Horizontal Well Injector/Producer Pair Platong Field, Pattani Basin, Thailand*

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Abstract

The 'X' Trend in the Pattani Basin of the Gulf of Thailand commenced oil production in 2001. The trend consists of a series of North-South oriented complexly faulted, extensional collapse grabens, and tilted half grabens. The Miocene-age clastic reservoirs can be generally characterized as small-compartmentalized fluvial reservoirs (5-60 feet in thickness). The reservoir sands are composed of multiple channel sands that have locally complex vertical and areal stacking patterns. Connectivity within these reservoirs is impacted by potential barriers including both mud-filled abandoned channels and fault compartmentalization. Primary oil production is typically low due to an absence of aquifer support. Waterflooding has been implemented to improve hydrocarbon recovery and sustain field production.

The Alpha Platform was infilled in 2012 with two horizontal wells (Alpha-02H and Alpha-03H). The two infill horizontal wells targeted a >25' oil column in the 'X' reservoir sand which had a single existing deviated producer (Alpha-01) with low produced oil volumes due to water coning without gaslift capability. Both the Alpha-02H and Alpha-03H horizontal sections were placed at the same structural elevation below the gas cap in the upper portion of the oil leg. The wells were completed with three strings of casing and equipped with inflow control devices (ICD) and gas lift mandrels (GLM). Production commenced in February 2012 with combined oil production from the two horizontals ramping up to close to 4,000 bopd before both wells died with >90% water cut in February 2013. Alpha-03H was converted to a waterflood injector in August 2013 and commenced injection in the same month. After one month of maintaining a voidage replacement ratio (VRR) of 1:1 at Alpha03H, the Alpha-02H GOR and water cut dropped substantially with oil production ramping up to close to 1,000 bopd. After waterflooding in December 2014 the reservoir, pressure had improved significantly. Within the two-year period of waterflooding, the Alpha-02H watered out and died. The horizontal waterflooding period has ended and the project's recovery factor (RF) is >30%. The Recovery Factor contribution from waterflood operations was >10%.

The reservoirs in the Gulf of Thailand are very complex and the reserves are quite marginal to develop. For these reasons, no dynamic modeling was attempted for this complexly faulted fluvial sand. A statistical model based on historical data was utilized to predict the benefit from both horizontal wells and waterflood operations. A comparison of current analogous reservoirs in the same trend with completed deviated injector/producer water floods shows about 50% higher recovery factor for this horizontal injector/producer waterflood.

The main lesson learned from utilizing horizontal wells as injectors is that it allows more flexibility in waterflood implementation and reservoir management strategy in complexly faulted reservoirs and potentially better connectivity leading to higher ultimate recovery factors. In order to capitalize on horizontal waterflood strategies it is necessary to fully utilize cross functional team work to identify target reservoirs from primary drilling programs and optimize production data by developing routine sampling collection methodologies.

Selected Reference

Jardine, E., 1997, Dual Petroleum Systems Governing the Prolific Pattani Basin, Offshore Thailand: Proceedings of the International Conference on Stratigraphic and Tectonic Evolution of Southeast Asia and the South Pacific (Geothai'97), 19-24 August 1997, Department of Mineral Resources, Bangkok, p. 525-534.

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AAPG Asia Pacific Geosciences Technology Workshop March 31 – April 1, 2016

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Horizontal Well Injector/Producer Pair
Platong Field, Pattani Basin, Thailand

- Pattani Basin Geology
  - Gulf of Thailand Tectonic Setting
  - Pattani Trend General Description
    - Structural History / Basin Evolution
    - Stratigraphy / Connectivity
  - Targeted Horizontal Reservoir Sand
    - Structure / Seismic Interpretation
    - Sand Thickness Relationships
    - Horizontal Well Results - Geological Interpretation

- Production/Reservoir Engineering
  - Horizontal Well Completion Design
  - Production Performance
  - Comparison of Horizontal injector / producer to alternative developments
  - Conclusions
  - Lessons Learned / Challenges

Asia and South-East Asia Tectonic Setting

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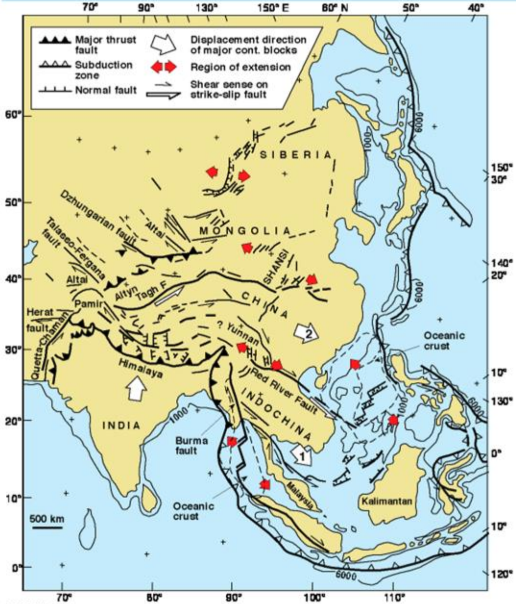
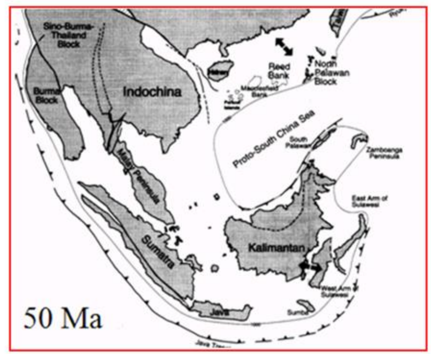


- **India-Asia collision**
- Subduction of Indian Oceanic Crust
- Australia-Sundaland Collision
- Extrusion Tectonics
- *"Back Arc" Extension*
- *Transpression/Transtension Associated with right-lateral Strike-Slip Faulting*



Presenter's notes: This is an overview slide of the Asia and SE Asia tectonic setting leading to the origin of the Gulf of Thailand.
The image on the left shows the tectonic setting from Late Cretaceous to Eocene time as the Indo-Australian plate separated from Gondwanaland moving northwards to collide with the Eurasian plate.
This formed a major thrust fault and subduction zone related to the plate collision with the Indo-Australian oceanic crust being subducted.
This subduction opened the Gulf of Thailand 50Ma with "back-arc" extension transpression/transtension associated with right-lateral strike-slip faulting (shown on the figure to the right).

Gulf of Thailand Basins Formation
Dextral "Right-Lateral" Movement Along Three Pagoda Fault

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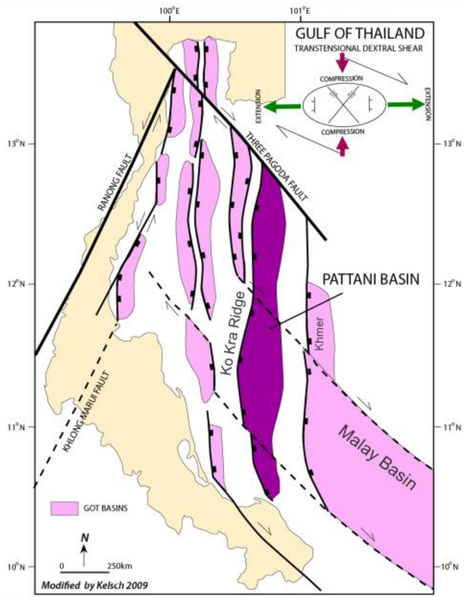


- Extensional faults (NS-trending link-up with NNW-trending transfer faults)
- N-S Basins – Rift History + Later Extension & Subsidence
  - Elongate Tertiary trough basins associated with Eocene / Oligocene oblique slip
  - Continued deposition through Miocene associated with extension resulting in linear collapse graben trends ("sag" phase)
- Physical Separation between Pattani Basin and Malay Basin to South

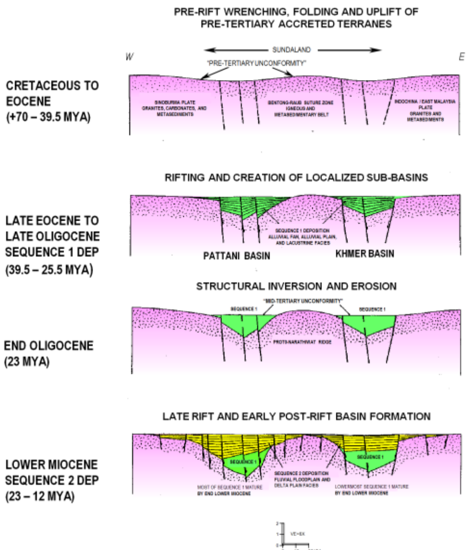
Presenter's notes: Looking closer at the formation of the Gulf Thailand Basins we see north-south extensional faults forming these Cenozic Basins which link up with the NNW trending Three Pagoda Transfer Fault.

The Pattani Basin is one of eleven N-S elongate "pull-apart" basins in the Gulf of Thailand associated with Eocene/Oligocene oblique slip.

The Western and Eastern Gulf of Thailand sub-segments are separated from one another by the Ko Kra Ridge with nine basins in the west and three basins in the east: the Pattani and Malay Basins and the smaller Khmer Basin.

The Pattani Basin, which is the focus of this presentation is the largest basin in the Gulf. Five sequences were recognized by Jardine in 1997 based on seismic reflection and well data.

Gulf of Thailand - Basin Evolution



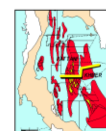
MAJOR TECTONIC EVENT

- THE SINOBURMA AND INDOCHINA / EAST MALAYSIA PLATES ACCRETE IN LATE TRIASSIC-EARLY CRETACEOUS CREATING THE INDOSINIAN OROGENY AND FORMING SUNDALAND
- INDIA PLATE SEPARATES FROM GONDWANALAND, MIGRATES PAST SUNDALAND, AND COLLIDES WITH EURASIAN CRATON IN THE EOCENE
- UPLIFT AND EROSION CREATES "PRE-TERTIARY UNCONFORMITY"

- INDIA - EURASIA COLLISION CREATES HIMALAYAN OROGENY AND CAUSES INTIAL PROPAGATION OF MAE - PING AND THREE PAGODAS SHEAR SYSTEMS
- SUB - BASINS FORM ALONG PRE-EXISTING NORTH-SOUTH TRENDING "INDOSINIAN" FABRIC
- MOST EARLY BASEMENT FAULTS FORM WITH EASTWARD DIPS

- WRENCHING OCCURS ALONG MAE - PING AND THREE PAGODAS FAULT SYSTEMS
- REGIONAL UPLIFT CREATES "MID-TERTIARY UNCONFORMITY"
- CHANGE FROM INTERNALLY DRAINED TO EXTERNALLY DRAINED REGION

- CONTINUED MOVEMENT OF INDIAN PLATE INTO ASIA, CLOCKWISE ROTATION OF INDOCHINA CREATING EXTENSION IN PATTANI / KHMER REGION



Credit: Eric Jardine

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Presenter's notes: The next two slides detail the Gulf of Thailand Basin Evolution from Late Cretaceous to Present Day.
The section is West to East across the Pattani and Khmer Basins.
From Late Cretaceous to Eocene the India Plate separates from Gondwanaland moving north to collide with the Eurasian Craton.
The resulting uplift creates the "Pre-Tertiary Unconformity"
From Late Eocene to Late Oligocene is the Himalayan Orogeny due to India-Eurasian plate collision.
This creates the Mae-Ping and Three Pagoda Shear Systems and the elongate N-S rifted sub-basins
"Sequence 1" Rift-fill deposits are Late Oligocene reddish brown claystones and siltstones predominate in lacustrine to alluvial deposits.
At the End of the Oligocene wrenching along the Mae-Ping and Three Pagoda Faults causes uplift and creates the "Mid-Tertiary Unconformity"
During the Lower Miocene continued clockwise rotation creates renewed extension and rifting.
"Sequence 2" Lower Redbeds formed as fluvial point bar and channel deposits in North and Central Pattani and Upper intertidal, fluvial and lower deltaic plains in the southern basin.

Gulf of Thailand - Basin Evolution

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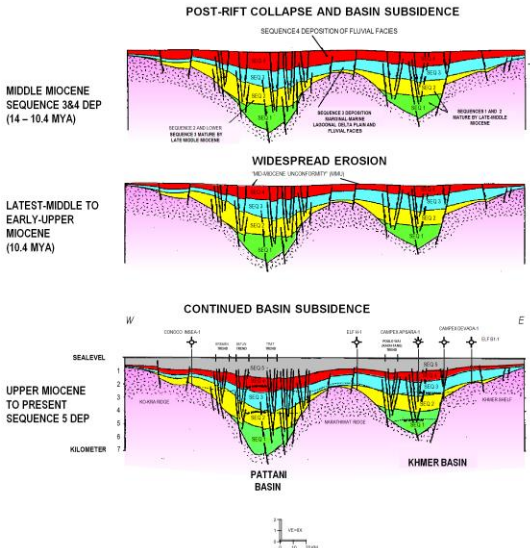


MAJOR TECTONIC EVENT

–CONTINUED CLOCKWISE ROTATION OF INDOCHINA BLOCK WITH EXTENSION AND DOWNDROPPING ALONG MAJOR RIFT ZONES

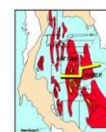
–"ACCOMODATION" GRABEN SYSTEMS FORM IN RESPONSE TO BASIN SUBSIDENCE

–EUSTATIC SEALEVEL DROP AND CREATION OF "MID-MIOCENE UNCONFORMITY" (MMU)

–CONTINUED COMPRESSION ALONG INDIAN-ASIAN SUTURE AND CLOCKWISE ROTATION OF INDOCHINA BLOCKS WITH EXTENSION IN THE GULF OF THAILAND

–CONTINUATION OF "ACCOMODATION" FAULTING AS BASINS SUBSIDE AND DEEPEN

–REGIONAL MARINE TRANSGRESSION AND DEPOSITION OF SEQUENCE 5 DELTA PLAIN TO SHALLOW MARINE FACIES



Credit: Eric Jardine

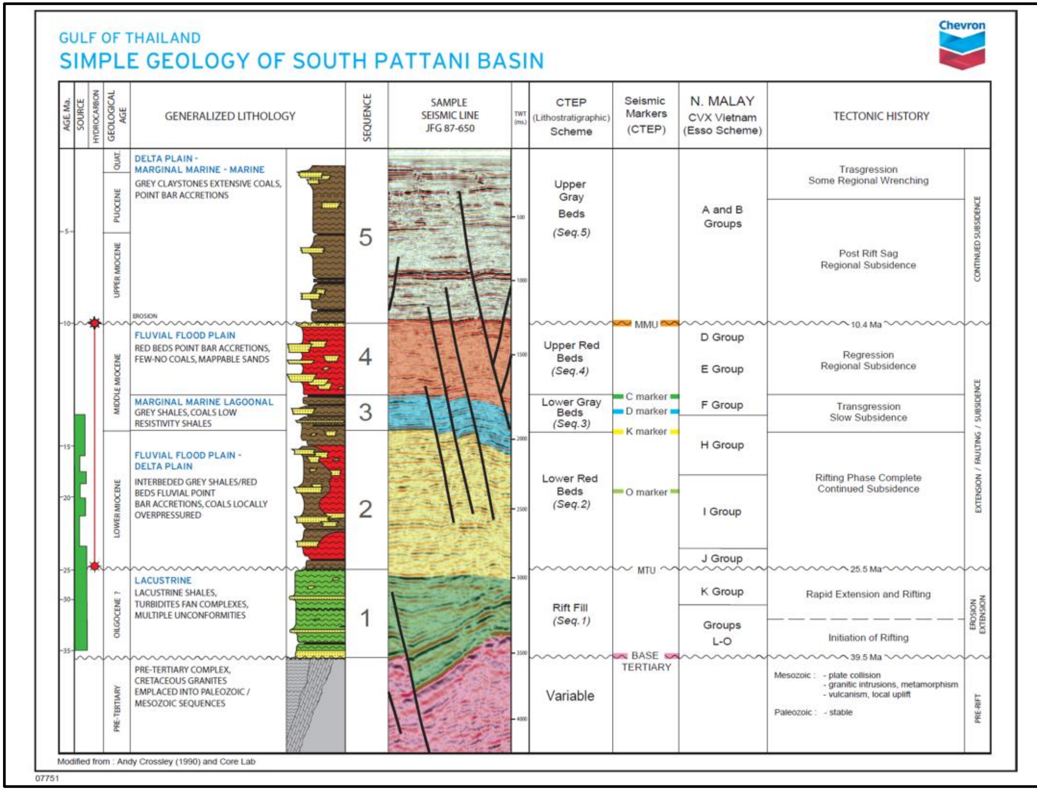
Presenter's notes: Continued clockwise rotation of the Indochina block during the Middle Miocene leads to post-rife collapse and basin subsidence.

"Sequence 3 "Lower Grey Beds" which are coastal plain and marginal marine deposits and "Sequence 4" "Upper Redbed" point bar and channel fill deposits in the fluvial-floodplain are deposited during this time period.

Eustatic sea-level drop during the Latest-Middle to Early Upper Miocene creates the MMU unconformity.

"Sequence 5", the youngest unit, was deposited from Upper Miocene to Present during continued compression and rotation with the basins continuing to subside and deepen.

The "Upper Gray Beds" were deposited during a regional marine transgression and are delta plain to shallow marine deposits.



Presenter's notes: This "Simplified Strat Column" for the South Pattani Basin shows the generalized lithologies from the Pre-Tertiary Complex up through Sequences #1 to #5 from the Oligocene to Present Day.

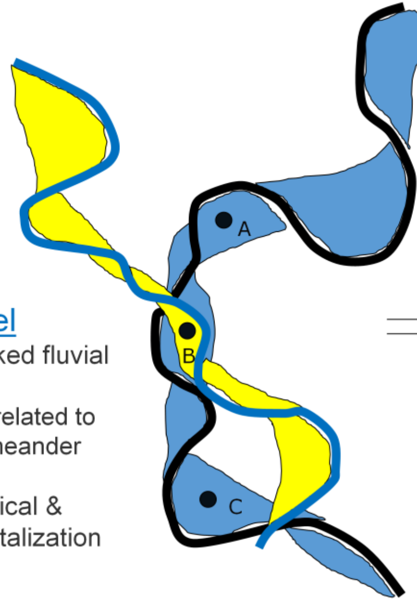
The sample seismic line shows each sequence in a different color and highlights the extensive faulting through the entire section

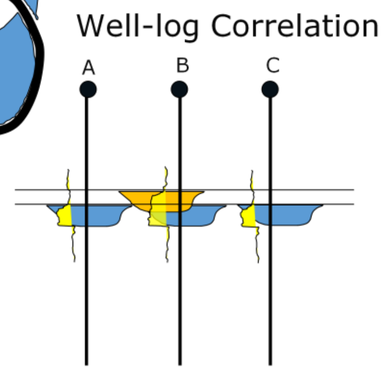
Source rock potential ranges from Sequence#1 to Sequence #3 deposits and Hydrocarbon potential from Sequence #2 to #4 deposits between the Mid-Tertiary to Mid-Miocene Unconformity.

The sandstone with the horizontal injector producer pair that we are going to discuss today is a Mid-Miocene point bar sand at the top of the "Upper Red Bed" Sequence #4 near the Mid-Miocene Unconformity.

Middle Miocene – Fluvial Floodplain

Amalgamated Crosscutting Channel Deposits

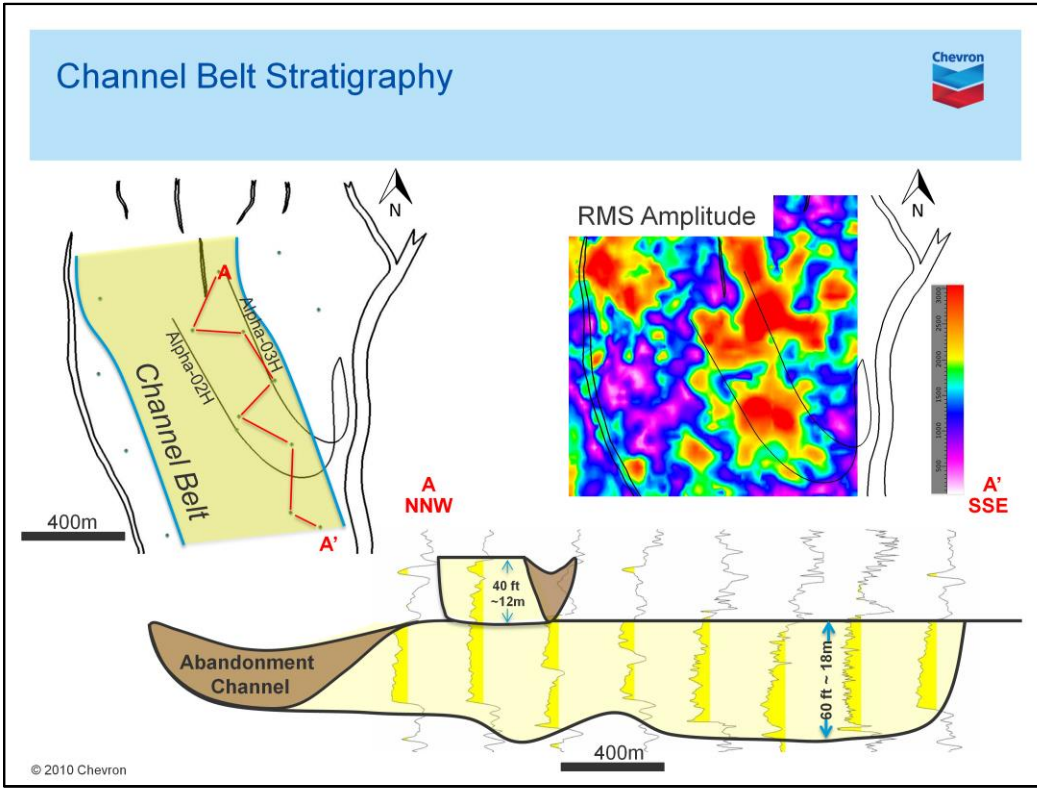




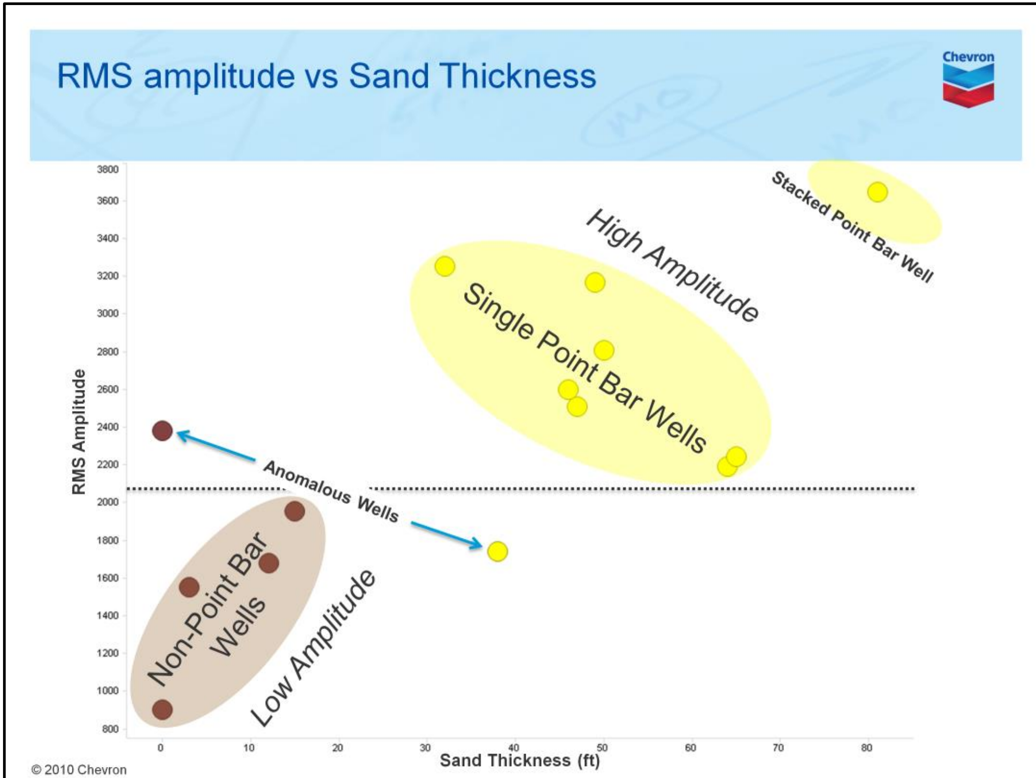
Depositional Model

- Individual and stacked fluvial point bar deposits
- Point bar geometry related to channel width and meander wavelength
- High degree of vertical & lateral compartmentalization

Presenter's notes: Here is a typical map view and three well strat section through these Mid-Miocene Pattani Basin fluvial deposits.
They are generally characterized as small compartmentalized fluvial reservoirs (5-50 feet in thickness).
The reservoir sands are composed of multiple channel sands that have locally complex vertical and areal stacking patterns.
Connectivity within these reservoirs is impacted by potential barriers including both mud-filled abandoned channels and fault compartmentalization.
Primary oil production is typically low due to an absence of aquifer support. Waterflooding has been implemented to improve hydrocarbon recovery and sustain field production.



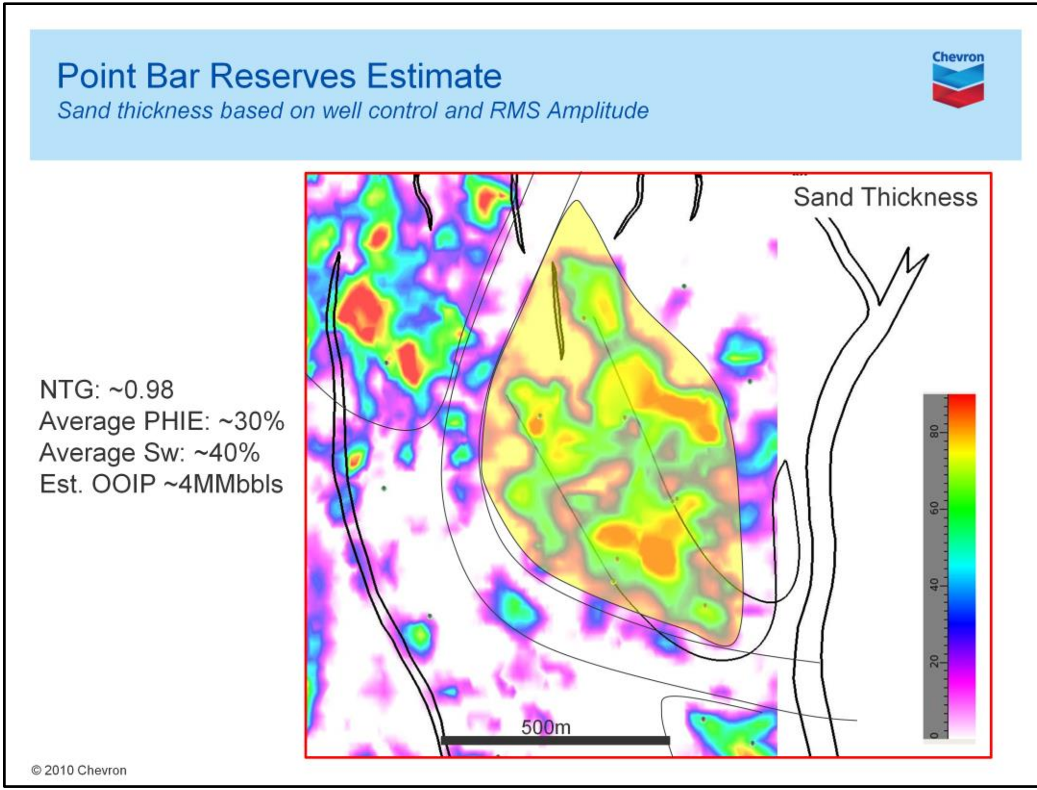
Presenter's notes: Here is a map view of the horizontal injector/producer pair. The offsetting deviated well control are the grey dots and the fault polygons are shown as black outlines.
Well control from fourteen wells with 400m well spacing defines the channel belt margins and a NNW-SSE orientation which is typically for the Pattani Basin.
The Stratigraphic Cross Section North to South from A-A' with highlighted GR curves shows approx. 60 foot thick point bar sand and a stacked 40' foot thick point bar deposit in one of the wells.
The RMS amplitude high amplitude response which are the green, yellow and red colors correlates well with the existing well control to define the margins of the thicker and more aerially extensive point bar deposit.
The lower amplitude response which are the pink and blue colors represents the abandoned channel mud-fill and flood plain deposits.



Presenter's notes: So if we plot the point bar sand thickness vs. RMS amplitude response we see a good correlation between low amplitude response and sand thickness for the Non-Point Bar wells shown in Brown.

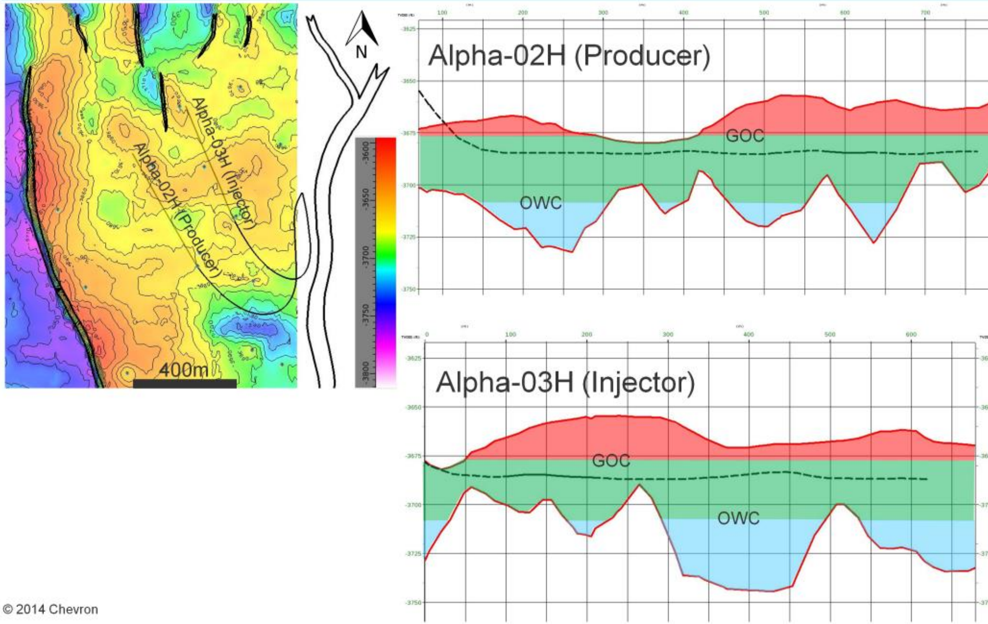
We also see a good correlation between the single thick point bar deposit wells and high amplitude response shown in yellow. The one well with the stacked point bar deposit having the highest amplitude and thickest sand thickness.

There are two wells which are anomalous. One with no sand thickness having a relatively high amplitude response and one well with 40' sand thickness having a relatively low amplitude response.



Presenter's notes: If we use the combination of well control and RMS amplitude to define the point bar edges and sand thickness shaded in yellow we can estimate our reserve size based on a net-to-gross ratio of 98% in the point bar wells.
Average porosity is ~30% and average water saturation is ~40% to give an estimated oil in place of 4 MMbbls for this Mid-Miocene point bar sand.
The abandoned mud-filled channel deposits acting as a flow barrier are outlined by the thin black lines.

Structure Map with Horizontal Well Sections



Presenter's notes: The map on the left is a structure map on top of the sand based on well control and seismic and shows the two horizontal wells Alpha-02H and Alpha-03H which were drilled as platform infill wells in 2012.

The contour interval is 10' with red being structural highs. Structural cross sections along both horizontal wells are shown on the right.

The two infill horizontal wells targeted a >25' oil column in a reservoir sand which had a single existing deviated producer (Alpha-01) with low produced oil volumes due to water coning.

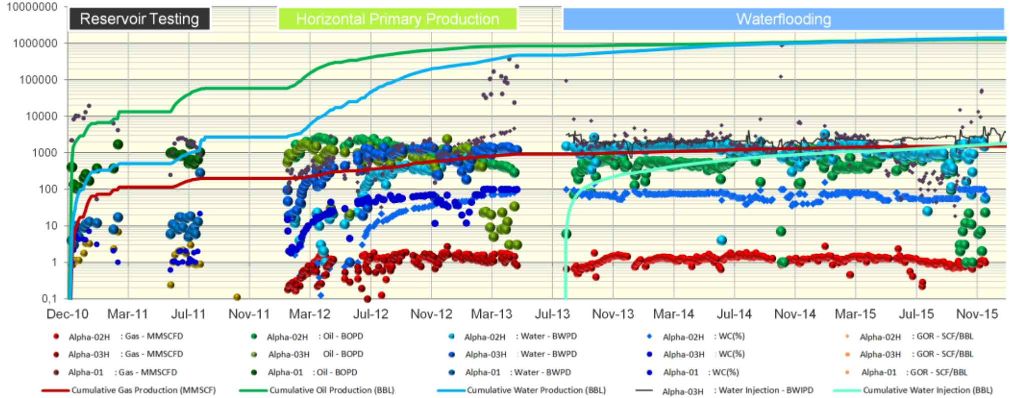
The primary gas cap and water legs in the the point bar can be seen with both wells placed at the same structural elevation approximately 1/3 2/3 between the gas/oil and oil/water contacts.

Each horizontal has ~600m lateral section.

Horizontal Well Completion Design

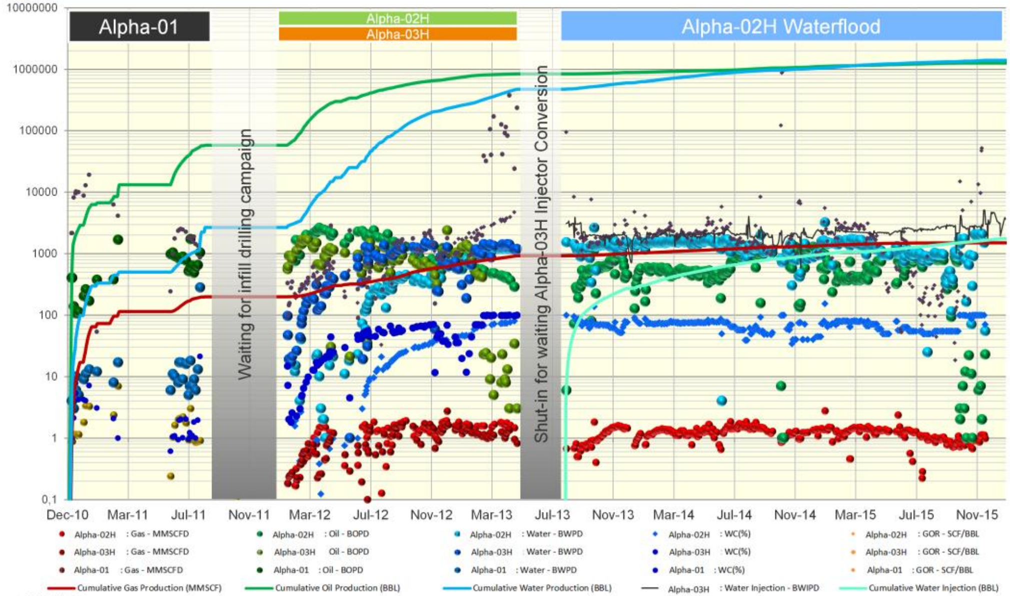
- Based on the log data collected from the primary offset wells, the reservoir contains the possibility of significant permeability contrasts and high heterogeneity
- Both the Alpha-02H and Alpha-03H were equipped with Inflow Control Device(ICD) screen completions to balance drawdown in the lateral section
- In order to optimize production, both wells were installed with Gaslift Mandrels (GLM) to improve wellbore lifting efficiency

Production Performance



- The production performance of this reservoir can be divided into 3 periods
  - Reservoir testing
  - Horizontal primary production
  - Waterflooding

Production Performance



Production Performance

Production History : Reservoir Testing

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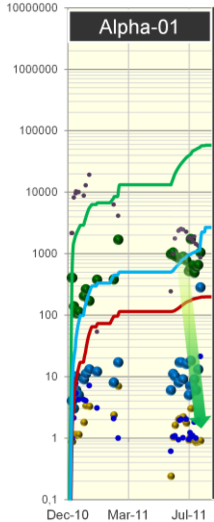
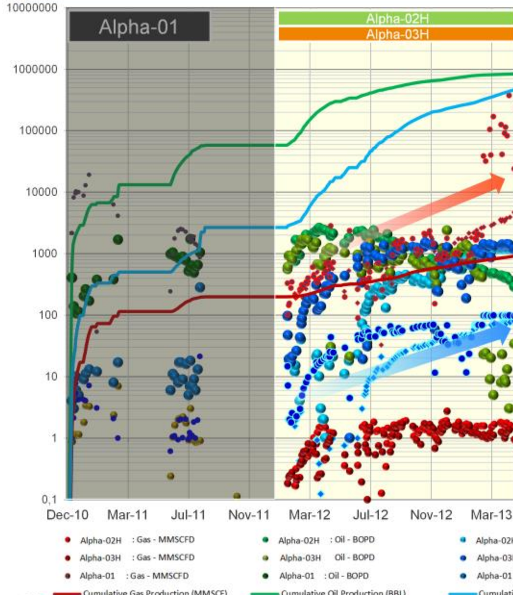


2010

- The Alpha-01 was selected to produce the ‘X’ reservoir and help with understanding the drive mechanism
- After perforating the ‘X’ reservoir, the Alpha-01 well production increased to almost 2,000 BOPD and 7 MMSCFD with low water production
- However, the well loaded-up and stopped flowing within a year due to depletion and water coning

Production Performance

Production History : Horizontal Primary Production



2012

- Infill drilling campaign was completed in February-2012
- Production from 2 HZ wells was ramped up to 4,000 BOPD

2013

- In March, oil production of Alpha-03H died with 100% water cut with higher GOR.
- Alpha-02H also reached 80% water cut after Alpha-03H 100% watered-out.

Production Performance

Production History : Waterflooding

May-2013

- Both wells were shut-in because of very high water production and wait Alpha-03H converting

August-2013

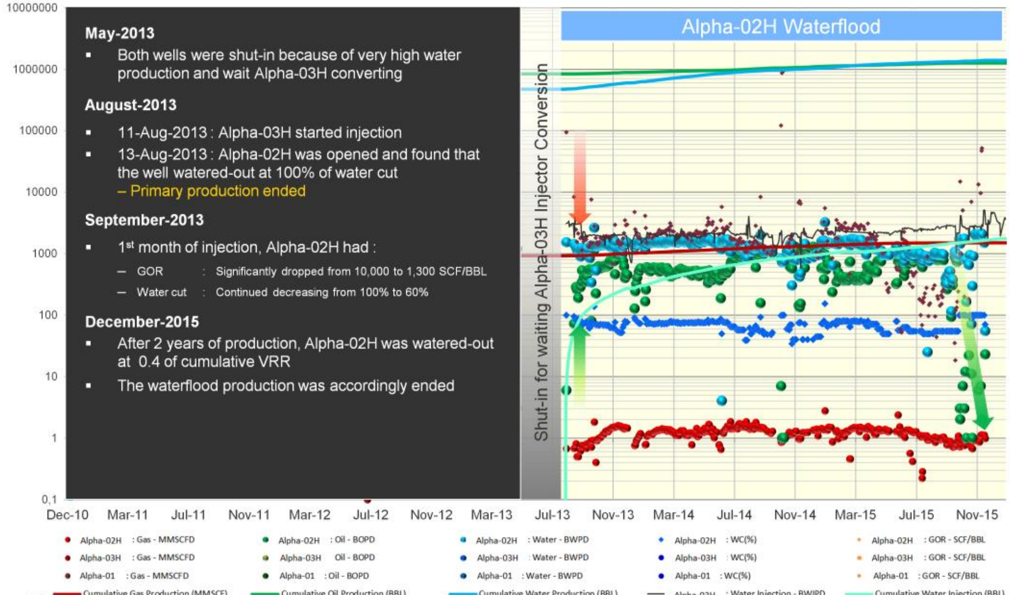
- 11-Aug-2013 : Alpha-03H started injection
- 13-Aug-2013 : Alpha-02H was opened and found that the well watered-out at 100% of water cut
  – Primary production ended

September-2013

- 1st month of injection, Alpha-02H had :
  – GOR : Significantly dropped from 10,000 to 1,300 SCF/BBL
  – Water cut : Continued decreasing from 100% to 60%

December-2015

- After 2 years of production, Alpha-02H was watered-out at 0.4 of cumulative VRR
- The waterflood production was accordingly ended



Cumulative Production and Reservoir Pressure Plot