The presence or absence of the above-mentioned cement types is, however, responsible for the wide range in porosity and permeability.

5.4. Reservoir rock type 4 (RRT-4)

RRT-4 (Figure 9) is comprised of partially dolomitised carbonates and is limited to the Serravallian (not present at Well-4; Figure 2). RRT-4 is a diagenetic reservoir rock type, overprinting RRT-1, RRT-3, and RRT-5. RRT-4 is characterised as dolomitised samples with > 12% dolomite. Dolomitisation generally enhances reservoir quality with the exception of samples interpreted to represent dolomitised RRT-5. RRT-5 shows somewhat reduced porosities and permeabilities when dolomitised. However, overall reservoir quality remains very good.

The pore system is dominated by intercrystalline, between particle, partial moldic, and moldic porosity, as well as minor microporosity (Figure 7).

Sediment texture and structure-mimetic dolomitisation is interpreted to occur early in the burial history after early dissolution and phreatic cementation, but prior to stylolite formation and late cementation. This event was likely initiated between 10.5 and 10Ma during sea-level rise that followed platform exposure, causing platform-top flooding and eventual platform demise (drowning).

Numerous models exist, discribing various diagenetic environments where dolomitisation is interpreted to take place [42]. One interpretation is that the freshwater lens thickness, which is relatively easy to determine based on the exposed platform or island dimensions, acts as an insulator to the dolomitisation front. This scenario favours seawater being the most likely dolomitisation fluid. More recently, the hypothesis of dolomitisation from early CO_2 charge was proposed by Rivers et al. [36]. Post-burial rapid charge of hydrocarbon and CO_2 displaces connate water and causes dissolution of magnesium calcite at the gas-water contact; as described above. Dissolution of red algae (high-Mg calcite) and resulting Mg-ion concentration drives aqueous systems near the gas-water contact toward high-Mg calcite and dolomite saturation. Simulation and reactive transport modeling of CO_2 gas injection into carbonate reservoirs shows CO_2 can drive dissolution and density driven convective mixing [35]. Dolomitisation ceases abruptly at the Serravallian-Langhian boundary, supporting a local source of magnesium for dolomitisation and/or the interpretations that dolomitisation is triggered by high-Mg calcite (coralline red algae) or dolomite "seeds" (nucleation sites) in the sediment. Rivers et al. [36] concluded that dolomitisation appears to preferentially

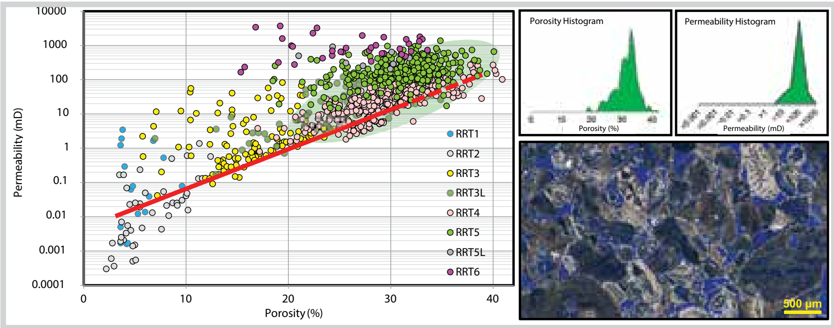

***Figure 10**. Reservoir rock type 5. Displayed are permeability/porosity cross-plot (left) and porosity and permeability histograms, as well as thin section photomicrograph (right). Microporosity line (red), showing microporosity-dominated (below the red micro porosity line) and non-microporosity-dominated (above the red microporosity line) samples [40, 41].*

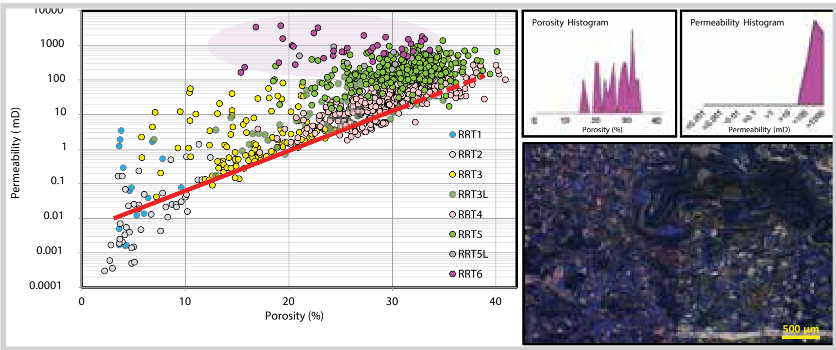

***Figure 11.** Reservoir rock type 6. Displayed are permeability/porosity cross-plot (left) and porosity and permeability histograms, as well as thin section photomicrograph (right). Microporosity line (red), showing microporosity-dominated (below the red micro porosity line) and non-microporosity-dominated (above the red microporosity line) samples [40, 41].*

affect mud-dominated facies. To test this interpretation, pre-dolomite RRTs were interpreted from core and thin sections of Well-2 and Well-3. The results support the initial conclusions made by Rivers et al. [36].

5.5. Reservoir rock type 5 (RRT-5)

Like RRT-3, RRT-5 (Figure 10) is dominantly a rhodolith-LBF grainstone. It dominates Well-3 and Well-4, and, to a minor degree, Well-2 (Figure 2).

RRT-5 can be described as a diagenetically altered (leached) RRT-3. The pore system includes between particle, partial moldic, moldic, as well as minor non-fabric selective vuggy porosity; the latter showing touching vugs. Dominant cement type is meteoric circumgranualar cement. Syntaxial and blocky cements (meteoric and/or shallow burial cements) are less common.

RRT-5 is interpreted to be the result of early meteoric dissolution, most probably related to exposure, and subsequent minor cementation in the meteoric phreatic zone. Later diagenetic, CO_2-related dissolution, might have additionally increased porosity.

5.6. Reservoir rock type 6 (RRT-6)

Like reservoir rock types RRT-3 and RRT-5, RRT-6 (Figure 11) is described as a rhodolith-LBF grainstone, representing a diagenetically altered (leached) RRT-3. Its vertical distribution is limited to the top of the Serravallian at Well-3 and Well-4 (Figure 2). RRT-6 samples show no cementation, but enhanced leaching.

The pore system is dominated by vuggy (touching vugs), partial moldic, moldic, and between partical porosity. The occurrence of touching vugs and the lack of cementation considerably enhances the permeability of RRT-6, compared to all other reservoir rock types.

Like RRT-5, RRT-6 is interpreted to represent early diagenetic, meteoric leaching of the carbonates, related to exposure (epikarst). However, later diagenetic leaching during burial, related to CO_2 invasion is also possible.

6. 3D Seismic Paleo-Structure and Karst Mapping

Paleo-structure reconstructions, showing the antecedent topography of the Ca Voi Xanh platform, can be used to spatially guide the distribution of RRTs. Topographic lows (deeper water) would have a higher probability of being occupied by RRT-1, whereas topographic highs (shallower water) would have a higher probability of being occupied by RRT-3.

Paleo-structure, in conjunction with seismically observed karst can also be used to define potential areas of exposure at top carbonate (Tor1_SB). The extent of exposure is a key control on distribution and probability of meteoric diagenesis associated with RRT-5 and RRT-6.

Two seismic horizons were selected that, when used as a datum, best represent the paleo-structure (antecedent topography) at the onset of Serravallian carbonate depostion and at the time of subsequent exposure at top carbonate (Tor1_SB).

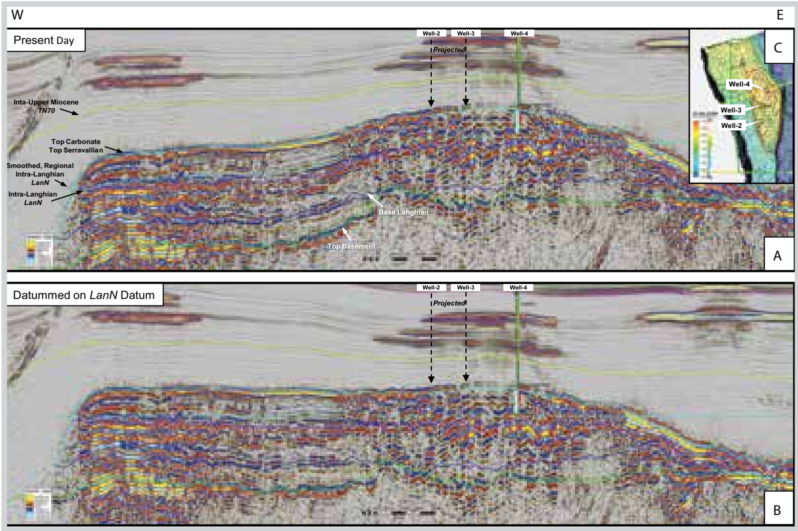

Figure 12. Seismic section showing present day structure (a). Seismic section showing paleo-structure reconstruction using intra-Langhian seismic horizon LanN as datum (b). Paleo-structure map showing position of seismic section shown on Figures 12a and 12b (c).

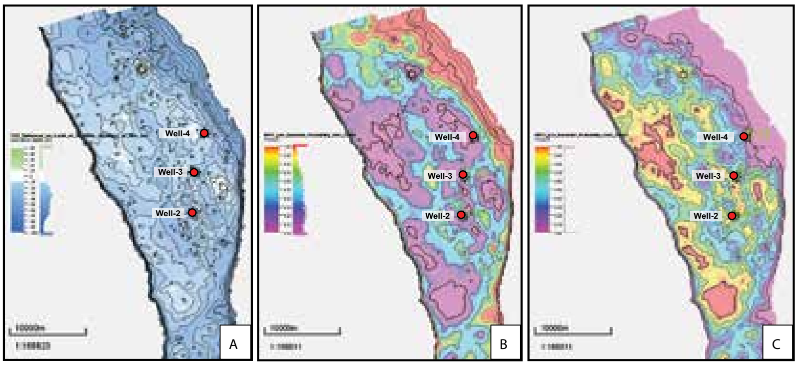

Figure 13. Serravallian paleo-structure map datummed on Langhian seismic horizon LanN (a). RRT-1 probability map (geologic model zone 2) showing high RRT-1 probability corresponding to topographic lows (darker blue areas: deeper water) (b). RRT-3 probability map (geologic model zone 2) showing high RRT-3 probability corresponding to topographic highs (lighter blue/whitish areas: shallower water) (c).

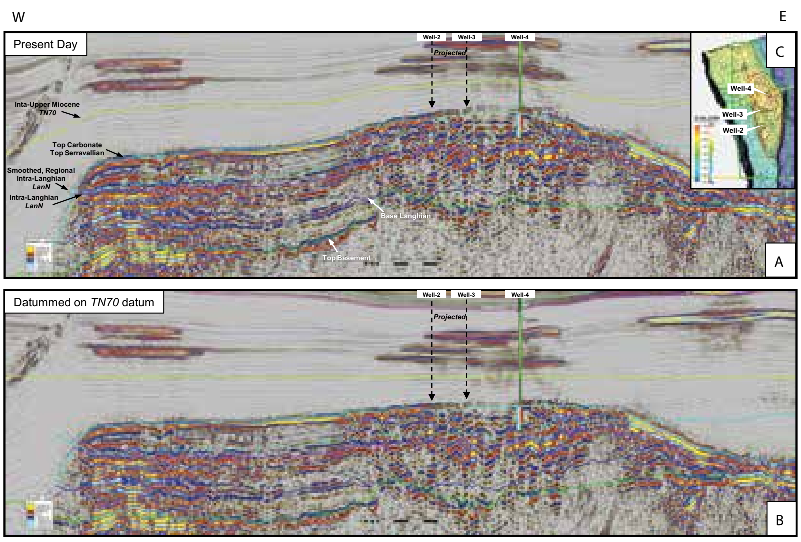

Figure 14. Seismic section showing present day structure (a). Seismic section showing paleo-structure reconstruction using intra-Upper Miocene horizon TN70 as datum. (b) Paleo-structure map showing position of seismic sections shown on Figures 14a and 14b (c).

An intra-Langhian seismic horizon (LanN) was used as datum for representing the paleo-structure (paleo-topography) at the onset of Serravalllian carbonate deposition (Figure 12). It is an interpretive smooth surface, based on anchoring sea-level in areas of strong constructional/aggradational facies on the western and eastern carbonate margins, and interpreting/interpolating paleo-water depth in between these anchor points. The selected surface is one of multiple possible realisations.

Figure 13 shows probability maps of RRT-1 and RRT-3 distribution throughout the lower part of the Serravallian; related to the constructed paleo-structure map. Topographic lows or somewhat deeper water conditions (Figure 13a) correspond to a high probablilty of RRT-1 occurrence (Figure 13b), whereas topographic highs or somewhat shallower water conditions (Figure 13a) correspond to a high probablility of RRT-3 occurrence (Figure 13c).

Within the overburden, an intra-Upper Miocene horizon (TN70) was used to show the inferred extent of exposure at top carbonate (Tortonian paleo-structure; Figure 14). It is a relatively well-defined seismic surface at the top of homogeneous marine shales encountered in all Ca Voi Xanh wells. Below this horizon, the clastic section shows significant thickening due to progradation and loading from the west and southwest.

Figure 15 shows a probability map of RRT-5 and RRT-6 distribution throughout the upper part of the Serravallian; related to the re-constructed Tortonian paleo-structure map. Structural highs (Figure 15a) correspond to more exposure and higher probability of RRT-5 and RRT-6 (Figure 15b). On the contrary, structural lows correspond to less exposure and lower probability of RRT-5 and RRT-6 (Figure 15b).

Observations from the 3D seismic data indicate that there is an extensive

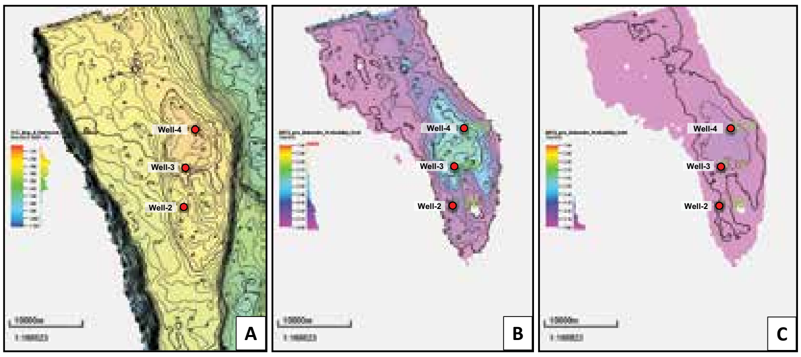

Figure 15. Tortonian paleo-structure map datummed on Upper Miocene seismic horizon TN70 (a). RRT-5 probability map (geologic model zone 3) showing high RRT-5 probability corresponding to structural high areas (b). RRT-6 probability map (geologic model zone 3) showing high RRT-6 probability corresponding to structural high areas (c).

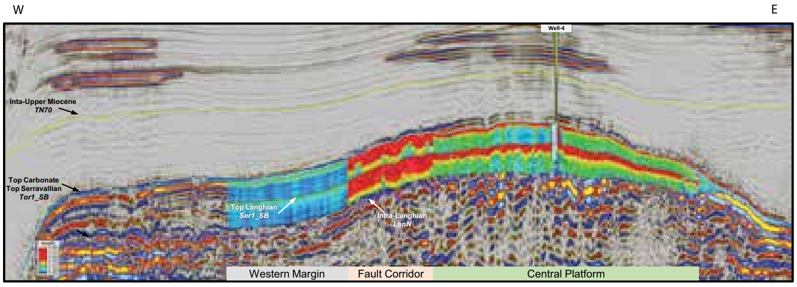

Figure 17. Seismic-conditioned karst density probability (hot colours corresponding to high density probability) co-rendered over seismic section (position shown on Figure 16); following sequence boundaries Ser1_SB and Tor1_SB. Highest karst density probability is directly below sequence boundaries Ser1_SB and Tor1_SB along the Central Platform. Fault Corridor shows highest vertical karst/fracture density. Less karst/fracture density characterises the area of the Western Margin.

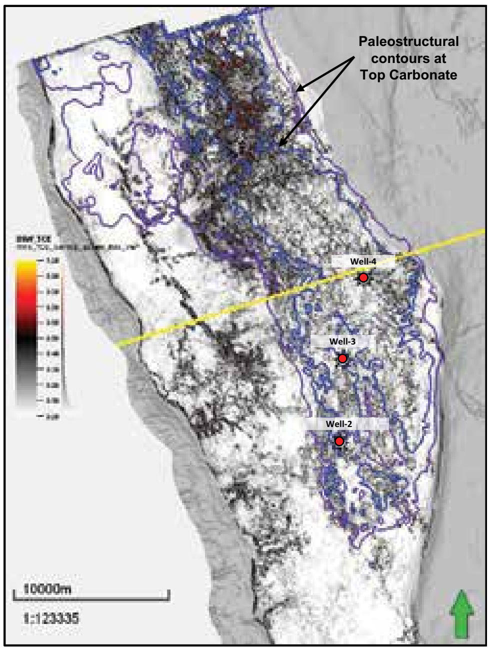

Figure 16. Variance volume draped on top carbonate structure map shows reasonable agreement between paleo-structural top carbonate highs and extent of dense seismically observed karst. Overall density of karst appears to lessen southwards, consistent with the interpretation of being paleo-structurally deeper, but complicated by data quality degradation beneath overlaying gas-filled siltstones. Pattern of western platform/margin karst typical of tidal channels (in paleo-structural lows) consistent with minimal/no exposure of western margin due to structural subsidence at that time. Blue contour line indicates area with greatest intensity of karst network (longest residence time in the meteoric realm). Yellow line shows position of seismic section shown on Figure 17.

karst network on the Ca Voi Xanh structure (Figure 16). Different karst geometries and features consistent with known hydro-geologic processes are identified in the seismic discontinuity cube (variance cube) and are used to interpret karst regions (Figure 17). A variance volume draped on the top carbonate structure map illustrates discontinuities in the seismic data, interpreted to be karst-related features (Figure 16). Observations from seismic data indicate that the platform was not karsted uniformly. There is a high-density network of karst features in the northern part of the platform, but they are more sparsely distributed in the central and western areas. Reduced imaging quality underneath gas-filled siltstones makes it difficult to determine the extent of the karst network around Well-2 and Well-3 in the main field area (Figure 16). Vertical trends in karst density honour the Ser1_SB and Tor1_SB sequence boundaries, resulting in more karst/fractures being populated near these interpreted exposure surfaces (Figure 17). Karst characterisation comprises the non-matrix component of the geologic model [43, 44].

7. Conclusions

Offshore Da Nang (Central Vietnam), Middle Miocene (Langhian and Serravallian) carbonates build the reservoir of the isolated Ca Voi Xanh platform; nucleating on top of the north-south striking Tri Ton horst (Figure 1).

Serravallian carbonates can be described by one third-order composite sequence, comprising three third-order depositional sequences. Four major, regionally correlative sequence stratigraphic surfaces, can be carried across the Ca Voi Xanh platform (Figure 2).

Langhian carbonates are characterized by a photozoan grain association, dominated by hermatipic corals, large benthic (Miogypsina) and, predominantly, small benthic foraminifera, including miliolids, soritids, and alveolinids. A warm, shallow marine, inner shelf environment of deposition is inferred for the Langhian carbonates.

Serravallian carbonates are interpreted to represent a deeper open marine, proximal to distal middle ramp environment. The carbonates are rich in large benthic foraminifera (LBF). Serravallian carbonates represent a typical heterozoan association of organisms.

Early and later diagenetic events rather than primary depositional facies mainly influence reservoir properties. Early, meteoric diagenesis (both vadose and phreatic) is tied to exposure of the carbonates, due to pronounced sea-level falls at the end of Langhian and Serravallian times (Figures 3 and 4). Cement types (cryptocrystalline meniscus, circumgranular, dog tooth, and blocky cements), fluid inclusion and stable isotopes, following the "inverted J" trend, support the interpretation that the carbonates were overprinted by meteoric diagenesis below sequence boundaries (Figure 4b and 4c).

Later diagenetic dissolution of Serravallian allochems rich in Mg-calcite (coralline red algae, and large benthic foraminifera) in the process of porosity inversion, might be driven by acidification of connate marine waters by CO_2 diffusion from the hydrocarbon reservoir down into the aquifer.

Partial dolomitisation of Serravallian carbonates, observed at Well-2 and Well-3, is interpreted to be related to CO_2 and hydrocarbon charging, causing secondary leaching of the Mg-rich coralline red algae and LBFs. This leads to the enrichment of the water with Mg-ions, favoring downward dolomitisation of Serravallian carbonates. The fact that dolomitisation does not cross the Serravallian to Langhian sequence boundary Ser1_SB argues for an internal and very local Mg source, but can also be controlled by the different grain composition of the Serravallian (high-Mg calcite dominated mineralogy) compared with the Langhian (aragonite dominated mineralogy). Dolomitisation of Serravallian carbonates is thought to be triggered by high-Mg calcite seeds or nucleation sites, missing in the Langhian.

A reproducible reservoir rock type (RRT) scheme was developed for Langhian and Serravallian carbonates, using a combination of depositional environment, diagenetic overprint, and reservoir parameters (Figure 5). The Langhian is characterised by two RRTs, depending on the degree of cementation (RRT-3L) and dissolution (RRT-5L). The Serravallian RRTs are separated into dominantly packstone (RRT-1; Figure 6) and dominantly grainstone textures (RRT-2, RRT-3, RRT-5, and RRT-6; Figures 7, 8, 10, and 11). RRTs with grainstone texture show varying degrees of cementation (RRT-2 and RRT-3; Figures 7 and 8) and dissolution (RRT-5 and RRT-6, Figures 10 and 11). Reservoir rock type RRT-4 is a diagenetic RRT, showing partial dolomitisation (>12%; Figure 9). The vertical and lateral distribution of RRTs, supported by seismically-derived paleo-reconstruction of the carbonate platform, adequately describes the matrix component of the Ca Voi Xanh reservoir.

Different karst geometries and features identified in the seismic discontinuity (variance) cube (Figure 16) are used to interpret karst regions with different degrees and/or types of karst. These karst regions are used to populate the non-matrix component of the geologic model. Vertical trendology of karst distribution follows sequence boundaries Ser1_SB and Tor1_SB, populating more karst/fractures near these interpreted exposure surfaces (Figure 17).

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RESERVOIR CHARACTERISATION OF DEEP WATER DEPOSITS: A CASE STUDY FROM MMF30 INTERVAL, HAI THACH FIELD, NAM CON SON BASIN

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Summary

A good understanding of the complexity and architecture of a deep water reservoir type becomes ever more important to optimise its development and production. Recent technology advances such as higher resolution 3D seismic data combined with sequence stratigraphy in deep water reservoir settings and well log evaluation have resulted in enhancement of the understanding of turbidite complex reservoirs. In MMF30 reservoir, the turbidite sand is of good quality with sand thicknesses between 31m and 52mTVDSS, the average effective porosity between 14% and 16%, and shale volume between 22% and 29%.

Key words: *Turbidite, reservoir characteristic, seismic attributes.*

1. Introduction

Hai Thach field is located in Block 05-2, Nam Con Son basin. It was discovered by the exploration well 1 drilled on the Hai Thach horst structure. The well found gas and condensate accumulations in multiple stacked sand in Upper Miocene (UMA10), Middle Miocene (MMH10), and Lower Miocene (LMH10, LMH20 and LMH30). Well 1 has not met MMF30 reservoir. An appraisal well (well 2) was then drilled on the eastern flank of the structure and encountered additional hydrocarbon-bearing Upper Miocene (UMA15) and Middle Miocene (MMF10, MMF15 and MMF30) sandstones.

The MMF30 reservoir was deposited in the deep marine environment during the syn-rift of Nam Con Son basin. This reservoir has then been confirmed by three more producing wells, namely well 3, well 8, and well 9. According to well evaluation, MMF30 interval is a good reservoir with 14 - 16% average effective porosity and the gross sand thickness from 31m to 52mTVDSS. The distribution of this reservoir was also mapped by using seismic attributes such as AVO and Spectral-decomposition (Discrete Fourier Transform). This attribute mapping shows the fan size of approximately 2km in width and 5km in length.

The research on MMF30 reservoir characterisation and implication was carried out to understand the reservoir quality, distribution, and connectivity in order to optimise the field development and production.

2. Geological setting

Block 05-2 is located in a rift basin, named Nam Con Son basin, which overlapped the Indochina platform structure. Rift pulses occurred from the Palaeogene to the earliest Late Miocene. The general stratigraphy and structure were recorded as the pre-rift stage during Eocene to Early Oligocene, the first syn-rift stage from late Early Oligocene to Late Oligocene, the subsidence stage during Early Miocene; the second syn-rift stage up to Middle Miocene and the post-rift from Upper Miocene to recent time [1,

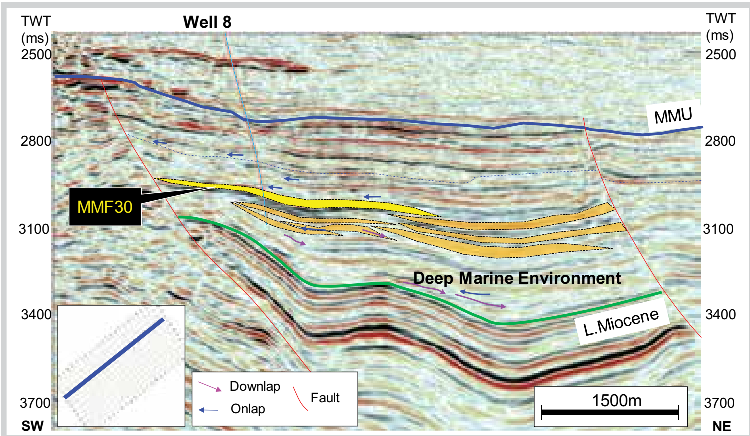

Figure 1. Illustration of turbidites developing strongly around T50 period with seismic features such as downlap and onlap terminations. Yellow colour shows MMF30 interval deposited above the surface of T50 sequence.

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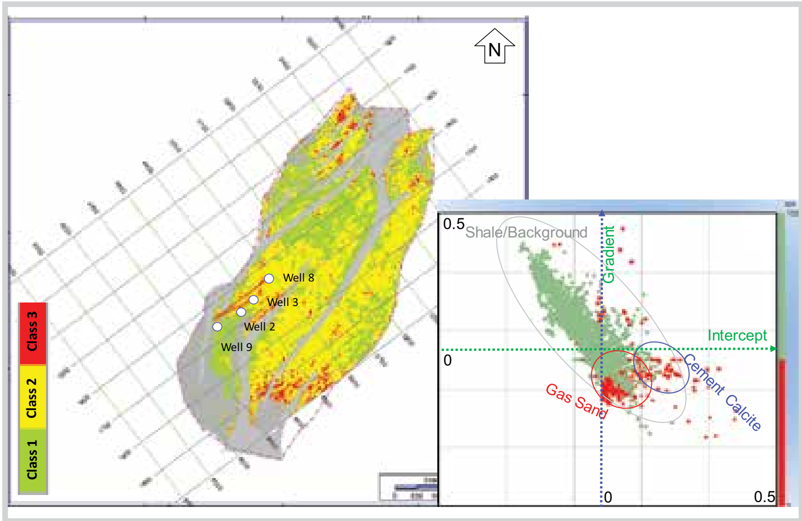
2]. The rifting period contains the study interval (MMF30 reservoir).

Depositional environment during rifting phase were predominantly shelfal to basin floor with both clastic and carbonate sediments preserved, the upper part of this composite sequence is characterised by the preservation of deeper water clastic sediments. There is an overall back-stepping of facies belts observed from T40 to T60 (MMU), and an increased variation in facies, palaeoenvironments and thickness. The uplift and/or magnitude of erosion on some footwall highs have resulted in the absence of T60 (MMU), either through non-deposition or erosion. The top of MMU is the most prominent unconformity in the Nam Con Son basin. It is characterised by local erosional truncation, and by a basinward shift of facies in deep-water settings. Structural discordance is locally developed, and is observed best in the southeast where it is interpreted to result from footwall uplift and mild inversion. The unconformity was enhanced in deeper marine settings by submarine channelling which eroded underlying sections, and may itself have been further modified by subsequent younger channelling events. Nannofossils and foraminifera date T60 as Middle-Miocene [1].

3. Database and methodology

Datasets used in this study include high-resolution 3D seismic data in both time and depth domain, four (4) wells with full log curves, FMI (1 well), conventional core images (1 well) and some results of petrographic analysis of wells (4). The 3D seismic data covering an area of approximately 1,000km^2 are of very good quality with high resolution, inline and crossline spacing of 12.5 x 12.5m. The dominant frequencies are from 30Hz to 60Hz. The seismic attributes including AVO and Spectral-Decomposition were used to interpret and predict distribution of turbidite MMF30 reservoir. The workflow of this research is defined in the following steps:



(a) (b)

Figure 2. *Agreement results between AVO from seismic and AVO from wells. (a) AVO from seismic analysis and (b) AVO from wells. Both shows mainly the AVO class 2/3*

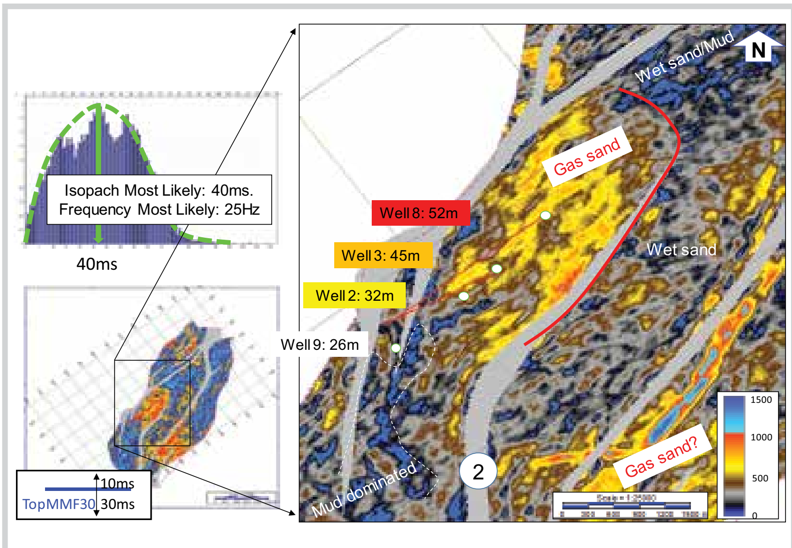


Figure 3. *Distribution map of spectral decomposition at most likely 25Hz frequency of MMF30 interval (The colour values from 1,000 to 1,500 is to focus on the background map). Hot colours reflect sandstone thicker than cold ones and have good connectivity of sand as well.*

- Step 1: Sequence stratigraphy and paleoenvironment study;
- Step 2: Seismic attribute analysis;
- Step 3: Well log evaluation;
- Step 4: Structural sedimentology interpretations.

Step 1: Sequence stratigraphy and paleoenvironment study

According to seismic sequence stratigraphy, it can be seen clearly that MMF30 interval was formed within the period of strong development of turbidites/slumps as downlap and onlap terminations (Figure 1) [3]. This interpretation has been supported by other data, such as biostratigraphy and sedimentology features.

Step 2: Seismic attribute analysis

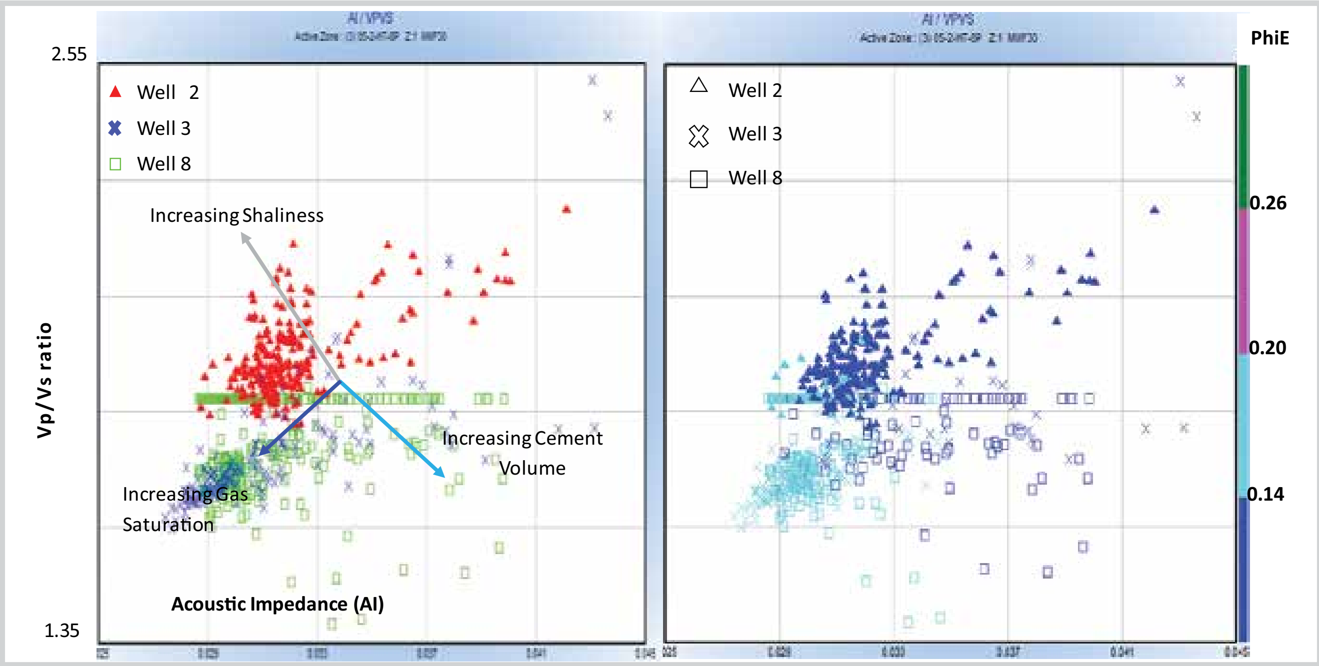


***Figure 4.** The cross-plot of AI and Vp/Vs of three wells with PHIE signatures is to compare the quality of MMF30 of well 2 showing more shale volume than others, while well 3 and well 8 representing high percentage of cement calcite*

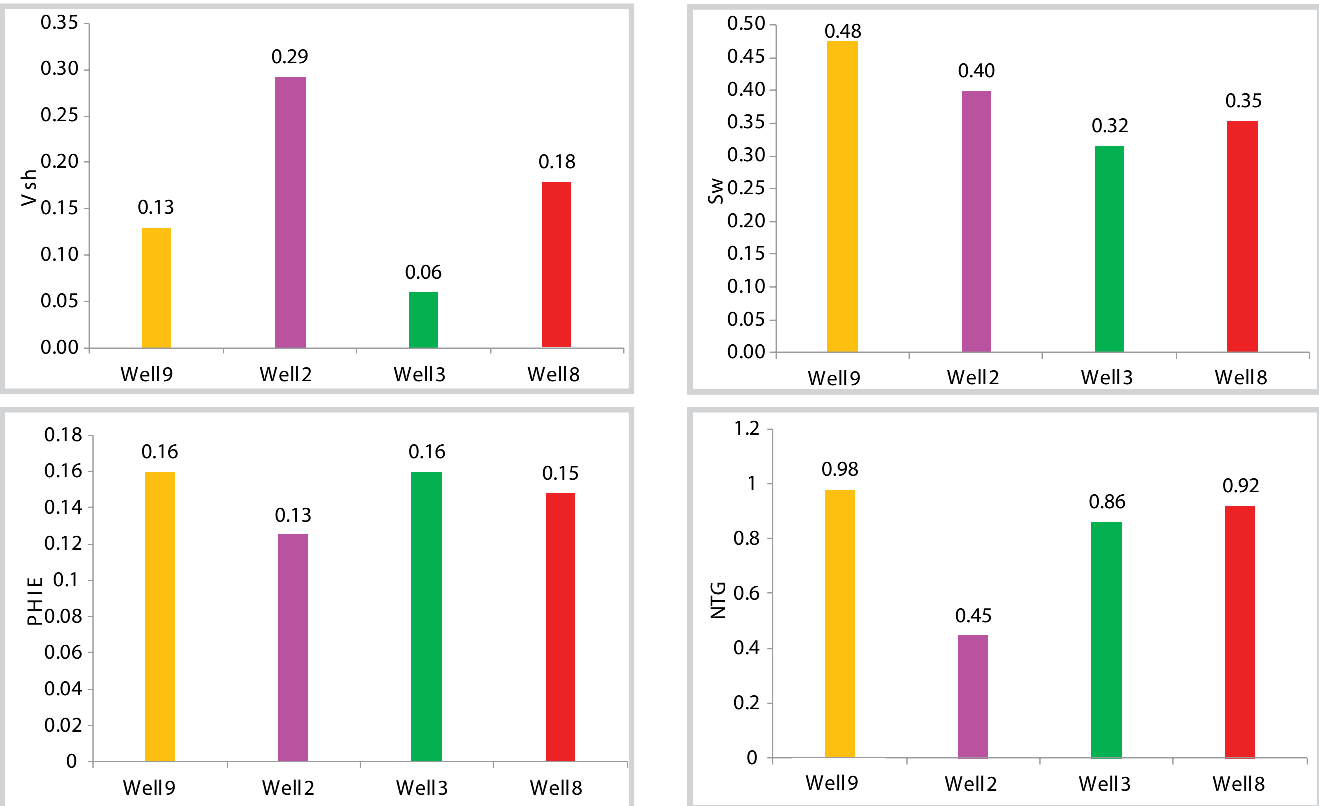


***Figure 5.** Reservoir quality of MMF30 interval based on log interpretation results. Well 2 has the highest shale volume and the poorest value of porosity*

Based on well logs, parameters of Vp, Vs, RHOB and NPHI of the four wells 2, 3, 8 and 9, AVO classes could be predicted as class 2 or 3 mainly (Figure 2).

Both AVO and Spectral decomposition attributes have been carried out to map MMF30 reservoir distribution. Spectral decomposition is a relatively common processing technique that allows anomalies to be identified corresponding to not only the sand distribution but also the presence of hydrocarbon in a reservoir (Figure 3) [4].

Step 3: Well log evaluations

Integrated data of log analysis and petrography for MMF30 reservoir qualitatively and quantitatively for four wells were evaluated to improve the understanding of the reservoir characterisation and implication. The results of well-log interpretations were demonstrated and compared to each other (Figures 4 and 5).

Step 4: Structural sedimentology interpretations

Generally, Bouma sequence is a favourite sequence deposited within deep marine environment. Each single Bouma sequence contains specific sedimentology structures. Ta has massive sand graded feature, Tb has plane parallel laminae feature, Tc has ripple, wavy or convoluted lamilae features and other upper layers (Td, e) are massive shale graded. According to conventional core images of well 8, the base of turbidite and its features of each sequence can be observed and interpreted as well (Figure 6) [5].

4. Results and discussion

According to published studies, MMF30 reservoir is deposited in deep water environment and interpreted as turbidite deposits. Moreover, based on conventional cores taken from well 2 and well 8, turbidite deposits cycles named Ta, Tb and Tc can be observed clearly. They were known as cycles of Bouma sequence (Figure 6). In addition to seismic sequence stratigraphic features, MMF30 interval was recognised as downlap and onlap terminations (Figure 1). These features were formed during sedimentation of turbidite deposits. The paleo-thrust submarine fan was seen clearly on seismic sections as truncational facies.

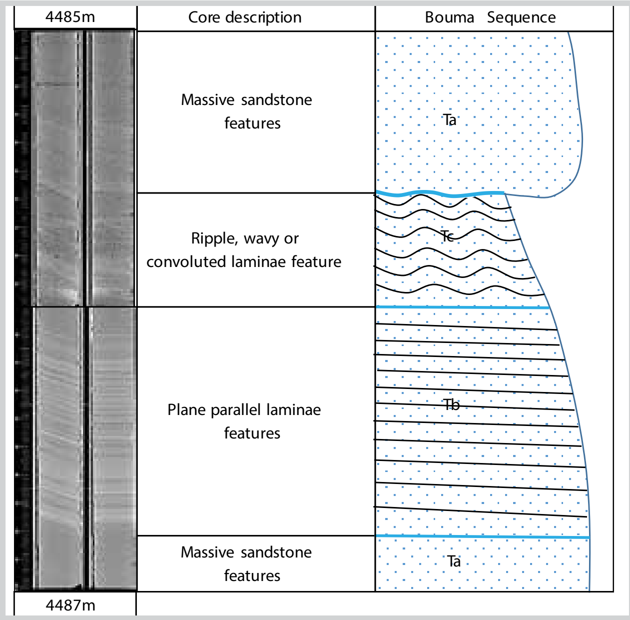


Figure 6. *Example of core interpretation of well 8 indicating deposition of stacked turbidites from 4,485 to 4,487mMD*

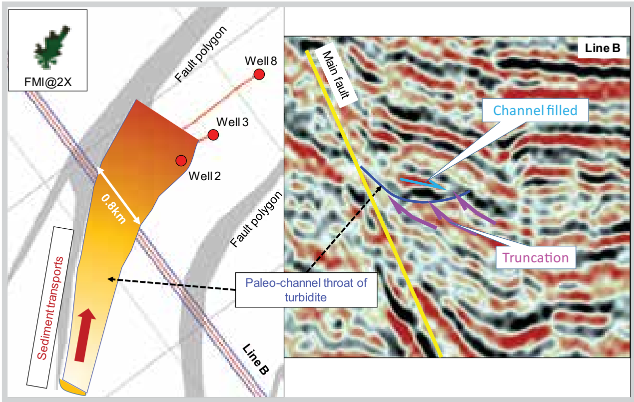


Figure 7. *The paleo-channel throat of turbidite flowing below MMF30 interval (Blue line is top of MMF30) can be seen on the seismic section*

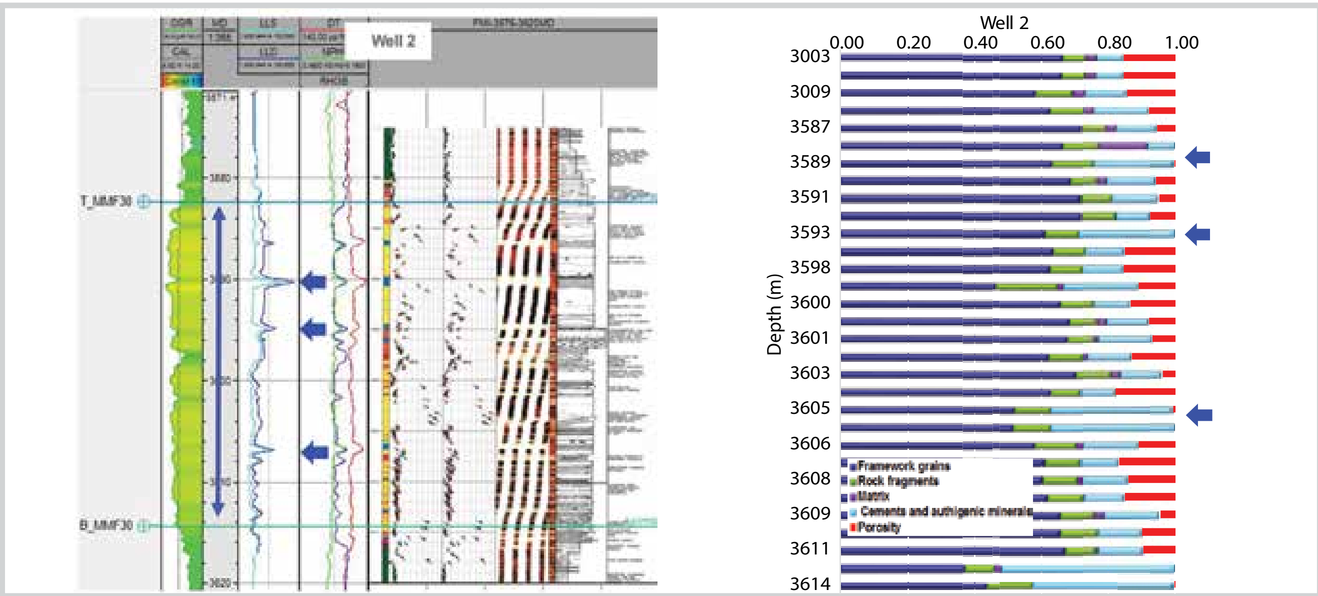


Figure 8. *Highlighted high cements (blue arrows) and authigenic minerals in some intervals of MMF30, well 2*

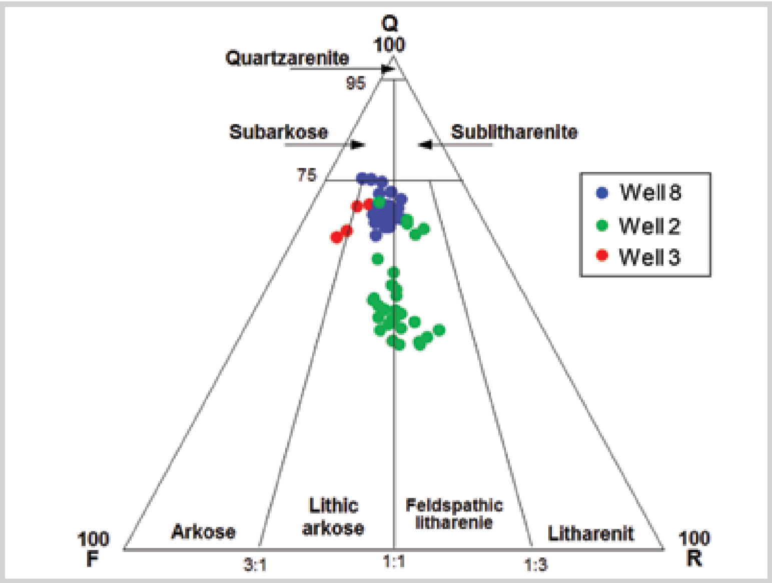


***Figure 9.** Classification of sandstone with more than 15% fine grained matrix from the three wells: well 2 (core), well 3 (cutting) and well 8 (core) (after R.L.Folk 1974)*

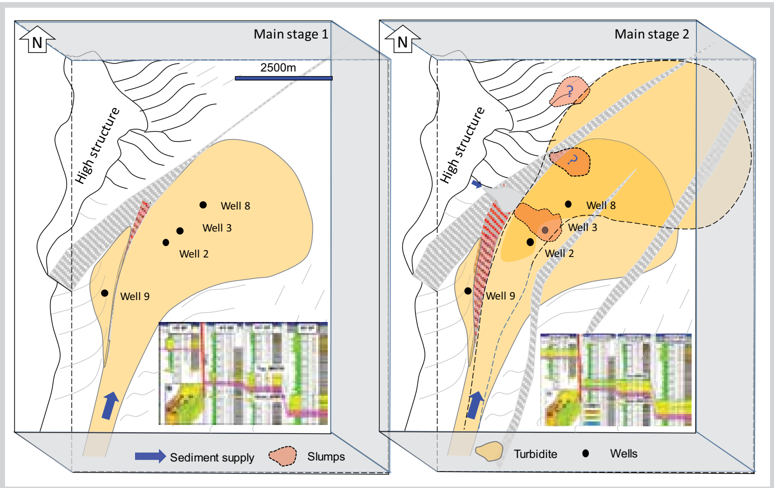


***Figure 10.** Schematic model showing two main stages of development of MMF30 reservoir in Hai Thach field*

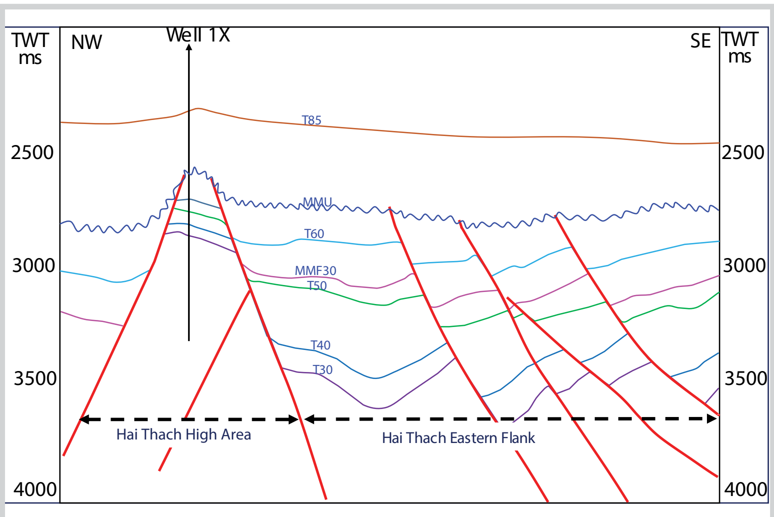


***Figure 11.** Schematically section through NW-SE trend*

Integrated with FMI interpretation, the direction of the main sediment supply is from SW to NE (Figure 7) [6].

Distribution of MMF30 reservoir can be seen and mapped on both attribute maps (AVO and Spectral Decomposition). Figure 3 of Spectral Decomposition map shows dimensions of the MMF30 sand fan approximately 2km in width and 5km in length. The dim area to the South - South West of well 2 could be related to lithology change from sandy to muddy facies. The red line in the North East reflecting bright to dim amplitudes could be linked to fluid phase change (gas to water contact). Fault 2 as labelled on the map is post-depositional fault, therefore the lithology on both sides could be similar. Thus, the difference in AVO/Spectral Decomposition map in both hanging wall and footwall likely relates to fluid types (gas reservoir on the footwall and water wet on the hanging wall).

The cross-plots of petrophysical parameters of MMF30 reservoir can be evaluated and verified by the results of log interpretation as well [7, 8]. Average porosity varies from 13% (well 2) to 16% (well 3) with gross sand thickness variation from 31 to 52 metres. This reservoir is a gas bearing zone with 60% to 70% of gas saturation. These results show that the quality of MMF30 at well 2 has not reflected so well as others (Figures 4 and 5).

Sedimentological analysis of well 2 cores indicates the lower slope to inner submarine fan depositional setting for MMF30 sequence (Figure 8). Further to the North East of well 2, the core features of well 8 show numerous stacked turbidite deposit cycles with thick massive sand in the lower part indicating rapid deposition and it is overlain by lamination sand and shale layer which can be contributed to different portions of a Bouma sequence. This is reflected by the sedimentological structures of core samples at well 8 (Figure 6). The debris-flow deposits which are indicated in well 2 by abundant mud-clast with different orientation cannot be clearly recorded in well 8. This suggests that the progradation of shelf-slope during formation of MMF30 interval was limited around well 2 and it did not extend to well 8. Well 8 is therefore mostly located in inner to mid submarine fan. The well log curves of well 3 and well 8 show amalgamated stacking patterns on GR curve indicating their formation during the regressive period. The formation of transgressive shaly layer in the middle part of well 2 could be related to a rapid flooding period which cannot be observed in the other two wells. In general, there are series of SW-NE elongated stacked fan-lobe turbidites in Hai Thach field which are probably resulted from syn-rift activities of southwest-northeast trending faults during the Middle Miocene.

According to sedimentological analysis, MMF30 interval is mostly fine to very fine sandstone with moderate to well sorted, which are subjected to Lithic Arkorse/Feldspathic Litharenite in Fold's classification (Figure 9). Classification of sandstone with more than 15% fine grained matrix among these wells indicates lower proportion of quartz contents of well 2 than that at wells 3 and 8. This could be interpreted that sediments at the well 2 location were deposited closer to the source supply than that at wells 3 and 8 due to the presence of less amount of any stable materials (quartz). Moreover, petrography analysis shows that the high cement content of calcite is an important key factor to reduce porosity. In addition, some thick calcite veins observed from log curves and sample analysis could be deposited from high carbonate structures formed in previous time (Early Middle Miocene) nearby Hai Thach field (Figure 8).

By integrating all data, it aims to define detailed subsurface for correlation of MMF30. As mentioned, some clear subsurfaces can be recognised to separate MMF30 interval into at least 3 main different zones. According to the correlation of MMF30, the conceptual model environment for this interested interval was constructed to demonstrate the MMF30 deposits. Figure 10 represents two main stages of MMF30 turbidites formed. Some slumps locally could be formed during the syn-rift period from local high structures.

It can be seen that a strong linkage between physical stratigraphy, depositional environments and reservoir architecture has been found in the MMF30 reservoir, turbidite sandstone. The advantages and limitations of development and production management at MMF30 reservoir provide a unique chance to test many of these deep-water reservoir/turbidite sandstone concepts, assumptions and interpretations regarding reservoir heterogeneity, connectivity and lithofacies distribution. These understanding and learnt lessons will be critical to the successful pursuit of future deep-water exploration, development and production opportunities.

5. Conclusions

Integration of geological and geophysical data showed the quality of MMF30 reservoir around the well 8 area is the best and decreasing to the North West (well 2) direction. Cores and log signatures around well 8 and well 3 show an amalgated sheet sand features (Mid fan) while around well 2 in upper most of fan with sand connectivity reducing around upper and outer fans. Some calcite veins could be considered as good markers and correlated from well to well.

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A NEW INTEGRATED APPROACH OF NATURAL FRACTURE MODELLING TO IMPROVE HISTORICAL MATCHING AND PREDICTION FOR DEVONIAN CARBONATE RESERVOIRS IN NENETSKOYE OIL FIELD, RUSSIA

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Summary

Natural fractures associated with karst systems certainly exist in a tight Devonian carbonate reservoir of the study field with primary porosity and permeability typically less than 3% and 1mD, respectively. Up to now, several workflows have been implemented to model natural fractures and karst networks; unfortunately, existing results cannot be used for managing the field in the future. This paper presents a new integrated approach to build the 3D geological model and simulation for Devonian carbonate reservoirs based on geology, geophysics and production data. With two kinds of reservoir porosity (primary and secondary porosity), the conventional stochastic pixel-based method is applied to populate the porosity and permeability distribution of matrix while the objective-based method is used to model vuggy affected cells along fractured zones which were defined from seismic curvature attributes. The properties of fracture corridors are predicted from the power law function of core, well and seismic data, which are consequently modelled by the Discrete Fracture Network (DFN) method and upscaled by ODA's method. The approach reflects better in matching based on 5 years of production and pressure history. Finally, various development scenarios are investigated.

Key words: *Carbonate reservoir, fracture modelling.*

1. Introduction

Natural fractures and karst networks significantly influence hydrocarbon production. Especially in this field, natural fracture networks associated with karst features existed in Devonian carbonate reservoirs such as IV, IIIa and III interval (Figure 1) based on core, BHI and production data. Fractured reservoirs are extremely hard to characterise, model and simulate due to the heterogeneity and irregular distribution of fracture properties and karst networks within the matrix background [1]. From a static point of view, the three-dimensional variability of the fracture networks associated with variations of matrix properties is a key parameter to assess. From a dynamic point of view, the large difference in flow behaviour observed between nearby wells should be understood to build predictive simulation models.

According to the heterogeneity of fractured reservoirs, any characterisation study should conclude analysis and close incorporation of multi-scale data of various origins [2]. In this paper, we describe such an integrated approach, from geology, geophysics to reservoir engineering,

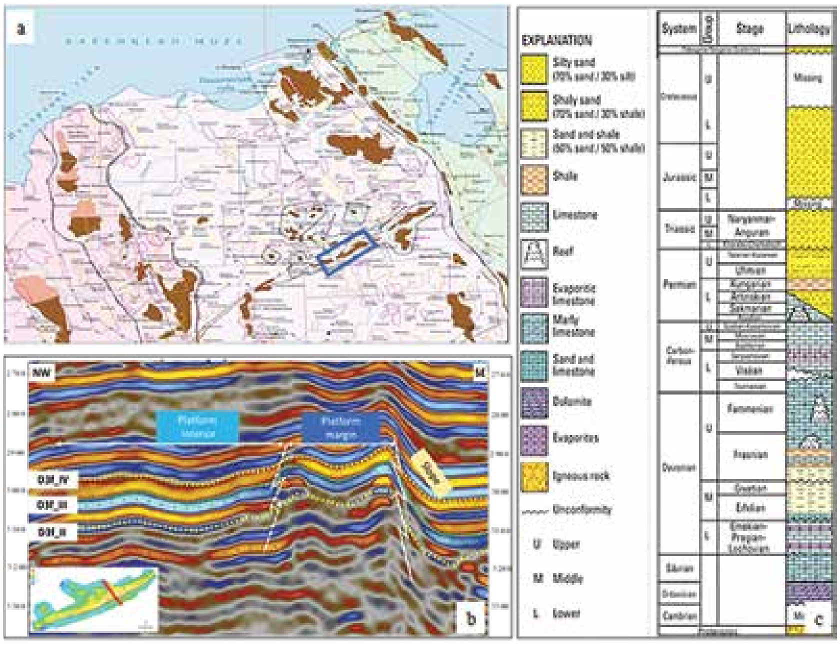

Figure 1. *The location of the study area (a); the section shows the carbonate platform of reservoirs (D3fm) (b) and general lithology of the field (c).*

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for the characterisation and modelling of natural fracture networks occurring in a Devonian carbonate reservoir of the field in Russia. The reservoirs are tight carbonnate with matrix porosity and permeability less than 3% and 1mD but extremely high permeability of 5 - 10D estimated from well test and production data, emphasising the importance of natural fracture networks on production.

2. Database and methodology

The available data sets in this study include 3D seismic data of depth domain, 96 wells with full log curves, FMI (36 wells), conventional core images (5 wells) and the results of the well interpretations and production data. The 3D seismic data covering a fulfill study area are of good quality with inline and crossline spacing of 25 x 25m. The seismic curvature attributes were used to interpret and predict distribution of faults and large fractures.

The main task of the effort presented was to build a representative, multi-scale fracture model of the reservoir. This implied a correct assessment of the components of fracturing (large-scale fracture corridors, sets of small-scale diffuse fractures), their properties (orientation, dip angle and density; aperture and conductivity) as well as their possible variability. This was achieved through an integrated workflow combining the analysis of geological, seismic and dynamic data. The main steps of the workflow include:

- Indicate a model concept of a depositional environment for each unit reservoir;
- Build 3D geologic model based on seismic, well data, and geologic concepts;
- Fracture analysis from cores, wells and seismic data;
- 3D fracture modelling and upscaling method;
- Build dual-porosity/dual-permeability simulation model;
- Validate model based on agreement with production data;
- Prediction and infill well plans.

The final output of this fracture characterisation and modelling effort was a set of matrix/fracture properties (porosity, permeability) computed in each cell of the simulation grid. Such fracture parameters are uncertain and usually very difficult to assess but are obtained in our methodology as an output of an integrated study whereas many other simulations require them as input parameters.

In a next step of simulation, satisfying a nice match of 5 years producing, and some historical pressures were reached with only minor adjustments of the fracture properties computed, showing the accuracy and adequacy of the fracture model.

Figure 2 presents the sensitive workflow to build up natural fracture networks. The workflow focused on the steps of fracture network modelling.

3. Conceptual geology

From a view of depositional environment, conceptual model plays an important role in constructing the

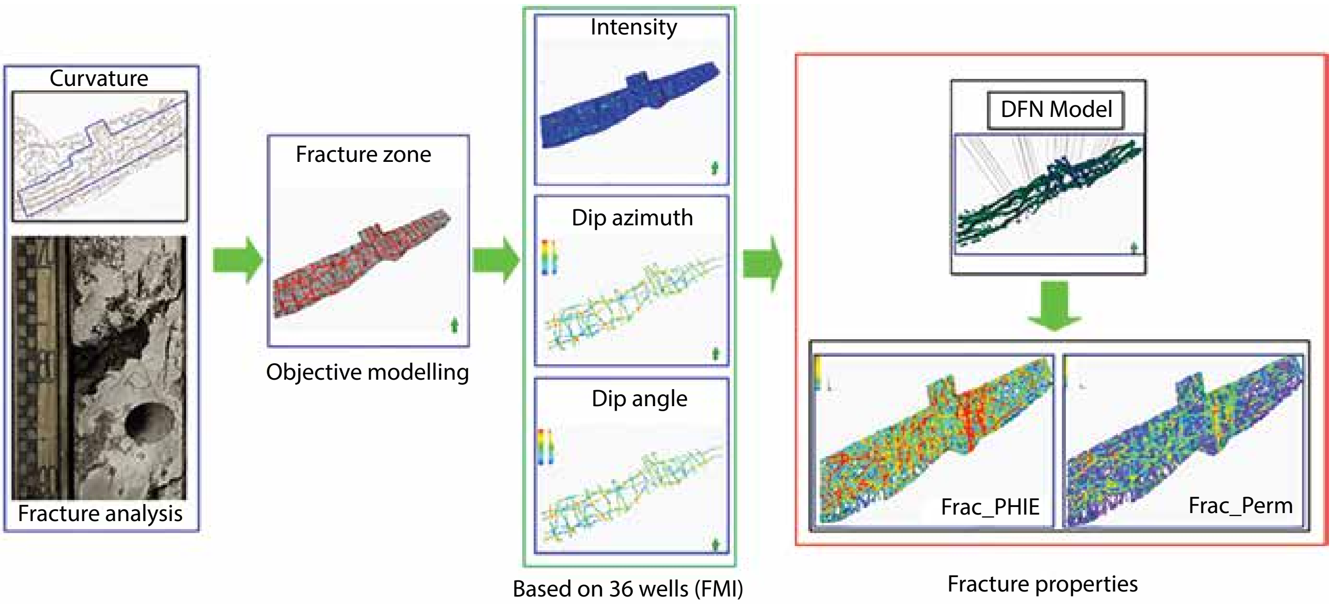

***Figure 2.** The sensitive workflow is to model fracture networks based on G&G data of the reservoir.*

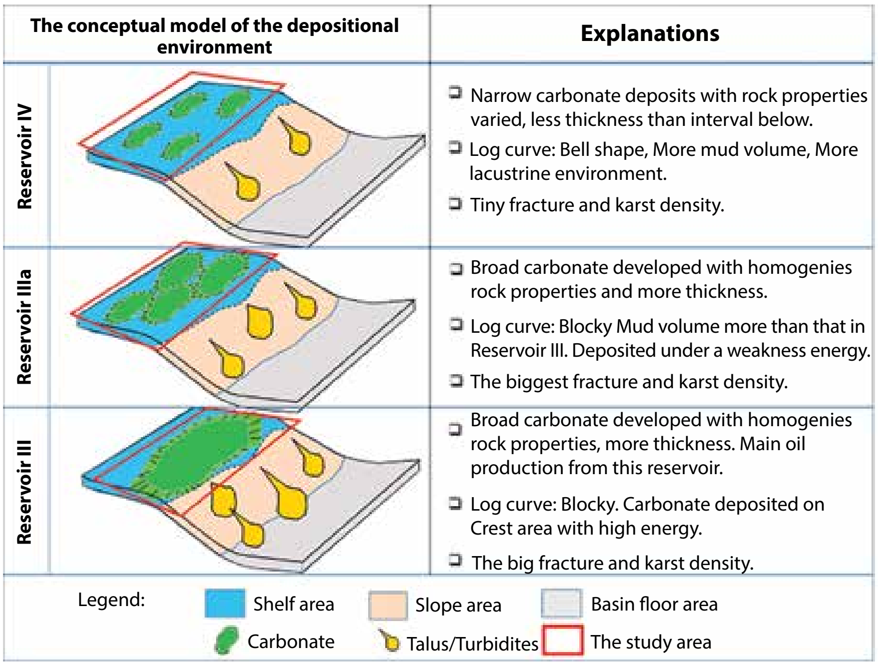

Figure 3. *The conceptual model of the depositional environment of each reservoir.*

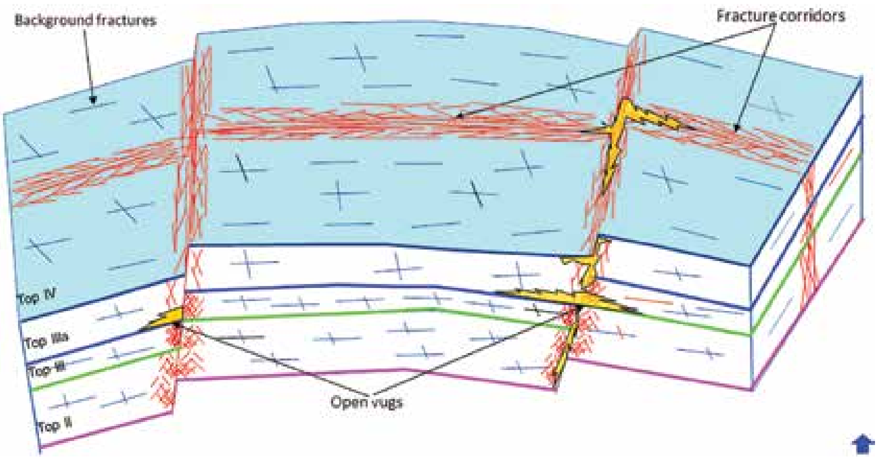

Figure 4. *A schematic diagram showing the conceptual model to populate fracture corridors (zone) and fracture geometry of the tight Devonian carbonate reservoirs in the Timan basin, Russia based on available core, BHI and seismic data. The figure shows that Reservoir III has the highest fracture density while Interval IV has the lowest one.*

reservoir properties. It helps to understand how lithology develops and how facies distribute in the study area. Based on core samples, the well log interpretation, structural geometry of field through seismic sections and maps as well as references of previous studies, reservoirs are considered as a carbonate platform deposited during Devonian period (D3fm) (Figure 1b). The conceptual model of the depositional environment for each sub-reservoir (Reservoir IV, IIIa and III) has been constructed and described in detail in Figure 3.

In particular, many ideas to model natural fractures and karst systems in a tight carbonate reservoir are carried out globally. Moreover, each certain concept cannot be applied to all fields effectively. This paper shows a successful conceptual model of natural fracture network for Devonian carbonate reservoirs. The distribution of fractures based on cores, well log, seismic and 5 year-production data was modelled via an objective-based method, which the method was applied to model vuggy affected cells along fractured zones that were defined from seismic curvature attributes. The properties of fracture corridors are predicted from the power law function of well and seismic data, which are consequently modelled by the method of DFN. The ideal model to populate fracture corridors (zone) and fracture geometry is presented in Figure 4.

4. Interpretation and discussion

The reservoir framework has been modelled based on the final seismic interpretations such as main key horizons (Figure 1) and fault systems. In combining with 94 well log data, the reservoir properties of matrix were generated by applying Gaussian Simulation or Sequential Gaussian Simulation Algorithm after completing well log analysis and evaluating variograms of the major/minor and vertical directions. Moreover, water saturation was computed via Leverett's J function [3] based on 145 Pc curves from 5 wells of the field, while the permeability of matrix was generated from a relationship between core porosity and core permeability within each layer. With uncertainty of each parameter such as structural maps, facies, petrophysics distribution and oil properties, 200 realisations have been investigated to choose a base-case of the 3D geological model. The base-case is selected to move to next steps for matching and forecasting. Figure 5 illustrates the workflow as well as the base-case properties of 3D geological model.

Cores were available in 5 wells in the field. Their analysis exposed the existence of two main types of natural fractures in the reservoir units (Figure 6): (1) Fractures

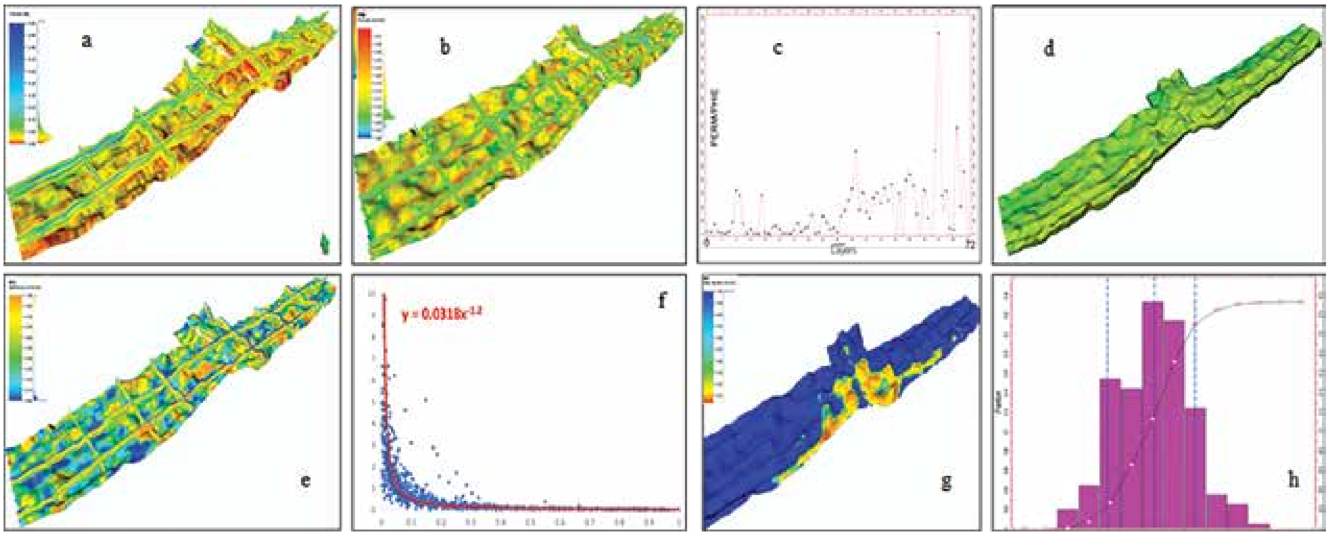

Figure 5. Mud volume modelled (a); Porosity modelled (b); The relationship of porosity/permeability for each layer (c); Matrix permeability modelled (d); NTG modelled (e); Leverett's J function was applied to determine water saturation (f); Water saturation modelled (g); Uncertainty with 200 realisations of 3D geological model (h). All; results show the base-case properties.

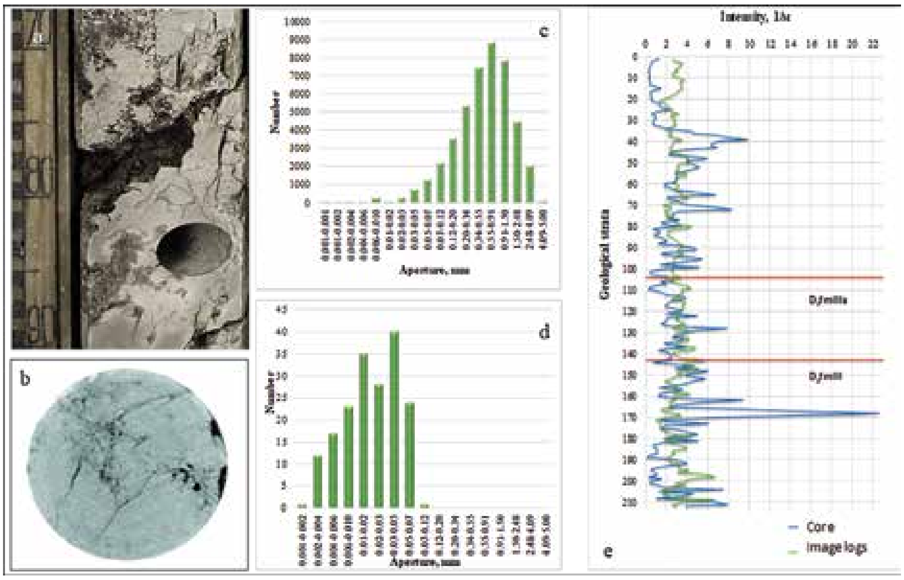

Figure 6. Core feature with vuggy/fractures (a, b); Distribution of aperture from BHI data with 0.842mm of average aperture (c); Distribution of aperture from core data with 0.023mm of average aperture (d); Intensity of fracture based on BHI and core data, using to model natural fractures (e). Intensity varies among units from 0.5 up to 22 (1/m).

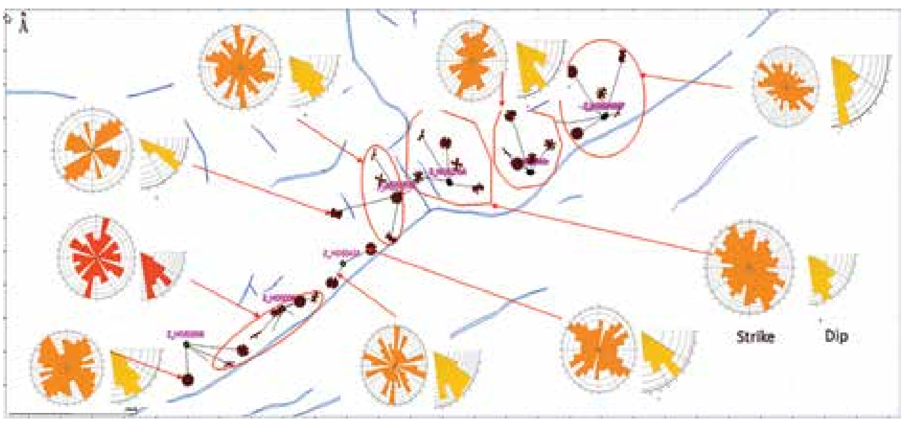

Figure 7. Strike and dip of fracture through well in Reservoir III show two main orientations such as NE-SW and SE-NW trend.

relate to processes occurring during the transformation. They are characterised by small dimensions. These characteristics suggest that they could not have an important impact on fluid flow and, as such, that they are treated as pseudo matrix in the reservoir model in this study; (2) Tectonic fractures, related to the deformation of cohesive rocks under stress. They were frequently observed, with large dimensions and no or partial cementation. These attributes suggest a possible important impact on fluid flow, indicating that tectonic fractures are the natural fractures to be represented in fracture models of the reservoir.

Thirty-six wells with acoustic image logs were available to interpret fractures and only the fractures considered as high or medium confidence features, based on the continuity of their traces on the images, were used for the analysis. Figure 7 demonstrates the strike and dip of fracture through well in the field, in which two orientations

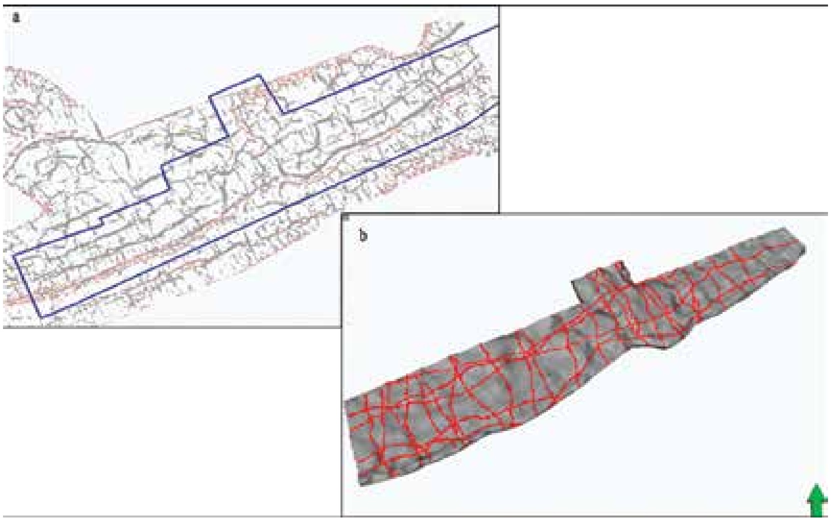

Figure 8. Seismic curvature attribute shows NE-SW and SE-NW main fractures corridor/fault trend (grey colour) (a); Corridor fractures (red colour) were modelled via the objective base method (b). Both of pictures are on top Reservoir IV.

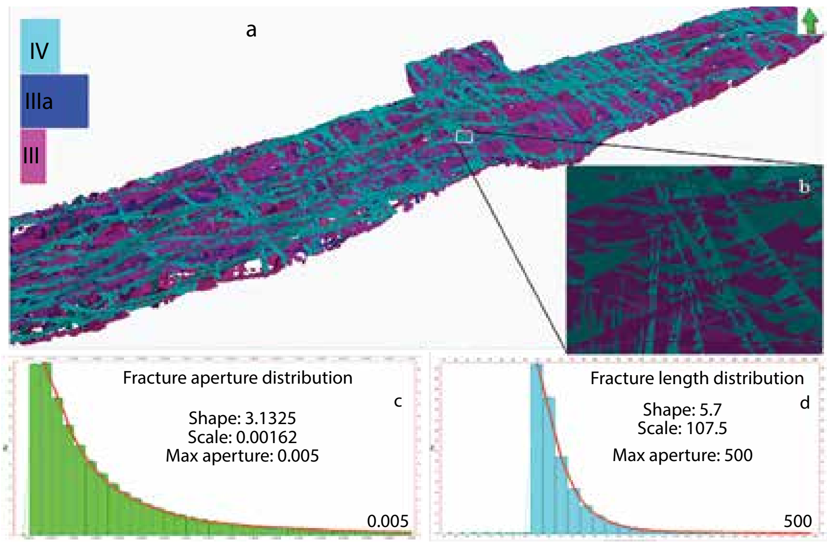

Figure 9. The fracture geometry modelled in fracture corridors of reservoirs (IV, IIIa and III) (a); Zoom out of fracture geometry to observe orientation of small fractures (b); The function of fracture aperture and length, respectively used to model and follow power law function (c, d).

of fracture such as NE-SW and SE-NW trend with dip value similarly can be seen clearly. Intensity, length and aperture of fracture were analysed based on BHI and core data. Figure 8 presents the result of fracture aperture analysis from core and BHI. Generally, the length and aperture of fracture were analysed from core, BHI, outcrops, and seismic attributes under power law function. The intensity of fracture was estimated from FMI through wells in the field. The results of fracture intensity show that Reservoir III has the highest intensity while Reservoir IV has the lowest one. All the mentioned information of fracture has been used to populate and model geometry and properties of fracture shown in later stages.

Seismic data (top horizon, faults and seismic attributes) were used to complete the detection of seismic faults by the identification and mapping of sub-seismic faults which are expected to form fracture corridors. Seismic curvature attribute performed on the top reservoir horizon is done to allow the validation and extension of the seismic faults, and the detection of many new fracture lineaments. These lineaments have NE-SW and SE-NW orientations, consistent with seismic fault orientations. Figure 9a shows all of the large fracture corridors occurring in the reservoir and served as a basis for the modelling of such features.

Once the fracture characterisation was completed, the information obtained in terms of the components of fracturing, their distribution in the reservoir units and their possible dynamic impact was used to build a 3D fracture model using an advanced modelling methodology [2].

As seen in the early stage of fracture analysis, two types of tectonic fractures occur in the reservoir intervals and should be represented in the DFN model: small-scale diffuse fractures with NE-SW and SE-NW orientations, and large-scale fracture corridors. The diffuse fractures were generated using an objective stochastic process based on considering diffuse fracture density established among seismic lineaments. The mean orientation in the fracture sets was interpolated in the 3D grid from values at wells with probability histogramestimated by fracture set based on wells results. Fracture lengths were considered to obey a power law distribution, as observed for larger-scale fracture corridors (Figures 8 and 9). The diffuse fractures were bounded by sub-layers created in each cell of the 3D grid. The DFN model built was controlled in order to check the expected behaviour in terms of fracture density and connectivity.

The modelling of large-scale fracture corridors was based on the interpretation of faults in seismic and

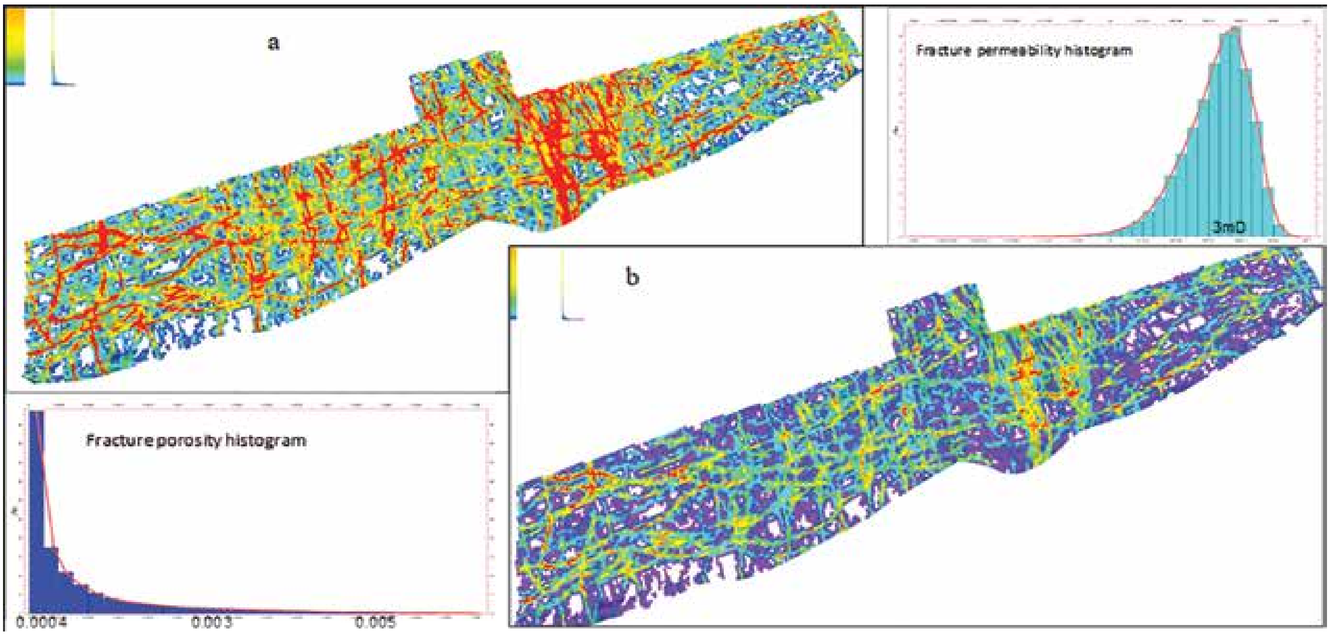

Figure 10. *The porosity distribution of fracture modelled with very small value (a); The permeability distribution of fracture modelled with most-likely 3mD of value (b). Both distributions show on top of Reservoir IV. The properties are the results of ODA's upscale method.*

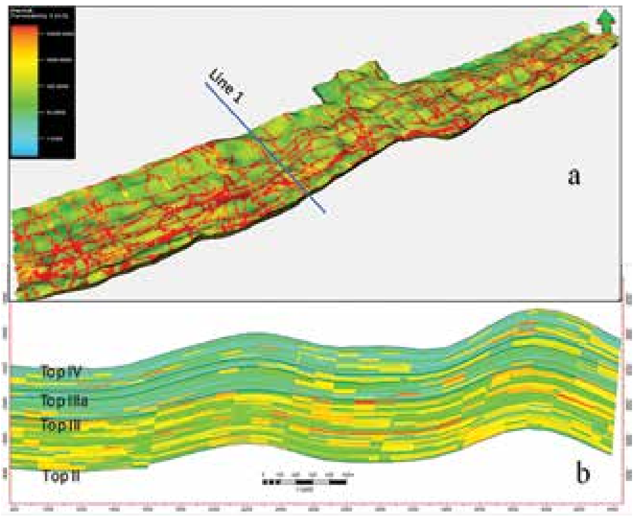

Figure 11. *A simplified dual permeability modelled when combining matrix and fracture permeability (a); An example section (line 1) of the simplified dual permeability model (b).*

lineaments derived from curvature analysis and seismic facies analysis. The position and geometry of the seismic curvature attribute were used to create fractured zones and tied to well data in the reservoir by objective-based method. These corridors were represented at the center of the fractured zones, cross-cutting all of the layers of the reservoir grid. Figure 9a illustrates the main trend of fractured zones based on the seismic curvature attribute and Figure 9b shows the fractured zones modelled by objective-based method.

When the hydraulic properties of fractures were calibrated in the DFN model, the ultimate task was to compute full field, equivalent properties of the fracture networks to be used in dual-medium simulations. This task consisted in converting a geological image of the reservoir, the DFN model with its complex fracture network architecture, into a simplified dual-porosity model. This simplified conceptual model represents the fractured reservoir as an array of parallel matrix blocks limited by a set of uniform orthogonal fractures [4].

In this study, the fracture parameters were computed from an upscaling of the fracture model by using an analytical ODA's method. The method is a statistical calculation that estimates permeability, based on the total area of fractures in each cell and their various parameters. It is relatively fast on a limited number of fracture planes but does not take the connectivity of fractures into account and can, thus, underestimate fracture permeability when the intensity is low [5]. Figure 10 illustrates these results by showing the fracture porosity and permeability modelled at the top of Reservoir IV. The storage of fracture is quite tiny, however; the permeability of fracture plays an important role in taking fluid from reservoir to well. Figure 11 presents a simplified dual-permeability model after combining matrix and fracture permeability modelled.

In term of history matching, three factors, which are oil volume, water cut and pressure, are significant issues in simulation. Generally, to reach a good history match of the production data, minor adjustments of parameters such as permeability, aquifer and end point values will be needed.

***Table 1.** The results of development cases*

Case	Description	Number of new infill production wells	Rel Oil Prod (fr)	Rel Water Prod (fr)	Recovery Factor (%)
A	Base case with optimised waterflood plus existing production wells	0	1	1	23.8
B	Case A plus new infill production wells	10	1.07	1.05	25.6
C	Case B plus increasing oil production rate of some wells to 20%	10	1.11	1.16	26.4
D	Case B plus increasing oil production rate of some wells to 35%	10	1.13	1.05	27

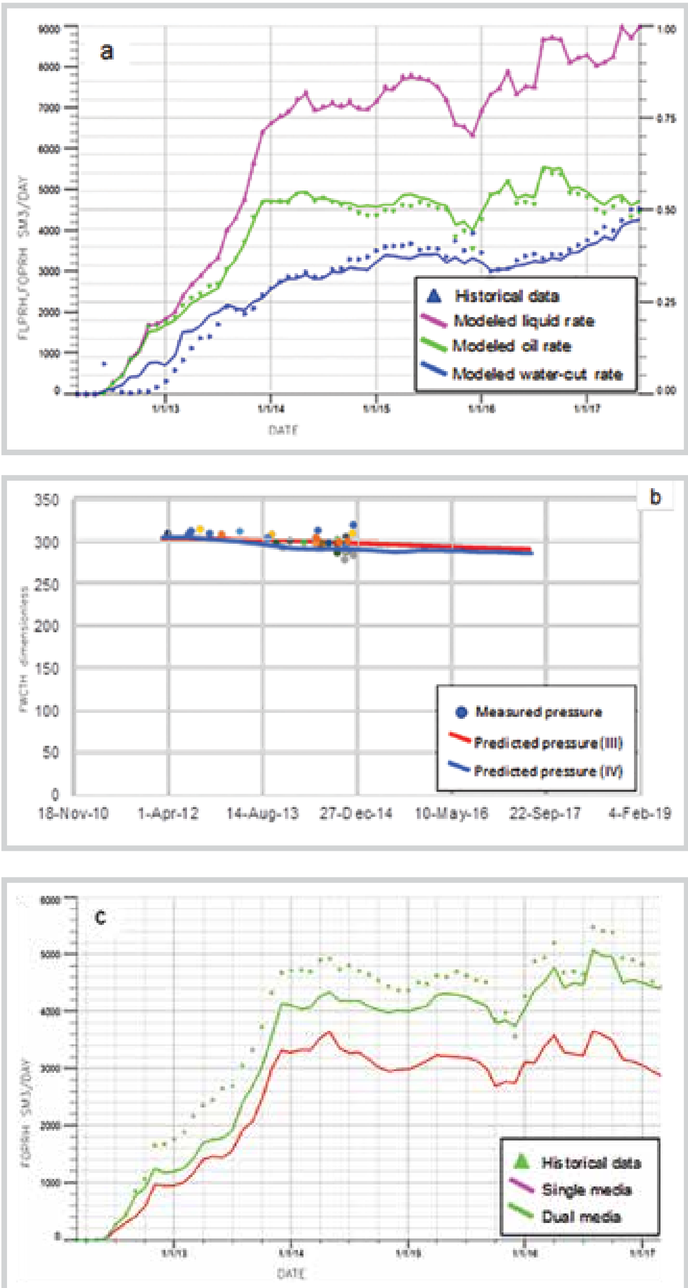

***Figure 12.** An example of an excellent history matching (liquid rate and pressure) of field production (a, b); Comparison of oil rate between a single and a simplified dual media model, suggesting the simplified dual media reflects a significant role of fracture modelled (c).*

For instance, the simplified dual-permeability of reservoirs was changed locally from 0.1 up to 100 times. Figure 12 (a, b) presents an excellent history matching of the field production. Similar quality matches are obtained for individual wells (84/96 wells) as well. Whereas Figure 12c illustrates comparison between a single and a simplified dual media one, suggesting the confidence of the fracture model developed.

According to agreement of history matching, several field development cases to establish such a waterflood and infill new production wells were used to predict and investigate for the future. A base case of field development (Case A in Table 1) is considered an optimised waterflood plus current producer wells. The results of this case are used to compare to other development cases. As a result, the relative liquid produced of the field among these cases is close to each other with recovery factor varying from 24% to 27%. Table 1 presents the results and description of each development case.

5. Conclusions

As dynamic and static data show a clear positive effect of fractures/vuggy on production, the integrated methodology of geophysics, geology and reservoir engineering was successfully used to model natural fractures associated with karst networks in matching and prediction of the field.

A reasonable good history match is obtained for the oil, water-cut and pressures based on 5-year production. The excellent matching suggests an accurate prediction of the movement of displacement front inside the reservoirs as well as a close approximation in modelling reservoir voidage and depletion.

These conceptual models presented will be useful to apply for other nearby fields in the future.

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POTENTIAL OF CO2-EOR ASSOCIATED WITH CCS IN VIETNAM

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Summary

CO_2-EOR has a potential not only in enhancing oil recovery but also in CO_2 storage. It is, however, necessary to understand the technical, operational and economic uncertainties by conducting a pilot test for applying CO_2-EOR to actual oil fields. This paper describes the methods and procedures to design an inter-well CO_2-EOR pilot test and discusses the potential of CO_2-EOR in offshore fields, Vietnam.

We devised screening criteria in terms of saturations and reservoir pressure to select locations for pilot tests based on the reservoir model developed and calibrated with the actual field data. The number of pilot wells was determined to be one (1) injection well and two (2) production wells in order to estimate areal sweep efficiency during CO_2 injection at a minimum cost. To confirm the effects of CO_2-EOR, well interval, cumulative CO_2 injection volume and duration were determined to be 300m, 2,000 tons and two weeks, respectively. The oil production rate began to increase after 1 month from the beginning of the pilot test, and the gas production rate and the vapour phase CO_2 mole fraction also began to increase at the same time. Then, the oil production rate reached the peak, which corresponds to oil bank, after 1.5 months from the beginning, and the effect of CO_2-EOR was confirmed clearly. If oil saturation is high at the target reservoir, it would be difficult for confirming the oil bank clearly. In such case, pre-water injection before CO_2 injection is conducted to reduce the oil saturation at the target reservoir.

In parallel, a CO_2 procurement and a new platform were designed through the process optimisation study. Manufactured CO_2 was selected as CO_2 source for the pilot test due to easy availability and minimum cost. The packed manufactured CO_2 into tank containers was transported to the injection site by trucks and supply vessels. From a CO_2 impact study, the potential risks related to corrosion and scale formation can be manageable by suitable countermeasures such as corrosion resistant alloys (CRAs) and inhibitors.

We also estimated the CO_2 volume for storage in the reservoir when CO_2 injection was applied. We found about half of the injected CO_2 volume to remain in the reservoir at the normal operational conditions for CO_2-EOR. Through this study we proposed a methodology to devise a pilot test plan of CO_2-EOR in any offshore, remote oil field.

Key words: *CO_2-EOR, pre-water injection, CO_2 injection.*

1. Introduction

Enhanced oil recovery (EOR) by CO_2 has a potential not only in enhancing oil recovery but also in CO_2 storage. CO_2 is a useful agent due to relatively high density and high solubility to crude oils. Because it is expected that sweep efficiency during CO_2 injection is better than that in other gases i.e. hydrocarbon gases. It is also expected that miscible displacement by CO_2 that enables to achieve high oil recovery is developed more readily in other gases.

In addition, CO_2 is one of the greenhouse gasses that address global warming and climate changes. Many efforts have been made to reduce CO_2 produced from industrial processes for a decade. Carbon stored underground is an important candidate for preventing CO_2 gas from entering the atmosphere. The potent underground is oil and gas reservoirs. This is because the rock caps that are impermeable layer are integrity and the volume is large enough to be stored.

To meet incremental oil recovery and carbon storage, CO_2-EOR associated with carbon capture and storage (CCS) has been proposed by many organisations. Similar to applications of CO_2-EOR, it is necessary to understand the technical, operational and economic uncertainties by conducting a pilot test to actual oil fields.

The Vietnam Oil and Gas Group (PVN) and JOGMEC conducted an international joint study on a design of inter-

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well CO_2-EOR pilot test at an oil field in Vietnam offshore from 2013 to 2015 in order to understand the applicability of CO_2-EOR associated with CCS. The objectives of this study are to understand the CO_2 injectivity, vertical sweep and areal sweep efficiency, incremental oil production, injected CO_2 volume and cost/risks.

To design the CO_2-EOR pilot test, not only subsurface study but also surface study is important to implement a proper and safe operation. When the injected CO_2 is produced, potential risks related to CO_2 such as corrosion and scale formation on the surface facilities will be increased. This paper describes the subsurface study including uncertainty analysis and countermeasure and the surface study including required CO_2 procurement method, optimised surface facility design, and corrosion/scale formation studies.

2. Subsurface study

2.1. Site selection

- Reservoir pressure > 2,600psi
- Oil saturation > 0.2
- Gas saturation = 0

The key factors to screen a pilot area for achieving the miscible displacement are the reservoir pressure in the pilot area. MMP of oil in this field was estimated to be 2,950psig based on the past laboratory studies such as slim-tube test and IFT measurement [1]. To observe the sufficient effects of CO_2-EOR, the reservoir pressure during CO_2 injection was set over 2,600psi based on the simulation study. A potential hydrocarbon zone was identified by a rule of thumb that porosity multiplied by the oil saturation is 0.05. We assume that the average porosity around the pilot test area is 0.25, thus, the oil saturation is estimated to be 0.2 as a screening criterion. If free gas is liberated in the reservoir, it leads to an undesirable oil displacement. Therefore, the gas saturation is set to 0. Some candidate areas for the pilot test were selected using the criteria.

Thereafter, a certain area was selected as the first option for the following reasons. The selected area is not close to the current producing areas and the large faults which may lead CO_2 leaking from the reservoir, and the sufficient incremental oil was clearly estimated to confirm the effects of CO_2-EOR based on the reservoir simulation results. Moreover, because the operator has a plan to develop the vicinity of this area, synergy between the development and the pilot test areas in terms of sharing the new platform has been expected.

2.2. Base case simulation

We designed a pilot test of CO_2-EOR based on a reservoir simulation study. A pilot well configuration was selected to be one injection well and two production wells because of the minimum number of wells in order to understand CO_2 areal sweep [4].

Some parameters such as well spacing, CO_2 injection rate and total CO_2 injection volume were determined based on the sensitivity analysis of reservoir simulation.

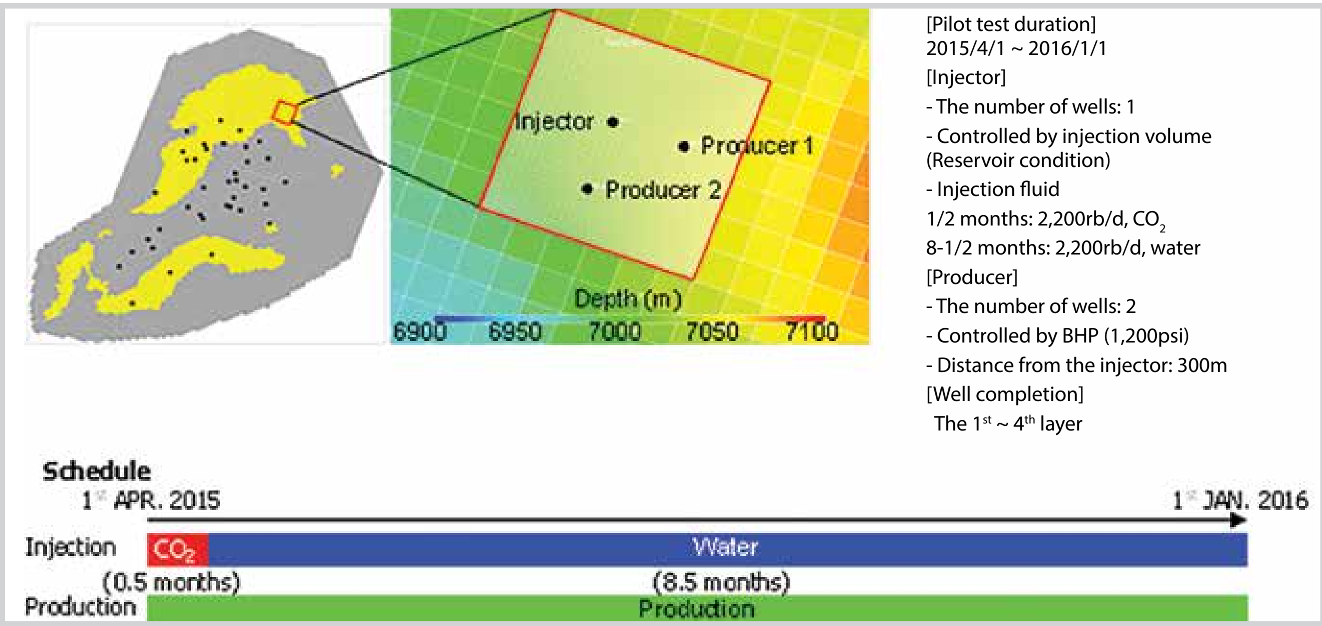


Figure 1. *Simulation scenario for the pilot test*

For determining these parameters, CO_2 utilisation factor (= cumulative incremental oil volume by CO_2-EOR/cumulative CO_2 injection volume) was used as a performance index. The selected simulation settings for the pilot test are summarised in Figure 1. For maintaining the reservoir pressure, the BHP control value in the production wells is set so that the voidage replacement ratio should be one. To save the required CO_2 volume for confirming the effects of CO_2-EOR, both injection well and production wells were perforated in the limited zone of reservoir. The horizontal grid was refined to investigate the fluid advancement in detail.

Production profile predicted by reservoir simulation is shown in Figure 2. The oil production rate began to increase 1 month after the beginning of the pilot test. In addition, the gas production rate and the vapour phase CO_2 mole fraction also began to increase at the same time. Then, the oil production rate reached the peak after 1.5 months from the beginning, and the effect of CO_2-EOR can be confirmed clearly. As a result, the cumulative CO_2 injection volume is 36,791Mscf (1,948 tons), and 52.8% amount of CO_2 is stored in the reservoir (19,437Mscf, 1,029 tons). We also simulated the stored CO_2 with various injection scenarios in the full field. The ratio of the stored CO_2 to the injected CO_2 during CO_2-EOR is around 50% and 80% without and with recycling of produced CO_2, respectively. Figure 3 shows the simulation results in the 2^{nd} layer. CO_2 sweeps mainly in this layer because the permeability is the highest in the other layers. Reservoir pressure near the injection well is higher than MMP during the simulation period. These simulation outputs also indicate practical aspects of CO_2 flooding as follows. The interfacial tension in the CO_2 swept area is very low (less than 1.0 dyne/cm). In addition, the oil viscosity in the CO_2 swept area except for the vicinity of injection well becomes less than that in the unswept area. Oil saturation is decreased near the injection well, and an oil bank is seen at the downstream side of CO_2 front. Residual oil saturation after the pilot test is small (less than 0.1) near the injection well.

2.3. Uncertainty analysis

The uncertainties of reservoir characteristic in the pilot test area are relatively high because it is an undeveloped area. For evaluating the uncertainties, based on the previous study [2, 3], sensitivity analysis using reservoir simulation and Monte Carlo simulation was conducted to address the key geological uncertainties which have significant impacts on the pilot performance, and make suitable countermeasures for a successful pilot implementation. In the sensitivity study, six geological parameters involving oil saturation, reservoir pressure, horizontal permeability, Kv/Kh, Sorw and Sorg were selected. For each parameter, low and high cases were set based on the representative values from the reservoir characteristics. This sensitivity analysis was conducted by changing the parameter one by one while keeping the other parameters same as the base case. Figure 4 shows the sensitivity results for CO_2 breakthrough

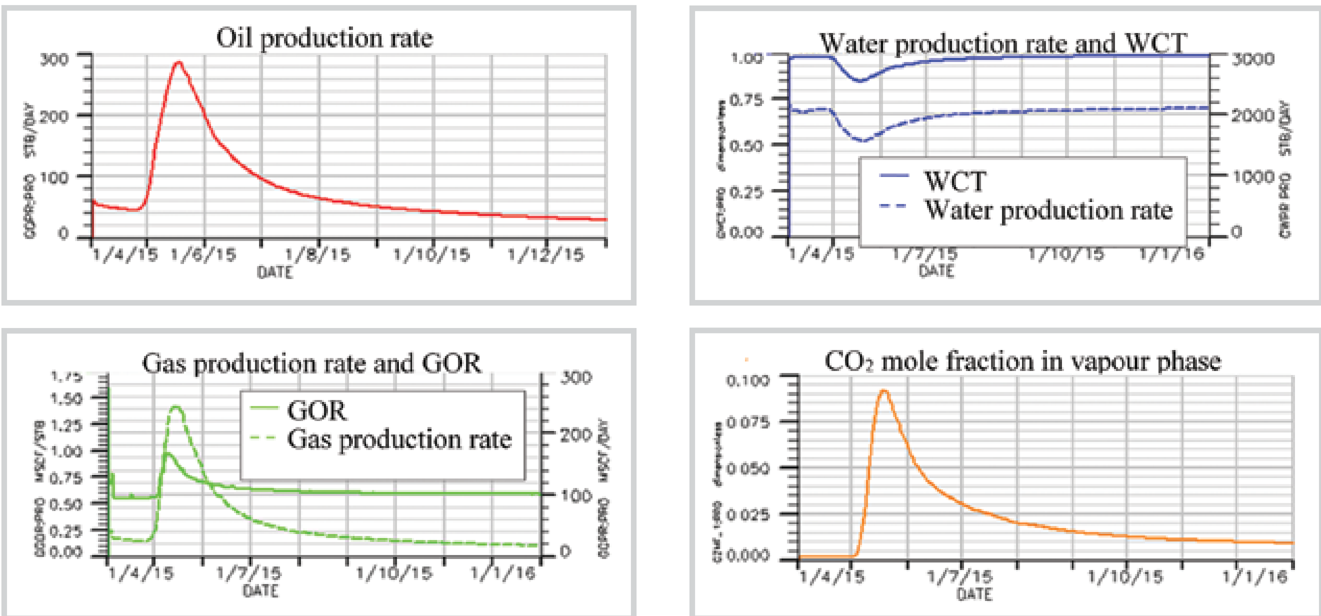


Figure 2. *Predicted production profile*

timing and cumulative production oil volume. The bar chart shows the difference over the base case. If the horizontal permeability or reservoir pressure is lower than the base case, the CO_2 breakthrough timing delayed about 1 month. If the oil saturation is higher than the base case, the cumulative oil production volume increases significantly.

Monte Carlo simulation was conducted to estimate the range of pilot performance. In order to apply the Monte Carlo simulation for evaluating the range of the pilot performance, the response surface equation (RSE) and the probability distributions were constructed. The modelling of response surface equation for the cumulative oil production (COP) and the CO_2 breakthrough timing (BTT) were conducted based on the regression of the sensitivity analysis results. The following equations were modelled as a function of geological uncertainties.

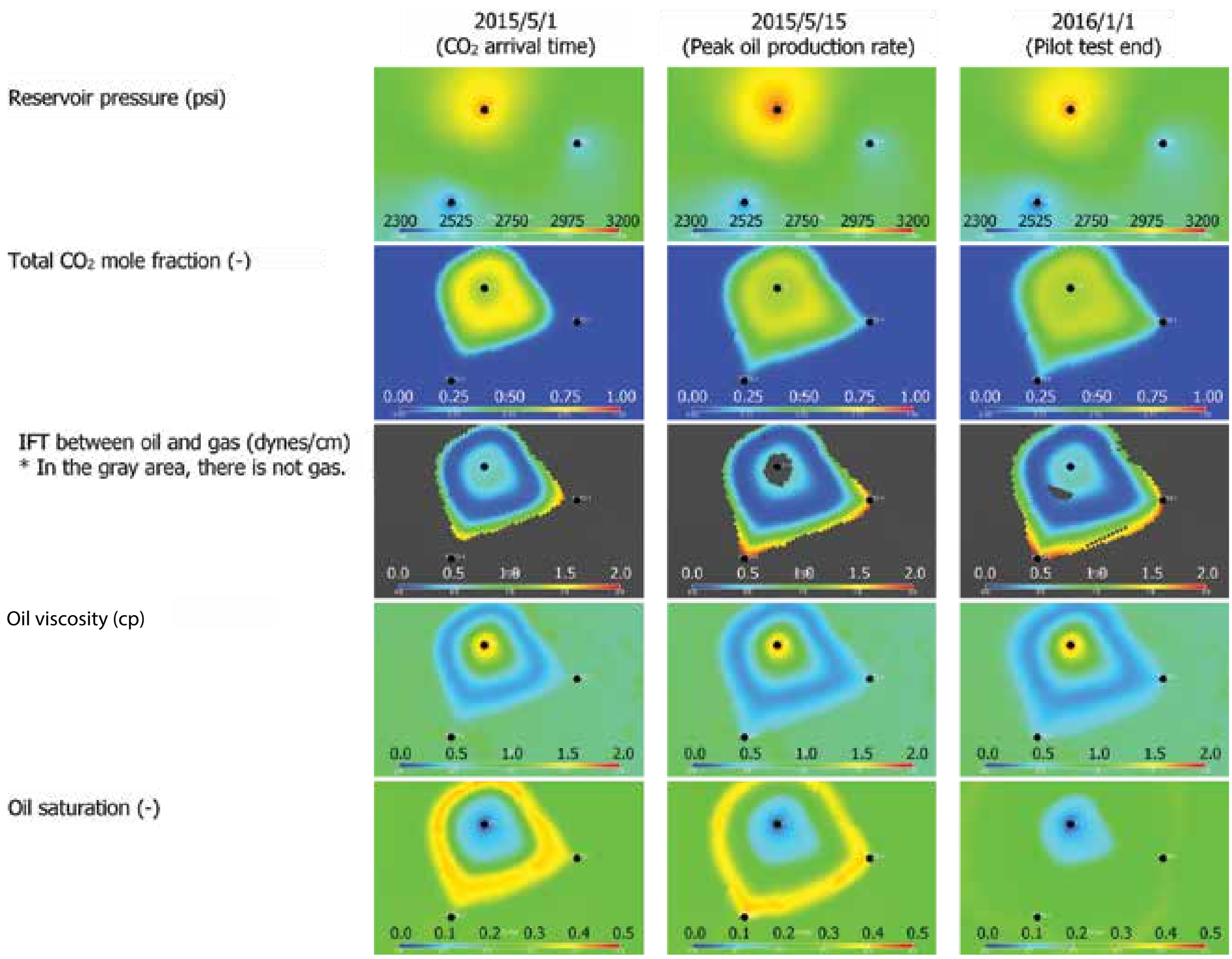


Figure 3. Simulation results in the 2nd layer

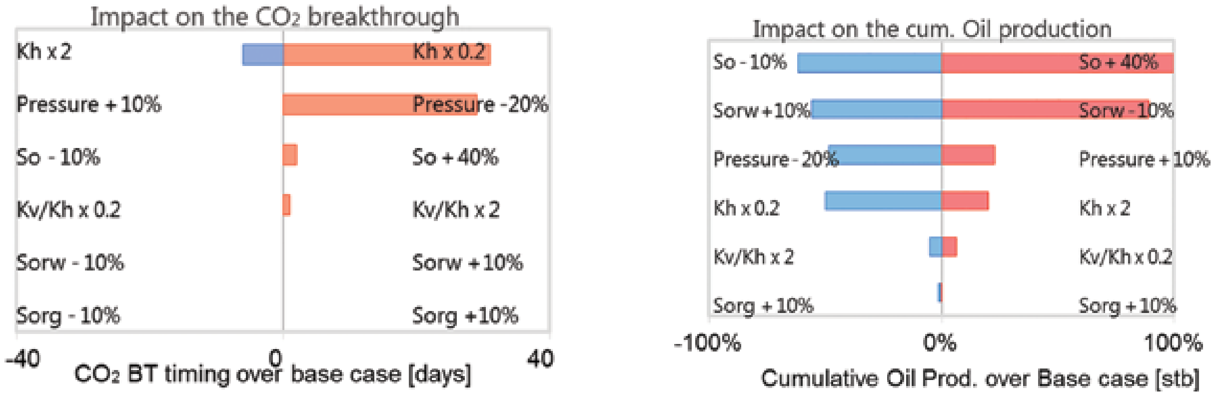


Figure 4. Sensitivity result for CO_2 breakthrough timing and cumulative oil production

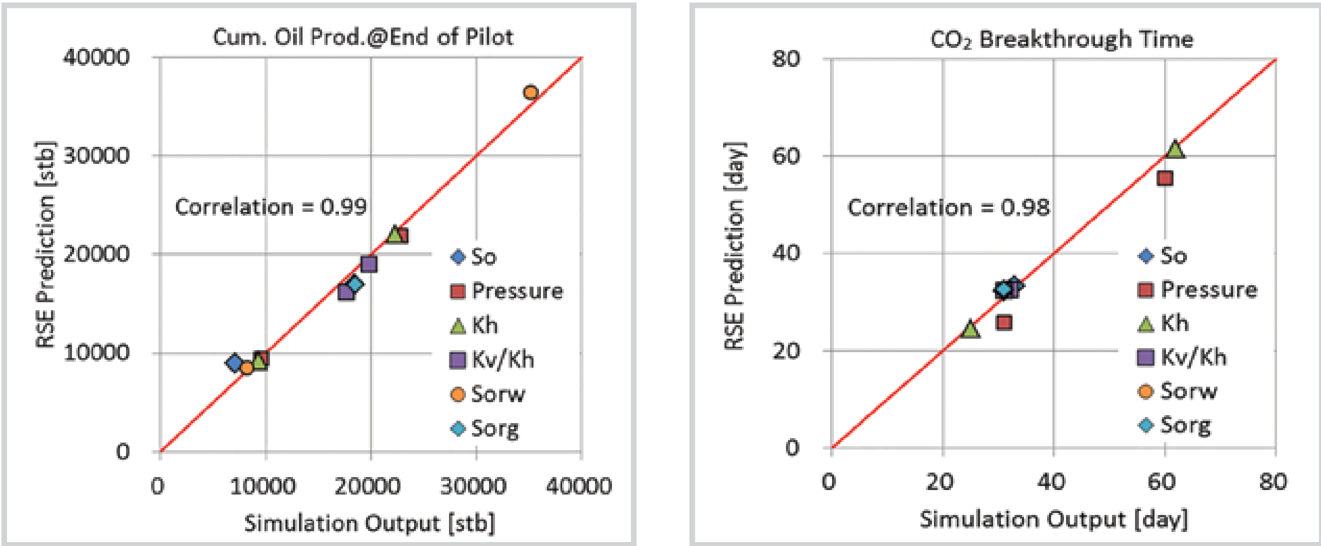


***Figure 5.** Correlation of response surface equation*

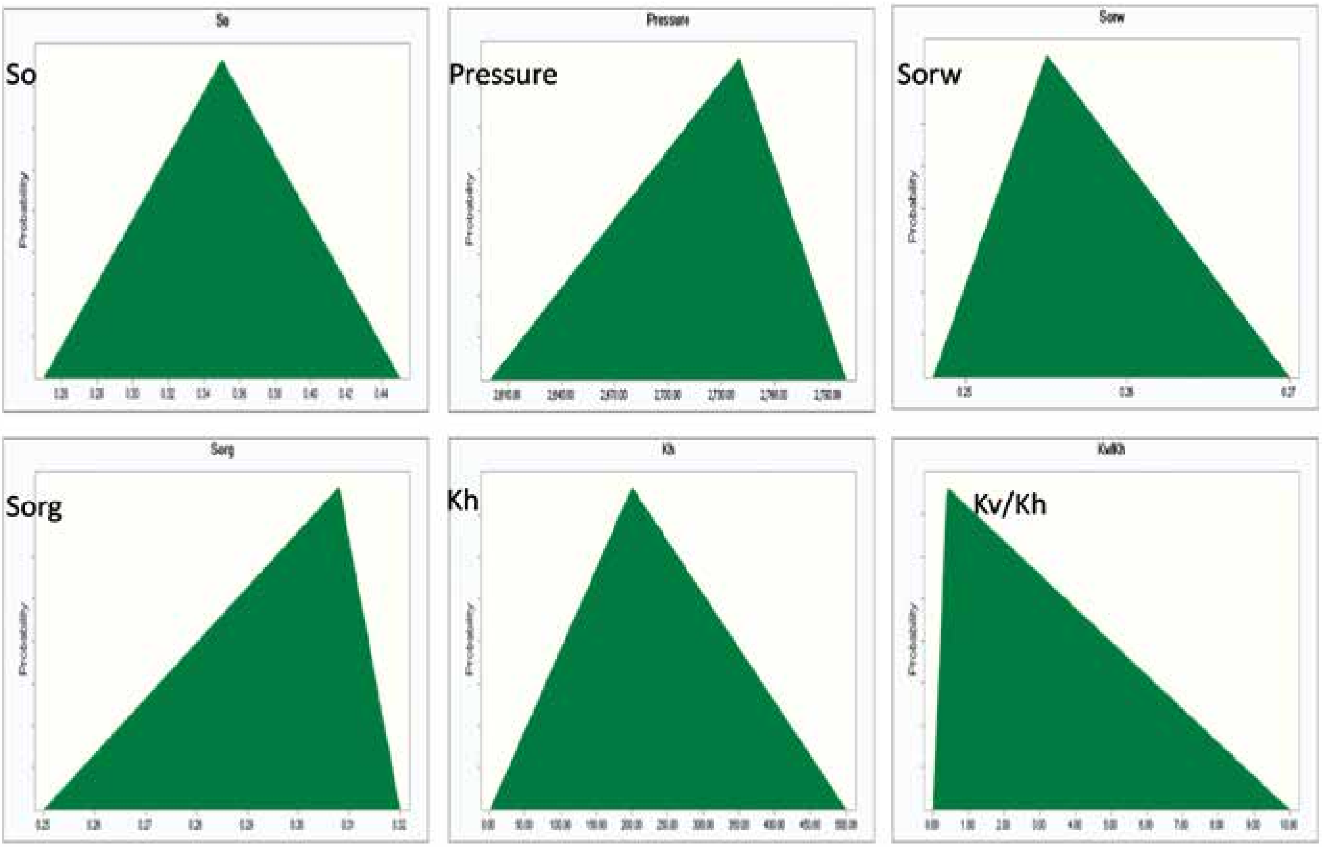


***Figure 6.** Assumed probability distribution*

$$COP = e^{-14.7} \times So^{6.12} \times P^{2.65} \times Kh^{0.37} \times (Kv/Kh)^{-0.07} \times Sorw^{-7.24} \times Sorg^{-0.03} \quad (1)$$

$$BTT = e^{24.6} \times So^{0.08} \times P^{-2.4} \times Kh^{-0.40} \times (Kv/Kh)^{-0.003} \times Sorw^{0.02} \times Sorg^{0.02} \quad (2)$$

Figure 5 shows the correlations between the prediction results by RSE and the reservoir simulation output. The figure suggests that the predicted value by RSE is high correlation with that of the reservoir simulation.

Figure 6 shows representative probability distributions of the geological parameters in the pilot area based on the simulation model. Figure 7 shows the output of Monte Carlo simulation for CO_2 breakthrough timing and cumulative oil recovery for each probability. It is predicted that more than 41,000bbl oil will be recovered with 90% probability. In other words, the probability to be less than 41,000bbl is only 10%. Those results depend on the assumed probability distribution significantly. Table

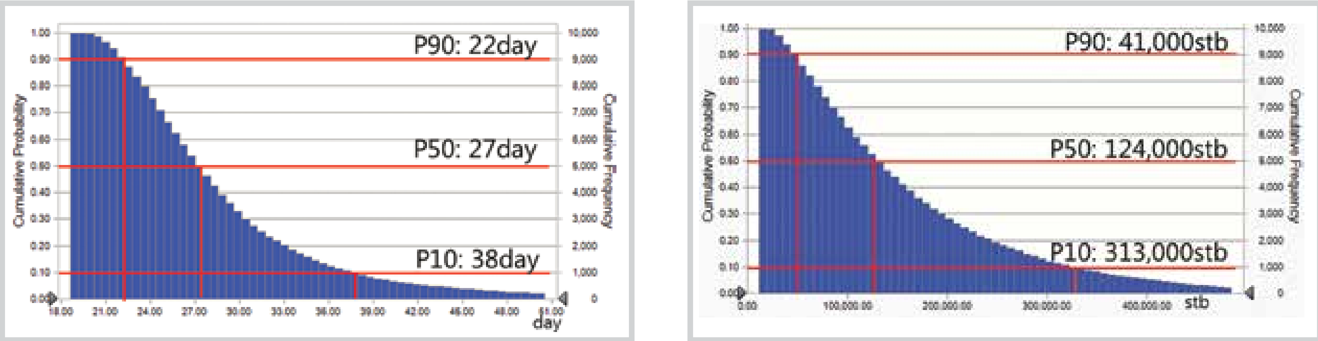


***Figure 7.** Exceedance probability curve for CO_2 breakthrough timing and cumulative oil production*

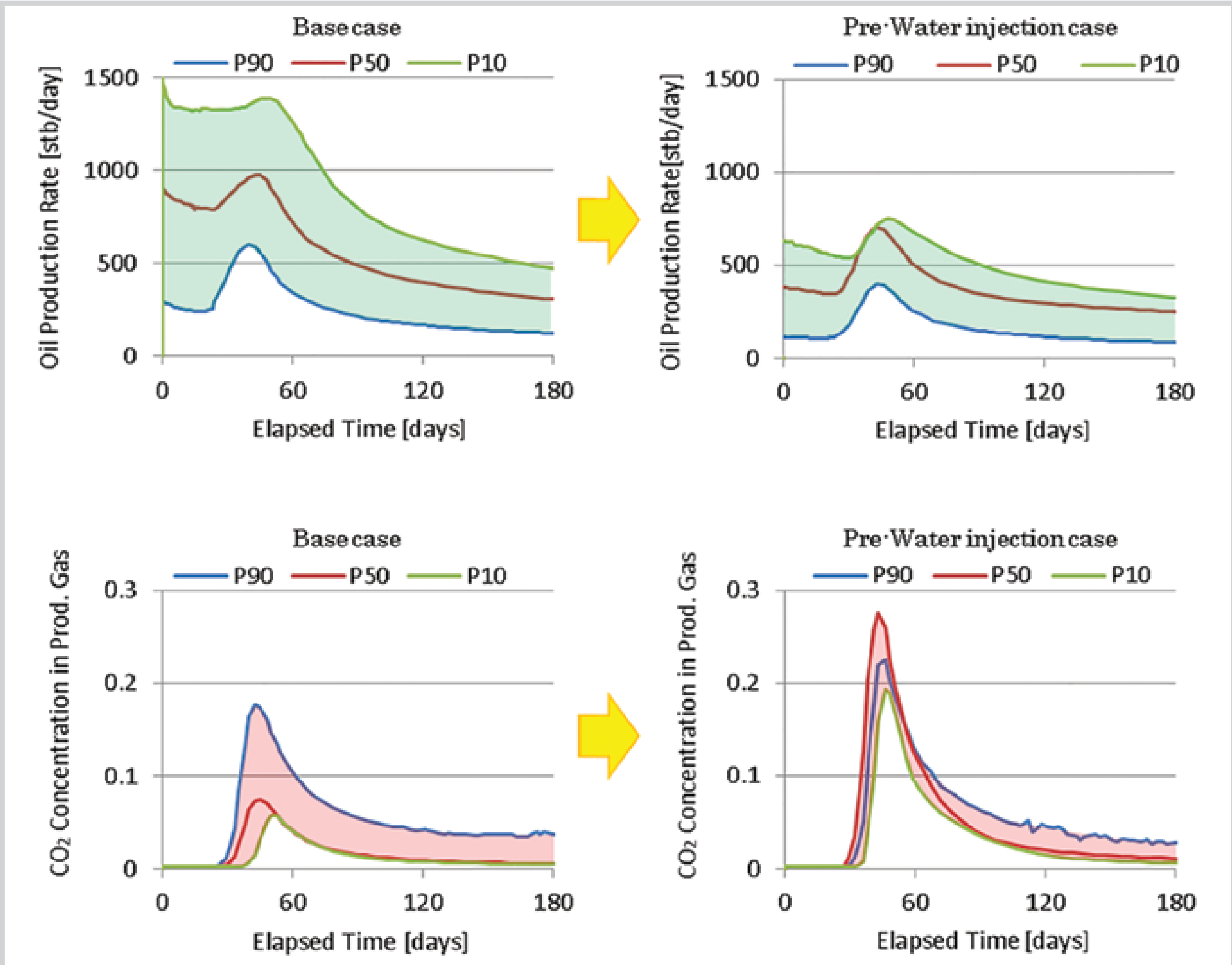


***Figure 8.** Predicted production performance*

1 shows the estimated geological parameters for each probability based on the most likely scenario.

The pilot production performance for each probability was predicted by reservoir simulation based on the estimated geological parameters. Figure 8 shows the oil production rate and CO_2 concentration in production gas for P10, P50 and P90 cases, respectively. The left figures show the prediction results of the base

***Table 1.** Estimated geological parameters for each probability*

	P90	P50	P10
So (-)	0.28	0.34	0.41
Pressure (psi)	2700	2800	2900
Kh (md)	400	200	70
Kv/Kh (-)	0.26	0.15	0.06
Sorw (-)	0.258	0.257	0.256
Sorg (-)	0.280	0.298	0.300

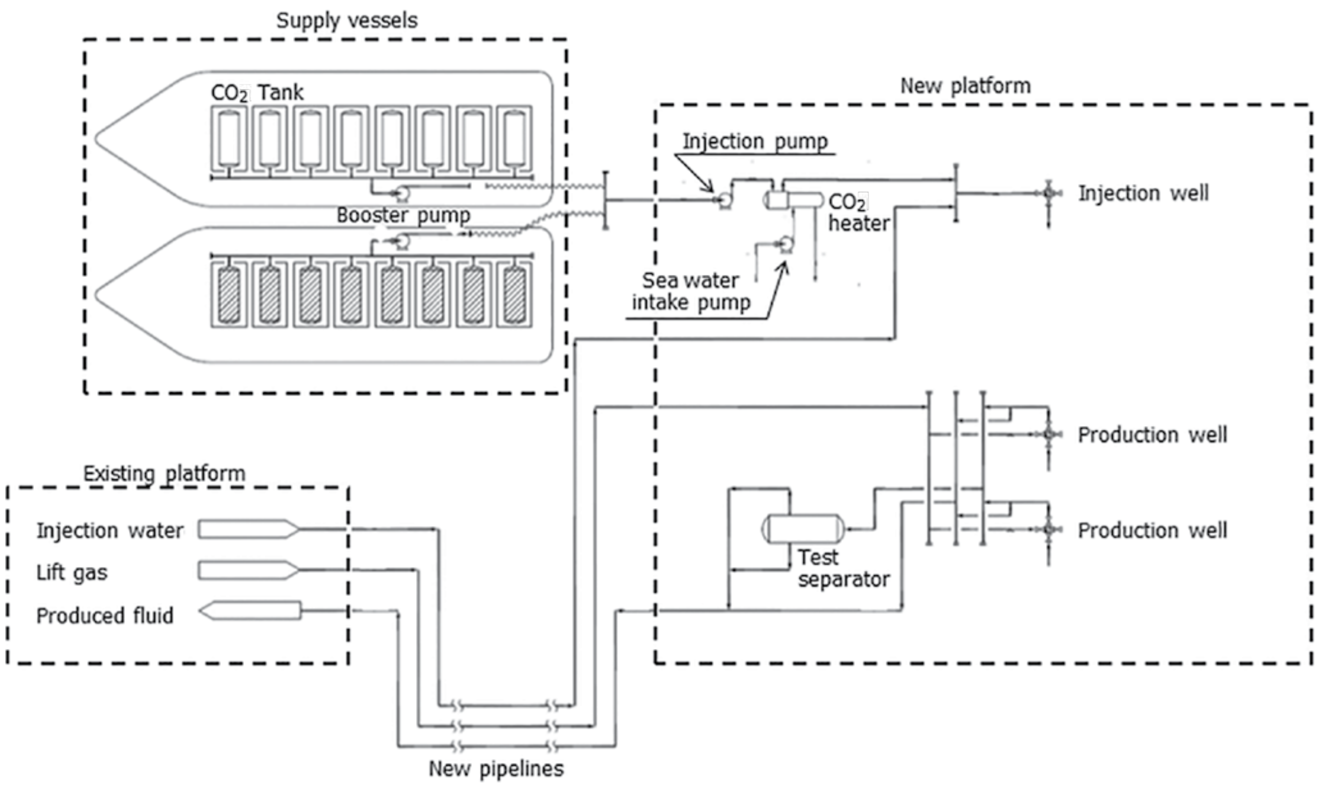


***Figure 9.** Process flow diagram of CO_2-EOR platform*

case. They indicate a wide range of the performance. It means that pilot production performance has a high uncertainty. Furthermore, it is found that the incremental oil production is not confirmed clearly in P10 case because of the shortage of CO_2 injection volume over the large amount of oil in the reservoir.

2.4. Countermeasure for successful pilot test

If a large amount of CO_2 can be prepared, we will confirm the oil bank readily even in P10 case. CO_2 procurement volume is, however, limited in the offshore field. We consider pre-water injection before CO_2 injection as an effective countermeasure for a successful pilot test implementation. The right figures in Figure 8 show the prediction results based on the base case scenario plus pre-water injection for 5 months. If pre-water injection is applied, not only the range of uncertainty decreases but also incremental oil by CO_2-EOR is confirmed readily. If the actual oil saturation is higher than the expected oil saturation around the newly drilled pilot wells, the pre-water injection will be conducted for understanding the effects of CO_2-EOR.

3. Surface study

3.1. CO_2 procurement

We purchase liquefied CO_2 which is the enough CO_2 volume required for CO_2-EOR pilot test from the supplier. It is assumed that liquefied CO_2 in the tank containers is transported to the offshore platform by trucks and vessels. Manufactured CO_2 is filled up into the tank containers and carried by trucks to temporary storage area in the nearby port. The tank containers are moved to the supply vessels on the sea and transported to the pilot test area.

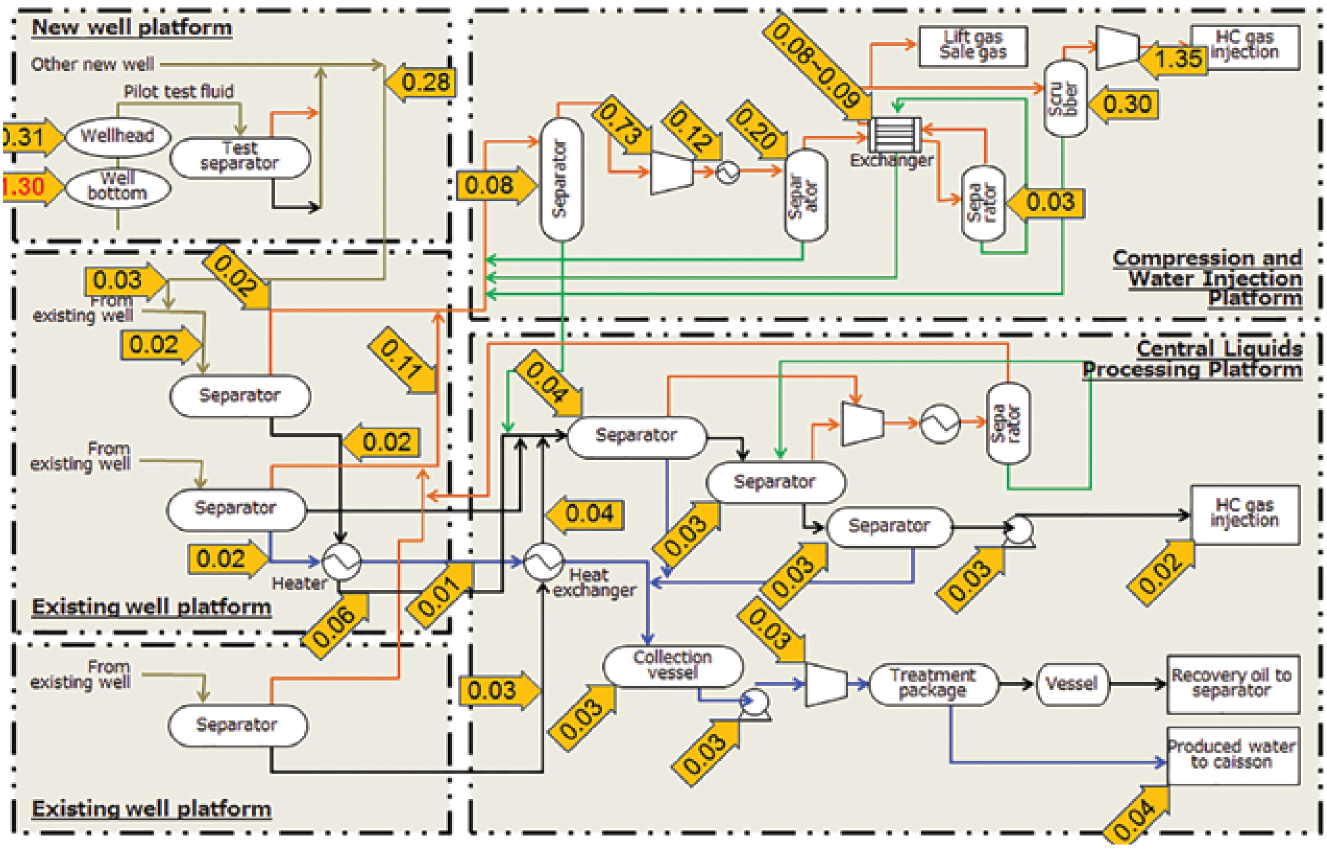
3.2. Surface facility design

Because the pilot test area is undeveloped, it is necessary to build a new platform for the pilot test as well as treatment of production liquid, water injection and gas lift pipeline. As shown in Figure 9, liquid CO_2 supplied from a supply vessel is send to the injection pump through the CO_2 header, and injected into the reservoir from injection well via heater. Liquid CO_2 heater is to prevent cracking of pipe and degradation of equipment materials. Injection water is supplied from the existing platform when water is injected after CO_2 injection. The volume of produced gas and liquid from each production well is measured with the test separator.

3.3. CO_2 breakthrough impact

The CO_2 impact study for all the related facilities was conducted and divided into the following steps:

- Process simulation for all the related facilities;



** Values in this figure indicate the estimated corrosion loss volume (mm) that will be accumulated during CO_2-EOR pilot test duration.*

Figure 10. *The quantified total amount of corrosion for each equipment*

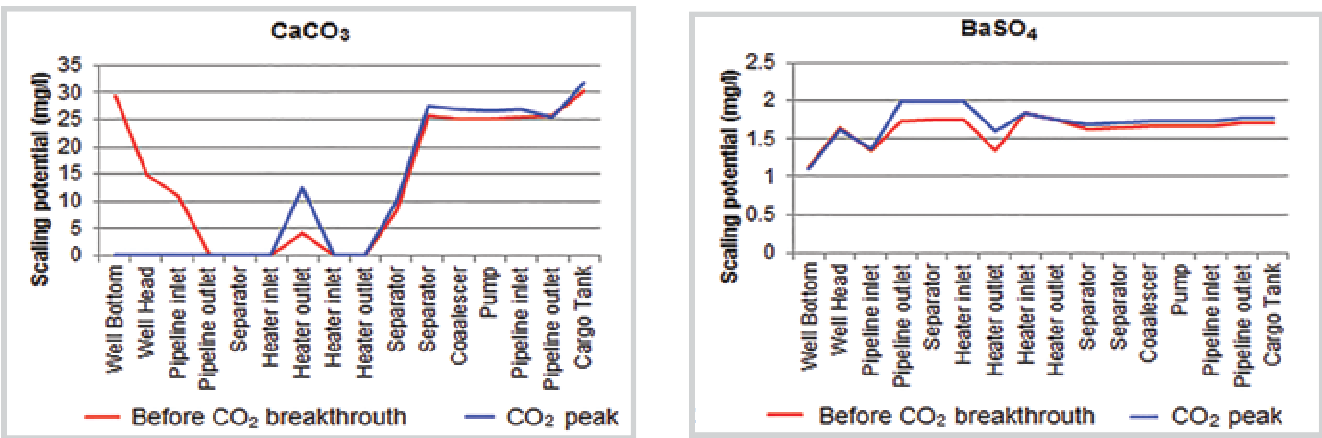


Figure 11. *Predicted scale formation potential in the production fluid system*

- Corrosion and scaling formation estimation study for the related facilities;

- Material selection study based on process simulation and estimation results of corrosion and scaling formation.

Process simulation has been conducted to confirm how much CO_2 is distributed to the related facilities. Corrosion rates and scaling formation potentials were estimated with a corrosion/electrolyte/scaling simulator, based on a "new fresh" carbon steel corroding surface.

3.4. Corrosion

Figure 10 shows the total predicted corrosion amount for each production equipment/flowline for carbon steel, for the duration of the CO_2-EOR project life. It was calculated by integrating the corrosion rate for each time. It shows that there is a very high total corrosion of 1.3mm of the production well tubulars downhole, with a reduced total corrosion of 0.31mm at the production wellhead once combined with lift gas, which further reduces to 0.28mm once combined

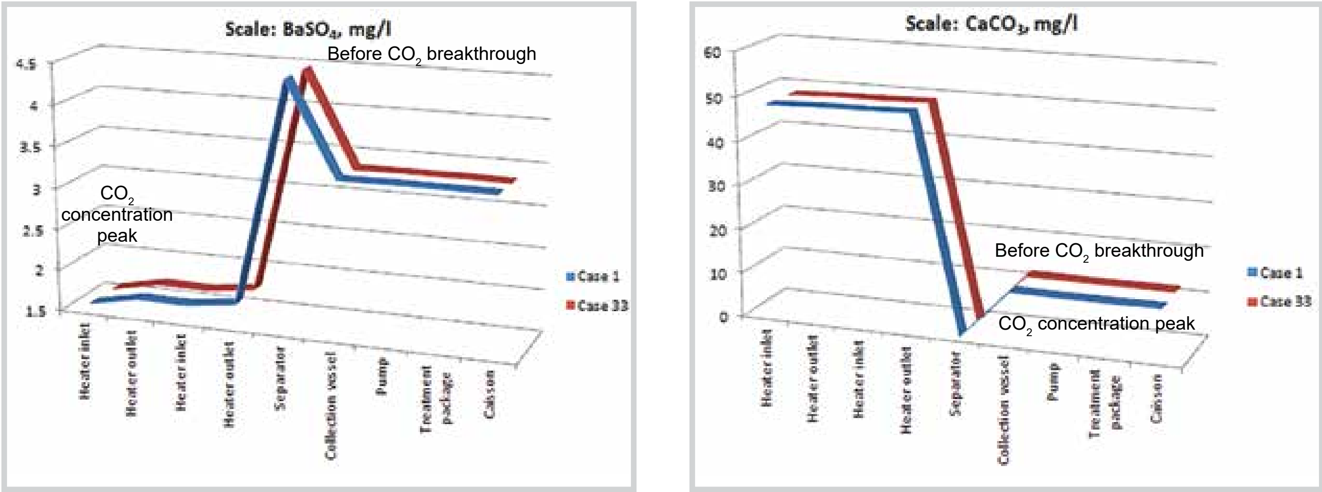


Figure 12. *Predicted scale formation potential in the produced water handling system*

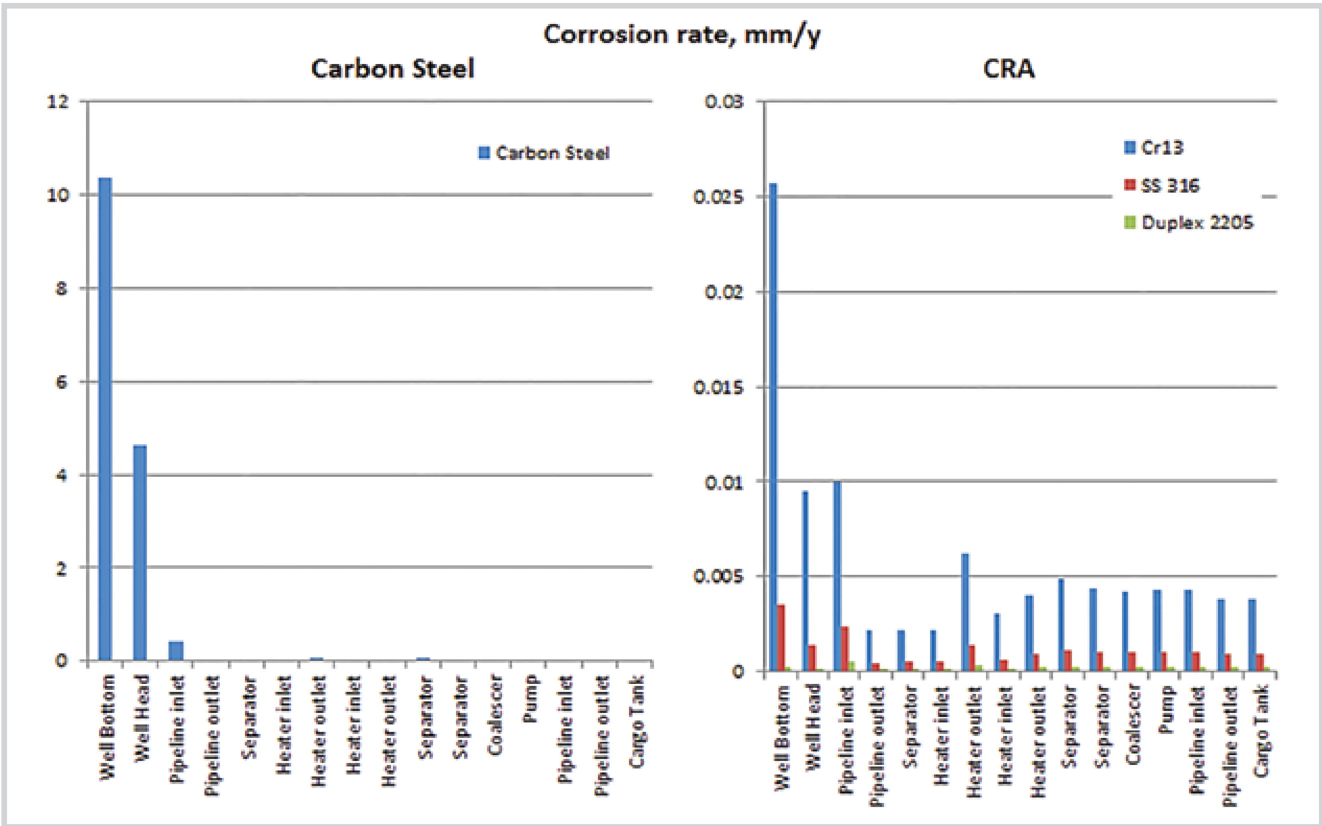


Figure 13. *Corrosion rate comparison by material in case of CO_2 concentration peak*

with the produced fluids from other well at the inlet to the flowline. The high predicted total corrosion depth for the well tubulars over the duration of the CO_2-EOR project for carbon steel is not deemed acceptable. It is noted that total corrosion of 1.35mm is predicted at the hydrocarbon gas compressor if the carbon steel is used. As high corrosion resistance alloy is used, the actual total amount of this equipment should become smaller and be negligible.

3.5. Scaling

The predicted potential of $BaSO_4$ and $CaCO_3$ scales in the production system is presented in Figure 11. This shows how the scale potential changes through the process, for the baseline simulation (before CO_2 breakthrough) and the predicted peak breakthrough of CO_2. Only the 2 cases have been plotted as the extreme cases. All of the simulated scale formation potentials for $BaSO_4$ in the production process train are less than 2mg/L,

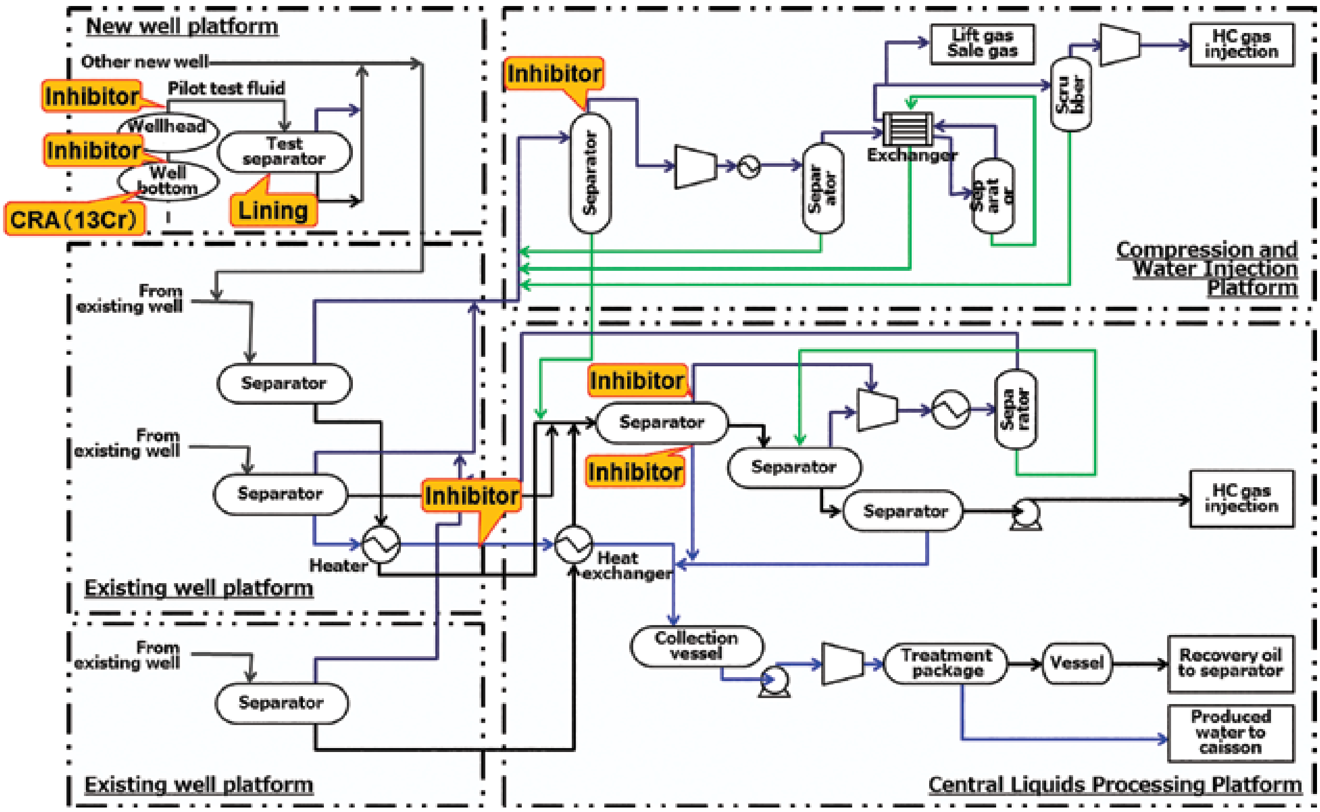


***Figure 14.** Mitigation plan for corrosion and scale formation*

and so are manageable by suitable scale inhibitors. The breakthrough of CO_2 into the production wells eliminates the scaling formation potential of $CaCO_3$ in the front end of the production process train from the new well bottoms through to the inlet to the 1st heater inlet. This is probably due to the addition of CO_2, shifting the pH of the produced fluids downwards (more acidic conditions) and therefore keeping the scaling ions in solution. With CO_2 breakthrough, there is an increase in scaling potential of $CaCO_3$ at the outlet of the 1st heater, but this level of $CaCO_3$ scale is manageable by a suitable scale inhibitor. At the water outlet of the 2nd separator and all vessels downstream, there is very little change in the scaling potential for $CaCO_3$, with only a 10% increase in the predicted amount of $CaCO_3$ scale from the baseline simulation to the predicted peak breakthrough of CO_2. This level of scale increase can easily be managed through the existing scale inhibitors used in this oil field.

The predicted scale formation potential for the produced water handling system is presented by scale type in Figure 12. It does not change significantly from the baseline simulation to the predicted peak breakthrough of CO_2. This level of scale in the produced water handling system can be easily managed through the existing scale inhibitors used in this oil field.

3.6. Material selection

Corrosion rate simulation was made using high corrosion resistance alloys as indicated below to determine their suitability:

- 13Cr steel alloy;
- Stainless steel 316;
- Duplex stainless 2205;

The simulated corrosion rates across the process for these higher steel grades are presented in Figure 13. It is seen that all of the corrosion simulated high corrosion resistance alloys offer a vast improvement in the corrosion rate in the case of CO_2 concentration peak. The corrosion rate at the well bottom for carbon steel at 10.37mm/year reduces to < 0.03mm/year when 13Cr steel alloy is used. This decrease in corrosion rate indicates the permissible corrosion limits that can be easily managed through the use of corrosion inhibitors. The corrosion rate can be further reduced through the use of either stainless steel 316 or duplex stainless 2205, as has been used in some oil fields to successfully mitigate corrosion. It should be noted that both stainless steel 316 and duplex stainless 2205 are very expensive for oil field process equipment.

3.7. Mitigation plan

The mitigation plan for corrosion risk and scale formation risk is summarised in Figure 14. It is quite evident that in the case of CO_2 concentration peak the well completions in carbon steel are not appropriate. It is said that 13Cr steel alloy has typically been used for high CO_2 gas wells. Stainless steel 316 appears to have a higher corrosion resistance than 13Cr steel alloy. It will, however, be prone to chloride stress corrosion cracking in higher temperature environments > 50°C in the presence of chloride ions. Duplex 2205 should provide even better corrosion resistance, but with very significant cost rise. The use of 13Cr steel alloy is suitable for the new production wells. It is effective to use also a variety of corrosion and scale inhibitors. As for test separator that will be installed on the pilot test platform, lining inside the separator by polymers such as polyethylene resin is desirable because fluid containing high CO_2 concentration will flow into the separator although CO_2 partial pressure decreases compared to wellhead and well bottom. In addition, it is necessary that regular pigging of the subsea flowlines and flaring of the associated produced gas at the pilot test platform reduce the corrosion potential in the topside process equipment and flowlines.

4. Conclusions

The CO_2-EOR inter-well pilot test in the offshore oil field was designed to achieve the aim in all situations as follows;

- The number of pilot well is determined to be 1 injection well and 2 production wells because of the minimum number of wells in order to estimate CO_2 areal sweep efficiency. To achieve the aim of the pilot test, the well interval, cumulative CO_2 injection volume and duration were determined to be 300m, 2,000 tons and 2 weeks, respectively, based on sensitivity study with reservoir simulation.

- We also simulated the stored CO_2 with various injection scenarios in the full field. The ratio of the stored CO_2 to the injected CO_2 during CO_2-EOR is around 50% and 80% without and with recycling of produced CO_2, respectively.

- Uncertainty analysis indicates that there is a possibility the oil bank becomes smeared if the oil saturation is high. For confirming the effect of CO_2-EOR clearly, pre-water injection before CO_2 injection is an effective countermeasure.

- To reduce the procurement cost of required CO_2 for the pilot test, CO_2 was determined to be secured from a CO_2 manufactory.

- New platform was designed through the process optimisation study.

- There will be increased potential risk of corrosion and scale formation. The high predicted total corrosion depth for the well tubulars over the duration of the CO_2-EOR project for carbon steel is not deemed acceptable, so the use of CRA's in the production wells are essential. In addition, inside lining at the test separator, pigging and corrosion/scale inhibitors are necessary.

When the CO_2-EOR pilot test will be planned in any oil field, it will be possible to make the test design with the same procedure as this study.

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DEVELOPMENT AND MODIFICATION OF LOW NICKEL CONTENT CATALYSTS FOR DRY REFORMING OF METHANE

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Summary

Both the Ca Voi Xanh (Blue Whale) gas field in Vietnam and biogas produced in Germany possess comparable high contents of CO_2. For further processing, in both cases it is important to find a way to handle the concomitant CO_2. One option is the direct production of synthesis gas - a mixture of CO and H_2. Accordingly, low content (2.5wt%) but active Ni catalysts supported on Mg-Al mixed oxides were developed and studied for methane dry reforming reaction (DRM). The main scope of this investigation was to design an active catalyst and modify it to avoid quick deactivation caused by coking. The samples in this study were characterised by N_2 physisorption (BET) and X-ray diffraction (XRD). The results revealed that our Ni/MgAlO$_x$ catalysts show high surface area and good Ni dispersion. Such properties contribute to the high activity of the catalysts already at 500°C. Modification with La^{3+} significantly increases the resistance toward carbon formation due to its ability for C gasification. Such La.Ni/MgAlO$_x$ type catalyst also shows high and stable DRM activity over at least 60 hours with low carbon accumulation at high weight hourly space velocity (WHSV = 170L/(g_{cat}·h)) compared to state-of-art.

Key words: *Dry reforming of methane, carbon dioxide, low content nickel catalyst, lanthanum, coking resistivity.*

1. Introduction

The global energy demand is growing rapidly, and about 88% of this demand is met at present time by fossil fuels [1]. However, this causes serious environmental problems such as air pollution beside fast depletion of resources. Henceforth, during the recent years, many European countries - especially Germany, Denmark, Austria and Sweden - have been focusing their interest in biogas production because biogas is considered as a sustainable energy source which has a large potential for reducing greenhouse gas emissions [1]. Germany is one of the largest biogas-producing countries utilising available organic wastes, by-products and energy crops [2]. The total biogas potential in Germany is calculated by the Federal Agricultural Research Centre (FAL) as 24 billion m^3 per year [2]. The final composition of biogas is 50 - 75vol% CH_4, 25 - 45vol% CO_2, 2 - 7vol% H_2O and less than 1vol% is O_2, N_2, NH_3 and H_2S [3]. Interestingly, in 2011 Vietnam discovered the Ca Voi Xanh gas field with a large reserve of about 150 billion m^3 available for power generation and industrial purposes [4]. This Vietnamese gas has a high content of CO_2 (~ 30vol%) which is comparable with the biogas in Germany, and in both cases it is important to find a way to handle the concomitant CO_2 [4]. There are several possibilities to reduce total CO_2 emissions into the atmosphere. One of them is to develop different technologies to capture and utilise CO_2 to produce valuable chemicals from it. One possible CO_2 utilisation might be the reaction with methane towards synthesis gas (H_2, CO), which is among the most important starting materials in large-scale chemical syntheses. At present, synthesis gas is the main source for H_2 production via steam reforming [5, 6]. However, both the evaporation of great quantities of water and the endothermic reaction itself are very energy demanding as well as the upstream CO_2 removal and downstream CO removal [7]. Another alternative and cheaper way would be CO_2 reforming of methane (Equation 1, [8]), which has been proposed as one of the most promising technologies for utilisation of these two gases to produce synthesis gas [9].

$$CO_2 + CH_4 \rightarrow 2CO + 2H_2 \qquad \Delta H_{298} = 247kJ/mol \qquad (1)$$

The syngas can be used in already existing industrial processes for chemical synthesis depending on the reaction conditions and the catalyst (Figure 1 [10]).

However, dry reforming is not yet commercialised due to the fast deactivation of the catalyst by carbon formation. Many efforts have been made to search for an active and stable catalyst. Nickel-based catalysts showed

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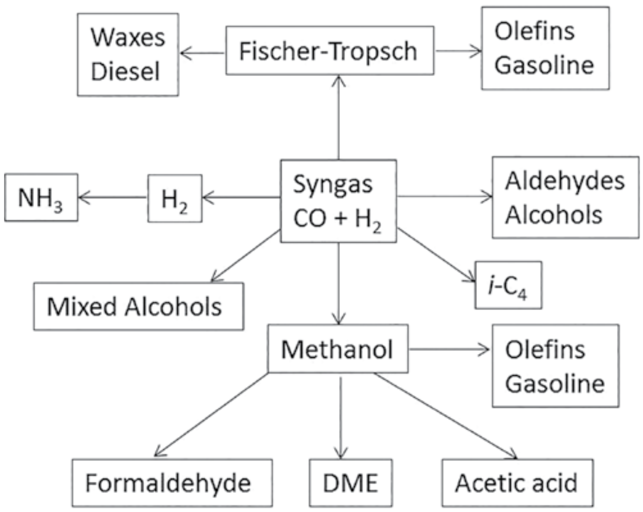

***Figure 1.** Selection of options to use syngas and methanol for products adapted [10]*

to be promising candidates but they tend to form Ni aggregates and then unreactive carbon easily forms on the surface leading to deactivation [11]. There are several approaches in the reduction of carbon deposition of Ni-based catalysts; the first is to decrease the particle size of the nickel and to improve its dispersion by supporting it on high-surface area supports [12, 13]. The second is to alter the acidity and basicity of the supports and the third is to apply different specific methods of catalyst preparation [14]. Liu et al. found that the method of preparation of different Ni loadings supported on MCM-41 has an effect on the activity and stability of the catalyst [15]. Supporting 7wt% of Ni on SiC monolithic foam resulted in an excellent activity (95%) and stability over 100 hours at 800°C [16]. Also Al_2O_3 and MgO were used recently as supports to prepare Ni-based catalysts for dry reforming. Zhang et al. studied a series of Ni/MgO-Al_2O_3 catalysts prepared by a simple two-step hydrothermal method. It was confirmed that Ni/MgO-Al_2O_3 (15wt% Ni) catalyst afforded 52% CH_4 conversion with excellent stability during reaction at comparatively high space velocity (6×10^5 $cm^3 \cdot g_{cat}^{-1} \cdot h^{-1}$) and lower reaction temperature (650°C) [17]. It seems that the addition of Al_2O_3 to MgO contributes to the formation of an $MgAl_2O_4$ phase, which is stable and could effectively increase the CO_2 adsorption due to the increased amount of basic sites on the catalyst surface. Kathiraser et al. investigated the behaviour of Ni particles supported on $LaAlO_3$-Al_2O_3 which were stable and active over 30 hours due to the formation of $NiAl_2O_4$ spinel structure [18]. Liu et al. investigated the activity of La-promoted catalysts which was higher than for non-promoted hydrotalcite derived catalyst [19]. From the previous research, we decided to prepare Ni supported on basic hydrotalcite precursors and to investigate the effect of La addition on the stability of such catalysts against coke deposition in DRM.

2. Materials and methods

2.1. Catalyst preparation

Mg-Al mixed oxides (calcined Mg-Al hydrotalcite, Pural MG, Sasol) supported Ni catalysts were prepared by wet impregnation. Mg-Al hydrotalcite precursor possesses the Mg/Al ratio ~1.0 (data from ICP-OES and AAS measurement). $Ni(NO_3)_2 \cdot 6H_2O$ (Alfa Aesar) and $La(NO_3)_3 \cdot 6H_2O$ (ABCR GmbH) were used as precursors for Ni^{2+} and La^{3+}. Prior to impregnation, the hydrotalcite precursor was calcined at 800°C for 6 hours in air to obtain the bare supports which are denoted as $MgAlO_x$. The calculated amounts of Ni and La precursors were dissolved together in deionised water and then the support was put into the solution and the slurry was stirred. Samples were then dried overnight and calcined at 800°C for 6 hours in static air. The final catalysts are abbreviated as Ni/$MgAlO_x$ and La.Ni/$MgAlO_x$. The nominal content of Ni in all supported Ni-containing catalysts was 2.5wt%.

2.2. Catalyst characterisation

Nitrogen physisorption method served for calculating the specific surface area and pore volume according to the BET theory. The measurements were performed on a Micromeritics ASAP 2010 apparatus (Micromeritics GmbH, Aachen, Germany) at -196°C. The samples were degassed at 200°C in vacuum for 4 hours before the analysis.

XRD powder patterns were recorded either on a Panalytical X'Pert diffractometer equipped with a X'celerator detector or on a Panalytical Empyrean diffractometer equipped with a PIXcel 3D detector system using Cu Kα1/α2 radiation (40kV, 40mA) in both cases. Cu beta-radiation was excluded by using nickel filter foil. Cu Kα2 radiation contribution was removed arithmetically using the Panalytical HighScore Plus software package. Peak positions and profile were fitted with Pseudo-Voigt function using the WinXPow software package (Stoe). Phase identification was done by using the PDF-2 database of the International Center of Diffraction Data (ICDD).

2.3. Catalyst tests

DRM was carried out in a fixed-bed continuous flow quartz reactor (ambient pressure, WHSV = 100 or 170L/(g_{cat}·h); T = 500 - 780°C). All volumetric flow rates given in this study are related to 25°C and atmospheric pressure. After in-situ pre-reduction in H_2 (700°C, 100% H_2, 50mL/min) for 1.5 hours, temperature was adjusted and maintained for 8 or 60 hours and the reactant mixture (45vol% CH_4, 45vol% CO_2, 10vol% He) was fed to the reactor. Helium was used as internal standard for volume change determination in reaction. The gas compositions were then analysed by an on-line gas chromatograph (Agilent 6890) equipped with flame ionisation detector (HP Plot Q capillary, 15m × 0.53mm × 40µm) and thermal conductivity detector (carboxene packed, 4.572m × 3.175mm) for analysis of hydrocarbons and permanent gases, respectively. Pure components were used as reference for peak identification and calibration. Carbon balances were calculated from gas products and reached more than 95% in this work. Conversions (X) and H_2/CO ratio were calculated using the formulas given below:

3. Results and discussion

$$X_{CH_4}\,(\%) = \frac{moles\ of\ converted\ CH_4 \times 100\%}{moles\ of\ CH_4\ in\ feed}$$

$$X_{CO_2}\,(\%) = \frac{moles\ of\ CO_2\ converted \times 100\%}{moles\ of\ CO_2\ in\ feed}$$

$$H_2/CO\ ratio = \frac{moles\ of\ H_2\ produced}{moles\ of\ CO\ produced}$$

3.1. Characterisation of the catalysts

The crystallographic structure patterns of the MgO-Al_2O_3 mixed oxides, as the support material, and the corresponding Ni-containing catalysts were determined by XRD. Figure 2 represents the spinel structure formation of $MgAl_2O_4$ (ICDD file No. 00-021-1152) in the support with reflections at 2θ = 19.5°, 31.3°, 37°, 45° and 59°. This spinel phase is favoured when calcining the Mg-Al hydrotalcite precursor at high temperature [20]. Besides, periclase (the cubic form of magnesium oxide, ICDD file No. 01-071-1176) is also observed with broad reflections at about 2θ = 43° and 63°. This phase is probably created due to the unity ratio of Mg:Al in the hydrotalcite precursor, which is higher than that of mentioned $MgAl_2O_4$ (0.5), leading to the formation of MgO species. XRD patterns of Ni containing samples (Ni/$MgAlO_x$ and La.Ni/$MgAlO_x$) expose almost no additional reflections of Ni^{2+}- containing species compared to the corresponding support. This suggests the formation of well-dispersed Ni^{2+} species on the surface or diffusion into the bulk of support, adapting those mentioned structures of MgO-Al_2O_3 mixed oxides forming solid solutions or spinel. This behaviour is predominant when low content of impregnated species and high calcination temperature were applied during the preparation [21].

The textural parameters of the calcined Ni samples and the support are summarised in Table 1. Compared to the pure support $MgAlO_x$, impregnated catalysts (with La^{3+} and/or Ni^{2+}) show lower specific surface areas. However, La.Ni/$MgAlO_x$ shows significantly less specific surface area (S_{BET}) and pore volume than Ni/$MgAlO_x$. By that, the accessibility of the support surface, the pore system and even the Ni^{2+} atoms were decreased.

3.2. Catalyst performance

Blank tests without catalyst or with Ni/$MgAlO_x$ without pretreatment by H_2 reduction exposed no conversion of CH_4 or CO_2 in the temperature range of 500 - 800°C. First, this proves the essential role of Ni metal as the active sites for DRM. Besides, tests on catalytic methane thermal cracking were also conducted on both catalysts. This is one of the known reactions responsible for coke formation during DRM (Equation 2). However, no remarkable conversion was obtained except small carbon deposition on the spent catalyst.

$$CH_4 \rightarrow C + 2H_2 \qquad (2)$$

$$2CO \rightarrow CO_2 + C \qquad (3)$$

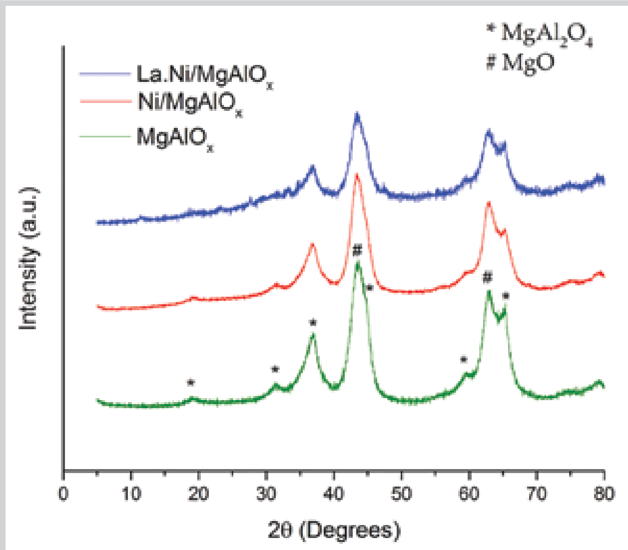

Figure 2. *XRD patterns of support $MgAlO_x$ and catalysts derived therefrom by impregnation*

Table 1. *Textural properties of calcined catalysts and the support*

Catalyst	S_{BET} (m^2/g)	Total pore volume (cm^3/g)
$MgAlO_x$	180	0.24
Ni/$MgAlO_x$	174	0.40
La.Ni/$MgAlO_x$	118	0.27

DRM performance tests of pre-reduced Ni/MgAlO$_x$ at different temperatures in the range of 500 - 780°C were investigated with the same feed composition and WHSV (100L/(g_{cat}·h)). Figure 3 discloses that the performance regarding the CH_4 and CO_2 conversions is close to thermodynamic equilibrium at corresponding reaction temperatures [22]. It is well understood that DRM is only effective at high temperature due to its highly endothermic nature [22]. According to literature, the DRM reaction could be thermodynamically beneficial above 647°C [8]. Some investigations concluded that the catalysts might be active in DRM already at lower temperature (400°C [23] or 450°C [24]). However, therein WHSV was lower, the content of active species was higher or noble metals were added which offered more beneficial conditions for high reaction rates than this study. Compared to some remarkable literature results regarding Ni catalyst systems (Table 2) and also other studies [14], Ni/MgAlO$_x$ of this study shows promising potential for DRM by activating the reaction at mild condition (low temperature and high WHSV) even with low Ni content. This high activity probably is in accordance with high surface of the catalyst (Table 1) and good dispersion of Ni (XRD). Below 650°C, CO formation via CO_2

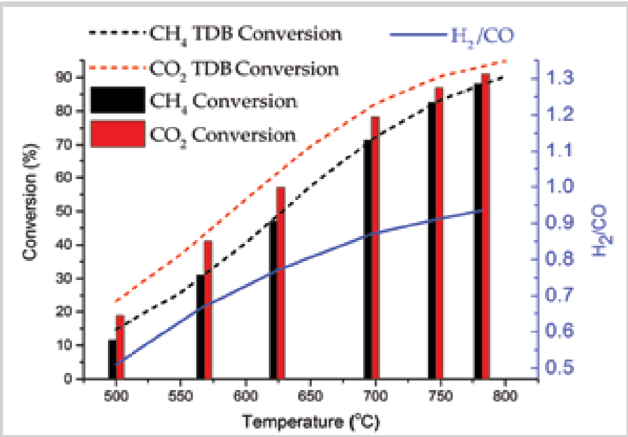

Figure 3. *Performance of Ni/MgAlO$_x$ in comparison with the thermodynamic balance (TDB) (1bar, CO_2/CH_4 = 1, WHSV = 100L/(g_{cat}·h)). Activity data were collected after 2 hours stabilisation at each temperature set point.*

by reverse water gas shift reaction (RWGS, Equation 4, [8]) is expected to get predominant [22].

$$CO_2 + H_2 \rightarrow CO + H_2O \quad \Delta H_{298} = 41 kJ/mol \qquad (4)$$

This reaction is less endothermic and thus more favourable at low temperature compared to DRM. This effect is seen clearly in Figure 3 which shows the effect of temperature on the H_2/CO ratio. The lower the reaction temperature, the lower the H_2/CO ratio and H_2 selectivity. Subsequently, H_2O forms as side product and the relative conversion ratio between CO_2 and CH_4 increases [22].

Figure 4 shows the conversions of CH_4 and CO_2 as well as the amount of carbon deposition depending on the CO_2/CH_4 ratio for runs with Ni/MgAlO$_x$ and La.Ni/MgAlO$_x$. The carbon accumulation in DRM was examined on the spent catalysts after 8 hours on stream in terms of weight percentage. Typically a CO_2/CH_4 ratio of 1 is used for DRM, whereas the ratio of 0.5 is close to the composition of typical biogas as well as the gas content discovered in Ca Voi Xanh gas field. With both catalysts, increasing CO_2/CH_4 ratio from 0 to 1 enhances CH_4 conversion (from almost 0 to around 50%) due to the DRM reaction between both CH_4 and CO_2. The CO_2 conversion achieves a maximum (70%) at CO_2/CH_4 = 0.5 as the result of excess amount of CH_4 shifting DRM more to the production side.

It is well known that carbon deposition during DRM causes catalyst deactivation and reactor plugging [32]. Carbon formation is the result of side reactions including mainly methane decomposition (MD) above 550°C as well as Boudouard Reaction (BD) (Equation 3) below 700°C [22]. The carbon amount on spent Ni/MgAlO$_x$ varies proportionally with CH_4 conversion (Figure 4a). On the other hand, the thermal cracking of methane (CO_2/CH_4 = 0) exposes negligible carbon deposition on spent Ni/MgAlO$_x$, reflecting limited coking rate in case of CO_2 absence, which prevents CO formation in DRM and further disproportionation in BD reaction. Therefore, it can be proposed that both MD and BD reactions

Table 2. *Remarkable recent studies with Ni catalysts for DRM*

Catalyst	Ni content (wt%)	Space velocity	Reactants $CH_4:CO_2:N_2$(He)	T (°C)	X_{CH_4} (%)	X_{CO_2} (%)	Ref.
Ni/SBA-15	12.5	12,000h^{-1}	N/A	800	43	70	[25]
Ni/Mo/SBA-15-La_2O_3	5	12,000ml/(g_{cat}.h)	N/A	800	84	96	[26]
Ni-MgO-$Ce_{0.8}Zr_{0.2}O_2$	15	480,000h^{-1}	1:1:3	800	96	97	[27]
Ni/Ce-Al_2O_3	10	20,000ml/(g_{cat}·h)	N/A	800	80	90	[28]
Ni/MgO-Al_2O_3	12.6	30,000ml/(g_{cat}·h)	1:1:1	800	92	95	[29]
Ni-Co/MgO-ZrO_2	3% Ni, 3% Co	125,000ml/(g_{cat}·h)	N/A	750	80	85	[30]
Ni/SiO_2	0.35	19,000ml/(g_{Ni}·h)	9:9:2	800	42	55	[31]
Ni/MgAlO$_x$	**2.5**	**100,000ml/(g_{cat}·h)**	**9:9:2**	**780**	**83**	**90**	**This study**

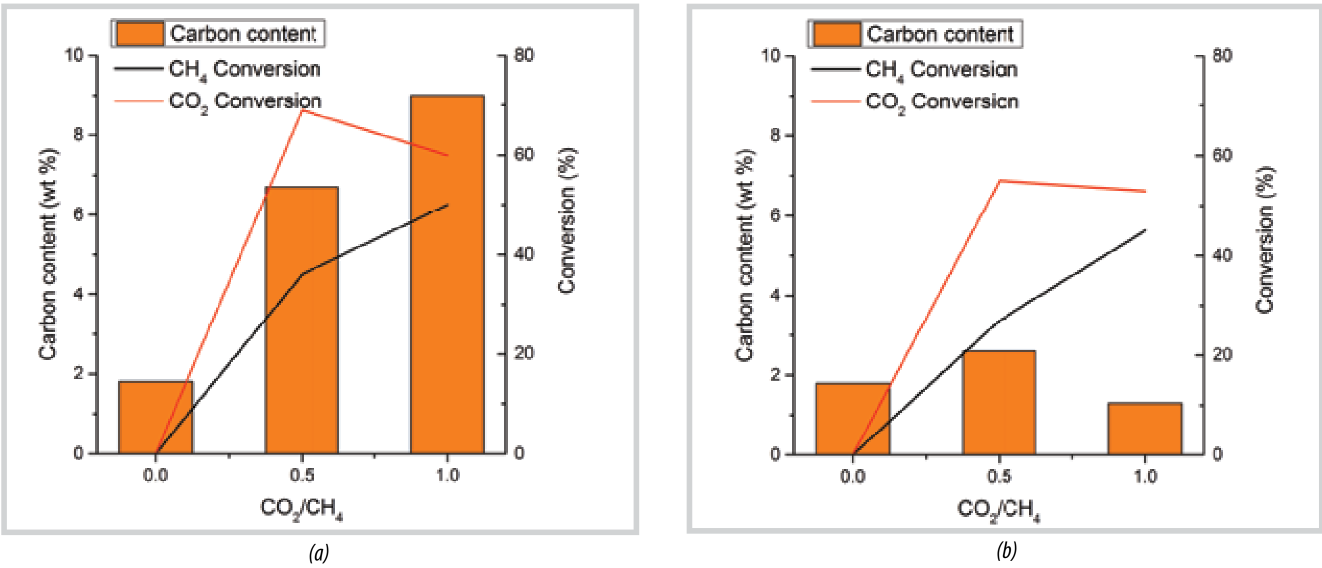

Figure 4. *Performance of Ni/MgAlO$_x$ (a) and La.Ni/MgAlO$_x$ (b) at different CO_2/CH_4 ratios (1bar, 600°C, WHSV = 170L/(g_{cat}·h))*

contribute to coke formation in DRM with different extent when changing the CO_2/CH_4 ratio. The occurrence of coke formation is as expected because the chosen reaction temperature (600°C) is in the thermodynamic range for both MD and BD [22].

La^{3+} addition to the catalyst results in slightly lower DRM activity (Figure 4b). This phenomenon can be explained by the lower surface area of La.Ni/MgAlO$_x$ compared to that of Ni/MgAlO$_x$ (Table 1). La^{3+} ions probably cover some Ni species in the preparation steps and prevent the active sites from being fully exposed to CH_4 and CO_2, lowering the conversion of those reactants. This behaviour was also seen elsewhere [33] on La-promoted Ni/$MgAl_2O_4$ which is similar to the catalyst formulation in this study. However, the La-promoted catalyst is significantly resistant toward coking in the DRM (Figure 4). This rare-earth metal oxide was also studied to eliminate the rapid coking in other reforming reactions (partial oxidation [34], steam reforming [33]). In this study, the tests without CO_2 (CO_2/CH_4 = 0) showed very low conversion for both catalysts and comparable carbon deposition. In DRM with La.Ni/MgAlO$_x$, the higher the CO_2 fraction in the feed, the lower the carbon deposition compared to that of Ni/MgAlO$_x$ under the same condition. This is a measure for the CO_2 activation in carbon gasification by La^{3+} species. Such activation was also discovered in other reforming reactions [33, 34]. Besides, both catalysts expose comparable CH_4 and CO_2 conversions as a function of CO_2/CH_4 ratio (Figures 4). However, the coke formation on La.Ni/MgAlO$_x$ is not proportional to the conversion as it was found on Ni/MgAlO$_x$. Therefore, CO_2 promotion by La^{3+} prevents the BD because carbon gasification is the reverse reaction of BD,

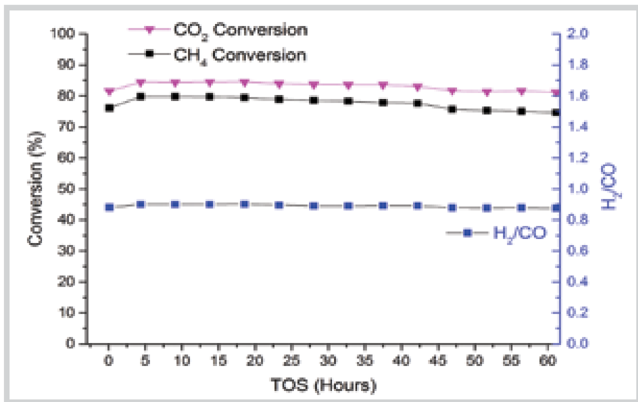

Figure 5. *Catalytic performance of La.Ni/MgAlO$_x$ in long-term DRM (T = 750°C, p = 1 bar, CO_2/CH_4 = 1, WHSV = 170L/(g_{cat}·h)).*

and also removes the carbon species formed via methane thermal cracking. Regarding the reaction pathway, DRM occurs on both catalysts, but La.Ni/MgAlO$_x$ promotes additional steps that activate C gasification by CO_2 which was also proposed elsewhere [35]:

$$La_2O_3 + CO_2 \rightarrow La_2O_2CO_3$$

$$CH_4 + 5x^* \rightarrow CH_x^* + 4\,H^* \qquad (x^*)\text{: surface sites}$$

$$La_2O_2CO_3 + CH_x^* \rightarrow 2CO^* + La_2O_3 + x/2\,H_2$$

$$La_2O_2CO_3 + C \rightarrow 2CO + La_2O_3$$

Finally, a long-term DRM test was carried out with La.Ni/MgAlO$_x$ (Figure 5). The considerably high WHSV of 170L/(g_{cat}·h) compared to literature review [6] was helpful to verify the activity and stability of catalysts during reaction away from thermodynamic equilibrium. The conversions of CH_4 and CO_2 are slightly lower than the thermodynamic balance for CH_4 (83%) and CO_2 (90%) at the corresponding reaction temperature [22].

The catalyst did not deactivate over at least 60 hours on-stream, representing its good stability. During the reaction, CO_2 conversion is always higher than CH_4 conversion, illustrating the contribution of RWGS reaction, causing the H_2/CO ratio to be lower than unity. Negligible carbon deposition (< 2wt%) was measured after 60 hours on stream, reflecting the contribution of C gasification by CO_2 which is promoted by mentioned effect of La^{3+}.

4. Conclusions

The $MgAlO_x$ supported 2.5wt% Ni catalyst shows high activity at 500 - 780°C, revealing the possibility to operate the catalyst at low temperature even at high WHSV and low Ni content. At low temperature, the H_2/CO ratio is low due to the contribution of reverse water gas shift reaction which also creates H_2O as the side product. Compared to $Ni/MgAlO_x$, $La.Ni/MgAlO_x$ shows significantly higher coking resistance, both for CO_2/CH_4 ratio = 0.5 and 1, due to C gasification by CO_2. The obtained results indicate that for $Ni/MgAlO_x$ the coking rate is proportional to methane conversion, whereas this is not the case for La-modified catalyst. Most likely La^{3+} affects the CO_2 activation and gasification of carbonaceous deposits. $La.Ni/MgAlO_x$ also exposes high and stable DRM activity over at least 60 hours at high WHSV.

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ORIENTATIONS FOR TREATMENT AND DEEP PROCESSING OF CA VOI XANH GAS

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Summary

Ca Voi Xanh gas field is located about 100km off the coast of the central region of Vietnam. This is the biggest gas field in Vietnam with its reserves of 150 billion m^3 of natural gas. However, gas from Ca Voi Xanh field has high contents of impurities, namely H_2S, CO_2 and N_2. Orientations for treatment and deep processing of Ca Voi Xanh gas are presented, including membrane separation of CO_2 and/or N_2; and processing of Ca Voi Xanh gas without CO_2 and/or N_2 removal to produce (i) syngas for methanol feed via combined reforming technology and/or (ii) ammonia for fertilizer via Haber process. Recovered CO_2 can be considered as a potential carbon supply to methanol and DME production if a sustainable and reasonable source of hydrogen is supplied. Development of advanced materials and catalysts for efficient processing of Ca Voi Xanh gas is discussed. It is highly expected that zeolite-based membrane would offer a techno-economically good approach of CO_2 and/or N_2 removal from a mixture of CH_4, CO_2, and/or N_2, and that nano-Ni-based catalyst brings a high conversion of methane (> 90%) towards lower temperature (550^{o}C) in comparison with current industrial conditions for methane reforming.

Key words: *Ca Voi Xanh, CO_2, DME, membrane, methanol, N_2, steam reforming.*

1. Introduction on Ca Voi Xanh gas field

Vietnam is in the region of high-CO_2-content gas fields. In 2011, the biggest gas field, named Ca Voi Xanh, was discovered about 100km off the coast of the central region of Vietnam with its reserves of 150 billion m^3 of natural gas. It is scheduled to have first gas in 2023 and its gas will be used for power and petrochemical production. However, Ca Voi Xanh gas has high contents of impurities, namely H_2S, CO_2 and N_2. Table 1 shows its hydrocarbon and non-hydrocarbon composition [1].

It can be seen that Ca Voi Xanh gas contains undesired components, including 0.21% of H_2S, 9.88% of N_2 and 30.26% of CO_2. At the gas processing plant (GPP), H_2S removal treatment is applied so that its remaining H_2S content is less than 30ppm. CO_2 and/or N_2 removal should be considered upon its uses and available technologies for its treatment and deep processing.

Table 1. *Composition of Ca Voi Xanh gas*

Component	Composition (mole %)
N_2	9.88
CO_2	30.26
H_2S	0.21
C_1	57.77
C_2	0.92
C_3	0.31
C_4	0.18

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Ca Voi Xanh gas is planned to be used for power production in priority. About 10 - 20% of produced gas could be considered for petrochemical production. In 2017, the Vietnam Petroleum Institute (VPI) conducted a study to evaluate the ability to use Ca Voi Xanh gas as feedstock for petrochemicals. It was shown that the best option to use Ca Voi Xanh gas for petrochemical production is to produce olefins via methanol production. Olefins can then be used to produce other products, including polypropylene (PP), methyl methacrylate (MMA), and styrene monomer (SM). Figure 1 shows two options for petrochemical production from Ca Voi Xanh gas.

2. Orientations for treatment and deep processing of Ca Voi Xanh gas

2.1. CO_2 and/or N_2 removal from Ca Voi Xanh gas using membrane technology

For CO_2 removal from Ca Voi Xanh gas, a membrane technology can be applied. Membrane separation offers the advantage of being highly impact, environmental friendly, scale-up flexible, and energy efficient relative to the more established gas separation processes such as adsorption and cryogenic distillation, and thus has been focused as subject of investigation for gas separation for years [3]. In the gas industry, some commercial

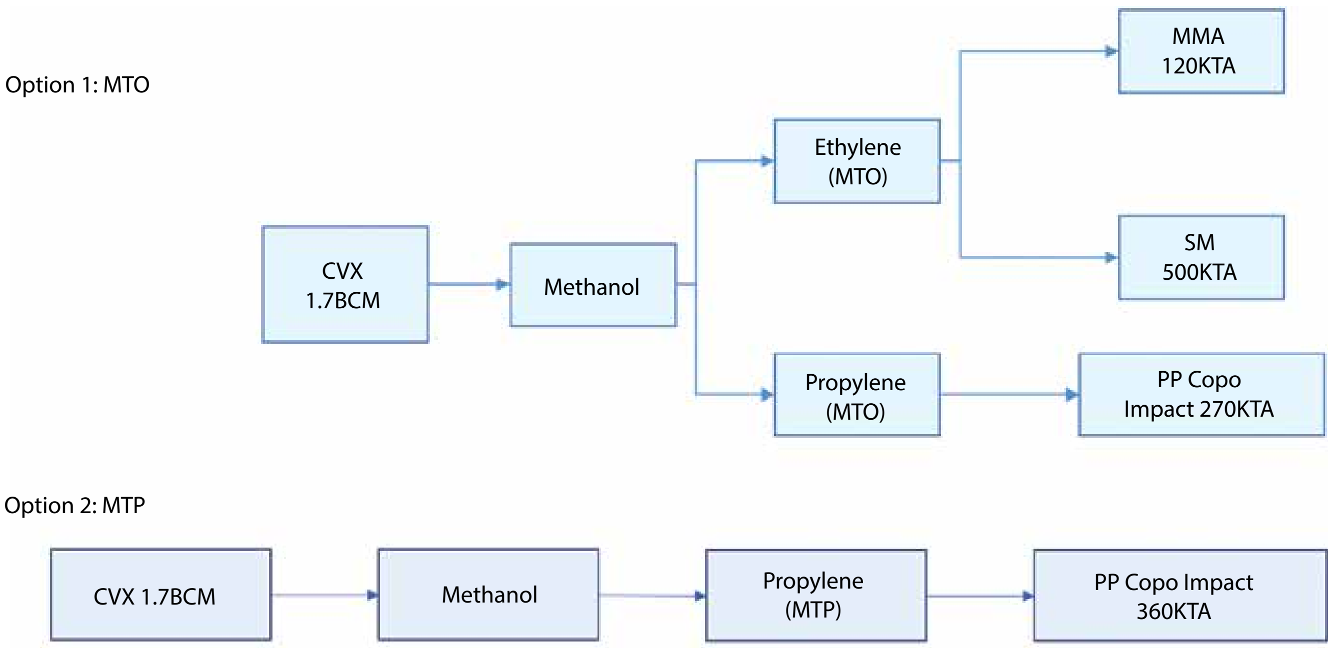

Figure 1. *Two options for petrochemical production from Ca Voi Xanh gas [2]*

technologies are available for CO_2 removal using polymer-based membranes. Table 2 shows selected suppliers of membrane natural gas separation systems [3]. Currently, commercial polymeric materials can bring a selectivity of about 10 - 20% for separation of CO_2 from natural gas [3].

Although polymeric membranes have been commercialised for gas separation, they show a number of disadvantages, clean feed requirement, selectivity-permeability trade-off (upper bound), physical aging and plasticisation in exposure to harsh working conditions and acidic gas contaminants. On the other hand, for N_2 removal, current technology based on cryogenic separation is energy consuming. Membrane technology for N_2 removal is currently not available in the gas industry. The challenge is to develop membranes with the necessary performance related to permselectivity of N_2 over CH_4 with closely matched dynamic diameters of 0.36 and 0.38nm, respectively. A polymeric membrane has been tested for N_2 removal, but its selectivity is relatively low (0.3). Ceramic membranes are being developed for higher efficiency in gas separation. A zeolite-based membrane can bring a selectivity of more than 200 for CO_2 removal, and/or 10 - 20 for N_2 removal from natural gas. Table 3 shows the strength and weaknesses of polymer membranes and inorganic membranes (mainly zeolite membranes) for gas separation.

To date, some inorganic membranes have shown excellent performance in CO_2 separation as well as exhibited potentially good performance in N_2 separation.

Table 2. *Selected suppliers of membrane natural gas separation systems for CO_2 removal*

Company/Technology	Membrane material
Medal (Air Liquide)	Polyimide
W.R.Grace	Cellulose acetate
Separex (UOP)	Cellulose acetate
Cynara (Natco)	Cellulose acetate
ABB/MTR	Perfluoro polymers silicone rubber

Table 3. *Strengths and weaknesses of polymer membranes and inorganic membranes (mainly zeolite membranes)*

Criteria	Polymer membrane	Inorganic membrane
Gas permeation rate	Low	High
Selectivity	Low	High
Producibility of membrane modules	High	Low
Cost effectiveness	High	Low
Stability	Low	High

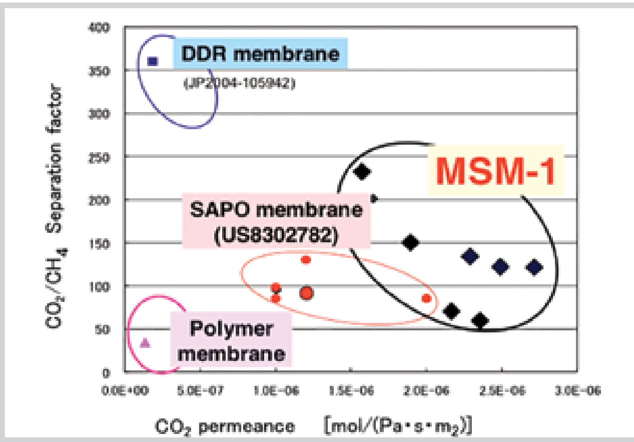

Figure 2. *Comparison of CO_2/CH_4 separation effectiveness of various membranes [4]*

Chiyoda Corporation and Mitsubishi Chemical Corporation have collaborated to develop a zeolite-based membrane for CO_2 removal from natural gas and named it MSM-1. Figure 2 shows a comparison of CO_2/CH_4 separation effectiveness of various membranes. The outstanding performance of zeolite-based membranes compared to polymeric ones can be seen.

However, the current cost for zeolite-based membrane production is quite expensive, and hence, preventing their commercialisation. A more realistic approach is to develop a hybrid membrane based on a mixture of polymer and zeolite. Although a lot of works still need to be done to bring hybrid membranes to the market, this is a potential way to have highly efficient membranes for gas treatment.

2.2. Methanol and/or dimethylether (DME) production from high-CO_2-content natural gas

Ca Voi Xanh gas can be processed without CO_2 removal using a steam reforming process to produce syngas (a mixture of CO and H_2) that can be later converted into methanol and/or DME. Currently, DME is produced via dehydration of methanol as feedstock [5]. Several licensors are available for DME production, including Haldor Topsoe, Linde/Lurgi, and Toyo Engineering, etc. Another under development technology is one-stage DME production via catalytic conversion of syngas or CO_2. Accordingly, the catalyst should have both methanol synthesis and methanol dehydration activities. As a result, an amount of water is formed during DME synthesis, and hence, an efficient water removal technology should be applied.

The CO_2 content in Ca Voi Xanh gas brings two sides during processing. In fact, CO_2 is needed for methanol synthesis, but at the same time, it also results in more coke formation during the reforming reaction. In 2014, Haldor Topsoe introduced a noble metal based catalyst for steam reforming of high-CO_2-content natural gas. Application of this catalyst can reduce the steam amount needed to prevent a high coke formation during the reaction. Its pilot test was performed with time on stream of 490 hours.

Several studies have been being carried out to develop new catalysts that can be applied for steam reforming of natural gas at a considerably lower temperature, just about 550°C. Chihaia et al. showed that steam reforming of methane could be achieved with the methane conversion of 82% over Ni/CeO_2-Al_2O_3 catalyst at 550°C [6]. Currently, VPI is developing a nano-Ni-based catalyst

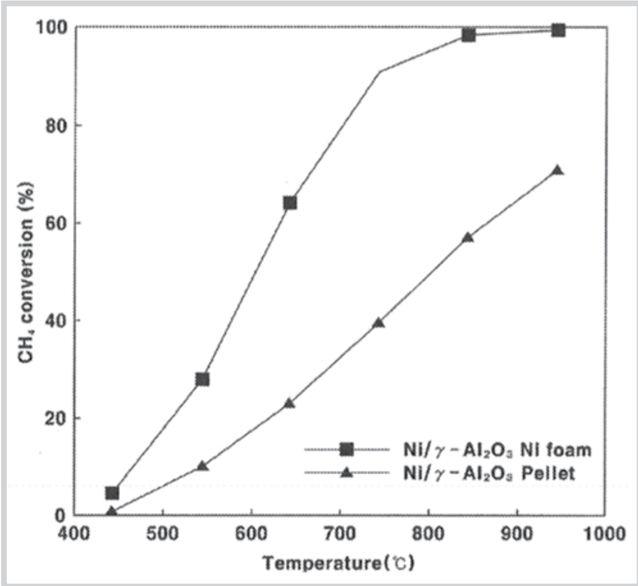

Figure 3. *Comparison of catalyst performance for foam and pellet shaped catalysts during steam reforming of a mixture of CH_4 and CO_2 (GHSV = 10,000^{h-1} and molar ratio for reactants of CH_4:$H_2$0:CO_2 = 1:2:1) [8].*

that brings a high conversion of methane (> 90%) under lower temperature (550°C) in comparison with current industrial conditions for methane reforming.

On the other hand, an integration of structured materials into catalysts for methane steam reforming has also been conducted to enhance the quality of mass and heat transfers inside the reactor, leading to a reduced reactor size or lower reaction temperature. Moon et al. showed that application of foam material into Ni-based catalyst for steam reforming of a mixture of CH_4 and CO_2 could bring a higher conversion of methane than that of conventional catalyst pellet under the same reaction conditions [7]. Figure 3 shows a comparison of catalyst performance for foam and pellet shaped catalysts during steam reforming of a mixture of CH_4 and CO_2. Therefore, application of advanced catalysts could bring high potential to improve energy efficiency during the steam reforming of high-CO_2-content natural gas.

2.3. Co-production of methanol and NH_3 from natural gas containing CO_2 and N_2

Another approach to use Ca Voi Xanh gas for petrochemical production is to produce methanol and NH_3. In this case, neither CO_2 nor N_2 removal is required. N_2 is reacted with part of H_2 in the syngas to produce NH_3, and a mixture of CO, CO_2 and remaining H_2 is a feedstock for methanol production. However, further study needs to be conducted to evaluate the facileness of NH_3 formation under this condition.

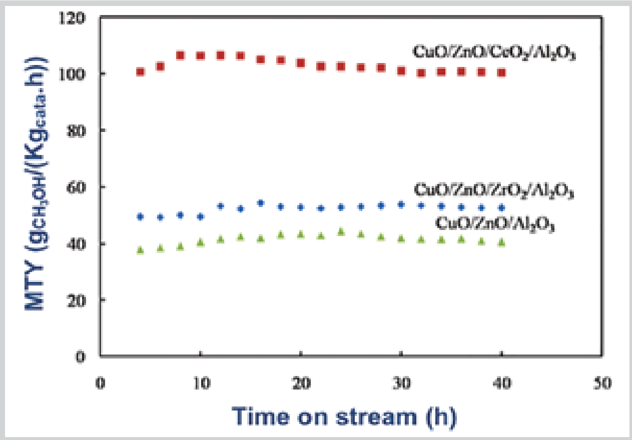

Figure 4. *Methanol yield from direct conversion of CO_2 to methanol over various catalysts (5 bar, 250°C, GHSV = 36,000^{h-1}) [9].*

2.4. Recovered CO_2 for methanol and/or dimethylether (DME) production

In the case that CO_2 is removed from Ca Voi Xanh gas, CO_2 could be considered as a potential carbon supply for methanol and DME production via CO_2 hydrogenation into methanol, and then, followed by methanol dehydration for DME. A one-stage technology is under development for direct DME production from CO_2.

In 2012, VPI conducted a study to develop new catalyst and apply membrane reactor for methanol production from CO_2 to improve its methanol yield. Figure 4 shows methanol yield from direct conversion of CO_2 over various catalysts. As a result, Cu-Zn-Ce-Al based catalyst and NaA based membrane reactor have been found to increase the methanol yield more than 1.5 - 1.7 times compared to the conventional catalyst and reactor for methanol synthesis [9]. A highlight was pointed out that this process only brings profits if a sustainable and reasonable source of hydrogen is supplied. Electrolysation of water using renewable energy could bring a good supply of hydrogen. This direction is highly potential for Vietnam because of its advantages in solar power production [10].

3. Conclusions

Ca Voi Xanh gas contains high contents of impurities, namely H_2S, CO_2 and N_2. Orientations for treatment and deep processing of Ca Voi Xanh gas include (1) CO_2 and/or N_2 removal using membrane technology; and (2) bi-reforming of Ca Voi Xanh gas to produce NH_3 and/or syngas that can then be used as feedstock for methanol production. Recovered CO_2 can be considered as a potential carbon supply for methanol and DME production if a sustainable and reasonable source of hydrogen is supplied. Development of new materials and catalysts brings opportunities for efficient processing of Ca Voi Xanh gas. It has been found that zeolite-based membrane creates a good separation of CO_2 and/or N_2 from a mixture of CH_4, CO_2, and/or N_2, and that nano-Ni-based catalyst brings a high conversion of methane (> 90%) under lower temperature (550°C) in comparison with current industrial conditions for methane reforming.

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RISK MANAGEMENT IN AN UNCERTAIN WORLD: FROM OPERATIONS TO STRATEGY - BENEFITS AND CHALLENGES

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Summary

The oil and gas industries face several long-term challenges: On the one hand, demand and pricing are likely to be constrained by the impact of alternative/renewable energy supplies and by environmental considerations. On the other, the increased technological challenges associated with more complex processes to discover and extract oil will increase cost and risk.

The future success of the sector will be closely linked to its ability to attract investment. This will more than ever depend on robust project selection, efficient project management, and sophisticated portfolio optimisation. The success of individual companies will partly depend on their ability to generate a deep understanding of project economics, and to use this understanding to create more robust decision-making processes, and to improve outcomes in negotiations with private sector partners and governments.

In this article, we highlight the key benefits and challenges in using risk and uncertainty techniques to support decisions relating to project evaluation, selection and portfolio optimisation. We note that over recent decades, the industry has made great strides in its approach to assessing and managing safety and operational risks: Regulations and guidelines have generally continued to be improved and adapted, and organisational processes have been developed to identify, mitigate and manage a wide range of operational risks, even as sometimes this has been in response to disasters. However, we argue that analogous approaches for decision-support are generally not yet adequately embedded within organisational processes and cultures, and that they are not implemented in a systematic manner. We emphasise the benefits in doing so, whilst also highlighting some key challenges. We argue that top-down leadership is essential in order to succeed and to embed the appropriate "risk culture" within an organisation.

Whilst noting that the key challenges are of an organisational and cultural nature, we also briefly mention some technical tools that are typically required, such as simulation techniques.

We conclude by noting that the issues highlighted here are similar in Vietnam to those in many other geographies around the world, even as the extent of implementation varies. In order to maintain a competitive advantage for Vietnam, it is important to enhance industry culture, capabilities and decision-making processes without undue delay.

Key words: *Risk management, benefit, challenge.*

1. Introduction

Risks and uncertainties are present in almost all areas of the oil and gas sector, from upstream to downstream, and from operational areas to those relating to strategy and financing.

For example, there are many risks associated with operations: These include hazards within the extraction process, fire risk, crane accidents, leaks, spillages, diving or other occupational accidents, general health and safety, as well as transportation, collisions and so on. Similarly, there are many risks and uncertainties that affect the economic profitability of major projects. These include the success or failure at the exploration or appraisal stage, uncertainty about the sub-surface volume and recovery levels, the capital expenditure required, the production profile, and the level of future operating costs. The overall success of a project, portfolio or business is also affected by factors such as price level, the potential for substitute products in end-user activities, and issues relating to environment/climate change, and government and international policy decisions. All of these affect the potential to create value within the sector and, crucially, to be able to generate a return-on-capital that is sufficiently attractive for potential investors.

In such a context, it is self-evident that one key factor that will determine the success of the sector (and create a differentiation between companies within it), is the ability

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to effectively assess, evaluate and quantify risks and uncertainties when evaluating investment projects, and to use this to inform decision-making and negotiations with private sector partners and governments.

In this article, we briefly note the progress that has been made by the safety and operational side of the industry over the last 40 - 50 years, in terms of introducing risk assessment and management processes. We note in comparison the relative lack of systematic risk assessment for the financial evaluation of projects. We discuss the importance of such approaches, the consequences when sufficiently robust assessments are not conducted, and the main challenges to achieving a successful transformation to a "risk culture". We note that a critical success factor will be the need for such changes to be driven top-down by industry and company leaders.

2. Requirements for the successful management of risk and uncertainty

This section briefly summarises some core requirements and characteristics of organisations that are most successful in their approach to risk and uncertainty assessment, focussing on the topics of awareness, processes and culture.

2.1. Awareness

The first component of being able to manage anything successfully is awareness of the issue. Whilst we as humans are often naturally aware of risks in many situations, we also seem to be programmed to deliberately ignore information about risks, especially where we feel that we do not understand them, cannot manage them, or if knowledge about them could bring unpleasant news or require us to change our existing beliefs (see later for a more detailed discussion of this). This concept of "information avoidance" or "deliberate ignorance" is a key challenge.

2.2. Processes

The effective assessment and management of risks requires formalised multi-functional processes. These include definitions of the types of analysis required, the criteria to determine the most appropriate approach and the way that the information generated should be used to support decisions. For example, a full quantified risk assessment may be required for all projects above a certain size, or where there is some key aspect to the project that is new, whereas a simplified form of analysis may be sufficient for smaller projects. These have knock-on implications for issues such as skills development and general organisational processes.

2.3. Culture

The most challenging component to successfully assess and manage risks and uncertainties relates to organisational culture. This has many facets, as discussed later. A "risk culture" is one in which there is a general, widespread and shared belief in the absolute requirement to formally assess risks and uncertainties, and a converse belief that a lack of such activity would likely lead to sub-optimal decisions in general.

It is worth noting that not only are all three components simultaneously necessary, but also that there is some interaction and overlap between them. For example (where one accepts that not all elements of a project are fully controllable), the issue of appropriately managing incentives is a complex one, and which involves all three components.

3. Progress made in the operational side of the industry

Over the last 40 - 50 years, the operational side of the industry has developed many processes to identify and manage risks, and these are now widespread and used reasonably systematically in most key areas that affect operational and safety matters.

Such developments were often driven by the need to respond to major events. For example, the Cullen report into the 1988 Piper Alpha disaster in the UK [1] stated that "Quantitative Risk Assessment… would be a valuable source of information to aid decisions about safety provisions offshore". Further, several countries have been particularly proactive in continuing to develop, improve and document general procedures for risk assessment [2]. To a large extent, these have been transmitted and adopted around the world, not least due to the global nature of the industry and its many partnerships and joint operations.

However, the path taken has not always been straight nor without its difficulties, and the process is not complete. For example, the report(s) issued by the Deepwater Horizon Study Group stated that "This disaster was preventable had existing progressive guidelines and practices been followed. This catastrophic failure appears to have resulted from multiple violations of the laws of public resource development, and its proper regulatory oversight". Further it is stated that "there were perceived to be no downsides associated with the uncertain thing…" and that "BP's corporate culture remained one that was embedded in risk-taking and cost-cutting".

Thus, although the path is not complete, and there are new challenges as extraction becomes more complex, it is fair to say that there is a widespread and strong awareness of risk-related issues, and a well-developed set of processes that are documented and can be followed in order to assess risks in these operational and safety contexts.

4. The consequences of insufficient assessment of risk and uncertainty in project evaluation and business strategy

In this section, we focus on the potential consequences of a lack of uncertainty assessment in the evaluation of projects and business cases. These are of course measured in financial terms, rather than health and safety or operational outcomes. It is worth noting that whilst the rest of this section discusses specific consequences of insufficient consideration of uncertainties (and so is arguably framed in "negative" terms), the discussion could (and should in many cases) equally be represented in a positive frame. The benefits achievable are essentially the opposite of the disadvantages of not conducting risk and uncertainty assessment in a systematic manner, and so, for the sake of conciseness are not covered explicitly here in detail.

Before discussing the consequences in detail, it is helpful to discuss a simple example which illustrates some of the quantitative outputs of uncertainty assessment and highlights some core principles which are partly developed further in later sections.

4.1. A simple illustrative example of quantification

Suppose that one wishes to assess how much time a friend will spend travelling to work over the next 10 working days. One may start by asking the friend a simple question: "How long does your typical journey last?". This is a natural and intuitive approach, and it would be fairly common for an answer to be given as a single number (such as 45 minutes) without any explicit consideration of the possible various scenarios or uncertainty ranges for the journey time.

To estimate the total time requirements for 10 journeys, one would then typically simply multiply this estimate by 10, or more generally add together the figure for each day's journey, perhaps in an Excel model in which each day is represented by an assumption for that day's journey time. Figure 1 shows such a model, in which the best estimate (45 minutes) is used for each day's journey time, with the calculated output showing a total

	A	B	C	D	E
1					
2		Type	Length		
3		Typical Day	45		
4					
5					
6					
7					
8		Model for 10 days	Estimate		
9		1	45		
10		2	45		
11		3	45		
12		4	45		
13		5	45		
14		6	45		
15		7	45		
16		8	45		
17		9	45		
18		10	45		
19		Total	450	=SUM(C9:C18)	

Figure 1. *Total journey time as the sum of that of individual journeys*

time of 450 minutes.

It is conceivable that, conscious of the potential uncertainty, one may use heuristic judgment to estimate a range around this total figure, such as the total journey time being "450 minutes plus or minus 10% (45 minutes)".

When thought of in probabilistic terms, the "best estimate" would usually correspond to the most likely of a set of possible values that could occur. For example, from experience it may be known that the most likely case (45 minutes) would occur for 60% of journeys, whereas in 20% of cases the journey may be slightly quicker (40 minutes), and in another 20% of cases, it could be longer (75 minutes), perhaps due to bad weather, traffic accidents or other "event risks", etc. Generally, the time gained through good journeys may not be totally compensated by that lost through bad ones (i.e. the possible times are not distributed symmetrically around the most likely value). Note that even where the friend has given consideration to uncertainty before providing an answer to the original question, the requirement to provide a single number will typically mean that the answer provided represents the "best estimate" of the journey time.

In fact, a formal uncertainty analysis (using statistical methods or simulation techniques) would show that the average total journey time is

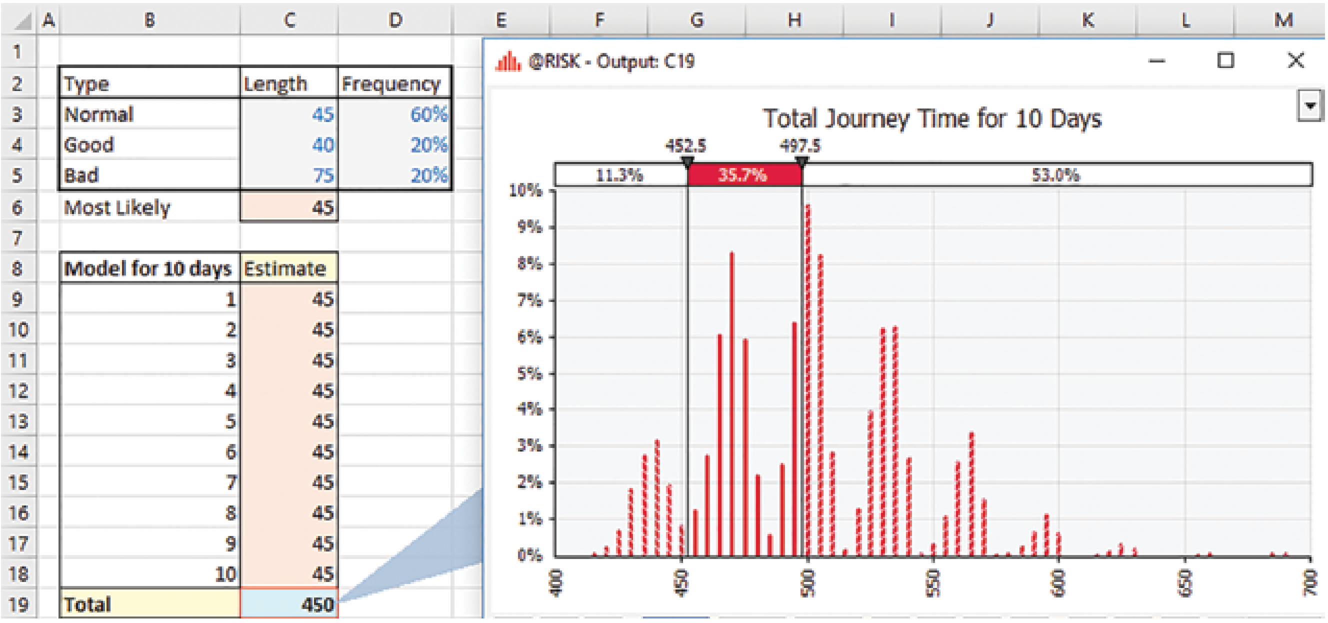

Figure 2. *Monte Carlo Simulation for simple example*

500 minutes, i.e. that 450 minutes is not the central point of the possible range. Further, the "base case" estimate of 450 minutes is exceeded with a frequency of approximately 90%. Indeed, the worst case estimated heuristically (i.e. 495 minutes or 450 minutes plus 10%) is still less than the average or central value. These values are demonstrated in Figure 2, which have been calculated using Monte Carlo simulation with the Excel add-in @RISK®.

Note that the same principles would likely apply in many other situations or projects, such as estimating the costs or capital expenditure for a project. Thus, these projects may have little chance of being delivered within the base budgets that have been defined using traditional methods.

This simple example highlights several important points:

- That much analysis of business cases is subject to the "trap of the most likely": This is the belief (usually implicit) that a forecasted base case reflects a "central" case whenever the input assumptions are in the "central" region of the possible range. In fact, even where a model's input assumptions are chosen to be in the "central" region of their individual possible ranges, the output case shown may be at a relatively extreme end of its true range.

- More generally, there is no correspondence (in terms of definitions) between a model's inputs and its calculated values; it is difficult (unless risk techniques are used) to determine how optimistic or pessimistic a calculated value is, based on the potential optimism or pessimism in individual input assumptions. Thus, the "base case" of many models is in fact very imprecisely defined.

- That, when several uncertainties are present, it is difficult to estimate (without using risk assessment) their overall effect on the possible range: Why it may be intuitive (after some reflection) that the base case output of the above analysis would not be in the central range, the location of the central point as well as the extent of the possible deviation around cannot be estimated reliably by informal judgment or even by traditional sensitivity analysis.

- If base case assumptions were biased for other reasons (motivational, political, or cognitive reasons) the problem of estimating true range is further compounded. For example, the base case may have assumed a single day's journey time of 42 minutes (rather than the true most likely figure of 45 minutes). In fact, what may appear to be a small bias in each individual input assumption will lead to much larger biases in aggregate: As can been seen in Figure 2, a total journey time of 420 minutes (i.e. the base case in this example) would arise only very infrequently.

For a more complete discussion of such phenomena, [3].

It is interesting to note that, in principle, the activities of project evaluation, business planning, and portfolio selection naturally require the use of quantitative techniques. The default approaches (e.g. for business case analysis using Excel) typically use fixed values for input assumptions augmented with sensitivity or scenario analysis. Given that uncertainties are ubiquitous in any project, one may ask why risk and uncertainty assessment is not automatically used as the default approach instead (i.e. to use models or analysis which simply reflects the reality of the situation).

4.2. Taking on incorrect projects or miscalculating their likelihood of success

Without an adequate risk assessment, even where the "base case" financial evaluation seems positive, the project may in fact have a low chance of success, or a high chance that financial expectations are not met in some way (cost or CapEx overruns, reduced revenues etc.). This has been illustrated with the simple example above. As noted, traditional analysis uses an ill-defined base case, and one which would mislead as to the true likelihood of achieving a specific project objective. In extreme situations, one may therefore accept a project which in fact has a low chance of success (or reject one with a high chance of success). In less extreme situations, the true likelihood of a project achieving its expected objectives may be much lower than originally believed if risk assessment approaches are not used.

More generally, the uncertainties that are present should be reflected in any analysis order to have information that is reliable to support decisions. Such analysis would use a structured process to include all relevant factors, it would include event risks, non-linearities (e.g. the potential to react flexible or real options), as well as correlations or more complex forms of dependency ([3] for more detail about modelling approaches).

The use of risk and uncertainty assessment can therefore help to ensure that one has a realistic assessment of the likelihood of achieving the objectives.

4.3. Authorising too few projects, sacrificing growth and profitability

Without a robust process to assess risks and uncertainties, one may inadvertently make overly pessimistic assumptions for capital expenditure or cost items. For example, within a project, it is not likely that all risks will materialise (and that within a portfolio, not all projects are likely to go wrong). Whilst one may be aiming to plan or budget "conservatively", in fact, the compound effect of being conservative in several areas typically results in excess conservatism, and one which is almost impossible to correctly assess using judgment. In other words, without an adequate assessment, one may plan for too much contingency, and hence reserve capital unnecessarily, so that other possible projects cannot be authorised or undertaken, thus reducing growth or profitability.

Growth can also be sacrificed if too few projects are authorised based on excessively optimistic assumptions about their success. For example, if a company's growth objectives can be achieved through having three successful exploration projects, then an (overly) optimistic approach could be to undertake only three projects; in reality, only one or two would succeed, so that growth objectives are not achieved after all.

The use of risk and uncertainty assessment can therefore help to ensure an appropriate balance between optimism and pessimism in budgeting, planning and long-term business strategy, especially where there are significant growth objectives that are desired to be met.

4.4. Authorising too many projects, increasing growth but reducing profitability

A poor risk assessment could lead to projects being authorised even when they have little chance of success (as discussed above). More subtly, as a "mirror-image" of the above discussion, an overly optimistic approach to capital expenditure or cost estimates could result in too many projects being authorised (in terms of genuinely available capital), so that planned contingency budgets are insufficient for the risks that materialise. As a result, even projects which are inherently profitable may run out of budget and become delayed, which will reduce profitability or may lead to forced sales or the need to raise additional financing at short notice.

The use of risk and uncertainty assessment can once again help to ensure an appropriate balance between optimism and pessimism in planning and long-term business strategy.

4.5. Designing sub-optimal projects

A risk assessment process that is not conducted adequately will typically result in projects having been designed in sub-optimal ways. This is because the process of risk assessment and mitigation/response should generally result in a change to the initial design of a project, so that the revised project is designed in the optimal way given its risk structure and the possible mitigation measures. One may develop several project options or design variations, from which one can choose the best. Similar comments apply to portfolio construction, where uncertainty assessment can assist to design better portfolios (e.g. creating portfolios so that cash generation in some projects best matches cash requirements in others).

4.6. Insufficient transparency and hidden biases

Biases can take many forms: cognitive, motivational/political or structural. Cognitive biases are those that are inherent to the human psyche and are believed to have arisen for evolutionary reasons. Motivational or political biases are those where someone (or a group) has an incentive to deliberately bias a process, a set of results, or the assumptions used. Structural biases are those created by the choice of a methodology or tool set. As noted in the simple example earlier, the traditional static approach to analysis using fixed numerical assumptions will often create a structural bias, and "base cases" are typically not clearly defined.

Whilst there may sometimes be valid (e.g. commercial) reasons for working with biased cases (such as when presenting a negotiating stance to a commercial partner), surely the most robust decisions can be made only if one knows the extent of these biases (even if only for internal use).

The uncertainty assessment process (particularly when quantitative) can help to discuss and expose such biases. First, the process to simply ask: "Why could the outcome be different to the one we have assumed?" can highlight that the assumption is not within a central region of the possible range. Second, a robust quantitative model will totally separate the value used for the base case (fixed) assumption of a variable from the possibility uncertainty range (probability distribution) for the values of that variable. The treatment of these as separate issues (and as separate modelling assumptions) will help to expose the biases (especially those that are structural, political or motivational). Thus, a lack of adequate consideration of uncertainty hinders the process to expose and (potentially) correct for biases.

4.7. Ineffective group working processes

In some cases, a lack of consideration of the uncertainty can hinder working processes. Although uncertainty analysis may appear to be more complex than traditional static analysis (and it generally is so), the fact that traditional approaches do not reflect the reality of a situation can sometimes hinder working activities.

As a simple example, given a set of exploration projects (each of which could succeed or fail individually and independently), a working group that is asked to budget for the required subsequent capital expenditure (i.e. that required to move beyond the exploration phase for successful projects) may have difficulty to decide on which scenario to plan for: When using traditional static methods, the group will need to first decide on a specific case to plan for, even though this is not realistic (e.g. perhaps by assuming that 3 out of 5 projects will succeed). Time will be spent discussing and deciding which fixed scenario to plan for, and biases in views on such issues can also hinder this process. On the other hand, a risk approach would allow for all valid scenarios to occur, and shift the discussion to the more realistic, practical and value-added topic of how much contingency budget is necessary, given the uncertainty in the required capital expenditure.

Uncertainty analysis can also reconcile conflicting views in some cases: An uncertainty distribution (for the value of a model's input assumption) may be able to capture all the valid views and reflect them in the analyses, without having to artificially choose one or the other (which can also be time-consuming, whilst probably not creating value). For example, two experts may each have a different view as to the capital expenditure requirements for a project, and each view may be valid, since it could implicitly represent either general uncertainty or specific scenarios. Once again, a more effective group process can be one which allows both views to be represented rather than having to choose one over the other, or to establish a compromise view that is possibly not even realistic or may be biased.

Thus, in some cases, the use of uncertainty assessment process can help to improve working processes, simply by allowing such processes to focus on discussing the reality of the situation.

4.8. Inappropriate decisions and poor corporate governance

The reflection of risk tolerances in decision processes is core to effective corporate governance: The management of a company has the challenge to balance the potential creation of value (through activities which are inherently uncertain) with the need to avoid excessive risk-taking (that could damage the company's prospects or contravene key principles of corporate governance), and to do so in a way which aligns with the expectations of shareholders or other key stakeholders. Without a formalised risk assessment, one cannot truly achieve this objective in a robust and systematic way. Thus, the lack of quantitative risk assessment for any of a company's major activities may significantly restrict a management team's ability to correctly make trade-offs in this respect. Conversely, the use of risk and uncertainty assessment process can help to improve corporate governance in a wide sense.

5. Challenges in creating risk cultures

Earlier, we mentioned the pre-requisites for successful implementation of risk and uncertainty assessment processes i.e. under the topics of Awareness, Processes, and Culture. We have noted that the health, safety and operational side of the business is generally well advanced on the criteria of Awareness and Processes and has made significant (yet imperfect) strides in the area of Culture.

In this paper, we advance the hypothesis that in non-operational sides of the business, the three components are insufficiently developed. Although all three need to be addressed simultaneously, the key challenge will be the development of "risk cultures". Indeed, a lack of sufficient cultural change will ultimately lead to failure of implementation of the other components. The cultural aspect is therefore key but is the one for which there are the most challenges. The following discusses some key aspects of these.

5.1. Human instinct in the face of uncertainty or complexity

Generally, humans seems to be programmed to ignore (or not react to) uncertainties in many types of situations. An important case is informally known as "ignorance is bliss". The more formal concept of "deliberate ignorance" or "information avoidance" has been explored by academic psychologists [4]. Such behaviour results from an underlying need for "psychological security" (in addition to physical security). For example, the willingness of people to want to know their true risk of developing a disease is very different according to whether that person had been briefed or not as to the actions that one could take to reduce the impact of the disease in the case of a positive diagnosis. The academics tested this in the context of diseases which have significant genetic risk factors (e.g. breast cancer in women, diabetes, cardiovascular risks), so that the risk for any individual could be determined using the genetic profile of that person. For a group which had not been briefed about disease-management measures, the perceived "lack of controllability" leads to a "preference for ignorance" (in which participants often did not want to be tested). Conversely, within groups that have been pre-briefed about possible disease management measures (i.e. where participants then perceive controllability to be higher), there is a desire for the testing to be conducted. The academics note that in general, for reasons associated with "psychological security", humans tend to ignore risks or uncertainties if we feel that we do not understand them, or cannot manage them, or if knowledge about them could bring unpleasant news, or may require us to change our existing beliefs. On the other hand, we are more likely to consider risks if we feel that we know how to control them, or if the uncertain outcomes could potentially be good for us.

A related instinct when faced with any form of apparent complexity is to "wait and see", to do nothing, or to search for overly simplistic solutions.

5.2. Lack of observability and feedback

In the operational side of the oil and gas business, risk assessment processes are largely concerned with health and safety issues (in the broadest sense of the term). In such contexts, an insufficient assessment of risks can lead to the occurrence of accidents or other events that may have been preventable, whose causes are identifiable, and for which responsibility can often be assigned.

On the other hand, for an oil and gas project that may develop over 20 - 30 years (or longer), its ultimate overall financial success may only become clear in the distant future. At such a time, the original business case on which the project was built is likely to be long-forgotten, or reasons can be found in retrospect as to why the original assumptions used did not materialise. Further, whereas (for example) for health and safety-related accidents, the consequences are often directly tangible and visible, such immediacy of feedback is not availability for the economic parameters of a project which develops over a multi-year time frame.

Indeed, it can be difficult to "prove" that the enhanced processes associated with risk assessment actually "work", since the overall effect of using enhanced processes is often diffuse (and in the future) and cannot be conducted within a "controlled environment". For example, due to uncertainty, it is very difficult to distinguish a good decision from a good outcome (a good outcome can happen even if the decision was poor and vice versa). Further, (by analogy) the fact that it is ill people that need to take medicine does not mean that the medicine is ineffective or not necessary; indeed, risk assessment is more necessary in a world of tight budgets, robust competition and uncertain environments. Yet, the projects that are in most need of robust risk and uncertainty assessment are generally precisely those which are the most challenging, and which may inherently have the highest chance of achieving poorer outcomes.

In summary, generally, the lack of direct feedback between decisions and outcomes increases the challenge relating to the introduction of risk assessment processes.

5.3. Responsibility and incentives

Concerning the issue of incentives, it is often the case that the personal consequences for ignoring risks is often none or extremely limited. A specific comment about this was noted earlier where the Deepwater Horizon Study Group stated that "there were perceived to be no downsides associated with the uncertain thing…". In general, there may be many reasons for such situations within organisations. First, quite simplistically, in many cases where an adverse event has happened, this is typically due to multiple factors, and reasons can usually be found that diffuse responsibility. Second, an attitude can exist that it may be better not to spend time and resources discussing, identifying, and mitigating items that may not even happen, but rather to simply wait for them to (perhaps) happen and then deal with them: Indeed, such an approach will often be favoured as the practical and cost-effective one within an organisation; those promoting such approaches may also be regarded as the more powerful and action-oriented ones, who may also take a leading role in dealing with the consequences of any risks that do materialise.

It is also interesting to note that the use of risk assessment techniques may transfer some responsibility for poor outcomes away from modelling analysts and onto the decision-makers: Since there are many possible future outcomes to a situation, the realised outcome will almost always be different to the single outcome shown by a traditional static model. Thus, a single forecast that is provided to a decision-maker by a modelling analyst will always be wrong. Decision-makers may try to heuristically compensate for this to improve their decisions, based on the insufficient and ill-defined information provided. If high quality risk assessment models are used instead, then the realised outcome will be within the forecasted range: a poor outcome (if due to risk factors that were accounted for in the forecast) is essentially then the responsibility of the decision-maker or of project management, and so on. However, without the use of such models, some responsibility for bad outcomes can be placed on the modelling analyst, for having provided incomplete information in the first place.

Further, and rather subtly, the admission that some items are not controllable can create ambiguity within incentive systems, and this may also need to be managed carefully.

5.4. Exposing biases

As noted earlier, a robust risk and uncertainty assessment process (especially a quantitative one) will help to expose biases, whether they are structural, motivational/political or cognitive.

The simple example earlier demonstrating the "trap of the most likely" showed how even a simple uncertainty analysis can expose a structural bias. Other biases (especially political and motivational) can be exposed through a robust quantitative process in which an explicit distinction is made between the base case (fixed) assumption for the value of a variable and the uncertainty range associated with that variable. Of course, one of the barriers in exposing any form of bias is that doing so may not be politically acceptable. It may be difficult to admit that a project is likely to not be as profitable as first thought, or that it is likely to be delayed, or that there are risks or uncertainties that exist which cannot be controlled. There may be a political desire to delay the realisation of bad news, for example, or to hope that the situation may be improved before any bad news has been conveyed. Thus, the potential of risk and uncertainty assessment to expose biases can hinder its genuine implementation in some cases.

5.5. Beliefs about complexity of new processes or efficacy of existing ones

The implementation of quantitative uncertainty assessment does require a change to existing analytic and decision-making processes (as well as to the cultural context around such activities).

In terms of the additional complexities that the introduction of risk or uncertainty assessment can pose, these can be thought of as analytic, process, change management and cultural challenges.

From an analytic perspective, the modelling of risk often requires more advanced skills to clearly design and structure models. Although the models can generally still be built in Excel (possibly with the use of Excel add-ins), the dynamic nature of risk models (i.e. to calculate many scenarios, each of which needs to be a genuinely valid outcome) often requires the use or development of modelling skills that may not originally be present within an organisation. On the other hand, it is worth noting that to some extent - since the aim of a model is, as far as practical, to represent reality (which is itself uncertain) - the modelling task is arguably more clearly defined than when it is based on input assumptions that are artificially fixed. Nevertheless, it is fair to say that the process of creating a model in which risks are mapped correctly is not always straightforward.

From a decision perspective, decision-makers also need to learn how to properly interpret the results of these new forms of analysis. This can add further complexity.

In terms of general processes, one may also need to add new forms of "gating processes" e.g. so that the depth of uncertainty analysis that is required to be undertaken is tailored to each project in a structured way. This may also require more cross-functional work, especially at the early stages of a project.

It is worth noting that some of the challenges may relate to the belief that existing analytic methods and decision-processes are already sufficient. For example, since such processes have been used to date, there may be perceived to be no compelling reason to change. Alternatively, risk and uncertainty assessment may be regarded as being already covered by a risk department, or by workshops that focus on operational risk factors. There can be scepticism as to the value for enhanced quantitative analysis. (On this point it is worth remarking that indeed, not least due to the "trap of the most likely", traditional quantitative methods are structurally biased, so this scepticism has some basis in truth, with the solution being to expand the analytic framework to include risk and uncertainty). Finally, there may be a belief that risks should be dealt with by individual project managers and analysts doing their day-to-day jobs. All of these viewpoints can pose challenges, even as counterarguments can be made for each.

5.6. Common understanding and philosophy

The most challenging point to the widespread introduction of risk and uncertainty techniques relates to cultural issues. A "risk culture" is one in which there is a general, widespread and shared belief in the absolute requirement to formally assess risks and uncertainties, and a converse belief that a lack of such activity is not sufficient to create optimal and robust decisions, at least in aggregate.

As a rule, it is fair to say that there is a lack of "risk culture" within the general population, from which organisations typically draw their staff. This itself is a consequence of many underlying issues, including human instinct, different personality types, a lack of quantitative or statistical skills, and education systems that mostly focus on teaching us to develop and defend a specific position, rather than asking why we may be wrong. This lack of a common philosophy poses a significant challenge to the creation of a "risk culture" within an organisation.

6. Overcoming challenges

There is little doubt that the issues discussed above pose truly formidable challenges in the widespread and systematic implementation of risk and uncertainty assessment. As noted at the beginning of the article, the creation of the appropriate awareness, processes and culture are all core components in this respect. The most challenging of these is the cultural one; indeed, an organisation with a strong "risk culture" and common belief system would inherently be one in which there would be high awareness and in which the appropriate processes would have already been developed. At the same time, when it does not exist, the creation of such a culture would require one to first (or in parallel) generate a widespread level of awareness, and to develop process that participants are to follow.

Whilst the obstacles are significant, it is worth also highlighting some issues that can be borne in mind in trying to overcome these.

6.1. Is there an alternative?

The more challenging general environment for the oil and gas sector, the increasing need to have robust decision-making processes, and the enhanced requirements for corporate governance, mean that robust project evaluation and selection is more important than ever. In such contexts, the use of risk and uncertainty analysis is key to create insightful and accurate analysis. At its simplest level, it attempts only to capture the reality of a situation, so that accurate and relevant information about project and business economics can be provided to decision-makers. It would seem logical that the alternative (i.e. the continued use of traditional methods, and insufficient attention given to risks and uncertainties within project economics) will not be sufficient to generate future success, attract investment capital, develop profitable projects and negotiate the successful partnerships that will all be required for the sector to continue to attract investment.

6.2. Focussing on the benefits, maximising success and the benefit-cost ratio

In order to facilitate change, it is important to emphasise the benefits of new approaches (and the disadvantages of current ones). Many of these have been mentioned in this article. Further, it can be helpful to demonstrate the success of any new efforts made, and the benefits achieved from them. It is worth noting that some aspects of the success may in fact be of a qualitative (rather than quantitative) nature, in that the new processes can create a better understanding of a situation. Working groups should try to systemically note how their understanding and results have been influenced by the use of these new approaches, as a way of communicating the benefits more widely.

6.3. Top down change and leadership

Due to the challenges discussed earlier, particularly around cultural issues, "bottom-up approaches" alone are likely to fail. For example, a working group that is itself convinced of the benefits of such analysis, will likely fail when trying to use their results within the wider organisation, unless there is a shared understanding by all key players throughout the process. Thus, although small working groups of "champions" may be created for some technical or analytic issues, a wider change process needs to be introduced to enhance awareness and create a shared understanding and beliefs. This should not be overlooked, but rather be treated as a major change management exercise, which needs to be driven by top management. For example, one practical initiative that management can take is to themselves insist that these approaches are used for major projects, to introduce the processes and capability-development that is necessary, and to "walk the talk" (that is, to systematically see the results of risk assessments for all major projects, and to show that this approach is valued). This requires genuine leadership, not just management support. Further, other aspects of general change management approaches (communication, new systems and processes, capability enhancement etc.) need to be employed.

7. Final remarks

In this article, we have argued that the future success of the sector, and of individual companies within it, will more than ever depend on robust decision-making in the areas of project selection, project management, and business portfolio optimisation. More specifically, we have argued that this will require the widespread use of risk and uncertainty assessment approaches to generate a deep understanding of project economics, and to use this understanding to create more robust decision-making processes, as well as to improve outcomes in negotiations with private sector partners and governments. We have discussed the decision-making benefits in doing so, whilst recognising and analysing the key challenges in achieving the strong "risk cultures" that are necessary to successful and sustainable implementation. We have noted that the scale of the change management challenges means that strong and determined leadership is required. It is probably fair to say that the issues highlighted here are similar in Vietnam to in many other geographies around the world, even as the extent of implementation varies. It is important to enhance industry culture, capabilities and decision-making processes without undue delay.

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COSO ERM AND CYBER RISKS IN OIL AND GAS INDUSTRY

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Summary

The business world is changing rapidly, new risks continue to emerge at a faster pace than has been seen in the past while existing risks are also evolved. To compact and bring more value in dealing with risks, the Committee of Sponsoring Organisations of the Treadway Commission (COSO) has updated its most widely recognised risk management frameworks - COSO ERM 2004. The newly introduced framework, COSO Enterprise Risk Management - Integrating with Strategy and Performance (COSO - ERM 2017), aims to provide companies with a more robust approach to managing risks, which helps to create, preserve and realise value of the companies.

Oil and gas is one of the highest risk and capital-intensive industries facing many uncertainties around exploration, extraction, distribution, volatile commodity prices and the perplexing political landscape. Therefore, a discipline and systematic approach for risk management is needed for oil and gas companies to identify, assess, manage and monitor risks, and COSO ERM provides a risk management framework to do so. Oil and gas companies are also in the forefront to adopt many technologies such as robotics, digitisation, and the Internet of Things (IoT) into the operational environment. As a result, cyber risk becomes increasingly important for oil and gas companies to respond to.

Key words: *Enterprise risk management, cyber risk.*

1. COSO ERM 2017

Enterprise risk management (ERM) has attracted much attention in the last several years, particularly following the great global financial crisis. In today's uncertain world of complex and interrelated risks, an increasing number of organisations have implemented or are developing an ERM system as an enabler to deliver their strategies and achieve their objectives.

However, gaps remain in using risk as a value creator. According to a Deloitte global survey in 2017 with over 300 board members and C-suite executives of companies from USD 1 billion in revenue and up, operating in various industries in the Americas, EMEA and Asia/Pacific regions, nearly 9 out of 10 organisations recognise that risk management should focus on value creation - not mere risk avoidance. But fewer than 20% are taking sufficient action in this regard.

Along with many available risk management frameworks such as COSO Enterprise Risk Management - Integrated Framework (2004), ISO 31000 Risk Management (2009) - Principles and Guidelines on Implementation, BS 31100 Code of Practice for Risk Management, FERMA A Risk Management Standard and OCEG Red Book 2.0 (GRC Capability Model), COSO Enterprise Risk Management - Integrating with Strategy and Performance (COSO - ERM 2017) was introduced in 2017 and distinguished itself from other risk management approaches by its emphasis on the connections between risk, strategy and value.

Traditionally, the key driver for enterprise risk management (ERM) implementation is to protect value of the organisation and the focus is mostly to reduce the risk impact and risk functions tasked with identifying threats to the organisation's business objectives or strategies. In many organisations, risk is an important, but largely supportive function focused on well-defined risks such as strategic, financial, operational and cyber risk, yet rarely integrated with the core business. This can create a gap of considering of risks in decision making process.

The right risk management should be embedded in management's business processes, where identifying and managing risks are integral parts of decision making process. This level of integration can help organisation achieve intended business objectives more effectively and get better value from its ERM program. The new ERM framework is focused on the relationship between risk and value and the important role of ERM in creating, preserving, and realising value. It helps an organisation exploring new opportunities by taking acceptable risks and realising the value of taking these risks.

There are also advantages to enhance ERM with a

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strategic risk approach by embedding risk into strategic planning process. This will help organisation to consider alternative strategies according to organisation's risk appetite. It also improves the resilience of the company's strategy and helps to address barriers to execution; encompasses activities to prepare for and respond to novel crises; covers the spectrum of risks, from high-level strategic risks that affecting all business units to the operational risks managed at the department level; links risk data at different levels, allows reallocation of resources to the organisation's top risks and embeds risk management into existing organisational processes.

2. Risks in oil and gas industry

Organisations in virtually industry and country are reminded frequently that they operate in a risky world. As a capital-intensive industry, oil and gas is not an exception. Risk is a characteristic of oil and gas business, as a part of fundamentals. Below are some common risks in oil and gas industry:

Political risk - An oil and gas company is covered by a range of regulations that limit where, when and how extraction is done, which differ from state to state. Political risk generally increases when oil and gas companies are working on deposits abroad. Numerous issues may arise from this, including sudden nationalisation and/or shifting political winds that change the regulatory environment. Depending on what country the oil is being extracted from, the deal a company starts with is not always the deal it ends up with, as the government may change its mind after the capital is invested, in order to take more profit for itself or for some other political reasons. An important approach that a company takes in mitigating this risk includes careful analysis and building sustainable relationships with international oil and gas partners - if it hopes to remain in business for the long run.

Geological risk - Many of the easy-to-get oil and gas is already tapped out, or in the process of being tapped out. Exploration has moved on to areas that involve drilling in less friendly environments, such as on a platform in the middle of an undulating ocean. There is a wide variety of unconventional oil and gas extraction techniques that have helped squeeze out resources in areas where it would have otherwise been impossible. Geological risk refers to both the difficulty of extraction and the possibility that the accessible reserves in any deposit will be smaller than estimated.

Price risk - Beyond the geological risk, the price of oil and gas is the primary factor in deciding whether a reserve is economically feasible. Basically, the higher the geological barriers to easy extraction, the more price risk a given project faces. This is because unconventional extraction usually costs more than a vertical drill down to a deposit. This does not mean that oil and gas companies automatically cease operations on a project that becomes unprofitable due to a price dip. Often, these projects cannot be quickly shut down and then restarted. Instead, oil and gas companies attempt to forecast the likely prices over the term of the project in order to decide whether to begin. Once a project has begun, price risk is a constant companion.

Supply and demand risks - Supply and demand shocks are a very real risk for oil and gas companies. As mentioned above, operations take a lot of capital and time to get going, and they are not easy to shut down when prices go south or to ramp up when they go north. The uneven nature of production is part of what makes the price of oil and gas so volatile. Other economic factors also play into this, as financial crises and macroeconomic factors can dry up capital or otherwise affect the industry independently of the usual price risks.

3. Cyber risk

The oil and gas industry is moving into the next stage of evolution, whereby robotics, digitisation, and the Internet of Things (IoT) are rapidly being integrated into the operational environment. The interest of cyber criminals in industrial operations has increased over the last decade resulting in cyberattacks that have compromised both production and safety. These attacks have made cyber security a hot discussion topic in boardrooms around the world, and now, a growing number of organisations are developing large transformation programmes to address these new operational threats.

On 30 March 2018, various major U.S. pipelines across the US reported data system blackouts after a third-party electronic communication system was attacked. That electronic data interchange (EDI) system, which was identified as Energy Services Group's Latitude Technologies Unit, controls computer-to-computer document exchanges with customers. The Energy Services Group provides the system to more than 100 natural gas pipelines, energy marketers and utilities nationally.

The EDI cyberattack led to the shutdown of the

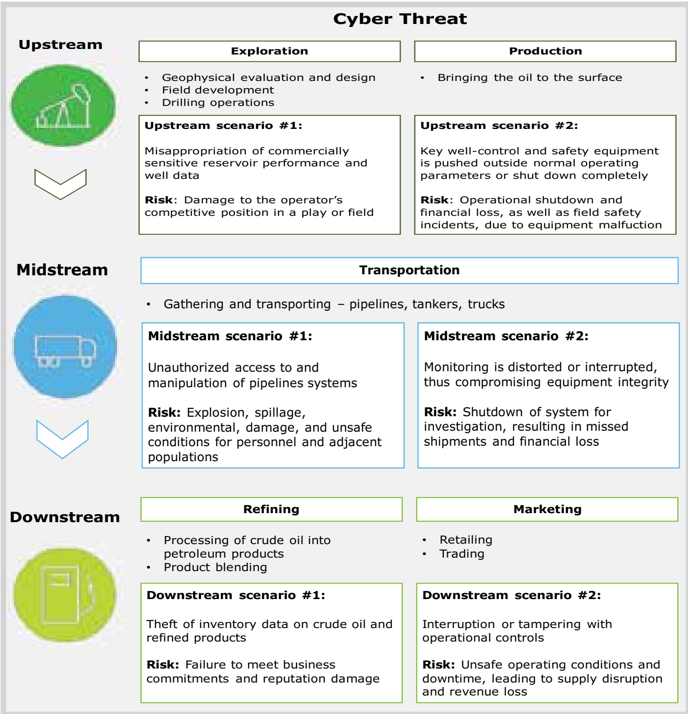

***Figure 1.** How cyber risk impacts oil and gas' value chain*

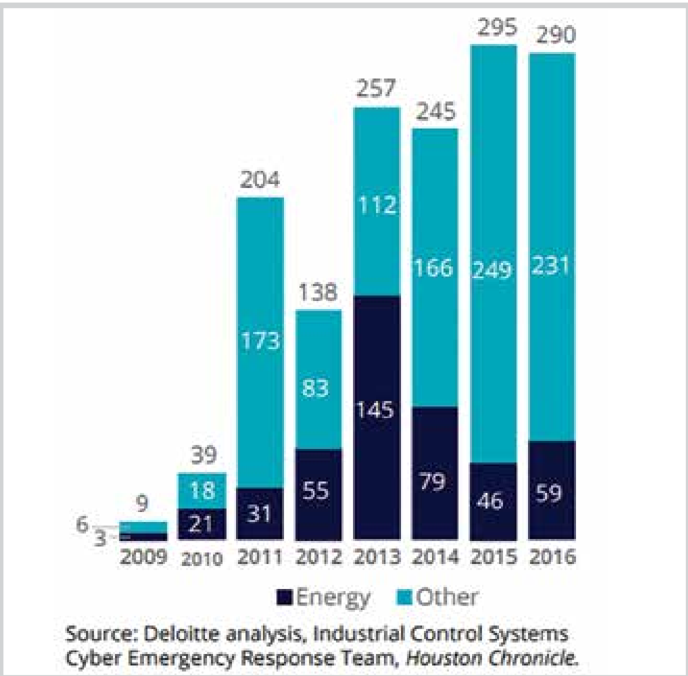

***Figure 2.** ICS-targeted cyberattacks disproportionately affect oil and gas companies*

communication systems for several pipelines utilising those services, including that of Dallas, Texas - based Energy Transfer Partners - a U.S. Fortune 500 natural gas and propane company owning more than 71,000 miles of pipelines containing natural gas, crude oil and other commodities.

Although the incident is presumed to have been focused on gaining pricing information for competitive advantage as opposed to disruption of the pipelines, experts are stressing the importance of securing third-party systems in supervisory control and data acquisition (SCADA) environments. There is a critical need that all supply chain network providers that connect to the companies' assets be held to the same high security standards. Fred Kneip, CEO of CyberGRX, said that it does not matter how well an organisation protects its own perimeter if third parties with weak security controls create vulnerabilities that can be easily exploited.

However, making operational processes secure, vigilant and resilient is a challenge as this requires the organisation to harmonise and align two cultures, engineering and IT. In addition, the operational environment demands tailored technical solutions that are not always easy to secure. Solving these challenges requires a clear understanding of both the engineering and IT disciplines as well as leading sector specific cyber security practices.

Consider the following scenarios, the possibility of which did not exist a few years ago:

• Insecure remote access communication allows a cyber-criminal to hijack a process control system and push production to unsafe levels.

• Poor security practices by a third party contractor allow a virus to migrate into the production environment, shutting down critical Supervisory Control and Data Acquisition (SCADA) systems and creating unsafe working conditions.

• Improper testing of IT systems prior to deployment results in a system crash, leading to disruption or shutdown of operations.

• Technology acquired directly by a facility, without adequate testing and evaluation, goes unpatched and introduces a vulnerability which allows members of an adversarial community to gain remote access to programmable logic controllers (PLC), thus giving them the ability to disrupt the production process at will.

This concern is not just academic: Hackers have initiated hundreds of cybersecurity incidents targeting US oil and gas control systems (Figure 2), many with significant real-world impacts.

Organisations have no alternative options but to be proactive in combating cyber risk.

Conduct a maturity assessment - Once the risks are understood, an oil and gas company should assess the maturity of its cyber security controls in an operational environment. While not every risk can be mitigated, it is important to know what type of controls are in place and where to focus improvement efforts. This means giving appropriate consideration to how potential security breaches within Industrial Control System (ICS) link to business risks. Importantly, this can not be done by an engineering or IT group independently; it requires a multi disciplinary team of business, operations, engineering, and IT security professionals.

Build a unified programme - Although building and implementing a program of this nature is a multi year, transformational effort, each phase of the initiative should have the same objective in mind, moving up the maturity scale to create an ICS environment that is secure, resilient, and vigilant.

Implement key controls - Including awareness training, access control, network security, portable media, incident response.

Embrace good governance - Clear ownership of ICS security is crucial, and roles and responsibilities should be clearly defined for everyone involved, from managers to process operators to third parties. Ultimately, there must be a single line of accountability. Without one, it is challenging not only to define requirements that apply to the whole organisation but also to identify where centralised versus local solutions are appropriate.

4. Conclusions

In the past few years, the oil and gas industry has seen the traditional boundaries between corporate IT and ICS largely disappear. Today, the evolution continues with the digitisation of the oil and gas field. Apart from the traditional risks that the oil and gas industry has faced up for decades, as this interconnectedness marches on, so does the frequency and sophistication of cyber-attacks. However, most companies have not kept pace in terms of their preparedness. The place to start is assessing the maturity of the cyber security controls environment. Going beyond traditional operational safety considerations to implement a secure, vigilant, and resilient programme is not only essential for enhancing an oil and gas company's ability to protect operational integrity amid a growing range of cyber threats, but also to achieve operational excellence by taking advantage of the productivity benefits offered by a digitised, fully integrated ICS environment.

In summary, boards of directors and senior executives at oil and gas companies cannot afford to manage risks reactively, especially in light of the speed of change in the industry that could accelerate beyond the current velocity. That the energy world is changing is not up for debate. The real question is: How fast can energy companies adapt to the speed of change and prepare for the unexpected?

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The Vietnam Petroleum Institute holds a Conference on the theme "More Efficiency, Toward Sustainability" to commemorate the 40th anniversary of its establishment on 22 May 2018.

The Conference is presented in English in the form of panel discussion and shows the multi-dimensional perspective of experts and scientists at home and abroad on various issues, e.g. current situation, opportunities and challenges, short, medium and long-term outlooks and trends of Vietnam's oil and gas industry. On that basis, the Conference seeks and proposes specific solutions for research and development, application of new technologies, improvement of governance and management efficiency for the Vietnam Oil and Gas Group.

In this special issue, the Editorial Board of the Petrovietnam Journal would like to introduce the summaries of speeches at this Conference

1978 - 2018

VIETNAM PETROLEUM INSTITUTE CONFERENCE
"MORE EFFICIENCY, TOWARD SUSTAINABILITY"

» PLENARY SESSION: MORE EFFICIENCY, TOWARD SUSTAINABILITY

» SESSION 1 (EXPLORATION): EFFECTIVE EXPLORATION IN A LOW OIL-PRICE ENVIRONMENT

» SESSION 2 (PRODUCTION): FACILITATING IOR/EOR IN VIETNAM

» SESSION 3 (PROCESSING): TREATMENT AND PROCESSING OF CO_2-RICH GAS IN VIETNAM

» SESSION 4 (MANAGEMENT): RISK MANAGEMENT IN THE VOLATILE OIL & GAS WORLD

MORE EFFICIENCY, TOWARD SUSTAINABILITY

INDUSTRY TRENDS, COSTS AND TECHNOLOGY-ENABLED COST REDESIGN

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This talk will discuss how companies have reacted to the low oil price environment with a focus on the intersection of costs and technology, posing questions about if and how our methods are really changing as we (hopefully) move into a new wave of developments.

Exploration and production organisations have dramatically reshaped their technology (and broader innovation) strategies over the past few years to better compete in a low-price environment. While painful cuts have certainly been a part of this process, market conditions have also compelled companies to prioritise those technology programmes that are best aligned with advancing overall corporate goals. With the industry effectively resetting its cost structure 35 - 40% lower and oil prices beginning to improve, these same companies are now looking to adapt their technology agendas for opportunities likely to emerge over the next few years.

EFFECTIVE EXPLORATION IN A LOW OIL-PRICE ENVIRONMENT

EXPLORATION ACTIVITIES OFFSHORE VIETNAM, OPPORTUNITIES AND CHALLENGES

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We briefly review recent exploration activities and hydrocarbon potential of sedimentary basins offshore Vietnam. The opportunities and challenges in hydrocarbon exploration are also introduced.

RESERVOIR CHARACTERISATION OF THE MIDDLE MIOCENE ISOLATED CARBONATE PLATFORM CA VOI XANH RESERVOIR

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The Ca Voi Xanh field is located offshore Vietnam in the Song Hong basin. Tertiary carbonates of Middle Miocene (Langhian and Serravallian) age form an isolated carbonate platform along the Tri Ton horst structural high. Shallow water corals and large benthic foraminifera (LBF) are the main constituents of the older Langhian carbonates, whereas the overlying Serravallian carbonates are dominated by deeper water coralline red algae (rhodolith) and LBFs.

The Langhian carbonates can be described by one lithofacies: coral-LBF grainstone/rudstone. Depending on the presence of mud in the samples, two lithofacies types are characteristic for the Serravallian: LBF-rhodolith packstone to mud-lean packstone and rhodolith-LBF grainstone to mud-lean packstone.

Two well-developed exposure surfaces can be identified on top of the Langhian (Ser1_SB) and on top of the Serravallian (Tor1_SB). Serravallian carbonates show an overall shallowing-upward trend from more horizontally-oriented rhodoliths (encrusted and bored pavements/hardgrounds) at the lower part of the section to large, roundish, irregular rhodoliths towards the upper part of the section. Petrographic thin section, stable isotope (oxygen and carbon), and fluid inclusion analyses confirm a freshwater (vadose and phreatic) diagenetic overprint of the carbonates below the exposure surfaces (sequence boundaries).

Sequence stratigraphic interpretation is based on detailed sedimentolological core description tied to well-log character. A sequence stratigraphic framework was established for the Serravallian carbonates, displaying three third-order depositional sequences (Ser1, Ser2, and Ser3).

A reproducible reservoir rock type (RRT) scheme was developed for the described carbonates, using a combination of depositional environment, diagenetic overprint, and reservoir parameters (porosity and permeability). The Serravallian RRTs are separated into dominantly packstone (RRT1) and dominantly grainstone textures (RRT2 - RRT6). The grainstone RRTs show varying degrees of cementation (RRT2 and RRT3), dolomitisation (RRT4), and dissolution (RRT5 and RRT6). The Langhian is characterised by two RRTs, depending on the degree of cementation (RRT3L) and dissolution (RRT5L).

The vertical and lateral distribution of RRTs, supported by seismically derived paleo-reconstruction of the carbonate platform, adequately describes the reservoir. Sequence stratigraphy-keyed RRTs were used as input to the geological (static) model, providing a more detailed reservoir description to the dynamic model.

TECTONIC EVOLUTION AND REGIONAL SETTING OF THE CUU LONG BASIN, VIETNAM

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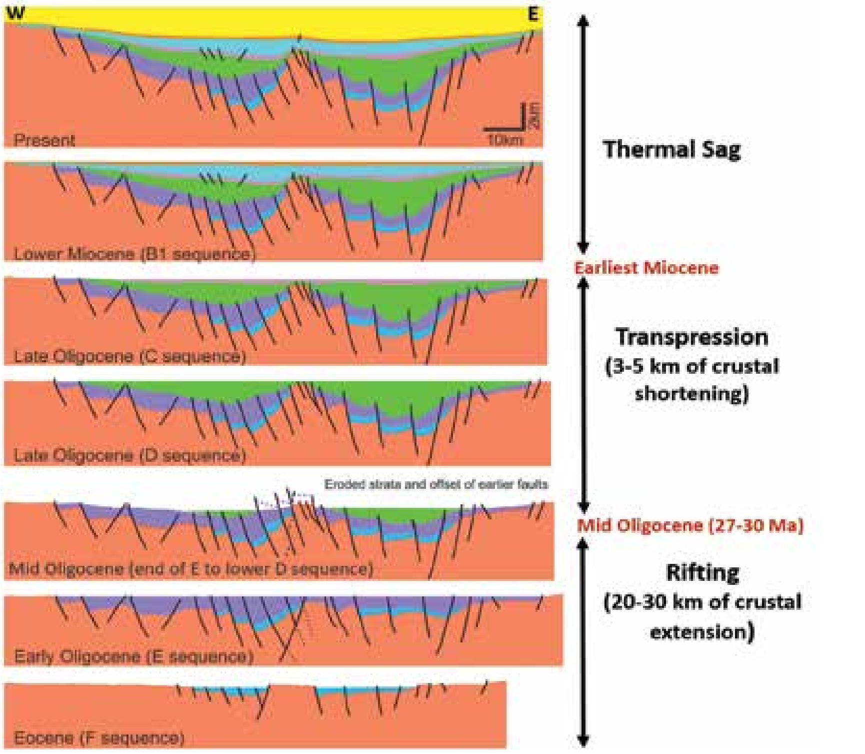
This study makes use of all the available seismic data in the Cuu Long basin, Vinh Chau basin and coastal Mekong Delta to constrain the tectonic history of the area. The linkage between the Mae Ping Fault Zone and deformation in the Cuu Long basin is examined in detail. Two major deformational events are observed: a rifting event during the Eocene to Middle Oligocene followed by right-lateral transpression from Middle Oligocene to the earliest Early Miocene. The data strongly indicates that all the major tributaries of the Mekong River Delta follow faults that rotate counter-clockwise into the Cuu Long basin fault system offshore. The sense of displacement of the Mekong Delta fault zone was left-lateral to accommodate Cuu Long basin rifting and right-lateral to accommodate the younger transpression. Because the orientation, age and sense of displacement of the Mekong Delta fault zone are consistent with slip on the Mae Ping fault zone in Thailand and Cambodia, the Mekong Delta fault zone is interpreted as the continuation of the Mae Ping fault zone. Based on a Chainat Duplex analogue and other data, the link between the Mekong Delta and Mae Ping fault zones appears to be a NNW-striking step-over zone, referred to here as the Mekong - Ton Le Sap step-over zone, which likely follows the trend of older Early Paleogene Kampot Fold Belt structures. The step-over zone was a restraining bend during left-lateral displacement and a releasing bend during right-lateral displacement. Transpression was followed by tectonic quiescence and thermal subsidence. Based on structural and stratigraphic similarities, it appears the Vinh Chau basin and the Cuu Long basin shared similar tectonic histories.



DIGITAL TRANSFORMATION: CREATE INCREMENTAL VALUE FROM MOST VALUABLE ASSET - THE DATA

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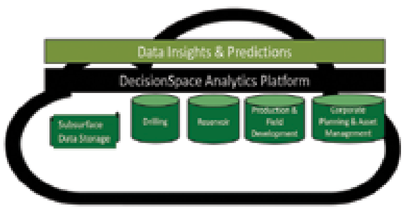
The current oil and gas (O&G) market has helped national oil companies (NOCs) expand their roles beyond national O&G assets to become international players. As a result, NOCs face the same challenges as international oil companies (IOCs) and other players, as well as additional problems that are specific to NOCs. To remain competitive and address these challenges, NOCs need to embark on a digital transformation journey. We discuss such a journey undertaken by Petrovietnam Exploration and Production Corporation (PVEP), highlighting how digital transformation can fulfil the company's mission to grow as an NOC, and the proven economic value that was extracted from the company unstructured data.



CHALLENGES OF GEOLOGY AND PROPOSAL OF SOLUTIONS FOR CONTINUOUS IMPROVEMENT OF FIELD DEVELOPMENT RESULTS OF COMPLEX GAS FIELDS IN BLOCKS B&48/95 - 52/97 OFFSHORE VIETNAM

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The main reservoirs in blocks B&48/95-52/97, located in the north-east of Malay - Tho Chu basin, are characterised by vertically repeating sequences of laterally, discontinuous, thin sands separated by laterally continuous shales stacked over several thousand metres - similar to many reservoirs in the Gulf of Thailand. These laterally, discontinuous sands were further compartmentalised by extensive post-depositional fault systems. These reservoir characteristics are more complex and completely different in comparison with many producing gas and oil fields offshore Vietnam. Consequently, the average gas reserves per well is only a few billion ft^3, and tentatively requires more than 900 wells drilled from more than 50 wellhead platforms for field development to supply about 4 trillion ft^3 of gas to the southwest of Vietnam for approximate 20 years. Therefore, in order to have better field development results and minimise subsurface uncertainties/risks, proposed solutions for continuous improvement of field development results should not only be based on lessons learned from operators in the Gulf of Thailand for field development plan, but also based on clear execution plan as well as successful deployment of drilling and completions slimhole technology.

A NEW INTEGRATED APPROACH OF NATURAL FRACTURE MODELLING TO IMPROVE HISTORICAL MATCHING AND PREDICTION FOR DEVONIAN CARBONATE RESERVOIRS IN NENETSKOYE OIL FIELD, RUSSIA

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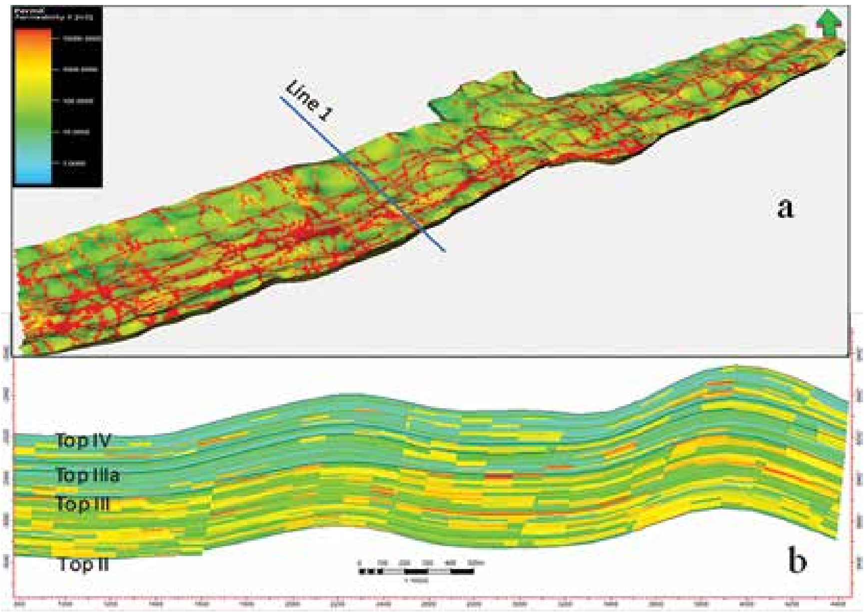

Natural fractures associated with karst systems certainly exist in a tight Devonian carbonate reservoir of the field with primary porosity and permeability typically less than 3% and 1mD, respectively. Natural fracture is a challenge in reservoir characteristic modelling. Up to now, several workflows have been carried out to model natural fractures and karst networks. Unfortunately, existing results cannot be used for managing the field in the future. We discuss a new integrated approach to build the 3D geological model and simulation for Devonian carbonate reservoirs based on geology, geophysics and production data. With two kinds of reservoir porosity (primary and secondary porosity), the conventional stochastic pixel-based method is applied to populate the porosity and permeability distribution of matrix while the objective-based method is used to model vuggy affected cells along fractured zones which were defined from seismic curvature attributes. The properties of fracture corridors are predicted from the power law function of core, well and seismic data, which are consequently modelled by the Discrete Fracture Network (DFN) method and upscaled by ODA's method. The approach reflects better in matching based on 5 years of production and some pressure history. Finally, various development scenarios are investigated.

RESERVOIR QUALITY OF OLIGOCENE COMBINATION/ STRATIGRAPHIC TRAPS IN CUU LONG BASIN, OFFSHORE VIETNAM

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Cuu Long basin, a Cenozoic rift basin located in the southeastern shelf of S.R. Vietnam with high potential of oil and gas. Up to date, most production in Cuu Long basin is from structural traps, making them more and more depleted after years of exploitation. Exploration activities in Cuu Long basin are shifting towards nonstructural traps including stratigraphic and/ or combination ones. The exploration and appraisal activities in recent years have discovered more hydrocarbons in the Oligocene section of Cuu Long basin, thus showing higher potential of Oligocene targets. Some of them were discovered in combination/stratigraphic traps, such as Ca Tam, Song Ngu and Kinh Ngu Trang Nam etc. These demand further attention to the nonstructural exploration targets. Many studies on Oligocene targets in Cuu Long basin have been carried out but only few mention nonstructural traps. This leads to unclear forming mechanism and distribution as well as unevaluated hydrocarbon potential of these nontraditional traps. Therefore, additional studies and assessments of recently discovered nonstructural traps need to be carried out in order to support future exploration and appraisal programme. By integrating of exploration methods such as seismic sequence stratigraphy and seismic attribute interpretation, petrophysical and petrographical analysis, we discuss the assessments of combination/stratigraphic trap types within Oligocene section in Cuu Long basin including (i) identification of several trapping mechanisms and (ii) some evaluations of the trap's reservoir quality utilising the database of some 2D/3D seismic sections, several wells and unpublished reports. The research results show that the key forming factor for primary stratigraphic traps of sand body is lithology change and the one for pinch-out stratigraphic traps is tapering off of sand layers landward or toward the horsts. The reservoir quality of these traps ranges from moderate to good. Further detailed studies on reservoir distribution and sealing capacity of these trap types, however, need to be carried out to fully evaluate hydrocarbon potential of these stratigraphic/ combination traps, and minimise risks in exploration drilling.

RESERVOIR CHARACTERISATION OF DEEP WATER DEPOSITS: A CASE STUDY FROM MMF30 INTERVAL, HAI THACH FIELD, NAM CON SON BASIN

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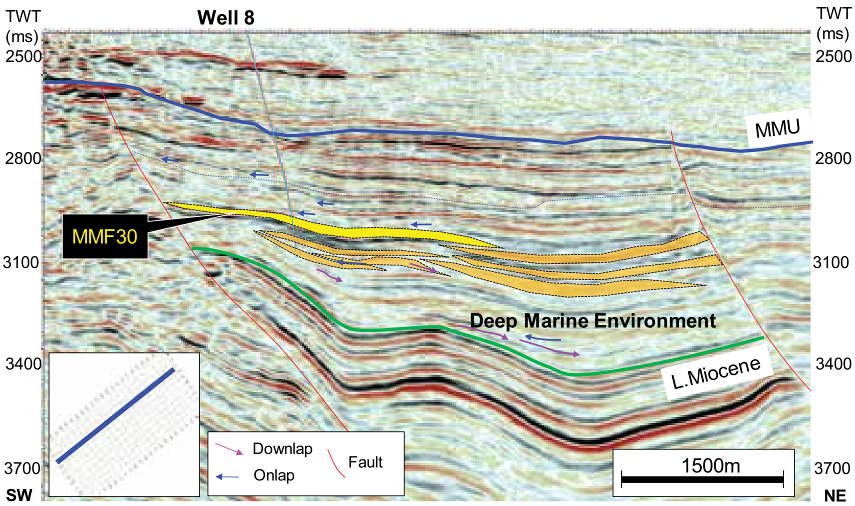

A good understanding of the complexity and architecture of a deep-water reservoir type becomes ever more and more important to optimise development and production. Recent technology advances such as higher resolution 3D seismic data combined with the sequence stratigraphy in deep water reservoir settings and the well log evaluation have resulted in enhancement in the understanding of turbidite complex reservoirs. In MMF30 reservoir, a turbidite sand is of good quality with sand thicknesses between 31m and 52mTVDSS, the average effective porosity between 14 and 16%, and shale volume between 22 and 29%.

INTEGRATED OPEN-HOLE DATA INTERPRETATION TECHNIQUE IN TIGHT/ DEEP INVADED RESERVOIRS

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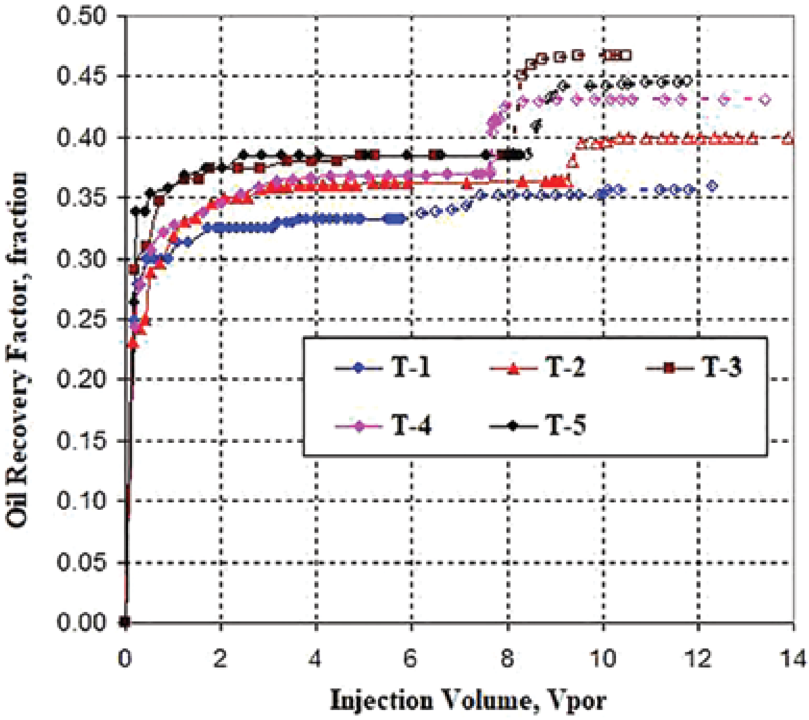

Modular Formation Dynamics Tester (MDT) and Reservoir Characterisation Instrument (RCI) are commonly used in appraisal/exploratory wells. The results of the MDT/RCI method allow to clarify the saturation of the reservoir, determine reservoir pressures, oil/gas-water contact (OWC/GWC), as well as intervals for drill stem test (DST), examine the properties of reservoir fluids. However, to get acceptable results with reasonable measure time is quite difficult sometimes, especially in tight reservoirs with low fluid mobility or deeply invaded zones. We describe a methodology which allows to improve the efficiency of obtained information by integrating different kind of well data.

ZEOLITE CEMENTS RELATED TO IGNEOUS ROCKS: IMPACT ON POROSITY OF LOWER OLIGOCENE SANDSTONE RESERVOIRS ALONG THE CON SON WELL, CUU LONG BASIN, VIETNAM

High porosities and permeabilities are commonly found in the arkosic and basal sandstones of the Lower Oligocene Tra Cu formation in the Cuu Long basin at burial depths greater than 3,500m in some structural highs in the centre of the basin. The Tra Cu sandstones comprise mainly fine to medium-grained arkosic to lithic-arkosic arenites deposited in alluvial and prodelta/lacustrine delta environments. The primary porosity of the arkose and lithic arkose sandstones is related to the grain size and grain sorting as showing the moderately-well sorted. Coarse sandstones have a higher visible porosity. The secondary porosity formed by leached volcanic fragments and dissolution of feldspar. In addition, micro-pore is common within zeolite crystals and zeolite cleavages.

We have used scanning electron microscopy, petrographic analysis, temperature and pressure history modelling to assess the timing of growth and origin of mineral cements, with generation, and the impact to reservoir quality. The results from our study show that zeolite (laumontite) in Lower Oligocene sandstone may have been formed by hydrothermal alteration of calcic plagioclase ($CaAl_2Si_2O_8$) and its volume can be predicted from the initial amount of calcic plagioclase and kinetic parameters. Reservoir quality appears to be spatially related to the locations of igneous intrusions.

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Laumontite production has been affected by heat from igneous activity. The late phase of igneous intrusion at 11.4Ma significantly accelerated laumontite production. Of the intrusive igneous rocks in the study area, sieno granite does not provide favourable conditions for laumontite cementation. Lower porosity and permeability in reservoirs due to laumontite cementation reduce the amount of hydrocarbon expulsion from source rocks to surrounding reservoirs.

FACILITATING IOR/EOR IN VIETNAM

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COMPREHENSIVE SOLUTION WITH THE GOAL OF OPTIMISING PRODUCTION - CHALLENGES AND OPPORTUNITIES FOR EOR APPLICATION

We analyse practical solutions that have been applied for oilfields in Vietnam in order to optimise oil production and improve oil recovery factor. In addition, by defining the constraints and challenges of the solutions, the author highlights the key justification to begin the stage of EOR.

POTENTIAL OF CO_2-EOR ASSOCIATED WITH CCS IN VIETNAM

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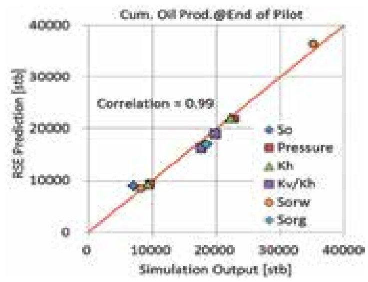
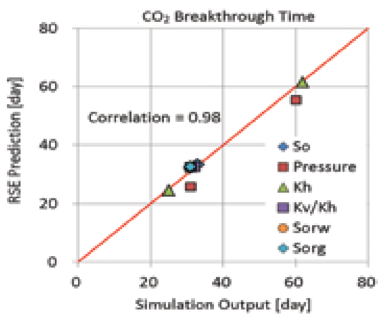
CO_2-EOR has a potential not only in enhancing oil recovery but also in CO_2 storage. It is, however, necessary to understand the technical, operational and economic uncertainties by conducting a pilot test for applying CO_2-EOR to actual oil fields. We describe the methods and procedures to design an inter-well CO_2-EOR pilot test and discuss the potential of CO_2-EOR in offshore fields, Vietnam.

We devised screening criteria in terms of saturations and reservoir pressure to select locations for pilot tests based on the reservoir model developed and calibrated with the actual field data. The number of pilot wells was determined to be one (1) injection well and two (2) production wells in order to estimate areal sweep efficiency during CO_2 injection at a minimum cost. To confirm the effects of CO_2-EOR, well interval, cumulative CO_2 injection volume and duration were determined to be 300m, 2,000 tons and two weeks, respectively. The oil production rate began to increase after 1 month from the beginning of the pilot test, and the gas production rate and the vapour phase CO_2 mole fraction also began to increase at the same time. Then, the oil production rate reached the peak, which corresponds to oil bank, after 1.5 months from the beginning, and the effect of CO_2-EOR was confirmed clearly. If oil saturation is high at the target reservoir, it would be difficult for confirming the oil bank clearly. In such case, pre-water injection before CO_2 injection is conducted to reduce the oil saturation at the target reservoir.

In parallel, a CO_2 procurement and a new platform were designed through the process optimisation study. Manufactured CO_2 was selected as CO_2 source for the pilot test due to easy availability and minimum cost. The packed manufactured CO_2 into tank containers was transported to the injection site by trucks and supply vessels. From a CO_2 impact study, the potential risks related to corrosion and scale formation can be manageable by suitable countermeasures such as corrosion resistant alloys (CRAs) and inhibitors.

We also estimated the CO_2 volume for storage in the reservoir when CO_2 injection was applied. We found about half of the injected CO_2 volume to remain in the reservoir at the normal operational conditions for CO_2-EOR. We proposed a methodology to devise a pilot test plan of CO_2-EOR in any offshore, remote oil field.





ENHANCED OIL RECOVERY IN VIETNAM: POTENTIAL AND OPPORTUNITIES

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In Vietnam oil is produced mainly from Cuu Long basin. The main producing formations are Miocene, Oligocene reservoir sands and Pre-Tertiary fractured granite basement. The largest oil and gas fields are Bach Ho, Rang Dong and Su Tu Den. The fractured granite basement is the main oil producer that produced over 50% oil production in Vietnam. Over more than 30 years, most of oil fields in Vietnam are in depleting phase. Most of oil reservoirs are applying secondary recovery with water flooding. However due to high reservoir heterogeneity especially in fractured basement water flooding may be less effective with high water cut in producing wells. The ultimate recovery factor by current water flooding is expected to be 20 - 30%. To improve the oil recovery Enhanced Oil Recovery is likely a key factor for oil fields in Vietnam.

We summarise Research and Development on EOR Projects in Vietnam oil fields. Some EOR research and study have been funded by Govern-

MAXIMISING PRODUCTION IN UNCONVENTIONAL RESERVOIRS: A CRITICAL REVIEW

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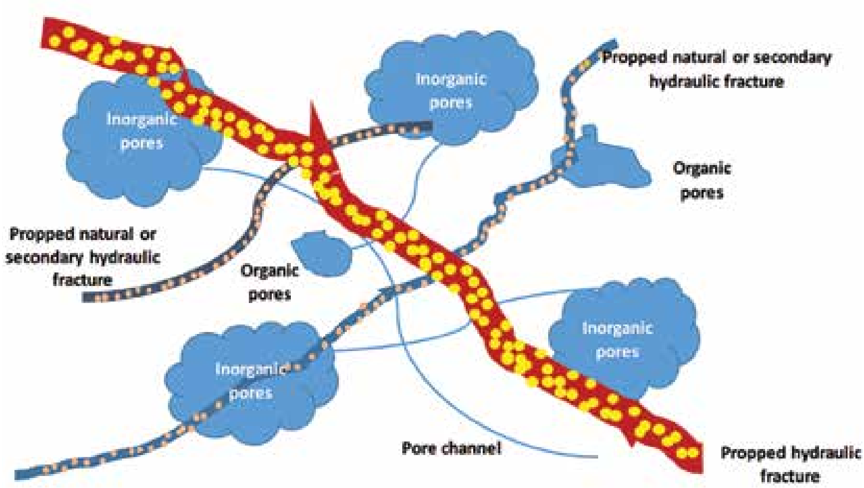

Because of their very low permeability (< 0.1mD), unconventional reservoirs require stimulation before hydrocarbon production can commence. The most commonly used technique is a long horizontal well with multi-stage hydraulic fracturing. Recent advances in stimulation techniques focus on designing better downhole hydraulic fracturing tools and optimising the number of stages and volume of fracturing fluid and proppant pumped. However, even with the best hydraulic fracturing techniques, the ultimate hydrocarbon recovery is still relatively low (< 12%) since only hydrocarbon close to these hydraulic fractures can be produced within a reasonable timeframe. Therefore, there is much room for enhanced oil recovery (EOR) or enhanced gas recovery (EGR). However, almost all EOR or EGR methods require the injection of substantial amount of chemicals or solvents into the reservoir. This is especially challenging in unconventional reservoirs because of their very low injectivity, and high degree of heterogeneity.

To gain a better understanding of how to maximise the production from unconventional reservoirs, we discuss the mechanisms of flow through a shale gas reservoir by first analysing the porosity and permeability distribution in a shale reservoir.

ment and PVN in early time. Fractured basement reservoir presents high EOR priority, however due to high temperature and heterogeneity most of the Research and Development of EOR projects for fractured basement are not feasible. Most of successful EOR Research and Development represent Miocene and Oligocene clastic reservoirs where chemical EOR methods have promised high efficiency.

For oil fields operated by oil companies, EOR present big interest. Rang Dong Miocene oil field became first EOR project that applied in field scale by WAG. The success of EOR Rang Dong field had demonstrated high potential of EOR applicability in Vietnam.

It is found that porosity in a shale reservoir consists of four components: organic (kerogen) pores, inorganic (mineral) pores, pore network, and natural fractures. These porosities provide storage space for oil or gas. The connectivity between them determines the effective permeability. Since these porosities have typical size ranging from nano to micro metres, the effective permeability is usually very small (< 0.001mD). The role of hydraulic fracturing is to create a network of conductive paths connecting these porosities to the horizontal wellbore. Nonetheless, the porosities that are not connected to the hydraulic fractures do not contribute to flow.

We propose methods to enhance the connectivity between the hydraulic fractures with the in-situ porosities thus enlarging the simulated reservoir volume significantly. Both EOR and EGR methods that take advantage of these enhanced connectivity will be discussed.

APPLICATION OF FULL FIELD EOR TO OFFSHORE OIL FIELD IN VIETNAM - RANG DONG LOWER MIOCENE WAG INJECTION CASE HISTORY, CHALLENGES AND PERSPECTIVE

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The Rang Dong field has been produced since 1998 and water injection was started in 2006. To improve oil recovery, hydro carbon gas (HCG) EOR application has been studied through an international joint study including laboratory test, reservoir simulation and feasibility study between Japan and Vietnam from 2008 to 2010. Pilot test was executed from 2011 to 2014 and yielded EOR impact such as oil rate increase and water cut reductions concurrently with oil property change. HCG-EOR full field scale project was started in 2012 and EPC was completed in 2014. HCG-EOR full field scale was commenced in October 2014 and ongoing with WAG optimisation.

The HCG injection for Rang Dong field is not under a fully miscible WAG flood since current reservoir pressure is lower than the minimum miscible pressure obtained through the laboratory analysis in the feasibility study. The IOR of this WAG injection has been observed with oil production incremental by combination impact of pressure maintenance, improvement of fluid displacement swept efficiency and well lifting performance. Furthermore, the reduction of oil viscosity and residual oil saturation that is considered as EOR effect is observed even under immiscible condition.

After three-year full field application, the incremental oil against "water injection case" was evaluated through the reservoir engineering analysis with a well history-matched simulation model. The wells in target reservoir are categorised in three groups based on sedimentary environments. The recovery mechanism of WAG operation was governed mainly by three factors (i.e. primary, secondary and tertiary effect). The performances of each well and each group were closely monitored and then the dominant factors were selected based on observed production behaviours. The WAG injection scheme was optimied for each group by reservoir simulation and dominant factors. Planned incremental oil was successfully achieved and also gas utilisation factor indicates that the effectiveness of gas floods improved compared to initial plan.

RESERVOIR ASSESSMENT AND SCREENING OF EOR FOR DAI HUNG FIELD

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The Dai Hung oil field, located in Block 05-1a offshore Viet Nam, is comprised of a complex subsurface structure containing stacked reservoir sequences typically found in many other Southeast Asian fields. Major petroleum containing reservoirs of the field are the Thong and Dua clastics, and overlying Mang Cau carbonates. Combined with areal fault compartmentalisation, particular at the lower formations, this situation has led to the observed, large variations in oil recovery.

Although the reservoir characteristics are quite good with average porosity and permeability of around 25% and 50mD respectively, the average recovery factor of the field is quite low, about 11%. The water injection and acidising have proven to be effective for Dai Hung field, therefore there would be high chance of success in increasing reserves with EOR/IOR application for the blocks.

Reservoir heterogeneity exists at all scales, from the micro to the megascopic. Previous workers have studied the effects of micro and meso-scale heterogeneities on IOR processes in detail, as many processes are designed to act at those scales but have ignored macro-scale heterogeneities such as facies variations. These can have a large effect on an IOR process; controlling the magnitude and nature of the connectivity between wells, compartmentalising the reservoir and influencing the balance of capillary, viscous and gravity forces.

A database of 499 IOR projects in clastic reservoirs was collated. The macro-scale heterogeneity present in each reservoir was categorised by depositional environment using the Tyler and Finley Heterogeneity Matrix. The results show that successful IOR projects using a particular process cluster at certain combinations of lateral and vertical heterogeneity.

Currently, most of the IOR/EOR projects in Vietnam have been being in pre-stage include: Preliminary screening, lab-analysis, pilot test. As a result, the database-informed screening indicates that mobility control method (ASP) and gas flooding/WAG might be recovery-enhancing alternatives to the current production method of Dai Hung field.

By preliminary evaluation of the IOR/EOR application for the Dai Hung field, it can be observed that with the existence of light, low viscosity oil, thermal processes probably will not be effective to enhance recovery. The implementation of miscible gas flooding will depend on gas source and equipment. In many cases it is suitable EOR for Dai Hung field using WAG and ASP processes.

IOR/EOR RESEARCH AND DEVELOPMENT FOR VIETSOVPETRO JOINT VENTURE OIL FIELDS

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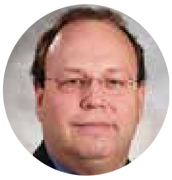
In recent years, the production of oil and gas in Bach Ho and Rong fields has been decreased with high water-cut. Although Vietsovpetro has brought some new fields such as Nam Rong-Doi Moi, Gau Trang, and Tho Trang into production and implemented many geotechnical solutions, the oil and gas production of Vietsovpetro still continues the decline. Recently, Vietsovpetro has co-operated with contractors on experimental implications for enhanced oil recovery (EOR). However, these experiments and researches are in small scale. According to full field development plan reports of Bach Ho, Nam Rong-Doi Moi, Gau Trang and Tho Trang, residual oil is just over 55 million tons. Due to this fact, Vietsovpetro plans to have a programme for research and implementation of EOR with the consultation of reputable companies in this area, in order to increase the probability of success of the project and obtain higher rates of recovery.

We present current production status, recent EOR method applied in Vietsovpetro's oil fields and the advanced approach in selecting mechanistic modelling of alkaline surfactant polymer flooding, hybrid process, and low tension gas flooding. We used a screen approach to identify the most potential applicable EOR method.

TREATMENT AND PROCESSING OF CO_2 RICH GAS IN VIETNAM

BULK CO_2 REMOVAL TECHNOLOGIES FOR HIGH CO_2 FIELDS



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There are a wide range of technologies to remove CO_2 from natural gas. In this presentation, we will discuss the key options and focus on technology options for high CO_2 containing natural gas streams.

The CO_2 content of the natural gas and the desired CO_2 content of the product are major factors in the selection of technology. Processing natural gas with very high CO_2 concentrations can be challenging to do economically with traditional process schemes. When processing very high CO_2 natural gas fields, consideration will be given to use the large volumes CO_2 for EOR, sequestration or some other use. In these cases, we find that a hybrid technology option should be the best solution.

We discuss various technology options while concluding that a hybrid technology option would be the best solution for processing high CO_2 natural gas.

DEVELOPING PETROCHEMICALS BASED ON THE FEEDSTOCK FROM CA VOI XANH GAS FIELD IN VIETNAM

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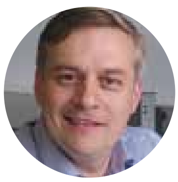
Natural gas production is an important part of the Vietnam petroleum industry and the Vietnam economy. Besides using the natural gas for power generation and industrial purpose, the Vietnam Oil and Gas Group has given priority to using natural gas for petrochemical production. The strategy for developing petrochemicals and chemistry from natural gas with high CO_2 content was built in accordance with the characteristics of the gas field and the available infrastructure of petrochemicals/refineries plants in Vietnam.

DEVELOPMENT AND MODIFICATION OF LOW NICKEL CONTENT CATALYSTS FOR METHANE DRY REFORMING



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Carbon dioxide - the most stable C1 building block - is still under debate of being a bulk source to generate more valuable products. In industry, only the production of urea has been established and some pilot plants produce cyclic and polycarbonates. With this contribution we want to give new impulses towards other possible directions of CO_2 conversion.

Synthetic natural gas (SNG) can be obtained from carbon dioxide and hydrogen. In Germany it is being discussed to use excess of solar or wind energy to generate hydrogen via water electrolysis for conversion of CO_2 waste streams. Hence, we developed and tested catalysts for the methanation reaction. Most promising are alumina supported Ni or zirconia supported RuNi bimetallic catalysts. The latter, working between 300 and 400°C at 10bar and GHSVs up to 36,000h^{-1}, reveals nearly complete CO_2 conversion at a SNG selectivity close to 100%.

Both the Ca Voi Xanh gas field in Vietnam and biogas produced in Germany possess comparable high contents of CO_2. For further processing, in both cases it is important to find a way to handle the concomitant CO_2. One option is the direct production of synthesis gas - a mixture of CO and H_2. Accordingly, low content (2.5wt%) but active Ni catalysts supported on Mg-Al mixed oxides were developed and studied for methane dry reforming reaction (DRM). The main scope of this investigation was to design an active catalyst and modify it to avoid quick deactivation caused by coking. The samples in this study were characterised by N_2 physisorption (BET) and X-ray diffraction (XRD). The results revealed that our Ni/$MgAlO_x$ catalysts show high surface area and good Ni dispersion. Such properties contribute to the high activity of the catalysts already at 500°C. Modification with La^{3+} significantly increases the resistance toward carbon formation due to its ability for C gasification. Such La.Ni/$MgAlO_x$ type catalyst also shows high and stable DRM activity over at least 60 hours with low carbon accumulation at high weight hourly space velocity (WHSV = 170L/(g_{cat}·h)) compared to state-of-art.

OPTIMAL UTILISATION OF CO_2 FOR METHANOL AND AMMONIA PRODUCTION

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With increasing global concern about atmospheric CO_2 levels the chemical industry is seeking to avoid, minimise or convert CO_2 into chemicals. Licensors are often approached with request to convert CO_2 rich feed gases into especially methanol. This makes sense, but only to a certain extent as methanol synthesis is limited by the available hydrogen. Even worse is it for ammonia synthesis. Only if the ammonia is converted to urea or co-produced with methanol some CO_2 can be utilised. This makes it important to optimise the processes and product split for a given feedstock. We will address the main guidelines for such optimisation.

ORIENTATION FOR TREATMENT AND DEEP PROCESSING OF CA VOI XANH GAS

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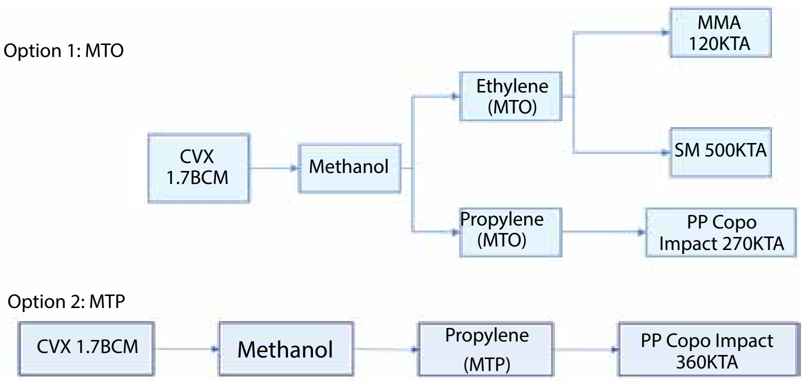
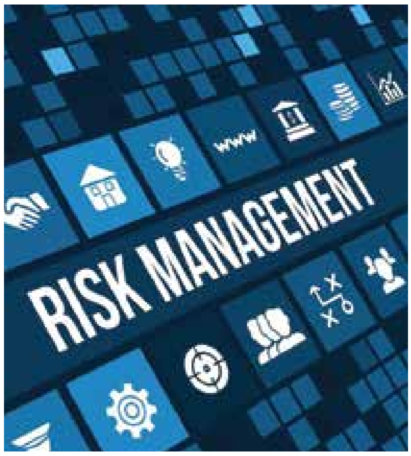
Ca Voi Xanh gas field is located about 100km off the coast of the central region of Vietnam. This is the biggest gas field in Vietnam with its reserves of 150 billion m^3 of natural gas. However, gas from Ca Voi Xanh field has high contents of impurities, namely H_2S, CO_2 and N_2. Orientations for treatment and deep processing of Ca Voi Xanh gas include (1) CO_2 and/or N_2 removal using membrane technology; and (2) bi-reforming of Ca Voi Xanh gas to produce NH_3 and/or syngas that can then be used as feedstock for methanol production. Recovered CO_2 can be considered as a potential carbon supply to methanol and DME production if a sustainable and reasonable source of hydrogen is supplied. Development of new materials and catalysts for efficient processing of Ca Voi Xanh gas is discussed. It has been found that zeolite-based membrane creates a good separation of CO_2 and/or N_2 from a mixture of CH_4, CO_2, and/or N_2, and that nano-Ni-based catalyst brings a high conversion of methane (> 90%) under lower temperature (550°C) in comparison with current industrial conditions for methane reforming.





COSO ERM AND CYBER RISKS IN OIL AND GAS INDUSTRY

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The business world is changing rapidly, new risks continue to emerge at a faster pace than has been seen in the past while existing risks are also evolved. Oil and Gas is one of the highest risk and capital intensive industry facing many uncertainties around exploration, extraction, distribution, volatile commodity prices and the perplexing political landscape. Therefore, a discipline and systematic approach for risk management is needed for oil and gas companies to identify, assess, manage and monitor risks, and COSO ERM provides a risk management framework to do so. Oil and gas companies are also in the forefront to adopt many technologies such as robotics, digitisation, and the Internet of Things (IoT) into their operational environment. As a result, cyber risk becomes increasingly important for oil and gas companies to respond to.

RISK MANAGEMENT IN THE VOLATILE OIL & GAS WORLD

RISK MANAGEMENT AT THE VIETNAM OIL AND GAS GROUP: CURRENT GAPS AND THOUGHTS FOR THE FUTURE

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The current status of risk management at the Vietnam Oil and Gas Group (PVN), as a conglomerate, is investigated under the Deloitte Capability Maturity Model which includes key elements as governance, procedure, people and technology and five stages of maturity: initial/ad-hoc, fragmented, comprehensive, integrated and strategic. This was done by a survey of 18 members and interviews with responsible at the mother company.

The three lines of defense within current risk management system also have been analysed in order to see how their roles are implemented in practice. The findings have been discussed to define the gaps between current status and the requirements.

Based on the gaps defined, some preliminary recommendations on the ways forward with risk management at the Vietnam Oil and Gas Group, from the strategic planning level down to the implementation stage.

RISK MANAGEMENT IN AN UNCERTAIN WORLD: FROM OPERATIONS TO STRATEGY - BENEFITS AND CHALLENGES

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The oil and gas industries face several long-term challenges: On the one hand, demand and pricing are likely to be constrained by the impact of alternative/renewable energy supplies and by environmental considerations. On the other, the increased technological challenges associated with more complex processes to discover and extract oil will increase cost and risk.

The future success of the sector will be closely linked to its ability to attract investment. This will more than ever depend on robust project selection, efficient project management, and sophisticated portfolio optimisation. The success of individual companies will partly depend on their ability to generate a deep understanding of project economics, to use this understanding to create more robust decision-making processes, and to improve outcomes in negotiations with private sector partners and governments.

We highlight the key benefits and challenges in using risk and uncertainty techniques to support decisions relating to project evaluation, selection and portfolio optimisation. We note that over recent decades, the industry has made great strides in its approach to assessing and managing safety and operational risks: Regulations and guidelines have generally continued to be improved and adapted, and organisational processes have been developed to identify, mitigate and manage a wide range of operational risks, even as sometimes this has been in response to disasters. However, we argue that analogous approaches for decision-support are generally not yet adequately embedded within organisational processes and cultures, and that they are not implemented in a systematic manner. We emphasise the benefits in doing so, whilst also highlighting some key challenges. We argue that top-down leadership is essential in order to succeed and to embed the appropriate "risk culture" within an organisation.

Whilst noting that the key challenges are of an organisational and cultural nature, we also briefly mention some technical tools that are typically required, such as simulation techniques.

We conclude by noting that the issues highlighted here are similar in Vietnam to those in many other geographies around the world, even as the extent of implementation varies. In order to maintain a competitive advantage for Vietnam, it is important to enhance industry culture, capabilities and decision-making processes without undue delay.