PARADIGM SHIFT IN MANAGING SAFE AND EFFICIENT JACK-UP RIG MOVES THROUGH ENGINEERING AND OPERATIONAL EXCELLENCE

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ABSTRACT

The Transocean "Ao Thai" (later renamed to MIST) jack-up rig was deployed by a major field operator for a fast-tracked asset retirement campaign in the Gulf of Thailand involving 32 rig moves over a 20-month period. The majority of the platform locations posed considerable geotechnical risks, which normally lead to extended rig move duration so that the safety of the installation can be assured. Managing safe and efficient jack-up rig moves for such challenging locations while satisfying project economics at the same time demanded a step change in rig move planning and execution. This paper discusses a successful implementation of a new approach to the jack-up operations which has led to safe and timely rig emplacement as well as significant positive impacts to the business viability of the asset retirement campaign.

KEY WORDS: Jack-up rig, rig move, geotechnical risks, business viability, asset retirement

INTRODUCTION

In February 2017, a major operator in Thailand began an asset retirement campaign in the Gulf of Thailand to decommission over 6,000 wells on more than 300 wellhead platforms. The wellhead platform locations are situated within the Pattani basin at the Gulf of Thailand with water depths ranging from 200ft to 250ft (61m to 76m). The operator deployed a single jack-up rig, Transocean "Ao Thai", to perform the first two phases of well plug and abandonment (P&A) operations. The rig was selected based on its prior performance within the asset. A full-time dedicated team from engineering and operation was formed and operational procedures were standardized. Noble Denton marine services (NDms), which is now an integral part of DNVGL Oil & Gas, supported Transocean by providing marine warranty and engineering services for the fast-tracked rig move campaign. Figure 1 shows the platform locations for the Phase 1 and 2 of the asset retirement campaign at the Gulf of Thailand.

In order to meet the project economics, the overall procedure and cost of the P&A operations needed to be optimized beyond the historical performance of approximately one day per well. Based on past P&A operations within the asset, the rig move cost was estimated to constitute 30-40% of the total project cost. Rig move records from the past operations within the asset suggested that, on average, a total of seven days was required to move a rig from one platform to the next, taking into account time spent waiting on weather and the complexity of rig installations in the majority of the platform sites at the Gulf of Thailand. A shorter rig move duration was therefore targeted at an average of three days per move, to help reduce the total cost of the relatively short operation at each platform.

Besides the project commercial demands, the marine operations also faced technical challenges, mainly due to geotechnical characteristics of the platform locations. The majority of the platform locations posed considerable geotechnical hazards which would normally necessitate more precautionary procedures, leading to an extended rig move time for assuring the safety of the installation. Managing safe and efficient jack-up rig moves for the P&A campaign at such geotechnically challenging locations in a consistent and timely manner therefore demanded a step change in rig move planning and execution.

JACK-UP RIG CHARACTERISTIC

The “Ao Thai” (later renamed to “MIST”) and its two sister rigs are KFELS Super B-Class Bigfoot design jack-up drilling units. The rigs were custom-designed not only to suit the rig owner specifications, but also the characteristics of the Gulf of Thailand, in consideration of an already-secured long-term charter for drilling campaigns in the area prior to the rigs’ construction.

The hull measures 246ft (75m) x 226ft (68.9m) x 25ft (7.6m) and is supported by three triangular ‘split-x’-braced truss legs, each with three driven split-tubular chords having double-sided racks. The legs are of 486ft (148.1m) length and spaced 129ft (39.3m) and 142ft (43.3m) apart in transverse and longitudinal directions respectively (identical to the leg spacing of the LeTourneau 116C design). The hull breadth was also slightly enlarged for greater preload tank capacity. The maximum bearing area of the bigfoot spudcan is approximately 27% larger than that of the standard KFELS B-Class design spudcan. Several additional submersible pumps were dedicated to speed up ballasting during preloading. The leg jetting system was enhanced with two rings of bottom nozzles and one ring of nozzles at the spudcan top.

The legs are elevated and lowered by means of a 3-high electrically powered rack and pinion jacking system (18 pinion units per leg), arranged in pinion-pairs which are braked once the unit has been elevated to the required airgap. The other standard KFELS B-Class or Super B-Class design jack-up rigs are typically equipped with two levels of rack and pinion jacking system (12 pinion units per leg) and a self-positioning fixation system. During the design inception of the three sister rigs, it was decided to substitute the fixation system with an additional tier of pinion units to provide greater redundancy in the jacking system, mainly during preloading, extending its design life. The unit is capable of jacking while carrying full preload, utilizing approximately 70% of its maximum design preload jacking capacity.

An add-on feature, called Pinion Load Monitoring System (PLMS), was also installed onboard to directly measure the load at each pinion. This provides continuous and more accurate monitoring of the load at all times (during jacking and static) as opposed to estimating jacking load from the pinion motor current. The pinion load is measured by torque transducers installed at each jacking unit between the motor and the gearbox. An extra output screen is provided in the rig monitoring system to show pinion load at the individual jacking units. During the preloading process, the calculated leg load from onboard stability software can be verified with the corresponding measurement from the PLMS. Similarly, actual leg load under non-static environments can be monitored in the course of leg extraction. Figure 2 shows the image of “Ao Thai” rig and its PLMS features.

GENERAL CHARACTERISTIC OF GULF OF THAILAND

Geotechnical Characteristics

The Gulf of Thailand is situated at the Northeastern part of the continental area of the Sunda Shelf. During the last major glacial episode, the worldwide lowering of the sea level exposed a large landmass in the Sunda Shelf [1]. The sea level had subsequently risen as a result of the glaciers melting over the previous 20,000 years. The highly undulating terrain, with valleys and depressions consisting of alluvial or marine clays during the Pleistocene age, was infilled with under-consolidated to normally-consolidated marine clay of late Pleistocene to Holocene age, which were deposited during the last marine incursion. During this period, two marine regressions occurred which produced a clay crustal layer as a result of exposure and desiccation of the shallow marine clay. Further depositions of marine clay overlying the crust layer took place during the final marine transgression. Figure 3 describes the model for evolution of crusts at the Sunda Shelf as discussed in [1].

As a result of this geological process, the soil profile at the Gulf of Thailand is generally characterized by the presence of surficial very soft clay overlying a clay crust layer which is underlain by firm to stiff clay. The common features of the clay crust layer include slickensides, iron oxide inclusions and fissures which are typically associated with the desiccation. The crust layer is on average 10ft (3m) thick, consisting of stiff to very stiff clay, and generally found at a depth of less than 20ft (6.1m) below seabed. In addition, shallow buried channels infilled with soft sediments are often encountered. In the context of jack-up rig operations, the seabed characteristics in the region present multiple geotechnical hazards which naturally require a more cautious approach during rig installation.

Figure 4 shows statistics of identified geotechnical hazards at the platform locations. The identified geotechnical hazards at the platform locations can be categorized into the following:

- Punch-through/rapid leg penetration
- Spudcan-seabed interactions (footprints or buried channels)
- Spudcan interactions with adjacent structures (pipelines or jacket piles)
- Moderate to deep penetrations (defined here as that greater than one spudcan diameter)

The figure suggested that at two-third of the platform locations, the risk of punch-through/rapid leg penetration was present and often combined with the potential for spudcan-seabed interactions. The previous drilling activities at the platform locations typically involved older jack-up rig designs, with lower spudcan bearing pressures of the order of 7 kips/ft^2 (34 ton/m^2), resulting in shallow footprints on the crust layer. The "Ao Thai" experienced deep penetrations in excess of one spudcan diameter at eight platform locations in total with a maximum penetration depth of approximately 100ft (30.5m) recorded. In several locations, due to the well slots and cantilever outreach, a minimum clearance of one spudcan diameter between the spudcan edge to the nearest pipeline was only marginally achieved.

Platform Characteristics

The wellhead platforms involved in the decommissioning work in the Gulf of Thailand are networked by approximately two thousand kilometers of subsea pipelines ranging from 6in (0.15m) to 42in (1.1m) in diameter [2]; a typical example of one of these platforms is depicted in Figure 5. The mostly four-legged platforms are located in water depths ranging from 200ft to 250ft (61m to 76m) with an average of 230ft (70m) below LAT. The platform main deck is nominally 70ft (21.3m) above LAT and the platform is generally oriented in Northerly direction.

During the desktop study, with a total leg length of 486ft (148.1m), the jack-up unit was anticipated to have an adequate leg length for all the platforms considering the water depths, operating airgaps and predicted maximum penetration depths. The statistics of the actual leg penetration depths and utilized leg length below the hull are summarized in Figure 6. It is worth noting that the lower guide was generally positioned at an elevation of between 290ft (88.4m) and 380ft (115.8m) above the spudcan tip or approximately three full-bay height. Such information is valuable for rig inspections and assessments of remaining fatigue life of the unit.

Metocean Characteristics

The Gulf of Thailand has two monsoonal winds, i.e. the Northeast monsoon during mid-October to mid-February and the Southwest monsoon during mid-May to mid-October. The tropical cyclone affecting the Gulf of Thailand is characterized by tropical depression (less than 34 knots sustained wind speed), tropical storm (34-64 knots) and typhoon (more than 64 knots). Tropical cyclones affect the gulf around 3-4 times a year with relatively higher frequencies from May and particularly in October to November. For the central basin, the nominal 50-year cyclonic wind speed extremes (1-min average) is 54 knots with the maximum wave height of 39ft (11.9m). The environmental extremes tend to be more severe at the northern part of the Gulf of Thailand.

SYNERGY BETWEEN DRILLING CONTRACTOR AND MARINE WARRANTY

With 2-3 rig moves taking place every month, Transocean worked closely with NDms to prepare, execute and monitor each rig move in the most efficient manner while ensuring safe operations as the utmost priority. Any delay in the rig move preparation or operation would significantly impact the remaining P&A program. As such, fundamental changes in the standard workflow between the drilling contractor and the marine warranty surveyor were instrumental for timely completion of operations.

Standard Approach

Upon request from drilling contractor (the insured), the involvement of a marine warranty survey (MWS) typically begins with location review based on supplied site information and the vessel's marine operations manual. As well as document review, additional engineering may be performed by the MWS to better assess the suitability of the proposed rig for the intended activities at the location in question. Upon satisfactory outcome, a certificate of location approval is issued by the MWS together with a summary of the review study and recommendations. The drilling contractor develops a rig move procedure considering the conditions and recommendations outlined in the location approval. During the rig move, a marine warranty surveyor attendance onboard the rig is often requested, to witness the rig move execution; to assess the compliance to the MWS-approved rig move procedures; and to confirm that the final as-installed condition meets the parameters specified in the location approval. Should there be any deviations, the as-installed condition may be reassessed, and if still satisfactory, the location approval can be reissued by the MWS.

Enhanced Approach

An enhanced approach was introduced to expedite the location review process and improve the efficacy of the engineering support for each rig move in the fast-tracked P&A campaign. In the new workflow between the drilling contractor and the MWS, the following key initiatives were integrated into the standard workflow:

a. a holistic engineering approach with an intelligent use of historical data and relevant experiences;
b. real-time monitoring and continual feedback between the on-board marine team and onshore engineering specialists, allowing timely decision making and updating of risk/caution levels as installation progresses;
c. continual improvement on safety and efficiency including lessons learned, recalibration of prediction models and developing field statistics for future operations.

During the rig move preparation, besides reviewing the data for the site in question, any existing historical rig move information at the same location or the same field was revisited. Such information was leveraged to improve the geotechnical assessment for the site of interest and reduce the uncertainty associated with relatively limited geotechnical borehole data. In the course of the location review and approval process, the MWS provided input to the drilling contractor for the preparation of the rig move procedure. Detailed engineering analysis was performed upfront to identify rig operating envelopes based on weather extremes for each possible case of penetration depths. An installation strategy was formulated based on the drilling contractor's standard operating procedures, taking into account the site characteristic and the rig's capabilities.

Prior to joining the rig move, the attending surveyor was equipped with a tool to enable data logging and frequent feedback to the onshore engineering team. The tool facilitated the MWS onboard the rig to update the preloading progress, forming a continuous observation of the actual leg penetration behavior versus the prediction during the rig installation in a consistent format. As the installation progressed, the installation risk level identified during the desktop study was adjusted and the preloading procedure could be modified on-the-fly for faster speed or greater caution. In addition, in case of an unprecedented situation, the "live" data allowed the stake holders to make an effective and timely decision. Where necessary, the onshore engineers performed reassessment based on this data to support the decision making.

Upon completion of the rig move, the rig move information and the detailed logged data were fed into a digital database for future use. Data warehousing was carried out using a structured database system, and the accumulated rig move data was made easily interrogable for subsequent rig move operations. The recorded engineering parameters, e.g. leg load-penetration data, could be used to evaluate and recalibrate the engineering model. The rig move data was also utilized to establish historical rig performance reports or field statistics. Furthermore, any lesson learnt from an unprecedented situation was also recorded in the system for future operations at nearby locations or similar site conditions. The new workflow between drilling contractor and marine warranty is illustrated in Figure 8.

Prior to working on the P&A program in the early 2017, the "Ao Thai" had performed drilling activities at 14 platform locations within the Gulf of Thailand since October 2013 together with its sister rigs, i.e. the Transocean "Andaman" (later renamed to "IDUN") and the Transocean "Siam Driller" (later renamed to "ODIN"). A total of 81 rig moves have been completed by the three sister rigs within the asset as summarized in Figure 1. Detailed and consistent high-quality data recorded from the rig moves performed by these rigs at a significant number of locations comprises an in-depth understanding of the geotechnical challenges and the corresponding effective mitigation strategies as well as the actual rig performance in the Gulf of Thailand.

MITIGATIONS OF GEOTECHNICAL HAZARDS

Geotechnical Challenges

In most of the platform locations, the local seabed condition exhibited a risk of punch-through/rapid leg penetration which was often complicated by the presence of existing footprints from previous rig visits. Besides the rigs with identical leg spacings to the KFELS Super B-Class design such as the LeTourneau 84/116C jack-up designs, the footprints in the Gulf of Thailand were also created by jack-up rigs of different leg spacings, e.g. the MODEC-300 C-38 jack-up design. This often led to a challenge in mitigating spudcan-footprint interactions in addition to managing the risk of rapid leg penetration at the same time.

Most of the previous rigs working in the platform locations have a somewhat lower bearing pressure and recorded relatively shallow penetrations on the crust layer. Owing to the bearing pressure of the "Ao Thai", the achieved penetrations were typically deeper than for previous rig visits and the spudcans normally penetrated through the clay crust layer. Therefore, the recorded penetration data of the older rigs could not be used to calibrate the design soil profiles for the preload level considered for the “Ao Thai”. Deep leg penetrations in excess of 53ft (16.2m), or one spudcan diameter, were recorded by the rig in several locations, mainly in the Central Southern region.

The available geotechnical boreholes at the rig location at each platform were sometimes relatively limited and not necessarily located at the proposed spudcan locations. When lateral soil variations were identified, the design soil profiles inferred from the boreholes were extrapolated using the available sub-bottom profiles.

In some locations, the presence of hazardous geological features such as pockmarks or buried channels, or man-made features such as irremovable large debris or newly installed pipelines, also necessitated a change in the rig heading to maintain a minimum avoidance distance. The new heading typically shifted the rig away from the existing borehole locations leading to greater uncertainty in the soil condition underneath the spudcans. Figure 7 shows an example of seabed conditions at the platform location visited by the “Ao Thai”.

Besides the relatively limited number of boreholes and their relative distance to the spudcan locations, the inherent scatter of shear strength data due to the characteristics of the local soils also made the interpretation of soil strength profiles more challenging. Calibrations of the actual soil strengths from previous rig moves at the same field or adjacent locations were therefore performed to help narrow the uncertainties in the shear strength variations. An example of shear strength data at a platform location is shown in Figure 9. Owing to these soil characteristics, the accuracy of leg penetration prediction was also somewhat compromised and therefore regular monitoring of leg penetration during the preloading process was critical. Figure 9 also shows an example of detailed leg penetration monitoring of the “Ao Thai” at the platform location.

Mitigations Strategy

In view of the identified common geotechnical hazards at the locations of interest, a robust mitigation strategy was developed to manage the installation risks in the most efficient manner possible. A minimum safe preload approach was adopted to minimize the overall installation time. The minimum safe preload footing reaction was location-specific, derived through engineering analyses taking into account the anticipated metocean extremes, cantilever extension and drilling load planned for each platform at the intended rig heading. In cases where a minimum safe preload did not represent a significant reduction in load level, the rig operating envelope was optimized for full preload through the engineering analyses.

Although most of the time the spudcans penetrated through the crust layer at the minimum preload level, the shallower penetrations helped ease the subsequent leg removal efforts for moving off to the next platform. In some locations with overlapping spudcan-footprints, the reduced preload also assisted with the RPD management, by avoiding excessive chord loads. The chord load was constantly monitored through the PLMS system in conjunction with the RPD monitoring. Early detections of any significant RPD development or uneven chord load distribution allowed the rig operator to make a timely correction prior to proceeding with subsequent steps.

A “dynamic” preloading strategy was also established to speed up the installation by fully leveraging the rig capability. Due to the anticipated risk of rapid leg penetration in combination with the potential spudcan-seabed interactions at most of the sites, the entire preloading process was carried out with the hull in water. As all the sites are platform locations, the bow leg was always preloaded first to the maximum preload level. In the event of the bow leg hanging-up on the crust layer, the preload was held at this level until its completion prior to working on the next leg. In the case of the leg penetrating through the crust layer, after reaching a certain threshold depth the maximum preload was reduced to the minimum safe level prior to the 3-hour preload holding period. The same procedure was applied for the stern legs. If both stern legs could be driven individually through the crust layer and no risk of punch-through/rapid leg penetration was identified at deeper depths, simultaneous preload holding for the stern legs could be performed. Leg by leg preloading was always adopted if any of the legs hung up. In the course of rig installation, the decision to adjust the preloading procedure based on the actual leg penetration response was collectively made by all the stake holders when the need arose.

During moving-off operations, no significant delay was observed during leg removal including at the deep penetration sites except occasional weather delays.

PERFORMANCE OF P&A OPERATIONS AND RIG MOVES

In October 2018, the “Ao Thai” jack-up rig completed the P&A operations at the 32 platforms after a 20-month long campaign. A total of 604 wells were delivered successfully, exceeding the initial target. The volume of the “Ao Thai” rig moves for the P&A campaign was equivalent to twice the total number of rig moves of the other four jack-up rigs operating within the assets during the same period.

Through the innovations and new technology adopted by the drilling team for the P&A operations as detailed in [3], the team was successful in delivering high volume, incident free P&A work. The AFE (Authorization For Expenditure) of 1.1 day per well was able to be reduced to 0.4 days, resulting in a total P&A duration of 179 days, ahead of the AFE for the first 343 completed wells. At one platform, a 3-string well was completed in 0.25 days per well, a record for this campaign. For the first 20 rig moves, the total rig move days including waiting on weather period was 48 days less than the AFE.

The completion time for various stages in the rig move process was captured in detail, from the onset of rigging down prior to going-off location, to the completion of rigging up at the subsequent platform location. The total rig move time was recorded and used as one of the indicators for measuring rig move performance. The statistics of the rig move efficiency are presented in Figure 10. As shown in the figure, gradual improvements of the rig move efficiency were achieved throughout the rig move campaign. The total rig move time, which was generally 7 days prior to the P&A campaign, was constantly reduced. The targeted 3 days on average for total rig was met successfully. The shortest total rig move time of 1.5 days, (or 1 day, excluding towing) was recorded. The improved practices not only made the rig move operation safer and more efficient but also minimized wear and tear on the critical rig equipment.

The overall P&A operations were optimized resulting in a significant impact on the project economics and future business strategy of the asset retirement campaign. The actual cost per well was significantly reduced by more than half of the AFE, corresponding to over $80 million cost saving for the 604 completed wells and the projected cost reduction of more than $800 million for the targeted total 6,000 wells.

Assuming a 7-day duration per rig move, historically the rig move cost made up approximately 30%-40% of the overall project cost of a P&A operation. The cost reduction associated with the optimization of the total rig move time from 7 to 3 days translated to a value creation of approximately $18 million for the completed 32 rig moves, contributing to approximately 20% of the total cost savings.

SUMMARY

The success of the P&A campaign and the gained performance efficiency through the use of a purpose-built jack-up rig and full-time dedicated team has created a step change in the asset retirement strategy and outlook for Thailand. Not only has the P&A cost for the full field abandonment been significantly reduced, but cycle time has also been minimized, extending the economic life of the petroleum fields.

In supporting the fast-tracked rig move operations, fundamental changes in the standard workflow between the drilling contractor and the marine warranty surveyor were driven through multiple initiatives: a holistic engineering approach with an intelligent use of historical data and relevant experiences; real-time monitoring and continual feedback between an on-board marine team and onshore engineering specialists, allowing timely decision making and updates of risk/caution levels as the installation progressed; and continual improvement on safety and efficiency including lessons learned, recalibration of prediction models and development of field statistics for future operations.

With the paradigm changes in managing rig moves through engineering and operational excellence, throughout the combined 14 rig-years of the three sister rigs of Transocean operating at the Gulf of Thailand in 2013-2018, an uptime of 99.2% was achieved, incident free, after spending a total of 8.4 million man-hours.

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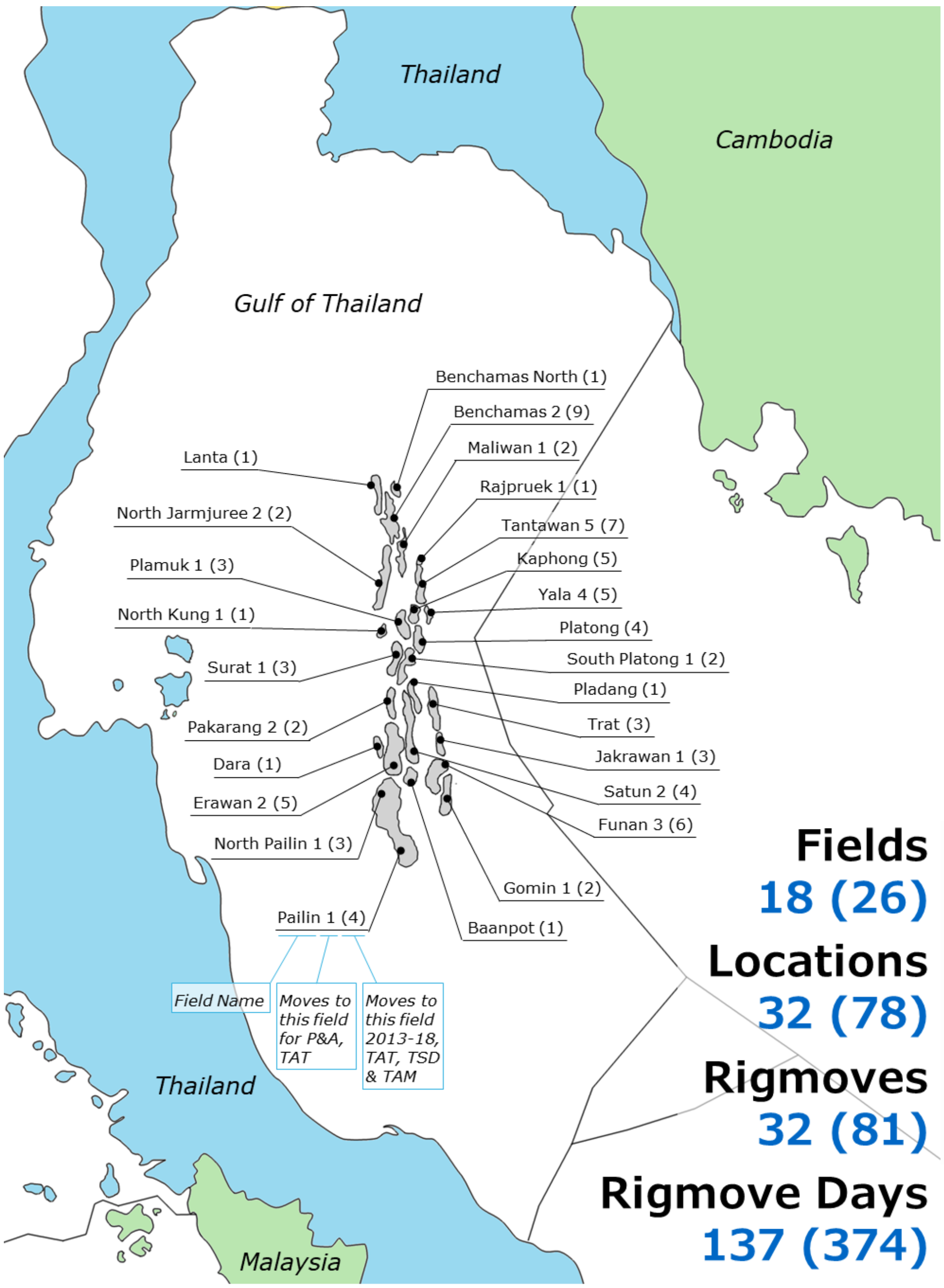

Figure 1 Platform locations visited by the “Ao Thai” for the asset retirement campaign and Transocean Super B-Class fleet in the Gulf of Thailand

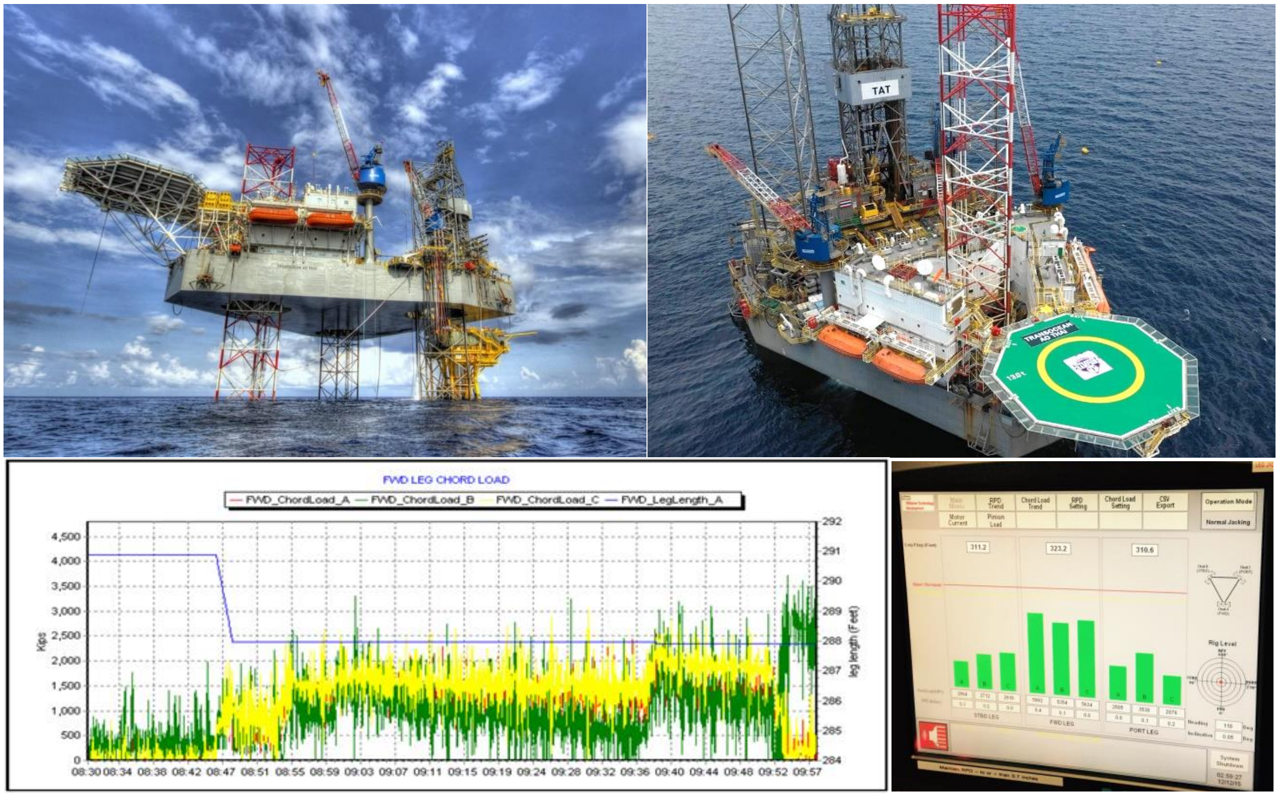

Figure 2 "Ao Thai" rig and its PLMS features

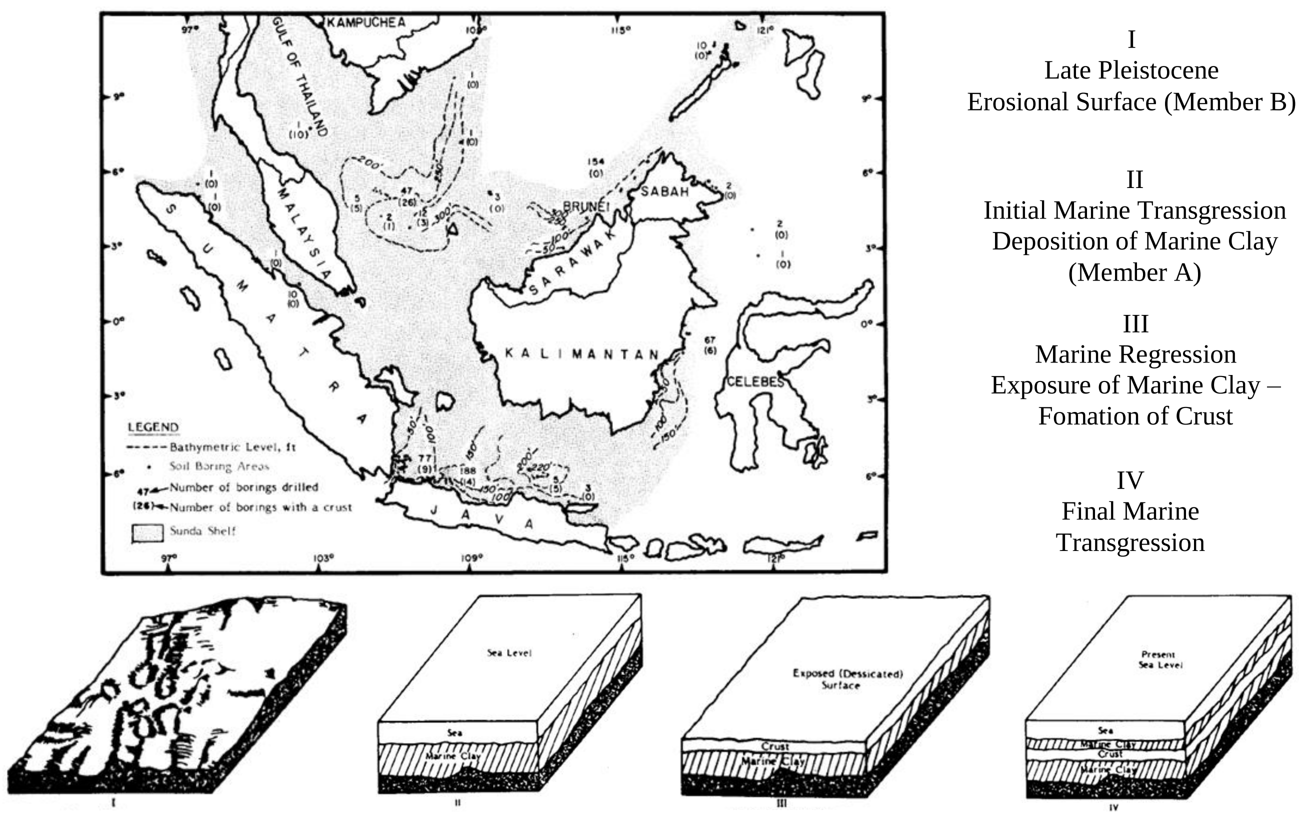

Figure 3 Model for evolution of crusts in the Sunda Shelf [Ref. 1]

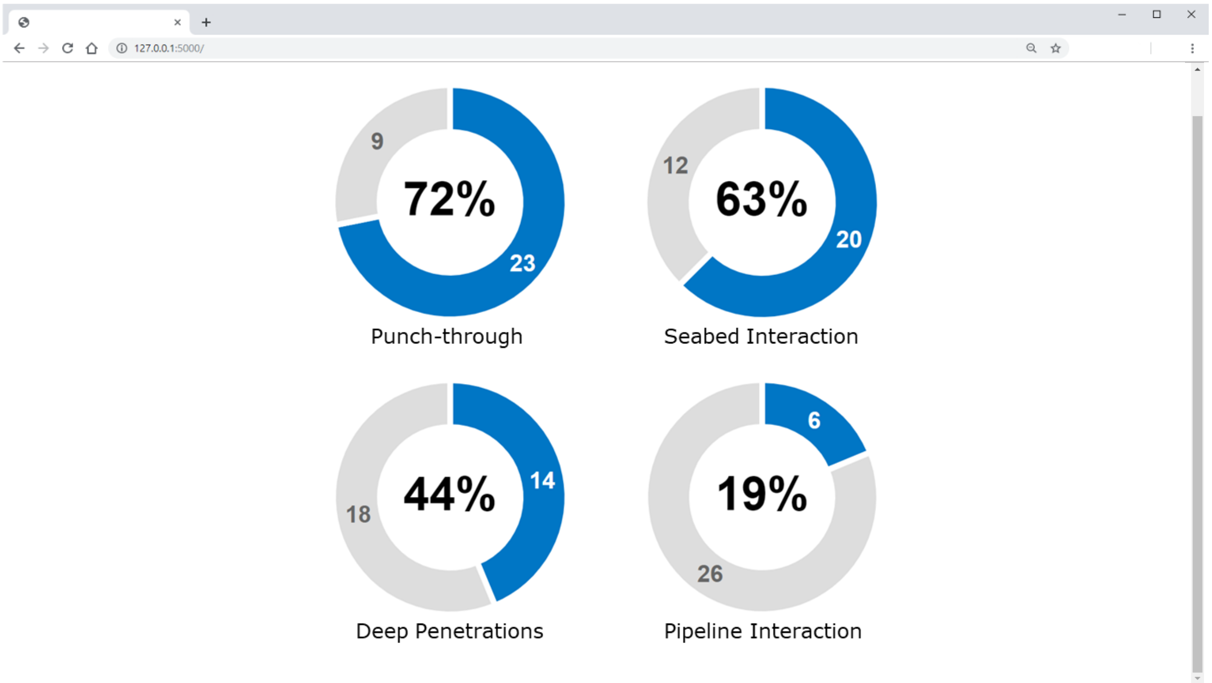

Figure 4 Proportions of platform locations with identified geohazards encountered during the “Ao Thai” P&A campaign

Figure 5 Typical wellhead platform in the Gulf of Thailand [Ref. 2]

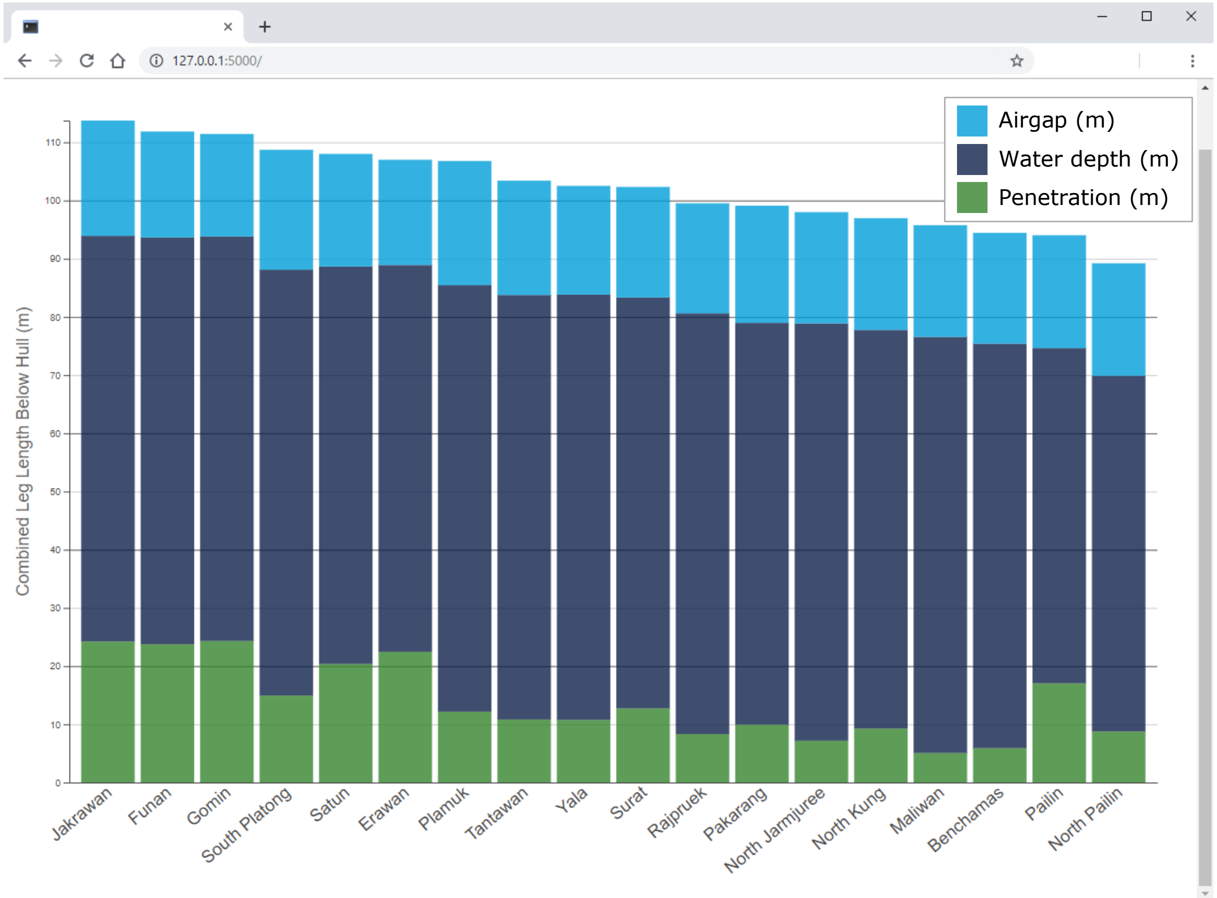

Figure 6 Statistics of the actual leg penetration depths and utilized leg length below the hull

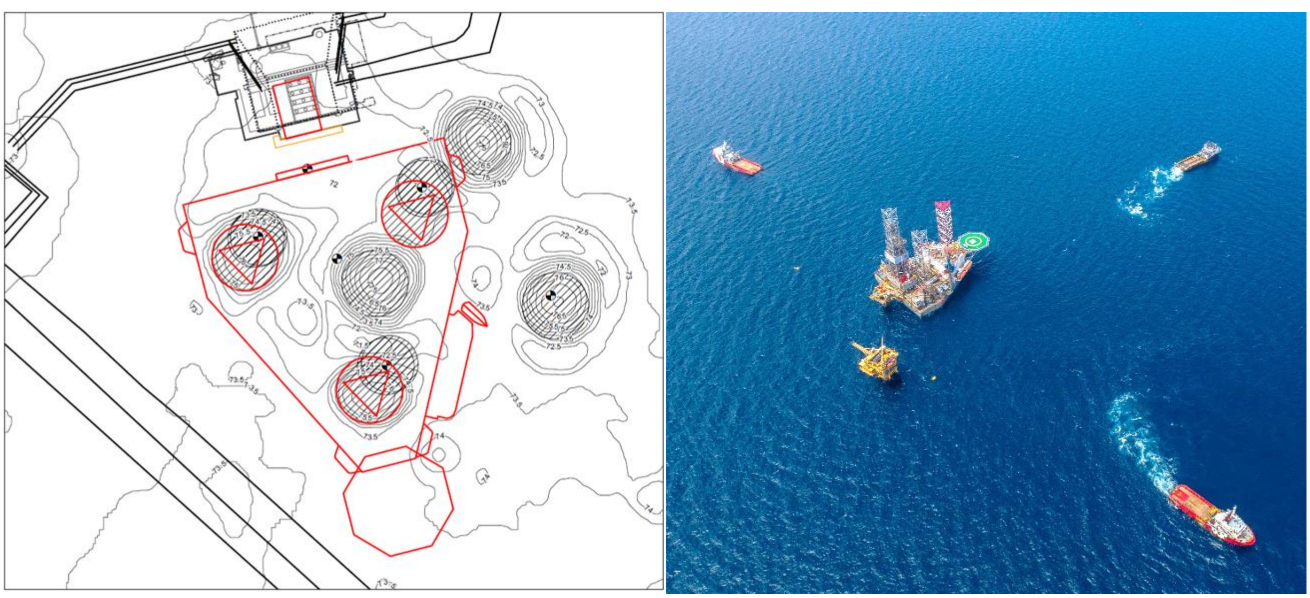

Figure 7 Example of seabed conditions at a platform location visited by the "Ao Thai" and rig positioning

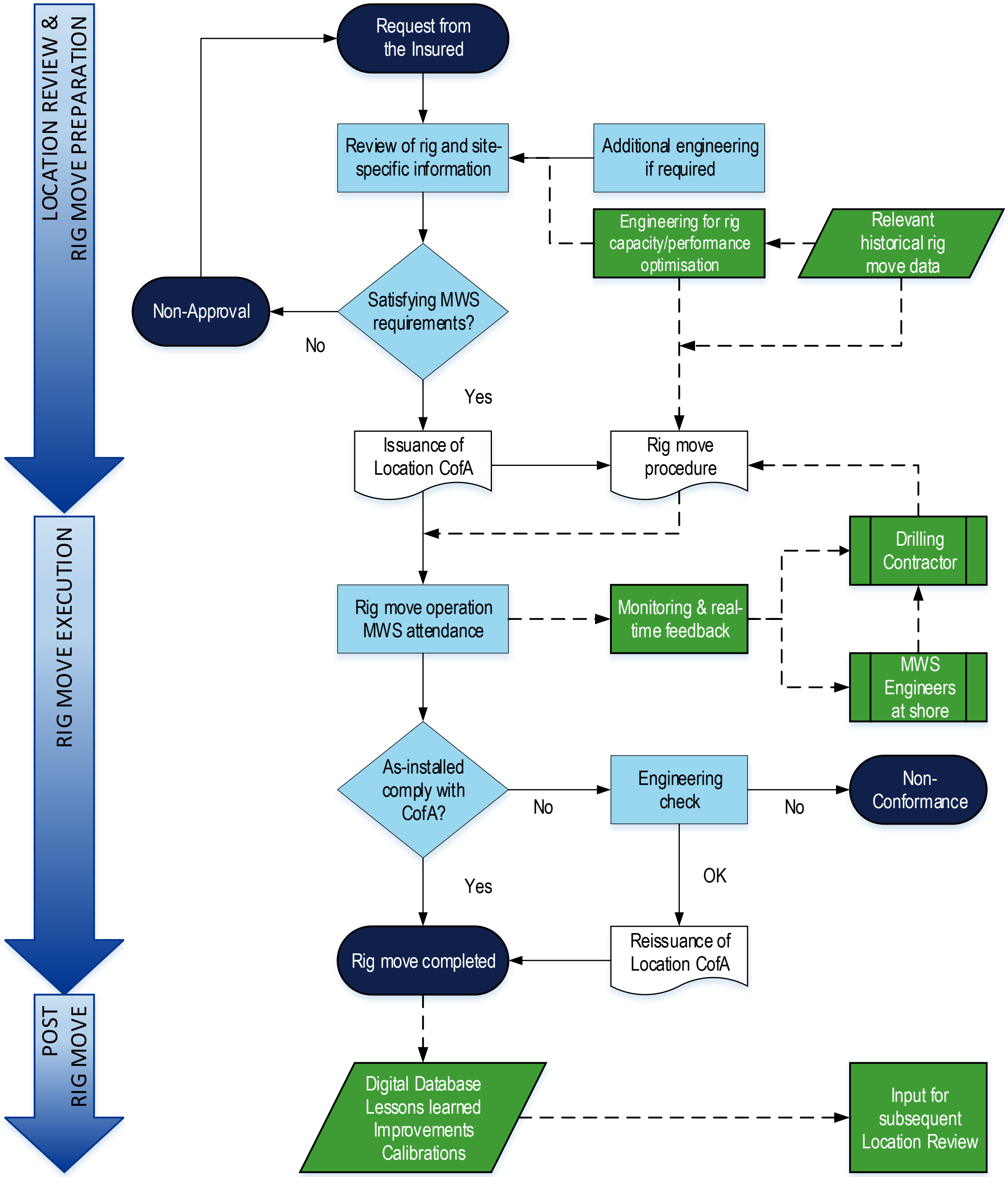

Figure 8 Enhanced workflow between drilling contractor and marine warranty surveyor (dashed-lines representing new steps added to the standard workflow)

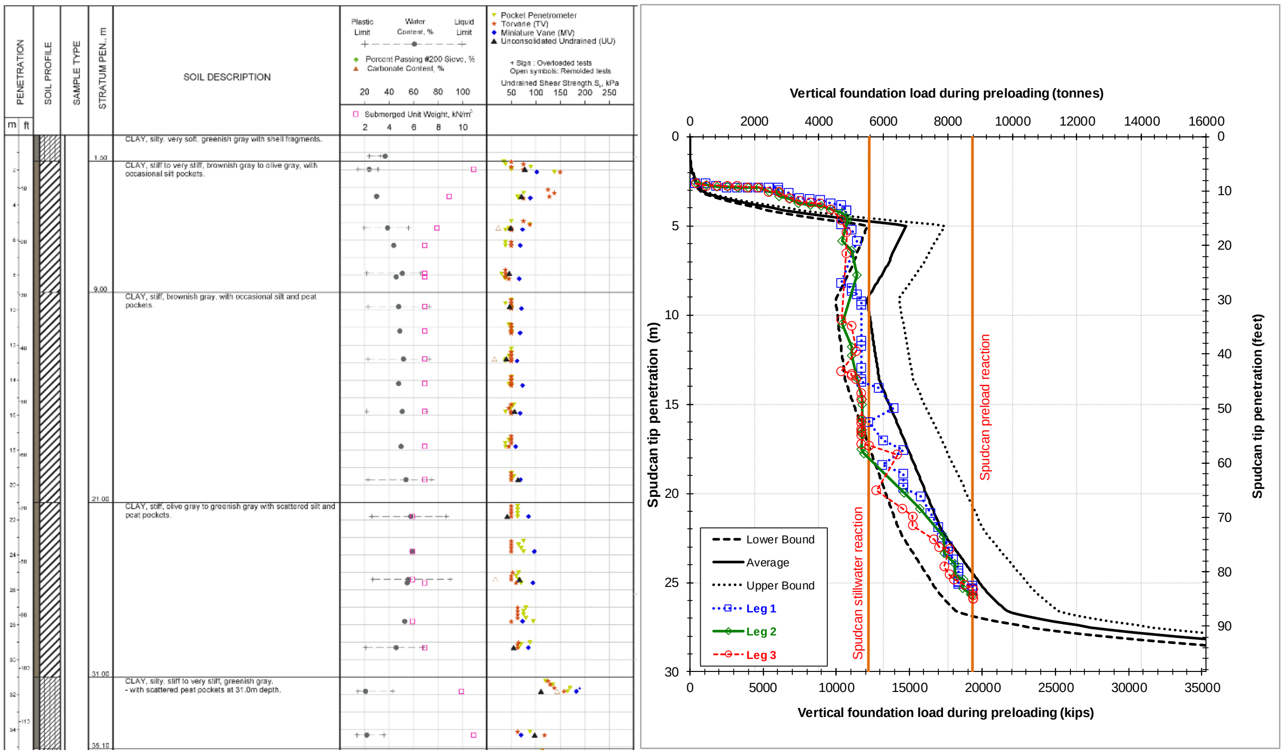

Figure 9 Example of shear strength data at a platform location in the Gulf of Thailand and detailed leg penetration monitoring data at a platform location visited by the "Ao Thai"

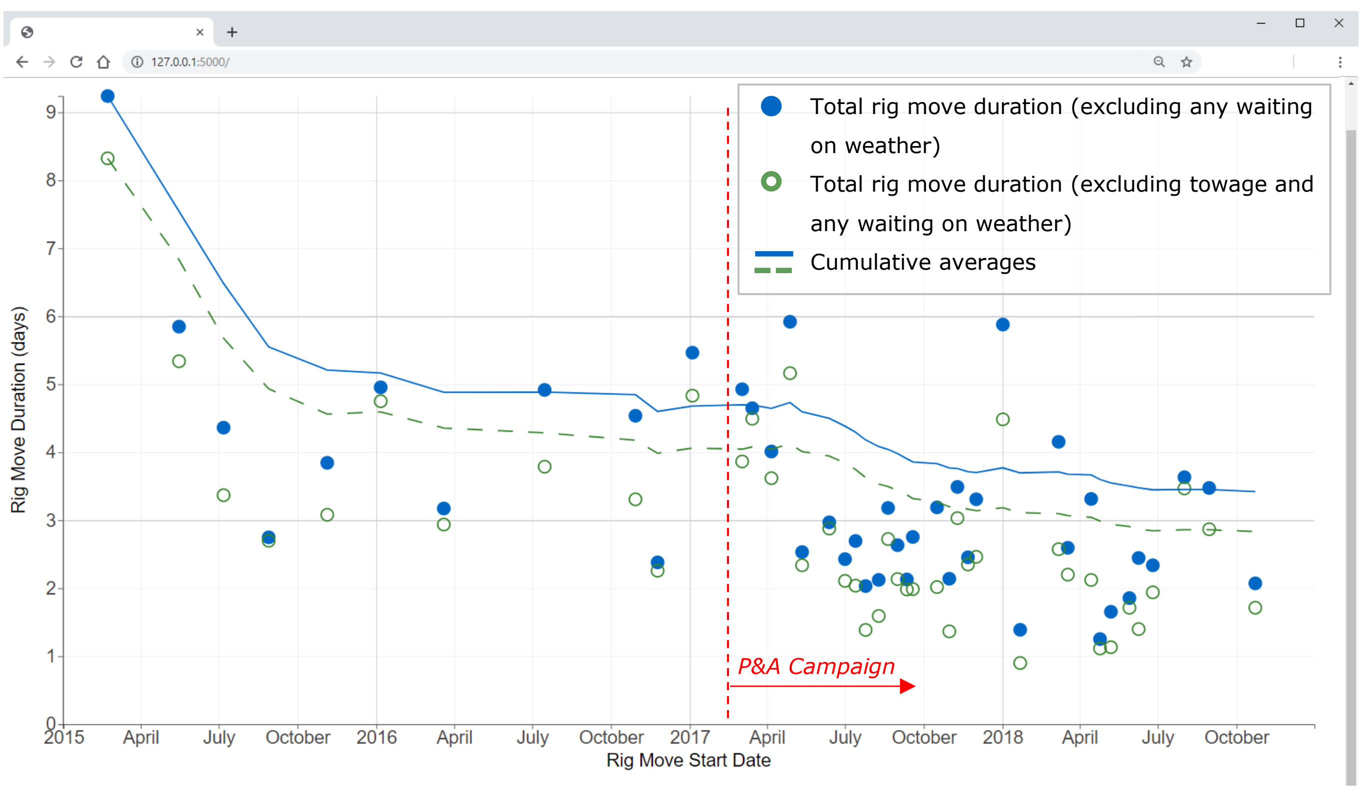

Figure 10 Statistics of rig move efficiency during rig moves carried out by the "Ao Thai" (2015-2018)