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DIRECTORATE GENERAL OF HYDROCARBONS

For Further Information Contact:

DIRECTOR GENERAL
C-139, Sector-63, NOIDA - 201 301 (INDIA)
Phone : (Direct) 91-120-4029400, Fax : 91-120-4029410
Web Site : www.dghindia.org

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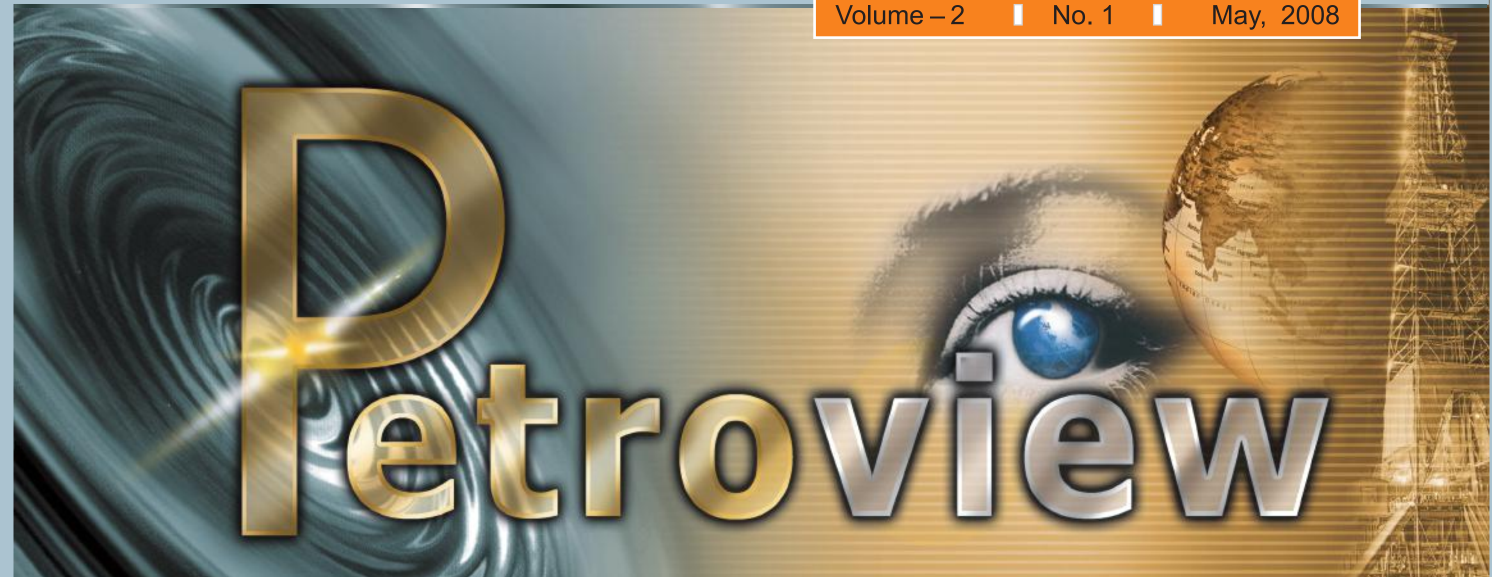

a quarterly journal of DGH India

RELEASE OF THE INITIAL REPORT ON THE NGHP EXPEDITION -01 BY HON'BLE MINISTER P&NG

DGH OFFICERS IN THE FIELD WITH PROF. PD PANT

Key Contents

Quarterly Journal of the Directorate General of Hydrocarbons
(Under Ministry of Petroleum & Natural Gas)

Vol.-II **May, 2008** **No. 1**

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V.K. Sibal, Director General
Directorate General of Hydrocarbons

Foreword

Energy security and climate change are amongst the most serious concerns for many developing countries.

Among the various definitions of energy security, the one that appears to sum up the issue reads: "*energy security is a country's ability to optimize its energy resource portfolio and supply of energy services for the desired level of services that will sustain economic growth and poverty reduction*".
The Asian Development Bank (ADB) has predicted that in the coming decades, Asia will experience an unprecedented growth in energy demand, and this demand will come primarily from China and India.

India's high dependence on oil import indicates the economy's vulnerability to oil supply disruptions and adverse impacts of sudden oil price shocks. A study carried out by the Government of India and The Energy and Resources Institute (TERI), mentions the country's increasing import dependence for all fossil fuels. The study has recommended the reduction in consumption of coal and petroleum products and makes a case for natural gas as the preferred fuel. The study also recommends that there is need for greater emphasis on renewable energy resources and nuclear power, which, currently, account for only a small fraction of our energy portfolio.

India is on the fast track of economic growth. In order that we maintain a growth rate of about 8 to 10 percent, there is a need for major inputs in infrastructure and energy. For this to be achieved, it is essential that planners and policy makers take timely decisions, by assessing the magnitude of total energy requirements as well as assess the economic, environmental, and geopolitical implications of India's alternative energy pathways in the next few decades.

Deliberating on *The Challenge for the E & P Industry*, Keith Millheim (2008) observes that "*Today, we are faced with the biggest need, ever, for new ideas, new approaches, new paradigms & individuals to challenge the conventional if we have any hope of meeting the future world demand. More money or people will not solve the problem – the investigative, brave minds will*". How true!

Keith further observes that the downplaying of R & D in the E & P, starting in early 1990s has resulted in a drought of investigative thinking. Concomitantly, a great deal of emphasis was placed on technology at the expense of R & D.

A similar malady seems to have struck the Indian E & P industry. Commenting on the R & D expenditure in some of the oil PSUs, the standing committee on demand of grants for petroleum & natural gas sector has conveyed its displeasure at the measly amounts spent on R & D activities and the decline in the same during the 10th Plan period.

The committee further states that there needs to be more emphasis on this most vital area of the sector. R & D provides the competitive edge that enables companies to survive and grow in a highly competitive environment.

It has been my firm belief; one that I have reiterated a number of times, that R & D should drive business and not the other way around. Fortunately, some of the companies worldwide have realized the folly of giving R & D a backseat and are now strengthening and rebuilding their R & D capacity. We need to do that in India too. We need to create an environment where investigative minds bloom and contribute to the growth and success of the industry. For this, the centers of higher learning, universities, and R & D institutes should actively take part in rebuilding the R & D capabilities in our country. To achieve this objective, there should be a close and continuous interaction between the industry, academia and policy makers.

Another vital component that is needed today in the energy sector is *good governance.* This is a vital key to opening markets and attracting investments needed for growth. It is also critical for the development of a peaceful, more secure society, as it enhances the trust of the people in the institutions that influence their lives. Governance is an issue that touches all of us directly, as well as indirectly.

The energy sector is particularly prone to governance problems, due to high capital costs, long lead times, monopolistic situations, and tariffs, which are often socially and politically sensitive. While the hallmark of good governance is total and unalloyed transparency, the other important components include: *accountability; non-discrimination; predictability; participation; and stable, objective-independent regulation*.

Delivering the keynote address at the Energy for Development Conference, Geert van der Linden observes that "*we only need to look to places like Delhi, where local politicians were persuaded to make power sector reform an integral part of a larger and winning election strategy. So, not only were political objectives achieved, but also the objectives of the people for better power sector management*".

There is an urgent need to have a review of our energy portfolio, so that alternative forms of energy, renewable energy sources and nuclear energy are given their due place. There is little time to wait for perfection in energy policy to arrive at our doorstep. We must get started now and improve as we go forth. If we fail to meet the challenges of poverty reduction, energy security and climate change, it won't be because of a lack of opportunity. The opportunities to work together and to build on one another's successes and experiences are plenty.

V.K.Sibal

Effective Reservoir Development Using Ultra Short Radius Drilling and Completion

By J. David LaPrade*, Kamonchai Kesonpat* and S.R. Das**
*Well Flow Drilling Services, U.S. and **Hydrocarbon Resources Development Company, India

Introduction

During the past two decades, the oil and gas industry has witnessed a steady increase in the use of horizontal drilling to enhance well productivity. This trend will continue no doubt well into the 21st century as operators become increasingly aware of the benefits associated with drilling horizontally. As the database of horizontal projects has grown, operators have developed a better understanding of how and where horizontal wells should be utilized and which technology is best for a given application.

Economics will, in most cases, dictate the technology to be used. The implementation of lateral in mature fields requires substantial cost reductions over the methods most often used for drilling horizontal wells. Initiating a lateral from an existing wellbore is often much more cost effective than drilling a new well to kickoff point. Because of this, the use of Ultra-Short Radius (USR) Drilling and Completion technology to re-activate and rejuvenate existing fields is being widely regarded as a viable technology for Brownfield development.

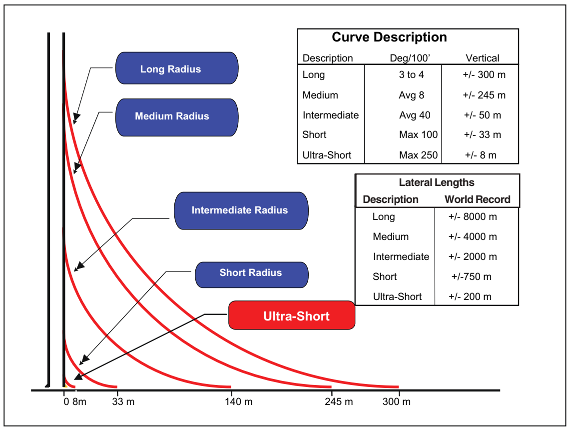
USR drainholes can also be used as an alternative to conventional completions of new wells. In many cases the cost is similar, but the advantage of putting a drainhole in the desired direction and at the desired depth can offer much greater benefit than perforating, acidizing and fracing a well.

In either case, whether it is a re-entry or a new well completion, horizontal drilling costs must be kept low to achieve acceptable economics. This paper describes USR, its applications, advantages and attributes, the USR drilling and completion technologies that are in use today and provides case histories of some of the wells where USR has been applied.

Most horizontal wells are currently drilled with conventional mud motor drilling systems or expensive rotary steerable systems. These systems are well-suited for drilling medium and long radius curves, but short radius and USR wells (particularly those with less than a 60' radius of curvature) are more difficult and risky.

What is USR?

By definition USR is Build Up Rates (BUR) of 100 to 250 degrees per 30m which equates to



Radius of Curvatures of 7 to 17m.

USR Can Be Used for a Variety of Applications, Including:

- Sidetracks from Vertical Wells in Tightly Spaced Fields;
- Sidetracks from Vertical Wells with Water Coning;
- Sidetracks from Vertical Wells with Near Wellbore Damage;
- Sidetracks into Channel Sands with Surrounding Shale;
- Exploitation of Attic Oil from a Vertical or Horizontal Wells;
- Exploitation of Low Producing Vertical or Horizontal Wells;
- Exploitation of Slim Hole Vertical or Horizontal Wells;
- Sidetracks from Water Injectors to Increase Injection Rates and Improve Sweep Efficiency;
- To Increase Injectivity and Deliverability in Gas Storage Reservoirs;

USR Offers the Following Advantages Over Conventional Horizontal Drilling Systems:

- USR drilling enables kick-off point to be at a depth very near, or in numerous cases, inside the objective hydrocarbon zone itself. This is due to its ultra short ROC of 14m as compared to over 300m in the above chart.

- Downhole Pumps or Gas Lift Valves, for instance, can be placed at or near the top of the payzone to maximize production efficiency and extend the productive life of the well due to lower abandonment pressures.
- USR drilling enables the landing of the well bore at a distance very near to original well bore in case of re-entry drilling from existing well i.e. Sidetrack, at 8-9m from original well bore as compared to a much greater distance of over 300m.
- Due to such low ROC, landing in thin targets near the existing well bore can be more easily achieved.
- It can eliminate the need of expensive electric wireline logging due to its ultra short vertical section and landing point from the original well bore from which geology, production and reservoir data are readily available.
- Tighter curves allow horizontal sections to be initiated nearer to the existing well bore with known data. Often times the objective pay zone is missed due to the presence of lenses or minor faults which are not identified by seismic or other field data.
- A more precise placement of the horizontal well bore allows for a more efficient development of closely spaced fields.
- Enables precision placement of a horizontal section across the objective hydrocarbon zone, at a very close distance to the kick-off point.
- The drilled distance from kickoff depth to end of curve depth is much shorter than conventionally drilled wells. USR curves require less than 20m of drilled hole as opposed to more than 500m.
- Shorter curves can in many cases save hundreds of thousands if not millions of dollars in drilling costs.
- In most cases kickoff points can be set below problem zones with water, gas caps or shales that can be difficult to drill due to hole stability. The entire curve and lateral can be drilled in the producing formation and below cap rock.
- Wellbores are slimhole which allows for less expensive Workover Type Rigs or Hydraulic Workover Hoists, smaller pumps and circulating systems to be used.

Capabilities of Current USR Technologies Include:

- Ability to Re-enter existing wells completed with 4-1/2" OD casing (or larger);
- Drills a consistent radius of curvature as small as 25 Feet;
- Multiple laterals can be drilled in opposing directions or in the same direction;
- landing at the same true vertical depth ("TVD") or at varying TVDs;
- Laterals ranging from 100' to 1,000' can be drilled;
- Multiple Laterals can be drilled from a single well-bore;
- Compatible with any drilling medium including air, Mist and Foam;
- Can be implemented with a drilling rig or service rig.

Current USR Drilling Systems

There are currently two systems used to drill short radius and USR wells.

USR Rotary Steerable System (USR RSS)

The only RSS developed for USR is a rotary steerable "push the bit" system that was developed by Amoco Production Company. Due to the low oil prices of the 1990's there was a need for a reliable cost effective USR drilling system that used the equipment and cost structures associated with workover and repair services. The need for a low cost system provided the impetus for the development of the initial USR technology.

Amoco's development criteria consisted of four main objectives:

1) develop a system low in cost to manufacture, repair and operate;
2) develop a system that will drill a predictable and consistent radius of curvature in a desired direction;
3) develop a system capable of operating from a service rig using a power swivel; and
4) develop a system capable of working inside 4.5" casing.

Following development of the prototype tools, more than 200 test wells were drilled at Amoco's Catoosa Test Facility near Tulsa, Oklahoma. Following testing, the technology was taken to the field where it was used to drill several wells at Amoco's Levelland Unit. These initial test wells proved the basic capability to install USR lateral drain holes at a reasonable cost with a top drive power swivel and workover rig.

Amoco's USR RSS has been tested, developed and improved to the point where it is a successful and commercially viable technology. Since the first quarter of 1995, more than 200 USR wells have been drilled with the system.

USR Mud Motors (USRM)

In 2007 Mud Motors were specifically designed and developed to drill 8-14m radii and achieve high build up rates (BUR) of 250° per 30m.

A key component required to drill USR wells with motors is that wellbore surveys must be taken near bit. Micro electronic tri-axial magnetic survey instrumentation can be placed only 2 to 2.5 m from the bit and provide inclination and azimuth readings. This reduced projection to the bit distance allows for a planar curve and smoother lateral section. Thin pay zones can be more accurately drilled with less wellpath tortuosity.

Both Curve Drilling and Lateral Drilling Motors have been developed with specially designed and manufactured Articulated Sections. These newly developed USRM have successfully drilled curves as short as 9m. An entire range of BUR can be achieved resulting in the desired ROC using varying sizes of kick pads for each type motor. The size and position of the kick pad will affect the BUR.

USRM combined with the miniaturized near bit surveying tools offers a USR system that delivers the accuracy necessary to land and steer within thin targets. Lateral lengths are similar in range to that of USR RSS.

As is the case with USR RSS the horizontal drainhole length of a USRM well is dependent on lithology, hole stability, compressive strength and radius of curvature.

USRM vs. USR RSS

The USRM system has distinct advantages over USR RSS. USRM totally eliminates drill pipe rotation while drilling the curve and reduces the total pipe rotation when drilling the horizontal section by up to 90%. USRM simply extends the useable life of various types of drill pipe used for USR and short radius drilling. USRM allows for a wide range of drill pipe for USR drilling.

Considerations in Well Planning

One key advantage associated with working within a producing field and existing wellbores is access to geological maps, core data, reservoir characteristics, well logs, wellbore schematics and well completion reports. The more complete the information, the better the chance of an operator achieving an economic success.

When selecting a target interval and screening a wellbore for suitability as a re-entry candidate, consideration should be given to overlying formation properties. Many times, problem formations such as reactive shales, washouts and gas or water zones exist above the zone of interest. While the application of USR drilling can often allow the operator to avoid drilling through these potential problems, consideration should be given early in the planning process to determine how they can be avoided. In addition, high concentrations of pyrite, anhydrite or chert can drastically affect penetration rates and should be avoided when possible.

The radius of curvature, which may range from 8 to 15m, is determined by up hole conditions, the desired lateral displacement, thickness of the target interval and completion requirements. The kickoff point is determined by the radius of curvature, desired landing depth of the curve and location of casing collars and perforations.

Once all data is reviewed, a proposed wellpath is chosen, the kickoff point is selected and a wellbore preparation schematic is prepared.

The planning process is not complete without careful review of the drilling medium to be used. Factors to be considered should include formation pressures, hole stability, drill cuttings transport, fluid flow regime, lithology, the presence of corrosive gases and fluids and fluid compatibility with formation water.

Borehole problems can be considerably more severe in a horizontal well than in a vertical well. Therefore, drilling fluids should be tailored to the target formation to ensure maximum production.

The curve is initiated at a predetermined kickoff depth from either a cement plug, whipstock or from formation below the casing shoe.

The major steps in a re-entry operation when the target is behind pipe include well preparation, drilling the curve, drilling the lateral and completing the well.

Completion of a USR Well

Articulated and Rotatable Pre-packed Sand Screens "SnakeScreen™" have been developed for use in USR wells where screened completions are required. These screens are run prior to displacing the drilling fluid and independently of a completion packer. After the screens are landed to TD a completion packer is then run separately. The key advantages to these screens are:

- Articulated, Rotatable and Pre-Packed
- 80% Screenage per 30' Joint
- Articulation Every Meter Serves as Standoff and Protects Screen while Being Rotated to TD.
- Rotation Reduces the Risk of Friction Lockup and Landing Completion Short of Objective
- Full 2" ID Allows for Clean Out with CTU
- Designed to Sand Particle Size

Equipment Requirements

Minimal surface equipment requirements give USR drilling an advantage over conventional mud motor technology. The rig is usually a standard service/workover rig capable of pulling double stands with an adequate hook load capacity of 60,000 lbs. over string weight and equipped with pipe racks and catwalk. Handling tools should include open faced tubing tongs with torque gauge, 2-7/8" bottleneck type elevators, an accurate weight indicator, a mud pump gauge on the rig floor and an adequate supply of spare parts.

Other equipment should include a 500 bbl frac tank for water storage, a 100 bbl mud mixing pit, a 200-400 bbl working pit, a lined sump pit, a high frequency linear shale shaker, a tri-plex pump, a standard workover BOP stack and accumulator, a power swivel, a workstring (2-7/8" PH-6, AOH or DSS), 3-4 light plants and a 60 KW generator. In the event hydrogen sulfide is present, a safety trailer containing air packs and fire extinguishers should be on location.

The power swivel is a key piece of the surface equipment. A remote control panel with electric controls over air or hydraulics and a back brake system is required. The remote controls should have an accurate torque gauge. Torsional control (both left and right) is critical. The swivel must respond immediately to the remote controls.

The exact equipment package may vary depending on formation pressure, depth, casing size, the drilling medium used, location restrictions and operator and/or state requirements.

Conclusion

USR Drilling offers operator a viable alternative technology that is especially well suited for use as a re-entry tool in mature highly developed “Brownfields” or as a completion technology for new wells.

Case Histories

Case Histories 1 through 11 offer a sampling of the wells drilled with the RSS and USRM Systems and indicate the capability and versatility of the system. Exact production increased can not be given due to confidentiality. Production increases have been noted where confidentiality allows.

Completion entailed sweeping the lateral with coiled tubing to spot acid. Total job time was approximately 3 weeks for the horizontal operation including well preparation and completion. Production resulted in a five fold increase over what is achieved from a vertical well.

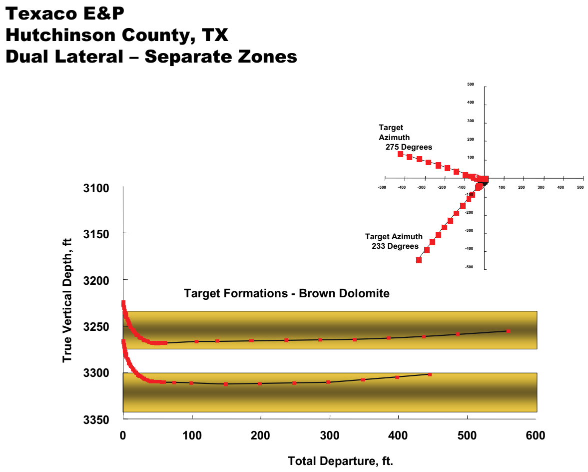


Fig. 1. illustrates a well drilled for Texaco in Hutchinson County, Texas. Two 4.5" laterals were drilled with a polymer based mud to complete a newly drilled vertical hole.

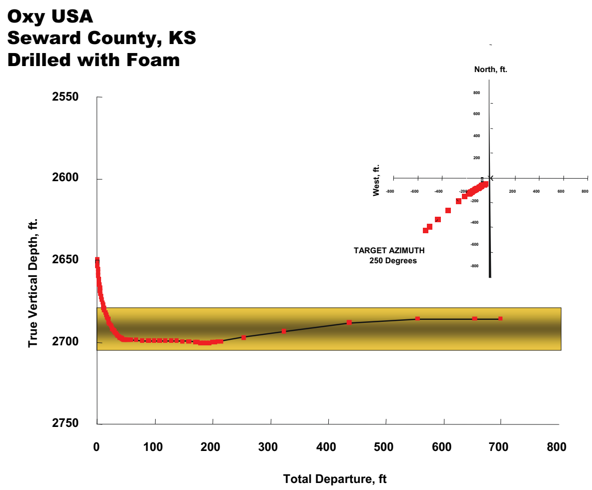


Fig. 2. illustrates a well drilled for Oxy USA in Seward County, Kansas. One 4.5" lateral was drilled with foam as an extension for a new vertical hole. Completion included a coiled tubing/acid treatment. Total job time for the horizontal operation was 7 days of daylights only.

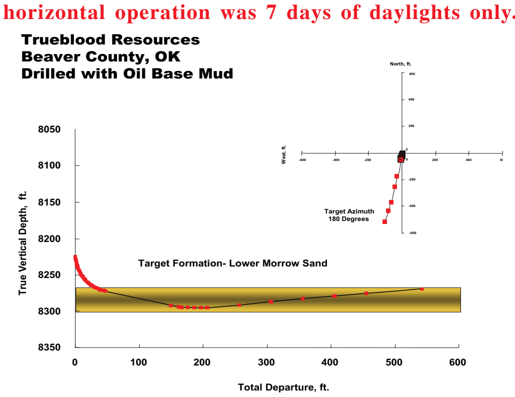


Fig. 3. illustrates a well drilled for Trueblood Resources in Beaver County, Oklahoma. One 3.875" lateral was drilled inside 4.5" casing as a new well completion. The lateral was drilled with an oil-based mud. No completion data is available. Total job time for the horizontal operation was 6 days.

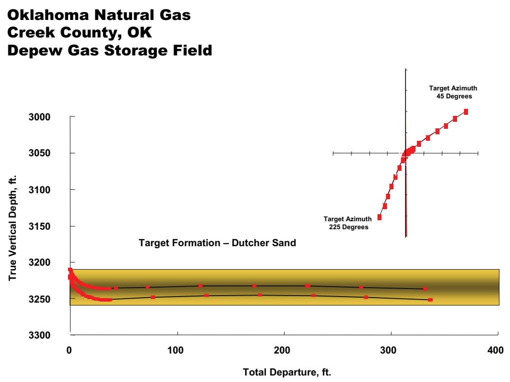


Fig. 4. illustrates a well drilled for Oklahoma Natural Gas in Creek County, Oklahoma. This was a re-entry inside 7" casing and two laterals were drilled in opposing directions. Radius of curvature was 27 feet and 28 feet respectively. The laterals were drilled with a water based balanced mud system. Total job time for the horizontal work was 3-1/2 days. Gas deliverability increased 5 fold.

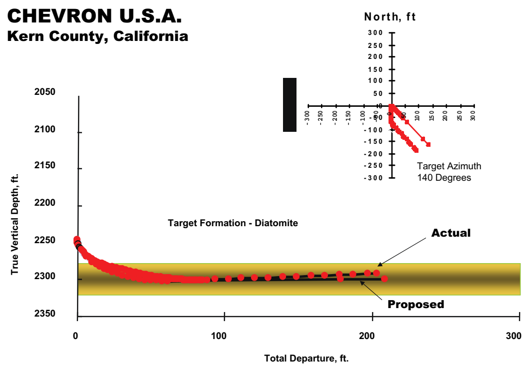


Fig. 5 . illustrates a well drilled for Chevron USA in Kern County, California. This was a re-entry inside 7" casing. Up hole perforations were preserved by sectioning below the perforations and drilling with a calcium carbonate system that temporarily sealed the perforations. Completion included running two frac subs in a solid liner string and applying a 200,000 lb. sand frac stimulation. Four days were required to drill the horizontal segment.

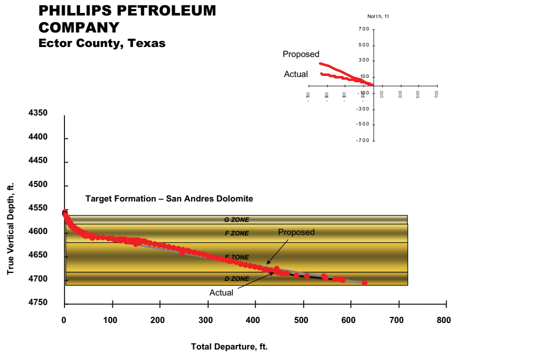


Fig. 6. illustrates a well drilled for Phillips Petroleum in Ector County, Texas. This was a re-entry inside 5.5" casing. The horizontal segment was drilled with a weighted water based mud system due to working in a carbon dioxide flood. Completion entailed jetting acid through coiled tubing. Total job time including wellbore preparation, drilling and completion was 3 weeks. Increase in production was from 0 to 84 BOPD.

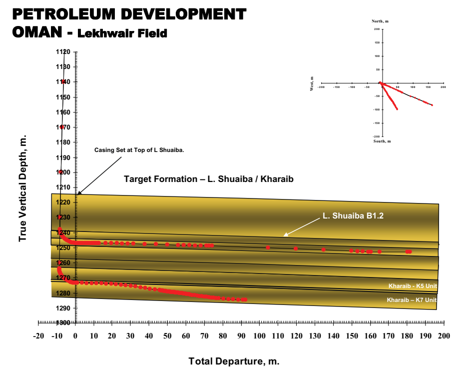


Fig. 7. illustrates a well drilled for Petroleum Development Oman. Two horizontal injectors were drilled with a polymer based mud to increase injectivity rates and improve sweep efficiency. Completion entailed the use of an articulated hydraulically actuated kicksub to re-enter each leg and displace drilling fluids until well flowed for natural cleanup. Total job time including wellbore preparation, drilling and completion was 17 days. Injectivity increase three fold.

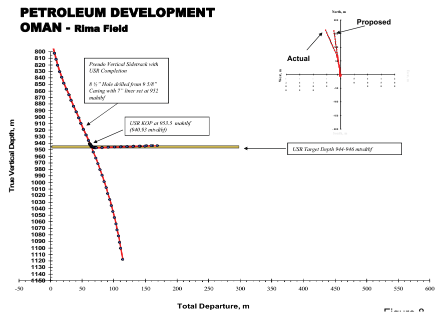


Fig. 8. illustrates a well drilled for Petroleum Development Oman. Existing well was watered out and completed with gravel pack. The objectives was to target by passed oil. An 8 ½" pilot hole was drilled to land approximately 80m of displacement away from vertical well. Logs were run and indicated 95% oil saturation in top 6m of formation. A 7" liner was topset one meter into the reservoir and a USR drilled with a horizontal section of approximately 100m. Total job time including pilot hole, logging, running liner, and USR section and completion was 21 days. Production increase was significant from 0 to more than 400BOPD.

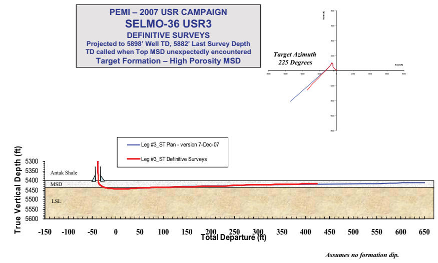


Fig. 9. illustrates a well drilled for Petroleum Exploration Mediterranean in SE Turkey. Existing well had 7" topset two meters in reservoir and open hole completion. The open hole was plugged back and a USR well was drilled exposing approximately 450' of reservoir. The well was completed open hole after acid stimulation with drill pipe. Total job time including wellbore preparation, drilling and completion was two weeks

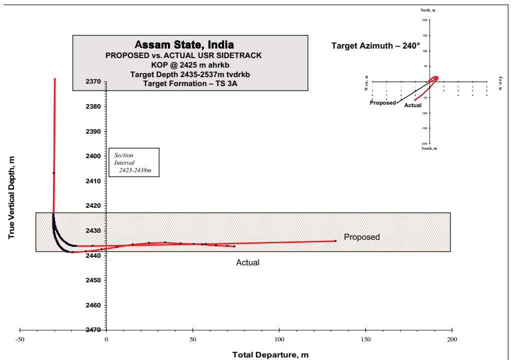


Fig. 10. illustrates a well drilled in Assam State in the North Eastern part of India. The horizontal section was drilled with non damaging water based drilling fluid. The well was completed with 2 3/8" slotted liner in the horizontal section. On activation the production increment from the well was about 16 times the production before USR operations.

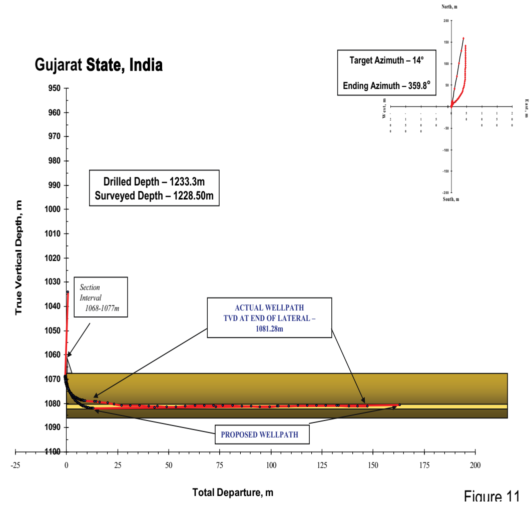


Fig. 11. illustrates a well drilled in Gujarat State on the West coast of India. The USR horizontal section was drilled with non damaging water based drilling fluid. The well was completed with a 3 1/8" pre-packed articulated and rotatable sand screen specially developed for USR completions. On activation the production increment from the well was 6 times the production before USR operations.

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1-D Basin Modelling: Case Study from Upper Assam Basin

N. Mathur
R & D Department, Oil India Limited, Duliajan 786 602, Assam
Email nmathur@oilindia.in

Introduction

Basin Modelling is a tool used by geoscientists to quantitatively describe complex geological systems. Basin models are used during exploration for prediction of amount of hydrocarbons generated, migrated and accumulated in a basin. Basin modelling can be done in one, two or three dimensions.

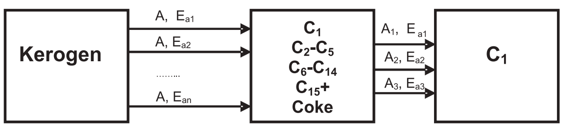
1-D modelling is concerned with thermal maturity, compaction, petroleum generation and expulsion in a single well. The outputs of 1-D models for several wells are used for creating 2-D and 3-D models. The input data required for a 1-D model are as follows (1).

- Stratigraphy i.e. depth and age of formation tops
- Geothermics i.e. measured temperature data or heat flow values for thermal calibration
- Maturity data for calibration of modelled maturity parameters e.g. Rock Eval Tmax or Vitrinite Reflectance
- Lithology type for compaction, fluid flow and flow calculations
- Kinetic parameters to predict the amount of hydrocarbon generated from a source rock
- Pressure to estimate expulsion and migration
- Crustal thickness variation to estimate the amount of section eroded at unconformities

The conversion of organic matter viz. kerogen to oil is considered a first order reaction (2), (3) & (4), whose rate of reaction is given by $-dC/dt = kC$, where C is the concentration of kerogen and t is time. The rate constant, k, of the reaction is given by the Arrhenius equation,

$$k = A * Exp(-E_a/RT)$$

where A is the frequency factor, E_a is the activation energy of the reaction, R is the universal gas constant and T is the temperature of reaction in Kelvin. The kinetic parameters refer to the set of activation energies, E_a's and the frequency factor, A, for a particular kerogen. It is generally assumed that a number of reactions, with different activation energies, take place simultaneously during the breakdown of kerogen, as shown below.



In a five fraction model (5),(6) considered here, degradation of kerogen results in three unstable fractions corresponding to oil viz. $C_{15}+$, C_6-C_{14} and C_2-C_5 and two stable fractions, methane (C_1) and coke. The three unstable fractions further breakdown to produce methane. Thus, there are n parallel reactions for breakdown of kerogen and three parallel reactions for breakdown of each unstable fraction. The kinetic parameters for standard Type I, II and III kerogen are available in the literature; however, it is advisable to use the kinetic parameters for the kerogen from the basin being modelled, as these parameters give more accurate results.

Kinetic parameters for a source rock are measured in laboratory using Rock Eval (7). This is a pyrolysis instrument, which simulates the natural hydrocarbon generation process. In a standard cycle of the instrument, the source rock sample is first heated at 300ºC for 2 minutes to give S_1, hydrocarbons present in the rock. It is then heated from 300ºC to 600ºC at a rate of 25ºC/min to give S_2, residual hydrocarbon generation potential of the rock and Tmax, a maturity parameter. In addition, it also measures the total organic carbon (TOC) content of the rock and determines parameters like hydrogen index ($HI = S_2*100/TOC$) and production index ($PI = S_1/(S_1+S_2)$). In order to measure the kinetic parameters, the organically rich, immature source rock samples are pyrolysed in Rock Eval at three different heating rates (say, 2ºC/min, 5ºC/min and 15ºC/min) and the pyrolysis curves are used as an input to the kinetics software (2). A source rock is considered organically rich if TOC is more than 2% and immature to have generated any hydrocarbons if Tmax < 435ºC.

Typically, 1-D modelling is first carried out for a drilled well where sufficient data are available for calibration. Rock Eval analysis of source rocks yields additional data on their organic richness, maturity and hydrocarbon generation potential. However, since the drilled wells are generally on structural highs, away from hydrocarbon kitchens, the calibrated 1-D model is extended to pseudo wells in depocentres to determine the maturity and hydrocarbon generation in hydrocarbon kitchen. The output of a 1-D model includes the following; burial history curve of each formation, fluid pressure, porosity and temperature of different layers of rocks, maturity of rocks, cumulative hydrocarbons generated, expelled oil and gas, gas:oil ratio, residual hydrocarbons, hydrogen index, production index and expulsion history of each source rock.

This paper describes the 1-D modelling carried out for a deep well in Samdang oilfield of Upper Assam basin.

Experiment

The Upper Assam basin has at least three potential source rocks belonging to Barail Formation (Oligocene), Kopili Formation (Upper to Middle Eocene) and Lakadong member of Sylhet Formation (Lower Eocene). Source rock samples were analyzed using Rock Eval 6 and organically rich and immature rocks (Table I) were selected from each of the formation for determination of kinetic parameters.

Table I: Rock Eval analysis results of source rocks used for determination of kinetic parameters

Sample	Formation	S_1 (mg/g)	S_2 (mg/g)	Tmax (ºC)	TOC (%)	HI	PI
SMDBB	Barail	3.33	152.96	421	48.79	314	0.02
KTHKO	Kopili	0.70	33.61	412	15.78	213	0.02
CBA7LK	Lakadong	6.46	109.63	423	26.17	419	0.06

The samples were extracted in dichloromethane to remove bitumen present in the rocks. Each sample was pyrolysed using Rock Eval 6 at three different heating rates, 2ºC/min, 5ºC/min and 15ºC/min. The pyrolysis data were exported to OPTKIN (Beicip-Franlab, France) software and kinetic parameters viz. distribution of activation energies and the frequency factor were determined. The kinetic parameters along with the well data were used as an input to GENEX (also from Beicip-Franlab, France), the 1-D modelling software. Rock Eval analysis of source rocks from Samdang well was carried out and parameters Tmax, HI, PI and S_1/TOC were used for calibrating the model.

RESULTS AND DISCUSSION

Input Data

In Upper Assam basin, the reservoirs are present in Girujan, Tipam and Barail Formation with Girujan also acting as a regional seal. Similarly, Lakadong member of Sylhet Formation is a prolific reservoir with Kopili Formation acting as a seal. Hydrocarbons are also being produced in increasing quantities from Langpar Formation. The Samdang well has been drilled to a depth of 4932 m in to the Langpar Formation of Paleocene age. The stratigraphic and lithologic data for the Samdang well is shown in Table II. Porosity and pressure data used for checking the expulsion of hydrocarbons and compaction of sediments is shown in Table III. Measured temperature data used for thermal calibration of the model is shown in Table IV.

Table II: Stratigraphic and Lithologic data for Samdang Well

Age	Formation		Lithology
Pleistocene	Alluvium		Sand – 80% Shale – 20%
Pliocene	Dhekiajuli		Sand – 80% Shale – 20%
	Namsang		Sand – 60% Shale – 40%
	Girujan		Sand – 20% Shale – 80%
Miocene	Tipam		Sand – 90% Shale – 10%
Oligocene	Barail 1/3		Sand – 20% Shale – 80%
	Barail 4/8		Sand – 85% Shale – 15%
Eocene	Kopili		Sand – 20% Shale – 60% Silt – 20%
	Sylhet	Prang/Narpuh Member	Shale – 70% Limestone – 30%
		Lakadong Member	Shale – 65% Sand – 25% Limestone – 10%
Palaeocene	Langpar		Shale – 65% Sand –30% Limestone – 5%

Table III: Porosity & Pressure Data for Samdang Well

Depth (m)	Porosity(%)	Pressure (MPa)
4712.0	6.0	45.14

Table IV: Thermal Data for Samdang Well

Depth (m)	Temp (ºC)
2113.0	75.0
4565.9	124.4

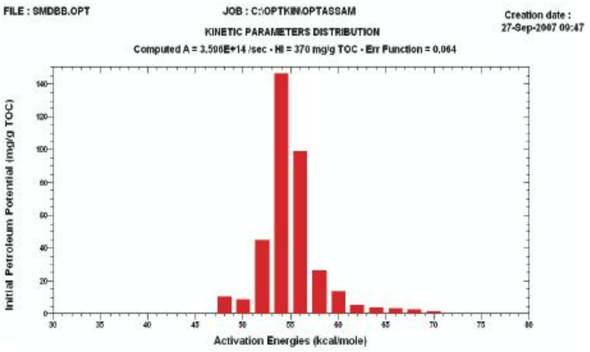


Fig. 1. Distribution of activation energies for source rock from Barail Formation

The kinetic parameters for the three source rocks viz. SMDBB, KTHKO and CBA7LK from Barail Formation, Kopili Formation and Lakadong member of Sylhet Formation respectively are shown in Figures 1, 2 & 3 respectively. Each of the source rocks shows a broad distribution of activation energies, typical of organic matter with significant terrestrial input. This is consistent with the fact that most of the oils in the basin are of terrestrial origin (8). A five fraction kinetic model, as described above, has been used.

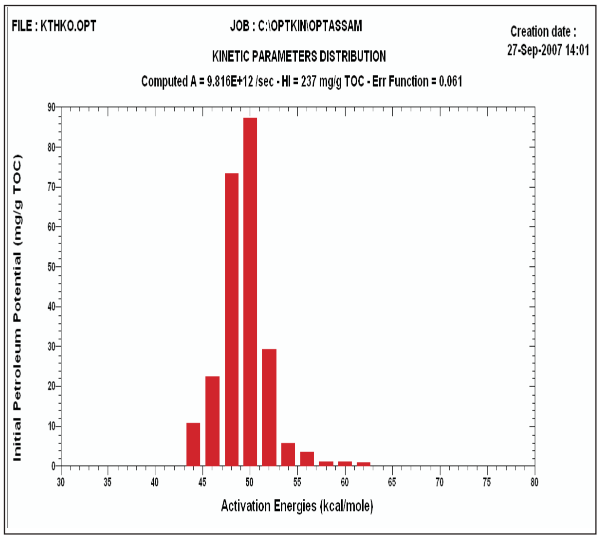


Fig. 2. Distribution of activation energies for source rock from Kopili Formation

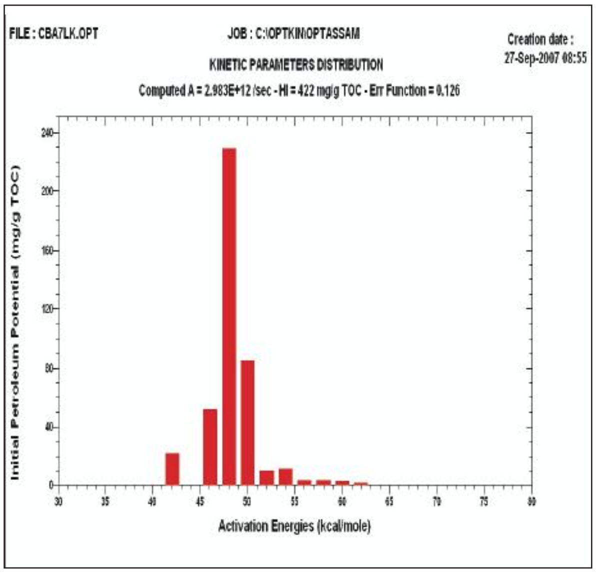


Fig. 3. Distribution of activation energies for source rock from Lakadong member of Sylhet Formation

The Barail Formation has been considered a source as well as reservoir, Kopili Formation as a source and seal whereas Lakadong member of Sylhet Formation as source and reservoir for modelling purpose (Table V). In different formations of Upper Assam basin, organic poor strata alternate with organic rich strata. The source rock thickness considered here is the cumulated thickness of only the organic rich strata and is, therefore, less than the formation thickness. The initial TOC modeled here also corresponds to the organically rich strata only. The expulsion saturation is the fraction of pore volume that must be occupied by petroleum for expulsion to begin. Both initial TOC and the expulsion saturation have been determined by trial and error so that the present day HI, PI and S_1/TOC match with the modelled values. The geochemical data from Samdang well, used for maturity, kinetic and expulsion calibration of the model, is shown in Table VI.

Table V: Source rock input data for Samdang Well

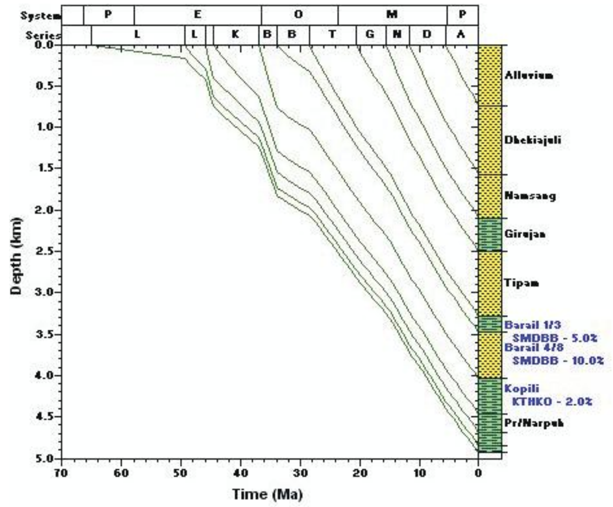
Formation	Source Rock	Initial TOC (%)	Source Rock Thickness (m)	Expulsion Saturation (%)	Petroleum History
Barail 1/3	SMDBB	4.0	50	5.0	Source + Reservoir
Barail 4/8	SMDBB	30.0	120	10.0	Source + Reservoir
Kopili	KTHKO	2.5	15	2.0	Source + Seal
Lakadong	CBA7LK	10.0	64	10.0	Source + Reservoir

Table VI: Geochemical data for Samdang Well

Depth (m)	S_1 (mg/g)	S_2 (mg/g)	Tmax (ºC)	TOC (%)	S_1/ TOC	HI	PI
3641	2.56	83.49	416	23.06	11.1	362	0.03
4190	0.22	2.26	429	1.56	14.1	146	0.09
4826	0.86	6.73	451	4.17	20.6	161	0.11

Output Results

Using the above input data, the 1-D basin model was prepared using GENEX. Figure 4 shows the burial history curve for modeled well. Erosion has not been considered during the entire sedimentation history of the basin as there is no evidence of significant erosion. Since no rock layer has experienced overpressure in this well, the fluid pressure is a function of burial and is equal to the hydrostatic pressure. Figure 5 shows the fluid pressure versus depth curve. The measured bottom hole pressure of 45.14 MPa (Table III) at a depth of 4712 m matches very closely with the modeled pressure. Due to compaction the porosity of each formation decreases with depth and follows the 1/Z law. The variation of porosity is different for different rocks and depends on its lithology. Figure 6 shows the variation of porosity versus depth as determined by the model. The measured value of porosity of 6% (Table III) at a depth of 4712 m matches closely with modeled value.



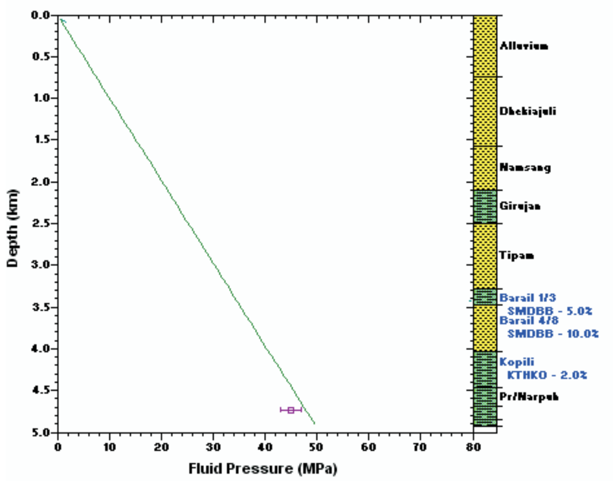


Fig. 5. Variation of modeled pressure with depth

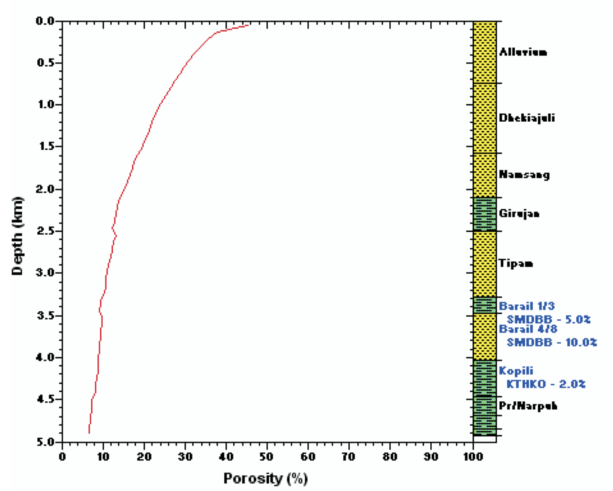


Fig. 6. Compaction of sediments of different lithologies with burial

The present day measured temperatures are used for thermal calibration of the model. Any discrepancy between calculated and measured temperature is due to incorrect values of thermal conductivities, radiogenic heat flow and bottom heat flow. In this model, default values of radiogenic heat flow and thermal conductivity have been taken and bottom heat flow has been calculated after thermal calibration. The measured (Table IV) and calculated temperatures are in agreement as evidenced by the temperature versus depth curve (Figure 7), thus validating the thermal calibration. Using this thermal calibration, heat flow versus depth is calculated (Figure 8). A heat flow value of approximately 35mW/m^2 is obtained at the bottom of the sedimentary column.

Variation of maturity parameter Tmax with depth (Figure 9) is used to check the accuracy of maturity thermal reconstruction and kinetic reconstruction. The measured Tmax values (Table VI) are in close agreement with values calculated by the model for both Kopili Formation and Lakadong member of Sylhet Formation. This confirms that both the thermal data for the well and the kinetic parameters determined for these source rocks are correct. However, there is a difference of about 7ºC in the measured and calculated Tmax values for Barail Formation. Since thermal data are same for both Barail Formation and deeper formations and a good match has been obtained for measured and calculated values of Tmax for the latter, the thermal data is accurate. Kinetic parameters have been determined separately for the source rocks from three formations and it is likely that kinetic parameters for Barail Formation are not very accurate. As we shall see later, this difference in Tmax values is insignificant for correctly modelling hydrocarbon generation.

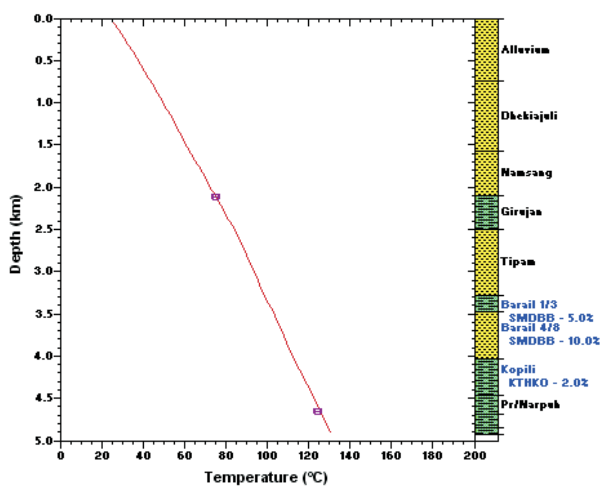


Fig. 7. Measured temperature used for thermal calibration

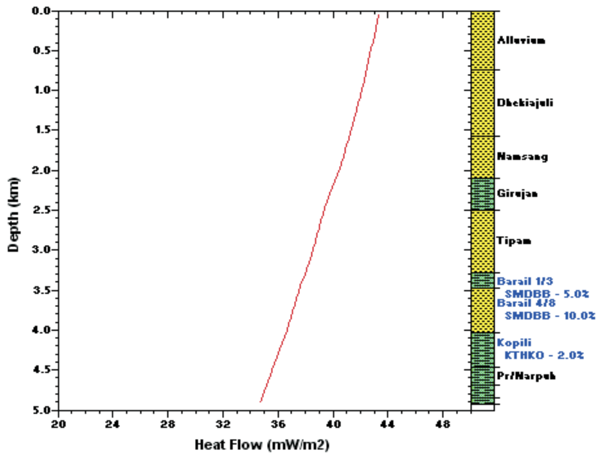


Fig. 8. Heat flows calculated from thermal calibration

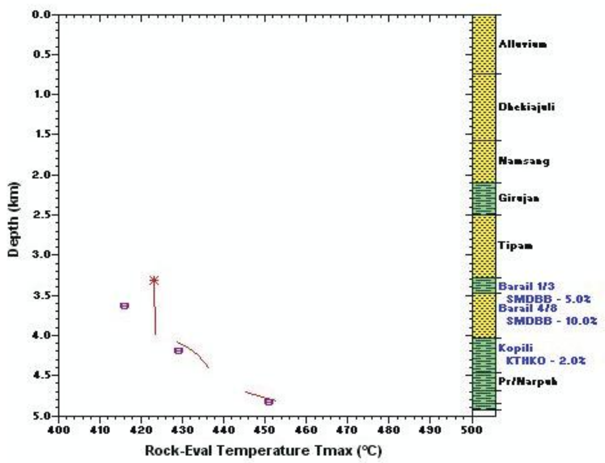


Fig. 9. Variation of Tmax with depth used for maturity and kinetic calibration

HI is a measure of the residual hydrocarbon generation potential of the source rock at the level of thermal stress to which it has been exposed. Like Tmax, the variation of HI is different for source rocks with different kinetic parameters, for similar thermal stress. Thus, variation of HI with depth is used for checking the accuracy of both thermal reconstruction and the kinetic reconstruction. Figure 10 shows the modeled variation of HI with depth where measured values of HI (Table VI) have also been marked. It can be seen that model has been able to predict fairly accurately the actual HI values of the source rocks. The ratio S_1/TOC is used to reconstruct expulsion and organic richness. Figure 11 shows the plot of S_1/TOC versus depth. By trial and error, the expulsion saturation for the source rocks were set at 5%, 10%, 2% and 10% and initial TOC contents were set at 4.0%, 30.0%, 2.5% and 10% for Barail 1/3, Barail 4/8, Kopili and Lakadong source rocks respectively (Table V). Using these values of expulsion saturation and initial TOC content, the modeled values of S_1/TOC match very closely with measured values of 11.1, 14.1 and 20.6 at depths of 3641m, 4190m and 4826m respectively (Table VI). PI is a further check on maturity, expulsion saturation and initial TOC content of the source rock. Figure 12 shows the variation of PI with depth. The measured values at three depths (Table VI) are also plotted. It can be seen that all the parameters have been correctly set resulting in close agreement between measured and calculated values.

Thus, it can be seen that the 1-D model has been properly calibrated using stratigraphic and lithological data, pressure and porosity data, thermal data, kinetic parameters specific to the source rocks and geochemical data. After calibration, the model is able to determine amount and type of hydrocarbons generated and expelled by the source rocks, generation and expulsion history of the source rock and the residual hydrocarbons present in the source rock.

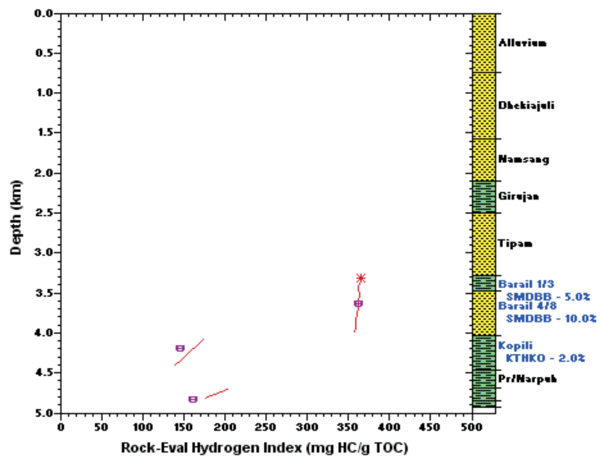


Fig. 10. Variation of HI with depth used for maturity and kinetic calibration

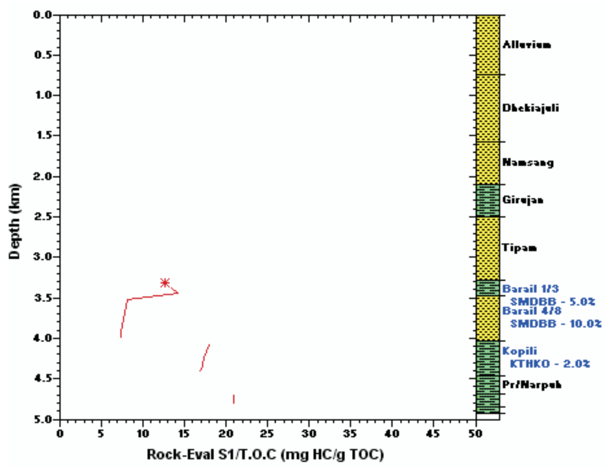


Fig. 11. S_1/TOC used for expulsion calibration

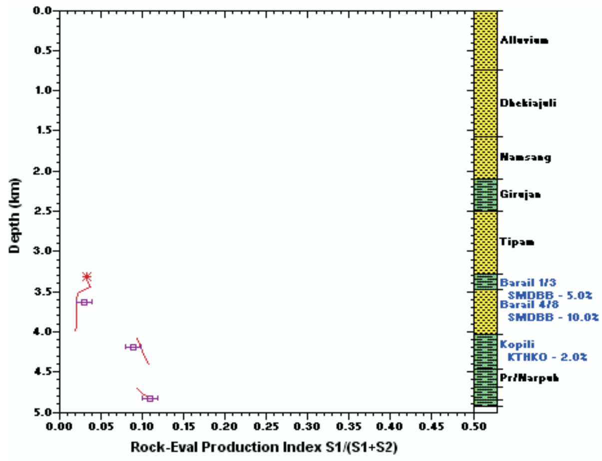


Fig. 12. PI used for maturity and expulsion calibration

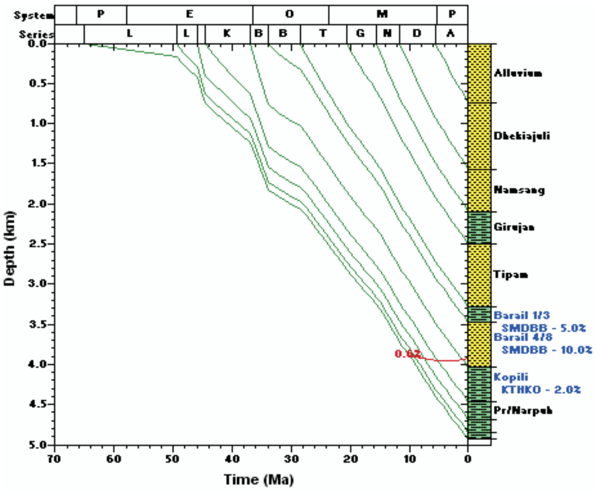


Fig. 13. Maturity windows for the well

Figure 13 shows the maturity windows for the Samdang well using calculated vitrinite reflectance values. Onset of oil generation occurs at a vitrinite reflectance value of 0.6% and peak oil generation at a value of 1.0%, In Samdang well, oil generation starts at a depth of approximately 3900m. Thus, most of the Barail source rocks are immature in this well. However, Kopili and Lakadong source rocks have attained maturity in this well but are not yet at the peak maturation stage. The plot of kerogen transformation ratio against depth (Figure 14) shows how much of organic matter has been converted into hydrocarbons at various depths. The kerogen transformation ratio for the Barail source rocks is only 4 - 6% as these rocks have hardly entered the oil window. For Kopili source rocks, the kerogen transformation ratio is 30-50% and for Lakadong source rocks, it is 65-70%. Figure 15 is a display of the petroleum generation history of the source rocks in the sedimentary column. The type of petroleum generated, above a certain value of transformation ratio (here, 10%), is highlighted by coloured areas. In Samdang well, only C_{15+} fraction has been generated in the Kopili and Lakadong source rocks, where the transformation ratio is more than 10%, hence only a single colour is displayed. The hydrocarbons generated for Barail source rocks are not displayed as the transformation ratio is less than 10%. Figure 16 shows the total hydrocarbons generated by each source rock. All the source rocks including the most mature Lakadong source rock (Tmax ~ 451ºC) have generated only the C_{15}+ fraction (denoted by blue color). Further cracking of C_{15}+ fraction to lighter hydrocarbons has not yet taken place. Figure 17 shows the amount of hydrocarbons expelled by each source rock. Lakadong source rock has generated more than 32 mg/g and expelled around 29 mg/g of hydrocarbons. Kopili source rock has generated 3 mg/g and expelled around 2 mg/g of hydrocarbons. Barail has generated 8 mg/g and expelled 6 mg/g of hydrocarbons.

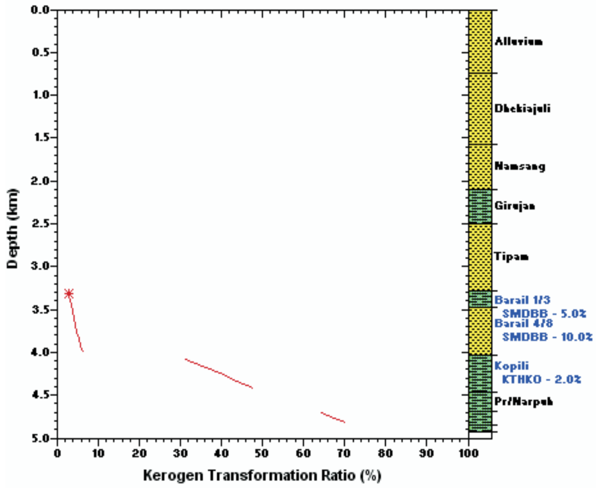


Fig. 14. Kerogen transformation ratio for the source rocks

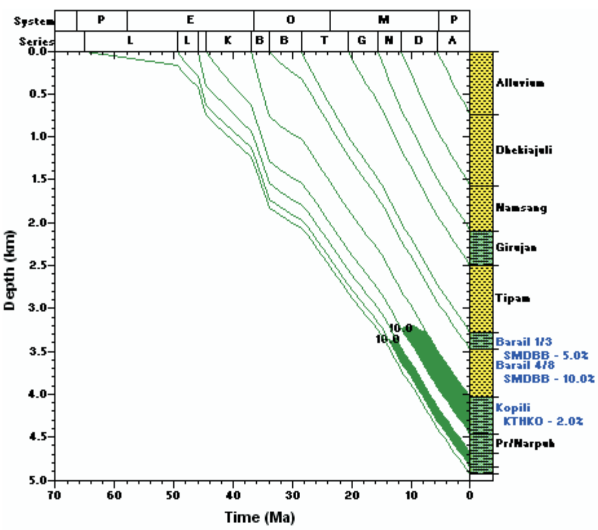


Fig. 15. Hydrocarbon generation window for the well

Thus, even though Barail source rock is very rich with good hydrocarbon generation potential, it has not generated and expelled significant amount of hydrocarbons at this depth. Kopili source rock is neither organically rich nor does it have good hydrocarbon generation potential. Lakadong source rock has generated and expelled substantial amount of hydrocarbons. The difference of total and expelled hydrocarbons is the residual hydrocarbons that are still present in the rock. The S_1 value, as measured by Rock Eval, corresponds to roughly half of the calculated residual hydrocarbons. This is because of evaporation losses before the measurement. Figure 18 shows the residual hydrocarbons for different source rocks which roughly match with half of determined S_1 values (Table VI).

Expulsion history plot is particularly useful for explorationist as one can determine the amount and type of hydrocarbons expelled in different time slices. One of the important criteria for a trap to be filled up is that the trap formation must have taken place before the expulsion of hydrocarbons started. Thus, using this plot and history of trap formation, the amount of hydrocarbons accumulated in a trap can be determined. Figures 19, 20 & 21 show the history of expelled hydrocarbons for Lakadong, Kopili and Barail source rocks. The expulsion of hydrocarbons started about 23 MY back for Lakadong source rock and so far a cumulated amount of 29 mg/g of hydrocarbons have been expelled. Similarly, for Kopili and Barail Formations, expulsion started 8 & 9 MY back respectively and they have expelled 2 & 6 mg/g of cumulated hydrocarbons respectively.

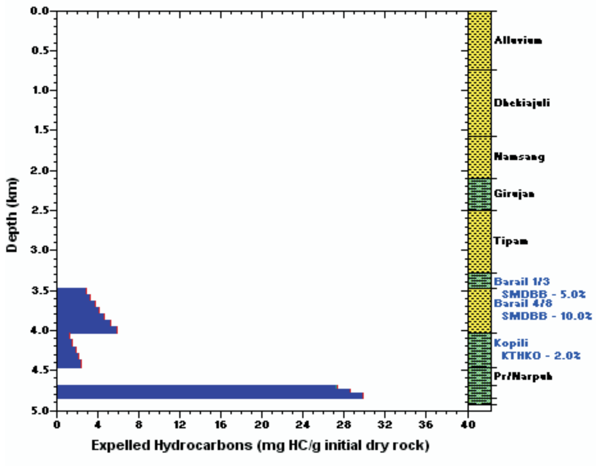


Fig. 17. Hydrocarbons expelled by each source rock

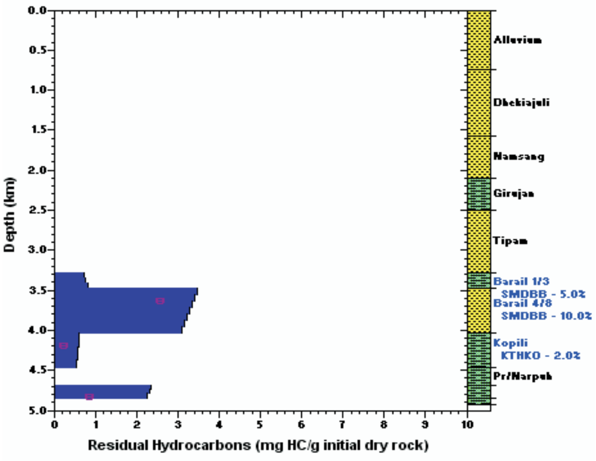


Fig. 18. Residual hydrocarbons present in each source rock

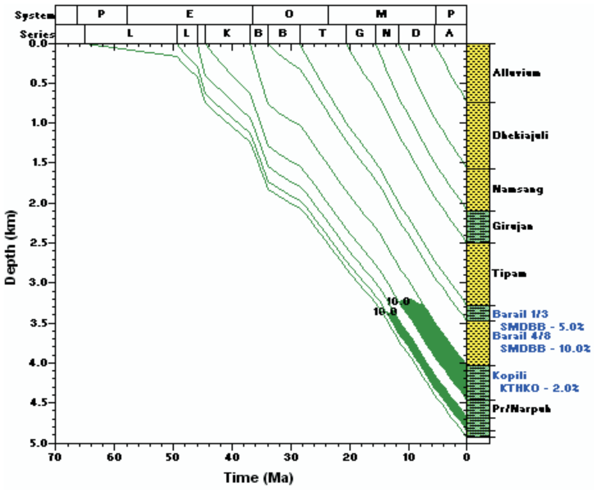


Fig. 16. Total hydrocarbons generated by each source rock

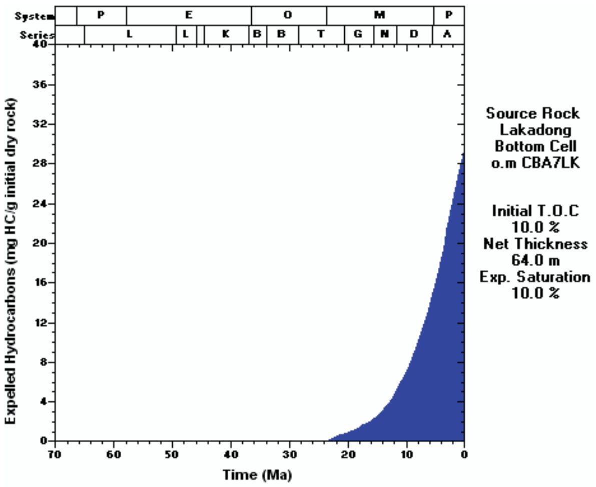


Fig. 19. Expulsion history of Lakadong source rock

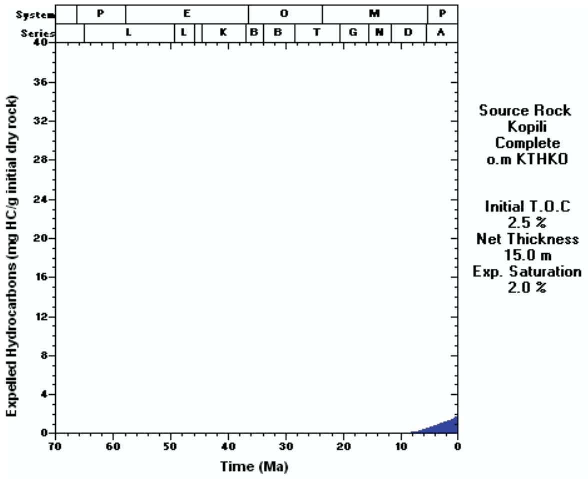


Fig. 20. Expulsion history of Kopili source rock

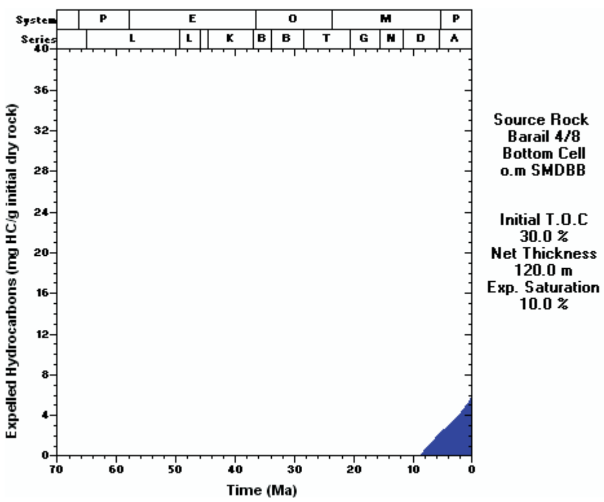


Fig. 21. Expulsion history of Barail source rock

Conclusions

A 1-D model has been prepared and calibrated for Assam basin using data from a deep well. The kinetic parameters for the three different source rocks of Assam basin namely Barail, Kopili and Lakadong have been determined using Rock Eval analysis and OPTKIN software. Stratigraphic, geochemical, pressure and temperature data for a deep well from Samdang area has been taken for thermal, maturity and hydrocarbon generation calibration. After running the model using GENEX software, parameters like heat flow, expulsion saturation, initial TOC of source rocks were suitably determined. The 1-D model has now been calibrated and is able to correctly predict the amount of hydrocarbons generated and expelled from different source rocks and also the history of hydrocarbon generation and expulsion. Extending this model to pseudo wells in the depocentre of the basin will help in determining the maturity and hydrocarbon generation in the Kitchen area. The output 1-D model can be used to prepare 2-D and 3-D models.

Acknowledgements

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Hydrocarbon Prospects in Sub Trappean Mesozoic Deccan Syneclise Basin, India: Evidences from Surface Geochemical Prospecting

C. Vishnu Vardhan[1*], B. Kumar[1], C.J. Kumanan[2] and Devleena Mani[1]
[1]National Geophysical Research Institute, Hyderabad – 500 007
[2]Center for Remote Sensing, Bharathidasan Universtiy, Tiruchirappalli - 620023
[*]Presently with Hardy Exploration and Production (India) Inc. Chennai – 600 004
E-mail: vishnucvardhan@gmail.com ; baleshk@yahoo.com

Abstract

The Mesozoic sediments contribute around 54 % of the oil and 44% of the gas reserves of the world[1]. Indian Mesozoic basins occupy an area of about 400x10^3sq.km and are characterized as Frontier Basins under category II - IV. These basins are mostly overlain by the Deccan Traps of the Late Cretaceous age and are least explored. Deccan Syneclise is one of the largest Mesozoic basins in India, covering an area of ~ 273x10^3sq.km. Geophysical studies have inferred hidden sub trappean Mesozoic sediments with thickness upto 2.5 km. It is considered that requisite heat generation due to Deccan Trap volcanism soon after the Cretaceous sedimentation may have acted as a catalyst in hydrocarbon generation. Surface geochemical prospecting surveys along with carbon isotopic studies have been used to assess hydrocarbon generation potential of the part of the basin. The area adjoining Nandurbar in Narmada-Tapti region of Deccan Syneclise was selected for geochemical studies where geophysical studies have shown considerable sediment thickness. Surface geochemical studies indicate the generation of light gaseous hydrocarbons, C_1 and åC_{2+} in the range of 3 to 1187 ppb and 1 to 1449 ppb, respectively. The carbon isotopic signatures of selected soil gas samples (dC^{13} CH_4 in the range of –24 to –39.4 ‰ PDB) suggest thermogenic origin.

Introduction

The large tract beneath the Late Cretaceous-Paleocene Deccan Trap in western India is called Deccan Syneclise (Figure 1). It is one amongst the 26 sedimentary basins of India and is grouped under category IV, i.e. potentially prospective basin. Geophysical studies have revealed hidden Mesozoic sedimentary basins under the Deccan Traps. Surface Geochemical Surveys have been carried out in one of the prospective zones to assess the hydrocarbon prospectivity of the basin. Geochemical prospecting of hydrocarbons identifies the surface or near surface occurrences of hydrocarbons or their alteration products, which are due to macro/micro seepage of the subsurface hydrocarbon occurrences. The micro/macro seepage is an established phenomenon and these occur because processes and mechanisms such as diffusion, effusion and buoyancy allow hydrocarbons to escape from reservoirs and migrate to the surface where they may be retained in the sediments and soils or diffuse into atmosphere or water columns. Microseepage of hydrocarbons has led to the discovery of many important petroleum producing areas in the world.

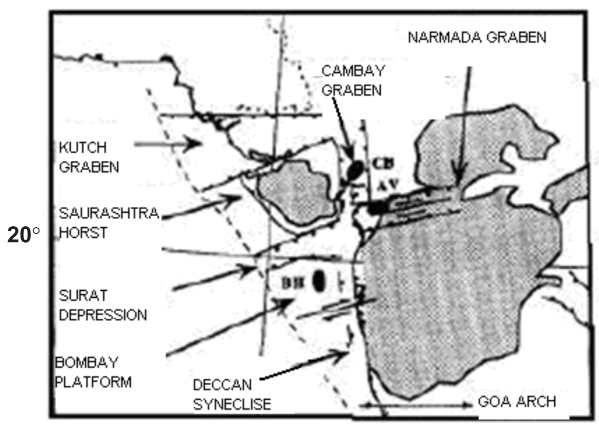

Fig. 1. Geological & tectonic map of Deccan Syneclise (modified after Gombos et. al.[2])

Deccan Syneclise Basin

Deccan Syneclise is an intracratonic sedimentary basin covering an area of ~273x10^3 Sq. Km. The basin is mostly covered by Deccan Traps, with the exposure of Bagh & Lameta beds in the adjoining areas. The Deccan trap thickness varies largely and is about 100 m in the northeastern part and >1500 m towards the west coast of India. Below the Deccan traps in the Narmada-Tapti region a hidden Mesozoic basin has been mapped in the form of two grabens separated by a small horst. In the southern part a larger Tapti graben with sediment thickness of about 2000 m is revealed, where as in the northern part smaller Narmada graben with sediment thickness of about 1000 m has been shown[3]. Integrated geophysical studies carried out by National Geophysical Research Institute (NGRI), Hyderabad and Directorate General of Hydrocarbons (DGH), New Delhi have revealed the presence of Mesozoic sediments with thickness of about 1000m to 2500 m in the central part of Narmada-Tapti region (DGH, Ann. Rep. 2003-04). This Mesozoic basin was deposited in a larger Mesozoic sea, which extended from Narmada-Tapti region through Saurashtra, Kutch, up to Sind and Salt Range in the form of horseshoe. The Moho configuration under the Deccan Trap covered area reveals the depression in the central part extending in an ENE-WSW direction which almost coincides with the region of hidden Mesozoic basin[3]. The marine transgressions and regressions that occurred in west central India before the Deccan volcanicity favored the deposition of organic rich source rocks. Further, the Deccan Trap volcanicity during Late Cretaceous might have generated the requisite thermal conditions and acted as a catalyst in Mesozoic hydrocarbon-generation process[4]. The generalized Stratigraphy of Deccan Syneclise is given in Table – 1

Table – 1 Generalized Stratigraphy of Deccan Syneclise Basin[5]

AGE	FORMATION/GROUP	ANTICIPATED MAX. THICKNESS	LITHOLOGY
Recent	Alluvium		
Pleistocene	Laterite		
Early Paleocene to Late Cretaceous	Deccan Trap	1 to 2 km	Basalt
		Unconformity	
Late Cretaceous	Lameta Beds		Arenaceous limestone
Middle Triassic	Upper Gondwana	2km	Sandstone & Shale
		Unconformity	
Early Triassic to Late Carboniferous	Lower Gondwana	1.5 km	Sandstone & Shale interbedded with coal
		Unconformity	
Basement with thin outliers of Vindhyan sediments at places			

Soil Sampling and Analytical Procedure

A total of 50 soil samples were collected in part of Deccan Syneclise basin at an interval of 5km along existing roads. The sample location map of the area is given in Figure 2. Samples have been collected in the depth range of 1.2 – 3.5 m using manual augers. The soil cores collected were wrapped in aluminum foils and sealed in poly-metal packs.

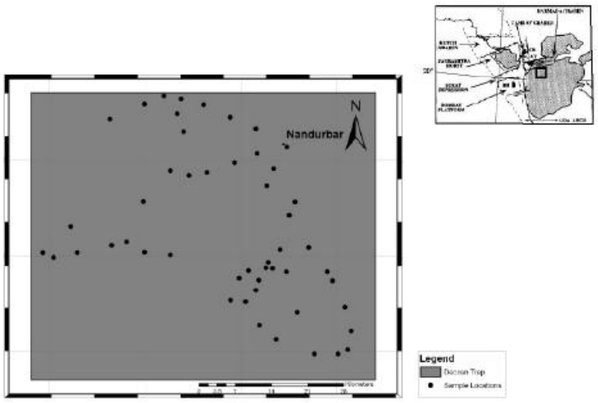

Fig. 2. Geological map of part of Deccan Syneclise showing sample locations

One gram of soil sample is reacted under vacuum with orthophosphoric acid to desorb the soil gases. The CO_2 released was trapped in KOH solution and the light gaseous hydrocarbons are collected by water displacement in a graduated tube fitted with rubber septa. The volume of desorbed gases is recorded, and 500 ìl of desorbed gas sample is injected into the Varian CP-3800 Gas Chromatograph fitted with Porapak 'Q' column, programmable temperature controller, and flame ionization detector. The GC was calibrated by using an external standard with known concentrations of methane, ethane, propane, i-butane, n-butane, i-pentane and n-pentane. The quantitative estimation of light gaseous hydrocarbon constituents in each sample was made using peak area measurement as a basis, and the correction for moisture content was applied. The accuracy of measurement of C_1 to C_5 components is < 1 ng/g.

Results and Discussion

The light gaseous hydrocarbon concentrations (CH_4, C_2H_6, C_3H_8, i-C_4H_{10}, n-C_4H_{10}, i-C_5H_{12} and n-C_5H_{12}) in soil samples of Deccan Syneclise vary from 3 to 1187 (CH_4), 1 to 633 (C_2H_6), 1 to 504 (C_3H_8), 1 to 123 (i-C_4H_{10}) and 2 to 159(n-C_4H_{10}) in ppb, apart from i-C_5H_{12} and n-C_5H_{12} -in few samples. The contour map of C_1 and ÓC_{2+} are plotted in Figures 3 and 4 and show that the samples south of Nandurbar are characterized by higher C_1 and ÓC_{2+} values. The crossplots between C_1-C_2, C_1-C_3, C_2-C_3 and C_1-ÓC_{2+}, show linear correlation (r >0.8), which indicate that the light gaseous hydrocarbon may have migrated from the same source, and the effect of secondary alteration during their seepage toward the surface may be insignificant.

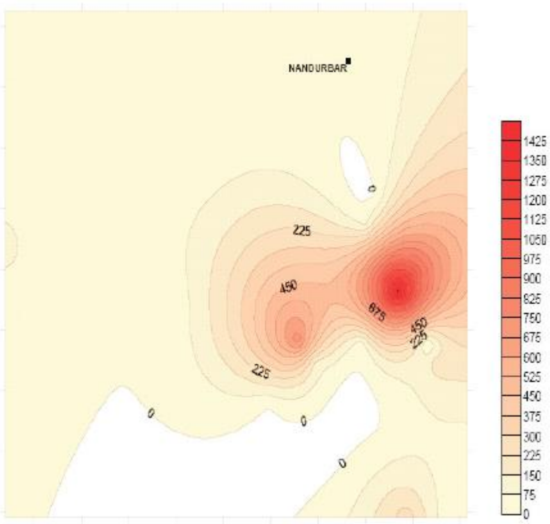

Fig. 3. Contour map showing the concentrations of methane in ppb for soil samples collected from part of Deccan Syneclise

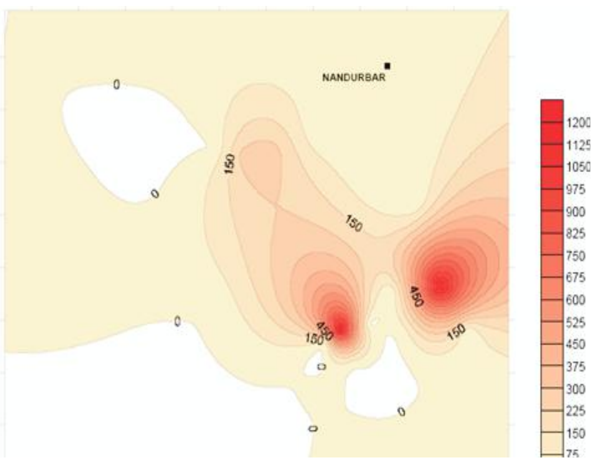

Fig. 4. Contour map showing the concentrations of åC$_{2+}$ in ppb, for soil samples collected in part of Deccan Syneclise

Analyses of the gas samples for the measurement of dC^{13} in methane were carried out using Thermo Finnigan Delta Plus XP Isotope Ratio Mass Spectrometer. The dC^{13} values are reported as parts per thousand (%) relative to the Peedee belemnite (PDB) standard (precision is ±0.2%). dC^{13} in methane lies in the range of –24 to –39.4 ‰ PDB suggesting a thermogenic origin.

The presence of C_1-C_5 hydrocarbons in the adsorbed soil gases in the samples collected from part of Deccan Syneclise indicate that hydrocarbon generation has taken place in the basin and gases are derived from thermogenic source[6,7,8]. The geochemical studies suggest that the part of Deccan Syneclise may prove to be warm area for future hydrocarbon exploration and exploitation.

Conclusions

Evidence of generation of hydrocarbons derived from thermogenic source beneath the Deccan Traps may open new vistas for commercial discovery of oil/gas in Mesozoics of India.

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Drilling Efficiency

J.M.B. Baruah
Petroleum & Management Consultant

[This paper is based on work done in the office of DGH. However, the views expressed in the paper are those of the author. Benefits of discussions with Shri Kripal Singh (Head of Drilling in DGH) during preparation of the paper is gratefully acknowledged.]

Preamble

The primary objective of drilling exploratory wells is to establish new reserves of oil and gas. The primary objective of drilling development wells is to provide production and injection points to enable recovery of maximum amounts of oil and gas from the underground reservoirs.

Considering that major part of an E & P company's annual expenditure budget is on drilling of wells, a clear understanding of drilling efficiency is necessary for ensuring success of an oil company in terms of establishment of underground reserves of oil and gas, production of oil and gas, and generation of adequate revenue stream and profit to ensure return on investments and business growth by improving success ratio and reducing cost of operations through adoption of appropriate technology and improvement in systems.

The term drilling efficiency has different meanings to different persons. Drilling efficiency as perceived by oil company geoscientists, production / reservoir engineers and drilling engineers are different. An objective analysis of drilling efficiency, therefore, needs to take into account the requirements of different interest groups.

For Exploration Geoscientists, drilling through all the potentially prospective formations, and drilling of a good hole with minimum wash-out to enable recording of requisite wire-line logs and testing in open hole are of paramount interest.

For Petroleum / Reservoir Engineers, successful landing of casing pipes / liners covering all the zones indicated to be potentially prospective by evaluation of the wire-line logs, and effective cementing having good isolation of different reservoir rock sections penetrated by the well, minimum formation damage during drilling and cementation operations are of great importance. Drilling Engineers of the E & P company would be interested in drilling the well in the shortest possible time at minimum cost, while the Drilling Contractors personnel would be more concerned about a continued contract.

In the ultimate analysis, improvement of success ratio of drilling wells resulting in improvement of Discovery Index and improvement of Well Productivity are critical to the survival and growth of an E & P company.

In this paper, various aspects of drilling efficiency will be examined under the following heads taking into account the interests of different stake-holders:

(a) Drilling of good quality hole;

(b) Reduction of drilling time and drilling cost; and

(c) Improvement of discovery index and well productivity.

Drilling of Good Quality Hole to Objective Depth

General

The success of an exploration and production venture depends upon several factors including proper understanding of the petroleum system, selection of correct drilling location, correct identification of oil and gas zones after drilling of a well, proper isolation of different reservoirs by ensuring good cement bonding, minimization of damage to formation near well-bore during drilling, completion and testing phases, etc.

Drilling of good quality hole to the desired objective depth plays an important role in enabling the geo-scientists to identify the oil and gas zones, and the petroleum reservoir engineers and production engineers to adequately test the production potential of the prospective zones identified on the basis of interpretation of wire-line logs, mud logging data, core data, etc.

Good hole also leads to minimization of down-hole problems like pipe-sticking during drilling and running in of casing, and helps in effective isolation of different reservoir sections during cementation of the oil-string casing.

Planning Phase

Correct determination of down – hole geological formation boundaries, lithology, formation pressure distribution, temperature profile, over-burden pressure distribution, tectonic forces, presence of faults, fractures and vugs, fluid properties, etc. prior to undertaking drilling operations help immensely in drilling a good quality hole and adequate testing of the zones of interest.

Detailed planning of drilling, casing, mud, cementing and completion, and testing policies of the well, and close monitoring of operations hold the key to drilling of good quality hole which in turn contributes to success of an exploration venture / field development project.

Operational Factors

Some of the important operational factors that contribute to drilling of a good hole will be discussed in the following paragraphs.

The drilling rig should have adequate horse - power and hoisting capabilities. The rig should have appropriate mud handling / loading facilities. It should have required back-up power packs capable of handling various emergencies that may arise in the course of drilling and testing operations.

The drilling rig should have facilities for drilling inclined holes and side-tracks. It should be equipped with requisite fishing tools. The rig should have dedicated cementing units including high pressure killing pumps.

Adequate inventory of various drilling consumables like drilling bits, drilling fluid (drilling mud) additives and chemicals, casing pipes, and cement and cement additives are to be maintained at or near the drilling well site. It is also important to ensure availability of acceptable quality water at or near the drilling site.

All the specialist service providers required for high quality mud engineering, mud logging, wire-line logging, cementing, perforation, and well testing services should be in place before the spudding of a well.

Requisite logistics services like helicopter, supply boat, oil-field trucks / trailers, camps, storage yards, etc. should also be arranged before drilling of a well is started.

Training of the drilling personnel in handling the rig equipment and motivation to work as a team are critical HR issues that need to be taken care of for successful drilling and completion of a well.

Drilling operations are often carried out at isolated places. Therefore, there is paramount need for empowerment of the drilling team as a whole for taking all the operational decisions at or near the well site.

As multi – disciplinary specialists are involved in conducting oil / gas well drilling operations, daily meeting of all the key personals should be held to

(a) review previous day's operations;

(b) identify the problems, if any;

(c) resolve all the problems without loss of time; and

(d) review future action plans.

Reduction of Drilling Time and Drilling Cost

Improvement of Drilling Rig Utilization

Improvement of drilling rig utilization is achieved through maximization of drilling meters per rig in a year. This is achieved by reducing the time required for each phase of the activities performed with a drilling rig.

It is industry practice to compute Cycle Speed and Commercial Speed of a drilling rig to measure its performance vis-à-vis the benchmark.

Cycle Speed of a Drilling Rig

A *Rig Cycle* covers all rig operations related to a well. It starts from rig-down in the previous well, rig move to the new well, rig-up at the new well , drilling of the well to the final depth, running in different strings of casings and cementation of the same , fitting in well-head / BOP, wire-line logging in both open-hole and cased-hole, running in and setting of production tubing, perforation of casing against selected zones and production testing.

Rig Cycle Time is the time span of a Rig Cycle expressed in month. Computation of Rig Cycle Time is shown in Table 1 with the help of a hypothetical example of drilling Well X with an objective depth of 4000m drilled with a 4 – stage casing policy. The main components of cycle speed are illustrated in Figure 1.

Table 1: Computation of Rig Cycle Time

Days required for rig down in previous well	: 10 days
Days required for rig move to present well X	: 20 days
Days required for rig up at present well X	: 10 days
Drilling and Completion of present well X	: 60 days
Production Testing of present well X	: 10 days
Total No of Days	: 110 days
Rig Cycle Time for Well X = 110 / 30 = 3.67	months

Cycle Speed of a rig may be defined as Drilling Meters / Rig Cycle Time. For the hypothetical well (Well X), Cycle Speed may be computed as follows :

Cycle Speed = 4000 meters / 3.67 months
= 1089.9 meters / month

For improving the utilization of a drilling rig, the Cycle Speed of a rig would need to be maximized.

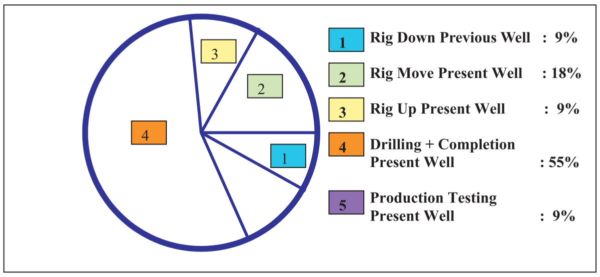


Fig. 1. Components of Rig Cycle Time.

Commercial Speed of a Drilling Rig

A *Commercial Cycle* covers all activities related to actual drilling, logging, casing, and cementation of a well starting from spud in (start of drilling operations) to hermitical testing carried out prior to start of production testing operations.

Commercial Cycle Time is the time span of a Commercial Cycle expressed in month . Computation of Commercial Cycle Time is shown in Table 2 with the help of the example of the hypothetical well (Well X).

Table 2: Computation of Commercial Cycle Speed

Days required for drilling	: 35 days
Days required for wire-line logging / testing	: 10 days
Days required for coring	: 5 days
Days required for casing running / setting	: 5 days
Days required for installation of well-head	: 3 days
Days required for well testing	: 2 days
Total No of Days	: 60 days
Commercial Cycle Time for Well X = 60 / 30 = 2.0 month	

Commercial Speed of a rig may be defined as Drilling Meters / Commercial Cycle Time. For the hypothetical well (Well X) , Commercial Speed may be computed as follows :

$$\text{Commercial Speed} = 4000 \text{ meters} / 2.0 \text{ months}$$
$$= 2000 \text{ meters} / \text{month}$$

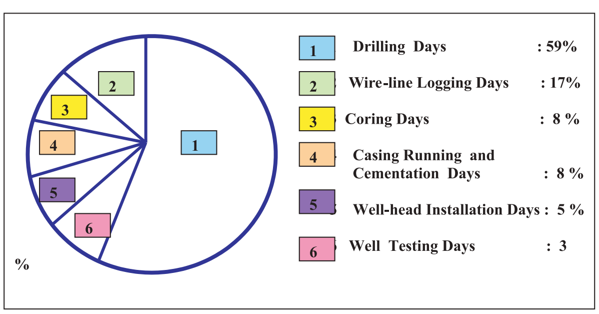


Fig. 2. Components of Commercial Cycle Time

In order to reduce drilling time of a well, special emphasis would need to be placed on improving the Commercial Speed of the rig.

Reduction of Drilling Time

Detailed and critical analysis of rig time utilization is required for each well in order to determine the major factors contributing to reduction of Commercial Speed. Some of the common factors are briefly outlined in the following paragraphs.

Down-hole problems like hole instability is often caused by inadequate understanding of various geological factors like presence of abnormal formation pressure, presence of low and variable pressure beds, influence of tectonic forces prevailing in the basin, presence of vugs, fractures, very high permeability beds, etc. It is, therefore, necessary to have a prediction of expected down – hole conditions prior to start of drilling operations in a well, so that necessary precautionary steps could be taken in time in order to avoid problems after the rig is mobilized and drilling operations are started.

Drilling fluid related problems like clay swelling, excessive mud filtrate loss, formation of thick mud – cake, inadequate control of formation pressure resulting in kicks / blow – out, mud loss resulting from use of over – weight drilling mud, excessive drag resulting from high mud viscosity, etc., significantly contribute to down – hole problems that adversely affect drilling speed.

Wrong bit selection is often an important cause of slow penetration rate. Another very important cause of slow penetration rate is use of hydraulic parameters like weight on bit, rpm , pump pressure , mud circulation rate, etc., which are not optimum for the type of formation. Size of hole, drilling depth, etc., also affect drilling speed.

Excessive rig down-time on account of equipment failure also causes reduction of Commercial Speed.

Technological Developments

Some of the recent technological developments contributing to improvement in Commercial Speed are as follows:

(a) LWD and MWD systems increase drilling efficiency through smarter drilling.

(b) Improved PDC bits could dramatically improve drilling efficiency by increasing rate of penetration, improving hole cleaning, and decreasing the number of round – trips required to change drilling bits.

(c) Use of improved mud systems like Sodium Silicate mud could increase drilling efficiency by solving bore- hole instability problems.

(d) New rig designs including retro-fitting of drilling rigs by top- drive drilling system can improve drilling efficiency by reducing pipe connection time and round –trip time.

(e) Use of Steerable Down-hole Mud Motors in the drilling rigs can considerably improve overall drilling efficiency.

(f) New wire – line logging devices that can be run in combination can significantly improve drilling efficiency by reducing logging time.

Reduction of Drilling Cost

Drilling costs represent the most important component of expenditure budget of an E & P company. Improvement of drilling rig utilization through increase of rig cycle speed holds the key to reduction of drilling cost of an exploration or development drilling campaign.

In addition to improvement of cycle speed of a drilling rig, other important aspects of reduction of drilling cost relate to optimization of various technical and other support and logistics related services, optimization of well planning and well design, drilling of the minimum number of wells, minimization of damage to productive formations during drilling and well testing operations, etc. Some of these aspects are briefly outlined in the following paragraphs.

Significant reduction in overall drilling cost can be achieved by keeping the hole size at the minimum requirement. This reduces drilling cost by reducing drilling time, having lower casing size, lower drilling mud volume, etc.

Optimization of various technical services like mud logging, wire-line logging, deviation drilling services, casing / liner running and cementation services, well testing services, etc., can lead to substantial reduction of drilling cost.

Optimization of support services like procurement, storage, and transportation of drilling rig spares and drilling consumables, supply boat services, helicopter services, etc. can also result in significant reduction of drilling cost. Sharing of some of these services with other oil companies operating in the same locality would result in additional cost savings.

Optimization of use of consumables like casing, drilling mud chemicals, cement and cement additives, water, fuel, etc. can result in very significant saving of overall drilling costs.

Setting up of drilling camps near well-sites and provision of efficient camp management services results in not only reduction of transportation costs but improves employee health and helps in building up team spirit. For better effectiveness , the drilling team needs to be adequately empowered to take various decisions at drilling well / camp site, as discussed earlier.

Detailed planning of operations in advance and regular operations meetings of all concerned including personnel of various service providers can lead to substantial reduction of drilling costs by ensuring drilling of good quality holes. These steps can eliminate the need for drilling replacement wells / costly side – tracks, etc.

Another area that needs considerable attention is minimization of damage to productive geological formations during drilling and well testing operations. These steps can result in improving well productivity on a sustained basis necessitating drilling of lesser number of wells with attendant cost advantage.

Considerable reduction in drilling and related operations cost can accrue if the Operators working in the same basin or in the same geographical area club together the requirements and hire the same drilling rig and engage the same service providers. This would reduce competition and help in getting better contractual terms including lower day rates even from high quality service providers. Moreover, there would be substantial reduction in mobilization time and costs. The combined effect on costs of operations would be substantial. The benefits to the companies having smaller work programs would be even more spectacular.

Similarly, considerable savings could result from reduction in cost of procurement, cost of storage of materials near drilling sites, and cost of other logistics and supply chain management related services like supply boat, helicopter etc., by having common materials procurement and storage system and maintenance of common transportation services.

Improvement of Discovery Index

General

The success of an E & P venture in terms of reserves accretion and improved recovery depends upon several factors. Some of the important factors are

- proper understanding of the petroleum system;
- selection of correct drilling locations;
- correct identification of oil and gas zones after drilling of a well;
- good cement bonding for effective isolation of different reservoirs;
- minimization of damage to formation near well-

bore during drilling, completion and testing phases, etc.

Discovery Index

Discovery Index is the amount of OOIP and oil equivalent of OGIP expressed in barrels per meter of exploratory drilling. Success of the exploration drilling phase is measured by the Discovery Index. Parameters which control Discovery Index are size of the discovery, depth of the reservoirs and the number of exploration and appraisal wells required to establish the size of the fields.

The main parameters which determine the size of the discovery are as follows:

(a) Areal extent of oil and / or gas field discovered,

(b) Net pay thickness,

(c) Petro-physical properties,

(d) Depth of the oil / gas reservoirs,

(e) Reservoir pressure and temperature conditions, and

(f) Reservoir drive mechanism, etc.

The main factors that determine the number of exploratory and appraisal wells are the geological complexity and reservoir heterogeneity. The only way to keep the number of wells at the minimum is not to drill redundant wells. To ensure this, it is essential to:

- Select the drilling sites after a thorough examination of all available data and modeling of sub-surface geology both in space and time;
- Drill good quality hole at the shortest possible time using non –damaging drilling mud;
- Carry out extensive logging operations using modern wire-line logging devices including imaging . Conduct formation interval tests using modern wire-line based systems like MDT;
- Carry out open-hole or cased-hole Drill Stem Tests (DST) of the intervals identified as potentially hydrocarbon-bearing in order to flow the well to the surface to establish the presence of producible hydrocarbon in some of the geological formations penetrated by the well and also to get data on well productivity, deliverability, etc.
- Collect reservoir rock samples during drilling and reservoir fluid samples during testing operations for evaluation of the size and the techno-economic viability of the discovery in the cases where an oil and / gas well has been successfully drilled and tested.

Release of Drilling Locations

Drilling locations are classified as exploratory, appraisal, development and infill locations depending upon the operational phase of an E & P venture as indicated in Figure 3.

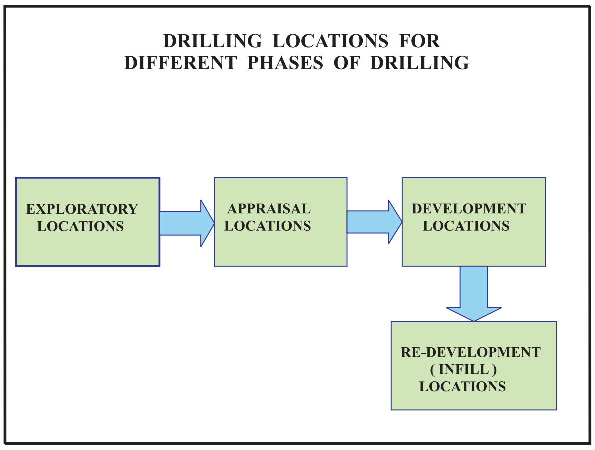


Fig. 3. Different Types of Drilling Locations

Drilling of exploratory well is the most critical and the most expensive item of work during the exploration phase of an E & P venture. It is , therefore, essential to minimize the risk of failure. Detailed geo-scientific studies and adequate technical due diligence are required prior to the selection of the exploratory drilling location site and release of the same for undertaking drilling operations.

In view of various uncertainties with respect to accumulation of commercial quantities of hydrocarbons in a sub-surface trap, the risks associated with presence of a suitable trap, its time of formation vis-à-vis the time of generation, expulsion, and migration of hydrocarbons from source rocks rich in organic matters to reservoir rocks, retention of the integrity of the trap after migration of hydrocarbons to the trap, etc. are to be studied in detail. As alternative interpretations of geo-scientific data are possible and individual bias of the interpreter cannot be entirely eliminated, it is essential to have independent evaluation of the basic geo-scientific data by different groups of geo-scientists prior to release of the location for carrying out drilling operations.

Although, no universally applicable technique of direct detection of hydrocarbon prior drilling of a well is available, recent advances of 3-D seismic surveys, and data processing and interpretation techniques have thrown up a host of seismic attribute analysis, that could under favourable conditions, indicate presence of hydrocarbon (particularly gas) accumulations in an area. The use of these techniques combined with conventional structural and stratigraphic interpretations, and modeling of hydrocarbon generation, migration and accumulation could significantly improve the chances of success of a drilling venture.

The use of seismic attribute analysis studies in determination of the extent of an oil-field or a gas-field is even more valuable as seismic attributes can now be tied up with well data. This could help in optimally locating the appraisal wells after a discovery is made.

Accordingly, 3-D seismic survey prior to drilling of any appraisal well is a must. The same is also desirable prior to drilling of an exploratory well if the trapping mechanism of the drilling target is not a simple 4-way closure and is dependent either on the presence of a sealing fault or a stratigraphic feature.

In the cases of Development drilling locations, the locations are normally released after a 3D-3P numerical reservoir simulation study. The reservoir simulation study first validates the static reservoir model constructed on the basis of interpretation of 3-D seismic survey data, well log interpretation data, core analysis data, and reservoir fluid analysis data. The model is then modified to match the available pressure-production data, and alternative development and production plans are worked out using the accepted reservoir model. The locations of the development (production and injection) wells are decided on the basis of the 3D-3P reservoir simulation studies.

However, at the initial stage, the availability of pressure-production data are meager. Therefore, extended conventional production tests of the successful exploratory and appraisal wells should be carried out prior to preparation of a Field Development Plan, so that a reasonably accurate reservoir model could be used for arriving at an acceptable depletion plan and hence selection of the development wells.

In order to avoid drilling of redundant or unsuccessful development wells, another option would be to plan field development in phases. The initial development could involve drilling of wells at a wide grid, followed up by drilling of a second generation of wells at a closer grid as demanded by the refined reservoir model and predominant reservoir drive mechanism. These second generation wells are usually known as infill wells.

Periodic Review of Release Drilling Locations and Prioritization of Drilling

Once a location is released for drilling, a series of other activities like acquisition of land for preparation of drilling plinth, approach road, drilling camp and storage yard, etc., various civil engineering / construction activities, hiring / mobilization of a suitable drilling rig , procurement of consumables for drilling and other related operations, hiring of different drilling, logging and production testing services, hiring of logistics related services, mobilization of required men and materials, etc. start. However, completion of these activities could take over a year particularly for on-shore operations.

If additional data or concepts become available in the intervening period, there may be a need for a change of the drilling location and its drilling policy. Therefore, it becomes necessary to review the prospects of each drilling location at least once a year and re-work the drilling program / priority of the oil company in order to enhance the chances of success.

Improvemement of Well Productivity

One of the primary causes of poor well productivity had been reduction of effective permeability and alteration of the relative permeability characteristics of the oil reservoirs near the well-bore on account of

- High mud filtrate invasion resulting from high differential pressure between the pressure exerted by the mud column and the formation pressure;
- High filtrate loss characteristics of the drilling mud on account of use of ineffective fluid loss additives;
- Swelling of clays present in the formation by mud filtrate on account of low concentration of salts dissolved in the mud as compared to the formation water, etc.

Another important reason of poor well productivity is excessive caving of formations during drilling on account of

- Faulty mud hydraulics like high annular velocity at the time of drilling operations, and
- High rate of pulling drilling string at the time of round trips for change of drilling bits or during hole probing trips.

It is, therefore, essential to use a properly formulated drilling fluid compatible to the sub-surface geological formation , and also to select drilling and mud hydraulic parameters such that there is no impairment to well productivity during drilling, completion , and testing of a well .

Concluding Remarks

It is hoped that the suggestions incorporated in this paper on Drilling Efficiency would be helpful in making the E & P business of India more efficient.

To achieve the desired results, Operator Groups may be formed with a view to reducing overall cost of operations by clubbing together activities of adjacent blocks. Government may also help the operators in scheduling drilling activities of different blocks as long as the prevailing conditions of shortage in availability of drilling rigs exists.

* * * *

International Conference on Gas Hydrates In India

Release of Initial Report on the NGHP Expedition–01 by Hon'ble Minister of Petroleum & Natural Gas Shri Murli Deora

Recently an international partnership led by the Directorate General of Hydrocarbons (DGH) under the Ministry of Petroleum and Natural Gas (Government of India) and the U.S. Geological Survey (USGS) released the results of the most complex and comprehensive gas hydrate field venture yet conducted. The occasion of release was the International Gas Hydrates Conference held in New Delhi, India from 6th-8th February, 2008 by the Indian National Gas Hydrates Program (NGHP). The participants in the NGHP Expedition 01 released the results of the first modern, fully integrated gas hydrate research and exploration program conducted in the Indian Offshore. The conference witnessed participation of delegates from various parts of the globe. There were 28 papers presented in the poster session and 20 papers presented in the oral session. Scientists from USA, Japan, India, Canada, Taiwan, Korea, UK, Spain, Australia and Russia participated in the conference A wide range of topics were deliberated, which included the progress made in the gas hydrate program of various countries to more technical ones like Geophysics, Petrophysics, Sedimentology, Paleontology, Core studies, Production and Reservoir. A topic on the commercialization of Gas Hydrate prospects was also made during the deliberations. A detailed scientific report is also being worked out which would elaborate scientific findings made after the conclusion of the studies on the expedition.

Expedition Objectives

NGHP Expedition 01 was designed to study the gas hydrate occurrences both spatially and temporally off the Indian Peninsula and along the Andaman convergent margin with special emphasis on understanding the geologic and geochemical controls on the occurrence of gas hydrate in these two diverse settings. The primary goal of NGHP Expedition 01 was to conduct scientific ocean drilling/coring, logging, and analytical activities to assess the geologic occurrence, regional context, and characteristics of gas hydrate deposits along the continental margins of India in order to meet the long term goal of exploiting gas hydrates as a potential energy resource in a cost-effective and safe manner. During NGHP Expedition 01, dedicated gas hydrate coring, drilling, and downhole logging operations were conducted from 28 April, 2006 to the 19 August, 2006.

Based on analysis of geological and geophysical data, the Expedition was planned to visit ten sites in four areas: the Kerala-Konkan Basin in the Arabian Sea-western continental shelf of India; the petroliferous Krishna-Godawari Basin and Mahanadi Basin in the Bay of Bengal-eastern continental shelf of India; and the previously unexplored Andaman Islands. The cruise aimed at conducting scientific drilling, well logging, coring, and shipboard scientific analyses of recovered samples from each site to provide further insight into:

- The distribution and nature of gas hydrate in marine sediments
- The geologic controls on the formation and occurrence of gas hydrate in nature
- The processes that transport gas from source to reservoir
- The effect of gas hydrate on the physical properties of the host sediments
- The microbiology and geochemistry of gas hydrate formation and dissociation
- The calibration of geophysical and other predictive tools to the observed presence and concentration of gas hydrates.

Participants

NGHP Expedition 01 was planned and managed through a collaboration between the Directorate General of Hydrocarbons (DGH) under the Ministry of Petroleum and Natural Gas (Government of India), the U.S. Geological Survey (USGS), and the Consortium for Scientific Methane Hydrate Investigations (CSMHI) led by Overseas Drilling Limited (ODL) and FUGRO McClelland Marine Geosciences (FUGRO). The platform for the drilling operation was the research drill ship JOIDES Resolution (JR), operated by ODL. The science team was led by Dr. Timothy Collett of the USGS, and consisted of more than 100 leading scientists and professionals representing the following organizations:

- Binghamton University Colorado School of Mines · Directorate General for Hydrocarbons (India) · Fugro-McClelland, Inc.
- GAIL (India) Ltd
- Geological Survey of Canada
- Geotek Ltd · Idaho National Laboratory
- Integrated Ocean Drilling Program
- Joint Oceanographic Institutions, Inc.
- Lamont-Doherty Earth Observatory
- Ministry of Petroleum and Natural Gas (India)
- McGill University
- National Energy Technology Laboratory
- National Institute of Oceanography (India)
- National Institute of Ocean Technology (India)
- Oil and Natural Gas Corporation (India)
- Ocean Drilling Limited
- Oregon State University OIL India Ltd
- Pacific Northwest National Laboratory
- Reliance Industries Limited (India)
- Schlumberger
- Technical University of Berlin
- Texas A&M University
- University of California, San Diego
- University of Cardiff
- University of New Hampshire
- Universität Bremen
- University of Rhode Island
- U.S. Department of Energy
- U.S. Geological Survey
- U.S. National Science Foundation
- Woods Hole Oceanographic Institution

Operational Highlights

During its 113.5-day voyage, the expedition cored or drilled 39 holes at 21 sites (one site in the Kerala-Konkan Basin, 15 sites in the Krishna-Godavari Basin, four sites in the Mahanadi Basin and one site in the Andaman deep offshore areas), penetrated more than 9,250 meters of sedimentary section, and recovered nearly 2,850 meters of core. Twelve holes were logged with logging-while-drilling (LWD) tools and an additional 13 holes were wireline logged. The operational highlights of NGHP Expedition 01 included the following:

- 113.5 days of operation without any reportable injury or incident.
- Only 1% of total operation time was down time due to equipment malfunction or weather.
- Examination of 9,250 meters of sedimentary section at 39 locations within 21 sites located in four geologically-distinct settings.
  - o Collected LWD log data in 12 holes at 10 sites.
  - o Collected wireline log data at 13 sites.
  - o Collected vertical seismic profile data at six sites.
  - o Collected 494 cores, encompassing 2,850 meters of sediment, from 21 holes (78% overall recovery).

- o Collected detailed shallow geochemical profiles at 13 locations.
  - o Established temperature gradients at 11 locations.
- Extensive sample collection to support a wide range of post-cruise analyses, including:
  - o Collected about 6,800 whole round core samples for examination of interstitial water geochemistry, microbiology, and other information.
  - o Collected more than 12,500 core subsamples for paleomagnetic, mineralogical, paleontological, and other analyses.
  - o Collected about 140 gas-hydrate-bearing sediment samples for storage in liquid nitrogen.
  - o Collected five one-meter-long gas-hydrate-bearing pressure cores for analysis of the physical and mechanical properties of gas-hydrate-bearing sediment.
  - o Collected 21 re-pressurized cores (nine representing sub-samples from gas-hydrate-bearing pressure cores).
- Conducted 97 deployments of advanced pressure coring devices, resulting in the collection of 49 cores that contain virtually undisturbed gas hydrate in host sediments at near *in situ* pressure conditions.

Scientific Findings and Impact

The NGHP Expedition 01 Initial Reports, released at the conference in New Delhi, includes a series of integrated site chapters (Sites 1-21) describing the operational history and scientific data collected during the expedition. The Initial Reports volume also includes a companion publication that contains all downhole log data collected during the expedition.

The NGHP Expedition 01 science team utilized extensive on-board lab facilities to examine and prepare preliminary reports on the physical properties, geochemistry, and sedimentology of all the data collected prior to the end of the expedition. Although the data will continue to inform gas hydrates science for years to come, the following are some key scientific highlights of the expedition to date:

- Conducted comprehensive analyses of gas-hydrate-bearing marine sediments in both passive continental margin and marine accretionary wedge settings.
- The calculated depth to the base of the methane hydrate stability zone, as derived from downhole temperature measurements, closely matches the depth of the seismic identified bottom simulating reflectors (BSRs) at most of the sites established during this expedition.
- Discovered gas hydrate in numerous complex geologic settings and collected an unprecedented number of gas hydrate cores.
- Most of the recovered gas hydrate was characterized as either pore-filling grains or particles disseminated in coarser grain sediments or as a fracture-filling material in clay dominated sediments.
- The occurrence of concentrated gas hydrate is mostly controlled by the presence of fractures and/or coarser grained (mostly sand-rich) sediments.
- Gas hydrate was found occurring in "combination reservoirs" consisting of horizontal or subhorizontal coarse grained permeable sediments (sands for the most part) and apparent vertical to subvertical fractures that provide the conduits for gas migration.
- Delineated and sampled one of the richest marine gas hydrate accumulations ever discovered (Site NGHP-01-10 in the Krishna-Godavari Basin).
- Discovered one of the thickest and deepest gas hydrate occurrences yet known (offshore of the Andaman Islands, Site NGHP-01-17) which revealed gas-hydrate-bearing volcanic ash layers as deep as 600 meters below the seafloor.
- Established the existence of a fully developed gas hydrate system in the Mahanadi Basin of the Bay of Bengal.
- Most of the gas hydrate occurrences discovered during this expedition appear to contain mostly methane which was generated by microbial processes. However, there is also evidence of a thermal origin for a portion of the gas within the hydrates of the Mahanadi Basin and the Andaman offshore area.
- Gas hydrate in the Krishna-Godavari Basin appears to be closely associated with large scale structural features, in which the flux of gas through local fracture systems, generated by the regional stress regime, controls the occurrence and distribution of gas hydrate.

Future Directions

NGHP Expedition 01 has shown that conventional sand and fractured-clay reservoirs are the primary emerging economic targets for gas hydrate production in India. Because conventional marine exploration and production technologies favor the sand-dominated gas hydrate reservoirs, investigation of sand reservoirs will likely have a higher near-term priority in the NGHP program. It is perceived that the NGHP effort will likely include future seismic studies, drilling, coring, and field production testing. It has been concluded that Site 10 represents a world class shale dominated fracture gas hydrate reservoir, worthy of further investigation.

A Report on the DGH Geological Field trip to Naukuchiatal area of Lesser Himalayas

The Directorate General of Hydrocarbons organized a Geological field trip to the Lesser Himalayas in the Naukuchiatal area on the 11th and the 12th of April 2008. This was followed by a brainstorming session on the future role of DGH in the Indian E&P sector. About 40 Officers and trainee officers participated in the event.

The DGH team left the DGH office on 11th April at 0630 hrs for Naukuchiatal. Upon arrival, the field guide, Dr P.D. Pant an Associate Professor from the Kumaon University and a renowned Structural Geologist together with a research scholar Ms Manjuri from the same university gave a detailed presentation on the Regional Geological setting of the Nainital Hills (Table 1) and correlated the same with the Mussoorie and Inner belt of the Lesser Himalaya (Ref. Fig. 1).

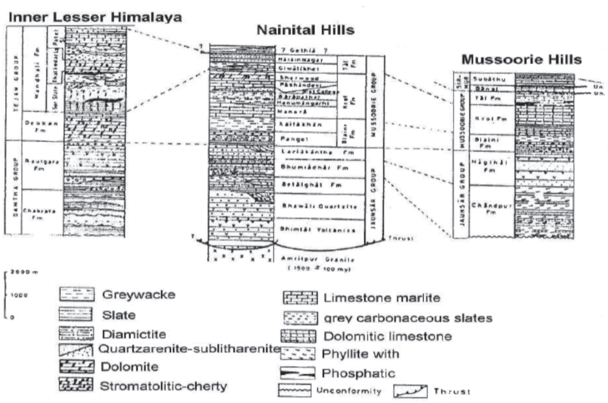


Fig. 1. Correlation of lithological units of the Nainital and Mussorrie Hills with those of the inner belt of the Lesser Himalaya. (Source Fig. 4.2 of Valdiya, 1988)

Table 1: Lithotectonic succession in Kumaun Lesser Himalaya (Valdiya, 1980)

Tectonic Unit	Out Belt	Inner Belt	
		Vaikrita Group	
		Vaikrita Thrust	
Almora (= Jutogh) Nappe	Almora Group	Munsiari Fm.	
Almora Thrusts (NAT/SAT)		Main Central Thrust (MCT)	
Ramgarh (=Chail) Nappe	Ramgarh Group	Bhatwari-Barakot Fm.	
Ramgarh Thrust		Bhatwari Thrust	
Sirmur Group	Subathu Fm. Bansi Fm.		
Mussoorie Group	Krol Nappe Krol Fm. Blani Fm.	Tal Fm.	
Jaunsar Group	Nagthat Fm. Chandpur Fm. Mandhali Fm.	Berinag Fm.	
Krol Thrust		Berinag Thrust	
		Tejam Group	Mandhali Fm. Deoban Fm.
Autochthon Damtha Group	Rautgara Fm. Chakrata Fm.	Damtha Group	Rautgara Fm.
	Main Boundary Thrust (MBT)		
	Siwalik		
	Himalayan Frontal Fault (HFF)		
	Ganga Pains		

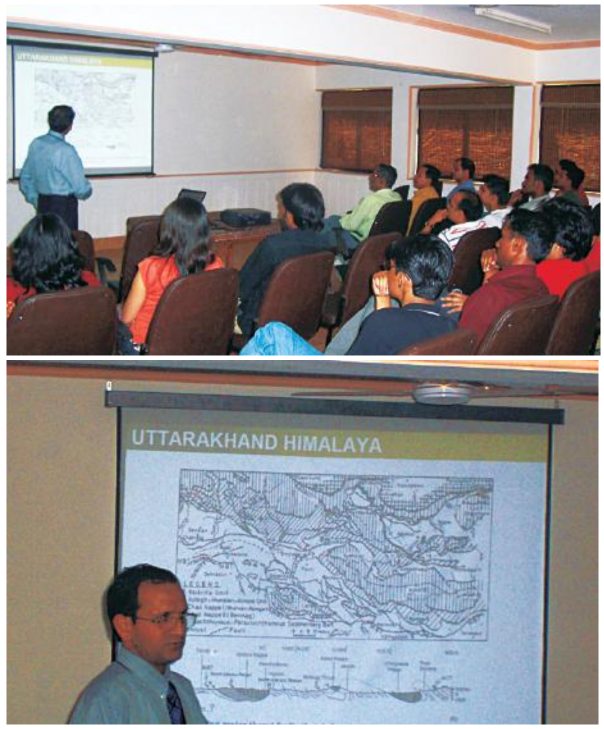


Photo 1. Prof. Pant giving a presentation to DGH officials on Geology of Lesser Himalayas

The following outcrops / locations were explained from the field work point of view :

1st transverse

1. Upper Krol - Tal succession, and Precambrian - Cambrian Boundary near Narain Nagar
2. Upper Krol and their Biohermal structures – at Durham House Nainital
3. Lower Krol and morphotectonism of Lake Fault, Nainital at Milestone one to Bhowali (Cantt.)
4. Early- Proterozoic rocks of the Blaini Formation at Pines Nala and summer spot of Pines
5. Quaternary-Holocene lake sediments of Bhowali and Bhimtal-Naukuchiatal basins at Bhowali and Bhimtal
6. Palaeo-Proterozoic Bhimtal Volcanic suit at Pandegaon (Bhimtal – Jangaliagaon road section)
7. Lower-Proterozoic rocks of the Nagthat Formation at Niglat (Bhowali Gaon)

2nd transverse

1. Garampani Fault at Ratighat

2. Ramgarh Thrust and mylonitized Ramgarh Porphyry at Lohai
3. South Almora Thrust at Kakrighat
4. ~560 m.y. old Champawat Granitoids Lodhiya (Almora)
5. Early folds and deformation of Almora Crystallines at Khatiyari (Almora)

3rd transverse

1. Main Boundary Thrust and its tectonic rejuvenation at Baldiyakhan and Joli - Suriyajala
2. Lower – Middle Siwalik succession near Ranibagh Kathgodam
3. ~1800my old Amritpur granite at Amritpur (Ranibagh)

Field Traverse

SPOT: 1

LOCATION: Durham House near Sherwood and All Saint's College

OBJECTIVES: To observe the rocks of the Upper Krol and their Biohermal Structures.

A thick succession of light to dark-grey dolomite of upper Krol succession characterizing development of 1000 to 900 m.y. old biohermal structures is well exposed at this site. The important bioherm (stromatolites) present in this rock unit are columnar, laminar, domal, oncoidal, plumose and irregular stromatolites. The bioherms are namely *Baicalia baicalica, Kursinella, Minjaria, Colonella Columnaris.* These bioherms suggest a shallow marine depositional environment in middle to late Proterozoic age.

STOP: 2

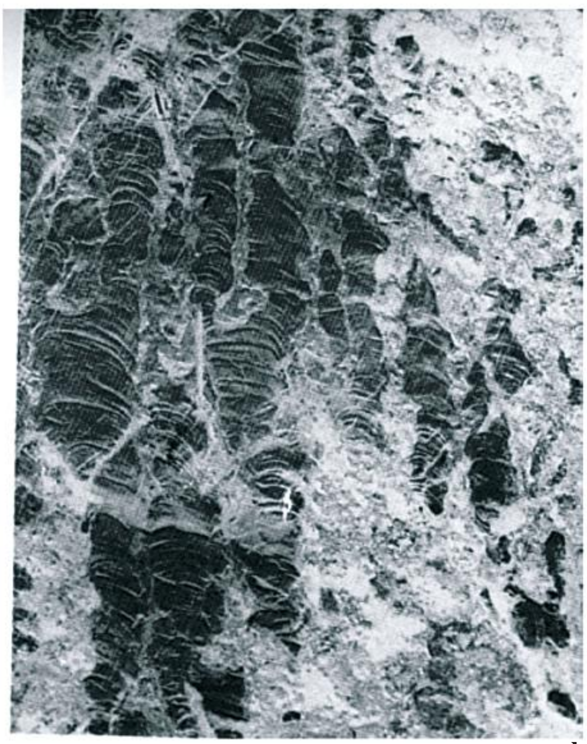
LOCATION: Milestone one to Bhowali (Cantt.)

OBJECTIVES: To observe the rocks of Lower Krol and morphotectonism of Lake Fault, Nainital

A. Rocks of Lower Krol (Krol- A) are greenish grey gypsiferous silty shales characterizing fining upward cycles. The sequence shows small-scale parallel laminations, micro ripples, ripples cross-laminations and faintly developed large scale cross-beds. The bed transitions are sharp and sometimes even erosional.

B. The lake fault passing through the Naini Lake has been responsible for formation of the lake (Ref. Photo 3b). A rotational motion involving strike-slip as well as dip-slip displacement caused the blocking of a mature perennial stream and the evolution of the depression. As a result of faulting, the upper Krol limestone lie in juxtaposition against the Lower Krol slates and marls (Ref. Photo 3a). The vertical displacement measurable on the saddle between Naina and Deopatta peaks is of the order of 80m, while in the Balia ravine just southeast of the bus station it is 20m. The movements along the Nainital/ Lake fault have involved upliftment of the Sear-ka-Dana-Naina peak block, which has resulted in a succession of landslides and rock falls in the block. Study of neotectonic movements and past seismic

a



b

Photo 02: 1000 to 900 m.y. old biohermal structures (stromatolites) built by algae-bacteria are exposed in All Saint's - Sherwood College section. (a) Baicalia Baicalica; and (b) Minjaria. ***(Source: Plat 5 of Valdiya, 1998)***

events using TL dating techniques indicate that the major neotectonic activity took place around 40 ka ago along the Lake fault.

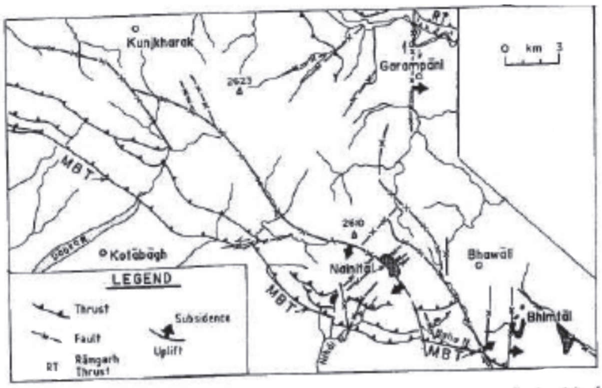


Fig. 2. Reactivation of the faults related to or branching off the MBT was responsible for the origin of lakes due to stream ponding in the very high mountains of the outermost Lesser Himālaya (modified after Valdiya[15]).

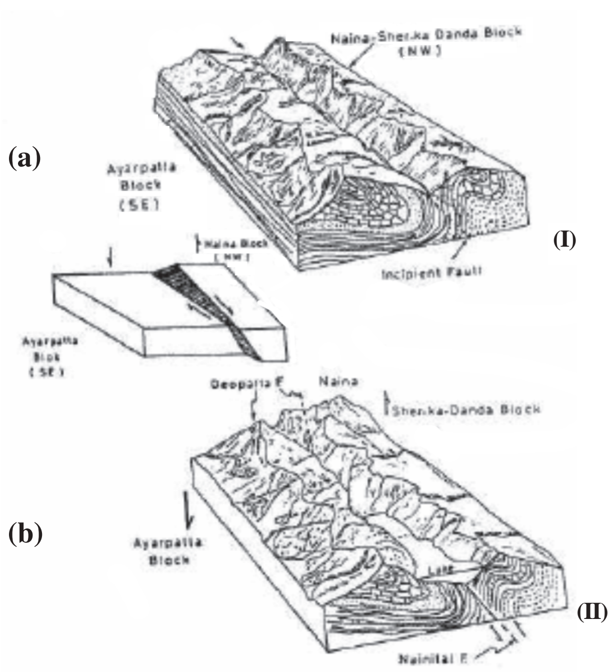


Photo 3a. Greenish grey gypsaceous silty shales and marls characteristic rocks of Lower Krol (Krol- A) are well exposed at Nainital Cantt.

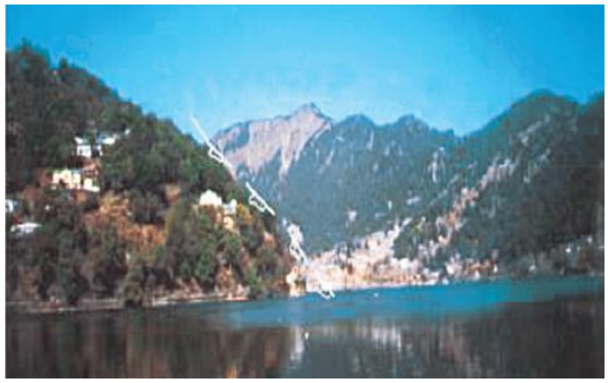


Photo 3b. The Lake Fault, Nainital.

SPOT: 3

LOCATION: Bhowali and Bhimtal

OBJECTIVES: To observe Quaternary-Holocene lake sediments of Bhowali and Bhimtal-Naukuchiatal basins.

Because of activeness of MBT and other faults, differential movements have taken place resulting in damming of drainage and formation of lakes. The lake basin of Bhowali (Ref. Fig. 2) was formed as a result of damming of ancient drainage in the Bhowali -Shyamkhet area due to neotectonic activity. The Bhowali -Shyamkhet tract is a wide valley with very gentle slopes. The Bhowali River in its upper reaches flows in a wide valley but has cut very deep gorge in the proximity of the active fault. Due to reactivation of the Ramgarh Thrust, the debris, avalanches resulting from slope failures dammed the Bhowali River resulting in the formation of the Bhowali and Shyamkhet lakes near Bhowali town (Ref. Fig. 2).

A At Bhowali, the section exposed along a gully cut by stream joining the Bhowali nala on the Bhowali-Ghorakhal road. The succession (base not exposed) is composed of alternating layers of silty clay and coarse gravels including a fluviolacustrine environment of deposition (Fig. 2). Muddy brown and dark coloured clays are of variable thickness. Laminations or wave ripples are absent. The sample in the top of the section was radiocarbon dated at 7.7. +0.13 ka.

B The ancient lake basin near Bhimtal was formed due to tectonic activity about 40-50 ka and drained out in the Holocene as a consequence of revival of fault movement (Photo 4). A ~52m thick upper Pleistocene-Holocene terrestrial succession in the Bhimtal-Naukuchiatal basin, south-central Kumaun Himalaya has been studied using sedimentological, chronological, palaeontological, palynological and 13C measurements. Originated at about 50 ka BP, the Bhimtal-Naukuchiatal Lake was a shallow and perennial lake. It was filled up by the fluvio-lacustrine processes operating in response to changing climate and tectonism in the Himalaya. The lakefill sequence comprises massive mudstone, silty sandstones, matrix- and clast-supported gravels (Ref.Fig.). The section shows characteristic evidence for climatic changes. At least two phases of humid climate were recognised. Preliminary palaeomagnetic studies revealed a reversal of polarity, correlatable with Mono Lake excursion. Prior to this, no reversal event in the upper Pleistocene–Holocene terrestrial sediments of Indian subcontinent is known. A fossiliferous horizon, discovered in the lower part of the section, consisted of *Sorex* and *Mus*. This is the only report of a late Pleistocene micro mammalian assemblage in the Kumaun Himalaya.

STOP: 4

LOCATION: Pandegaon (Bhimtal – Jangaliagaon road section)

OBJECTICES: To observe Palaeo-Proterozoic Bhimtal Volcanic suit

The Palaeo-Proterozoic volcanism has been found in abundance in the region of the Kumaun Himalaya that led the stretching and partings of the floor of the Lesser Himalayan Sea. The Bhimtal Volcanics are vesicular, amygdaloidal, cut by dolerite dykes and sills and are associated with spilitic lavas. The mode of the Bhimtal Volcanic Suites (BVS) and its explosive nature at very shallow-water sediments contemporaneous with sedimentation has been recognized. The lava was poured out by volcanoes related to faults and fractures which have developed simultaneously with increasing load of sediments. The outpouring of lava took place 2060 to 2500my ago. The mode of BVS emplacement and its explosive nature at very shallow-water sediments contemporaneous with sedimentation have also been recognized. The BVS and associated sedimentary formations are traversed by younger dyke and sills of dolerites transitional and gabbroids.

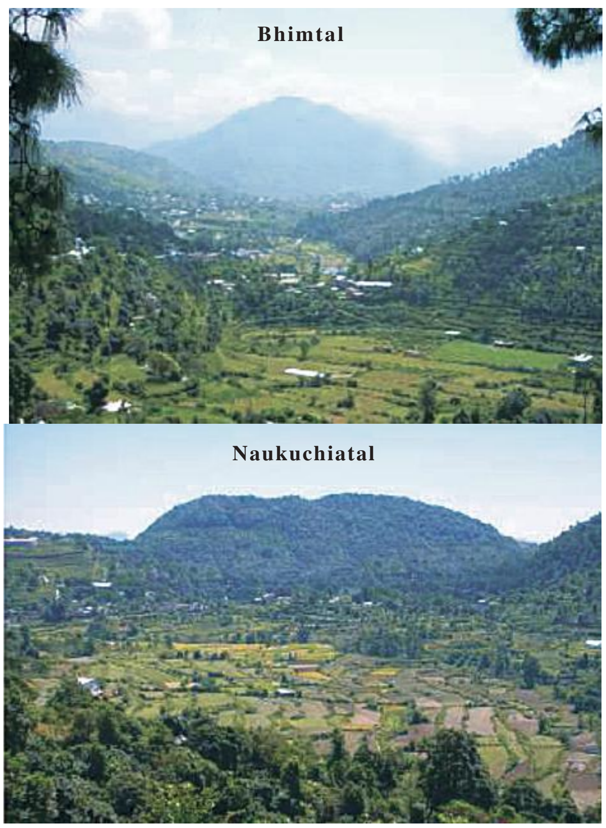


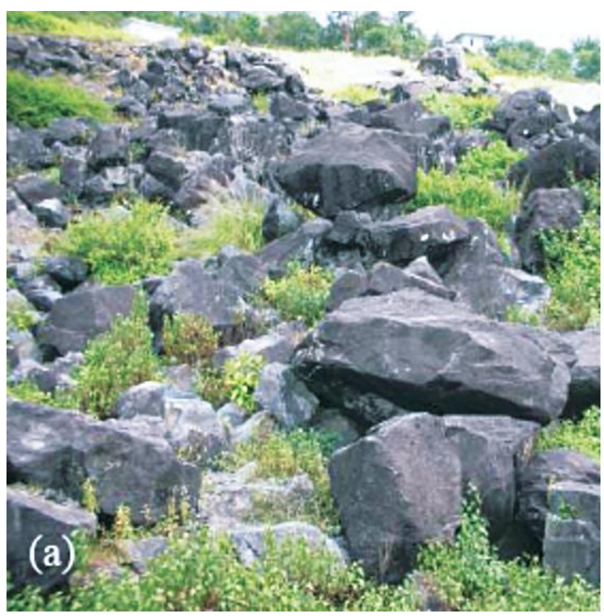
Photo 4. The ancient lake basin near Bhimtal - Naukuchiatal lake basins.

STOP: 5

LOCATION: Niglat (Bhowali Gaon)

OBJECTIVES: To observe the Lower-Proterozoic rocks of the Nagthat Formation

The Nagthat Formation, made up of a thick succession (~1400m) of quartzarenite associated with penecontemporaneous lava flows, constitutes the lowest siliciclastic litho unit of the Krol-Belt. The basaltic flows are interbedded with the quartzarenite horizons. It is overlain by the Blaini Formation with a distinct sharp contact. The quartzarenites sequence of the Nagthat Formation comprising fine to coarse-grained quartzarenite interbedded with siltstone and grey to pink silty shales, shows coarsening upwards (Ref. Photo 6). However, the unit facies cycles are 8-12m thick and fining up in nature. Large scale cross-bedding (8-50cm thick) with mud drapes, horizontal lamination with discordance, ripple cross-lamination, lenticular and flaser bedding, load structures and synsedimentary deformation are the noticeable features in the sequence.



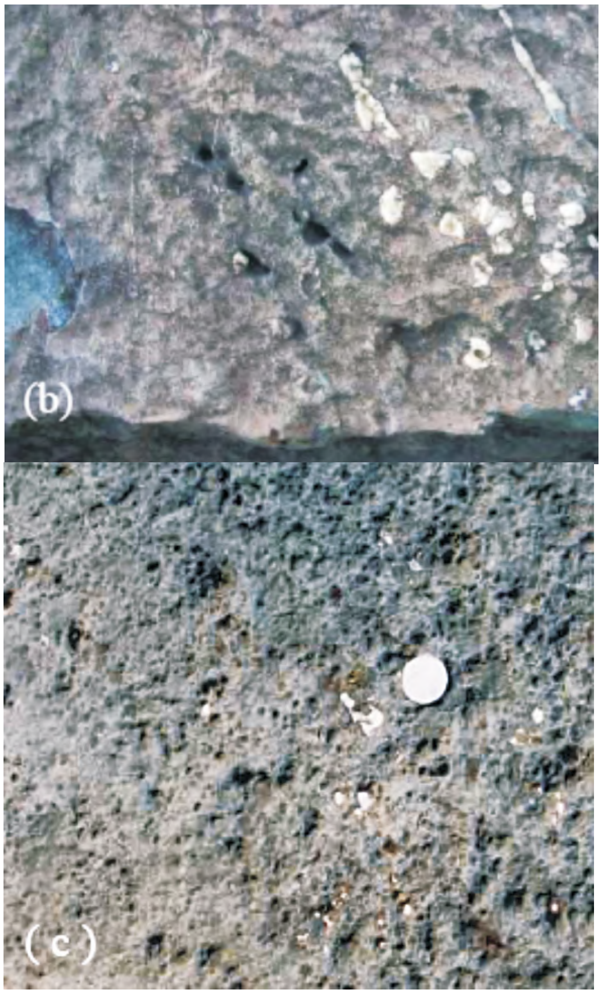


Photo 5a, b, c: The Bhimtal Volcanic Suites (BVS) contemporaneous with sedimentation has been found in abundance in the Bhimtal - Ratighat area such as (a & b) Pandegaon and (c) Sakuna.

SPOT: 6

LOCATION: Baldiyakhan

OBJECTIVES: To observe the Main Boundary Thrust (MBT)

The Main Boundary Thrust (MBT), generally steeply inclined thrust constitutes the boundary between the Lesser Himalayan parautochthonous formations of Precambrian age and autochthonous Cenozoic sedimentary rocks of Siwalik. An eloquent evidence of recent and sub-recent movements is discernible all through the extent of the MBT. The MBT zone is occupied by anomalously wide valleys characterized by discontinuous fringes comprising cones and fans of landslide debris. In the Baldiyakhan – Bajoon tract the Lower Siwalik, arkose sandstone, have been thrust over by dolomite and marls of Lesser Himalayan sequence. A series of landslide fans, fringing the southern scarp of Ayarpatta and Land-ends ridge are important geomorphic features of MBT.

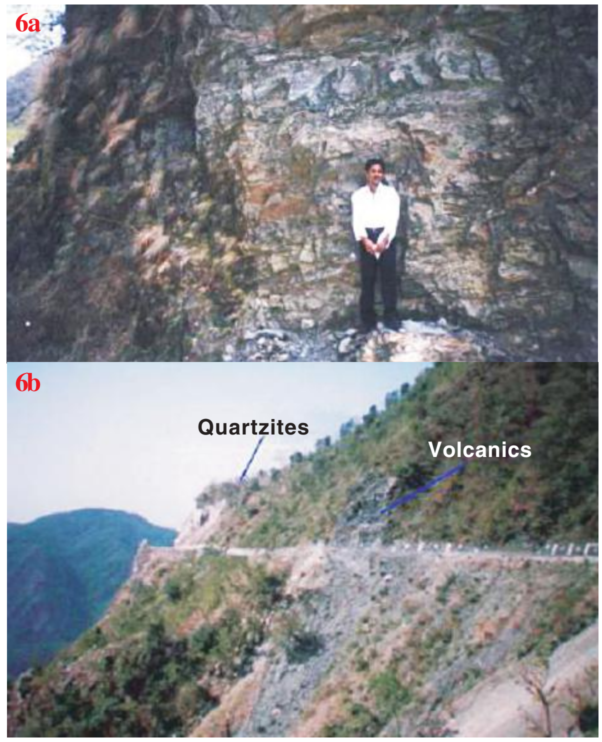
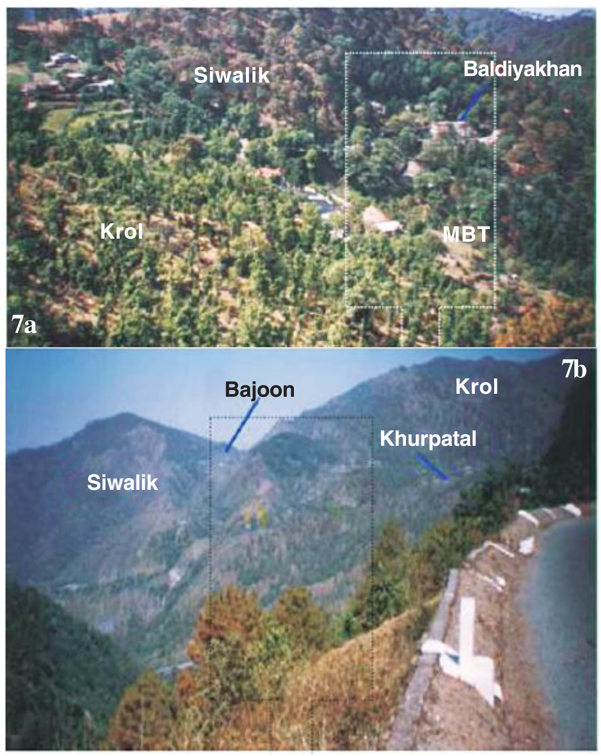


Photo 6a, b: Penecontemporaneous lava flows associated with a thick succession of quartzarenites constituting the lowest unit of the Nagthat Formation, exposed at (a) Niglat and (b) Sakuna, representing northern and southern limb of Bhowali anticline respectively.



Lower Siwalik (arkose sandstone) thrust over by dolomite and marls of Lesser Himalayan sequence mark the Main Boundary Thrust (MBT) as seen in the (a) Baldiyakhan and (b) Bajoon localities.

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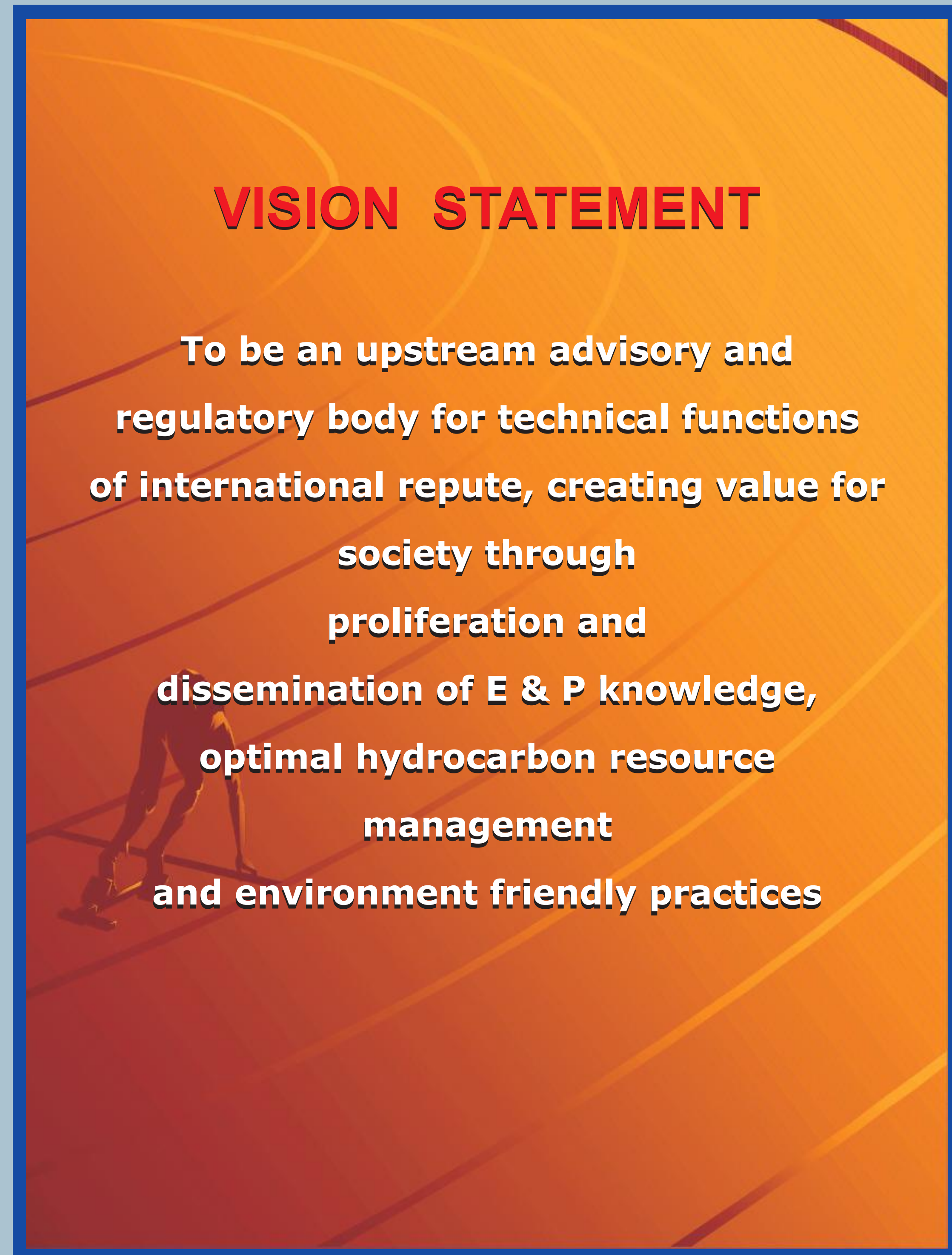

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