Real-Time Pore Pressure Gradients: An Example from the Pattani Basin*

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Abstract

Prolific hydrocarbon fields in the Pattani Basin, Gulf of Thailand (GOT) are the result of syn-rift deposition of fluvial-delta plain sands and shales filling the basin during the Miocene. The fluvial nature of the depositional environment leads to many small reservoirs locally charged by proximal coals found in the generation window. This leads to steep pressure ramps and locally highly charged sands that are above the expected pore pressure profile. Drilling exploration and delineation wells is challenging in the overpressure areas where there is less offset well information to define the pressure profile. Well design, casing design, mud program and cementing program are all dependent on the expected pressure profile, and a conservative pre-drill design is needed for safety. However, during drilling operations, the program can be modified to reflect the measured pressure profile. In some cases, mud weight (MW) can be cutback, reducing the over-balance conditions, limiting formation damage and invasion, and extending total depth (TD).

The A-17 well was the first delineation well drilled in the outboard fault block of Pattani Field A and the deepest well drilled in the Pattani Basin in the last 39 years. It also was one of the hottest wells in the GOT and the first well in the Field A operating area to drill into the Lower Miocene, which was targeting analogous reservoir-quality pay sands in nearby platforms. In other fault blocks, formation pressure is high and the current three-string monobore well design limits the well TD. Previously, all of the wells in the Field A could only access the Middle Miocene reservoirs due to the pressure constraints.

During the planning phase, A-17 drilling program was designed based on the pressure profile predicted from RFT data obtained in nearby wells. Two alternative pressure models were created, one for the “low trend”, controlled by data points from wells in a similar

structure (an outboard fault block), and one for the "high trend", controlled by the nearest well, one fault block away. The well was planned using the "high trend" with a four-string well design and a detailed well execution strategy developed to obtain pressure data at critical stages to make decisions on MW and TD. The actual pressure profile of the well ended up following the "low trend", which indicates that future drilling in this block can be done with a less costly three-string well. Besides pressure data, important information was obtained from the A-17 well on pay window, reservoir quality and hydrocarbon resource potential for future development in the Field A.

Introduction

Accurate pore pressure prediction in the Pattani Basin, of the Gulf of Thailand is a major obstacle for drilling successful wells and exploiting the hydrocarbon resource in the basin. Exploration and delineation wells in this region are drilled in order to collect reservoir properties and petroleum system information. The A-17 well was planned as a delineation well to evaluate one of the prospects of the field A. This untested part of the "A area" has sparse information about the pore pressure especially in the deeper section (Lower Miocene 'O' sands). This information is very important to design the well for safe drilling operation. The well was planned using a conservative four-string design based on the high pore pressure trend obtained from an analogous area and unknown pore pressure for the deeper section. Drilling progress was slower than other exploration wells, due to stopping several times to take pressure surveys to update pore pressure prediction before a decision to continue drilling.

Regional Geology

Field A is one of the hydrocarbon development areas in the Pattani Basin (Figure 1). The basin formed in response to crustal extension caused by the northward movement and collision of the Indian plate into Eurasia during Tertiary time (Jardine, 1997). Crossley (1990) suggested that the primary-rift faulting, during the Eocene to Oligocene timeframe, was associated by movements along major dextral strike-slip fault systems to the north and to the west. The pre-rift fault system appears to have been primarily east dipping en-echelon listric faults soling into basement. Much of the early basement extension evidently occurred along these pre-rift faults. The syn-rift section (Lower Miocene) contains a series of major en-echelon extensional faults, which control the basin morphology and define half-grabens, tilted fault blocks, and horst blocks. In the post-rift section (Lower Miocene to the Middle Miocene), the structures are open, gently dipping, faulted antiforms cut by numerous converging conjugate normal faults which form a network that extend from above basement into the Upper Miocene units. The basin subsided relatively rapidly during the post-rift stage and continually subsided from upper Miocene to present creating accommodation and graben systems (Watcharanantakul and Morley, 2000).

More than 25,000 feet of non-marine and marginal marine siliciclastic sediments have been deposited in the basin since Oligocene time. The main source rock in this area is the Oligocene early-rift lacustrine unit. The main hydrocarbon reservoirs are the fluvial sandstones within the two main units; the Lower Miocene and the Middle Miocene. The Lower Miocene unit consists of fluvial and alluvial sediments. It contains red claystone, sandstone, some gray claystone, and coal. More extensive and thicker sand reservoirs were formed in this unit known as the "O" sands. This unit was targeted and drilled by nearby platforms and found reservoir-quality pay sands but never drilled in the A area. The Middle Miocene unit consists of fluvial and marginal marine sediments. This sequence contains gray claystone, sandstone, and coal. All of the wells in Field A were drilled to this unit, which is the main pay reservoir unit (Jardine,1997 and Crossley, 1990).

Pore-Pressure Prediction and Well Drilling Strategy

Overburden of the sediment and the hydrocarbon generation process are major mechanisms for generating overpressure in the sandstone reservoirs in the Gulf of Thailand. According to Bradley (1982) in order for abnormal fluid pressures to develop and to be maintained, fluid flow must be inhibited or prevented by means of both a vertical and lateral seal. The porosity-depth relationships in the over-pressured wells indicate that the sediments underwent normal compaction to a certain depth and then were isolated to some extent, preventing fluid expulsion and further porosity reduction. Isolation probably occurred because of the lenticular, discontinuous nature of the sands enclosed in low permeability shales, rather than through the development of a "seal" in the strict sense. Increased burial depth and exposure to high temperatures, fluids in the pore spaces would naturally tend to expand while the volume (i.e. porosity) is essentially constant. The increased temperature and hydrocarbon generation from local sourcing is accompanied by an increase in pore pressure. This mechanism can create significant overpressures, especially in areas where all of these factors coexist.

The timing of isolation is important when considering migration of hydrocarbons. Pressure and porosity information indicate that the sediments underwent normal compaction to a depth on the order of -6,500' tvdss ±500', during time water and any generated hydrocarbons could migrate vertically. Source rock studies indicate that the thermally mature zone occurs approximately at the depth of isolation and it is unlikely that any significant amounts of hydrocarbons were generated prior to isolation (Figure 2). Migration probably occurred later, up along active fault planes during the period that structures were forming. Seismic evidence suggests that the majority of faulting and structural development within the Tertiary section took place post Middle Miocene and it is probable that the majority of vertical hydrocarbon migration took place at this time.

The overpressure generation process in the Gulf of Thailand is uniquely related to sedimentation rate and hydrocarbon generation. Hydrocarbon was generated from source rocks and migrated to fill in the reservoir sands. Small, compartmentalized point bar sand reservoirs in the Middle Miocene unit are over pressurized from this hydrocarbon charging. In the Lower Miocene unit, the reservoir sands are thicker and more widely continued; therefore, the sands could accommodate more pressure than in the shallower reservoirs. The pore pressure in the Lower Miocene formation tends to drop back to be normal, especially in the larger Lower Miocene incised valley or estuarine sands.

Overpressure is commonly found in the middle of the Pattani Basin, Gulf of Thailand. Reservoirs in the fields along the basin axis appears to be highly over-pressured, and lower pressure in the fields that step out of the basin center, until close to normal pressure at the edge of the basin (Figure 3). The conventional method to predict pore pressure trends of planned wells in the Gulf of Thailand is by gathering RFT and/or DST pressure profiles, taken from well completion reports of analogous wells (Bradley, 1982). The well data to be used in predicted pore pressure trend should come from the nearby wells that have similar geological settings (analogy set) such as structural positions (graben center or flank, east or west terrace), pay window, size of the fault block and stratigraphic levels. The predicted pore pressure trend line is defined at the highest pore pressure points in the area. In some cases, nearby wells with same geological settings have lower pore pressure but the predicted trend is still controlled by higher pore pressure points from nearby wells to accommodate the possibility of encountering high pressure in more isolated sands for increased risk mitigation, the example of this case is demonstrated in Figure 4.

The Field A is located near the basin axis around the middle of the basin and is highly overpressured. Previous drilling has been challenging in this area. All of the wells were 3-string well designs and had limited TD confined to the Middle Miocene formation. Field B, located west of Field A, is higher in structural position and has lower pore pressure trend. The wells drilled in this field had deeper TD and drilled to the Lower Miocene formation and found the extensive “O” sands.

The A-17 well was drilled directly behind an east-dipping fault, in the western most of the Field A (Figure 5A). This new fault block is wide (3.3 km) and located between Field B and A. The A-17 well was planned as a 4-string well in order to drill deep into the Lower Miocene, which was targeting analogous reservoir-quality pay sands in the Field B.

Pressure data from Field A, and nearby Field B were used to predict the pore pressure trend. To reduce the amount of data points on the plot, only selected points that represent the pressure trend for the area are shown in this plot (Figure 5B). The pore pressure behavior in the A-17 was expected to be similar to characteristics that have been observed in the other wells drilled in the Field A and nearby Field B. The pressure trend in the Field B (low trend) is lower than in the Field A (high trend), corresponding to the structural level (same formation at deeper depth has higher pressure). Structurally, A-17 well was similar to B well to the north (low trend), which was drilled in the same fault block and expected to have similar pore pressure. However, The A-15 (high trend), which is the closest well of A-17 (1.6 km), was drilled one fault block to the east towards the graben, and had the highest formation pressure profile in the analogy set. Hence, the detailed well execution strategy decision tree (Figure 6) was developed based on these two pressure trends to operate the A-17 safely and the A-17 well was designed to drill based on the high trend until the pressure data were obtained and the pore pressure trend is recalculated.

From the well strategy decision tree (Figure 6), the 8-1/2" hole-section was planned to TD (on the high trend) at -7,800' tvdss and formation pressure data would be collected. After that, drill the 6-1/8" hole section to maximum depth of the designed (13.9 ppg) at -8800' tvdss based on high trend and obtain the pressure data and re-calculate the pore-pressure trend base on the actual data obtained during operation. If the new pressure data suggests the well path was on the low pore pressure trend, drill the 6-1/8" hole section to planned TD (-11,800' tvdss or at 13.9 ppg EMW). If the pressure data suggests that the well path is on the high pore pressure trend, drill the 6-1/8" hole section to maximum depth around -8,800' tvdss or at 13.9 ppg EMW.

Well Design and Drilling Operation

The 8-1/2" hole section casing depth was one of the key success factors for this well. The optimum depth should not be too deep that required high drilling mud-weight in case the actual pressure follows low trend so it would cause lost circulation, and should not be too shallow to get good FIT (Formation Integrity Test) result for the next drilling section.

After reviewing the casing design and running hydraulic model in planning phase, the decision was made to plan casing shoe at -7,800' tvdss, which required 12.1 ppg mud weight. Minimum required Leak off Test was 16.3 ppg. This setting depth was also close to the temperature limitation of motor assembly. With good hole cleaning practice and controlled Equivalent Circulating Density (ECD), this section was successfully drilled as planned with only seepage lost circulation.

Running casing to setting depth at almost 10,000' MD was one of the key challenges for this well. Almost 2,000' MD beyond the guideline, a precautionary wiper trip was performed prior to running wireline logging and casing. With pore pressure uncertainty, temperature limitation of MWD/LWD (Measurement While Drilling/ Logging While Drilling) tools, and long section of blind drilling, multiple Bottom Hole Assembly (BHAs) and multiple logging runs were planned for this well.

- First BHA: Drilled this section to 8,800'TVDss and pulled out of hole for running wireline formation tester. (Note that during that time, we could not find 4-3/4" formation tester while drilling which could withstand with high temperature of this well). Actual pore pressures followed our predicted low pressure trend, so we made decision to drill ahead to planned TD at

11,800'TVDss (this planned TD was the deepest record in the Pattani Basin but we shortened TD a little shallower to actual TD at -11,468' tvdss, which was still deepest record in the last 39 years or second deepest).

- Second BHA: Drilled to the limitation MWD/LWD tools then pulled out of hole, took M/LWD out and ran BHA back in to the hole without MWD.
- Third BHA: Drilled without MWD, as of blind drilling section is quite long and we also had risks of unintentionally drilling cross through the known high pressure fault block, the mitigation plan was to drip check shot gyro tool and pull out of hole to confirm well path and also give us an opportunity to choose proper BHA to continue drilling.
- Fourth BHA: Continue drilling without MWD.

Twelve BHAs (including trip for tool failure) and 7 successful wireline logging runs were done on this well, and the well was plug and abandon as per planned.

Result and Discussion

The A-17 pore pressure data were taken in 8-1/2" and in 6-1/8" sections until at -8,800' and re-calculated immediately after obtained. The actual pore pressure trend fell on the "Low trend" that was predicted as one of the two alternative models at the planning stage. The well was drilled using the "Low trend" to design the well from depth -8,800' to TD (Figure 7).

The result may infer the relationship that pressure corresponds to the structural level. The B wells, drilled on the most western side of this area, at highest structural level, found lowest pore pressure trend. The A-17 well was located in between A and B wells, at lower structure than B wells, found higher pore pressure and the A wells drilled on the eastern side of the area, at lowest structural level, had highest pore pressure trend. However, this relationship might not be always true in the Gulf of Thailand as it depends on reservoir connectivity. If the high-pressure reservoirs are big and correlate across the fault, high pressure might be found in different fault block or some distanced reservoirs.

Conclusion

Different areas have different pore pressure regimes. Good understanding of the predicted pore pressure behaviors of the area is very important to execute a well efficiently. All pressure profile alternatives should be considered when developing the well execution strategy decision tree, which was very effective in the execution of this well. The real-time pore pressure gradient, combined with the well execution decision tree gave us the flexibility to change the well design in response to observed pressures. This additional procedure really helped to reduce the risk of encountering higher pressure than the well design capability when drilling in an overpressure area with high uncertainty in pore pressure.

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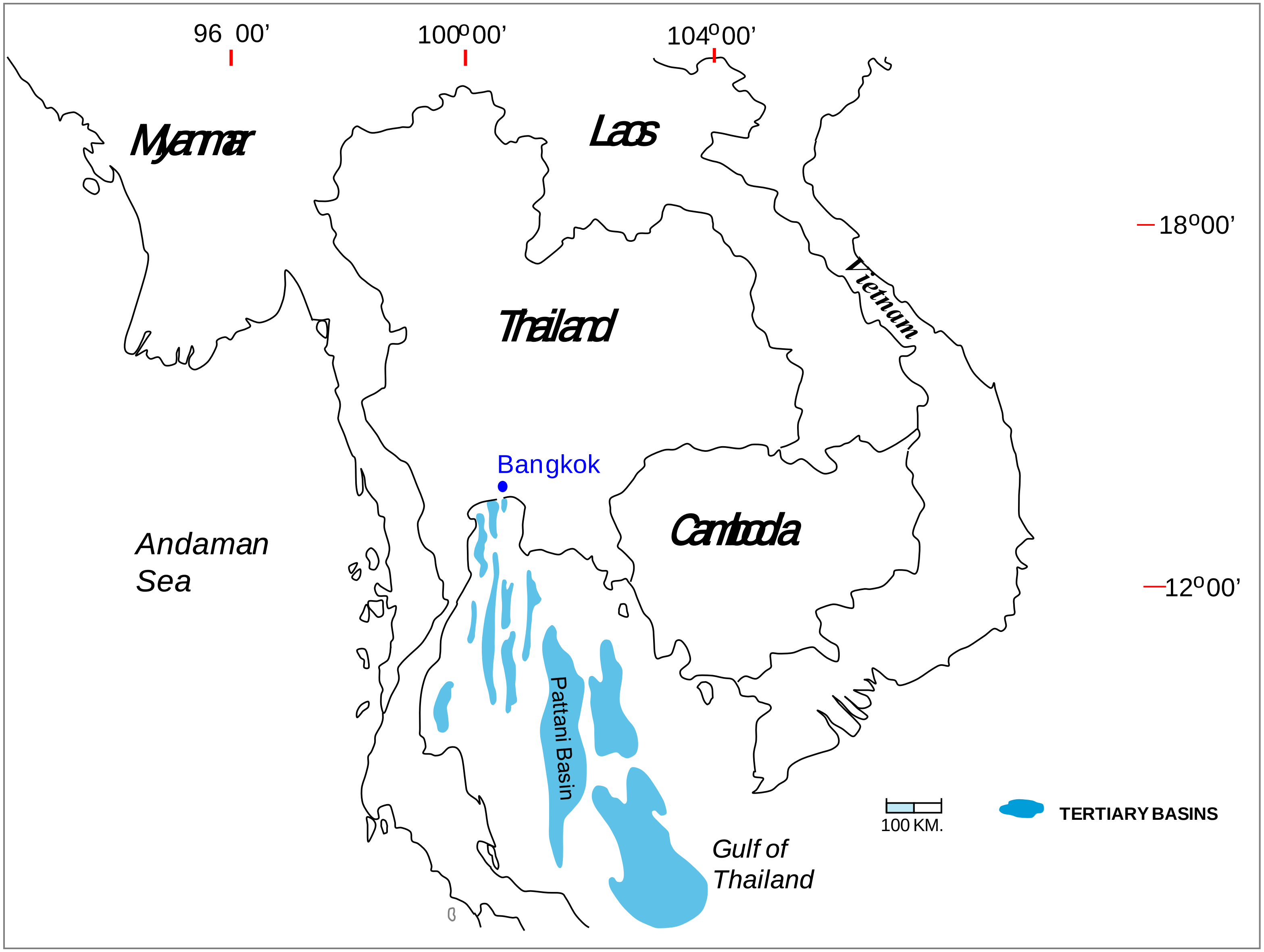

Figure 1. Location of the Pattani Basin, Gulf of Thailand.

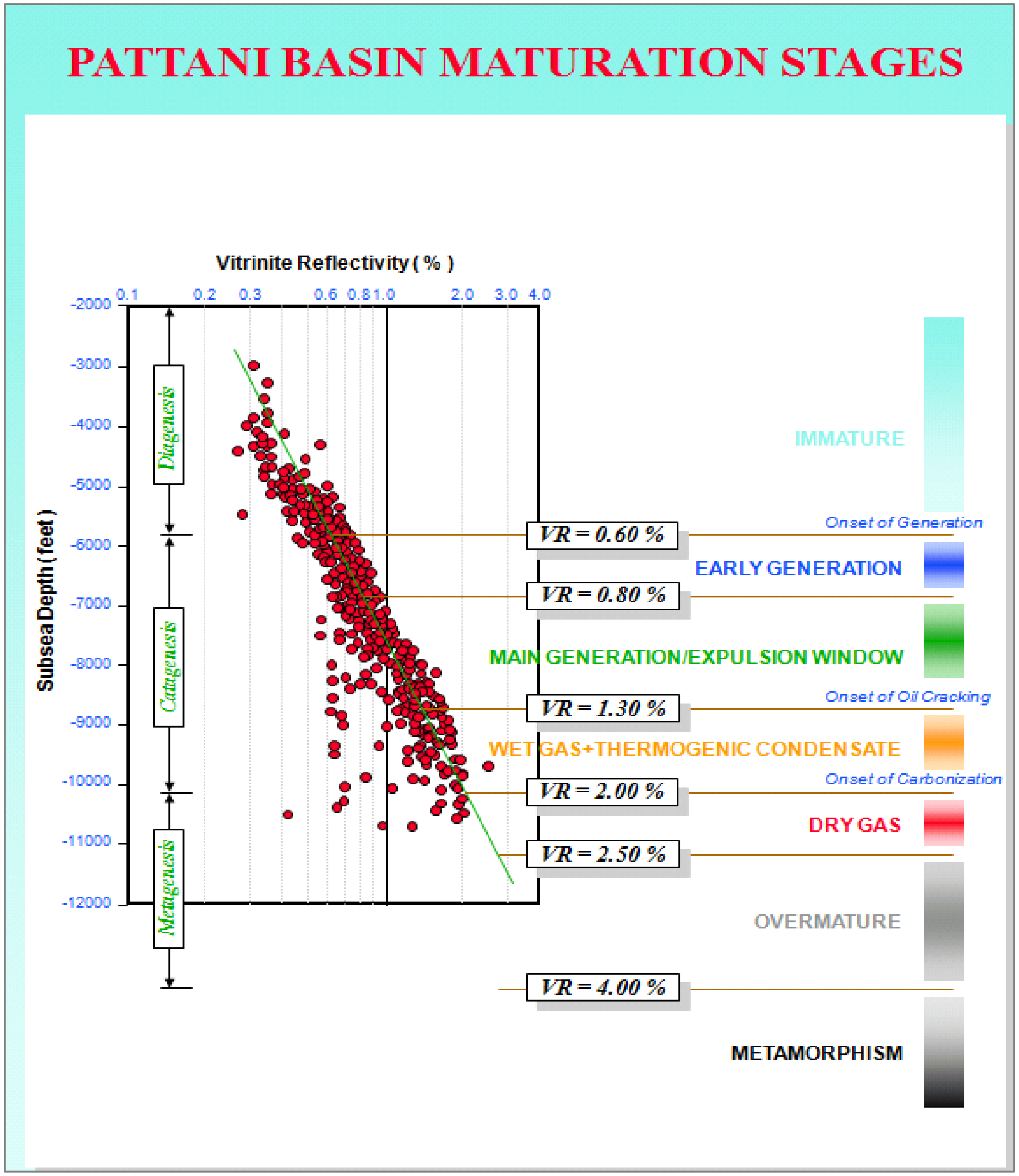

Figure 2. Pattani Basin Maturation Stages (Rui Lin, 2006).

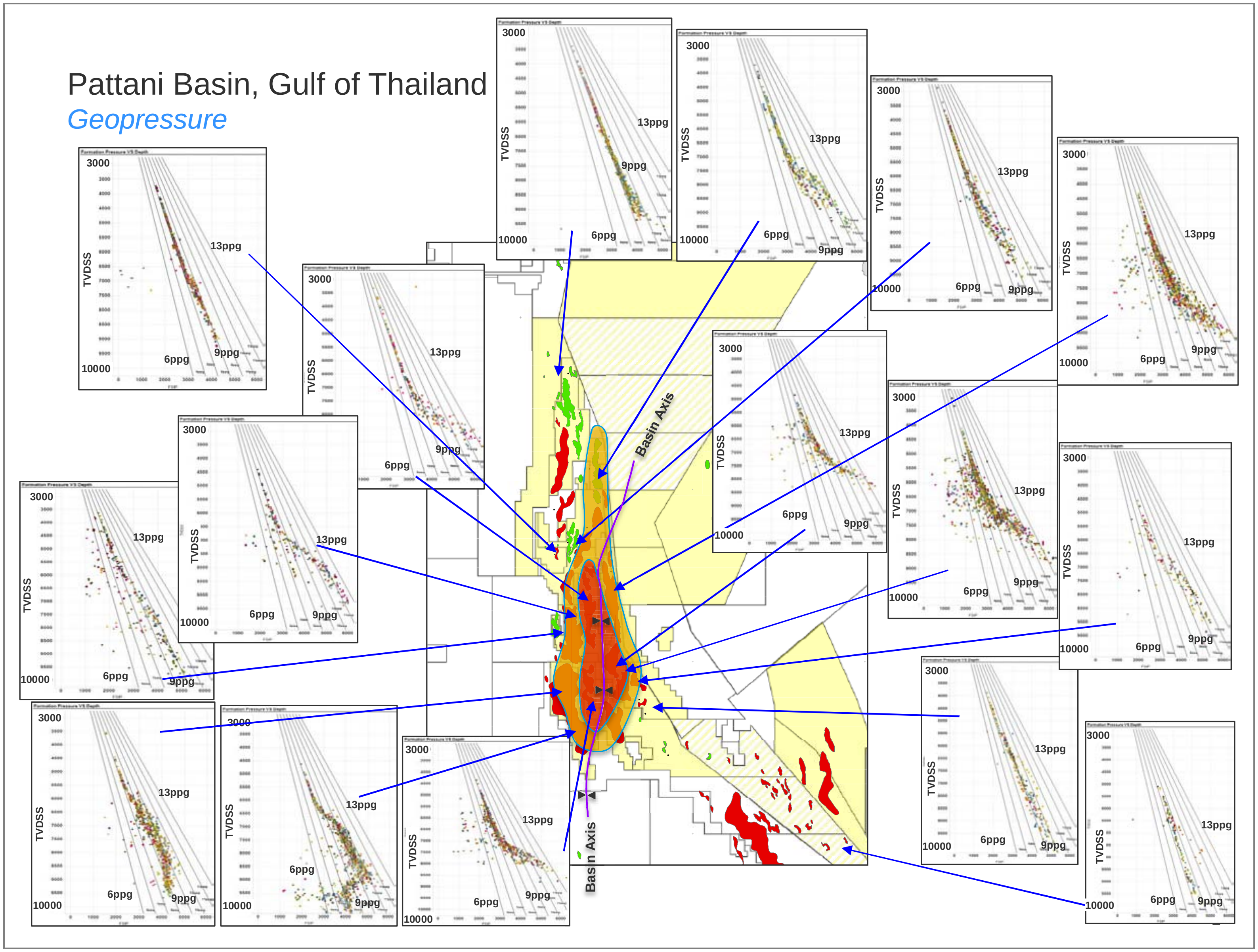

Figure 3. Introduction to Local SBU Geology (Korakot S. et al, 2010).

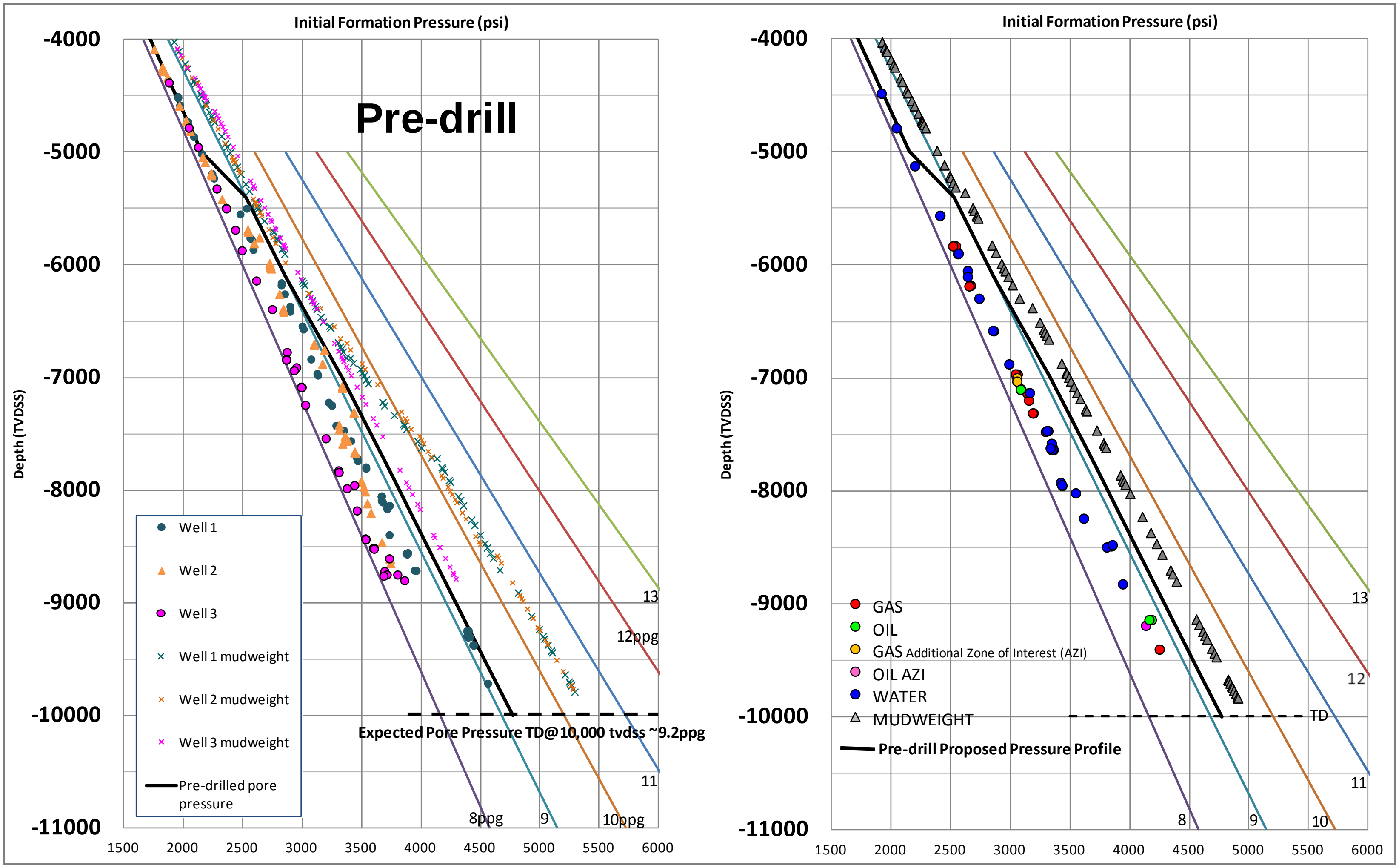

Figure 4. Example pore pressure profiles of the well in the Pattani Basin. In this case, the pre-drilled pore pressure profile is controlled by maximum pressure data to ensure safety, although the actual pore pressure is lower than the pre-drilled profile.

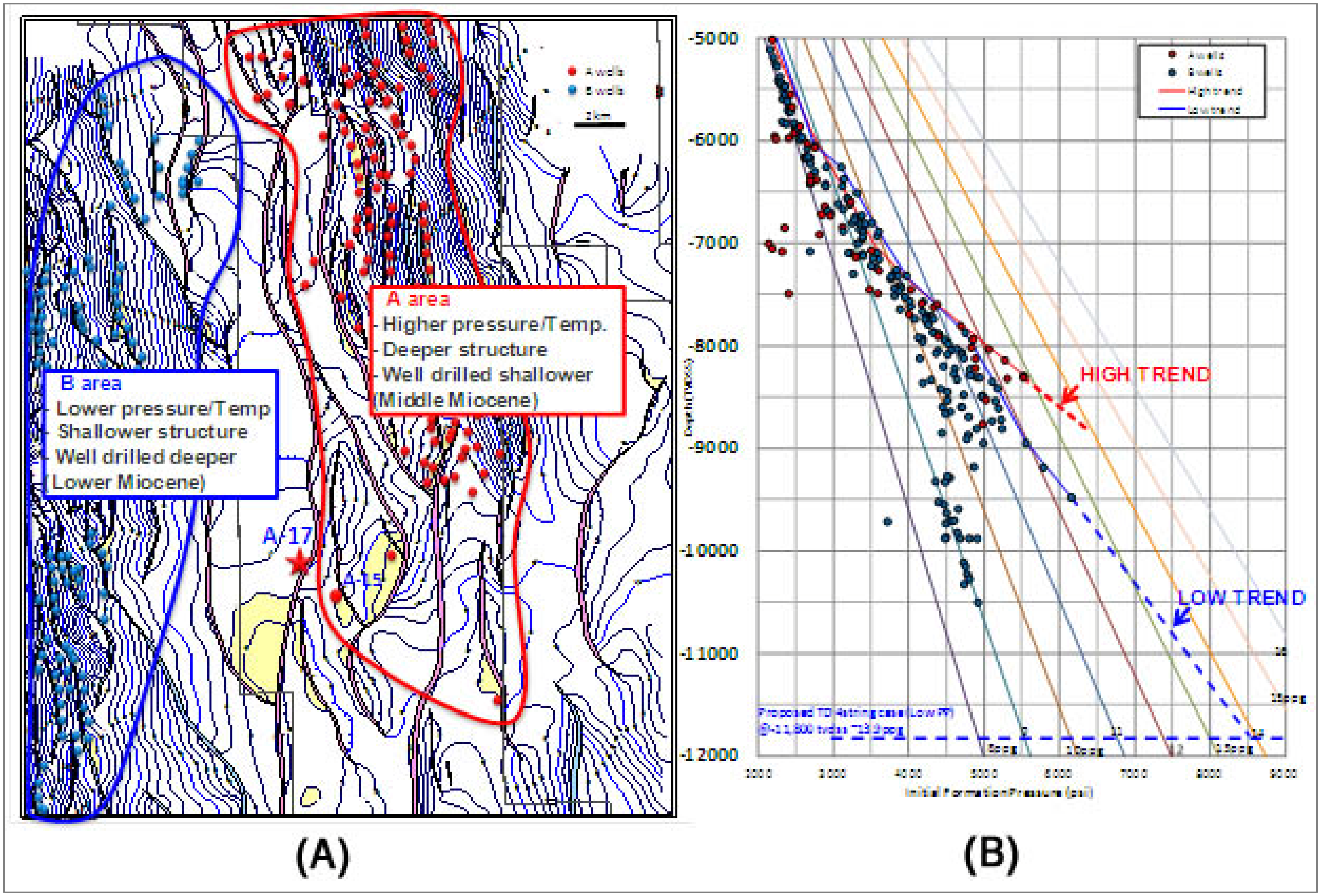

Figure 5. (A) The map of A-17 well and (B) two pre-drilled pore pressure profile alternatives.

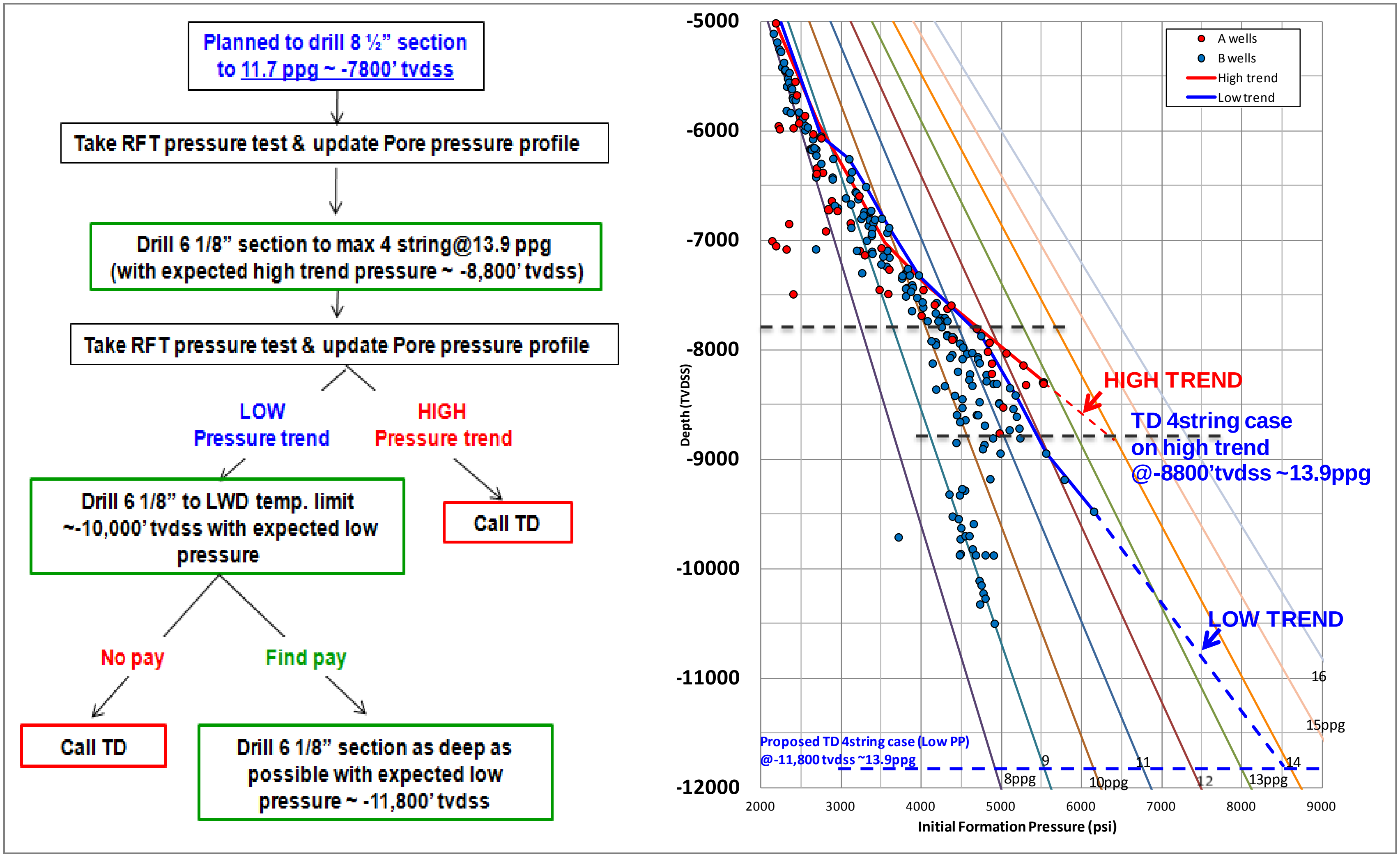

Figure 6. The A-17 Well Execution Strategy Decision Tree based on the two-pressure profile alternatives.

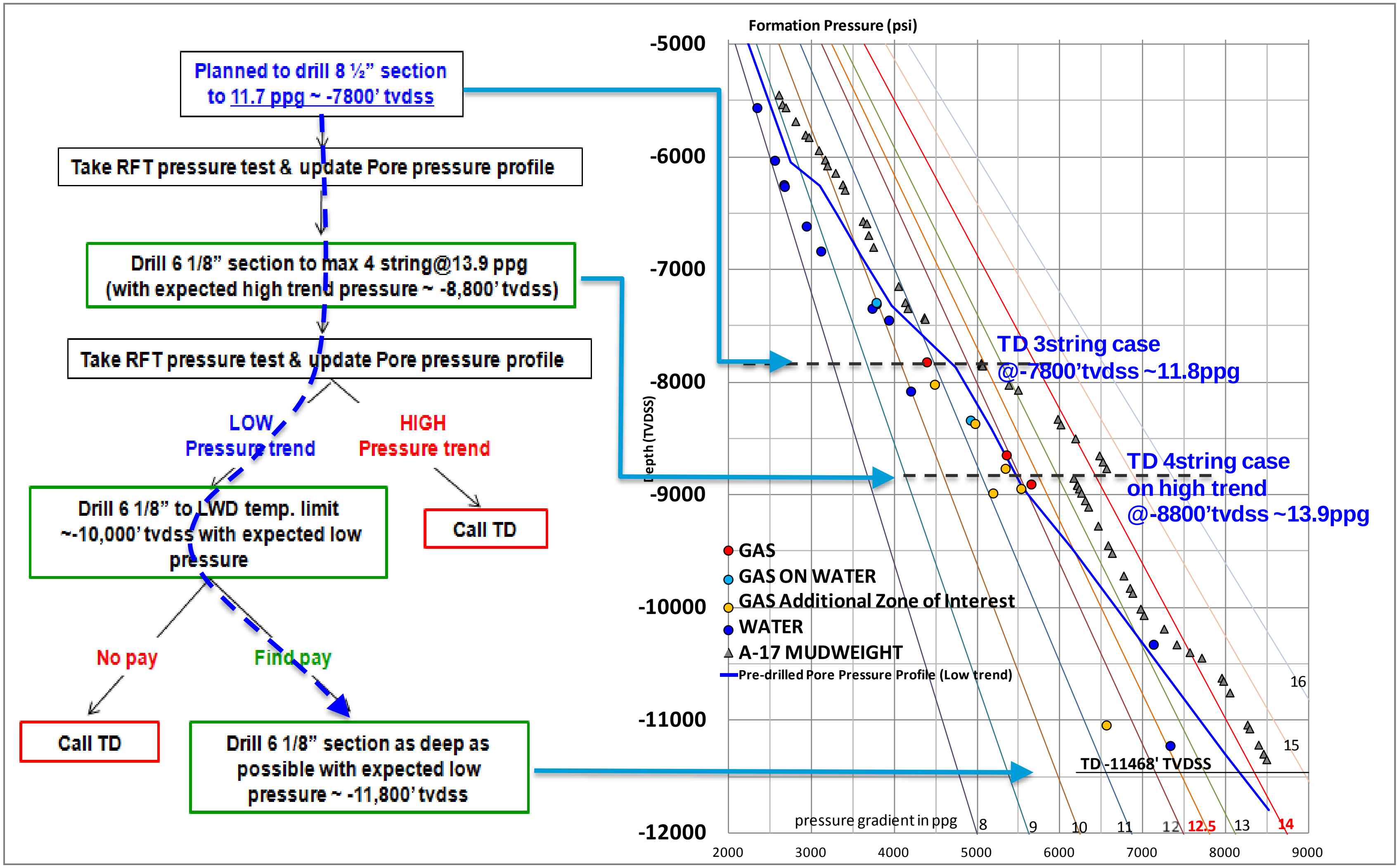

Figure 7. The A-17 Well decision path relates to the real time Pore Pressure Profile.