PS Success of Structural Stratigraphic Combination Trap, Arthit Field, Gulf of Thailand*

Chayarus Centhonglang[1], Pornpimol Promsen[1], Parichat Loboonlert[1], Tanaporn Charoenpun[1], and Jakkrich Yingyuen[1]

Search and Discovery Article #20333 (2015)**
Posted November 30, 2015

*Adapted from poster presentation given at AAPG/SEG International Conference & Exhibition, Melbourne, Australia, September 13-16, 2015

[1]PTT Exploration and Production PCL., Bangkok, Thailand (ChayarusC@pttep.com)

Abstract

The Arthit gas field is located in the northwest of the North Malay Basin, offshore Thailand. The hydrocarbon accumulation is mostly discovered in Miocene to Oligocene reservoir. The subsurface geology shows the existences of structurally complex, as highly faulted seen over the entire Arthit concession. The field was started on production since 2008. Most of the gas production is primarily produced in stacked channel reservoir in structural trap e.g., 3-way dip closure and 4-way dip closure. However, to prolong the field life by upsurge gas production, developing hydrocarbon production only from structural trap might not effectively sufficient. Therefore, in recent years, the structural stratigraphic combination trap such as Nose structure is becoming more interested. In the past, Nose structure was rarely considered to be drilling target for development wells. Apparently, in Arthit Field, Nose structure is believed that it contains higher risk in term of trap and seal compared with other trap styles. Furthermore, seismic reservoir characterization and hydrocarbon indication of stacked channel reservoirs are unfeasible due to the properties. Moreover, the combination of the complexity of trap style and the complication of reservoir indication has increasingly more complicated to develop hydrocarbon in Nose structure. In 2012, an appraisal well was drilled to appraise hydrocarbon in nose structure (structural stratigraphic combination trap). Additionally, another objective was to prove the geological model assumption of reservoir distribution and direction. The result of this well has been represented by the success of proven 88 mTV net pay in stacked channel reservoir. As a result, in 2013, the production platform with fifteen development wells, which were targeted in gas accumulation, was successfully drilled. All of the wells were revealed by the proven gas, good reservoir properties, with the maximum 90mTV of gas sand. By this rewarding, it has been clearly proved that the geological model assumption is applicable for Nose structure in Arthit Field. Five wells were subsequently perforated with the initial rate of 15.7 MMscfd. Currently, the production from only these five wells becomes 25.0 MMscfd, represented about 10% of field daily production rate. This favorable outcome is inspiring and encouraging to get more interest in Nose structure in Arthit Field.

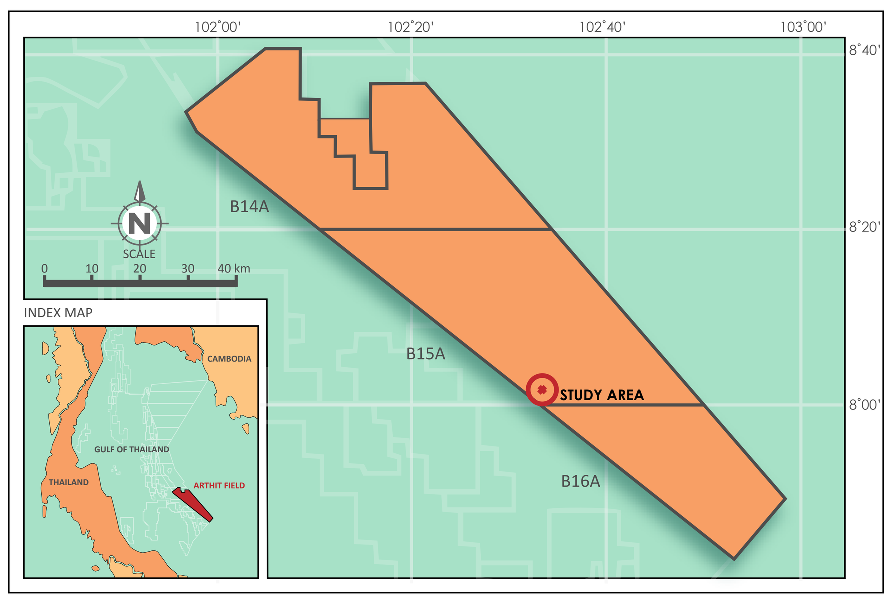
Success of Structural Stratigraphic Combination Trap Arthit Field, Gulf of Thailand

Chayarus Centhonglang, Pornpimol Promsen, Parichat Loboonlert,
Thanaporn Charoenpun, Jakkrich Yingyuen
PTT Exploration and Production PCL.

AAPG|SEG International Conference & Exhibition 2015

1. INTRODUCTION

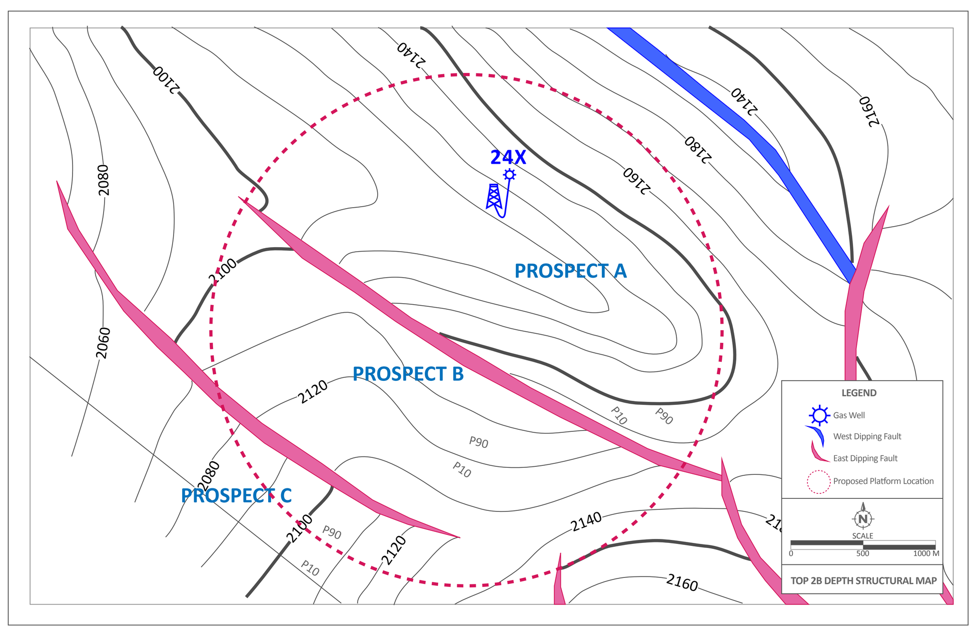
The Arthit gas field is located in the northwestern part of the North Malay Basin, offshore Thailand. The hydrocarbon accumulations are mostly discovered from Miocene to Oligocene reservoir. The existences of structurally complex, as highly faulted seen over the entire Arthit concession. The field was started on production since 2008. Most of the gas production is primarily produced from stacked-channel reservoirs in structural trap. To prolong the field life by upsurge gas production, developing hydrocarbon production from the structural stratigraphic combination trap such as Nose structure is becoming more interested.



2. NOSE COMBINATION TRAP

The main structural subdivisions in Arthit will be referred to as "Geological Trends", each of which bestows a set of dominant trapping styles and configurations. The dominantly geological trends which frequently developing hydrocarbon production are Graben Trend, Basemant Ramp, Basement Flank, Hinge Zone, Horst Trend Ton Son, Re-entrant Flank and Nose Trend.

The study area was situated in Horst Trend Area but main prospect of this platform was defined as "Nose Combination Trap" which is basically referred to "Fold Nose".
The fold nose is defined as a plunging fold with a gently dipping surface and commonly usage for both anticlinal and synclinal folds.



3. RESERVOIR GEOMETRY

1) Channel-belt Width
The amplitude anomaly is the capable method to directly measured the channel-belt width and predicted spatial distribution of channelized reservoir in Arthit Field. Average channel-belt width is about 300-600 meters.
2) Reservoir Thickness
The sandstone reservoir facies were interpreted using the log characteristic. The thickness from blocky sandstone is only usable facies that can produce seismic amplitude anomaly trend due to their thickness were over 5 meters thick. Average thickness is 10 meters and maximum observed thick is 30 meters in Unit 2C.
3) Channel Orientation
Channel direction can be generally observed from amplitude anomaly map. Unfortunately for this platform, the channel-like feature is not shown in seismic Therefore, the major trend of channel orientation was applied for geological.

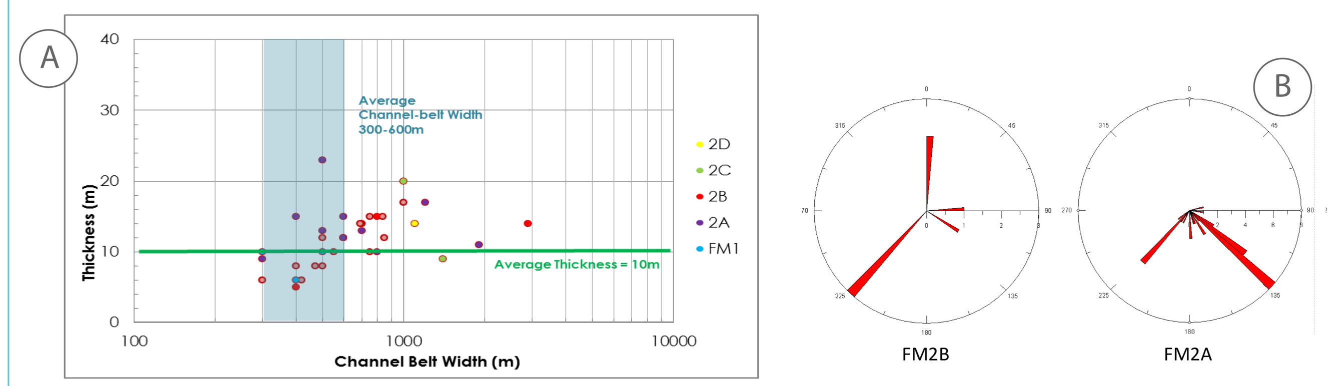
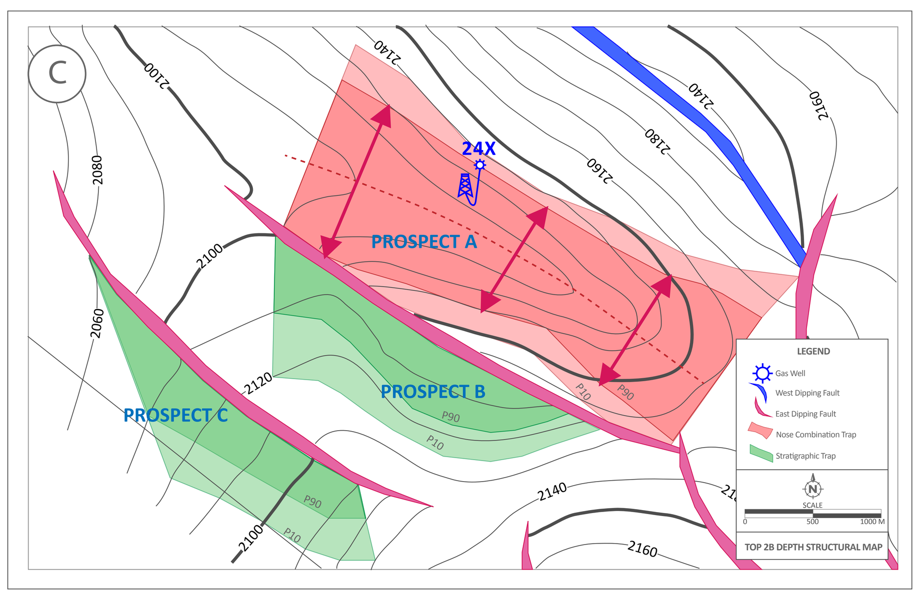


Fig 3 Arthit Reservoir Geometry Characteristics, A) Average Channel-belt width VS reservoir thickness over the entire Arthit Area, B) Channel direction plotted by unit (from referenced area)

4. GEOLOGICAL MODEL ASSUMPTION

There are two geological models which assumed for this project:

1) Trappable channel directions are defined by analyzing the structural contours in relation with the fault orientation. From this project, a median trapping direction is derived in northeast-southwest orientation.
2) Net gas area is calculated using the statistics of hydrocarbon column height (HCCH) and a projected direction need to perpendicular to the nose axis.



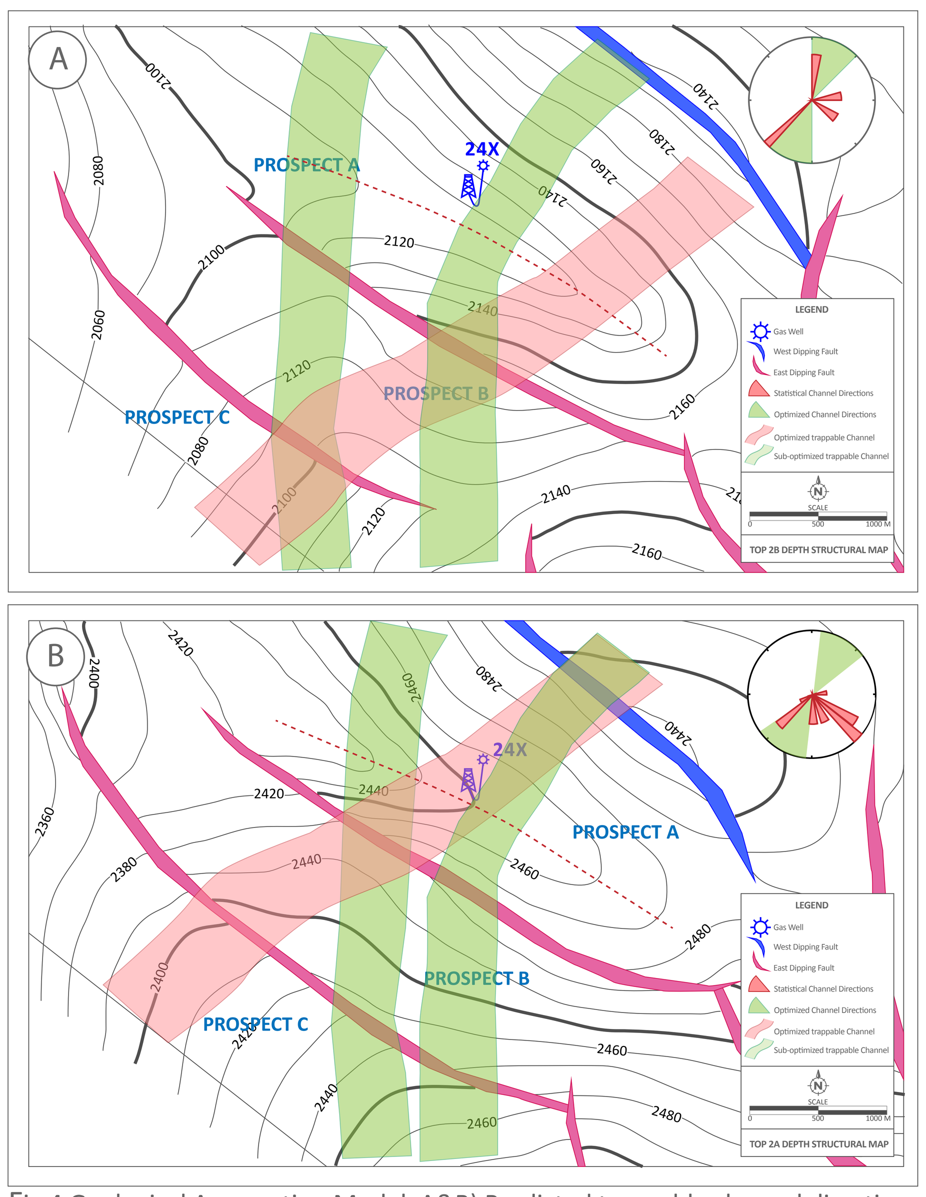


Fig 4 Geological Assumption Model, A&B) Predicted trappable channel direction of Unit2B and Unit 2A, following to regional channel orientation, C) Predicted net gas area mapping from HCCH statistics

5. CONCEPTUAL WELL DESIGN

In order to prove the geological model assumption, these development wells have been conceptually planned by following the new well planning scheme: well spacing concept. The optimal well spacing should be a function of trap styles, channel direction and trapping fault orientations.

A study of average channel belt width was conducted over Arthit Field wherever seismic data permitted. The results given the number of average channel belt width over the whole reservoir stack is around 400m.

Comparing to drainage map which constructed from Decline Curve Analysis, the effective drainage radius ranges from 200m to 400m yielding an average optimal well spacing between 400m to 800m therefore very consistent with the channel belt geometry statistics.

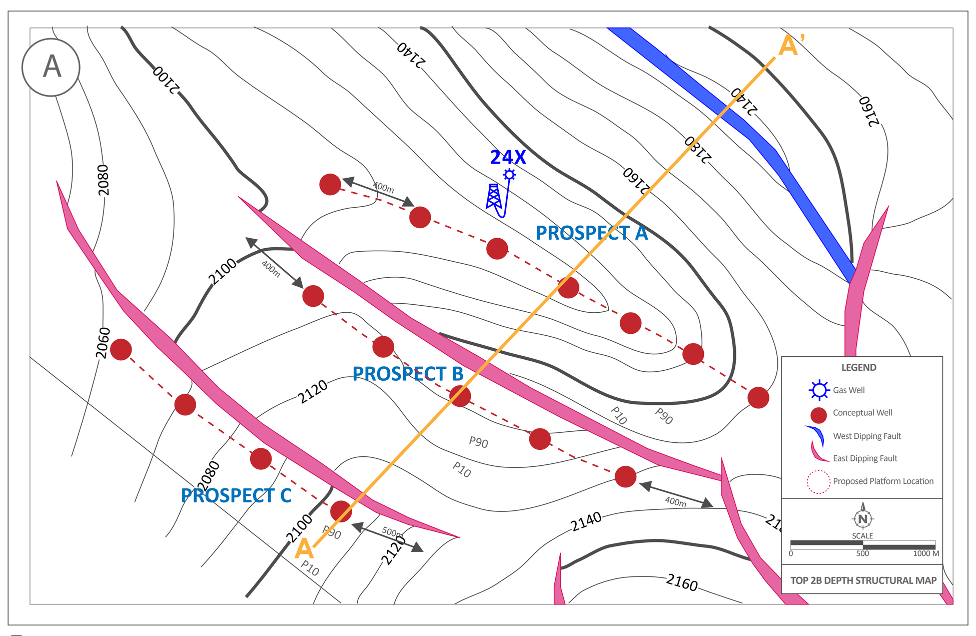
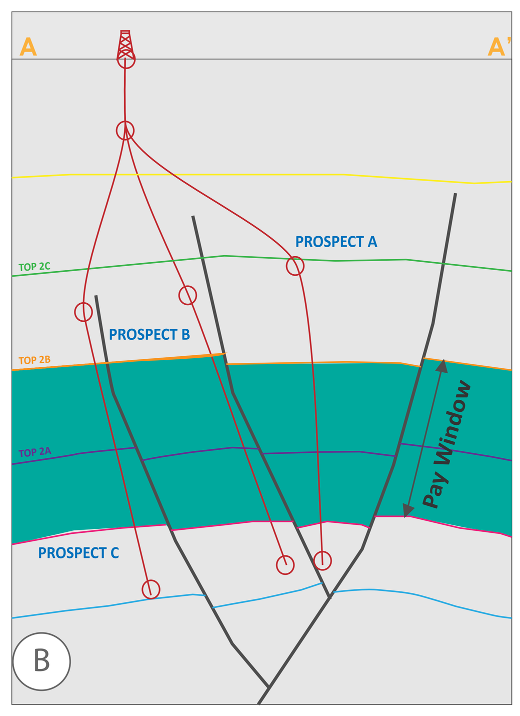


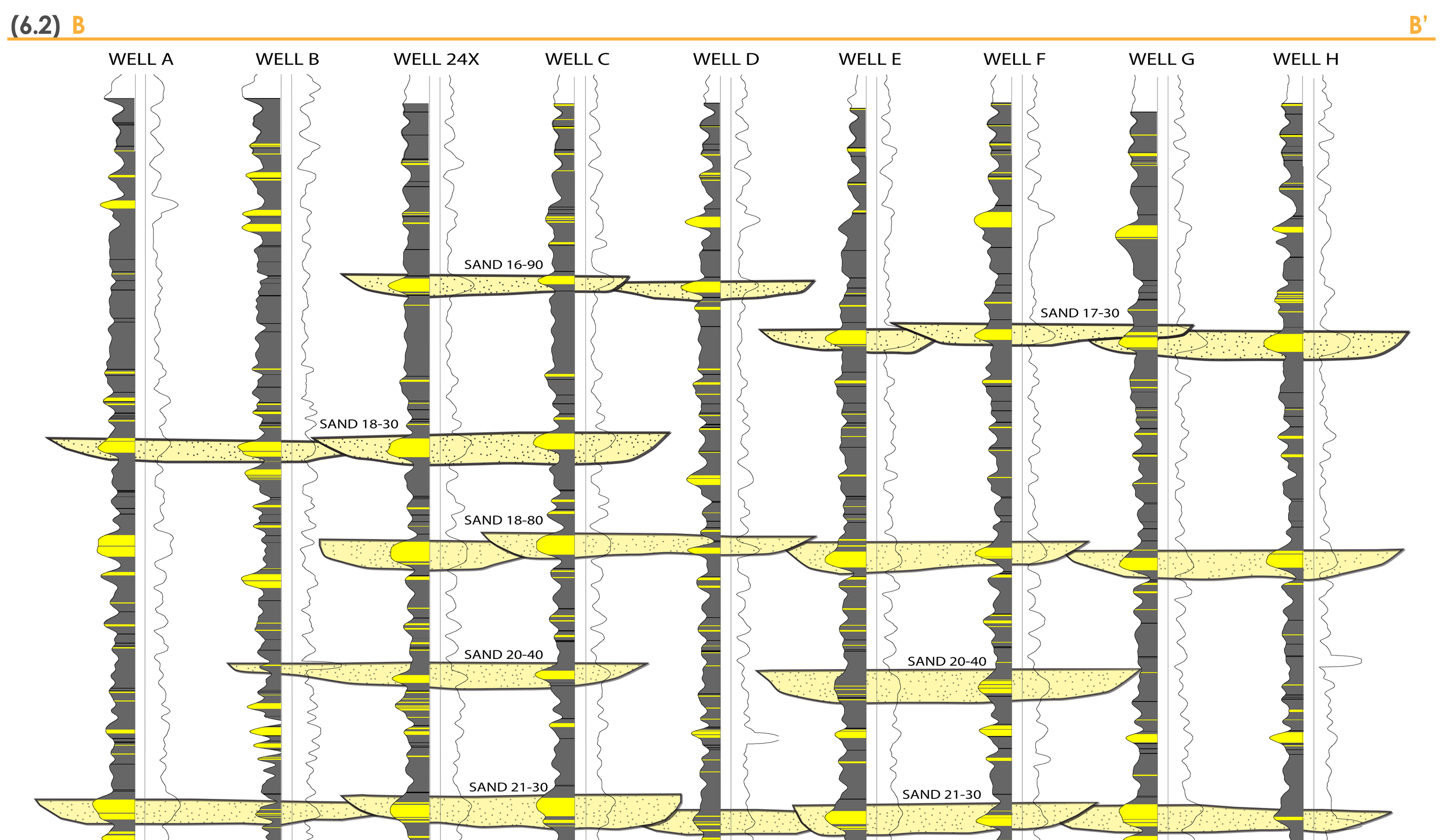
Fig 5-A) Shown conceptual well targeting of sixteen wells from three prospects and B) show conceptual well profile



6. POST-DRILLED EVALUATION

CALIBRATION METHODS
To evaluate the well results, net pay and post-drilled reserve are key criteria calibration

1) Net Pay Evaluation is methods to compare the actual pay and predicted netpay from the summation of the net pay distribution associated to the trap styles in the various targeted units. In case actual individual well net pay fits within the predicted P90-P10 range and the average net pay is close to the mean from the analogy by trap style by unit by geological trend then the assumption is successful.
2) Reserve Assessment: The reserve assessment is done by calibrating the estimating OGIP (pre-drilled) with post-drilled OGIP. The calibration should ideally be done with wells that drill same trap styles and making of probability distributions; hence, individual well data should be checked for their consistency with P10 and P90 values.



(6.2)

Unit	Pre-drill OGIP (Bscf)				Post-drill OGIP (Bscf)			
	P90	P50	P10	Mean	P90	P50	P10	Mean
FM2C	2.16	3.81	6.70	**4.20**	2.45	5.30	11.48	**6.36**
FM2B	11.73	29.04	71.87	**37.29**	24.00	42.71	75.99	**47.25**
FM2A	7.44	16.44	36.34	**19.91**	11.97	24.32	49.39	**28.33**
ALL	**21.34**	**49.29**	**114.91**	**61.40**	**38.42**	**72.32**	**136.86**	**81.94**

Fig 6.1 Net Pay Comparison between Actual Net Pay and Predicted Net Pay (low/base/high Case). Almost of the wells are fit within low-high range and average actual net pay (62m.) is very close to most likely case of predicted net pay (60m.), proven that the geological assumption was success. The orange and green bar represent over-estimated case and under-estimated case , respectively.
Fig 6.2 Allocated OGIP comparison betweenPre-drill and post-drill OGIP, post-drill OGIPwas higher than expectation.

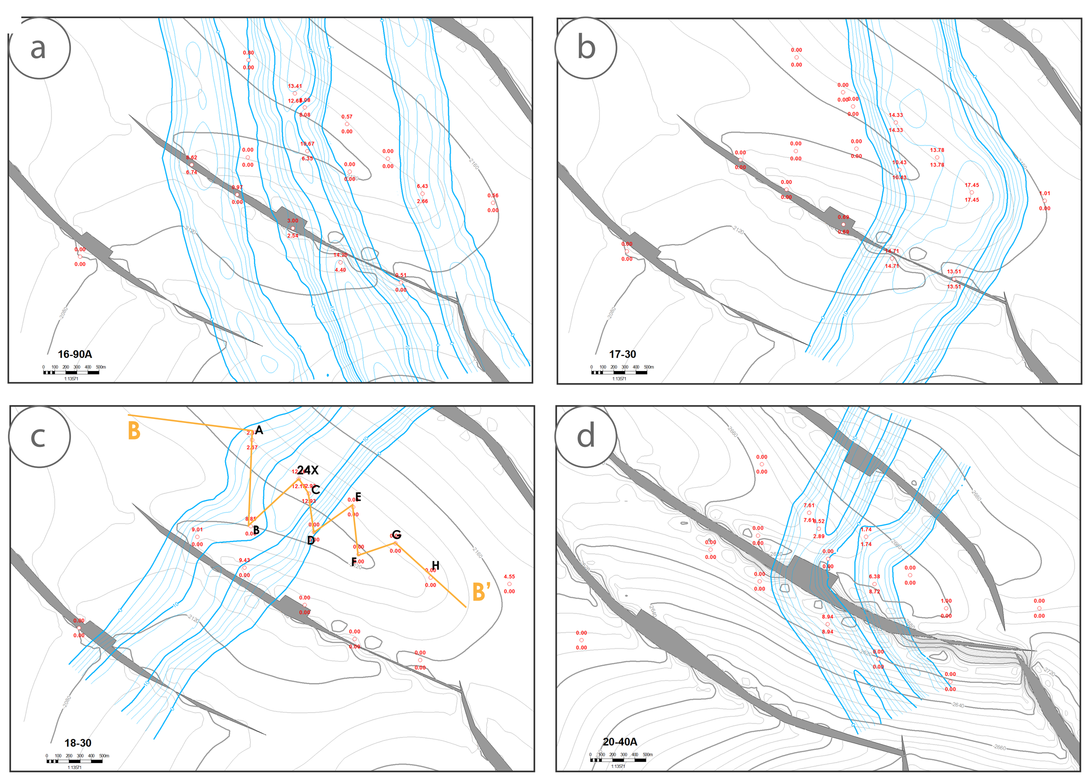


Fig 6.3 Correlation along nose axis, a-d) Post-drill sand map shown sand 16-90, 17-30, 18-30 and 20-40, respectively

7. PLATFORM REWARDS

The result of this well has been represented by the success of proven gas sand up to 90mTV in stacked channel reservoir and average of 62mTV net gas sand. Fifteen development wells were targeted in gas accumulation, was successfully drilled.

By this rewarding, it has been clearly proved that the geological model assumption is applicable for Nose structure in Arthit Field.

Currently, the production from only these five wells becomes 25.0 MMscfd, represented about 10% of Arthit daily gas production rate and 20% of Arthit condensate production rate.

This favorable outcome is inspiring and encouraging to more interest in the Nose structure area in Arthit Field.