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An Efficient Development 2011 Case History from the Gulf of Thailand

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From January to December 2011, Coastal Energy (CEC International, Ltd.) has discovered, appraised and started production from the Bua Ban North field. This project encompassed drilling and completing 21 wells with a subsequent hook-up to two Mobile Offshore Producing Units (MOPUs) and Floating Storage Options (FSOs). By year end, average daily oil production over the last five months had increased by over 70% from the previous seven months. The development of this new Lower Miocene field has added Proven plus Possible(2P) Stock Tank Original Oil in Place(STOOIP) of 204MMBO with recoverable reserves of 67MMBO to CEC's G5/43 permit which encompasses the offshore Songkhla Basin. It is located downthrown to the western margin bounding fault of the basin some five to ten kilometers north of the main Bua Ban field. (Figure 1) Prior to 2011, CEC exploration and production efforts were focused primarily on the Lower Oligocene and Eocene sands which are the producing reservoirs for the Songkhla A and Bua Ban fields. These two fields were developed utilizing an early production concept as well going from zero production in 2008 to 10,000BOPD in 2010. They provided a valuable learning curve for the 2011 success.

The general development scenario used by CEC for the Songkhla Basin is to select a central location from which to drill a prospect. In the event of a discovery, the appraisal and development drilling can proceed immediately. All wells are directionally drilled and designed as a three hole-section free standing through a slotted Caisson Deck, which can be tied back to a MOPU. It is planned to produce the well, however there is also an option to sidetrack to additional targets. All completions included the installation of Electric Submersible Pumps (ESPs). Using this type of early development concept requires daily cross discipline cooperation between drilling, engineering and geoscience to ensure operations run efficiently.

The challenges for the geoscientist are varied. Much depends on the geology and geophysics of the individual basin, its petroleum system and the prospects. Initially, one of the main challenges is the selection of the central location. One must consider the primary and secondary objectives, their target depths and structural configuration as well as any shallow hazards. Once that location is determined the main challenge consists of assimilating the drilling, log and pressure analysis into any ongoing structural mapping and analysis of the 3D seismic. This integration is critical for real time decision making and additional well path planning. The difficulty of this particular challenge is dependent on the time it takes to drill, evaluate and complete a well. In the case history for the Bua Ban North field to be described, the average drilling time for each well to total depth was ten to fifteen days, which results in a continuous flood of data for the geoscientist.

In order to understand this development and its challenges, some background will be provided regarding the exploration history as well as the geological setting for G5/43 in the Gulf of Thailand's Songkhla Basin. The Songkhla Basin is one of three narrow early Tertiary rift basins inboard of the main Gulf of Thailand rift, Pattani Basin. It is a N-S trending half-graben (40x20kms.), with the controlling fault system along its western edge and contains up to 13000 feet of sedimentary section with the early section dominated by lacustrine sediment systems. Dating of the oldest sedimentary fill was obtained from the Benjarong-1 well where clays from a core in the syn-rift sequence gave a late early Eocene age. Structures are mainly tilted fault blocks or anticlinal folds related to roll-over into faults. Heat flows are relatively high with an average temperature gradient of 2.5 deg F/100 feet. This has facilitated the expulsion of large quantities of waxy crude oil typical of algal lacustrine source rocks. Throughout the 70's and 80's exploration was limited in the area as the focus was on the Miocene gas in the central Gulf's Pattani Basin. In the early 90's, Premier Oil was the first to actively explore the Songkhla Basin. They drilled five wells with only one dry hole. Two wells(Songkhla-1 and Bua Ban-1) flowed oil at significant rates (1500 and 768 BOPD respectively) on drill stem tests, one well(Songkhla Southwest-1) encountered a small oil column but did not flow to the surface on testing and another well(Benjarong-1) encountered a significant oil column, but was not tested. Reservoir objectives for all were the Lower Oligocene sands at depths of 7000-8000 feet TVD. The results were considered marginal and there was no further activity until Coastal's Thailand application. Concession G5/43, awarded in July 2003 to a CEC subsidiary (NuCoastal Thailand Ltd) is located offshore eight kilometers from the Songkhla village in the south and 50 kilometers from the Island of Ko Samui in the north. Water depths range from 50-100 feet. Originally a large concession of 17,100 km2, it is currently two areas totaling 4775 km2 following required relinquishments. (Figure 1) The southern portion covers most of the Songkhla Basin and is the focal point of CEC's current exploration and development. In 2005, three wells were drilled to appraise the Bua Ban 1 discovery. These wells were followed by a 3D survey (334km2) in 2006 covering this Bua Ban trend and the western half of the basin. The eastern half had previously been covered by Premier's 1989 3D survey (327km2).

Phase One development of the Songkhla A field commenced in September 2008 with three wells, 2 targeting the Lower Oligocene and 1 targeting the Eocene. All wells were completed and first oil commenced in February 2009 at 6000 BOPD. With the rig released, Phase Two did not begin until September 2009 with the arrival of Atlantic's Vicksburg jack-up. This phase included the drilling of 3 more development wells and 2 water injectors. The Songkhla Basin oils are waxy and viscous in nature with an API gravity around 30 degrees and no gas in the petroleum system. This crude type coupled with a nearly fresh water drive can create early water breakthrough. Thus, selection of perforation intervals when completing a well is an important challenge for the engineer. Also, water injection and handling capacities are an important consideration in facility design.

Having retained the Vicksburg, the rig moved in 2010 to the western side of the basin to further appraise and develop the Bua Ban field with the drilling of 11 wells. One of the geoscience challenges on the western side is the variable distribution of the Lower Oligocene sands in conjunction with a complex faulted structure. Well path design becomes a critical component to an efficient development. One of the benefits of deviated wells is the section traversed in the shallow Miocene section above the target Lower Oligocene may catch a fault block different than that of a vertical well. To capitalize on this, it is important to have a complete and careful petrographic analysis over the entire length of the wellbore that can be integrated into the mapping. A key example of this is the Bua Ban C-03 well which encountered a thin Lower Miocene pay sand. Integrating this new information with detailed mapping at the Lower Miocene revealed an additional location that could be targeted with the well Bua Ban C-11. This well further confirmed the Lower Miocene as a new viable reservoir target in the Songkhla Basin.

Still under contract, the rig moved five kilometers north to the Bua Ban North A and B prospects in 2011. These two prospects were originally developed with Lower Oligocene/ Eocene objectives, thus the central locations were selected based on that mapping. However, given the success with the Lower Miocene at the Bua Ban C-11 area, the detail structural mapping at this level was used extensively in the well path planning. While the Lower Oligocene results were disappointing at Bua Ban D-01, by tagging a Lower Miocene fault block in a closed position 32 feet of net pay was logged at that level. Following a second disappointing Lower Oligocene well, two additional wells, both successful, were planned and drilled to test only the Lower Miocene section in different fault blocks. In fact, the Bua Ban D-03 logged 125 feet of net pay in five different intervals. This scenario was repeated with the move six kilometers north to Bua Ban North B prospect in that the Bua Ban E-01 had disappointing Lower Oligocene results but discovered 31 feet of net Miocene pay. The following seven wells were all designed to appraise and develop the multiple Lower Miocene reservoirs with excellent results. The Bua Ban E-05 encountered 178 feet of net pay with average porosity of 27%, while the E-08 confirmed a significant eastern block with 85 feet of net 28% porosity pay in only one zone. The shallow depths (3100-4600 feet TVDSS) of the Miocene reservoirs as well as the opposing fault plane dips created a unique challenge in planning the well paths. It is difficult to penetrate each zone in the optimum location with one well bore, thus creating the need for additional wells. This problem requires close cooperation between drilling, engineering and the geoscience discipline in order to minimize the number of wells. The exploration/ appraisal of these two prospects totaling 12 wells had been accomplished in four months, March thru June. These efficiencies were possible due to a rig and crew that had gained experience since starting on Songkhla A in 2009. Logging and completion programs were essentially the same throughout, although the shallow depths and deviated wellbores sometimes precluded using certain tools. The geoscience challenge throughout was incorporating all the data in order to determine whether it was one or two fields as well as to keep progressing towards early production. A Miocene sand correlation was established for the different productive intervals as well as synthetic seismograms which enabled more detailed mapping. The density and resistivity curves proved to be excellent tools for the higher porosity productive sands. While the MOPU was being installed at E, additional wells, including the first horizontal were planned and drilled at the D location which confirmed the continuation of the western fault block between North A and B as well as the oil water contact for the eastern block. The horizontal well is considered a solution to the early water breakthrough challenge previously identified as well as increasing production. First oil from the North B MOPU began in July and was producing close to 8000 BOPD by September. The second MOPU was installed and began production at the end of December. All the data continues to be integrated in order to better understand some of the productive fault relationships. A further challenge to fully utilizing the 3D seismic is the absence of any gas in the petroleum system, thus precluding the use of any pre-stack data for Amplitude Versus Offset (AVO) analysis which could have aided in defining the different productive zones and contacts.

In summary, most of the geoscientific challenges encountered in developing this field were not unique, however, the time period in which they needed to be addressed was critical. New technologies were not required, instead established exploration and development practices were utilized in a rapid, detailed and integrated manner. This geoscience integration with the drilling and engineering expertise has made for an efficient and timely development of a significant new field offshore Thailand, which will provide the template for future exploration.

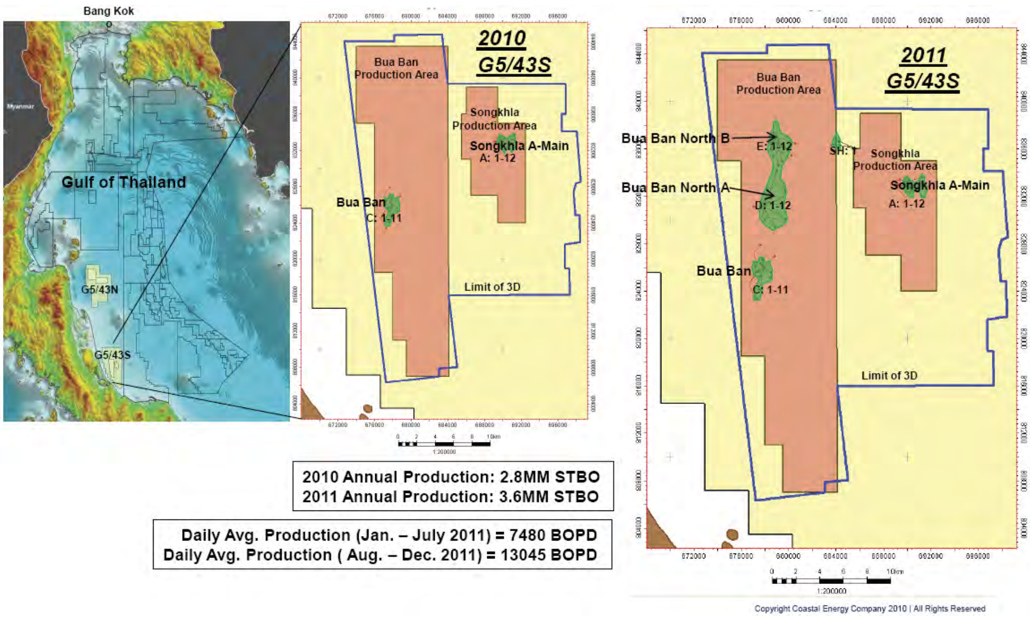

Figure 1: Coastal Energy Gulf of Thailand G5/43 Asset