**UPDATED REPORT ON**

# BANGLADESH GAS RESERVE ESTIMATION 2010

**Under**

**Strengthening of Hydrocarbon Unit in the**

**Energy and Mineral Resources Division (Phase-II)**

**ADB Grant 0019: GTDP**

**For**

**HYDROCARBON UNIT**

**Energy and Mineral Resources Division**

**Government of the People's Republic of Bangladesh**

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# 1. SUMMARY

## 1.1 PREFACE

The current report is an update of the 2003 HCU-NPD gas reserves report entitled, "Bangladesh Gas Reserve Estimation 2003". As with the 2003 report, the present report only addresses the discovered gas reserves that are located in the country's 23 gas fields. At the time of the 2003 report, a total of 22 gas fields had been discovered. At the time the report was drafted, 12 of these fields were producing, 3 fields had been suspended, and 7 fields remained undeveloped, including Bibiyana gas field, which in 2010 is the largest single gas producer in Bangladesh accounting for approximately 33 percent of the nation's daily production.

Subsequent to the 2003 reserve report, one additional gas field, Bangora, has been discovered. At the end of 2009, the effective date for the present 2010 update of the previous reserve report, 17 gas fields were producing, 3 fields are suspended, and 3 fields remain undeveloped.

The results of this present study are expected to provide the Government, policy makers, geoscientists, petroleum engineers and other users' access to the current reserve base of the country. This updated information should help the planners to draw mid and long-term development plans from the individual field development level to the national level.

For this 2010 reserve update, a large body of literature including many pre-2003 technical reports on most of the gas fields was heavily relied upon for basic reservoir parameters and historic test data. This extensive set of documents and technical reports was assembled by the HCU for its 2003 report and is located in the HCU library.

In addition to the collection of pre-2003 reports, additional technical data that served to update the information from 2003 was provided directly by Petrobangla and its subsidiary companies BAPEX, BGFCL, SGFL and by the four International Oil Companies (IOCs) i.e. Chevron Bangladesh Ltd., Tullow Bangladesh Ltd., Cairn Energy Bangladesh Ltd., and Niko Resources

(Bangladesh) Ltd on a specific request basis. Contribution of Petrobangla, its subsidiaries, the International Oil Companies and other related agencies are sincerely acknowledged.

## 1.2 SUMMARY

The subject update to the estimated gas reserves for the country of Bangladesh yielded Proved plus Probable Gas Initially in Place (GIIP) of 35.5 Tscf for 23 gas fields. Table 1-1 shows a summary of the Proved plus Probable GIIP and reserves estimates. Table 1-2 shows Estimated Ultimate Recovery (EUR) and reserves by field and reserve category. Recoverable reserves are estimated at 24.3 Tscf (1P) and 28.2 Tscf (2P). Of this, 8.8 Tscf have been produced as of December 31, 2009, leaving 15.5 Tscf as remaining reserve (1P) or 19.5 2P. Possible reserves are estimated at 4.4 Tscf.

Titas remained as the largest gas field of the country with GIIP of 9.0 Tscf. In terms of GIIP, Bibiyana occupies second position with a GIIP of 5.3 Tscf. Titas also has slightly more reserves than Bibiyana, 4.5 as compared to 4.1 TCF, 2P. Begumganj is the smallest field with GIIP of 0.0047 Tscf.

Proved plus Probable estimated GIIP is compared to the 2003 reserve estimates as well as the results of the 2009 studies prepared by RPS Energy in Table 1-3 and Figure 1-1. The largest discrepancy in these numbers is for Bibiyana, where the previous 2P estimates were based on only the first two wells. The difference between the 3P estimates is much less. Another large difference is found for Titas. This number reflects the current A Sand estimated based on material balance, which is larger than the other estimates but in our opinion is more reliable.

## Table 1-1 Summary of Bangladesh Gas Reserves – 2010

(Figures in Bscf)

| Sl no. | Field | Operator | GIIP Proved + Probable | Expected Ultimate Recovery | Recovery Factor % | Cumulative Production, 12/09 | Remaining Reserves, 12/09 | Possible Reserves |
|---|---|---|---|---|---|---|---|---|
| **A. Developed Reserve** | | | | | | | | |
| **a. Producing** | | | | | | | | |
| 1 | Bakhrabad | BGFCL | 1,825 | 1,387 | 76.0% | 698 | 689 | 65 |
| 2 | Bangora | Tullow | 730 | 621 | 85.1% | 99 | 522 | 207 |
| 3 | Beani Bazar | SGFL | 225 | 137 | 60.9% | 60 | 77 | 32 |
| 4 | Bibiyana | Chevron | 5,321 | 4,532 | 85.2% | 476 | 4,056 | 457 |
| 5 | Fenchuganj | BAPEX | 483 | 329 | 68.1% | 72 | 258 | 146 |
| 6 | Habiganj | BGFCL | 3,981 | 2,787 | 70.0% | 1,671 | 1,116 | 434 |
| 7 | Jalalabad | Chevron | 1,346 | 1,128 | 83.8% | 545 | 583 | 122 |
| 8 | Kailas Tila | SGFL | 3,463 | 2,880 | 83.2% | 480 | 2,400 | 346 |
| 9 | Moulavi Bazar | Chevron | 630 | 494 | 78.3% | 152 | 342 | 108 |
| 10 | Narshingdi | BGFCL | 405 | 345 | 85.1% | 106 | 239 | 27 |
| 11 | Rashidpur | SGFL | 3,887 | 3,134 | 80.6% | 457 | 2,677 | 856 |
| 12 | Salda Nadi | BAPEX | 393 | 275 | 70.0% | 60 | 215 | 128 |
| 13 | Sangu | Cairn | 976 | 771 | 78.9% | 466 | 304 | 93 |
| 14 | Shahbazpur | BAPEX | 415 | 261 | 63.0% | 1 | 260 | 54 |
| 15 | Sylhet | SGFL | 580 | 408 | 70.4% | 189 | 219 | 103 |
| 16 | Titas | BGFCL | 9,039 | 7,582 | 83.9% | 3,068 | 4,514 | 754 |
| **b. Production Suspended** | | | | | | | | |
| 17 | Chattak (West) | SGFL | 677 | 474 | 70.0% | 26 | 448 | 253 |
| 18 | Feni | BAPEX-NIKO | 185 | 130 | 70.0% | 63 | 67 | 72 |
| 19 | Kamta | BGFCL | 72 | 50 | 70.1% | 21 | 29 | - |
| 20 | Meghna | BGFCL | 122 | 101 | 82.8% | 36 | 65 | 0 |
| Total Developed Reserve: | | | 34,757 | 27,826 | 80.1% | 8,746 | 19,080 | 4,258 |
| **B. Undeveloped Reserve** | | | | | | | | |
| 21 | Begumganj | BAPEX | 47 | 33 | 70.0% | 0 | 33 | 76 |
| 22 | Kutubdia | BAPEX | 65 | 46 | 70.0% | 0 | 46 | - |
| 23 | Semutang | BAPEX | 654 | 318 | 48.6% | 0 | 318 | 51 |
| Total Undeveloped Reserve: | | | 766 | 396 | 51.8% | 0 | 396 | 127 |
| **Total Reserves in BCF:** | | | **35,522** | **28,222** | 79.4% | **8,746** | **19,476** | **4,385** |
| **Total Reserve in Tcf:** | | | 35.5 | 28.2 | 79.4% | 8.7 | 19.5 | 4.4 |

*Best reconciled estimates. Note that the total reserves may not equal the total of the numbers shown above due to rounding.*

### Table 1-2 Gas Estimated Ultimate Recovery and Reserves by Category

| Field | Estimated Ultimate Recovery (Bscf) | | | Cumulative Production (Bscf) | Reserves (Bscf) | | |
|---|---|---|---|---|---|---|---|
| | $P_{90}$ | $P_{50}$ | $P_{10}$ | | $P_{90}$ | $P_{50}$ | $P_{10}$ |
| Bakhrabad | 1,200.7 | 1,387.2 | 1,594.4 | 698.1 | 502.6 | 689.1 | 896.3 |
| Bangora | 557.7 | 621.4 | 686.3 | 99.4 | 458.3 | 522.0 | 586.9 |
| Beani Bazar | 107.7 | 136.6 | 168.6 | 59.8 | 47.9 | 76.8 | 108.8 |
| Bibiyana | 4,075.2 | 4,531.7 | 4,988.3 | 475.7 | 3,599.5 | 4,056.0 | 4,512.6 |
| Fenchuganj | 194.5 | 329.3 | 475.8 | 71.6 | 122.9 | 257.7 | 404.2 |
| Habiganj | 2,412.8 | 2,786.8 | 3,220.8 | 1,670.9 | 741.9 | 1,115.9 | 1,549.9 |
| Jalalabad | 1,013.1 | 1,127.8 | 1,250.3 | 544.7 | 468.4 | 583.1 | 705.6 |
| Kailash Tila | 2,553.4 | 2,880.2 | 3,226.3 | 480.0 | 2,073.4 | 2,400.2 | 2,746.3 |
| Moulavi Bazar | 401.9 | 493.6 | 601.6 | 152.0 | 249.9 | 341.6 | 449.6 |
| Narshingdi | 316.8 | 344.7 | 371.5 | 106.2 | 210.6 | 238.5 | 265.3 |
| Rashidpur | 2,415.5 | 3,134.0 | 3,989.9 | 456.6 | 1,958.9 | 2,677.4 | 3,533.3 |
| Salda Nadi | 155.7 | 275.3 | 403.2 | 60.2 | 95.5 | 215.1 | 343.0 |
| Sangu | 677.3 | 770.5 | 863.7 | 466.1 | 211.2 | 304.4 | 397.6 |
| Shahbazpur | 213.7 | 261.2 | 315.7 | 1.3 | 212.4 | 259.9 | 314.4 |
| Sylhet | 322.7 | 408.3 | 511.5 | 189.3 | 133.4 | 219.0 | 322.2 |
| Titas | 6,837.8 | 7,582.2 | 8,336.4 | 3,068.0 | 3,769.8 | 4,514.2 | 5,268.4 |
| Chhatak (West) | 265.0 | 474.0 | 727.0 | 25.8 | 239.2 | 448.2 | 701.2 |
| Feni | 62.8 | 129.6 | 202.0 | 62.8 | 0.0 | 66.8 | 139.2 |
| Kamta | 21.1 | 50.3 | 50.3 | 21.1 | 0.0 | 29.2 | 29.2 |
| Meghna | 76.4 | 101.2 | 208.6 | 36.2 | 40.2 | 65.0 | 172.4 |
| Begumganj | 10.0 | 32.7 | 108.0 | 0.0 | 10.0 | 32.7 | 108.0 |
| Kutubdia | 45.5 | 45.5 | 45.5 | 0.0 | 45.5 | 45.5 | 45.5 |
| Semutang | 318.0 | 318.0 | 318.0 | 0.0 | 318.0 | 318.0 | 318.0 |
| **TOTAL** | 24,255.3 | 28,222.1 | 32,663.6 | 8,745.8 | 15,509.5 | 19,476.3 | 23,917.8 |

*Best reconciled estimates. Note that the total reserves may not equal the total of the numbers shown above due to rounding.*

### Table 1-3 Comparison of GIIP with Earlier Estimates

| Field | GIIP, Bscf | | | | Maps Used for Areas | Vintage |
|---|---|---|---|---|---|---|
| | HCU/NPD 2003 2P | 2010 RPS Petrobangla | | 2010 GA Reconciled* | | |
| | | Volumetric | Sim/Mat Bal | | | |
| Bakhrabad | 1,499 | 1,418 | 1,700 | 1,825 | RPS Study | 2010 |
| Bangora | 637** | | | 730 | **Tullow estimate | 2005 |
| Beani Bazar | 243 | 231 | 231 | 225 | RPS Study | 2010 |
| Bibiyana | 3,145 | | | 5,321 | D&M (Ryder Scott 2P GIIP 5.9 TCF) | 2000 |
| Fenchuganj | 404 | 447 | 450 | 483 | Petrobangla Report | 1988 |
| Habiganj | 5,139 | 3,103 | 3,684 | 3,981 | RPS Study | 2010 |
| Jalalabad | 1,195 | | | 1,346 | Degolyer & McNaughton (1490 Bscf) | 1999 |
| Kailash Tila | 2,720 | 3,540 | 3,610 | 3,463 | RPS Study | 2010 |
| Moulavi Bazar | 449 | | | 630 | Unocal Report | 2003 |
| Narshingdi | 307 | 365 | 369 | 405 | RPS Study | 2010 |
| Rashidpur | 2,002 | 4,191 | 3,650 | 3,887 | RPS Study | 2010 |
| Salda Nadi | 166 | 384 | 380 | 393 | RPS Study | 2010 |
| Sangu | 1,031 | | | 976 | Shell (Cairn 814 Bscf, 2010) | 2000 |
| Shahbazpur | 665 | 394 | 393 | 415 | BAPEX report | 1996 |
| Sylhet | 684 | 528 | 370 | 580 | RPS Study | 2010 |
| Titas | 7,325 | 7,169 | 8,148 | 9,039 | RPS Study | 2010 |
| Chhatak (West) | 677 | | | 677 | previous studies audited and accepted | |
| Feni | 185 | | | 185 | previous studies audited and accepted | |
| Kamta | 72 | | | 72 | previous studies audited and accepted | |
| Begumganj | 47 | | | 47 | previous studies audited and accepted | |
| Meghna | 171 | 185 | 185 | 122 | previous studies audited and accepted | |
| Kutubdia | 65 | | | 65 | previous studies audited and accepted | |
| Semutang | 227 | 654 | 654 | 654 | previous studies audited and accepted | |
| **Total** | **28,418** | | | **35,522** | | |

*Note that the total reserves may not equal the total of the numbers shown above due to rounding.*

* These represent Gustavson's best estimate, and may be a combination of material balance and volumetric calculations

** Bangora Field was not included in the 2003 report. The numbers shown here are Tullow's estimates from 2005.

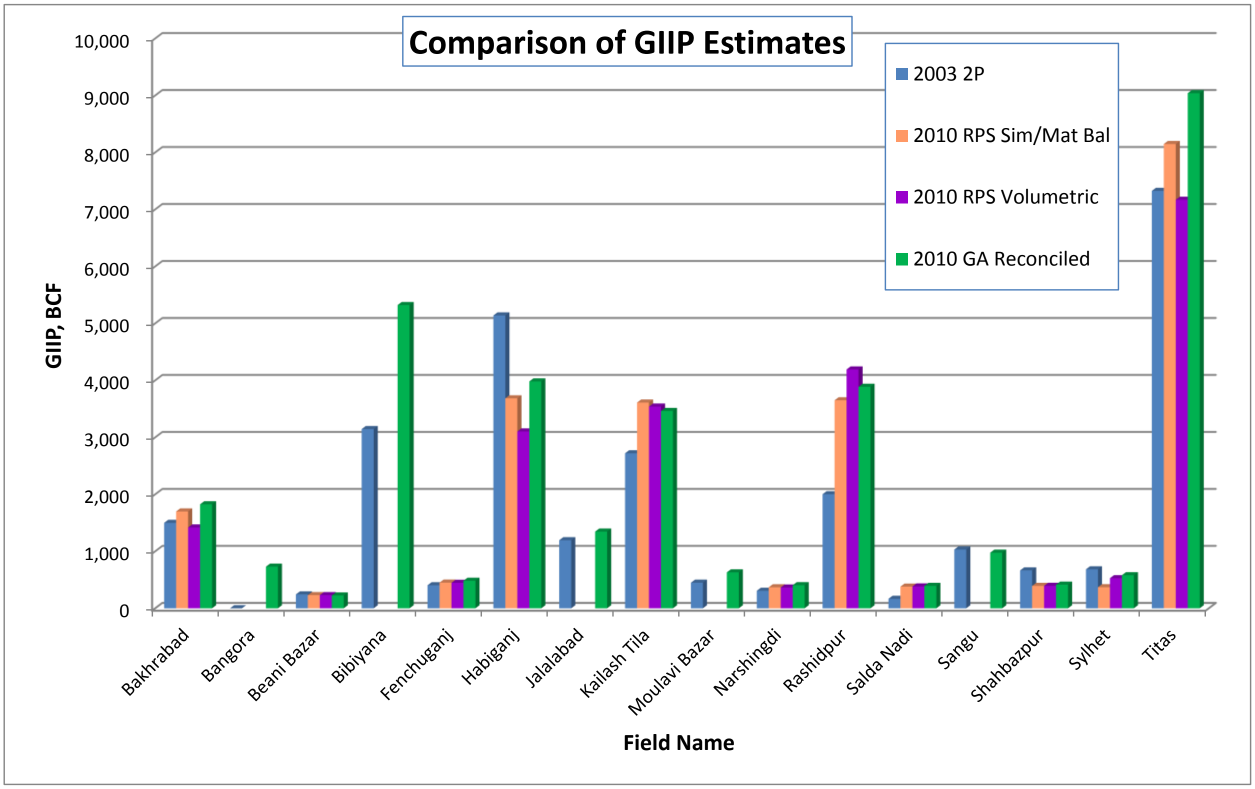



**Figure 1-1 Comparison of GIIP with Previous Estimates**

## 1.3 <u>RECOMMENDATIONS</u>

There are opportunities to increase both production and reserves from some of the existing fields in Bangladesh. The Government should carefully consider policies and support in order to encourage the companies to take advantage of these opportunities. These opportunities are discussed in more detail in Section 8 of this report.

The current block size is approximately 5,000 sq. km. for both onshore and offshore blocks. Given the exploratory nature of the offshore and logistical considerations, the size of the offshore blocks could be increased in future bid rounds. The minimum work commitment should be evaluated to insure that maximum development is taking place by the companies operating them. Production companies should draw a plan for optimizing production from the reservoir management point of view. At present all the wells in producing gas fields are continuously producing to cope with the demand. This cannot be considered as a comfortable situation. Any interruption in gas supply due to well/reservoir/process plant will result in disruption of gas supply to consumers including power plants and / or other major consumers. Because of such marginal production capacity of wells in a field, production cannot even be shut down for pressure survey which is a prerequisite for reservoir management. To address this critical situation, it is recommended that pressure surveys could be obtained during long holidays when demand decreases.

### 1.3.1 Production Enhancements

Most of the opportunities for production enhancements at existing fields are operational in nature and would be achieved through redesign and upgrades to surface facilities, installing compression, making changes in wellbore design, improved reservoir management, and implementing workovers and recompletions of existing and suspended wells. These issues have in some cases been studied in detail as a result of recent consulting projects commissioned by various Petrobangla companies. Implementation requires capital investment and the government should encourage companies to make these operational improvements.

### 1.3.2 Rate Acceleration

That are some fields still have a relatively low drilling density in comparison with the overall size of the reservoir limits. It would be possible to increase gas production through encouragement of additional drilling in the fields as a form of rate acceleration. Additional drilling may or may not result in increases (also possibility of decreases) in reserves and increases in rate at a specific field should be implemented after careful study so as not to damage the reservoir. Specifically, rates at the Bibiyana field could possibly be increased through the drilling of additional wells in low density areas of the field.

### 1.3.3 Reserve Growth

There are opportunities to increase reserves through the acquisition and interpretation of new 3D seismic surveys and also analysis of bypassed pay zones in existing fields. Some of this work is ongoing while some has not yet been implemented.

### 1.3.4 Field Specific Recommendations

#### 1.3.4.1 Developed Gas Fields

**Producing Fields**

**Bakhrabad**

- There is recompletion potential for certain zones that are behind pipe but have not yet been completed for production.

**Bangora**

- Plans for additional work were reported in the Tullow questionnaire and these appear to be comprehensive and prudent, no recommendations are made at this time.

**Bibiyana**

- No detailed information was provided and therefore no recommendations are made for this field.

**Beani Bazar**

- Additional seismic data may be recorded to confirm existence of gas on the south.

**Fenchuganj**

- The field is currently producing. Recommendation is to acquire additional seismic to better define the reservoir prior to full field development.

**Habiganj**

- There is potential for improvements to both facility and well design and operations to reduce inefficiencies and improve production.

**Kailash Tila**

- 3D seismic survey was recommended in the 2003 HCU/NPD report and still should be conducted. This new survey will help in delineating a tested oil zone and also additional pay zones that may be contained within stratigraphic traps.

**Meghna**

- The current workover and recompletion in another pay zone may bring the field back into production.

**Narshingdi**

- An additional well has been drilled and is under production and at this time. There is limited potential for any future upside.

**Rashidpur**

- 3D seismic survey is currently being acquired over the structure. Based on the result of seismic survey and pressure data analysis from existing wells, field development plan can be better defined.

**Salda Nadi**

- After review of new maps and information, the recommendations from the 2003 HCU/NPD report are still considered reasonable and presented below:
  - Due to the discontinuous nature of the reservoir sands, high resolution/3D seismic will be required. As the north, south, and eastern parts of the structure is within Indian territory, seismic will be a difficult option. Drilling of several wells using a truck-mounted rig and monobore completion could be an option. Alternatively,
  - Cooperation with Indian oil company ONGC could be considered.

**Sangu**

- Plans for additional work were reported in the Cairn questionnaire and these appear to be comprehensive and prudent; therefore, no recommendations are made at this time.

**Shahbazpur**

- Currently producing from one well. Recommendation is to acquire additional seismic to better define the reservoir.

**Sylhet**

- Consider drilling nearby relief wells to drain gas leaking from previous blow-out.
- A high resolution 3D seismic survey should be conducted over the structure.

- Based on the result and interpretation of seismic survey, the structure and the discrete reservoirs in the field should be better mapped and defined for additional drilling targets.
- Run cased-hole logs to evaluate source of high water production to properly design remedial work to shut off water influx
- Rename Surma well 1 as Sylhet well 8.

**Titas**

- 3D seismic survey is planned for acquisition next dry season, likely in 2011. Based on the results and interpretation of the seismic survey, the reservoir can be mapped with a higher degree of resolution and accuracy, especially the B and C sands. Based on this analysis, a prudent field development plan can be prepared.

**2. Suspended Gas Fields**

**Chhatak and Feni**

- These fields still have substantial remaining reserves; all efforts should be made to bring these fields back into production to augment daily production volumes for the country.

**Kamta**

- Field is currently being reevaluated and there are no recommendations at this time.

### 1.3.4.2 Undeveloped Gas Fields

**Begumganj**

- This field is currently being reevaluated for new well drilling and there are no recommendations at this time.

**Semutang**

- Field is currently being considered for redevelopment and no recommendations are made at this time.

# 2. INTRODUCTION

## 2.1 PURPOSE AND SCOPE OF PROJECT

The Hydrocarbon Unit of the Energy and Mineral Resources Division (HCU) was assigned the task of re-estimating the country's gas reserves. This effort represents the first coordinated countrywide estimate that has been undertaken by the HCU since the reserves were estimated by the government agency in its 2003 published report.

The work on "Updated Report on Bangladesh Gas Reserve Estimation", the 2010-2011 update to the HCU-NPD 2003 report entitled "Bangladesh Gas Reserve Estimation 2003" was started in November, 2009. This 2010-2011 report's focus is on the update of the gas reserves of the country's discovered gas fields including the re-estimation of gas originally in-place (GIIP), updating of production history through December, 2009, and the estimation of the remaining gas and condensate reserves as of the country's gas fields as of the end of December, 2009 – the effective date of this report. A re-estimation of Bangladesh's undiscovered oil and resources will be the subject of a second report.

For updating the gas reserves of the country, a nine member technical expert team was formed with members drawn from the Hydrocarbon Unit (HCU), Gustavson Associates LLC, and in-country technical experts under contract to Gustavson Associates. The contract technical experts have many years of experience with oil and gas exploration and development with Petrobangla and its subsidiaries and predecessors and are highly valued member of the team. A list of the team members is given below:

Engr. Anwar H. Khan, Director General, Hydrocarbon Unit, Project Director (Engineer)
Mr. Abu Syed Mohammed Faisal, Assistant Director (Geologist), Hydrocarbon Unit
Mr. M. Moinul Huq, Strategic Policy Expert (Consultant), Hydrocarbon Unit (Geologist)
Mr. Edwin C. Moritz, Gustavson Associates Team Leader, President, Gustavson Associates LLC (Geologist)
Ms. Letha Lencioni, Gustavson Chief Reservoir Engineer
Mr. Kenneth W. Grove, Gustavson Chief Geologist
Mr. Md. Maqbul-E-Elahi, National Consultant (Geologist)
Mr. M. Jamaluddin, National Consultant (Geophysicist)
Mr. Rick Hildebrand, Gustavson Staff Geologist

According to the current industry practice, volumetric estimates can be done following deterministic and probabilistic methodologies. The deterministic method was traditionally widely used both within Bangladesh as well as worldwide for many years. However, in more recent years, the probabilistic methodology has been widely accepted as the methodology of choice by the international oil and gas community, governmental entities, and the banking community because it can take into account and evaluate uncertainties in the technical parameters used to calculate oil and gas reserves.

In the Deterministic method a single best estimate of reserves is made based on known geological, engineering, and economic data. Single-value estimates of the various reservoir parameters are used to calculate the reserves. This method does not take into account the uncertainties associated with the individual parameters.

When a range of estimates and their associated probabilities is generated using ranges of known geological, engineering, and economic data the method is called Probabilistic. Each reservoir parameter is assigned a range of values and a probability distribution is generated for the parameter. All of the independent parameter probability distributions are then analyzed using Monte Carlo probabilistic modeling software to yield a probability distribution of the estimates of reserves.

A more detailed discussion of the two volumetric approaches to reserves estimation is included in Chapter 5 of this report.

For the re-estimation of reserves for this 2010 update report, we have relied heavily on the application of the probabilistic volumetric methodology supplemented by material balance where appropriate and where required data is available. We believe that the use of the probabilistic approach is following a "best engineering practices" approach which is now widely accepted as the benchmark for reserves estimation.

The gas fields of the country are divided into two groups – Developed Gas Fields and Undeveloped Gas Fields. For the purpose of re-estimation, developed gas fields are divided into two subgroups. Producing Gas Fields and Suspended Gas Fields. Under each group/subgroup fields are discussed in alphabetical order. Each field also carries a number in parenthesis which is its current ranking on the basis of production level in 2009.

## 2.2 DATA SOURCES AND LIMITATIONS

For updating of the gas reserves, old reports for selected fields were used extensively including: field appraisal reports, reserve reports, individual well reports where available, petrophysical reports, reservoir engineering reports, well test and pressure analysis reports, daily and monthly production and other relevant data. Most of these reports were previously acquired by the HCU for its 2003 study from Petrobangla and its subsidiaries and International Oil companies (IOCs). Requests for updated technical information on critical fields were made directly to Petrobangla and indirectly to the IOCs through Petrobangla. The results of the requests were mixed with regard to obtaining new post-2003 information, particularly on Bibiyana, the currently largest single producing gas field in the country.

## 2.3 ORGANIZATION OF THE REPORT

This report is organized into eight sections that follow the Executive Summary and Introduction sections. Section 2 is a review of earlier reserve estimation reports that have been prepared for either multiple fields or the entire country of Bangladesh. Various summary tables are presented to present these prior estimates. Section 3 is a discussion of the different reserve classification systems and definitions that have been considered for reporting purposes. The internationally recognized PRMS reserve classification system is discussed and is also reproduced in Appendix A.

As part of our report, we have included a review of production rate practices in Section 4. Questionnaires were sent to various companies regarding their practices and their responses have been included in Appendix B. Section 5 presents the detailed findings of the updated reserve estimates. Reserve estimation methodologies are first discussed and then the results are discussed and presented for each field. Section 6 summarizes the results of the updated reserve estimates.

Opportunities for enhancing production and increasing reserves are discussed in Section 7 of the report. There are opportunities to improve production through facilities, workovers and compression and to increase reserves through 3D seismic and identification of bypassed pay zones. A reference for the abbreviations and acronyms used in the report is provided in Section 8 followed by a bibliography and subsequent appendices. Individual well production history charts are included in a separate annex volume.

## 3. REVIEW OF EARLIER RESERVE ESTIMATION REPORTS

As part of the reserve re-estimation/evaluation 2010, reports prepared by different authors and organizations over the years are reviewed and results of the review are discussed in this chapter. This follows the precedent set in the Bangladesh Gas Reserve Estimation Report produced through the joint efforts of the Hydrocarbon Unit (HCU) and the Norwegian Petroleum Directorate (NPD). Because that report discusses earlier reserve estimates in great detail, only a summary of the early findings will be presented in the present report. The reader is referred to the HCU-NPD 2003 report for a thorough and exhaustive review of all of the major pre-2003 reserve estimates. This present 2010 report will also include a summary of the findings of the 2003 report.

Only countrywide reserve reports incorporating multiple gas fields are included in this chapter as an overview of the history of knowledge regarding Bangladesh's discovered gas reserves over the 55-year period spanning the initial gas discoveries of Sylhet and Chhatak gas fields in 1955 and 1959. Reports on individual gas fields are discussed under respective gas fields. In the tables in this chapter, the gas fields are arranged alphabetically for the reader's convenience.

A total of 23 gas fields have been discovered in Bangladesh since 1955. Only one new gas field has been discovered since the HCU-NPD 2003 reserves report. Bangora gas field was discovered by Tullow in 2004. Of the 23 discoveries, 17 fields are currently producing, 3 fields are suspended, and 3 fields are undeveloped and have not been produced. Out of 23 gas fields discovered so far, 8 were discovered prior to Bangladesh's independence in 1971. Except for one field, International Oil, companies made all these early discoveries.

Post-discovery reserve estimation reports of these fields could not be located in some cases. However in some of the reports compiled by Petrobangla, post-discovery estimated figures have been reported.

After 1971, a good number of studies were undertaken by Petrobangla to update the reserve base. Most of these reports are prepared by third party consultants. One of the earliest reports was prepared by DeGolyer and MacNaughton (D & M) in 1978 but this report could not be located for either the HCU 2003 report or the present one. In 1979, Petrol-Consult GmbH prepared a report on gas reserve of Bangladesh and this report included eight gas fields.

During 1980, four additional reserve estimates were published incorporating data from 4-10 fields depending on the study. Those studies were by Khan and Husain, IMEG, Khan and Badruddoja, S.M. Mamun, and R. Schmidt and T. Haque.

Under a German technical assistance program, gas reserves for the country were re-estimated in 1982 by R. Schmidt and T. Haque. The authors, for the first time, used the probabilistic method for volumetric estimates. This report could not be located but a summary of their results was included in the HCU-NPD 2003 reserve report. For some of the fields, reserve estimates were carried out by Petrobangla with technical assistance from advisors provided by the former Soviet Union.

Welldrill, a consulting house, conducted the first major study on the reserve and resource base of the country during 1984-86 and this was part of Petroleum Exploration Promotion Project (PEPP). The Report on the Hydrocarbon Habitat Study in Bangladesh (HHSP), published in 1986, is the outcome of this project. Welldrill followed up their original reserve study with updates in 1987, 1990, 1991, and 1993. Details of their 1991 update were included in the HCU-NPD 2003 reserve report and are also reviewed here.

Also in 1986, under German technical assistance program, re-estimation of the gas reserves for ten gas fields and resource potential for a number of prospects was estimated and reported by M. Eder and G. Hildebrand.

In the subsequent years, several other studies were conducted by independent agencies under different programs of technical/financial assistance. Apart from these studies, individual discoveries were followed by reserve estimation by the operating companies. All of those reports were not available for this study. However, a number of these reports could be collected and added as part of the HCU database.

Table 3-1 below lists all of the major countrywide estimates that have been performed during the period from 1979 through 2008. This list has been compiled from the HCU-NPD 2003 reserve estimation report described in the opening section of this chapter and a recently published paper by M.B. Haq and M.K. Rahman of the School of Mechanical Engineering, University of Western Australia (Haq and Rahman, 2008). For the reader's convenience, the four most recent countrywide gas reserve/GIIP estimates are summarized in tabular form in Tables 3-2 through Table 3-5.

With the exception of the 2003 HCU-NPD report, all of the estimations reported only initial recoverable reserves based on estimated recovery factors applied to the GIIP estimates. In their 2003 report, HCU-NPD also accounted for cumulative production to June 2003 and also estimated the remaining recoverable reserves as of that date. The HCU-NPD 2003 estimate of remaining recoverable reserves is included in Table 3-4 below. In our 2010 update report, we will follow the same practice.

Subsequent to the 2003 HCU-NPD reserve report, two additional reserve estimate studies have been published. M.B. Haq and M.K. Rahman of the School of Mechanical Engineering, University of Western Australia did a comparative study of three methods for estimating GIIP for 15 gas fields in Bangladesh. They calculated GIIP using a traditional volumetric approach, a standard material balance methodology using shut-in formation pressures, and a flowing material balance methodology using flowing wellhead pressure (FWHP) rather than shut-in bottomhole pressures (SIBHP). Haq and Rahman did not attempt to estimate recoverable reserves. Their GIIP estimates are presented in Table 3-5.

Additionally, another major multi-field reserve study has been recently completed. RPS Energy, under contract to Petrobangla, performed a comprehensive reservoir engineering-geological-geophysical-petrophysical-and reservoir simulation study of 14 gas fields that are operated by BGFCL, SGFL, and BAPEX. The study estimated GIIP and technically recoverable reserves for each field, incorporating history matching of production and reservoir simulation using the Petrel and Eclipse modeling software developed by Schlumberger. The results of the study were released in mid- to late 2009 in a series of six technical discipline reports for each field.

The results of the new RPS Energy study are summarized under the sections for the subject fields in Chapter 6 of this report along with a review of previous reserve estimates including those from the HCU-NPD 2003 reserve report.

**Table 3-1 Summary of Previous Reserve Estimates 1979-2008**

| Year | Estimator | No. of Fields Included in Estimate | Aggregate GIIP (Bscf) | Initial Recoverable Reserves (Bscf) | Remarks |
|---|---|---|---|---|---|
| 1979 | Petrol-Consult GmbH | 8 | | 5390 (P50) | Probabilistic Methodology |
| 1980 | Khan & Husain | 8 | | 7310 | |
| 1980 | IMEG | 4 | 4693-4954 | 2386-2529 | |
| 1980 | Khan & Badruddoja | 10 | | 7500-11,780 | |
| 1980 | S.M.Mamun | 9 | | 9300-10,400 | |
| 1982 | R. Schmidt & T. Haque | 7 | | 5579.7 (P50) | Probabilistic Methodology |
| 1986 | M. Eder & G. Hildebrand | 10 | 12,543.6 (P50) | 9449.7 (P50) | Probabilistic Methodology |
| | | | 12,834.6-13,078.8 | 9614.3-9776.4 | Deterministic Methodology |
| 1986 | HHSP, Welldrill | 13 | 13,068 (2P)<br>22,760 (3P) | 12,775.6 (2P)<br>20,534.2 (3P) | |
| 1989 | Petrobangla/HHSP | 14 | | 14,140 (2P) | |
| 1989 | Gasunie | 14 | | 4771 (1P )<br>11,440 (Exp.)<br>18,340 (High) | |
| 1991 | Welldrill | 17 | 22,620 (2P) | 16,780 (2P) | |
| 1989-1992 | IKM | 8 | 15,650.3 (2P)<br>17,182.4 (3P) | 8775.1 (2P) | |
| 1992 | Gasunie | 17 | 26,074 (2P) | 15,559.49 (2P) | |
| 1993 | Petrobangla | 17 | 21,300 | 12,430 | |
| 1997 | Petrobangla | 20 | 23,090 (2P) | 13,740 (2P) | |
| 2001 | PMRE-BUET | 15 | 28,490 | | Volumetric Methodology |
| | | | 24,400 | | Material Balance |
| 2001 | HCU/NPD Resource Study | 22 | 28,767 (2P)<br>40,221 (3P) | 20,421 (2P)<br>28,452 (3P) | Volumetric Methodology +<br>Material Balance (5 fields) |
| 2002 | National Committee | 22 | 28,373 (2P)<br>32,509 (3P) | 20,150.3 (2P) | Estimate 1 |
| | | | 25,839.8 (2P)<br>37,680.4 (3P) | 16, 633.0 (2P) | Estimte 2<br>(incl. re-estimate of<br>4 largest fields) |
| 2003 | HCU/NPD<br>Gas Reserve Estimation<br>Study | 22 | 28,417 (2P)<br>38,400 (3P) | 20,500 (2P)<br>28,200 (3P) | first study to report<br>remaining reserves<br>(initial recov. res. - cum. prod.) |
| 2008 | M.B. Haq & M.K. Rahman | 15 | 24,401 (1P) | | Volumetric Methodology |
| | | | 28,490 (1P) | | Material Balance (FWHP) |

**Table 3-2 HCU-NPD 2001 Bangladesh Petroleum Potential and Resource Assessment Gas Field Reserve Estimate**

| Name of Gas Field | GIIP (Bscf) | | | Recoverable Reserve (Bscf) | | |
|---|---|---|---|---|---|---|
| | P1+P2 | P3 | Total | P1+P2 | P3 | Total |
| Bakhrabad | 1432 | | 1432 | 1002 | | 1002 |
| Beani Bazar | 243 | | 243 | 170 | | 170 |
| Begumganj | 46 | 108 | 154 | 32 | 76 | 108 |
| Bibiyana | 3145 | 3422 | 6567 | 2202 | 2395 | 4597 |
| Chhatak | 474 | 254 | 728 | 332 | 178 | 510 |
| Fenchuganj | 404 | | 404 | 283 | | 283 |
| Feni | 165 | 72 | 237 | 116 | 50 | 166 |
| Habiganj * | 5139 | | 5139 | 3854 | | 3854 |
| Jalalabad | 1256 | | 1256 | 879 | | 879 |
| Kailash Tila* | 2720 | 1279 | 3999 | 1931 | 908 | 2839 |
| Kamta | 38 | 11 | 49 | 27 | 8 | 35 |
| Kutubdia | 861 | | 861 | 603 | | 603 |
| Meghna | 159 | 128 | 287 | 111 | 90 | 201 |
| Moulavi Bazar | 500 | | 500 | 350 | | 350 |
| Narshingdi | 111 | 84 | 195 | 77 | 59 | 136 |
| Rashidpur* | 2002 | 2674 | 4676 | 1401 | 1872 | 3273 |
| Salda Nadi | 200 | | 200 | 140 | | 140 |
| Sangu | 1049 | 365 | 1415 | 734 | 256 | 990 |
| Semutang | 174 | | 174 | 122 | | 122 |
| Shahbazpur | 665 | 957 | 1621 | 465 | 670 | 1135 |
| Sylhet | 684 | | 684 | 479 | | 479 |
| Titas * | 7300 | 2100 | 9400 | 5110 | 1470 | 6580 |
| Total | 28767 | 11454 | 40221 | 20421 | 8032 | 28452 |

* Material Balance HCU-NPD, 2001

## Table 3-3 National Committee 2002 Gas Field Reserve Estimate 2

| Name of Gas Field | GIIP (Bscf) | | | | Recoverable Reserve (Bscf) | |
|---|---|---|---|---|---|---|
| | Proved P1 | Probable P2 | P1+P2 (2P) | Possible P3 | R.F. | P1+P2 (2P) |
| Bakhrabad | 1369.7 | 62.3 | 1432.0 | | 0.6 | 873.5 |
| Beani Bazar | 243.1 | | 243.1 | | 0.7 | 158.0 |
| Begumganj | 14.0 | 32.6 | 46.6 | 107.7 | 0.7 | 30.3 |
| Bibiyana | 1583.7 | 1660.9 | 3144.5 | 3422.7 | 0.8 | 2389.8 |
| Chhatak | 265.0 | 209.0 | 474.0 | 728.0 | 0.6 | 284.0 |
| Fenchuganj | 85.0 | 319.0 | 404.0 | | 0.7 | 262.6 |
| Feni | 66.0 | 105.0 | 171.0 | 207.0 | 0.6 | 102.6 |
| Habiganj | 3501.7 | | 3501.7 | | 0.5 | 1820.9 |
| Jalalabad | 1015.3 | 179.4 | 1194.7 | 299.3 | 0.6 | 685.8 |
| Kailash Tila | 1722.1 | | 1722.1 | 1780.0 | 0.7 | 1188.2 |
| Kamta | 38.0 | | 38.0 | 36.0 | 0.6 | 22.8 |
| Kutubdia | 61.0 | 800.0 | 861.0 | | 0.6 | 559.7 |
| Meghna | 76.0 | 83.0 | 159.0 | 128.0 | 0.7 | 103.4 |
| Moulavi Bazar | | | 500.0 | | 0.7 | 350.0 |
| Narshingdi | 64.8 | 46.0 | 110.8 | 84.0 | 0.7 | 72.0 |
| Rashidpur | 1304.3 | 697.8 | 2002.0 | 2948.0 | 0.6 | 1161.2 |
| Salda Nadi | 134.8 | 244.8 | 379.6 | | 0.7 | 246.7 |
| Sangu | 592.0 | 439.0 | 1031.0 | | 0.8 | 845.4 |
| Semutang | 24.5 | 149.7 | 174.2 | | 0.7 | 113.3 |
| Shahbazpur | 306.6 | 207.2 | 513.8 | | 0.7 | 334.0 |
| Sylhet | 383.0 | 61.0 | 444.0 | | 0.7 | 288.6 |
| Titas | 4045.6 | 3247.1 | 7292.8 | 2100.0 | 0.7 | 4740.3 |
| Total | 16896.1 | 844.7 | 25839.8 | 11840.6 | | 16633.0 |

National Committee, 2002, Estimate 2

## Table 3-4 HCU-NPD 2003 Bangladesh Gas Reserve Estimation

Figures in Bscf

| Sl no. | Field | GIIP Proved + Probable | Recoverable | Recovery Factor % | Additional Recovery Using Compressor ( 500 psi ) | Possible Rec. |
|---|---|---|---|---|---|---|
| 1 | Bakhrabad | 1499 | 1049 | 70 | | |
| 2 | Beani Bazar | 243 | 170 | 70 | | |
| 3 | Habiganj | 5139 | 3852 | 75 | | |
| 4 | Jalalabad | 1195 | 837 | 70 | | 149 |
| 5 | Kailas Tila | 2720 | 1904 | 70 | 245 | 908 |
| 6 | Meghna | 171 | 119 | 70 | | |
| 7 | Narshingdi | 307 | 215 | 70 | | 56 |
| 8 | Rashidpur | 2002 | 1401 | 70 | 200 | 700 |
| 9 | Salda Nadi | 166 | 116 | 70 | | |
| 10 | Sangu | 1031 | 848 | 82 | | |
| 11 | Sylhet | 684 | 479 | 70 | 60 | |
| 12 | Titas | 7325 | 5128 | 70 | 730 | 1703 |
| 13 | Chattak ( West) | 677 | 474 | 70 | 68 | 253 |
| 14 | Feni | 185 | 130 | 70 | | 72 |
| 15 | Kamta | 72 | 50 | 70 | | |
| 16 | Begumganj | 47 | 33 | 70 | | 76 |
| 17 | Bibiyana | 3145 | 2401 | 76 | | 3124 |
| 18 | Fenchuganj | 404 | 283 | 70 | 40 | |
| 19 | Kutubdia | 65 | 46 | 70 | | |
| 20 | Moulavi Bazar | 449 | 360 | 80 | | |
| 21 | Semutang | 227 | 150 | 66 | | |
| 22 | Shahbazpur | 665 | 466 | 70 | 66 | 670 |
| Total Reserve in Bscf : | | **28417** | **20510** | | **1409** | **7711** |
| Total Reserve in Tscf : | | 28.4 | 20.5 | | 1.4 | 7.7 |

| | Proven+Probable | Proven+Probable+Possible |
|---|---|---|
| GIIP | 28.4 | 38.4 |
| Reserve | 20.5 | 28.2 |
| Cumulative Production (up to June 2003) | 5.1 | 5.1 |
| Remaining Reserve | 15.4 | 23.1 |

**Table 3-5 Haq and Rahman 2008 Estimation of GIIP for 15 Gas Fields, Bangladesh**

| Field | No. of sand | No. of well | Estimated GIP[a], TCF | | GIP Petrobangla, 1998, TCF |
|---|---|---|---|---|---|
| | | | Vol. | FMB | |
| Producing | | | | | |
| Titas | 13 | 14 | 9.050 | 10.24 | 4.132 |
| Habigonj | 12 | 7 | 3.669 | 8.022[b] | 3.669 |
| Bakhrabad | 5 | 8 | 1.332 | 1.120 | 1.432 |
| Narshingdi | 2 | 1 | 0.194 | 0.402 | 0.194 |
| Meghna | 1 | 1 | 0.160 | 0.095 | 0.159 |
| Saldanadi | 2 | 2 | 0.351 | 0.227 | 0.200 |
| Sylhet | 2 | 2 | 0.444 | 0.840 | 0.444 |
| Rashidpur | 2 | 7 | 2.243 | 3.189 | 2.242 |
| Kailashtilla | 3 | 4 | 3.656 | 3.588 | 3.657 |
| Beanibazar | 2 | 2 | 0.243 | 0.108 | 0.243 |
| Non-producing | | | | | |
| Shahbazpur | 1 | 1 | 0.514 | | 0.514 |
| Fenchuganj | 3 | 2 | 0.404 | | 0.350 |
| Production suspended | | | | | |
| Chhatak | 1 | 1 | 1.900 | 0.406 | 1.900 |
| Kamta | 1 | 1 | 0.109 | 0.137 | 0.325 |
| Feni | 2 | 2 | 0.132 | 0.117 | 0.132 |
| Total, TCF | | | 24.401 | 28.490 | 19.593 |

[a] Proven GIP only.
[b] May be overestimated due to water drive.

(after Haq and Rahman, 2008)

# 4. RESERVE CLASSIFICATION

## 4.1 BACKGROUND

For planning and economic development of a country, knowledge of the quantities of the petroleum reserves available is essential. Equally important is following a consistent classification system for assessment of the reserves estimated to be available in the future.

Over the years, government agencies, international organizations, oil companies have worked out their own classification systems. Attempts to standardize reserve terminologies began during 1930s when American Petroleum Institute made attempts to standardize classification for petroleum and definitions of various reserve categories. Since then, advances in technology have highlighted the need for an improved nomenclature to achieve consistency among professionals working with reserve terminology.

SPE and WPC drafted strikingly similar sets of petroleum reserve definitions for known accumulations in 1987. These became the preferred standard for reserve classification. In 2007, SPE, WPC, AAPG, and SPEE jointly approved and published the most recent version of a document entitled "Petroleum Resources Classification and Definitions". The classification system provides simple subdivisions based on discovered vs. undiscovered, commercial vs. sub-commercial petroleum accumulations (Section 4.3).

Oil and gas reserves cannot be measured directly in subsurface reservoirs. Consequently, volumes are estimated on the basis of geological and engineering knowledge and principles, and have an inherent degree of uncertainty. The SPE/WPC/AAPG/SPEE classification system considers the level or range of uncertainties and provides an indication of the probability of recovery.

The traditional method known as deterministic method ignores the range of uncertainty, giving a single number for each class of reserve. This system is the most commonly employed worldwide, and involves the selection of a single value for each parameter in the reserve estimate. The discrete value for each parameter is selected based on the estimator's analysis. This system is practiced in Bangladesh.

A probabilistic criterion in reserve definition was included in the 1997 version of the SPE/WPC reserve definition after many years of debate. Despite the inclusion of probabilistic criteria, the meanings of the definition remained unclear. Probabilistic analysis involves describing a full range of possible values for each parameter. This approach requires computer software to perform repetitive calculations to generate full range of possible outcome and their associated probability of occurrence.

## 4.2 CLASSIFICATION USED IN BANGLADESH – 2003 REPORT

As stated in the 2003 report and based on informal discussions with officials in the petroleum industry, no petroleum classification system, has been officially accepted in Bangladesh to the best of our knowledge.  In absence of an official classification system, workers and consulting houses engaged by Petrobangla or donor agencies for the estimation of gas reserves in the country followed systems of their choice. It is the case with International Oil Companies working under a PSC arrangement in Bangladesh. Some of these reports contain a chapter or section on reserve classification and describe the system that was utilized.

The various classification systems used by different workers for estimation of gas reserves of Bangladesh are discussed in the HCU-NPD 2003 gas reserve study (2004). A brief history of the classification system used in the aforementioned 2003 report follows.

In 1966, the CCOP (Coordination Committee for Offshore Prospecting in Asia) was initiated by China, Japan, Republic of Korea and the Philippines under the auspices of ESCAFE and the UN. CCOP became an independent intergovernmental organization in 1987. The name was of the committee was changed to Committee for Coastal and Offshore Geosciences Program in 1994, but the acronym was retained. The member countries of CCOP are Cambodia, China, Indonesia, Malaysia, Papua New Guinea, The Philippines, Republic of Korea, Thailand, and Vietnam.

CCOP completed projects like Working Group on Resource Assessment, Oil and Gas Resource Management during the period 1988-1991. In order to contribute to sustainable development of the petroleum sector in the CCOP member countries by providing governments with reliable information about their petroleum reserve and value estimation, CCOP Resource Classification System was released in 1999.

In 2001, the Hydrocarbon Unit carried out a study on hydrocarbon reserve and resource of the country in participation with the Norwegian Petroleum Directorate (NPD). The resulting report was entitled 'Petroleum Potential and Resource Assessment 2001'. A chapter on classification was included based on the CCOP and SPE/WPC/AAPG (1997) Resource Classification Systems, with recommendation for adopting a classification system for Bangladesh. The classification system proposed in the 2001 HCU-NPD report (Table 4-1) was used for the 2003 gas reserve study (2004). The 2003 study did not include resources so discussion of a resource classification scheme was omitted.

**Table 4-1 Resource Classification System Used in 2003 HCU-NPD Reserve Report**

RESOURCE CLASSIFICATION

<table>
<tr><th colspan="5">Discovered Resources</th><th colspan="2">Undiscovered Resources</th></tr>
<tr><td colspan="5">Discovered Resources comprise the total discovered deliverable petroleum quantities from the start of production to the cease of production, based on current understanding of the quantities in place and the recovery factor.</td><td colspan="2">The total estimated quantities of petroleum to be recoverable from accumulations that remain to be discovered.</td></tr>
<tr><th colspan="4">Reserves</th><th>Contingent Resources</th><th>Hypothetical Resources</th><th>Speculative Resources</th></tr>
<tr><td colspan="4">Petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward.</td><td rowspan="6">There are not commercially producible at present date.</td><td rowspan="6">Resources in mapped prospects that are not yet drilled.</td><td rowspan="6">Resources in prospects that have not yet been mapped.</td></tr>
<tr><th colspan="2">Proved Reserves</th><th colspan="2">Unproved Reserves</th></tr>
<tr><td colspan="2">Petroleum that can be estimated with reasonable certainty to be commercially recovered.</td><td colspan="2">Unproved reserves are less certain to be recovered than proved reserves.</td></tr>
<tr><th>Developed Reserves</th><th>Undeveloped Reserves</th><th>Probable Reserves</th><th>Possible Reserves</th></tr>
<tr><td>These are expected to be recovered from existing wells</td><td>These are expected to be recovered from new wells</td><td>There are more likely than not to be recovered.</td><td>There are less likely than likely to be recovered.</td></tr>
</table>

Increasing segregation

Increasing Certainty

## 4.3 PETROLEUM RESOURCE MANAGEMENT SYSTEM (PRMS)

The Petroleum Resource Management System (PRMS) was published jointly in 2007 by the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE). This system defines both reserves and resources, including Contingent and Prospective Resources, and the reserve categories of Proved, Probable, and Possible. The relationship among these categories is illustrated in Figure 4-1 below.

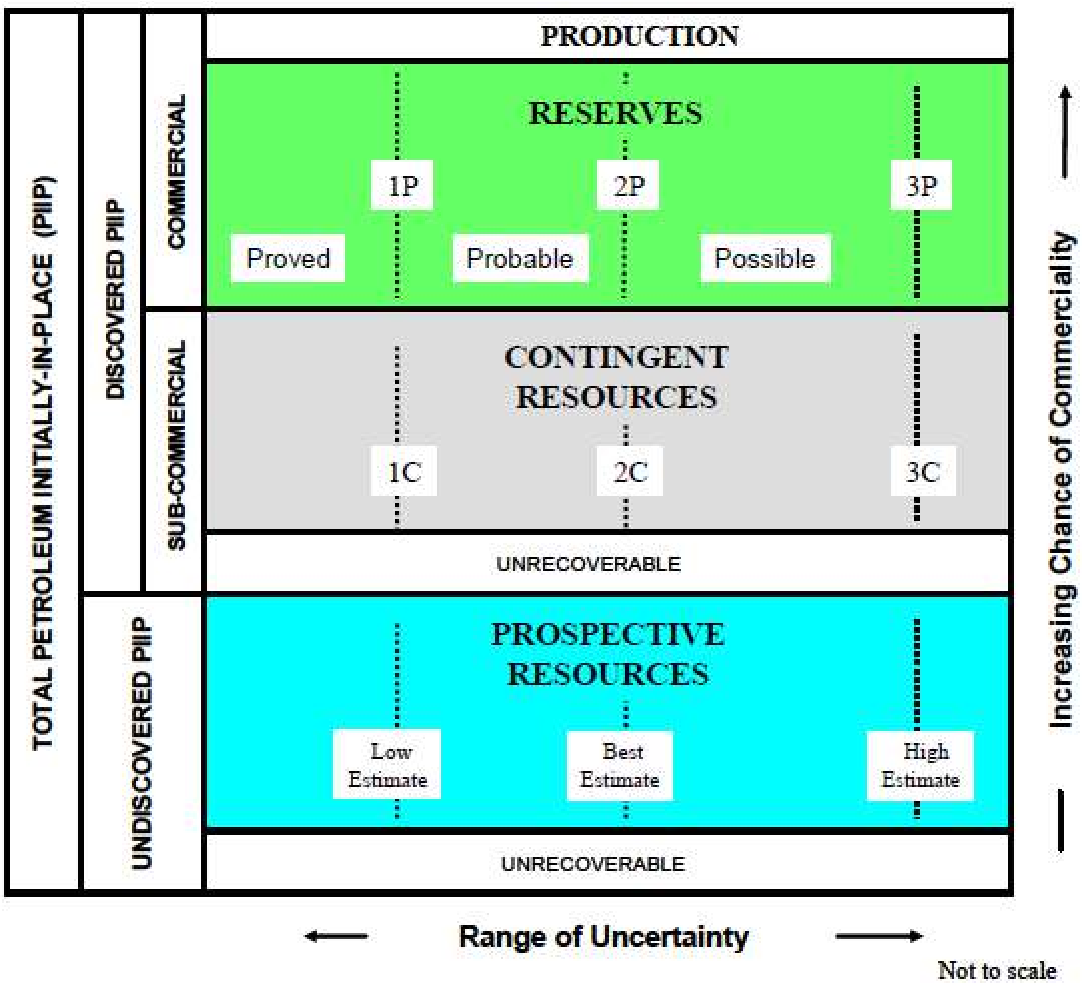



**Figure 4-1 PRMS Resource Classification Framework**

(SPE/WPC/AAPG/SPEE, 2007)

Reserves, as defined under PRMS are "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions" (SPE/WPC/AAPG/SPEE, 2007). Reserves must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. "Commercial" in this context denotes a commitment to develop the reserves within a reasonable time frame. "Remaining" means that volume of reserves that has not yet been produced and still is contained in the reservoir. Hydrocarbon accumulations that do not meet these criteria are classified as resources.

The three main classes of reserves are proved, probable, and possible, which are based on the level of uncertainty in the available geologic and engineering data. If the gas water contact (GWC) has been determined, this is considered the proved limit of the reservoir. In the absence of fluid-contact data, the lowest known occurrence of hydrocarbons generally indicates the proved limit.

Proved reserves are those quantities that have reasonable certainty of being recovered. Proved reserves may be subdivided into developed (PDP) or undeveloped (PUD). Probable and possible are collectively called unproved reserves. Probable reserves are more likely to be recoverable than possible reserves. Proved reserves assume recoverability under current economic conditions, operating methods, and government regulations. For unproved reserves, recoverability may depend on future economic conditions and technology. A more complete description of the PRMS system is included as Appendix A to this report.

## 4.4 CLASSIFICATION SYSTEM USED IN THIS REPORT

For this report, we use the PRMS Resource Classification Framework as developed and jointly adopted by the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE). We will categorize the reserves as Proved, Probable, or Possible. These definitions specify, for probabilistic analysis, that Proved reserves are those with at least a

90% probability of being present and recoverable, with Proved plus Probable reserves requiring at least a 50% probability, and Proved plus Probable plus Possible reserves requiring at least a 10% probability.

Note that the reserves estimates presented in this Report have not been fully calibrated with the PRMS definitions. Specifically, the SPE definitions require that Proved reserves be commercially recoverable. Economic analysis of development and production of gas from individual fields was outside the scope of work for this project and has not been conducted. Thus, these estimates are considered to be "technically recoverable" reserves, and this Consultant has no opinion at this time as to whether or not these are economically recoverable reserves. The technically recoverable reserve estimates appear to reflect actual operating conditions in Bangladesh for most of the fields.

# 5. REVIEW OF PRESENT PRODUCTION RATE PRACTICES

## 5.1 NATIONAL COMPANIES PRACTICES (BAPEX, BGFCL, SGFL, PETROBANGLA

Questionnaires were sent out to the various national companies regarding their production practices and none were received to incorporate into this report. However, a summary discussion of the related issues is presented in Chapter 7 of this report.

## 5.2 IOC PRACTICES

Questionnaires were sent out to the four IOC companies operating in Bangladesh. Two companies responded (Tullow and Cairn) and these companies provided completed questionnaires for this report. Tullow operates the Bangora field while Cairn operates Sangu. The questionnaires are provided in Appendix B of this report.

Overall, the companies appear to be using prudent standard operating practices that are employed in other parts of the world. In the case of Sangu, Cairn has installed compression to enhance facilities while Tullow is contemplating installation 2012 to 2013 when wellhead pressures are anticipated to reach 1000 psi.

Also the companies are employing a combination of techniques to both enhance production and increase reserves. Both companies regularly schedule workovers to make repairs and if applicable, commingle production with other reservoirs. The use of 3D seismic and reservoir modeling techniques are being employed to better map the reservoirs across the field areas to update estimates of reserves and exploit undeveloped or bypassed potential.

In the case of Sangu, Cairn hopes to have to positive outcomes from their 3D survey and interpretation of the South Sangu reservoir sands to justify drilling in the near future to confirm approximately 124 BCF (mid case) of GIIP that is now booked as contingent resources. Tullow reports that studies are underway to establish the merits of drilling additional wells in the Bangora South – Lalmai area.

## 5.3 DIFFERENCE IN MAXIMUM DAILY FLOW RATES BETWEEN PETROBANGLA AND IOCS

In general, the international oil companies operating in Bangladesh tend to produce individual wells at higher rates than the Petrobangla group of companies. Several reasons contribute to this, such as:

1. Use of larger tubing sizes (5 ½" as opposed to 4 ½ or 3 ½) by Chevron at Bibiyana which allows for less frictional pressure drop in the tubing string, and lower producing wellhead pressures. This results in larger pressure differentials between the reservoir and the surface, which is directly related to flow rate.
2. Concerns at some Petrobangla-group fields that higher production rates result in migration of fines within the reservoir and excessive fines/sand production. Sand production creates operational issues and could damage the reservoir.
3. Variations in producing wellhead pressure due to variations in gas transmission line operating pressures in the field locations, varying design/optimization within field gathering lines and facilities, and the installation of compression at some IOC-operated fields, i.e. Sangu.

This implies that producing rates could possibly be increased at some fields, by installing larger tubing, optimizing facilities and field gathering lines, and/or installing additional compression. This is indeed the case, but any such investment to increase rate should be evaluated on a detailed basis in order to estimate the cost/benefits of each considered improvement. Investment in some cases for rate acceleration may be less efficient than spending this money on additional step-out or exploration drilling. Also, carrying out production tests at varying choke sizes/rates at the fields with suspected sand production issues would help establish critical velocities at which sand production occurs. These issues are discussed further in Section 8 of this Report.

## 5.4 DETERMINATION OF OPTIMUM FLOW RATES FROM WELLS AND FIELDS

The gas production flow line network at an individual field and the transmission and distribution pipelines for the country are complicated interrelated systems. Optimization of these systems, aside from the issues discussed in the previous section, is a complicated problem beyond the scope of this Report. Commercial software is available, such as PIPESIM Pipeline and Facilities Design and Analysis available from Schlumberger,[1] to assist in such efforts.

It has been reported that, on occasion, particular industrial users may be asked to curtail their gas usage do to perceived shortages in supply on a particular day. The result of this may be as follows:

1. Less offtake at downstream end of pipeline system results in more gas volume in pipeline short term,
2. More gas volume results in higher downstream pipeline pressures,
3. Higher downstream pressures result in higher upstream pressures, higher wellhead pressures, and lower well production rates.

We repeat that this is a complex system which may not behave as expected based on a simplistic analysis; however, this line of thinking indicates that restriction of usage downstream may be contrary to the goal of providing more gas for key uses.

[1] http://www.slb.com/services/software/production_software/prod_design_modeling_sim/pipesim/pipelineandfacilities.aspx

# 6. RE-ESTIMATION OF RESERVES

## 6.1 RECOVERY FACTOR

Recovery factor is an important variable in reserves estimation. Consideration of actual apparent performance of producing fields, and producing analogs, should be considered. Reservoir modeling with a finite-difference reservoir simulator can also be an effective tool in estimating recovery factor. If fields behave under a simple depletion drive mechanism, or as a "volumetric reservoir," the recovery factor is a straight-forward calculation of the difference between GIIP and gas in place at abandonment pressure. Abandonment pressure, in turn, is directly related to minimum wellhead flowing pressure, minimum economic flow rates, liquid content (if any), reservoir deliverability, and tubing string performance.

### 6.1.1 Recovery Factor Used by Previous Workers in Bangladesh

Recovery factors used in the 2003 reserve estimate were generally 70 percent for 2P reserves. IOC-operated fields with compression already in place were estimated to recover up to 82%, and additional recovery estimated in this study due to installing compression were categorized as Possible reserves, increasing recovery factor up to 80%.

### 6.1.2 Factors to be Considered for Recovery Factor Using Best Engineering Practices

Engineering practices to result in optimum recovery factors include a combination of optimizing wellbore and surface facility configuration and potential installation of compression. Optimal recovery factor from an economic standpoint is likely lower than the maximum recovery from a physical standpoint alone. In other words, it may be possible to produce the reservoir down to a very low abandonment pressure using extensive compression, but this may not be economically feasible, and may generate low incremental production rates for the investment required. All such projects should be evaluated on an individual basis before proceeding.

### 6.1.3 Rationale for Recovery Factor Used in this Report

Although it appears that many if not all of the producing gas fields in Bangladesh have a small component of water drive in their performance behavior, we agree with previous conclusions that, in general, it is possible to accurately estimate reserves of these fields treating them as behaving as volumetric reservoirs. Thus the recovery factor can be estimated based on an estimated pressure at field abandonment. For this study Gustavson has generally used three different abandonment well head pressures in our probabilistic reserves estimates: 250, 500, and 800 psi. We understand that for most fields, it would be necessary to install compression to produce into the 1100-psi transmission line at these lower wellhead pressures; however, they are considered practical to achieve. For the larger fields, reservoir pressures associated with these well head pressures were estimated using spreadsheets to estimate flowing bottomhole pressure at a low rate, generally about 1 MMCFPD, and the Darcy flow equation to estimate what average reservoir pressure would result in such a flow rate at that bottomhole flowing pressure.

For the smaller fields, abandonment reservoir pressures were set at varying percentages of initial reservoir pressure: 10% for the minimum, 14% most likely, and 20% maximum. Additional time and effort could refine these assumptions.

Habiganj is the one Bangladeshi field which appears to perform with a strong water drive. In this case the best methodology to estimate recovery factor include analogy to a similar field (none in the area), or analysis and history-matching with a reservoir simulator. For this study, the limits for the recovery factor distribution for Habiganj were based on the results of the recent simulation study conducted by RPS Energy.

## 6.2 RESERVE ESTIMATION METHODOLOGIES

The petroleum industry uses four main methods for estimating reserves and this includes: analogy, volumetric and performance based material balance and decline analysis. Selection of the most appropriate reserves estimation method(s) depends on the stage of field development and type of information that is available. The range of uncertainty associated with reserve estimation typically decreases and confidence level increases as more information becomes available and when the estimate is supported by more than one method. Components of uncertainty are the geologic, engineering, and economic information used to classify reserve categories.

During the early development phase, before production data becomes available, reserve estimates may be calculated by use of the analogy and volumetric methods. The analogy method is applied by comparing factors for a new field or well with those of an appropriate analog, such as a close-to-abandonment field, to approximate the new field production characteristics. This method is most useful when evaluating the economics of the new field.

Volumetric methods require information on the areal extent of the reservoir, the rock pore volume, and the fluid content within the pore volume to estimate of the amount of hydrocarbons-in-place. The portion of reserves estimated as proved, probable, or possible should reflect the quantity and quality of the available data and the confidence in the associated estimate. Each of the variables used in the calculation of reserves has inherent uncertainties that, when combined, cause significant uncertainties in the reserves estimate. Volumetric reserves may be calculated by deterministic or probabilistic techniques (discussed below).

As production and pressure data from a field accumulate, material balance and decline analysis calculations become practical methods of calculating reserves. These methods greatly reduce the uncertainty in reserves estimates, but may generate inaccurate results during early depletion.

Material balance is a simple but effective means for estimating original GIP and gas reserves at different stages of reservoir depletion. The fluid properties and pressure history are averaged, treating the reservoir as a closed system. Decline-trend analysis refers to the estimation of reserves based on a reasonably well-defined behavior of a performance characteristic as a function of time or cumulative production. These methods are discussed in more detail below.

### 6.2.1 Volumetric

Deterministic and probabilistic volumetric methods both involve the calculation of the reservoir rock volume, the hydrocarbons in place within this volume and the estimation of the portion of the hydrocarbons in place that ultimately will be recovered. For various reservoir types at different stages of development and depletion, the unknowns in volumetric reserves determinations may be rock volume, porosity, fluid saturation or recovery factor. Important considerations that affect a volumetric reserves estimate follow:

1. Rock volume – Volume may simply be determined as the product of a single well drainage area and wellbore net pay or by more complex geologic mapping or geophysical surveys. Volume estimates consider reservoir characteristics, reservoir fluid properties, and the drainage area expected for the wells, and pressure depletion or boundary conditions noted in available well test data. In the absence of data that clearly defines fluid contacts, the structural interval for volumetric calculations of proved reserves should be restricted by the lowest known structural elevation of occurrence of hydrocarbons (LKH) as defined by well logs, core analyses, or formation testing (SPE/WGA/AAPG, 2007).
2. Porosity, fluid saturation, and other reservoir parameters – This information typically determined from logs and core and well test data.
3. Recovery factor – Value based on analysis of production behavior from the subject reservoir, by analogy with other producing reservoirs, and/or by engineering analysis. In estimating recovery factors, consideration is given to factors that influence recoveries such as rock and fluid properties, hydrocarbons-in-place, drilling density, future changes in operating conditions, depletion mechanisms, and economic factors.

The accuracy of volumetric estimates depends on the availability of sufficient and reliable data to characterize the reservoir's areal extent and variations in net thickness, particularly on the quality of seismic and log data. In a fluvio-deltaic sequence, as in Bangladesh, the likelihood of large errors in estimating reservoir rock volume by seismic and log data is very high. Limited exploration and drilling activities suggest that most of the reservoirs of the country are stratigraphic as opposed to structural in nature. As a result, significant errors can result in estimating original GIP and reserves by the volumetric method (Haq and Rahman, 2008). As more production data become available, material balance techniques can be used verify and to update reserve estimates.

#### 6.2.1.1 Deterministic

When calculating reserves by the volumetric method, deterministic or probabilistic calculation procedures may be used. The deterministic approach involves the selection of a single value for each parameter in the reserves calculation, based on known best estimates of geologic, engineering, and economic data. A discrete value for each parameter is selected that seems most appropriate for the corresponding reserves category. Two fundamentally different deterministic methodologies are incremental (risk-based) and scenario (cumulative).

The incremental approach involves a separate estimation of each reserve category as a discrete volume from a single reservoir model. No uncertainty is assigned to probable or possible reserves. The risk is that reserves may be determined for volumes that are not present or that will not be recovered. Separate volumes are categorized according to areal extent, vertical contacts and/or recovery. Hydrocarbon quantities at each level of uncertainty are discretely estimated and separately assigned to proved, probable, and possible reserves.

For the scenario approach, a derivation of a best estimate is identified through multiple models of 2P (best estimate), 1P (downside), and 3P (upside) cases. When following the scenario approach, low, best, and high estimates should be based on qualitative assessments of and ranges of variation in areal, vertical, or recovery uncertainty.

A comparison of reserve estimates by both deterministic and probabilistic methods can provide quality assurance. Reserves are calculated both deterministically and probabilistically and the two values are compared. If the two results generally agree, then confidence in the calculated reserves increases. If the two values greatly differ, then the assumptions and data need to be reexamined.

#### 6.2.1.2 Probabilistic

General Discussion

The current Society of Petroleum Engineers and World Petroleum Congress joint reserve definitions[1] discuss the use of a probabilistic method for estimating gas reserves which has become established as an international standard technique. It is especially appropriate for fields in the early stages of development for which relatively great uncertainty may exist regarding one or several of the parameters governing expected hydrocarbon reserves.

The probabilistic methodology is being used in this reserves update report for three main reasons.

Although some previous probabilistic reserves estimations have been performed for some of Bangladesh's gas fields (e.g., Petrol-Consult. GmbH, 1979; Schmidt and Haque, 1982; and Eder and Hildebrand, 1986), this methodology has not been systematically applied to all of the country's fields in prior countrywide reserves reports, including the 2003 HCU report. Only in the recently released (2009) RPS Energy/Petrobangla reserve estimation of 14 Bangladesh fields, has this methodology been applied on a uniform basis to a group of gas fields.

Despite the number of previous reserve estimates, there is still considerable uncertainty in a number of the parameters governing expected hydrocarbon reserves. Of particular importance is the Recovery Factor which is both a function of geological and reservoir properties and engineering practices such as use or nonuse of compression and decisions on abandonment pressure. Reservoir geometry is a second source of uncertainty. Because the fields have been developed with a relatively few number of wells based on excellent reservoir quality, the areal distribution and limits of individual reservoirs is uncertain. Stratigraphic variations across the gas fields will affect estimates of reservoir size and geometry. Reservoir geometry uncertainty has been documented in many of the technical reports for the various fields.

In today's industry, the probabilistic reserves methodology is a standard and accepted practice for not only estimating reserves but also for economic evaluation and planning and for investment decisions on both the part of governments and oil and gas companies. All IOCs that are currently developing reserves or considering new exploration or development opportunities in various countries rely on probabilistic reserve and resource estimates for making decisions on participation in bidding rounds and for periodically reporting reserves to the regulatory agencies of their host countries as required by the terms in their PSCs. Likewise, Petrobangla should rely on probabilistic estimates of known reserves and undiscovered resources in its planning decisions on blocks to be offered during bid rounds and for accurate forecasting of remaining reserves.

The probabilistic method involves estimating probability distributions for uncertain parameters and performing a risk analysis, or Monte Carlo simulation, with multiple trials of outcome generated by random numbers and the specified distributions of reservoir parameters. The most common type of distribution used for the input parameters is a triangular distribution, because generally not enough data are available to develop any more sophisticated distribution. A triangular distribution is a simple one, defined by three values: minimum, maximum, and most likely. The distribution can be, and often is, skewed: the most likely value may be closer to the minimum or the maximum than to the average of the two extreme points.

The result of this technique is a probability distribution of reserves. The reserve definitions specify that Proved reserves as determined probabilistically must have at least a 90% probability of occurring, the sum of Proved plus Probable reserves must have at least a 50% probability of occurring, and the sum of Proved plus Probable plus Possible reserves must have at least a 10% probability of occurring. The reserve probability distribution provides an assessment of downside risk in reserves, as well as upside potential. The 50% probability value (Proved plus Probable equivalent) would typically be used for project planning and equipment sizing.

In addition to performing Monte Carlo simulation on reserve parameters, it may also be useful to examine probable distributions of other factors affecting project economics, such as capital investments, operating costs, and product prices. Although those additional simulations were beyond the scope of this study, performance of such an analysis to examine the effects of the high degree of uncertainty in these economic factors would be advisable.

Methodology

To apply the method just described to the present reserve report, triangular distributions will be defined for all input parameters. Based on our evaluation of available data, maps, and results from previous studies and reports on the Bangladesh gas fields, estimates will be made using engineering and geologic judgment of minimum, maximum, and most likely values for all the factors entering into the calculation of estimated reserves. This will be further discussed for each individual gas field in the Sections 5.3 trough 5.5 of the report. For each field, the list of input parameters used in the probabilistic analysis will be presented in table format.

Risk analysis spreadsheet software will be used to generate the reserve probability distributions using Monte Carlo simulation. The software allows the user to describe input parameters as a variety of different distributions. The software then utilizes a Monte Carlo sampling type to randomly generate the input values. The individual samplings are called 'iterations.' During each iteration, all distribution functions are sampled. The sampled values are then returned to the cells and formulas in the worksheet and the worksheet is then recalculated. The values calculated for output cells are collected from the worksheet and stored. The Monte Carlo sampling stops when the output distribution becomes stable or reaches a pre-defined convergence. When each of the output parameters has reached convergence, and the simulation is halted, the output parameter distributions are complete. The program monitors three convergence statistics (mean, standard deviation, average percent change in percentile values) on each output distribution during a simulation. Convergence occurs when all three statistics reach a low enough change threshold where the distribution is considered stable.

It should be noted that it is not appropriate to simply add together the distributions for each field to establish the total countrywide reserve distributions. This is why the total probabilistic results do not equal the simple arithmetic sum of the results for the various fields, with the exception of the mean.

### 6.2.2 Material Balance

A material balance approach is a conservation-of-matter technique that is appropriate for estimating gas reserves and also provides verification of estimates by the volumetric method. Reserves may be based on material balance calculations when sufficient production and pressure data is available. If a reservoir is a closed system and contains single-phase gas, the pressure in the reservoir will decline proportionately to the amount of gas produced.

Material balance methods of reserves estimation involve the analysis of pressure behavior as reservoir fluids are withdrawn, and generally result in more reliable reserves estimates than volumetric estimates. The method accounts for reservoir heterogeneity and continuity variations. The accuracy of this method increases with time as more and more production data become available. Confident application of material balance methods requires knowledge of rock and fluid properties, aquifer characteristics, and accurate average reservoir pressures.

This method generally requires fully built-up reservoir pressures, usually obtained by shutting in the wells for a few days. In producing gas fields of Bangladesh, reduced production resulting from shut-in well testing is not practical. A modified flowing material balance method (Haq and Ramen, 2008; Mattar and McNeil, 1998) allows determination of GIP and reserves in situations where shut-in well data are not available.

Complex situations, such as those involving water influx, multi-phase behavior, and multilayered or low permeability reservoirs may also provide erroneous material balance results. Bottom water drive in gas reservoirs (Habiganj Field) contributes to the depletion mechanism, altering the performance of the non-ideal gas law in the reservoir. An alternate formulation of the material balance allows for water influx and production, and gas, water, and formation compressibility (Shagroni, 1977).

Computer reservoir modeling can be considered a sophisticated form of material balance analysis. Although modeling can be a reliable predictor of reservoir behavior, the accuracy of input rock properties, reservoir geometry, and fluid properties are critical to generate a representative model. Predictive models should be carefully reviewed before using the results for estimation of reserves.

#### 6.2.3 Production Decline Analysis

Decline analysis refers to estimation of reserves based on the behavior of a performance characteristic (e.g., production rate or volume) as a function of time or cumulative production. The method usually is typically used for analysis of individual wells. Production decline curve analysis consists of plotting gas production rates or volumes versus time on a semi-log plot, and projecting the exhibited trends into the future. The trend established from past behavior is extrapolated to the economic limit. The basic assumption is that the trend established in the past will continue uniformly in the future.

Decline curve relationships are empirical, and reliable trends depend on uniform, lengthy production periods. The most common decline curve relationship is the constant percentage decline (exponential). This approach is more reliable for oil wells, which are usually produced against fixed bottom-hole pressures. Wellhead back-pressures tend to fluctuate in gas wells, which can generate erratic production trends.

#### 6.2.4 Reservoir Modeling

Reservoir modeling is a highly reliable method of estimating oil and gas reserves, but requires a great deal of data, time, and effort.  A three dimensional grid is set up to represent the reservoir. Reservoir parameters such as effective thickness, depth, porosity, permeability, pressure, fluid saturations, and fluid property data, are assigned to each cell in the grid, based on the geologic and engineering data available for the reservoir. Wells are placed in grid cells based on where actual or planned wells are located in the field. Darcy flow and material balance equations are solved simultaneously for all blocks in the grid, over time steps specified by the user. For a study of a field with production history, a "history match" is performed. To do a history match, actual production rates are specified for the wells. Reservoir pressures and, for oil reservoirs, water cuts and gas/oil ratios, are calculated by the model and compared to historical data. Reservoir properties assigned to the model grid are adjusted as necessary to obtain a close match between pressures and production calculated by the model and field data.

Such a comprehensive study was beyond the scope of this Report.

## 6.3 PRODUCING GAS FIELDS (BACKGROUND, PRODUCTION, RESERVE METHODOLOGY, AND ESTIMATES)

This section of the report summarizes and updates production and reserves information for each of the Bangladesh gas fields. For each field, there is a brief description of geologic setting, including structure and stratigraphy of producing horizons, exploration and development history, production history, review of earlier reserve estimates, and the re-estimation of reserves performed by Gustavson Associates for this present report.

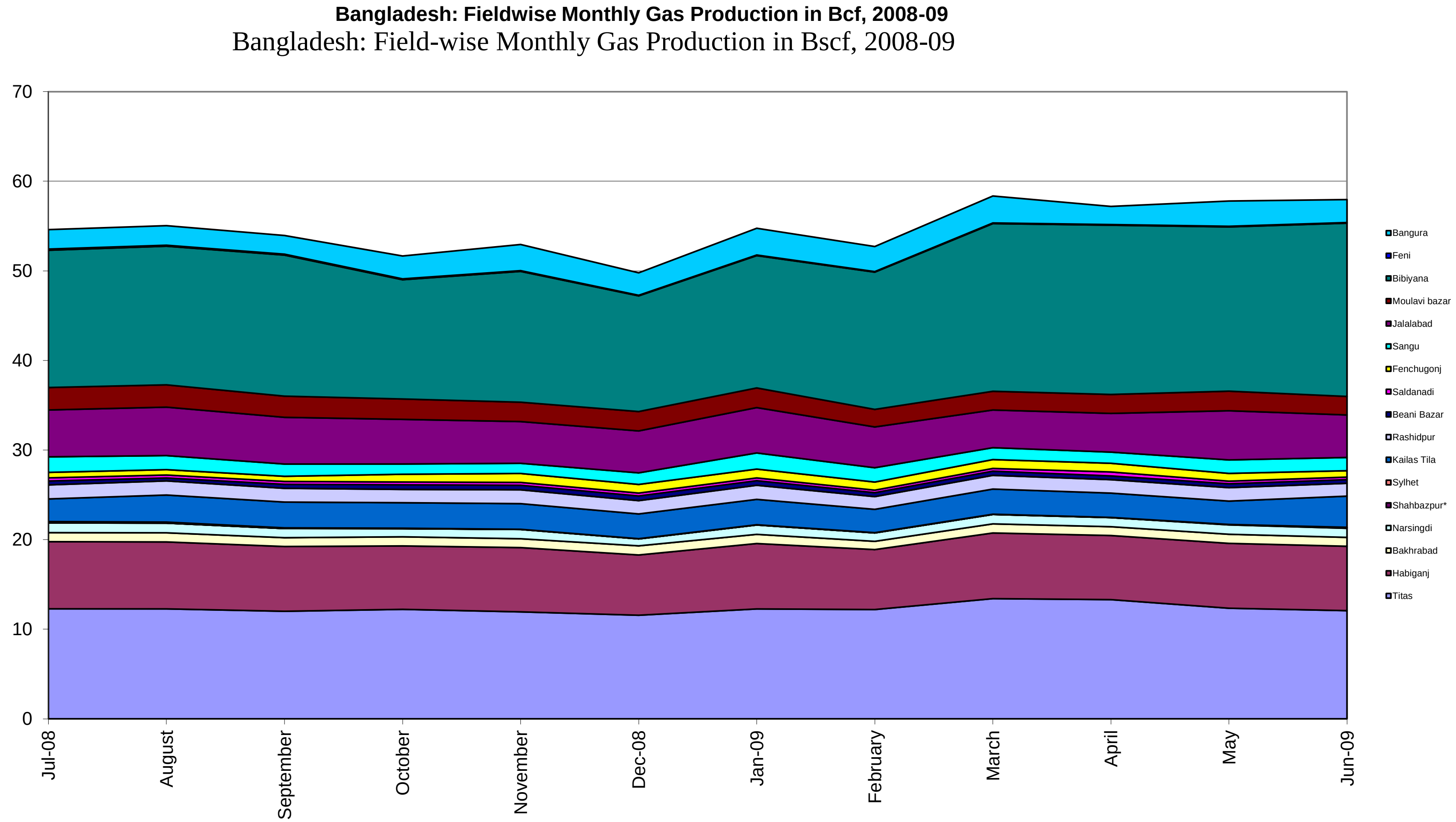
The gas fields are discussed in alphabetical order for easy reference. In June of 2009, there were 17 producing gas fields in Bangladesh. Five fields accounted for 81% of the country's June 2009 monthly production of 58 Bscf and the top nine fields accounted for 94% of the production. The Bangladesh producing gas fields are assigned rank numbers (number in parentheses behind the field's name) based on current production levels (Table 6-1). A field's ranking is based on its current production level as a percentage of the countrywide gas production based on 2008-2009 production statistics, and more specifically the June 2009 monthly production. The fields are listed below in Table 6-1 and their 2008-2009 monthly production rates are shown in graphical form in Figure 6-1.

## Table 6-1 Gas Field Ranking by Production

| Field-wise Monthly Gas Production June 2009 | | | | | |
|---|---|---|---|---|---|
| Field Rank | Gas Field | Bscf | % | Cum. % | |
| 1 | Bibiyana | 19.34 | 33.38 | 80.8 | 93.8 |
| 2 | Titas | 12.07 | 20.83 | | |
| 3 | Habiganj | 7.19 | 12.40 | | |
| 4 | Jalalabad | 4.74 | 8.19 | | |
| 5 | Kailas Tila | 3.48 | 6.00 | | |
| 6 | Bangora | 2.56 | 4.42 | 13.0 | |
| 7 | Moulavi bazar | 2.07 | 3.57 | | |
| 8 | Sangu | 1.48 | 2.55 | | |
| 9 | Rashidpur | 1.43 | 2.47 | | |
| 10 | Narsingdi | 1.02 | 1.75 | 6.2 | |
| 11 | Bakhrabad | 0.99 | 1.71 | | |
| 12 | Fenchuganj | 0.71 | 1.23 | | |
| 13 | Beani Bazar | 0.41 | 0.71 | | |
| 14 | Salda Nadi | 0.28 | 0.49 | | |
| 15 | Shahbazpur* | 0.09 | 0.15 | | |
| 16 | Feni | 0.07 | 0.12 | | |
| 17 | Sylhet | 0.02 | 0.04 | | |
| | Total | **57.95** | 100.00 | | |

(Source: HCU, Division of Energy and Mineral Resources)

Bangladesh: Field-wise Monthly Gas Production in Bscf, 2008-09




(58 Bscf)

**Figure 6-1 Bangladesh Field-wise Monthly Gas Production 2008-09***

(Source: Hydrocarbon Unit Production Database)

### 6.3.1 Setting of Bangladesh Gas Fields

Twenty-three gas fields have been discovered in Bangladesh. All of the fields are located in the eastern half of the country (Figure 6-2). The westernmost field, Shahbazpur, lies beneath an island on the west side of the Meghna River in Block 10. Two fields, Kutubdia and Sangu are located offshore in the Bay of Bengal in Block 16. Seventeen of the remaining 20 fields, including all five of the country's largest and most important gas fields, are clustered in the northeastern sector of the country centered in Blocks 9, 12, 13, and 14. Figure 6-3 is an enlarged map of the northeastern sector of the country showing the locations of 11 fields that include the three largest fields, namely, Titas, Bibiyana, and Habiganj. Three relatively small fields (Feni, Begumganj, and Semutang) lie in the coastal region of eastern Bangladesh in Blocks 10 and 15. The latter two latter fields have not yet been produced, however Semutang is being considered for production because of its proximity to the Chittagong industrial area.

All of the gas fields are associated with anticlinal structures that exhibit four-way dip closure. All of these structures are located within and marginal to the Eastern Foldbelt Province that is the western outermost part of the NNW-SSE-trending compressional zone of the Indo-Burman Range that forms the eastern boundary of the Bengal Basin at its boundary with the Eurasian tectonic plate. The compressional zone developed as a right lateral transpressional zone caused by the oblique subduction of oceanic crust and overlying Tertiary-age fluvial, deltaic, and deep marine sediments during the collision of the Indian Plate and subjacent ocean crust with the Eurasian Plate in Neogene time.

The Eastern Foldbelt consists of roughly north-south trending folded, thrusted, and wrench-faulted Paleogene and Neogene sediments consisting of shales and reservoir-quality sandstones. The intensity of the deformation diminished westward into the central Bengal Basin and the folds become broader and less complex westwards. The western boundary of the Eastern Foldbelt trends approximately north-south along the Ganges/Brahmaputra River (Figures 6-4 and 6-5).

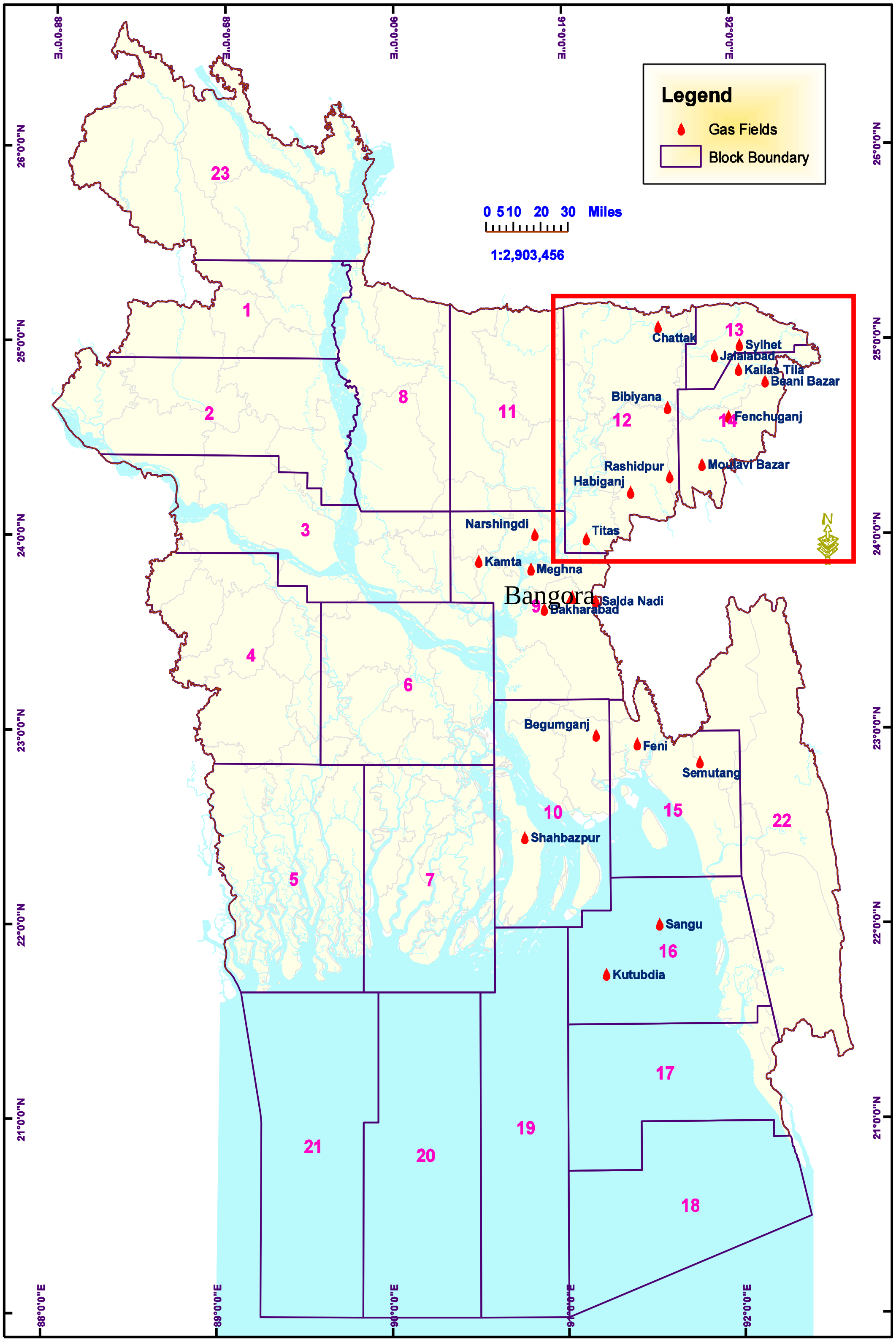



**Figure 6-2 Location Map for Gas Fields of Bangladesh**
(after HCU-NPD, 2004)

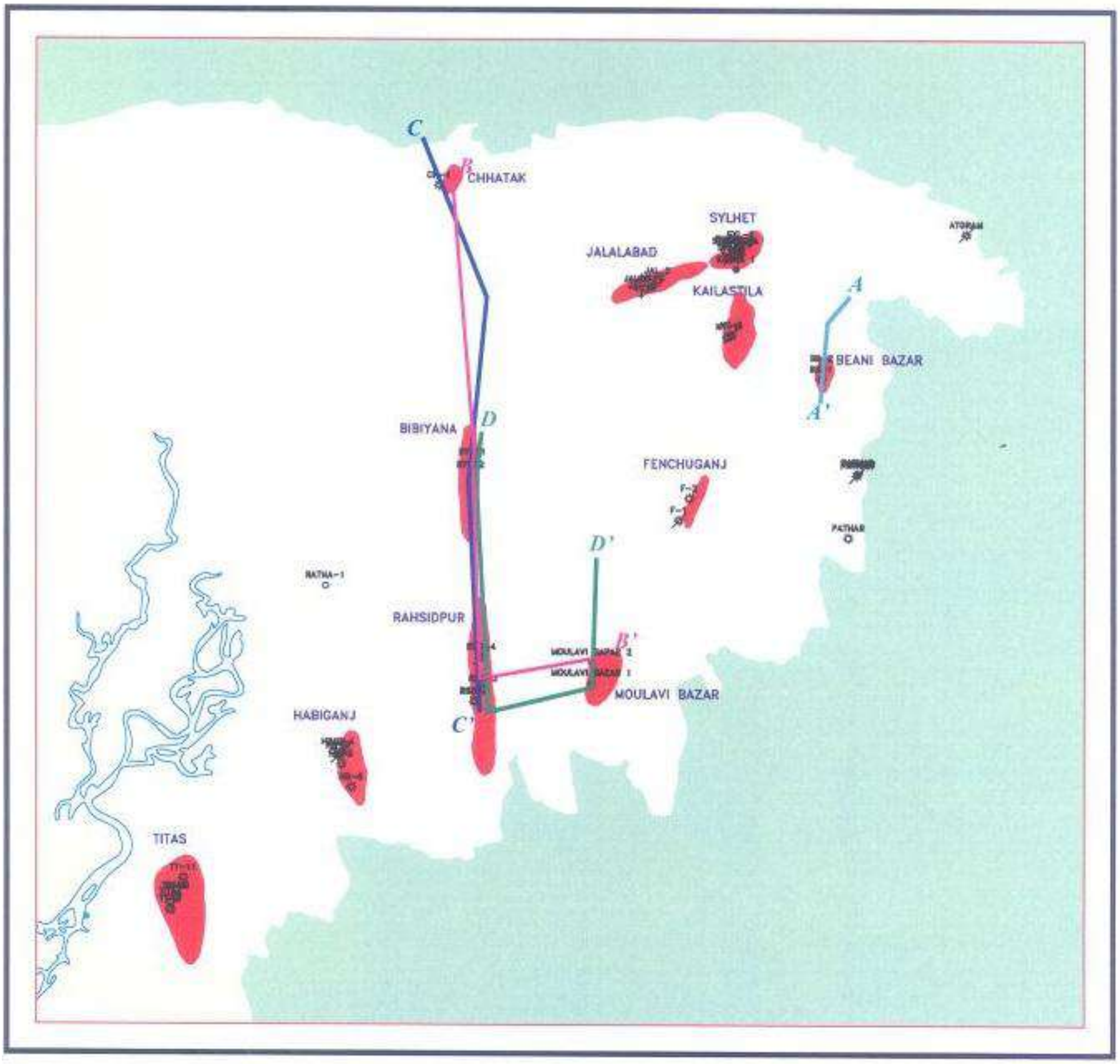



**Figure 6-3 Index Map of Surma Basin Showing Major Gas Fields**
See Figure 6-2 for location (after Unocal, 2000).

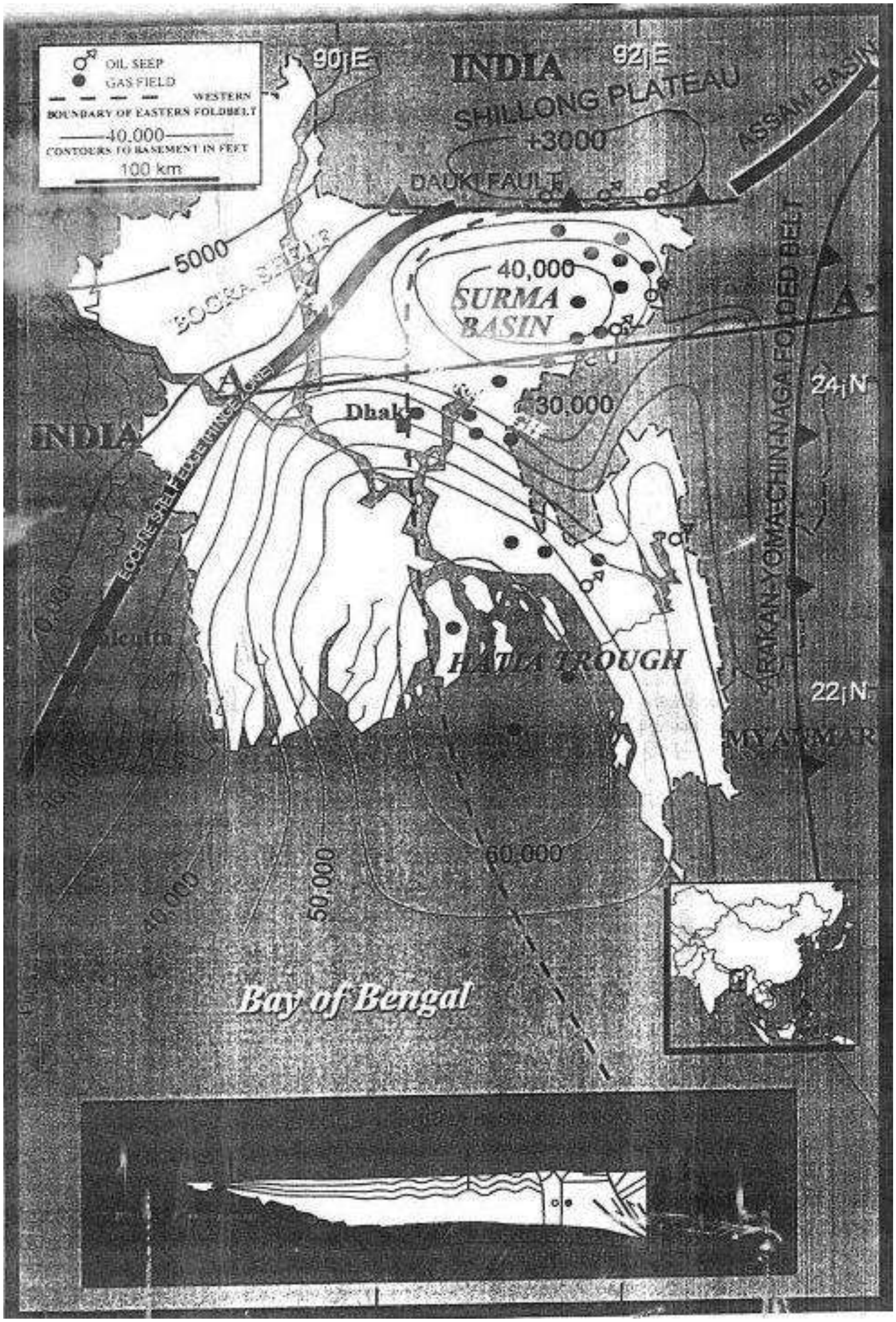



**Figure 6-4 Tectonic Map of Bangladesh**
(modified after Samsuddin and Abdullah, 1997, *in* Shamsuddin et al., 2001).

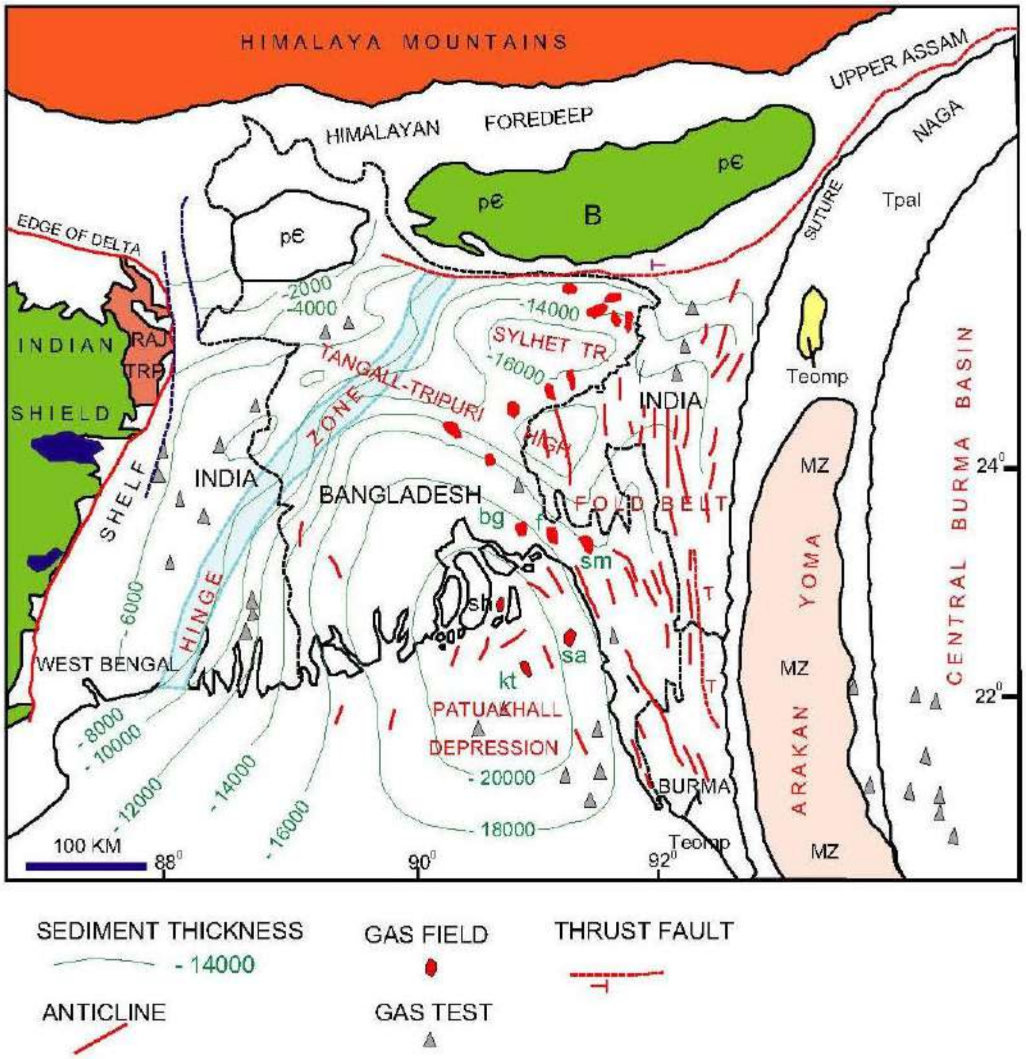



**Figure 6-5 Generalized Geologic Map of Bangladesh and Adjacent Areas**
Sylhet Trough is same as Surma Basin and Patuakhall Depression is same as Hatia Trough (modified after Shamsuddin and Abdullah, 1997 *in* USGS, 2001)

The eastern Bengal Basin is subdivided into two smaller sub-basins, the Surma Basin in the north and the Hatia Trough in the south. The two sub-basins are separated by a gentle east-west trending intra-basinal arch, the Tangall-Tripuri High, at approximately the latitude of Dhaka (Figure 6-5).

The productive sandstone reservoirs are distributed vertically and laterally within two formations of Miocene age. The upper productive formation is the Bokabil that is generally considered to be Late Miocene to Early Pliocene in age. The lower productive formation is the underlying

Bhuban Formation that ranges in age from Early Miocene to Late Miocene in age. Lack of high-resolution paleontological control may limit the accuracy of these age assignments.

Two different systems of nomenclature have been used to name the various productive horizons in many of the fields and a third system is used in fields now operated by Chevron. In the early history of gas field exploration and development, the pay zones were designated in many of the fields as the “Upper Gas Sand”, the “Middle Gas Sand”, and the “Lower Gas Sand”. In other fields a letter designation system has been used. For example, in Titas gas field, the pay zones are referred to the “A,” “B,” and “C” sand groups. These first two systems of pay zone designations are widely used in the fields that are currently operated by the three national oil and gas companies, BGFCL, SGFL, and BAPEX.

Chevron has inherited a system of pay zone designation from its predecessors Occidental Petroleum and Unocal for its three operated fields located in the eastern Surma Basin (Bibiyana, Jalalabad, and Moulavi Bazar). In these three fields, pay sands in the Bokabil Formation are designated with the prefix BB (e.g., BB50, BB60, BB70 etc.). Pay intervals in the underlying Bhuban Formation are designated with the prefix BH (e.g., BH10, BH20, BH25, BH30, etc.). The Chevron terminology is shown in Figure 6-6.

A fourth pay zone nomenclature system has been adopted by Cairn for Sangu gas field in the Bay of Bengal, and there the pay intervals are named the SG1.2635, SG1.3085, SG1.3155, and MS 2.7. The use of different nomenclature systems has resulted in confusion when correlating pay zones in one field with those in other fields.
Figures 6-7 and 6-8 are attempts to reconcile some of the differences in nomenclature used in the various gas fields and to provide regional correlation of individual pay zones both among the various fields and to tie the pay zones stratigraphically to the two productive formations.

From the various stratigraphic charts, it appears clear that the “Upper Gas Sand” is a Bokabil pay zone in several of the fields and the “Lower Gas Sand” is a Bhuban pay interval. It is unclear to which formation the “Middle Gas Sand” and Middle (High Resistivity Zone” pays of Kailash Tila field should be assigned. The single letter designated sands at Titas and Bakhrabad have been assigned to the Bhuban Formation by Shamsuddin et al. (2001). Similarly, the Bangora D and E Sands and the Feni K through R Sands appear to be Bhuban Formation pay zones. At Rashidpur gas field, the BTA and BHA sands that occur above the Lower Gas Sand and below the Upper Gas Sand have been assigned to the Bhuban Formation.

The correlation of the distal sands at Sangu to the more shoreward sands in the fields to the north is somewhat uncertain. The main pay sands may be assigned to the informal Upper Miocene MS 1 megasequence which suggests a Bokabil age equivalency. The MS 2.7 Sand is assigned to the informal MS 2 megasequence that is considered to be Upper Miocene to Pliocene in age. This sand may be a distal offshore equivalent to the Tipam or Dupi Tila formations (Figure 6-6), i.e. post-Bokabil.

The significance of determining accurate inter-field pay zone correlations is highlighted by the presence of important upper Bhuban thinly laminated productive reservoirs at Bibiyana field. These pay zones were only detected with modern thin-bed logging tools. Similar pays may be present in the older gas fields that were only logged with older tools that averaged or “smeared out” log characters of thin-bedded pays. Thus, knowing regional correlations could lead to identifying bypassed thin-bedded pays in the older fields. This issue is discussed later in Section 6.5.5 (Bibiyana Gas Field) as well as in Chapter 7 on enhancing production and in Section III following the Executive Summary at the beginning of the report.

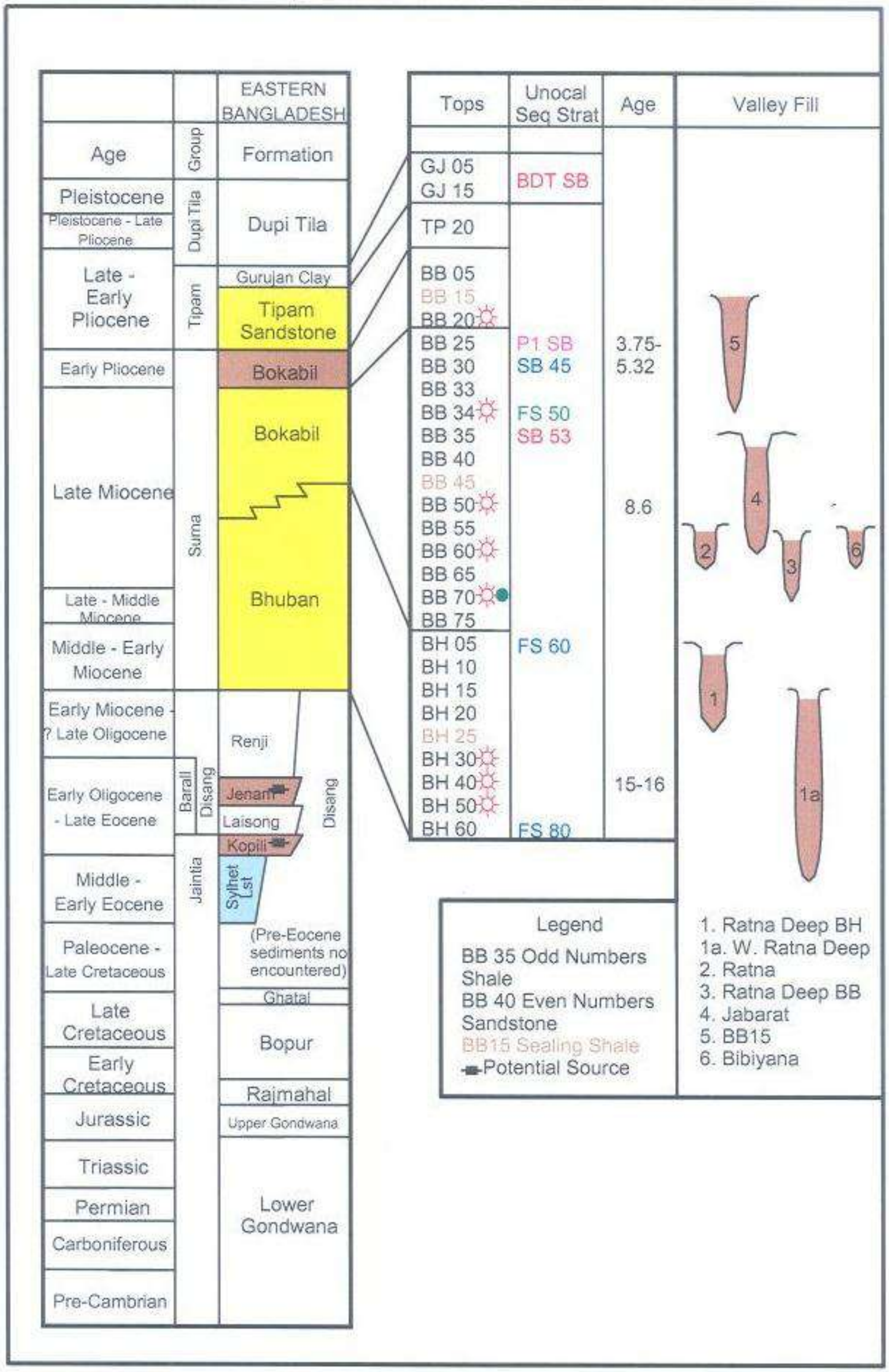



**Figure 6-6 Surma Basin Stratigraphy and Reservoir Nomenclature of Unocal/Chevron**
(after Unocal, 2000)

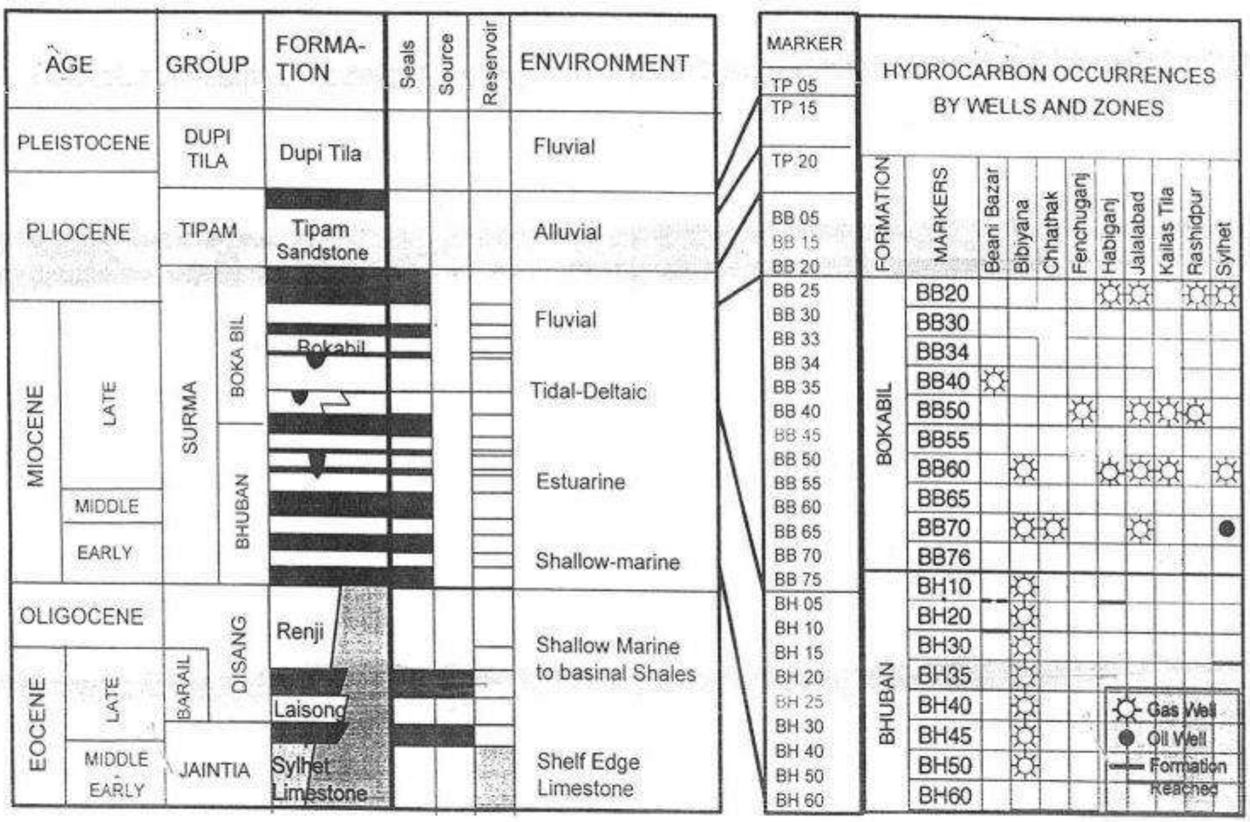



**Figure 6-7 Correlation of Production Zones for Selected Surma Basin Gas Fields**
(after Shamsuddin et al., 2001)

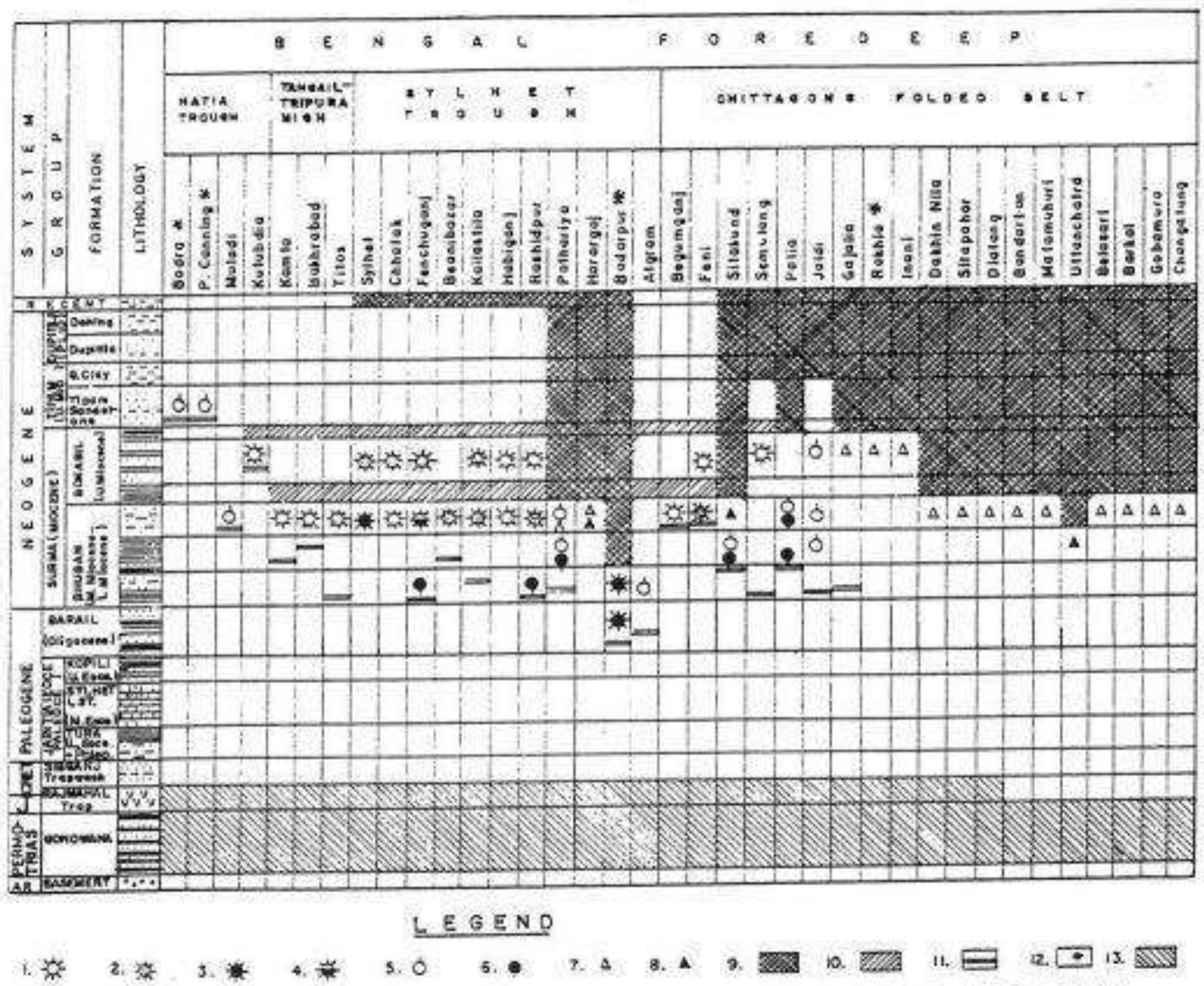



Fig. 2. Present status of oil and gas content in the sedimentary sequences of the Bengal Foredeep. (1) Gas field; (2) gas-condensate field; (3) oil field; (4) gas field with oil indication; (5) gas show in well; (6) oil show in well; (7) gas seep; (8) oil seep; (9) sediment eroded; (10) cap rock; (11) total depth of the well; (12) structure located in the territory of India; (13) assumed non-deposition of sediments.

**Figure 6-8 Correlation of Production Zones for Bangladesh Gas Fields**
(after Shamsuddin and Khan, 1991)

### 6.3.2 Individual Well Histories

In order to streamline the flow of the report, individual well production histories for wells in the more important gas fields are presented in The Annex alphabetically by field name. In addition to a brief description of the individual well history where available, two production charts are included for each producing reservoir in each well. One chart documents the average daily flow rates for gas, condensate, and water. The second chart plots average daily gas production vs.

flowing wellhead pressure (FWHP). In some cases, additional charts showing liquid/gas ratios are also included.

It should be noted, water and condensate recoveries are commonly gauged on a field basis rather than an individual well basis. It is our understanding that bypasses are available at most, if not all, of the field separator facilities that would permit the periodic gauging of liquid recoveries on an individual well basis, but that this procedure is not followed on a regularly scheduled basis. Therefore it is not always possible to determine from which individual well(s) the produced water is coming at any given time.

### 6.3.3 Bakhrabad Gas Field

#### 6.3.3.1 Geologic Setting

Bakhrabad structure is located on the western margin of the Eastern Foldbelt in Block 9 to the west of Bangora and Salda Nadi gas fields (Figure 6-2). In context with regional geology, this folded belt is the western part of Indo-Burman hill range. Bakhrabad structure is a subsurface anticline with no surface expression. Bakhrabad gas field was discovered in 1969.

The structure is a broad four-way dip closure. It is about 70km long and 10km wide. The reservoirs are sandstones of Upper Miocene age that occur in the Bhuban and Bokabil Formations.

The sedimentary succession is of Upper Paleozoic to recent age. A large proportion of the sediment has been deposited since Late Eocene. Only in the Western Shelf and adjacent part of West Bengal state of India, is complete succession within drillable depth. The basin infill is comprised of mainly clastic sediments which reach an estimated thickness of 20 to 22 km in the foredeep area. The foredeep follows a SW-NE trend parallel to the rifted continental margin. It also includes the Surma Sub-basin in the northeast.

#### 6.3.3.2 Structure

This structure was delineated by PPL using gravity data of 1953. During 1966 Pakistan Shell Oil Co. (PSOC) recorded single fold seismic data and mapped the structure. Seismic interpretation shows that Bakhrabad structure is a large elongated anticline with a NNW-SSE trend, conforming to the regional trend. In early interpretations, four separate culminations were identified by Shell and marked as A1, A2, B1 and B2 (Figure 6-2). B1 culmination is named as Bakhrabad. B2 is situated on the south of Bakhrabad structure. A1 and A2 culminations were later named as Meghna (A1) and Belabo (A2) and subsequently the names were changed to Meghna and Narshingdi, respectively. B2 is known as Kashimpur. From geological study (A. Bakr 1977), it can be inferred that the structure was formed recently and is still active.

Figure 6-9 is an early structural interpretation of the greater Bakhrabad structure by Shell in 1974 following the drilling of the initial discovery well. Figure 6-10 is a 1993-vintage structure map on the J Sand after the drilling of eight wells. Figures 6-11 through 6-13 display more recent structure maps at different horizon levels.

#### 6.3.3.3 Reservoir

Bakhrabad well # 1 discovered 10 distinct gas reservoirs named as A, B, C, $D_{Upper}$, $D_{Lower}$, F, G, J, K and L sands. B, $D_{Upper}$, $D_{Lower}$, G and J sands are categorised as the major sands due to their initial volumes and production potentials. The other sands are considered as minor sands. The potential of the K and L sands are to be confirmed.

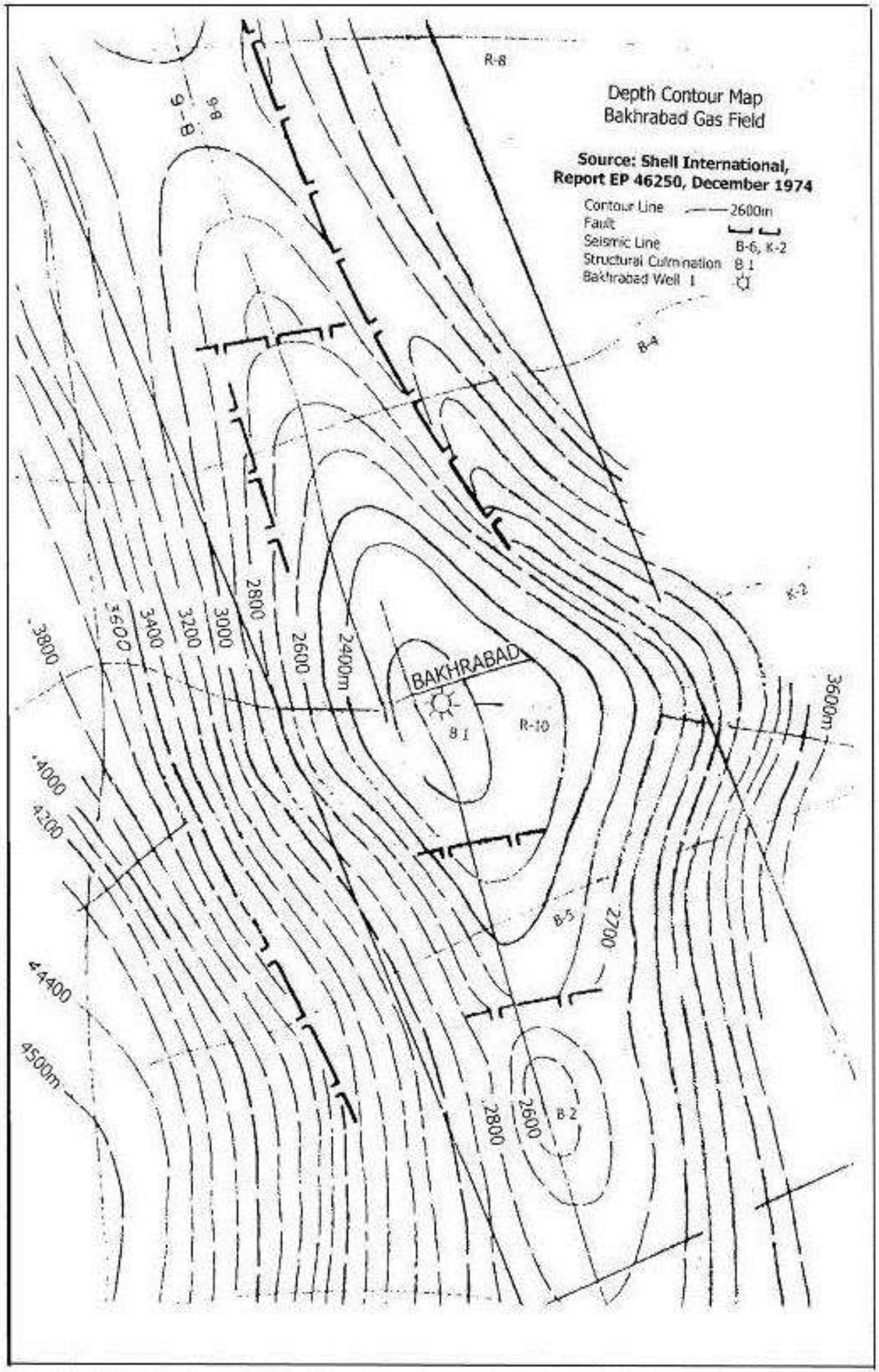



**Figure 6-9 Bakhrabad Gas Field Structural Contour Map of Greater Bakhrabad – Shell Int. Interpretation – 1974**

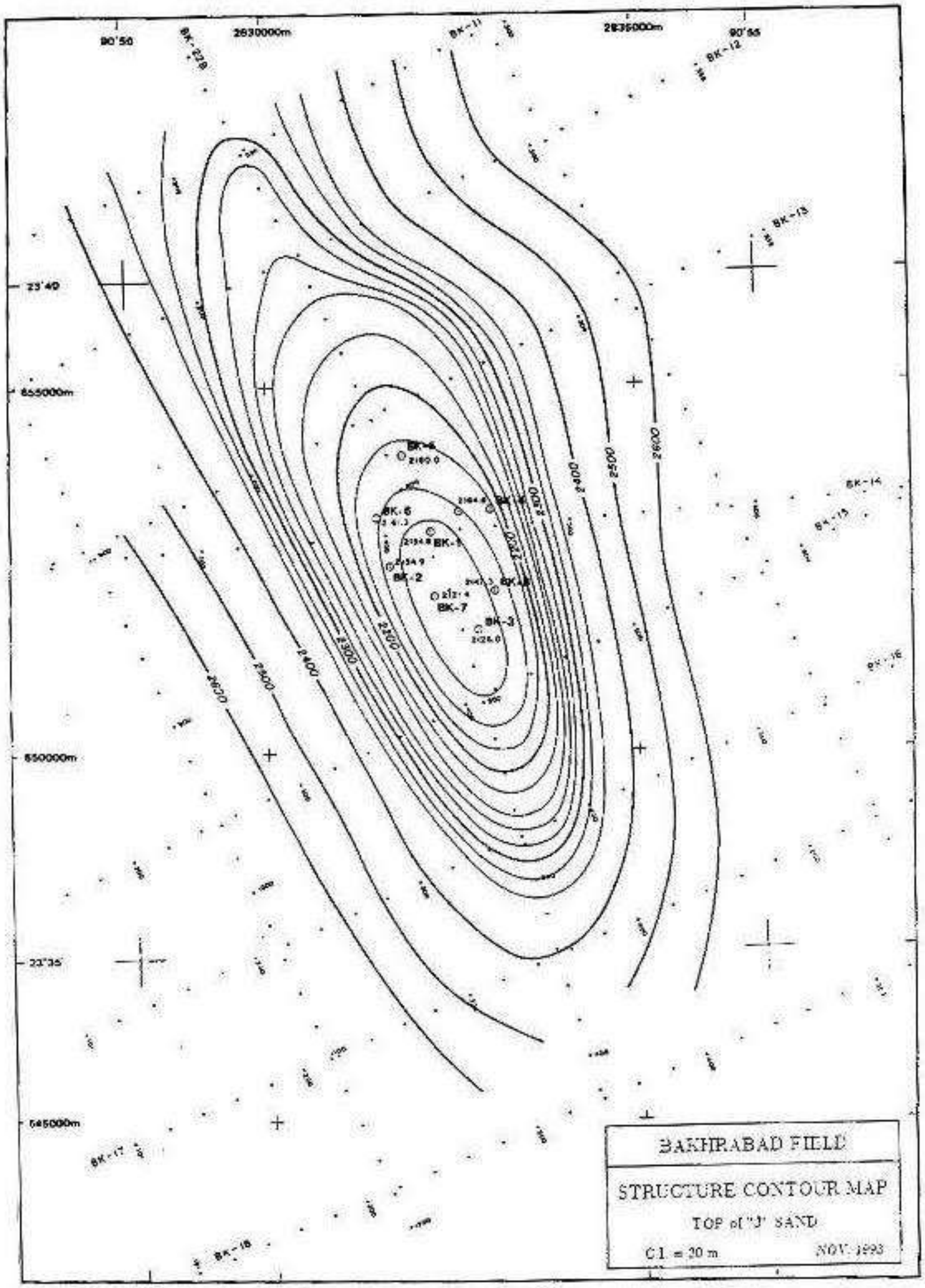



**Figure 6-10 Structure Map on the Top of the J Sand – SAPS Report Interpretation-1993**
Map drawn after the drilling of all eight wells in the field (after SAPS, 1993).

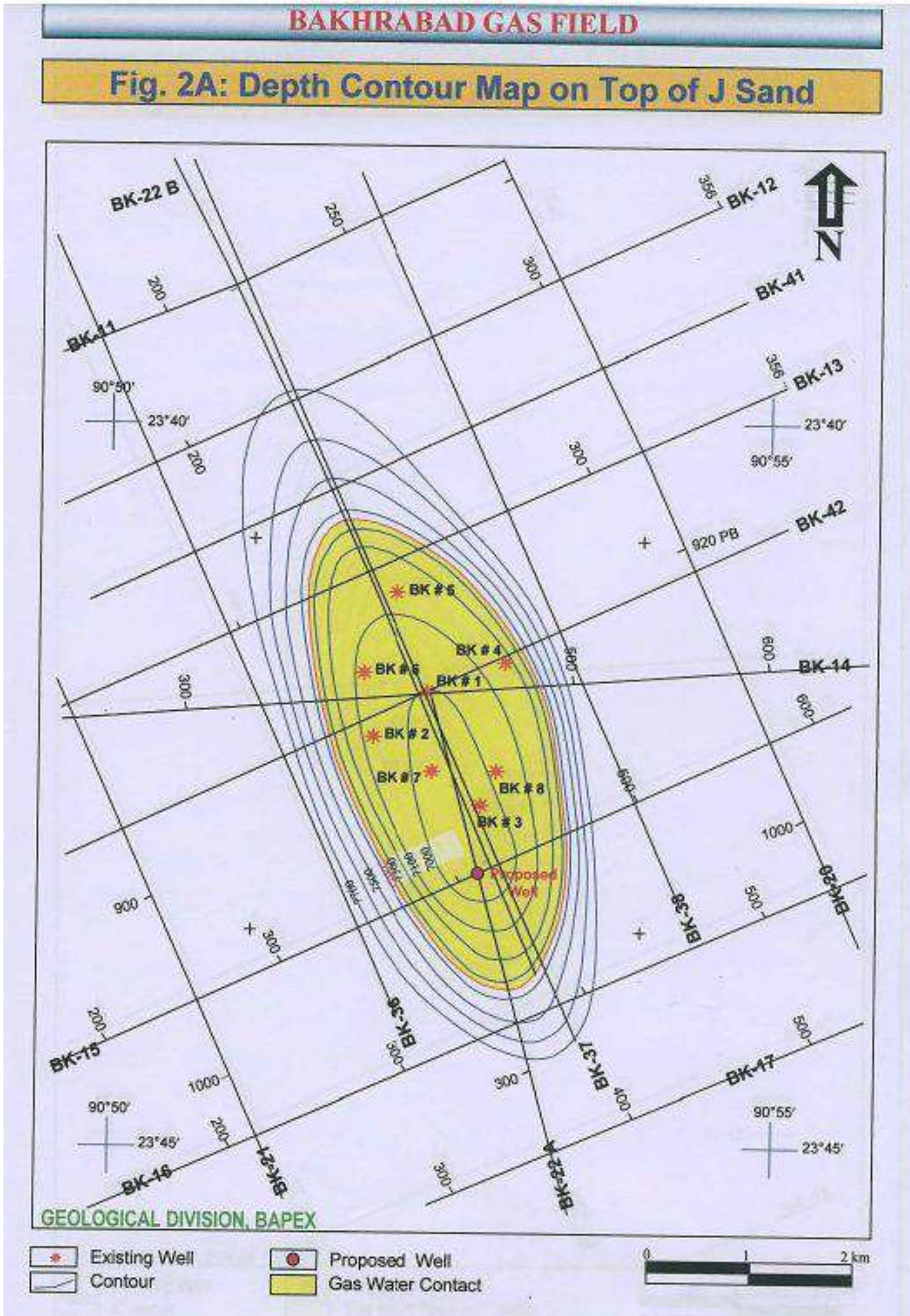



**Figure 6-11 Recent Map of J Sand Structure with Proposed New Well Location**
Well is scheduled to be drilled in late 2010 or early 2011 (courtesy of BGFCL).

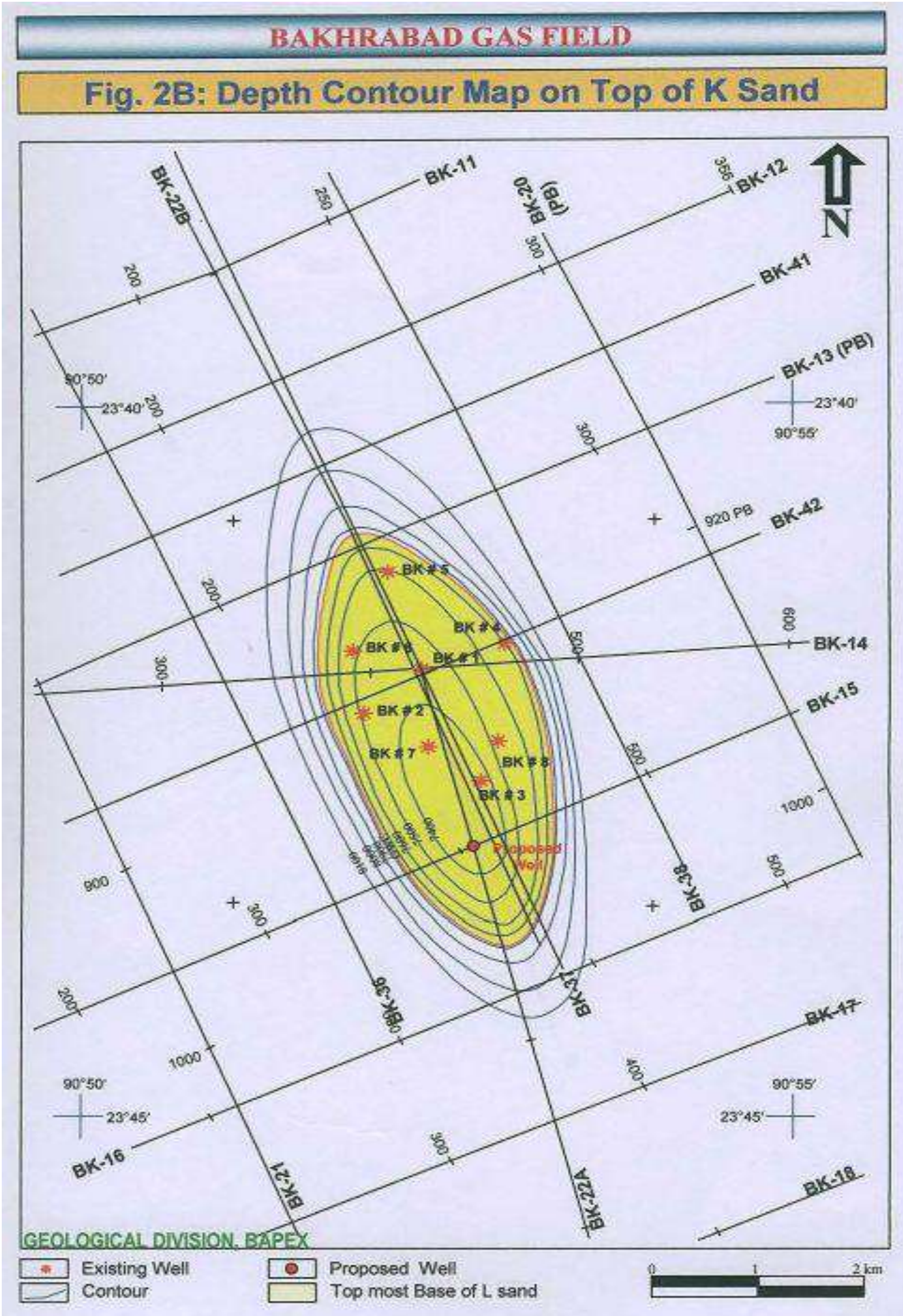



**Figure 6-12 Recent Map of K Sand Structure with Proposed New Well Location**
K Sand reservoir has not yet been developed. Well is scheduled to be drilled in late 2010 or early 2011 (courtesy of BGFCL).

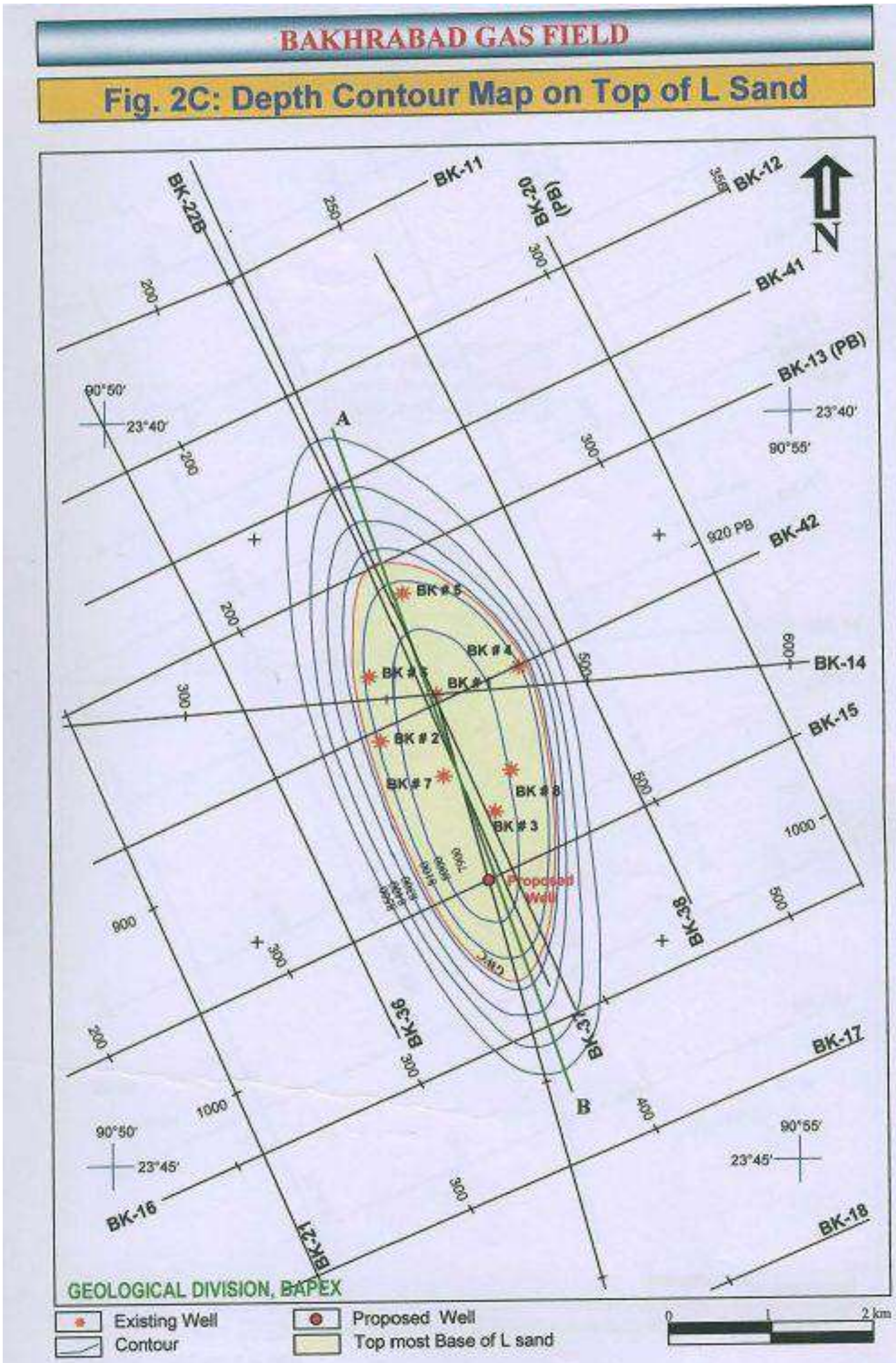



**Figure 6-13 Recent Map of L Sand Structure with Proposed New Well Location**
L Sand reservoir has not yet been developed. Well is scheduled to be drilled in late 2010 or early 2011 (courtesy of BGFCL).

In Bakhrabad, as well as throughout the Eastern Fold Belt, the reservoir rocks belong to Upper Miocene.

According to SAPS study, the sedimentary sequence encompassing the reservoir sequences are composed of sandstone and shale. This can be considered to be deposited in a delta or delta front environment. According to IKM, B to G sands are interpreted to have been deposited in a bay mouth bar environment. The Upper part of the J sand can be considered to be a distal mouth bar – beach bar complex and further below i.e. lower part of J and K and L sands are offshore bar fingers.

In Bakhrabad, three cores ranging between 1.8 to 8 m (6 to 26 ft) in length were cut in Well # 5. In Well # 7, a total of 13 cores were cut from reservoir sections. In the remaining 6 wells, no cores were cut.

Average porosity of the reservoir sands of Bakhrabad field ranges from 16 to 21% and average permeability ranges from 27 to 166 md. J sand is the best reservoir in terms of production potential. It is laterally continuous but the reservoir quality of the middle and lower part is somewhat poor due to addition of more silt and clay. The other sands are regarded as minor sands. Most of the minor sands have high initial water saturations and they have not been tested to ascertain their production potentials. The depositional environment of the reservoir sands are delta front to outer shelf.

#### 6.3.3.4 Exploration and Field Development

The first well was spudded in September 1968 by PSOC with a target depth of 3657m. Drilling was suspended in October 1968 after reaching 2442m. The drilling crew was mobilized to Cox's Bazar #1, first offshore well of the country. After completion of drilling of the offshore well, drilling of Bakhrabad #1 resumed in April 1969 and was terminated at 2838m.

For development of Bakhrabad gas field, a new company, Bakhrabad Gas System Ltd. (BGSL) was formed in 1981. The company was vested with the responsibility of production from

Bakhrabad field as well as transmission and distribution of gas in the south eastern part of the country. During 1981-83, Well #2, #3, #4 and #5 were drilled and all five wells are completed as production wells, Well #1 was completed in J sand. Well #2 was completed in $D_{Lower}$, Well #3 and #4 in G and Well # 5 in B Sand. Simultaneously, a gas processing plant (240 MMscfd) was installed and transmission line was laid.

Gas production from Bakhrabad field started with Well #2 ($D_{Lower}$) in May 1984. About five months later Well #5 (B) was opened in October 1984. Well #1 (J) was opened for production in August 1985, and Well #3 (G) started producing in October 1986.

Second phase of development was taken up in 1988-89 when 3 wells were drilled and all were completed in J sand.

6.3.3.5 Well-wise and Sand-wise Production History

Production histories, both well-wise and sand-wise, for Bakhrabad gas field are shown in Figure 6-14 and Figure 6-15, respectively.

It is apparent from Figure 6-15 that the J Sand is by far the main producing horizon in this field. In early 1999, production rates were stabilized on a field-wide basis and the field has maintained a greatly reduced but relatively uniform level of daily production of about 33 MMscfd from the four producing wells. This has been accomplished mainly by a dramatic reduction in production rate from the J Sand.

Detailed individual well histories and accompanying production charts for Bakhrabad wells are included in The Annex. The reader is encouraged to study these charts to gain insights into potential production problems and to better understand the production patterns on a well-by-well basis.

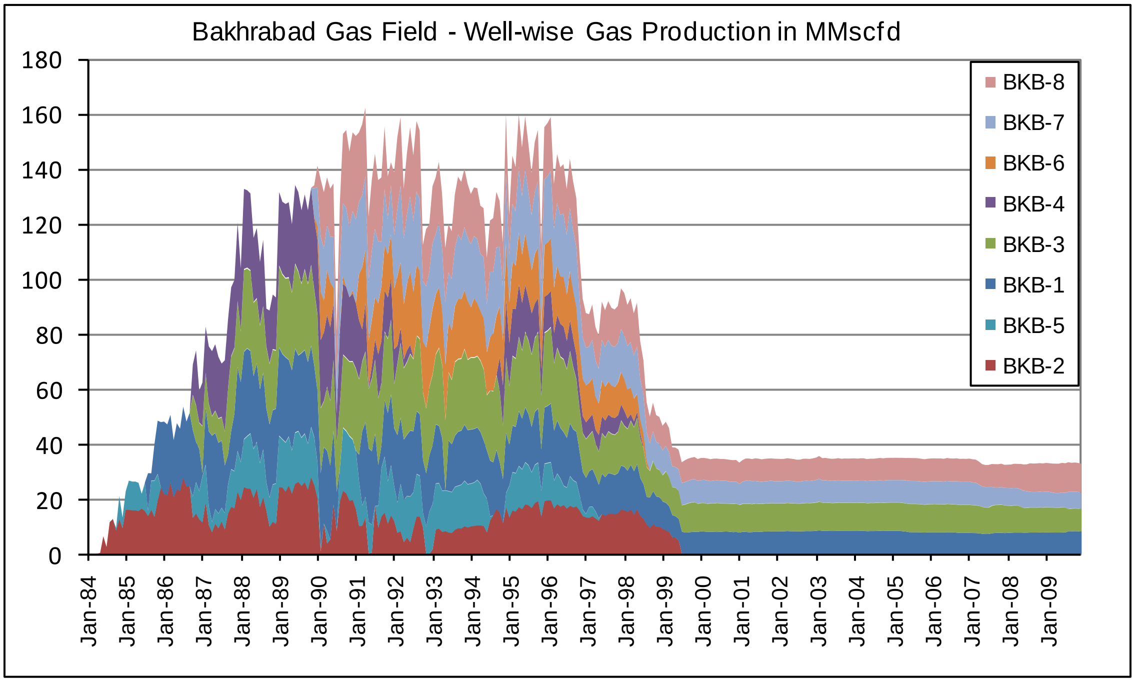



**Figure 6-14 Well-wise Gas Production – Bakhrabad Gas Field**

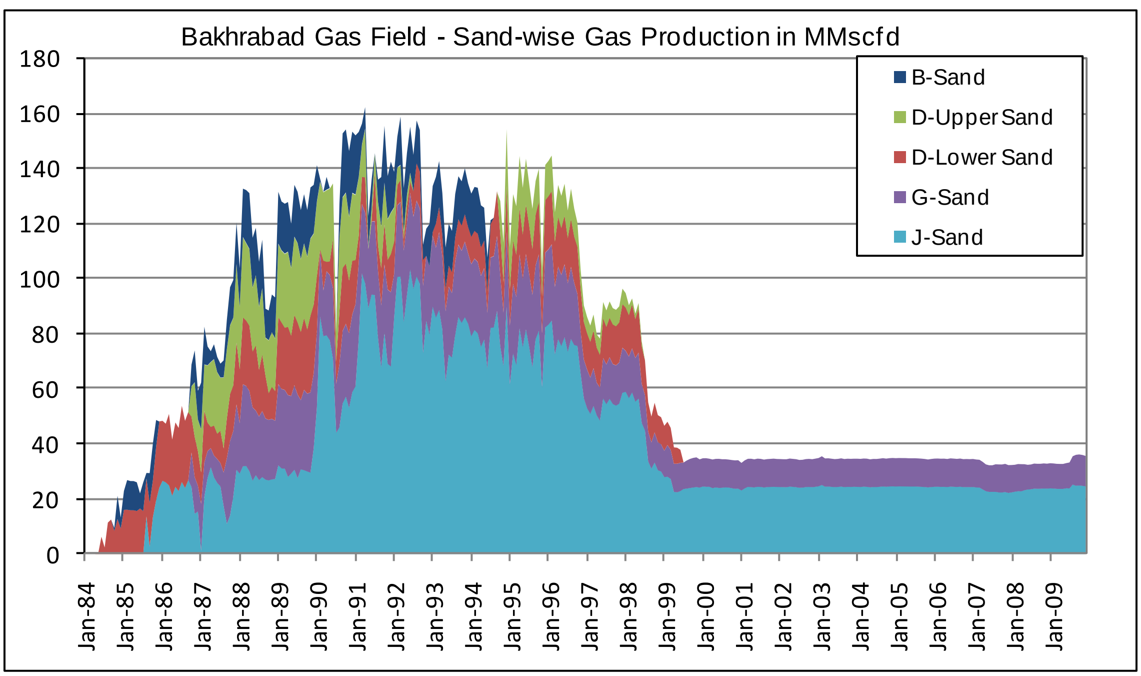



**Figure 6-15 Sand-wise Gas Production – Bakhrabad Gas Field**

### 6.3.3.6 Cumulative Production

Over its 26-year productive life, Bakhrabad gas field has produced 698 Bscf of gas, 998,000 barrels of condensate, and 2,000,000 barrels of water from five separate sandstone intervals. The field is currently producing at a daily rate of 35 MMscf of gas, 22 barrels of condensate, and 446 barrels of water (December 2009 production figures, HCU database).

Sand-wise gas cumulative production for Bakhrabad gas field at end of December 2009 is summarized in Table 6-2.

**Table 6-2 Sand-wise Cumulative Gas Production – Bakhrabad Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| B Sand | 42.2 |
| D Upper | 42.4 |
| D Lower | 87.9 |
| G Sand | 153.7 |
| J Sand | 371.9 |
| **Total** | **698.1** |

1 Production through end of December 2009
HCU production database

### 6.3.3.7 Earlier Reserve Estimates

According to a post-discovery volumetric estimate (Shell) GIIP was 2.78 Tscf. This estimate was based on a provisional interpretation of geological information. In some of the technical papers compiled during late 70's and early 80's, it was mentioned that this figure includes 740 Bscf Proved and another 740 Bscf Probable of reserves. In addition to this, another 1340 Bscf was estimated as Possible.

Since then, a number of reserve studies based on single well data were conducted by different workers. Both probabilistic and deterministic methods were applied and the results were wide ranging. These reports are not discussed in detail in this report, however; the results are briefly summarized below. Table 6-3 summarizes the results of previous volumetric estimates of GIIP for Bakhrabad gas field in tabular form with the data broken out by individual sand reservoirs. Figure 6-16 is a graphical comparison of the previous volumetric estimates of GIIP for the sand reservoirs of Bakhrabad gas field.

Table 6-4 summarizes the results of previous Material Balance (p/z) estimates of GIIP for Bakhrabad gas field in tabular form with the data broken out by individual producing sand reservoirs. Figure 6-17 is a graphical comparison of the previous Material Balance (p/z) estimates of GIIP for the producing sand reservoirs of Bakhrabad gas field. The Material Balance methodology requires formation pressure data for at least two times, and preferably more, during the producing history of the reservoir and therefore is only applicable to producing reservoirs. For this reason, Sands A, C, F, K and L were not included in the p/z analyses of the previous studies.

After first phase of development, Welldrill did volumetric estimate and field GIIP was 1693 Bscf. Out of this total GIIP, the producing sands accounted for 1441 Bscf of this estimate.

During 1988-89, four wells were drilled in Bakhrabad. Welldrill, consultant of the project, re-estimated the GIIP at 1844 Bscf. Producing gas sands account for 1585 Bscf. Welldrill also opined that at 400-600 psig abandonment pressure, recoverable reserve of the field could be 1260 Bscf. Welldrill also used material balance (p/z) method to estimate the reserve of the producing sands and the result was 1553 Bscf for the producing sands.

During 1986, both GGAG and Gasunie re-estimated the reserves of this field using the volumetric method.

**Table 6-3 Comparison of Previous Volumetric Estimates of GIIP - Bakhrabad Gas Field**

| Volumetric Estimate of GIIP. Bakhrabad Gas Field | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Welldrill 1983 | HHSP 1986 | Welldrill 1987 | Welldrill 1990 | Welldrill 1991 | IKM 1991 | HCU-NPD, 2003 | RPS Petrel. 2009 |
| A | 4 | 3.2 | 63 | 1 | 12 | | 1.57 | 2 |
| B | 65 | 63.6 | 248 | 77 | 145 | 142.8 | 108.83 | 154 |
| C | 11 | 13.7 | 14 | 19 | 20 | 24.1 | 31.3 | 34 |
| D lower | 246 | 248 | 248 | 261 | 167 | 222.4 | 183.24 | 163 |
| D upper | 105 | 87.7 | 88 | 243 | 150 | 151.5 | 149.85 | 211 |
| F | 15 | 12.3 | 12 | 15 | 16 | 37.7 | 45.3 | 44 |
| G | 332 | 377 | 377 | 425 | 300 | 261.7 | 244.48 | 191 |
| J | 693 | 558 | 558 | 579 | 610 | 554 | 539 | 433 |
| K | 114 | 190 | 190 | 113 | 120 | | 147.9 | 186 |
| L | 108 | 126 | 120 | 111 | 119 | | 143.7 | |
| **Total** | **1693** | **1679.5** | **1918** | **1844** | **1659** | **1394** | **1595.17** | **1418** |

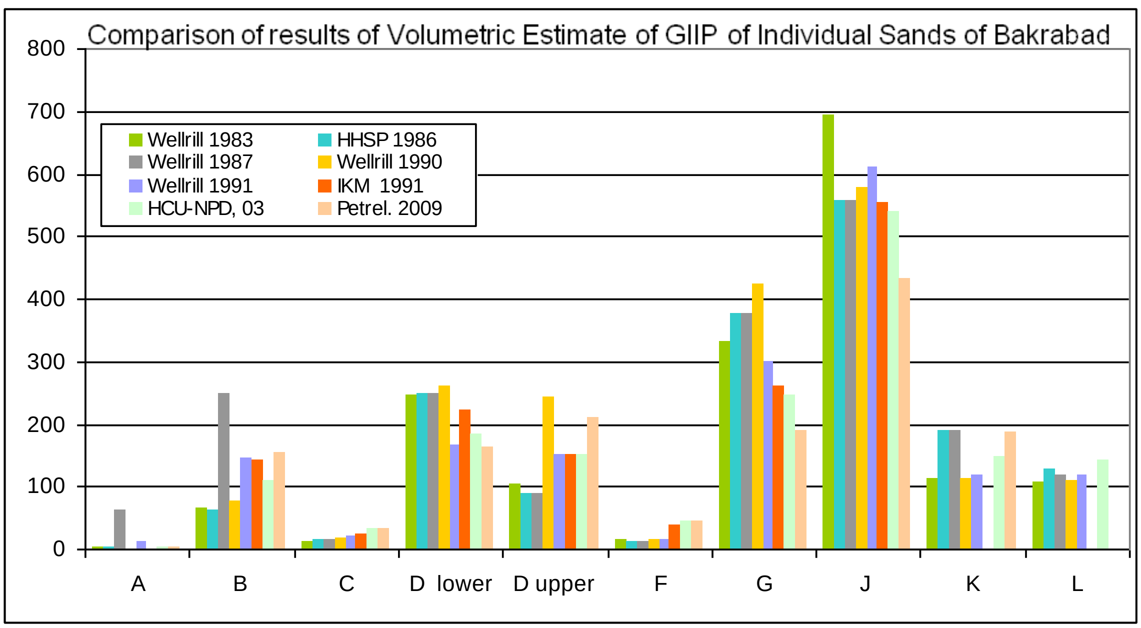



**Figure 6-16 Comparison of Previous Sand-wise Volumetric Estimates of GIIP - Bakhrabad Gas Field**

**Table 6-4 Comparison of Previous Material Balance Estimates of GIIP - Bakhrabad**

| p/z Analysis of GIIP. Bakhrabad Gas Field. Bscf | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Welldrill 1990 | IKM 1991 | SAPS 1993 | Petrobangla 1993 | Clyde 1995 | Mobil 1997 | Shell 1997 Tub Head | Shell 1997 Avg Press. | UTP & Murphy 1997 | PMRE BUET 1999 | Petobangla 2000 |
| A | | | | | | | | | | | |
| B | 231 | 145 | 151 | 166 | 169 | 167 | 112 | 138 | 155 | 153 | 181 |
| C | | | | | | | | | | | |
| D lower | 167 | 180 | 184 | 180 | 202 | 188 | 144 | 178 | 185 | 150 | 207 |
| D upper | 200 | 148 | 155 | 176 | 176 | 175 | 157 | 222 | 167 | 142 | 181 |
| F | | | | | | | | | | | |
| G | 370 | 299 | 270 | 246 | 251 | 244 | 434 | 274 | 233 | 216 | 223 |
| J | 585 | 597 | 620 | 665 | 669 | 666 | 1102 | 730 | 460 | 461 | 481 |
| K | | | | | | | | | | | |
| L | | | | | | | | | | | |
| **Total** | **1553** | **1370** | **1380** | **1433** | **1466** | **1440** | **1948** | **1542** | **1200** | **1122** | **1273** |

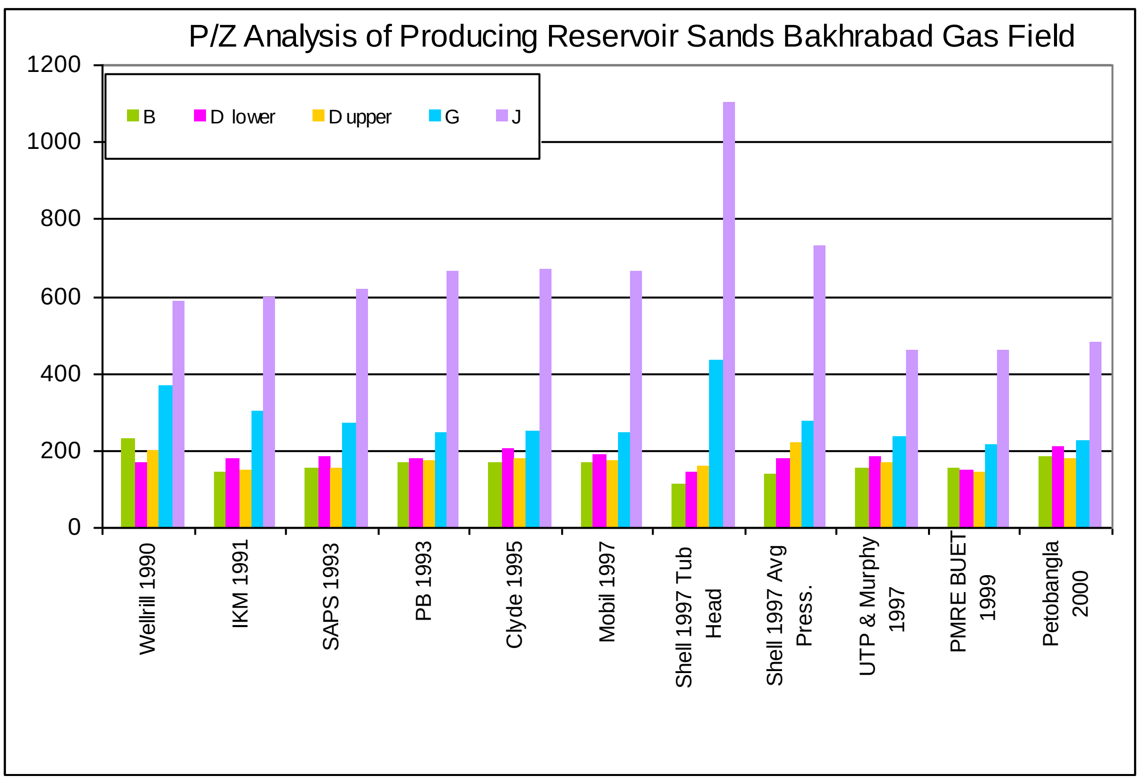



**Figure 6-17 Comparison of Material Balance (p/z) Estimates for Bakhrabad Gas Field**

In 1993, Reservoir Study Cell (RSC) of Petrobangla did a study on gas reserves of Bakhrabad gas field. This study was limited to producing sands only. According to this study, gas reserve of producing sands of Bakhrabad field was 1433 Bscf.

During the same period SAPS team (OECF, Japan) did another study using pressure data. The result was 1380 Bscf. The SAPS study estimated the recovery factor for the producing gas sands. For B and D sands recovery factor was 50% and that for G and J sand at 63%. This study opined that recovery factor for B and D sands could be 50% and for G and J sand it is 63%.

Clyde Petroleum of UK estimated the reserves of Bakhrabad field (1995). The company used simple p/z analysis. As a result, the study was limited to producing gas sands. According to Clyde Petroleum, the estimated GIIP of the producing sands is 1466 Bscf. According to their study, the recovery factor is about 52% and this could be increased to 82% by using compression. This amounts to an additional 400 Bscf gas.

Union Texas and Murphy Exploration did another study (1997) and according to them, GIIP of the producing sands is 1200 Bscf. The study also estimated recoverable reserve at an abandonment pressure of 1000 and 500 psi, which is 814 and 1017 Bscf, respectively.

In 1997, Shell and Mobil (former) conducted two independent studies on the reserve of Bakhrabad gas field. Shell used both average reservoir pressure and tubing head pressure data. Mobil estimated the reserve of the producing sands at 1440 Bscf. Shell came up with two results. The tubing head pressure data resulted in 1948 Bscf and Average pressure data resulted in 1541 Bscf.

In 1999, Petroleum and Mineral Resources Department of BUET carried out a study on gas reserve of Bakhrabad gas field. The study used flowing wellhead pressure, shut-in bottom hole pressure, shut-in wellhead pressure, flowing bottomhole pressure and flowing well head pressure. The result was strikingly similar. It ranged between 1122 to 1142 psi.

In 2009, RPS Energy completed a study on gas reserves for Petrobangla. This study was limited to 13 gas fields operated by the companies of Petrobangla. The RPS methodology used advanced reservoir modeling and history matching using Petrel and Eclipse software (Schlumberger). The results of this study are shown in Table 6-5 and are also included in summary form in Table 6-3.

In summary, Table 6-4 showed that the results of different Material Balance (p/z) studies are quite close with some exceptions. GIIP using volumetric estimates (Table 6-3) ranges between 1400 to 1700 Bscf with two high figures above 1800 Bscf, both by Welldrill. In case of p/z analysis the result shows a decrease in GIIP with time. IKM 1999 and Petrel 2009 did not include L sand in their estimates. The reader is referred to the HCU-NPD 2003 Reserves Report for more discussion of these previous estimates.

**Table 6-5 Summary of Results of RPS Energy 2009 Study for Bakhrabad (GIIP in Bscf)**

| | Volumetric Calculation | | Simulation Model | | Connected Volume | |
|---|---|---|---|---|---|---|
| | Petrel | REP m 50 | Pre History Match | Post History Match | MB Analysis | Published GIIP |
| A | 2 | 10 | 2 | 2 | | |
| B | 154 | 4 | 157 | 157 | 171 | 142.8 |
| C | 34 | 89 | 35 | 35 | | 24.1 |
| D lower | 163 | 98 | 169 | 169 | 181 | 222.4 |
| D upper | 211 | 123 | 216 | 216 | 195 | 151.5 |
| F | 44 | 17 | 46 | 46 | | 37.7 |
| G | 191 | 49 | 194 | 216 | 221 | 261.7 |
| J | 433 | 304 | 436 | 658 | 677 | 554 |
| K | 186 | 33 | 201 | 201 | | |
| L | | | | | | |
| **Total** | **1418** | **727** | **1456** | **1700** | **1445** | **1394.2** |

RPS Energy 2009a

6.3.3.8 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Bakhrabad field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below.

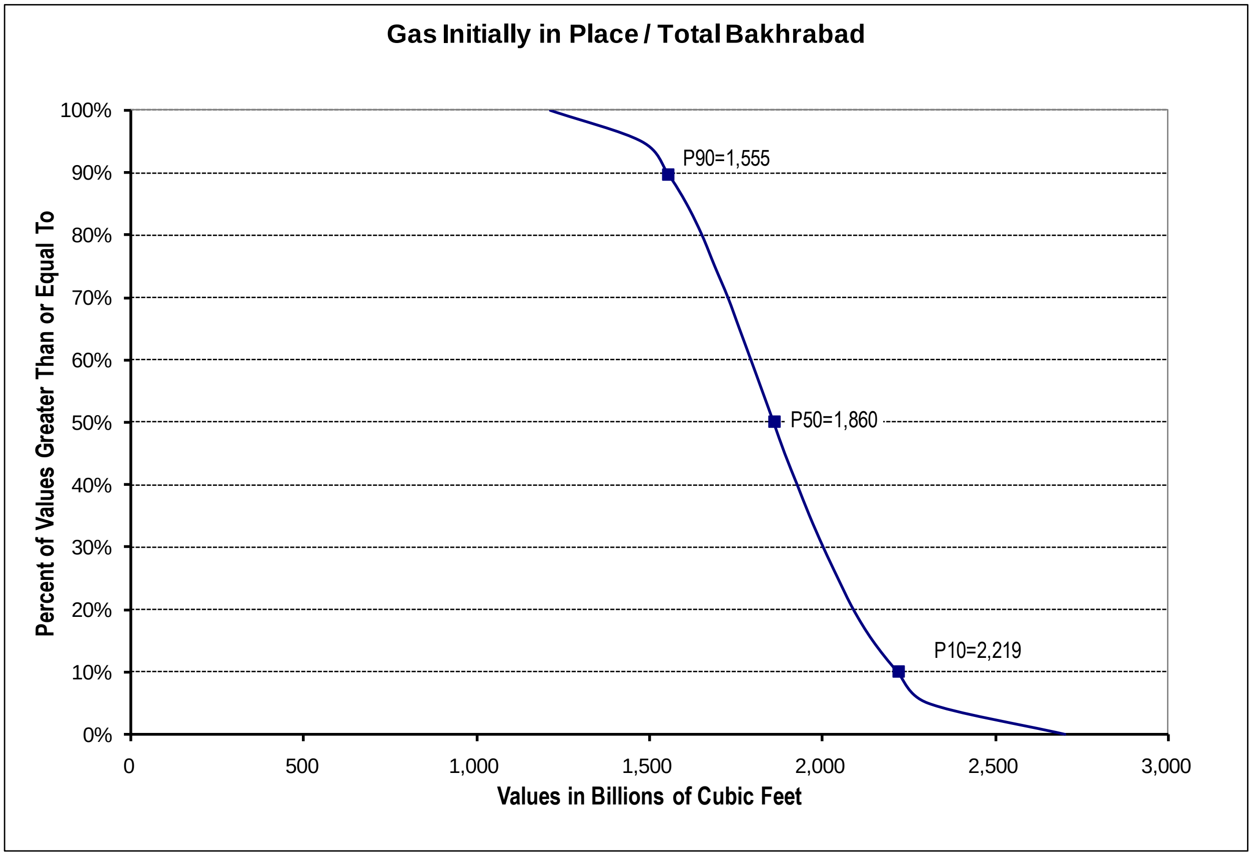



**Figure 6-18 Distribution of GIIP, Bakhrabad**

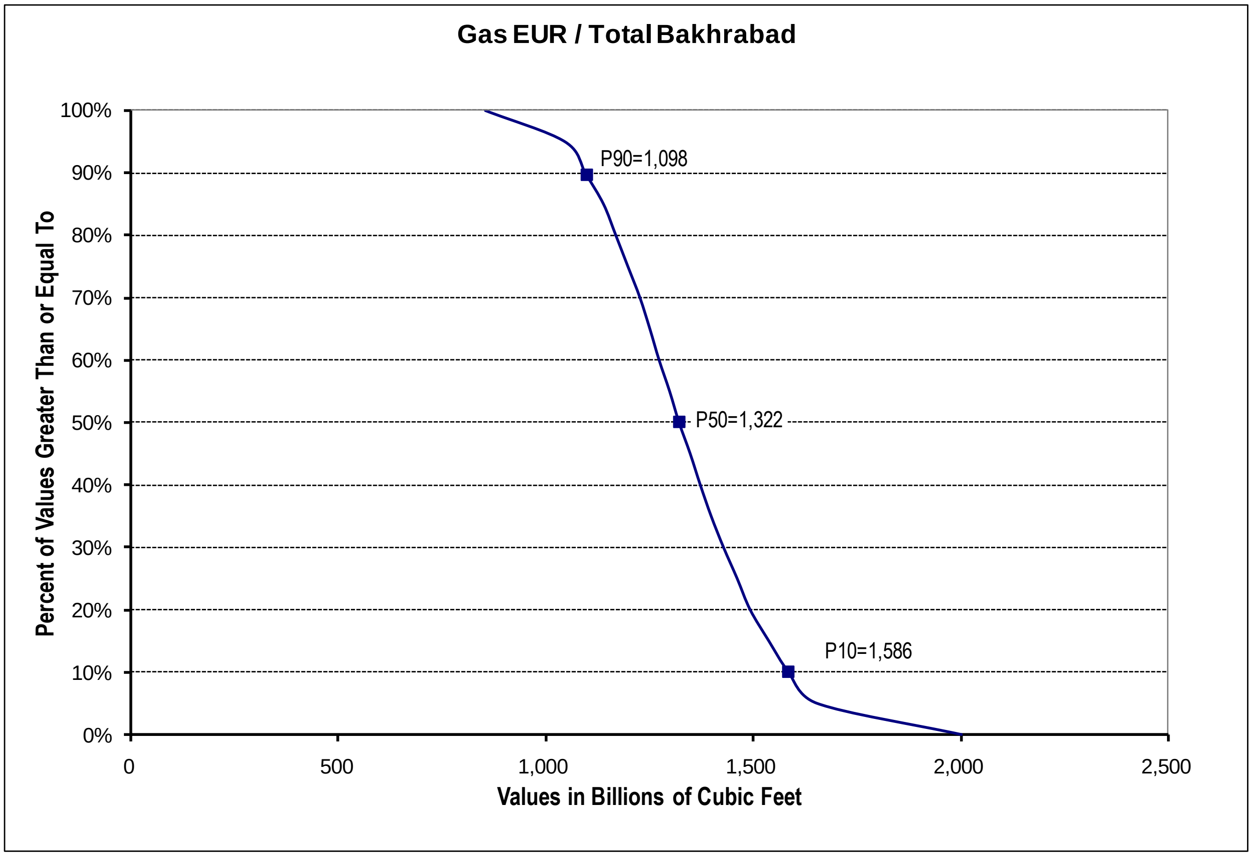



**Figure 6-19 Distribution of Gas EUR, Bakhrabad**

**Table 6-6 Summary of Estimated Ultimate Recovery at Bakhrabad**

| **Reservoir** | **Mean Gas EUR, BCF** | **Cumulative Production (1/1/2010), BCF** | **Reserves (1/1/2010), BCF** |
|---|---|---|---|
| B Sand | 112 | 42 | 70 |
| C Sand | 27 | 0 | 27 |
| D Upper Sand | 154 | 42 | 112 |
| D Lower Sand | 137 | 88 | 49 |
| F Sand | 36 | 0 | 36 |
| G Sand | 197 | 154 | 43 |
| J Sand | 438 | 372 | 66 |
| K Sand | 133 | 0 | 133 |
| L Sand | 101 | 0 | 101 |
| **TOTAL** | **1,335** | **698** | **637** |

Additionally, reserves and GIIP were estimated for the G and J sands at Bakhrabad (the only currently producing sands) using the Approximate Wellhead Material Balance (AWMB) technique.[2] For this technique, where more than one well is producing from a reservoir, the FWHP values are averaged. Any data deviating significantly from the established trend were excluded. The results are shown in Figure 6-20 and Figure 6-21. The slope of the line is determined from the flowing wellhead pressure vs. cumulative production graph. Then a line with this slope is extended from the initial shut-in wellhead pressure to zero pressure. The projection on the x axis at 0 psi is the estimated GIIP, and the point on the projected line at a y value equal to the expected abandonment well head pressure yields the estimated ultimate recovery (EUR) on the x axis at that point.

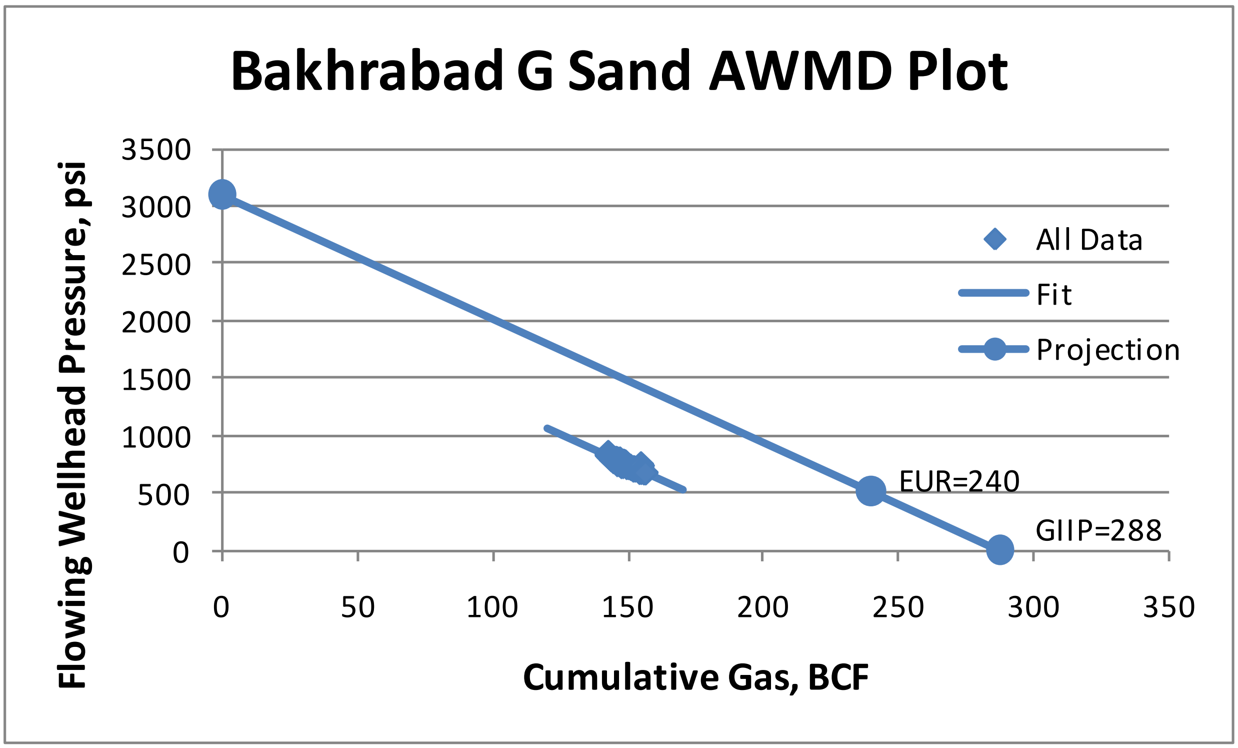



**Figure 6-20 Bakhrabad G Sand AWMB Plot**

[2] Mattar and McNeil, 1998.

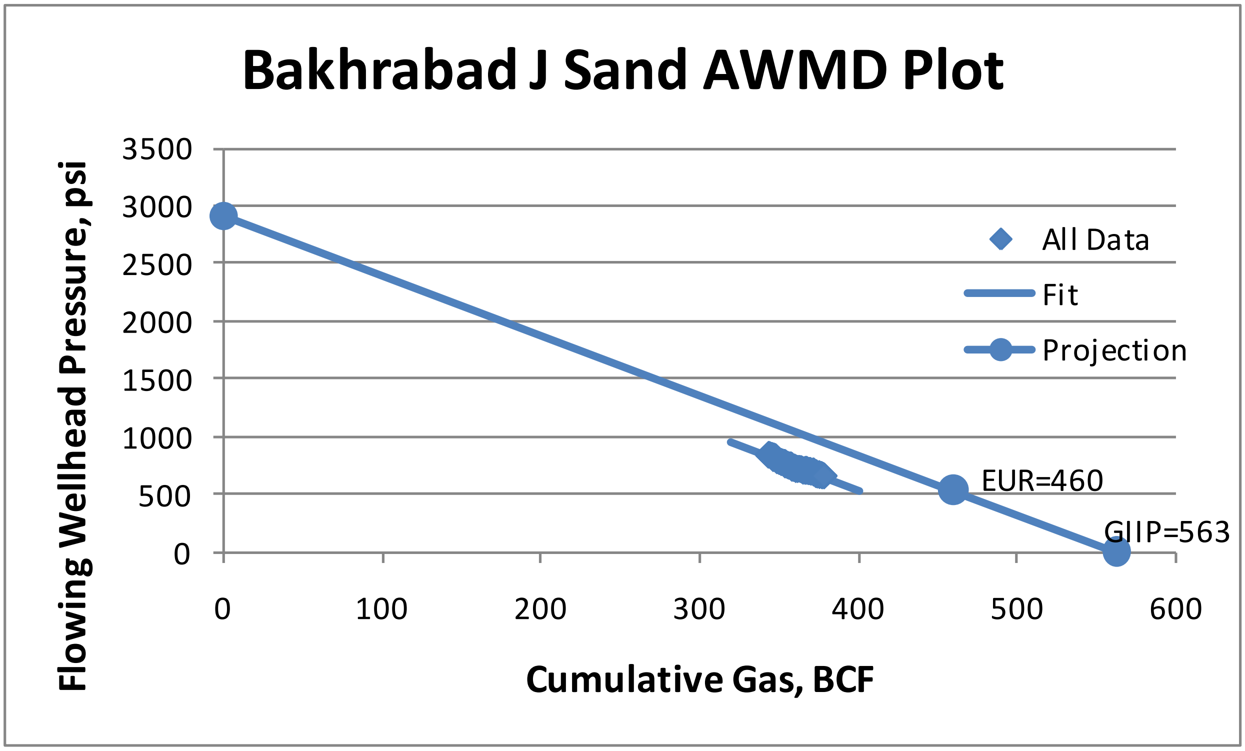



**Figure 6-21 Bakhrabad J Sand AWMB Plot**

These results compare with the mean volumetric calculations as follows:

| **Reservoir** | **G Sand** | | **J Sand** | |
|---|---|---|---|---|
| **Method** | **Volumetric** | **Mat Bal** | **Volumetric** | **Mat Bal** |
| GIIP, BCF | 272 | 288 | 617 | 563 |
| EUR, BCF | 197 | 240 | 438 | 460 |
| Cum. Gas, BCF | 154 | 154 | 372 | 372 |
| **Reserves, BCF** | **43** | **86** | **66** | **98** |

This is considered to be fairly good agreement. The material balance method is considered more reliable.

## 6.3.4 Bangora (6)

### 6.3.4.1 Geologic Setting

The Bangora-Lalmai anticline is positioned on the east side of the Bengal basin. At the beginning of Eocene Time, deltaic sands and shales prograded into the Bengal basin as the region subsided. Clastic sediments accumulated in marine and marginal marine sequences intercalated with deltaic deposits until the Pliocene. Continental fluvial deposits covered the older marine sediments during the Pliocene-Recent. The area (Block 9) lies within the Inner Foldbelt Prospectivity Zone of the Eastern Fold Belt. Stacked sequences of shallow marine sandstones of upper Bhuban Formation (Middle Miocene) constitute the primary gas reservoirs of the Bangora field (Figures 6-6 and 6-7).

#### 6.3.4.2 Structure

Anticlinal structures in Block 9 tend to be NW-SE to N-S trending, elongate en echelon features. The structure of the Bangora field was interpreted from two-dimensional (2-D) seismic data obtained in 2002 and 2003 as well as earlier data. A 3-D survey was subsequently acquired by Tullow in 2005. An elongated anticline having a NNW-SEE trend was mapped in the subsurface based on these data. Figure 6-20 is a structure map on top of the D Sand (main pay) based on interpretation of the 3-D seismic survey. Figure 6-21 is an enlarged image of Figure 6-20 in the vicinity of Bangora field. Figure 6-22 is a similar seismically derived structure map on top of the slightly shallower H30 seismic horizon showing the estimated limits of gas accumulations within the shallower A, B and C Sands. The gas columns in these shallower sands appear to be mainly controlled by structure closure along the crest of the anticline.

The southern trap of the Bangora-Lalmai anticline (Lamlai) is fault bounded with indications of independent (four-way) closure. The northern trap (Bangora) exhibits similar but more definite dip closure. A NW-SE trending shale-filled erosional channel located along the crest of anticline forms the updip trap for the D and E Sand intervals. This channel is shown in gray in Figures 6-20 and 6-21.

Folding of strata in Block 9 occurred during the Late Pliocene. Overlying strata are largely undisturbed, and structural features rarely exhibit expression at the surface. Faults are widespread and may facilitate hydrocarbon migration from underlying source rocks. Based on seismic mapping, the operator, Tullow Oil plc, has concluded that faulting has not negatively impacted hydrocarbon accumulation in the Bangora field area (Tullow, 2005).

### 6.3.4.3 Reservoir

Exploratory drilling in the Bangora field in 2004 identified a stacked sequence of sandstone hydrocarbon reservoirs in the Upper Bhuban Formation at the H30 sand horizon. The complex nature of the deltaic depositional setting makes local and regional correlation of individual sandstone units difficult. Test results showed sands underlying H30 in the Bangora #1 well were mostly wet. Sands above the H30 zone in this well contained little gas.

Reservoir sands in the Bangora field are laterally discontinuous, but lateral reservoir continuity appears to be preserved due to the nature of sand stacking within depositional sequences. Sand accumulations thin to the south away from the basin margin. Discontinuous and thin but laterally extensive marine shales serve as top and lateral (channel-cut) reservoir seals.

Net reservoir thickness, porosity, and water saturation were determined from petrophysical analyses of available wireline geophysical logs and well test data. Average porosity of the reservoir sands in the Bangora field ranges from 11.8 % to 23.4%. Water saturation ranges from 46.2% to 71.6%.

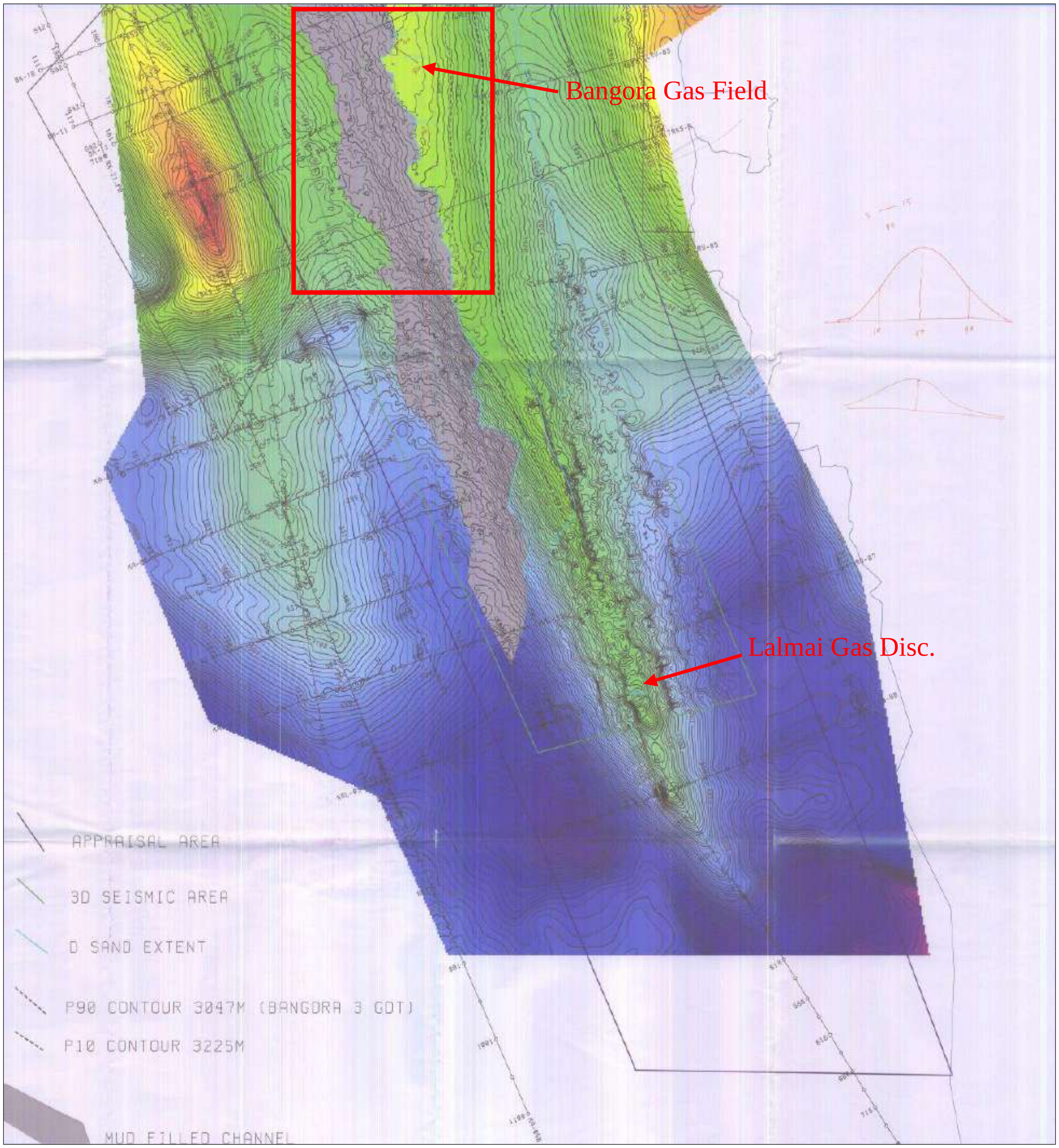



**Figure 6-22 Regional Depth Structure Map of Bangora-Lalmai Anticline**

Structure map on top of the D Sand (main pay) in the region of the Bangora-Lalmai Anticline. The locations of the producing Bangora gas field and the undeveloped Lalmai gas discovery are labeled. Structurally high regions are shown in lighter shades of green and yellow. Structurally low regions are shown in darker shades of blue. Map is based on 3-D seismic survey conducted of the by Tullow Bangladesh Ltd. in 2005. A detailed enlargement of the Bangora gas field area (red outline) is shown in Figure 6-21 (map provided by Petrobangla).

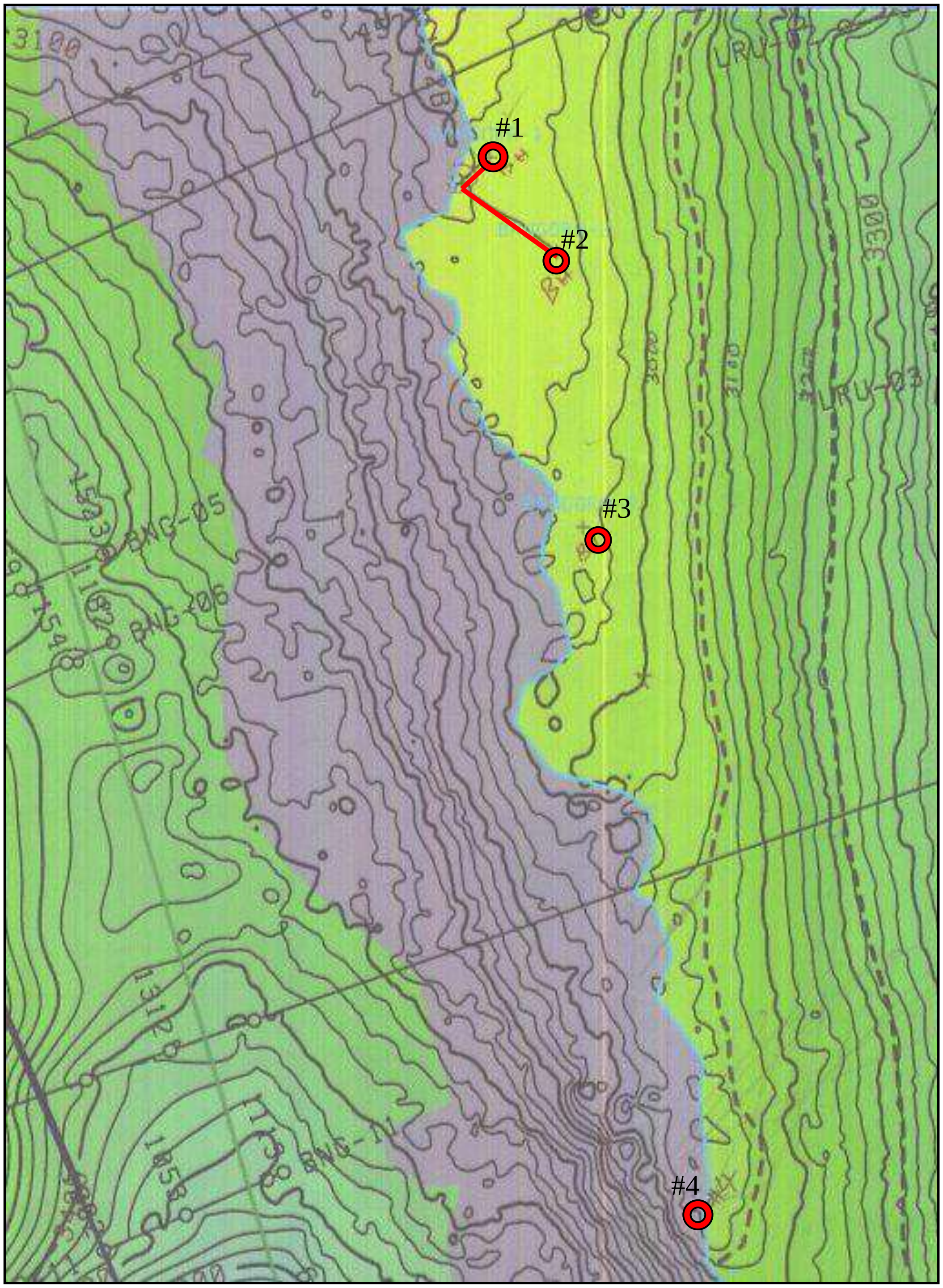



**Figure 6-23 Detailed View of D Sand Structure - Bangora Gas Field Area**

Depth structure map on top of D Sand showing bottomhole locations of Bangora #1, #2, #3, and #4 wells (red circles). The updip trap is a shale-filled channel shown in light purple. Map is based on a 3-D seismic survey conducted by Tullow Bangladesh Ltd. in 2005. See Figure 6-20 for location of detailed view shown here (map provided by Petrobangla).

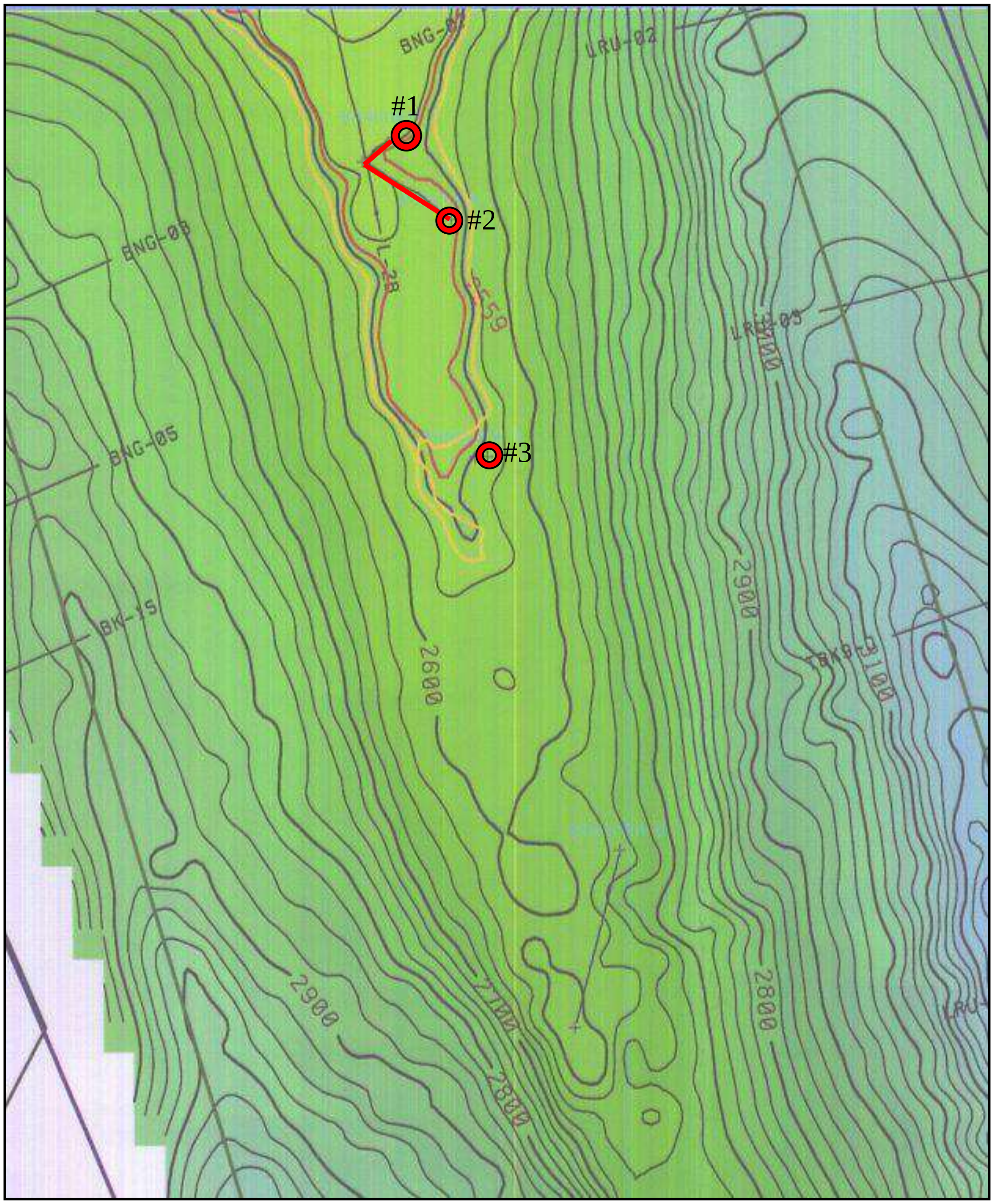



**Figure 6-24 Detailed View of H30 Horizon Structure - Bangora Gas Field Area**

Depth structure map on top of H30 seismic horizon showing locations of Bangora #1, #2, and #3 wells. A, B, and C Sand gas pools are trapped structurally along crest of structure. Estimated limits of gas pools are shown in Red (A Sand), Blue (B Sand), and Yellow (C Sand). These sands are stratigraphically higher than the main pay D Sand and are only considered minor gas zones. Map is based on a 3-D seismic survey conducted by Tullow Bangladesh Ltd. in 2005. See Figure 6-20 for approximate location of detailed view shown here (map provided by Petrobangla).

### 6.3.4.4 Exploration and Field Development

The Bangora field, encompassing an area of 1,770 km, was discovered by two exploration wells drilled by Tullow Oil plc. The Lamlai #3 well, spudded in March, 2004, found gas in three sands of the Upper Bhuban Formation (H30 sequence, A through C sands) between 2,184 and 2,729 meters MD. Total depth of the well was 2,800 m. Three production tests were performed but only one was successful. This well is not currently in production.

The Bangora #1 well was spudded in June, 2004. This well encountered gas in five zones of the Upper Bhuban Formation (H30 and post-H30 sequences; A through E sands) at depths between 2,581 and 3,287 meters MD. This directional well reached a total depth of 3,495.84 meters (TVDBRT), which was less than its programmed TD. Production tests were performed on four intervals of interest. Current production from this well is from the upper D sand.

Three additional production wells were drilled after 2005 in the northern part of the field. Bangora #2 (spudded in 2006) produces from the D and E sands. Bangora-3 and Bangora #5 (both spudded in 2007) produce from the upper and lower D sands.

The Bangora field is currently operated by Tullow Oil (30% interest) in partnership with Niko Exploration Ltd (60%) and BAPEX (10%).

### 6.3.4.5 Well-wise and Sand-wise Production History

Figures 6-23 and 6-24 below graphically display the well-wise and sand-wise gas production from Bangora gas field in MMscfd. As clearly shown in Figure 6-24, the various D Sand reservoirs account for over 95% of both daily and cumulative production from the field. The E Sand has only been a minor producer to date.

Detailed individual well histories and accompanying production charts for Bangora wells are included in The Annex.

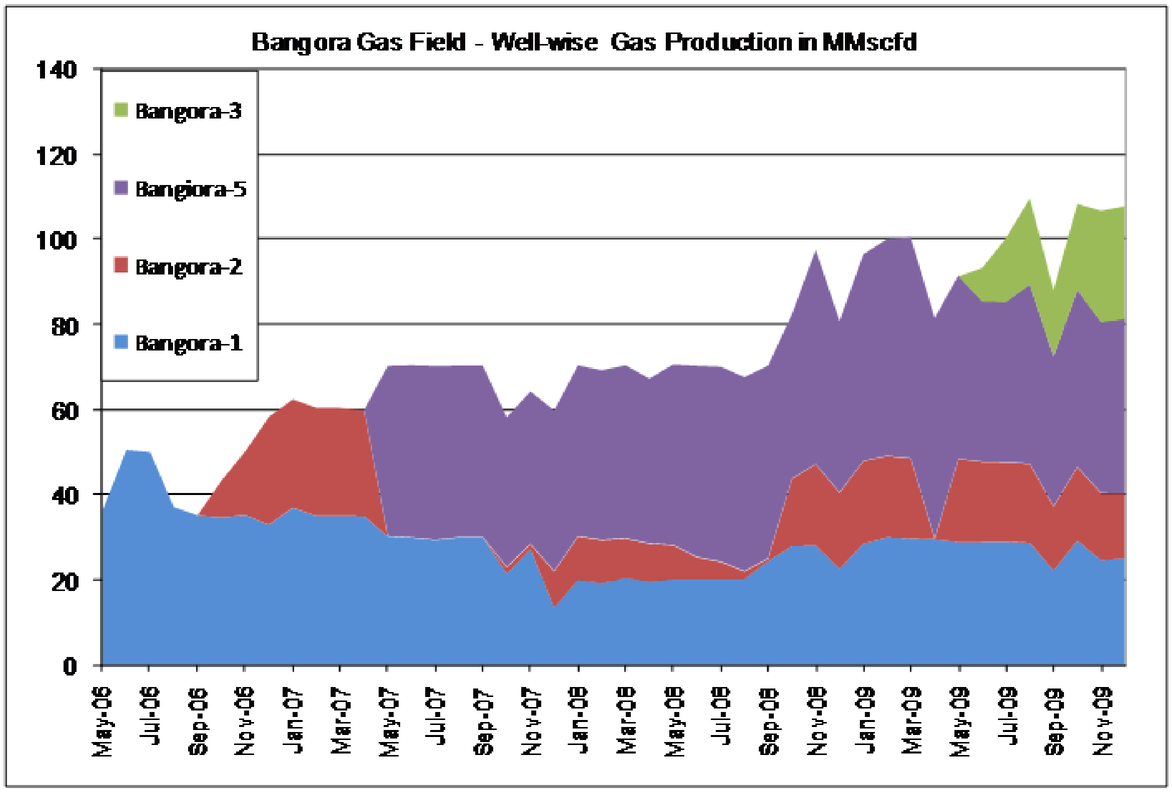



**Figure 6-25 Well-wise Gas Production – Bangora Gas Field**

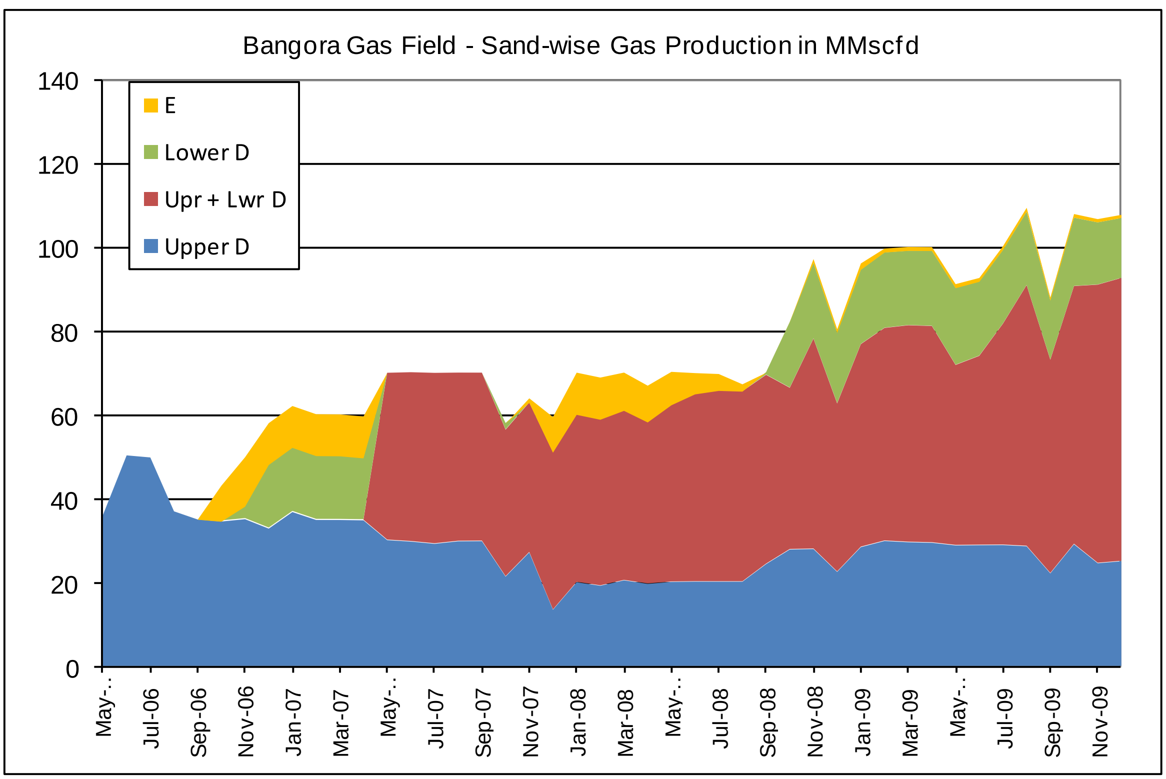



**Figure 6-26 Sand-wise Gas Production – Bangora Gas Field**

6.3.4.6 Field-wise Cumulative Production

Table 6-7 summarizes the cumulative production for Bangora gas field through the end of 2009.

**Table 6-7 Sand-wise Cumulative Gas Production – Bangora Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Upper D Sand | 38.5 |
| Lower D Sand | 10.2 |
| Upper/Lower D comingled | 45.0 |
| E Sand | 4.6 |
| **Total** | **98.3** |

1 Production through end of December 2009
HCU production database

6.3.4.7 Earlier Reserve Estimates

The Bangora field was discovered after issuance of the most recent HCU countywide reserve assessment (HCU-NPD, 2004). Based on results of production tests at wells Lalmai-3 and Bangora-1, Tullow (2005) prepared GIIP probabilistic estimates for six reservoir sands (Table 6-8). No other resource or reserve estimates for the Bangora field are available.

**Table 6-8 Tullow 2005 Reserve Estimate - Bangora Gas Field**

| GIIP ESTIMATES (BCF) | P90 | P50 | P10 | MEAN |
|---|---|---|---|---|
| A SAND | 3 | 4 | 7 | 5 |
| BSAND | 17 | 25 | 35 | 26 |
| C SAND | 5 | 34 | 99 | 45 |
| D SAND | 37 | 175 | 512 | 235 |
| E SAND | 20 | 118 | 308 | 146 |
| LALMAI SAND | 64 | 280 | 696 | 340 |
| TOTAL | 146 | 637 | 1656 | 796 |

6.3.4.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Bangora field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

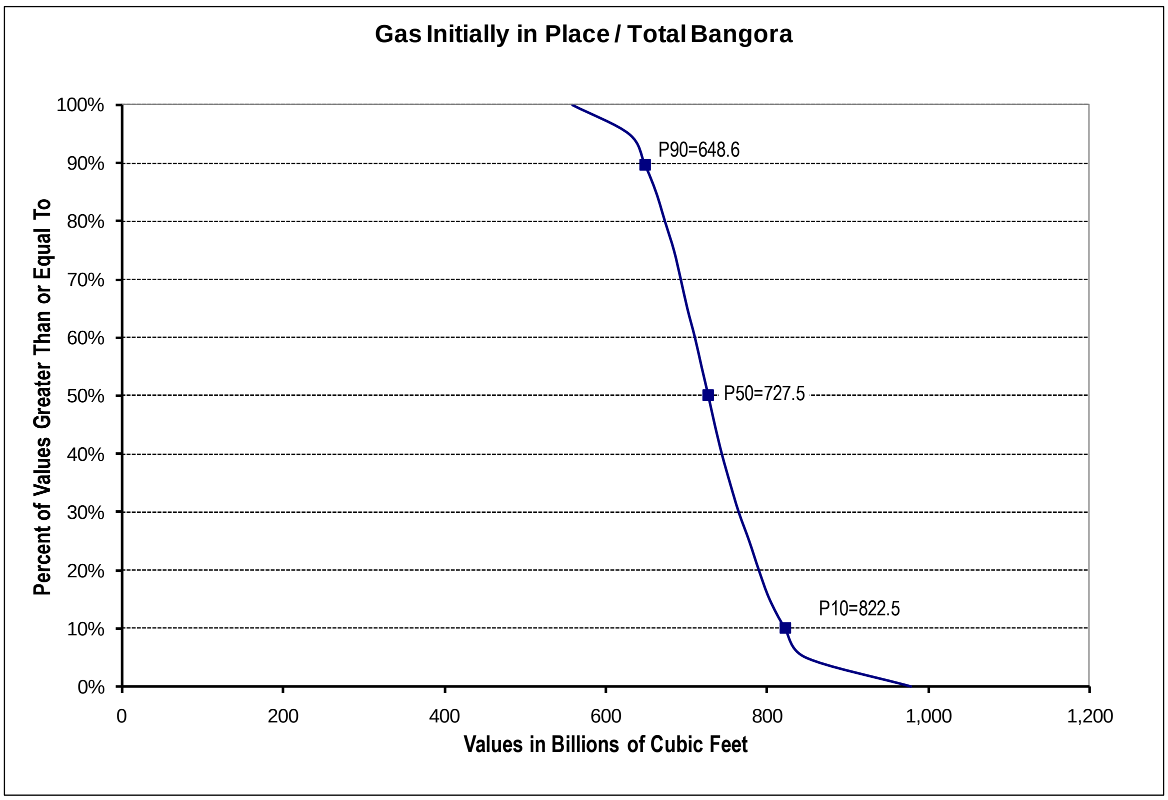



**Figure 6-27 Distribution of GIIP, Bangora**

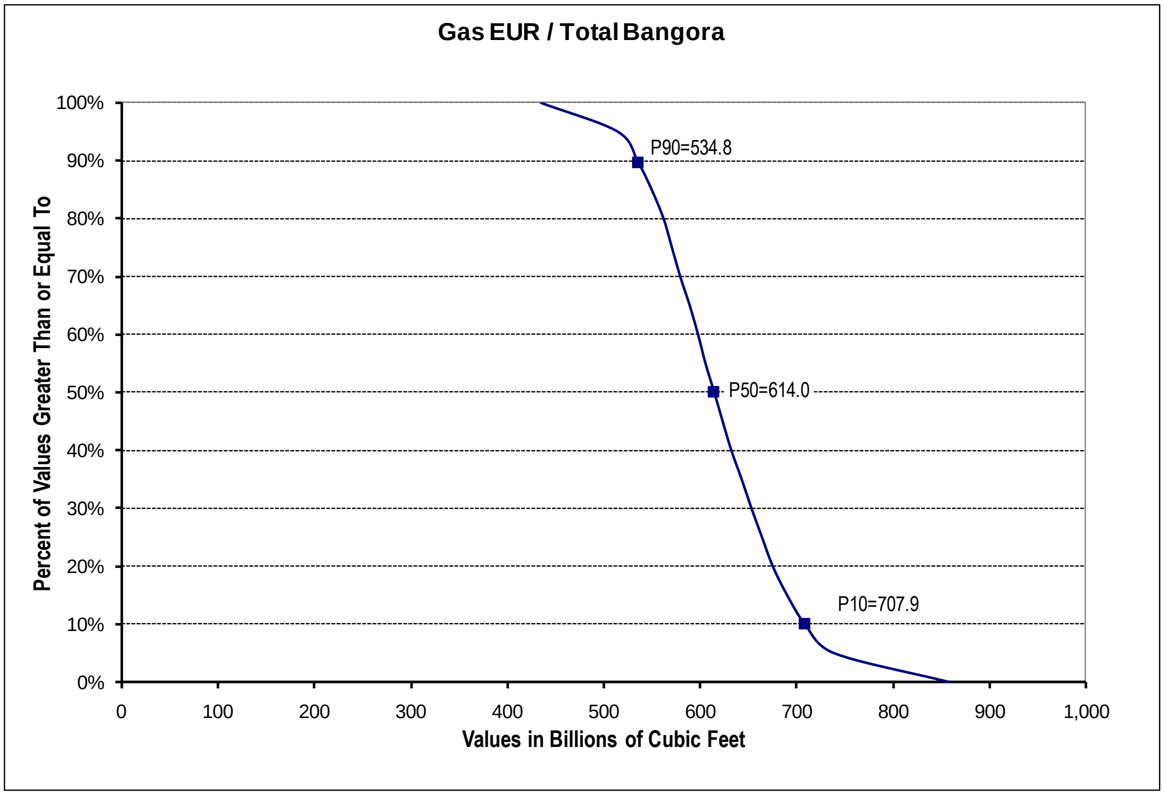



**Figure 6-28 Distribution of Gas EUR, Bangora**

**Table 6-9 Summary of Estimated Ultimate Recovery at Bangora**

| **Reservoir** | **Mean Gas EUR, BCF** | **Gas Production, 1/1/2010, BCF** | **Reserves, 1/1/2010, BCF** |
|---|---|---|---|
| A Sand | 19 | 0 | 19 |
| B Sand | 15 | 0 | 15 |
| C Sand | 19 | 0 | 19 |
| D Sand | 548 | 94 | 454 |
| E Sand | 17 | 5 | 12 |
| **TOTAL** | **618** | **99** | **519** |

Additionally, reserves and GIIP were estimated for the D and E sands at Bangora (the only currently producing sands) using the Approximate Wellhead Material Balance (AWMB) technique.[3] For this technique, where more than one well is producing from a reservoir, the FWHP values are averaged. Any data deviating significantly from the established trend were

[3] Mattar and McNeil, 1998.

excluded. The results are shown in Figure 6-29 and Figure 6-30. The slope of the line is determined from the flowing wellhead pressure vs. cumulative production graph. Then a line with this slope is extended from the initial shut-in wellhead pressure to zero pressure. The projection on the x axis at 0 psi is the estimated GIIP, and the point on the projected line at a y value equal to the expected abandonment well head pressure yields the estimated ultimate recovery (EUR) on the x axis at that point.

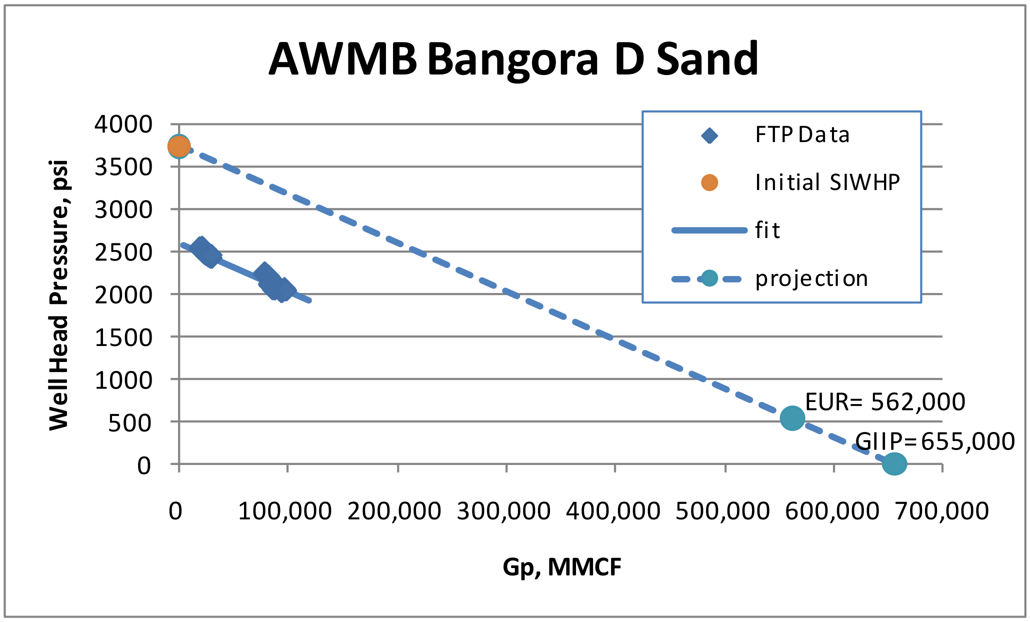



**Figure 6-29 Material Balance Plot, Bangora D Sand**

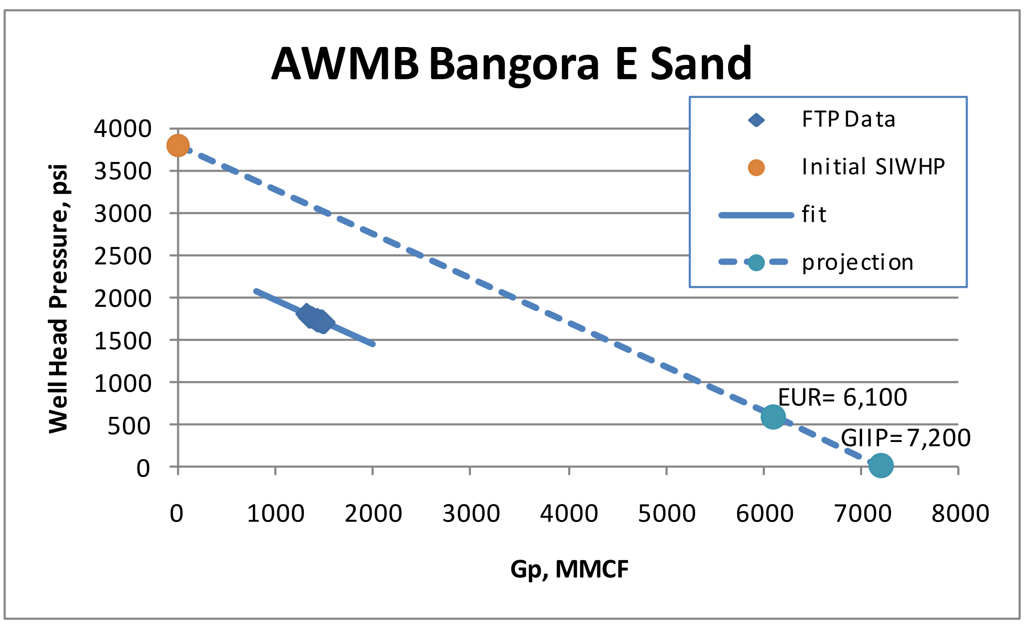



**Figure 6-30 Material Balance Plot, Bangora E Sand**

These results compare with the mean volumetric calculations as follows:

| Reservoir | D Sand | | E Sand | |
|---|---|---|---|---|
| **Method** | **Volumetric** | **Mat Bal** | **Volumetric** | **Mat Bal** |
| GIIP, BCF | 643.2 | 655.0 | 20.6 | 7.2 |
| EUR, BCF | 547.6 | 562.0 | 17.2 | 6.1 |
| Cum. Gas, BCF | 97.9 | 97.9 | 1.5 | 1.5 |
| **Reserves, BCF** | **449.7** | **464.1** | **15.7** | **4.6** |

This is considered to be good agreement for the D Sand. It is not clear why the E Sand exhibits such a large percentage difference in the two methods. In general, the material balance method would be considered more reliable.

### 6.3.5 Beani Bazar (10)

#### 6.3.5.1 Geologic Setting

Beani Bazar anticline is exposed on surface. It is located in the northeastern part of the country in Block 14 to the southeast of Kailash Tila gas field (Figure 6-3). Geologically the area is known as Surma Basin. This region is a part of the Eastern Foldbelt. The Beani Bazar structure was also known as Mama Bhagna structure. On the surface the area is covered by outcrop of Plio-Pleistocene to recent sand/sandstones and clay. The area is covered by low hills.

During the early sixties, PSOC conducted seismic survey over the area and delineated the subsurface geometry. During mid-sixties Oil & Gas Development Corporation (OGDC), carried out surface geological mapping and prepared geological maps.

#### 6.3.5.2 Structure

Beani Bazar is an elongated oval-shaped anticline. The axis of the anticline is oriented in north-south direction. However, the northern plunge of the anticline is slightly swinging towards west. The western flank of the structure is slightly steeper than the eastern one. The closure height of the Lower Gas Sand is about 425m. The closure height of the Upper Gas sand is about 260m.

Figure 6-31 is a structure map of Beani Bazar gas field drawn on the top of the Upper Gas Sand. Figure 6-32 is a similar structure map drawn on top of the Lower Gas Sand. Both maps were prepared by IKM in 1989. The structure is considered to be quite young and formed during Late Pliocene to Early Pleistocene time.

#### 6.3.5.3 Reservoir

Like all other hydrocarbon reservoirs of the country, reservoir rocks of Beani Bazar are sandstones. The reservoir was studied mainly by wireline logs and very limited core data. One core was cut through the Lower Gas Sand in Well #1, i.e. 8-meter core of the reservoir section was cut. In Well #2, core went through the cap rock and only 4.6m of the reservoir section was cut. Core control can be described as poor. Based on this earlier data, workers described that the Upper Gas Sand was deposited in a shallow marine beach transgressive beach bar and barrier bar with extensive lateral distribution in the depositional basin. For the Lower Gas sand, very little data is available. However from seismic evidence, it was considered to be comparable to a position further offshore.

In earlier report, porosity of the Upper Gas sand was considered at 23% and that for the Lower Sand was 20%. Water saturation was estimated at 23% for the Upper Sand and 43 % for Lower Gas Sand.

#### 6.3.5.4 Exploration and Field Development

After independence of Bangladesh, Federal Republic of Germany came forward with technical and financial assistance for the exploration sector. During late seventies, digital seismic data was recorded and time and depth contour maps were prepared. Based on the result of the survey, an exploratory well was drilled in Beani Bazar in 1980-81. The well discovered two gas sands within depth intervals 3230-3278m and 3451-3465m, respectively. Both the sands were tested. The condensate/gas ratios (CGRs) in both zones were quite high: 16-20 bbl/MMscf for the Upper Gas Sand and 14-19 bbl/MMscf for the Lower Gas Sand. In 1982, Well #1 was completed as selective dual producer in the Upper and Lower Gas Sands. The discovery well remained shut-in for nearly two decades. Well #2 was drilled and completed in the Upper Gas Sand.

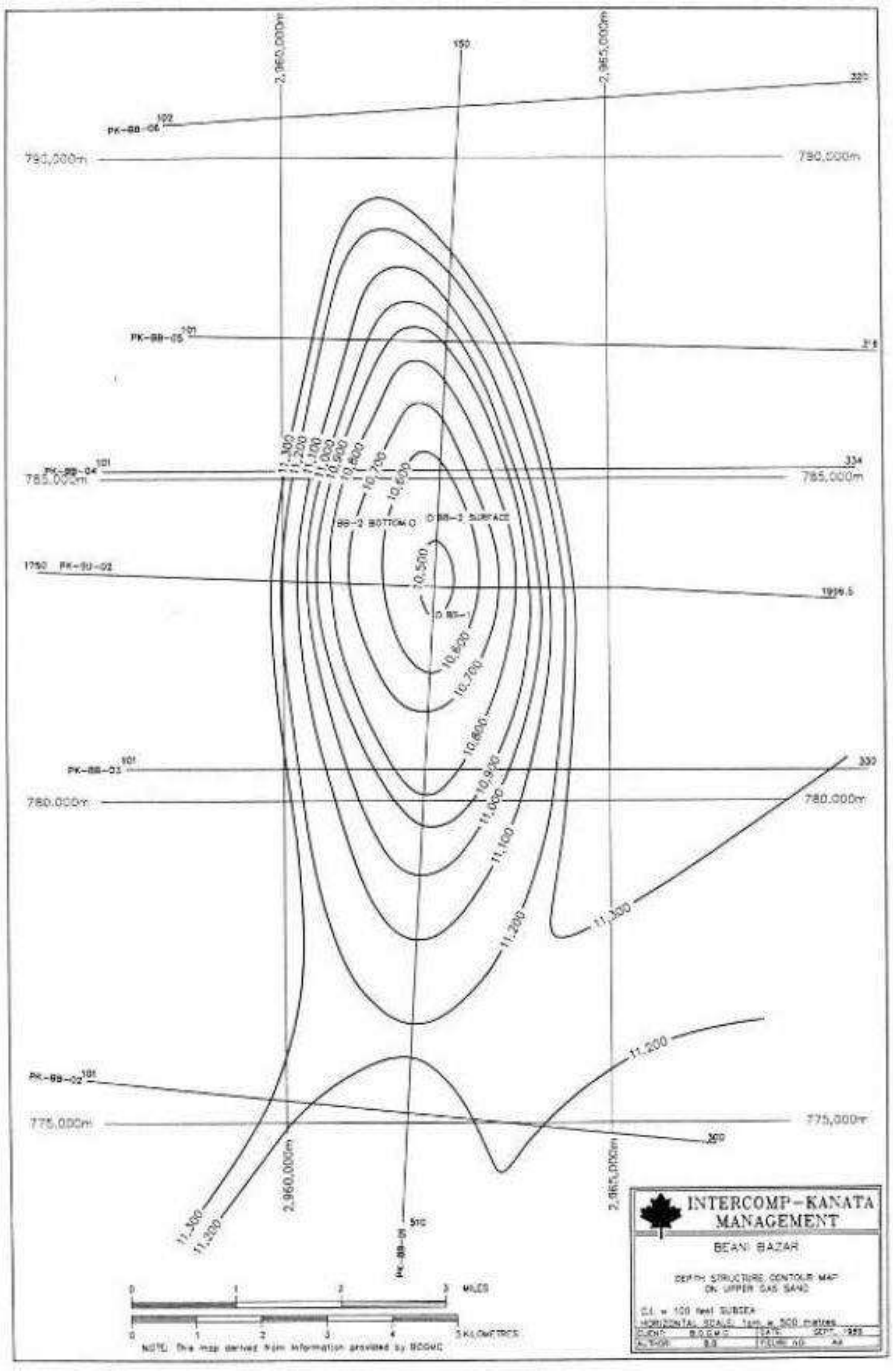



**Figure 6-31 Structure Map on Top of Upper Gas Sand - Beani Bazar Gas Field**
**(**after IKM**,** 1989)

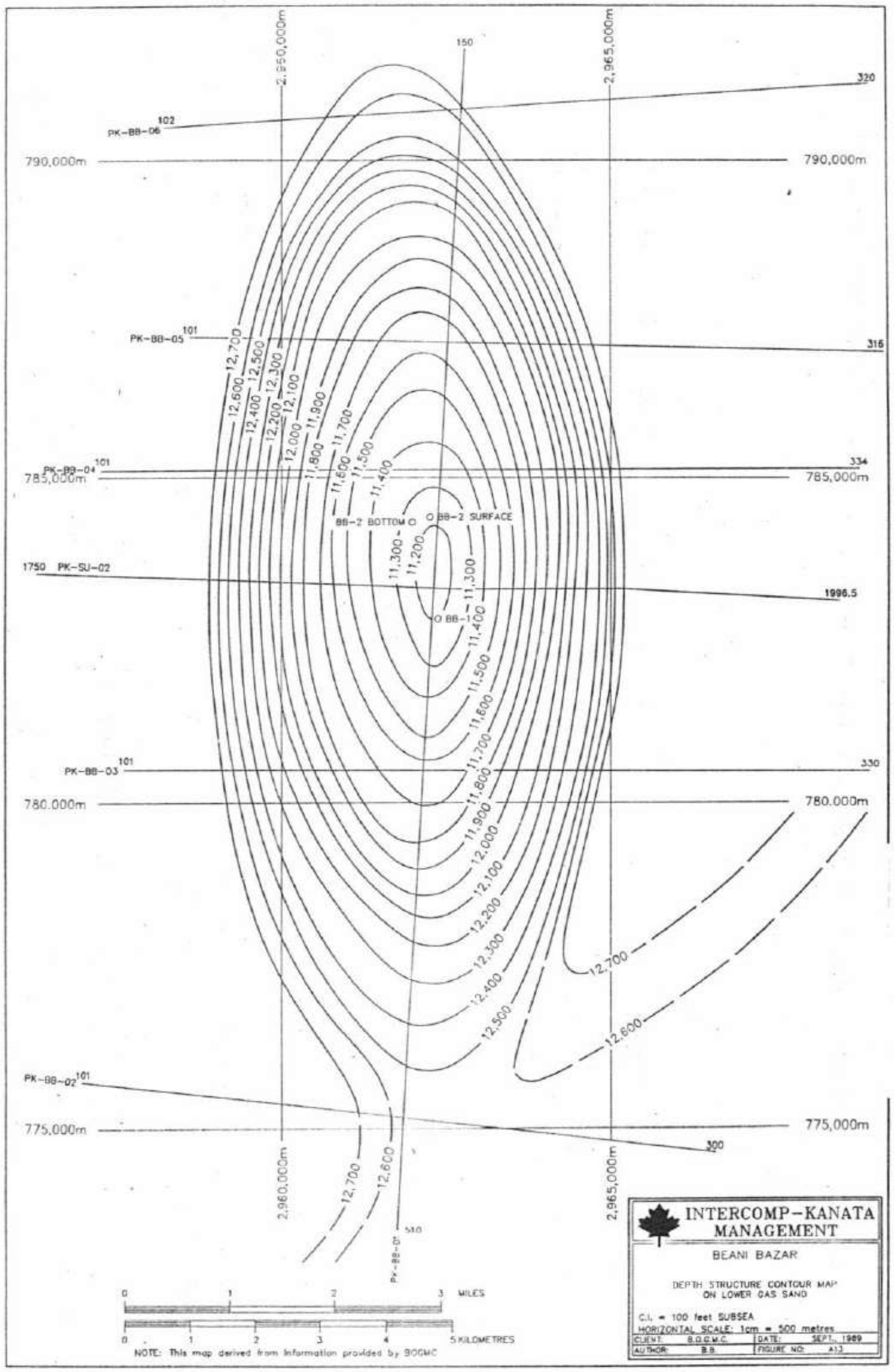



**Figure 6-32 Structure Map on Top of Lower Gas Sand - Beani Bazar Gas Field**

Beani Bazar was never developed beyond a 2-well field with each well producing from separate sand. BB #1 is completed in the Lower Gas Sand (after IKM, 1989).

Production from Beani Bazar gas field started in May 1999 with selective production from the Lower Gas Sand in Well #1. Well #2, completed in Upper Gas Sand, started to produce in January 2002. Individual well production history charts are included in The Annex.

#### 6.3.5.5 Well-wise and Sand-wise Production History

Figure 6-33 through Figure 6-35 below graphically display the sand-wise gas, condensate, and water production from Beani Bazar gas field.

At the beginning, the gas flow rate in Well #1 fluctuated between 7 and 14 MMscfd. Initially, FWHP was 3150 psig at a flow rate of 15-17 MMscfd. In August 2000, the well was shut down for six months and SWHP was 3750 psig. Production from Well #1 resumed in February 2001 and within a short period, production started to decline. Flow rate was 15-16 MMscfd at the end of 2001 and it gradually declined to 2-3 MMscfd at the end of 2009. Flowing wellhead pressure was fairly uniform at around 3350 psig for the entire period.

Condensate production data was not available for the early period of production. The condensate yield was reported to be 17 to 18 bbl/MMscf of gas that resulted in daily production of 100 to 200 bbl/day. Water production rate was quite low at the beginning. However it started to increase in 2004. In December 2009 water production rate was 15 bbl/MMscf.

Detailed individual well histories and accompanying production charts for Beani Bazar wells are included in The Annex.

#### 6.3.5.6 Field-wise Cumulative Production

At the end of December 2009, cumulative production from the Lower Gas Sand in Well #1 was 31.2 Bscf, and cumulative production from the Upper Gas Sand reservoir in Well #2 was 28.6 Bscf. Total cumulative production for Beani Bazar gas field has amounted to a very modest 59.8 Bscf. See Table 6-10 below.

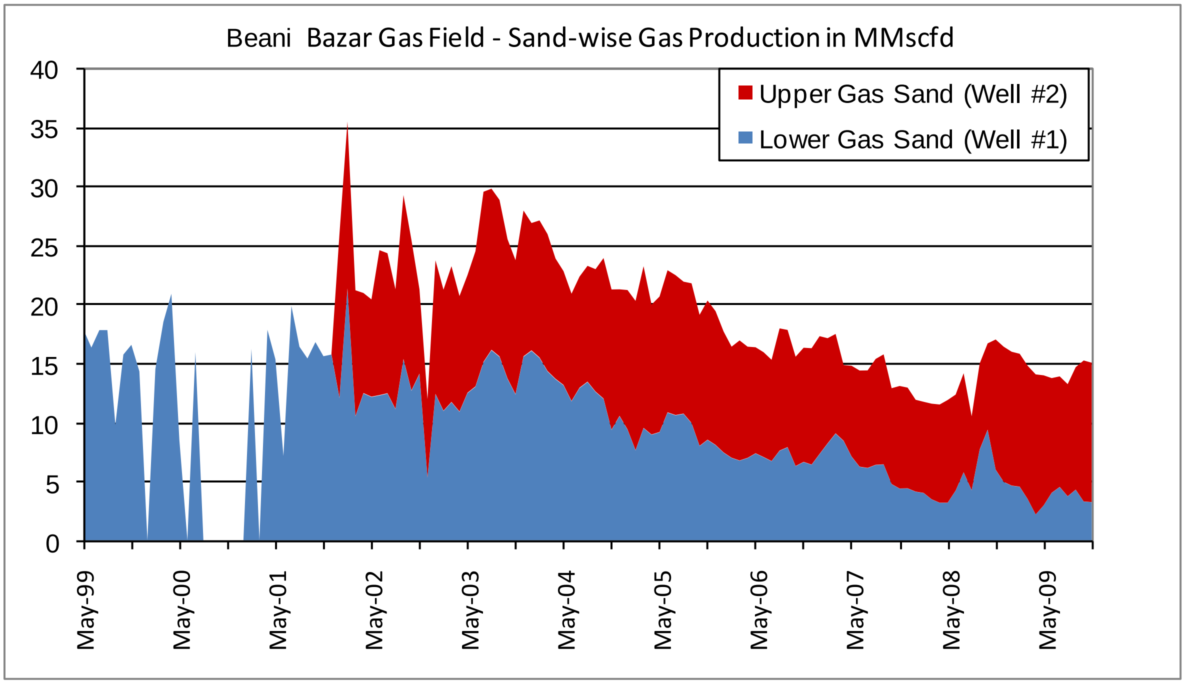



**Figure 6-33 Sand-wise/Well-wise Gas Production – Beani Bazar Gas Field**

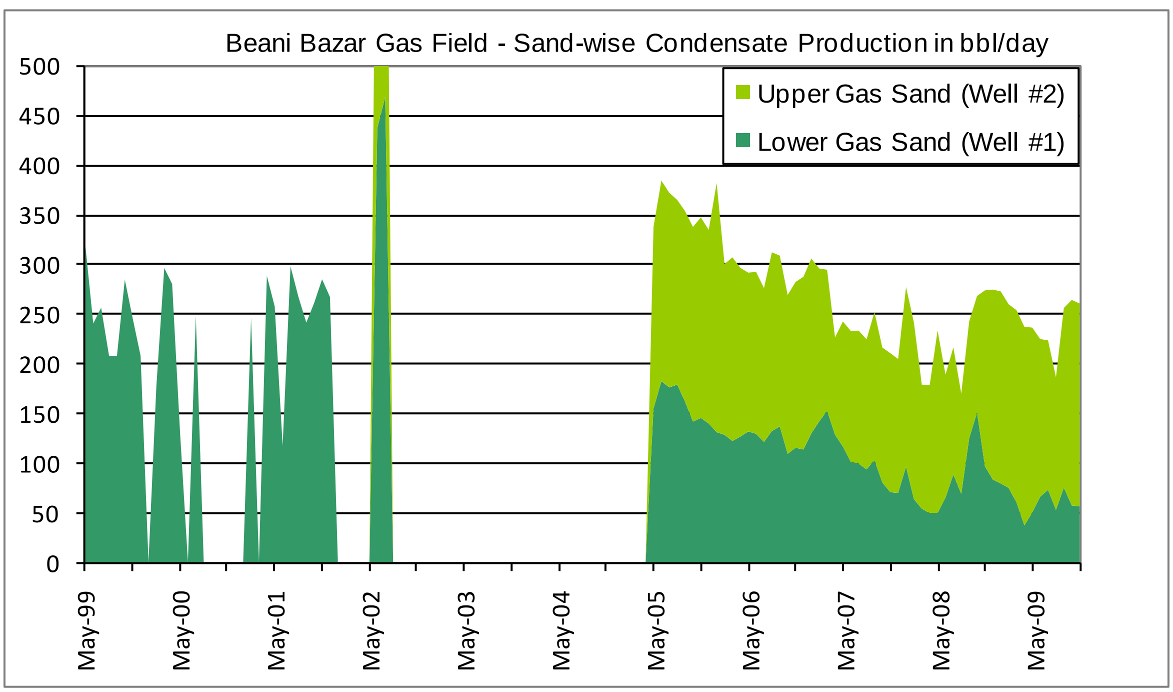



**Figure 6-34 Sand-wise/Well-wise Condensate Production – Beani Bazar Gas Field**

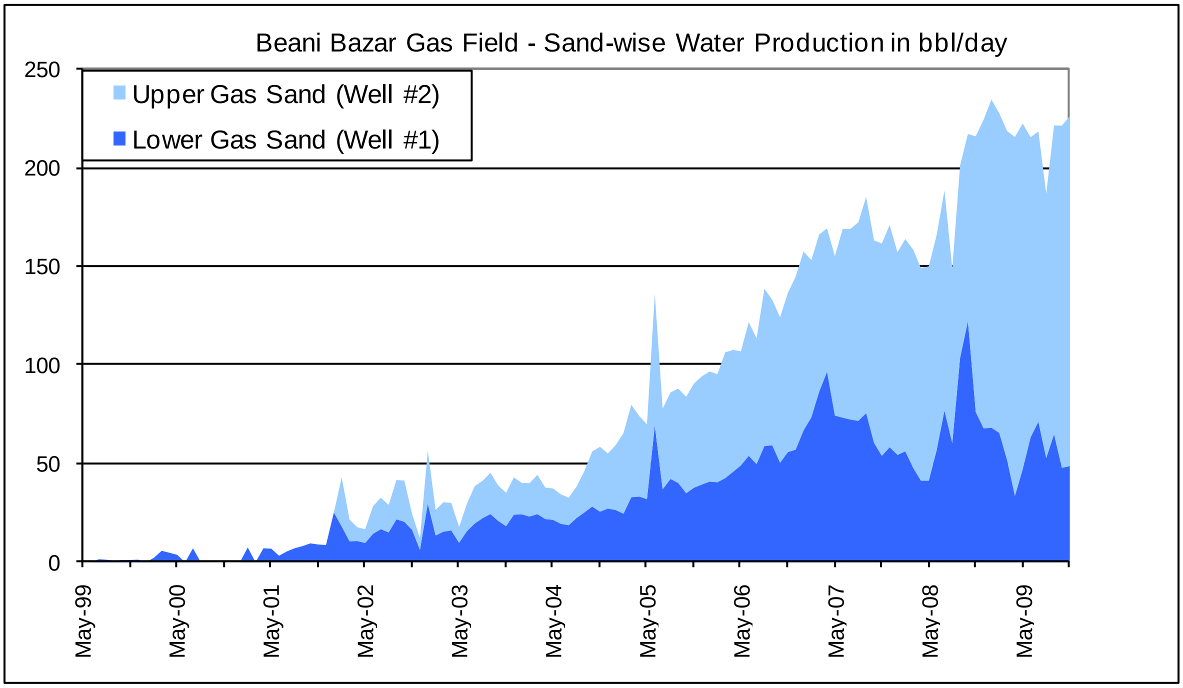



**Figure 6-35 Sand-wise/Well-wise Water Production – Beani Bazar Gas Field**

**Table 6-10 Sand-wise Cumulative Gas Production – Beani Bazar Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Upper Gas Sand | 28.6 |
| Lower Gas Sand | 31.2 |
| **Total** | **59.8** |

1 Production through end of December 2009
HCU production database

### 6.3.5.7 Earlier Reserve Estimates

Since discovery, a number studies on gas reserve of Beani Bazar field were conducted by different agencies. The results of these studies are summarized in Table 6-11 below. Last estimate was conducted by RPS Energy who was engaged by Petrobangla. The final RPS report for Beani Bazar field was released in August 2009.

According to volumetric estimate also conducted by RPS Energy, GIIP of the Upper gas Sand was 163.4 Bscf and that for the Lower Gas Sand was 67.5 Bscf.

From Table 6-11, it is evident that the results of all these estimates are within a narrow range. Only IKM total GIIP is much higher than the rest because of including the Possible category. If the Possible category is removed from the IKM GIIP, then the range of all these estimates narrowed down to a range from 183 Bscf to 368 Bscf.

**Table 6-11  Comparison of Previous Reserve Estimates – Beani Bazar Gas Field**

| | | Reserve Category | Petrobangla Oct, 82 | GGAG 82 | HHSP '86 | GGAG 86 | Gasunie 89 | Welldrill 91 | IKM 91 | HCU 2003 | RPS Energy. 2009 History Match |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Upper Gas Sand | GIIP in Bscf | Proven | 93 | 230 | 145.2 | 183 | | 187 | 187 | 189 | 163.5 |
| | | Probable | 80 | | | | | | | | |
| | | Possible | | | | | | | 755.7 | | |
| | | Total | 173 | 230 | 145.2 | 183 | 340 | 187 | 942.7 | 188 | 163.5 |
| | Condensate in MMbbl | Proven | 1.862 | 4.439 | 2.69 | 1.2 | | | | | |
| | | Probable | 1.597 | | | | | | | | |
| | | Possible | | | | | | | | | |
| | | Total | 3.459 | 4.439 | Sand | 1.2 | | 1.19 | 2.47 | | |
| Lower Gas Sand | GIIP in Bscf | Proven | 11 | 20 | 6.5 | 0.38 | | 56 | 56.1 | 56 | 67.2 |
| | | Probable | | | | | | | | | |
| | | Possible | 82 | | 168.6 | | | | 564.9 | | |
| | | Total | 93 | 20 | 175.1 | 0.38 | 28 | 56 | 621 | 56 | 67.2 |
| | Condensate in MMbbl | Proven | 0.182 | 0.349 | 0.09 | 0.554 | | | 0.88 | | |
| | | Probable | | | | | | | | | |
| | | Possible | 1.308 | | 2.45 | | | | | | |
| **GIIP** | | | **266** | **250** | **320.3** | **183.4** | **368** | **243** | **1564** | **244** | **230.7** |

6.3.5.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Beani Bazar field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

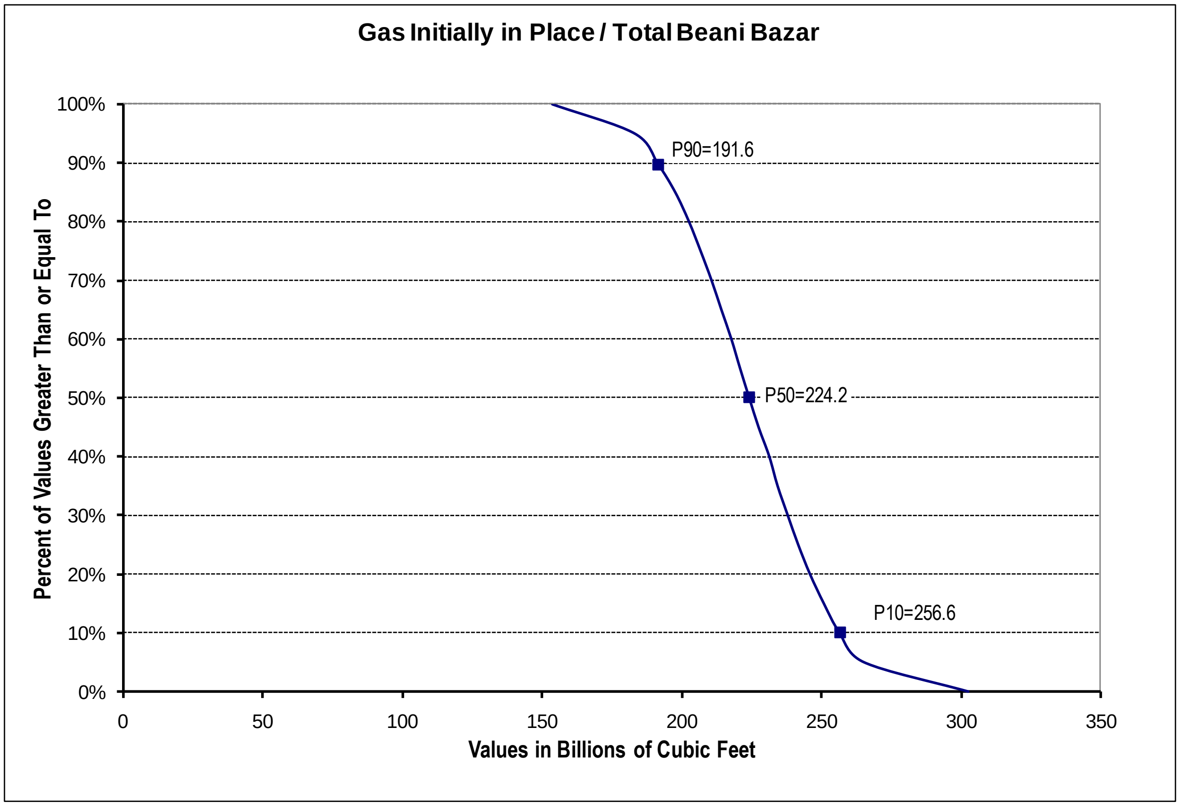



**Figure 6-36 Distribution of GIIP, Beani Bazar**

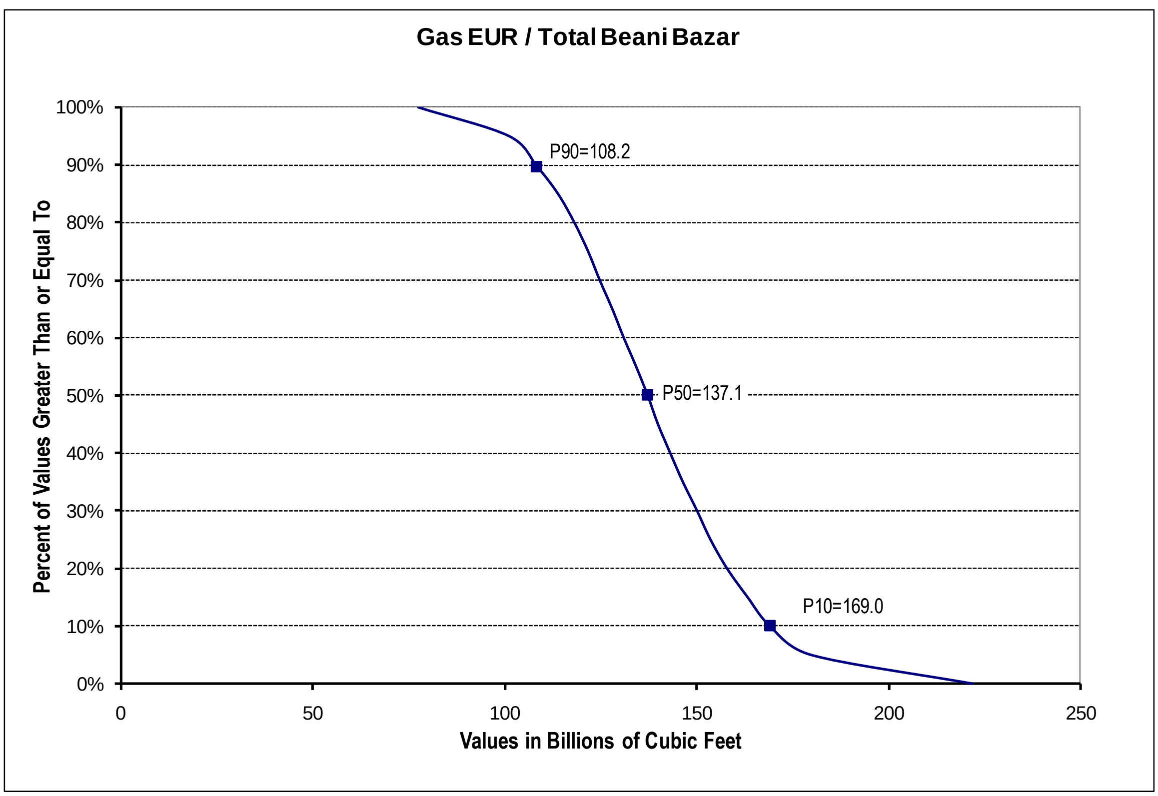



**Figure 6-37 Distribution of Gas EUR, Beani Bazar**

**Table 6-12 Summary of Estimated Ultimate Recovery at Beani Bazar**

| Reservoir | Mean Gas EUR, BCF | Cumulative Gas (1/1/2010), BCF | Gas Reserves (1/1/2010), BCF |
|---|---|---|---|
| Upper Gas Sand | 107 | 29 | 78 |
| Lower Gas Sand | 31 | 31 | 0 |
| **TOTAL** | **138** | **60** | **78** |

In addition, the wellhead pressure data for Beani Bazar was reviewed. Not enough shut-in pressure data are available for a p/z analysis, and the flowing wellhead pressure data did not evidence a valid trend to enable the AWMB analysis (for example, see Figure 6-38).

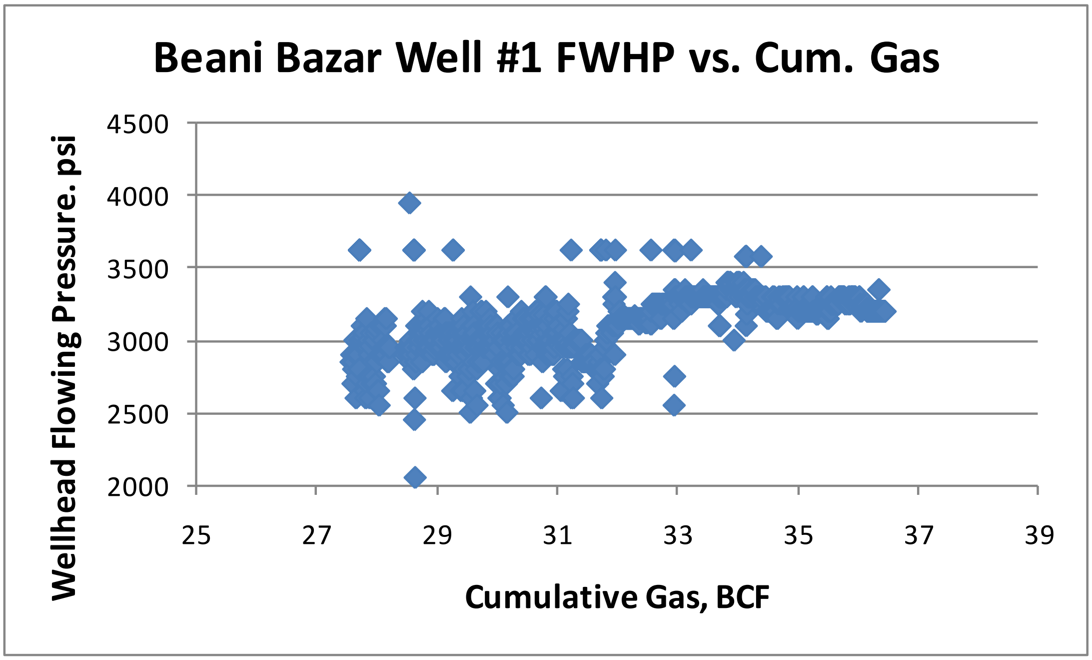



**Figure 6-38 Example Plot of Wellhead Flowing Pressure vs. Cumulative Gas, Beani Bazar**

### 6.3.6 Bibiyana (1)

#### 6.3.6.1 Geologic Setting

Bibiyana is located in Surma Basin of northeastern Bangladesh in the eastern part of Block 12 within the Eastern Foldbelt Province (Figure 6-3 and Figure 6-39). It is located immediately north of Rashidpur gas field. In context with regional geology, this folded belt is the western part of Indo-Burman hill range. Bibiyana structure is a subsurface anticline with no surface

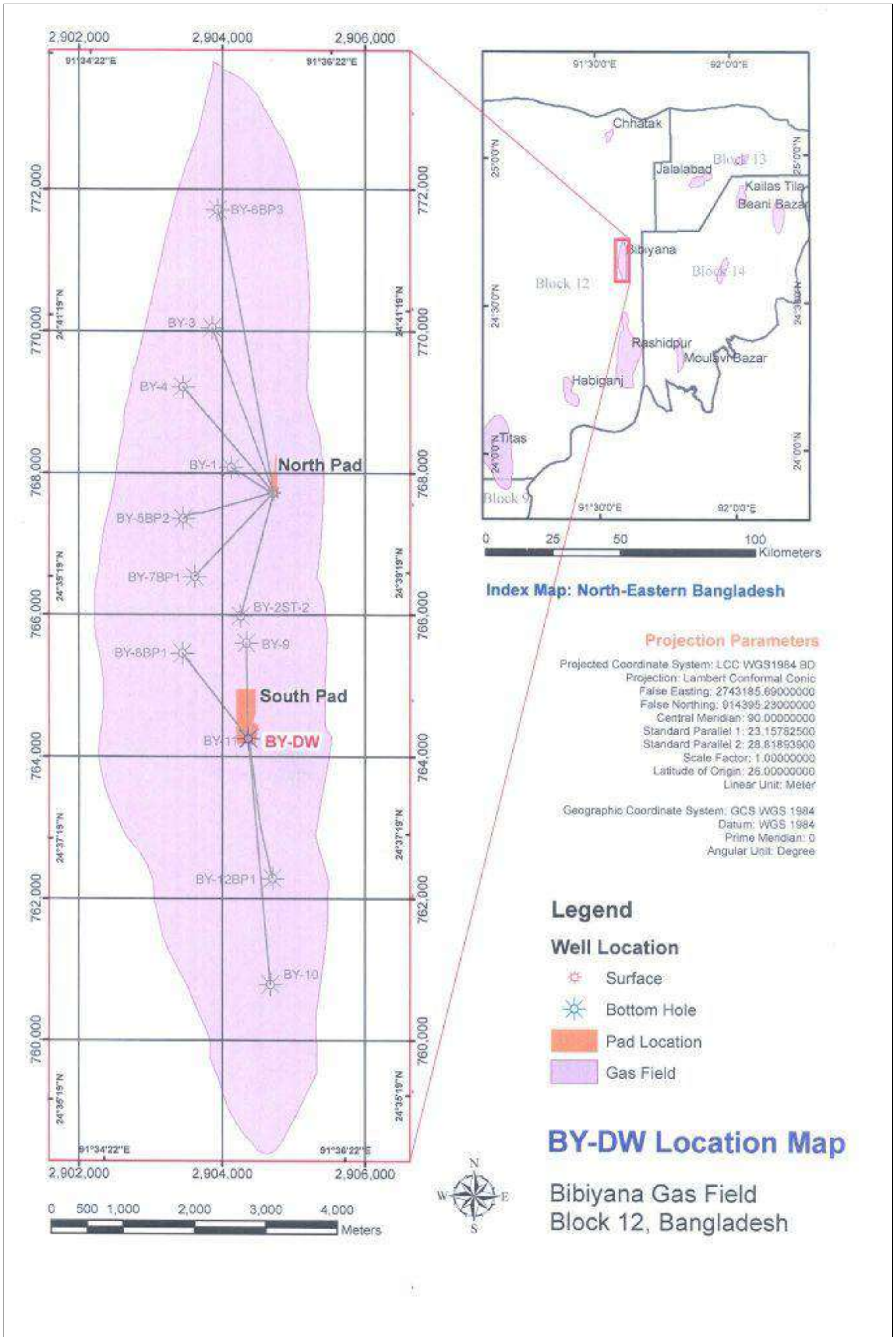



**Figure 6-39 Index Map with Well Locations – Bibiyana Gas Field**
(map provided by Petrobangla)

expression.  The area is covered by alluvium and there is no surface expression of the structure. Bibiyana gas field was discovered in 1998 by Occidental Petroleum.

#### 6.3.6.2 Structure

The structure is an elongated anticline with a north south trend and bounded by faults on both east and northwest. The closure area is about 15 km long and 4 km wide.  Figure 6-40 and Figure 6-41 are two structure maps at different horizons that are based on the first two wells and the 3D seismic interpretation.

#### 6.3.6.3 Reservoir

In Bibiyana, ten gas-bearing horizons have been identified. The horizons within Bokabil Formation are named BB60, B65, BB70 and those within the underlying Bhuban Formation are named BH10, BH20, BH25, BH30, BH40, BH 50, and BH60.  Figure 6-42 is a “net gas isopach” map that shows the thickness of the net pays in the field.  The stratigraphy of these sands are complex and developed by the processes of marine sedimentation followed by sea level drops accompanied by channel incision and deposition of fluvial sand and shale sedimentation and channel fill.

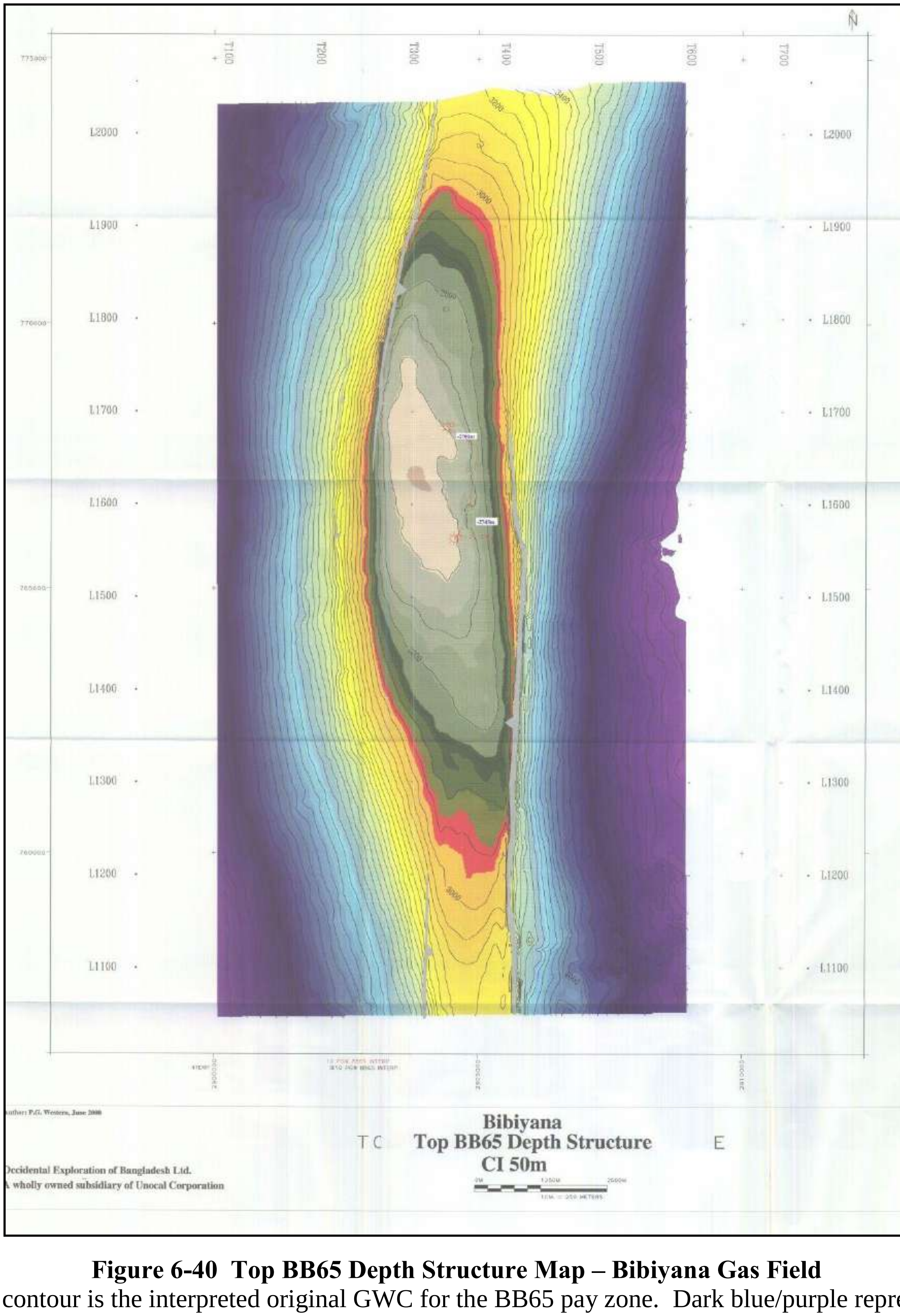



**Figure 6-40 Top BB65 Depth Structure Map – Bibiyana Gas Field**
Red contour is the interpreted original GWC for the BB65 pay zone. Dark blue/purple represents structural lows. Map based on first two wells and 3-D seismic interpretation (Unocal, 2000)

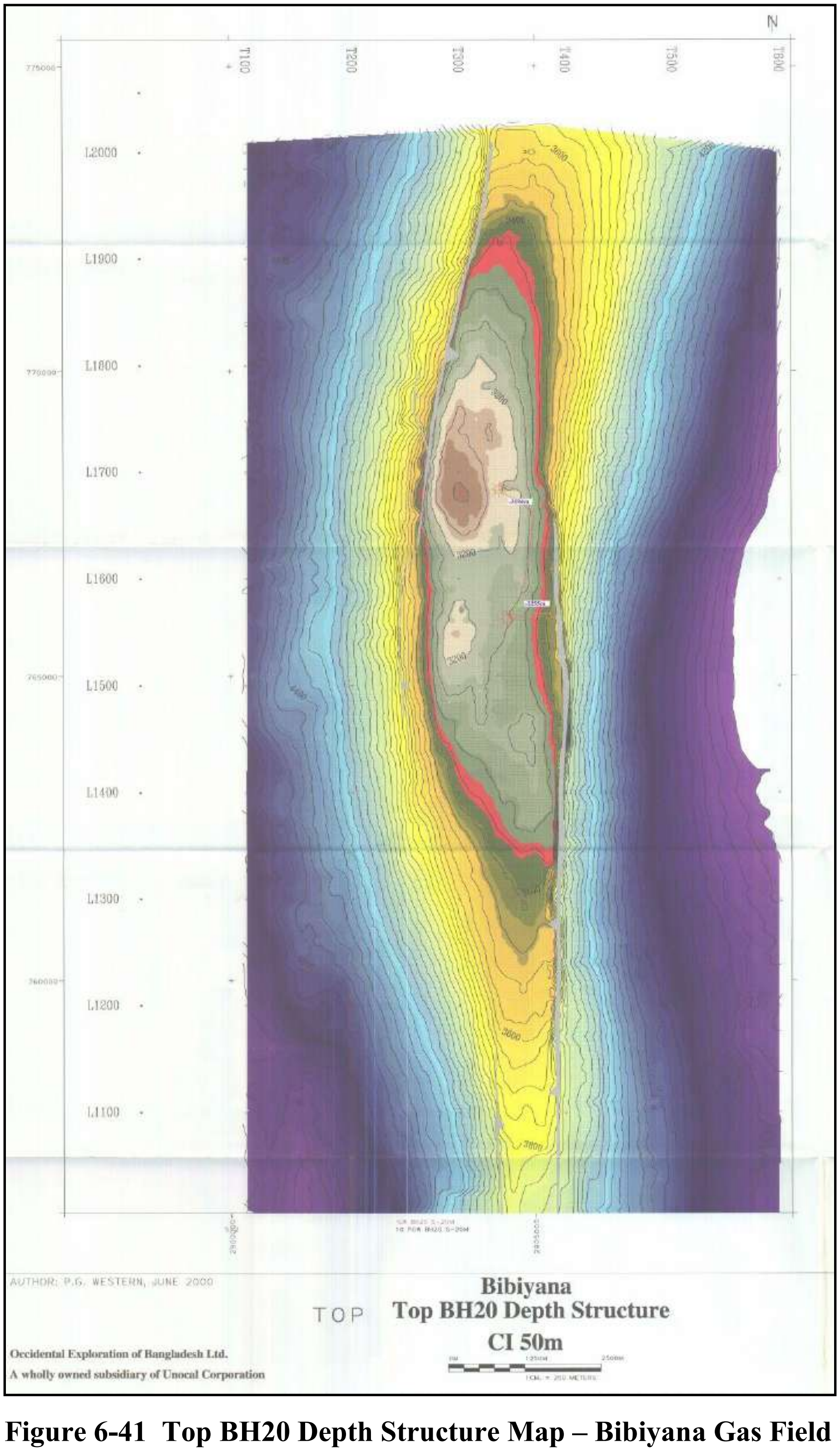



**Figure 6-41 Top BH20 Depth Structure Map – Bibiyana Gas Field**

Red contour is the interpreted original GWC for the BB20 pay zone. Dark blue/purple represents structural lows. Map based on first two wells and 3-D seismic interpretation (Unocal, 2000).

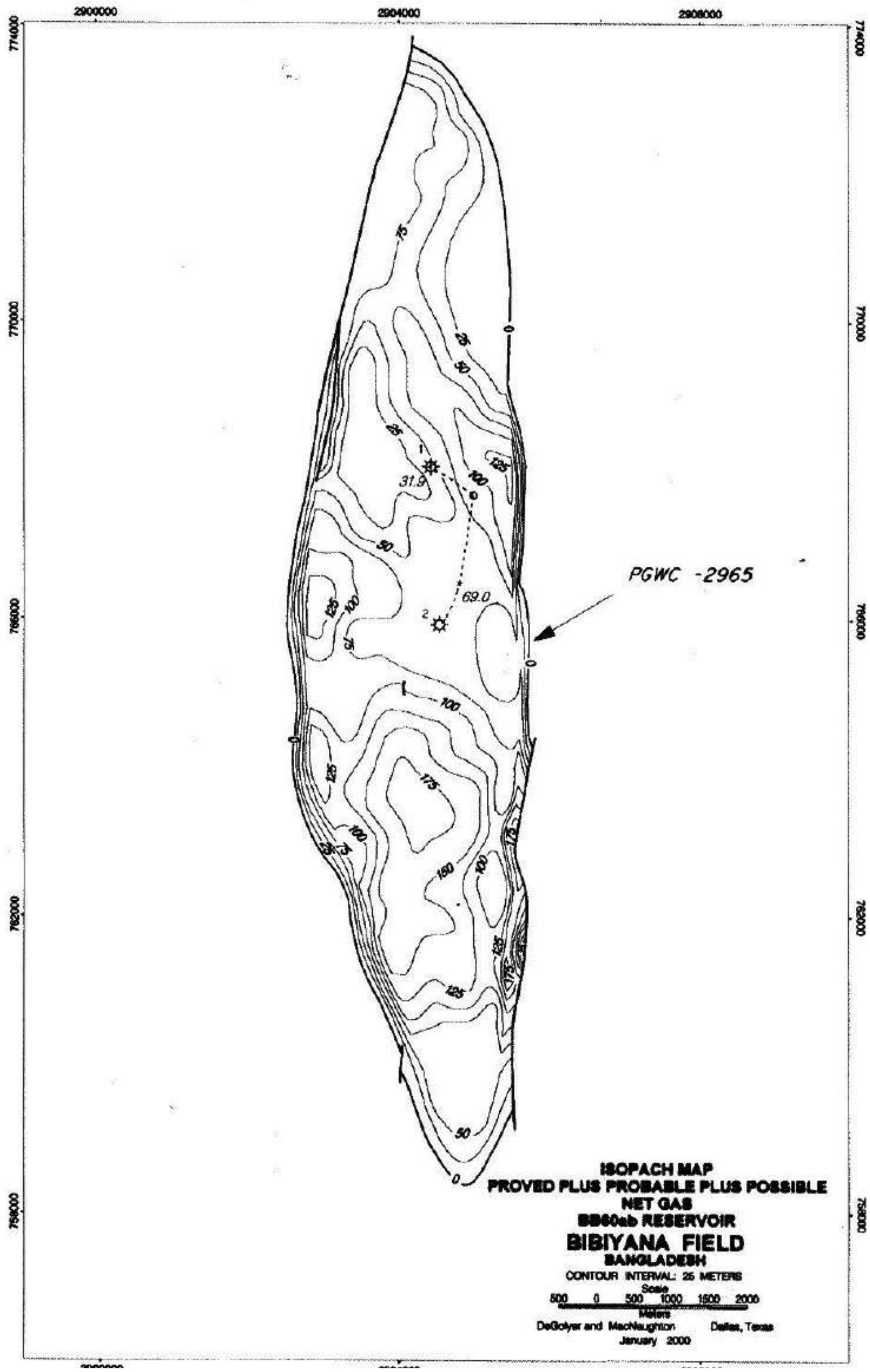



**Figure 6-42 BB60ab Net Gas Isopach (3P) – Bibiyana Gas Field**
Seismically-derived net gas isopach map of BB60ab pay zone. Map based on first two wells and 3-D seismic interpretation (Unocal, 2000).

BB 60 is the main reservoir with a total GIIP of over 3000 Bscf. This unit is a thick sequence of interbedded sandstones and shales. Based on 3-D data, D & M observed that parts of the overall BB60 sequence is eroded by channels and those channels were subsequently filled up by nonmarine sandstone and shale. The fluvial sands in the channel facies have generally poorer reservoir quality. This has resulted in the presence of different reservoir units within this sequence as well as varying thicknesses of pay.

Some of the reservoir intervals within the lower Bokabil and underlying Bhuban Formations consist of thin-bed, interlaminated pay consisting of thin alternations of reservoir-quality sands and non-reservoir shales. These intervals were identified by thin-bed logging tools, in particular the STAR tool, a micro-resistivity device. Some of these zones make up a large part of the pay in some wells. These types of thin-bedded reservoir sequences traditionally showed up as low-resistivity "shale" zones on older resistivity logs with larger detector spacing. The older logging tools tended to "smear" the signals and mask the true reservoir potential of such laminated pay sections. A discussion of this reservoir type and the logging methods for identifying such pay was included in the Unocal 2003 report on Bibiyana field.

#### 6.3.6.4 Exploration and Field Development

Occidental of Bangladesh delineated Bibiyana structure during 1997-98. In the following year the first well, a directional one, was drilled to a depth of 4014m (TVD 3825m). A fish with top at 3618m (MD) was left in the hole. A total of six DSTs were conducted.

Bibiyana #2 was drilled also by Occidental in 1998. The well was a directional one and total depth was 4276m (3790m TVD). Only lowermost gas sand was tested in this well. Distance between bottomhole locations of these two wells is about 2 km. During the winter of 1998-99, 3-D seismic data was recorded over the structure. In 1999 Unocal acquired Occidental's interest in Blocks 12, 13 and 14 and became the operator.

Following seismic interpretation and mapping of the various reservoir intervals, ten additional wells were drilled to develop the field. As of December 2009, six of the reservoirs are producing gas, namely the BB60, BB65, BB70, BH10, BH20, and BH25 from a total of 12 wells. Some of the wells produce from single reservoirs while others were completed with comingled production from two reservoirs.

One well (BY-10) was completed only in the BB60 reservoir Two wells (BY-1 and BY-2) were completed with comingled production from the BB60 and BB65 sands, two wells (BY-3 and BY-6) were completed in the BB70 sand, three wells (BY-7, BY-9, and BY-12) were completed as single-zone producers from the BH10 sand, one well (BY-4) was completed with comingled production from the BH10 and BH20 sands, two wells (BY-8 and BY-11) were completed in the BH20 sands, and one well (BY-5) was completed as a single-zone producer from the BH-25 sand.

No wells have been completed in the deeper Bhuban zones (BH 30, BH 40, BH 50, and BH 60) and therefore no production has been established in these intervals.

6.3.6.5 Well-wise and Sand-wise Production History

Figure 6-43 and Figure 6-44 present the well-wise and sand-wise production histories for the field. By reservoir, the BB60-65 sands are the largest contributor of the field production followed by BB70 and BH10 sands. The field is also currently producing about 3500 barrels of condensate per month (Figure 6-45) along with some water.

Figure 6-46 shows the pressure history associated with the gas production at Bibiyana field as measured by the FWHP (flowing wellhead pressure) for the 12 wells in the field. This chart shows that despite wells producing from different zones over a range of depths, all of the wellhead pressure histories are similar and show similar trends in pressure drop with time over a relatively narrow range of wellhead pressures.

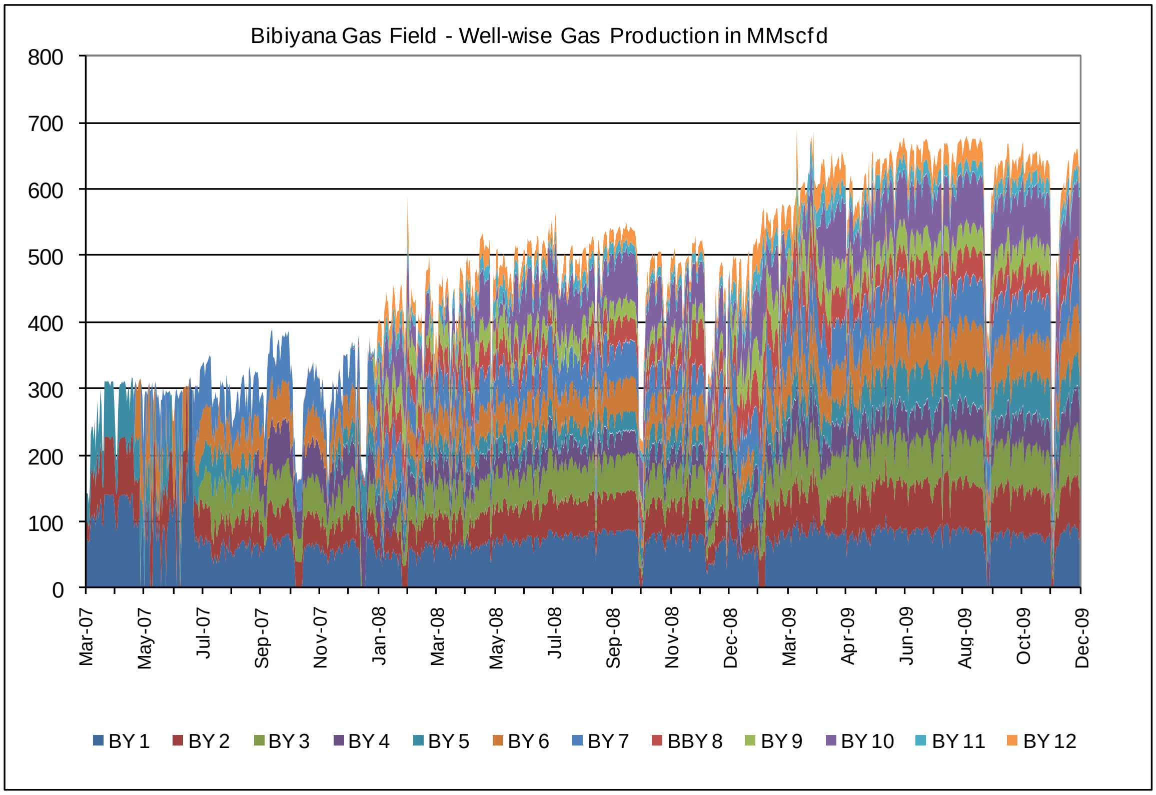



**Figure 6-43 Well-wise Gas Production – Bibiyana Gas Field**

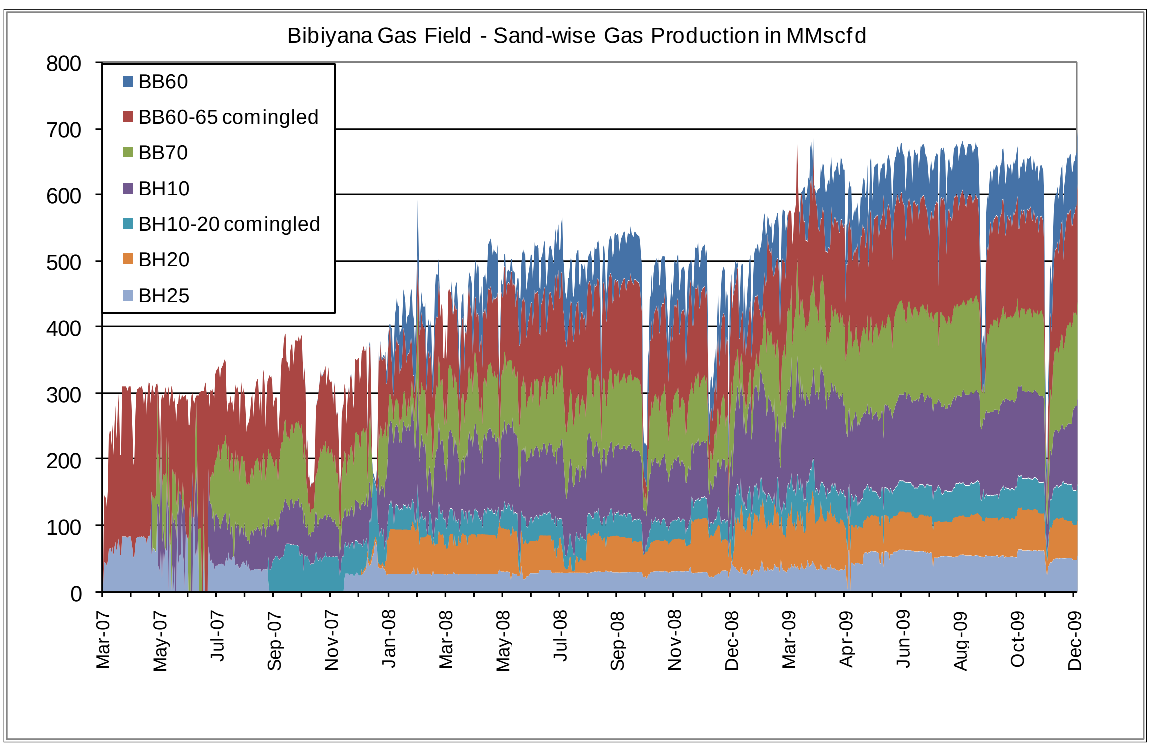



**Figure 6-44 Sand-wise Gas Production – Bibiyana Gas Field**

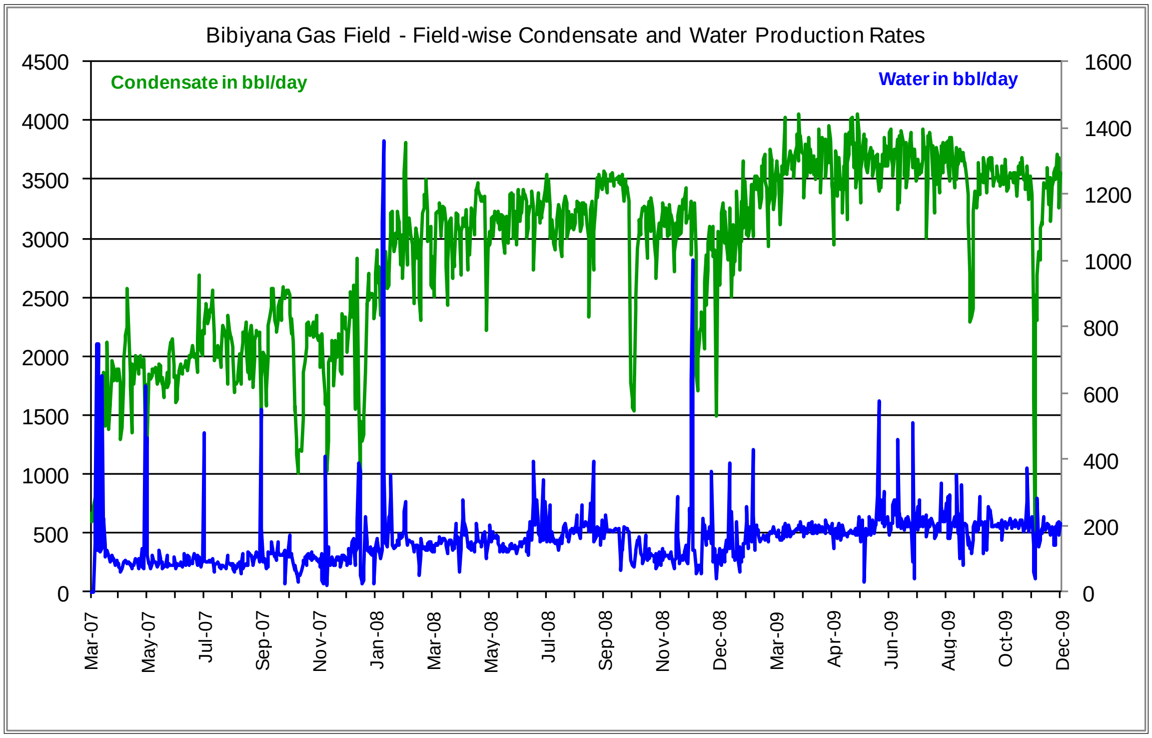



**Figure 6-45 Field-wise Condensate and Water Production – Bibiyana Gas Field**

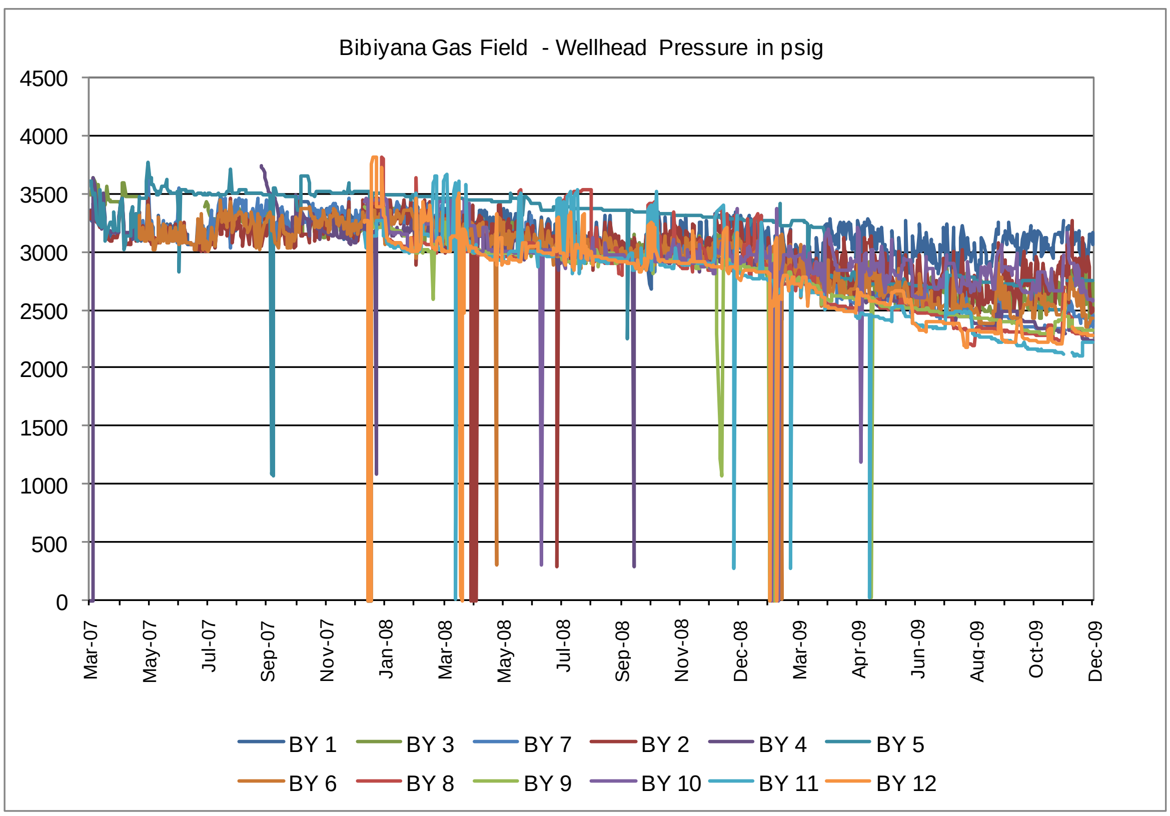



**Figure 6-46 Wellhead Pressures – Bibiyana Gas Field**

Superimposed wellhead pressure plots for all wells producing from all zones in Bibiyana gas field. Despite wells producing from different zones over a range of depths, all of the wellhead pressure histories are similar and show similar trends in pressure drop with time over a relatively narrow range of wellhead pressures.

Detailed individual well histories and accompanying production charts for Bibiyana wells are included in The Annex.

#### 6.3.6.6 Field-wise Cumulative Production

Cumulative production for the field by reservoir is shown in Table 6-13. The BB60 and BB65 reservoirs together account for about 36% of the field's cumulative gas production through the end of 2009. The BH1- and BH20 reservoirs account for an additional 36% of the field's production.

**Table 6-13 Sand-wise Cumulative Gas Production – Bibiyana Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| BB60 | 45.0 |
| BB60-65 comingled | 128.2 |
| BB70 | 94.3 |
| BH10 | 95.0 |
| BH10-20 comingled | 33.2 |
| BH20 | 42.3 |
| BH25 | 37.7 |
| **Total** | **475.7** |

1 Production through end of December 2009
HCU production database

6.3.6.7 Earlier Reserve Estimates

Unocal engaged DeGolyer and MacNaughton (D & M) of USA to estimate the Bibiyana gas reserve. D & M released their report in early 2000. They used all available data and estimated the reserves using the deterministic approach. To comply with United States Security and Exchange Commission (SEC) requirements for Proved reserves, which require a definite gas sales contract and field development plan, the volume that would otherwise be classified as Proved reserves was designated as “Probable (PVD)”. The remainder of the Probable reserves were designated as “Probable (G&E).”

In Bangladesh, reserves qualify as Proved based on the degree of certainty and not on gas sales agreement. For all the past estimates including estimates for IOC-operated gas fields, classification as Proved reserves did not include a consideration of a gas sales agreement. In the 2003 HCU-NPD reserve report, the D & M Probable (PVD) volume was reclassified as Proved. The HCU-NPD modified GIIP volumes as estimated by D & M are given in Table 6-14.

**Table 6-14 DeGolyer and MacNaughton (D & M) of USA 2000 Reserve Report**
GIIP (in Bscf)[4]

| OGIIP | BB60a | BB60b | BB65 | BB70 | BH 10 | BH20ab | BH 20c | BH 20d | BH 30ab | Bh 30c | BH 40a | BH 40b | BH 40c | BH 50a | BH 50b | BH 60 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Proven | 140.7 | 165.8 | 213.5 | 367.4 | 229.4 | 344.7 | 85.8 | | | | | | | | | 36.3 | 1583.7 |
| Probable | 33.2 | 774.5 | 177.7 | 202.8 | 139.7 | 109.0 | 91.4 | 32.4 | | | | | | | | | 1560.9 |
| Possible | 30.2 | 2168.1 | 266.3 | 198.6 | 146.7 | 57.2 | 130.2 | 62.4 | 71.6 | 29.3 | 24.7 | 29.8 | 35.4 | 83.4 | 88.7 | | 3422.7 |
| Total | 204.1 | 3108.4 | 657.6 | 768.8 | 515.8 | 510.9 | 307.4 | 94.8 | 71.6 | 29.3 | 24.7 | 29.8 | 35.4 | 83.4 | 88.7 | 36.3 | 6567.2 |

According to D & M, average recovery factors are about 76% for their Probable (PVD) and 77% for their Probable (G & E) categories. For Possible reserves, recovery factor is 91%. The report did not indicate recovery by using compression separately but mentioned that the recovery is based on wellhead pressure of 1786 to 748 psi for Probable (PVD), 600 psi for Probable (G & E) and 300 psi for Possible reserves. In the report, it was mentioned that Possible reserves, based on

[4] GIIP volumes listed were re-categorized by HCU-NPD 2003 Reserve Report into Proved, Probable, and Possible to remove the issue of lack of gas sales contract.

300 psi well head pressure, include incremental reserves associated with the higher recovery factor applied to Probable reserves.

Based on the estimated recovery factors for the various reserve categories, D & M estimated Total Probable (PVD) ["Proved"] recoverable reserves of 1,200.1 Bscf out of an estimated total Proved (1P) GIIP of 1,583.7 Bscf, using an overall blended recovery factor of 75.8%. In addition, D & M estimated the 3P GIIP for Bibiyana at 6,567.2 Bscf.

Seven years later in 2007, after further development drilling, Ryder Scott was engaged by Chevron to estimate the reserves of Bibiyana gas field. The complete Ryder Scott report is not available. However, a summary table of their results is presented in Table 6-15.

Ryder Scott's estimate of Proved (1P) reserves shows considerable growth in this category of reserves from the previous 2000 estimate. This, of course, is expected due to the drilling of 10 additional successful development wells. Ryder Scott estimated 1P GIIP of 3,970.4 Bscf with an estimated 2,510.8 Bscf of recoverable 1P reserves using a rather conservative recovery factor of 63.2%. This represents more than 200% growth in Proved reserves from that estimated in the D & M report that was based on the first two wells drilled in the field. For the combined Proved +Probable category (2P), Ryder Scott estimated 2P GIIP of 5,864.0 Bscf with an estimated 4,421.9 Bscf of recoverable 2P reserves. On the downside, Ryder Scott estimated a somewhat smaller value of 3P GIIP of 5,864.0 Bscf compared to D & M's 2000 estimate of 6,567.2 Bscf. That represents about an 11 decrease in the estimate of overall original gas-in-place.

The reason for this reduction in the estimate of total GIIP is not clear. It may be the result of differences in estimating methodology and conservatism in approach between the two companies, or it may result from the incorporation of additional information from the new wells drilled in the field.

## Table 6-15 Ryder Scott 2007 Reserve Estimate – Bibiyana Gas Field

Ryder Scott Recovery Breakdown by Reservoir
Bibiyana Gas Field (2007)

| | 1P OGIP (MMCF) | 1P EUR (MMCF) | 1P R.F. (%) | Proved EUR (MMCF) | Developed R.F (%) | Proved EUR (MMCF) | Undeveloped R.F (%) |
|---|---|---|---|---|---|---|---|
| BB-60 | 2,015,828 | 1,285,908 | 63.8% | 743,650 | 36.9% | 542,258 | 26.9% |
| BB-65 | 105,012 | 66,629 | 63.4% | 38,606 | 36.8% | 28,023 | 26.7% |
| BB-70 | 999,443 | 645,859 | 64.6% | 398,254 | 39.8% | 247,605 | 24.8% |
| BH-10 | 457,288 | 278,514 | 60.9% | 141,125 | 30.9% | 137,389 | 30.0% |
| BH-20A | 177,410 | 108,888 | 61.4% | 56,195 | 31.7% | 52,693 | 29.7% |
| BH-20B | 71,927 | 41,463 | 57.6% | 21,593 | 30.0% | 19,870 | 27.6% |
| BH-20C | 96,249 | 55,645 | 57.8% | 32,924 | 34.2% | 22,721 | 23.6% |
| BH-20D | 47,252 | 27,850 | 58.9% | 17,028 | 36.0% | 10,822 | 22.9% |
| Total | 3,970,409 | 2,510,756 | 63.2% | 1,449,375 | 36.5% | 1,061,381 | 26.7% |

1P OGIP Volumes Assumptions

Additional water production creates liquid loading
Developed reserves include current and assumed future behind-pipe recompletions
Undeveloped reserves are for assumed compression (200 psi inlet at EUR)
Field life truncated at contract term limit (2034), not technical limits

| | 2P OGIP (MMCF) | 2P EUR (MMCF) | 2P R.F. (%) | 2P EUR (MMCF) | Developed R.F (%) | 2P EUR (MMCF) | Undeveloped R.F (%) |
|---|---|---|---|---|---|---|---|
| BB-60 | 2,290,706 | 1,772,073 | 77.4% | 1,385,972 | 60.5% | 386,101 | 16.9% |
| BB-65 | 446,415 | 325,570 | 72.9% | 260,652 | 58.4% | 64,918 | 14.5% |
| BB-70 | 1,070,207 | 835,034 | 78.0% | 659,030 | 61.6% | 176,004 | 16.4% |
| BH-10 | 893,413 | 651,389 | 72.9% | 539,907 | 60.4% | 111,482 | 12.5% |
| BH-20A | 576,451 | 417,127 | 72.4% | 347,256 | 60.2% | 69,871 | 12.1% |
| BH-20B | 156,601 | 115,405 | 73.7% | 94,977 | 60.6% | 20,428 | 13.0% |
| BH-20C | 277,141 | 195,384 | 70.5% | 163,191 | 58.9% | 32,193 | 11.6% |
| BH-20D | 153,060 | 109,935 | 71.8% | 90,676 | 59.2% | 19,259 | 12.6% |
| Total | 5,863,994 | 4,421,917 | 75.4% | 3,541,661 | 60.4% | 880,256 | 15.0% |

2P OGIP Volumes Assumptions

Limited water production creates effectively zero liquid loading
Developed reserves include current and assumed future behind-pipe recompletions
Undeveloped reserves are for assumed compression (200 psi inlet at EUR)
Field life truncated at contract term limit (2034), not technical limits

| | 3P OGIP (MMCF) | 3P EUR (MMCF) | 3P R.F. (%) | 3P EUR (MMCF) | Developed R.F (%) | 3P EUR (MMCF) | Undeveloped R.F (%) |
|---|---|---|---|---|---|---|---|
| BB-60 | 2,290,706 | 1,789,847 | 78.1% | 1,385,972 | 60.5% | 403,875 | 17.6% |
| BB-65 | 446,415 | 328,856 | 73.7% | 260,652 | 58.4% | 68,204 | 15.3% |
| BB-70 | 1,070,207 | 843,108 | 78.8% | 659,030 | 61.6% | 184,078 | 17.2% |
| BH-10 | 893,413 | 657,719 | 73.8% | 539,907 | 60.4% | 117,812 | 13.2% |
| BH-20A | 576,451 | 421,216 | 73.1% | 347,256 | 60.2% | 73,960 | 12.8% |
| BH-20B | 156,601 | 116,453 | 74.4% | 94,977 | 60.6% | 21,476 | 13.7% |
| BH-20C | 277,141 | 197,177 | 71.1% | 163,191 | 58.9% | 33,986 | 12.3% |
| BH-20D | 153,060 | 110,889 | 72.4% | 90,676 | 59.2% | 20,213 | 13.2% |
| Total | 5,863,994 | 4,465,265 | 76.1% | 3,541,661 | 60.4% | 923,604 | 15.8% |

3P OGIP Volumes Assumptions

Identical assumptions as 2P except
Undeveloped reserves are for assumed final compression inlet pressure of 50 psi
Field life truncated at contract term limit (2034), not technical limits

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In 2008, Chevron contracted with DeGolyer & MacNaughton (D & M) to produce a follow-up reserve estimate to their original 2000 reserve report for Bibiyana gas field. Their report was completed in 2009 with an effective date of December 31, 2008. Although the complete report is not available, a summary of the results of their latest estimate are presented in Table 6-16.

D & M's latest reserves forecast is somewhat more optimistic than the Ryder Scott estimate from two year earlier, although the information available to both companies is essentially the same. D & M estimates that Bibiyana field originally contained 3,600.8 Bscf of 1P GIIP, 7,427.8 Bscf of 2P GIIP, and 8,350.9 Bscf of 3P GIIP as compared to Ryder Scott's 3,970.4 Bscf of 1P GIIP and 5,864.0 Bscf of 2P/3P GIIP. In other words, although D & M is slightly more conservative on assigning 1P GIIP, they are more bullish on their assignment of total field 2P and 3P GIIP by about 127 to 142%.

**Table 6-16 DeGolyer & McNaughton 2009 Reserve Estimate – Bibiyana Gas Field**

**Reservoir Parametres and Condensate**
**as on**
**DECEMBER 31, 2008**
**for the**
**BIBIYANA FIELD**
**DeGolyer & MacNaughton (D&M)**

| | Bibiyana Field | | |
|---|---|---|---|
| | **Proved** | **Probable[3]** | **Posible[4]** |
| Original Gas in Place, MMcf | 3,600,788 | 7,427,746 | 8,350,881 |
| Recovery Factor, % | 66.9 | 18.0 | 15.9 |
| Gross Ultimate Full Well stream Gas Recovery, MMcf | 4,415,619 | 1,339,807 | 1,330,288 |
| Cumulative Full Wells tream Gas Production, MMcf | 257,833 | | |
| Gross Full Well stream Gas Reserves, MMcf | 4,157,786 | 1,339,807 | 1,330,288 |
| Sales Gas Shrinkage, % | 0.89 | 0.89 | 0.89 |
| Sales Gas Reserves, MMcf | 4,120,782 | 1,337,883 | 1,318,448 |
| Developed Reserves, MMcf | 3,464,400 | | |
| Undeveloped Reserves, MMcf | 656,382 | | |
| Compression, MMcf | 211, 950 | | |
| Recompilations, MMcf | 444,432 | | |
| Gross Ultimate Condensate Recovery, Mbbl | 18,897 | 5,708 | 5,605 |
| Cumulative Condensate Production, Mbbl | 1,698 | | |
| Gross Condensate Reserves, Mbbl | 17,199 | 5,708 | 5,605 |
| Developed Reserves, Mbbl | 14,459 | | |
| Undeveloped Reserves, Mbbl | 2,740 | | |
| Compression, Mbbl | 885 | | |
| Recompletion, Mbbl | 1,855 | | |

Note:
1. Probable and possible reserves have not been adjusted for risk.
2. Probable and possible reserves include additional recovery from estimated proved reserves.
3. OGIP associated with proved-plus-probable reserves is shown in this table with probable reserves.
4. OGIP associated with proved-plus probable-possible reserves is shown in this table with possible reserves.

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6.3.6.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Bibiyana field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

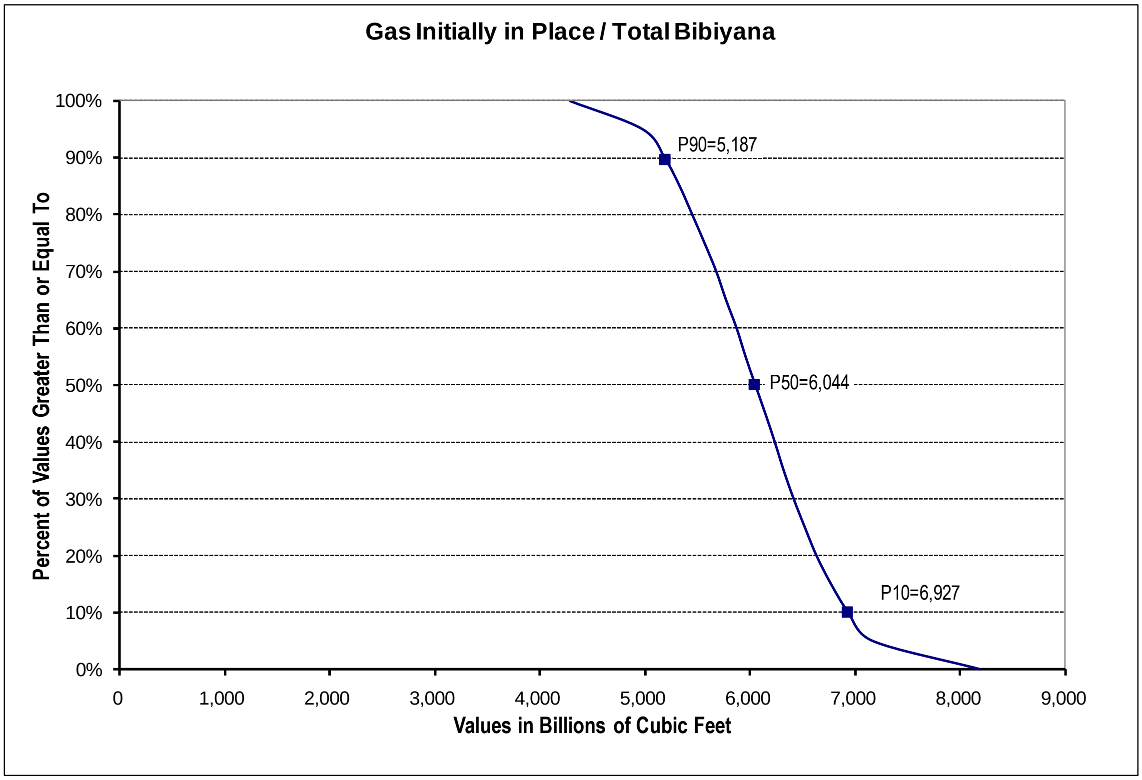



**Figure 6-47 Distribution of GIIP, Bibiyana**

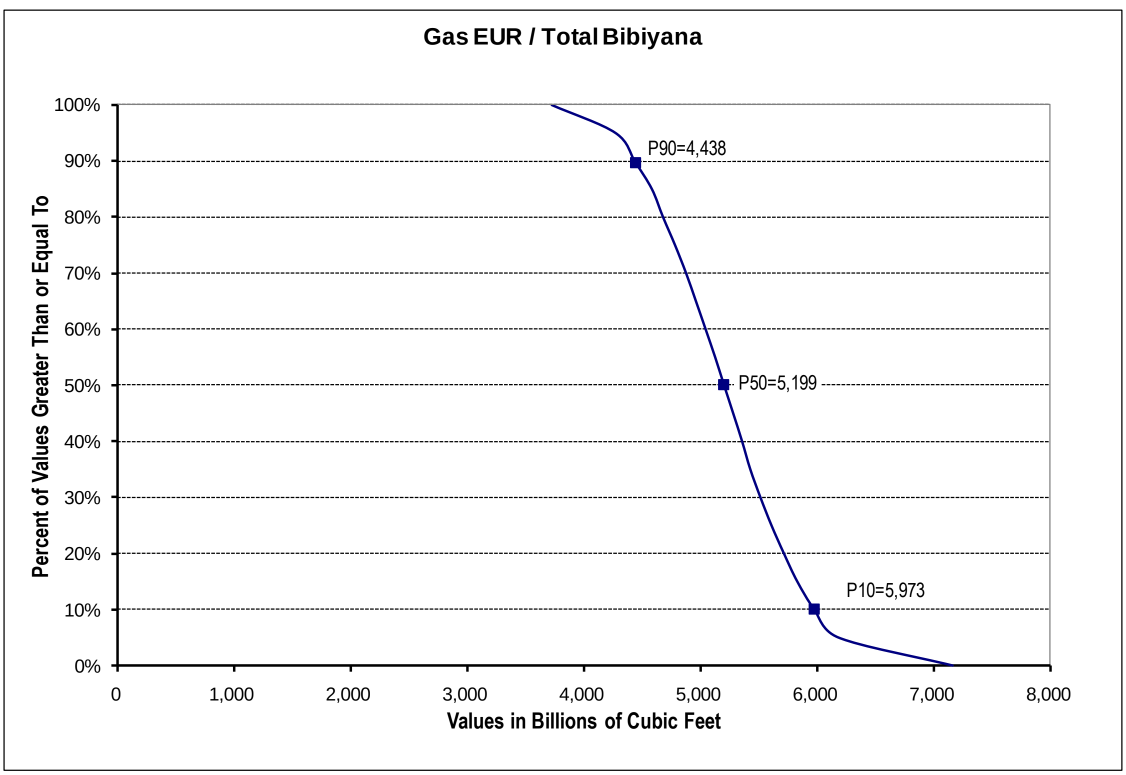



**Figure 6-48 Distribution of Gas EUR, Bibiyana**

**Table 6-17 Summary of Estimated Ultimate Recovery and Reserves at Bibiyana**

<table>
<tr><th>Reservoir</th><th>Mean Gas EUR, BCF</th><th>Cumulative Gas, 1/1/2010, BCF</th><th>Reserves, 1/1/2010, BCF</th></tr>
<tr><td>BB60ab</td><td>2,488</td><td rowspan="2">173</td><td rowspan="2">2,750</td></tr>
<tr><td>BB65</td><td>435</td></tr>
<tr><td>BB70</td><td>784</td><td>94</td><td>690</td></tr>
<tr><td>BH10</td><td>369</td><td rowspan="4">170</td><td rowspan="4">948</td></tr>
<tr><td>BH20ab</td><td>420</td></tr>
<tr><td>BH20c</td><td>225</td></tr>
<tr><td>BH20d</td><td>104</td></tr>
<tr><td>BH25</td><td>64</td><td>38</td><td>26</td></tr>
<tr><td>BH30ab</td><td>31</td><td>0</td><td>31</td></tr>
<tr><td>BH30c</td><td>33</td><td>0</td><td>33</td></tr>
<tr><td>BH40a</td><td>26</td><td>0</td><td>26</td></tr>
<tr><td>BH40b</td><td>23</td><td>0</td><td>23</td></tr>
<tr><td>BH40c</td><td>24</td><td>0</td><td>24</td></tr>
<tr><td>BH50a</td><td>64</td><td>0</td><td>64</td></tr>
<tr><td>BH50b</td><td>82</td><td>0</td><td>82</td></tr>
<tr><td>BH60</td><td>33</td><td>0</td><td>33</td></tr>
<tr><td>TOTAL</td><td>5,205</td><td>475</td><td>4,730</td></tr>
</table>

In addition, material balance calculations were made for Bibiyana using conventional p/z analysis. Bottom-hole shut-in pressures were calculated from reported surface shut-in pressures and gas properties, assuming no liquid accumulation above the reservoir in the wellbore. This is considered a valid assumption, since the low water and condensate volumes would be expected to be in the gaseous state at reservoir conditions. Two of the Bibiyana wells are producing from the BB60 and BB65 wells commingled (BY1 and BY2), and a third well produces from the BB60 (BY10). The pressure data were reviewed and found to be in close agreement between the three wells. Therefore, the pressure data were averaged and the cumulative production was summed for these wells to analyze the BB60 and BB65 reservoir as a whole (Figure 6-49).

Insufficient shut-in pressure data were available to perform a conventional p/z analysis for any of the other producing reservoirs (BB70, BH10, BH20, or BH25).

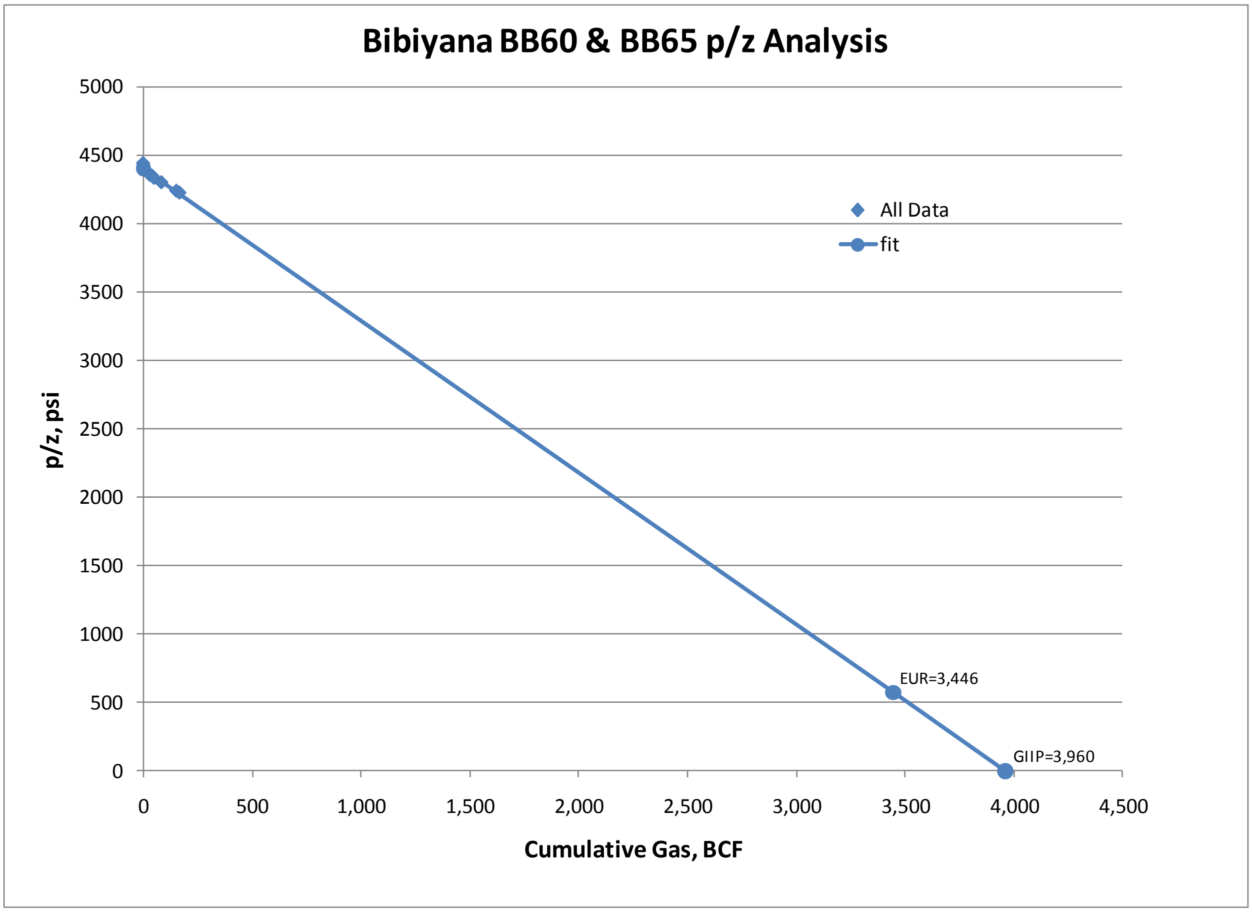



**Figure 6-49 Bibiyana BB60 and BB65 p/z Analysis**

Additionally, reserves and GIIP were estimated for the sands at Bibiyana using the Approximate Wellhead Material Balance (AWMB) technique.[5] For this technique, where more than one well is producing from a reservoir, the FWHP values are averaged. Any data deviating significantly from the established trend were excluded. The results are shown in Figure 6-50 through Figure 6-53.

[5] Mattar and McNeil, 1998.

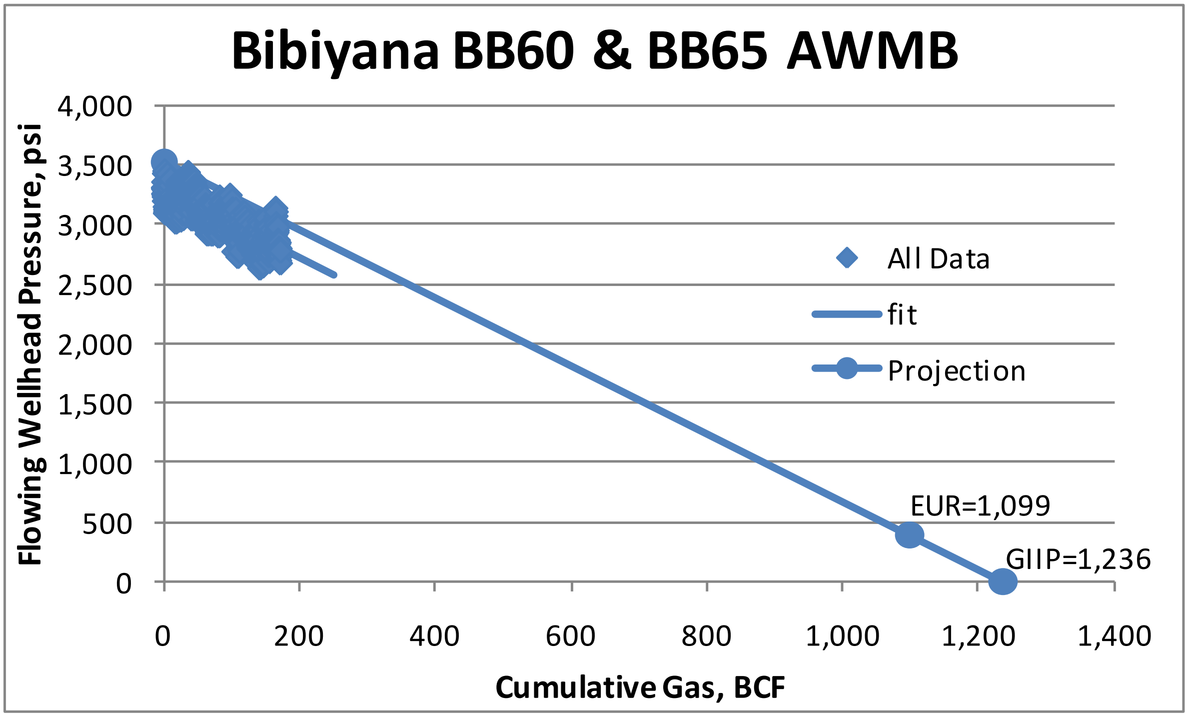



**Figure 6-50 Bibiyana BB60 and BB65 AWMB Plot**

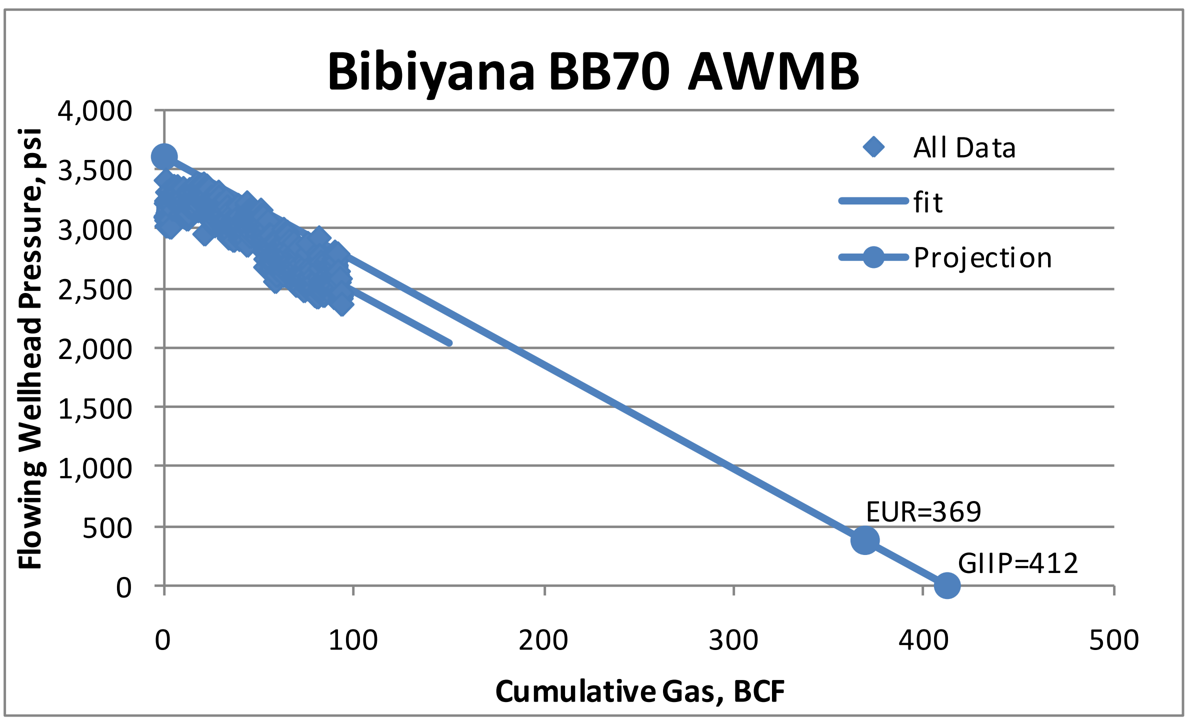



**Figure 6-51 Bibiyana BB70 AWMB Plot**

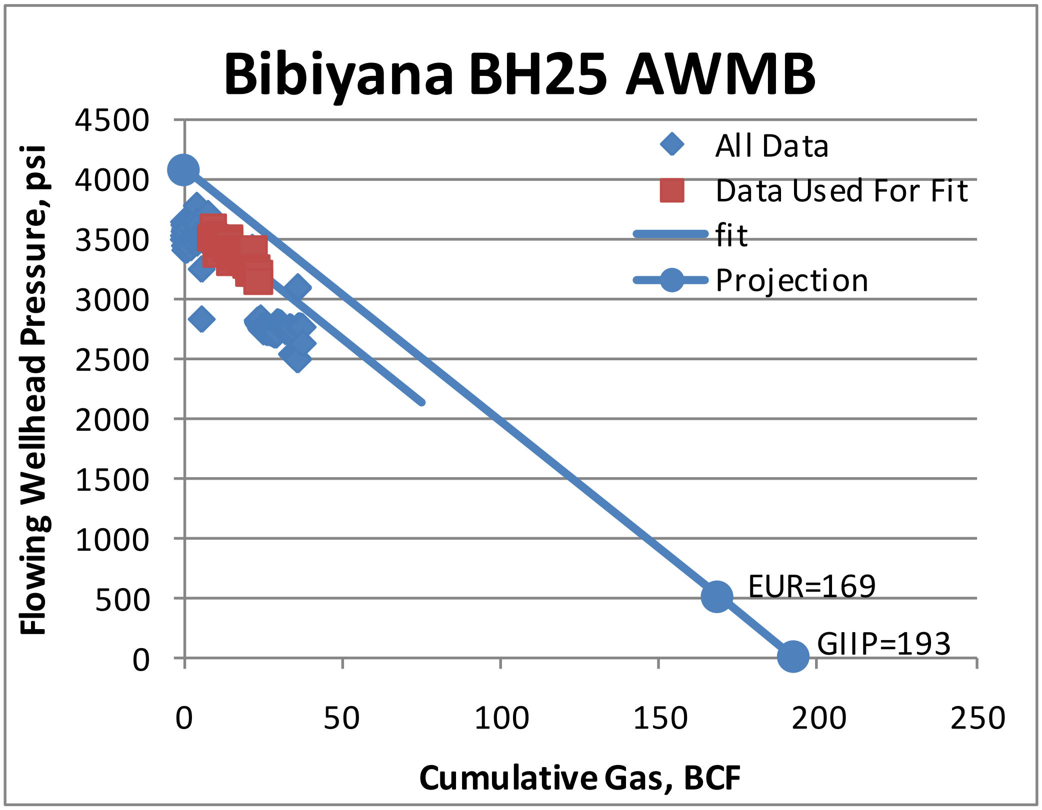



**Figure 6-52 Bibiyana BH25 AWMB Plot**

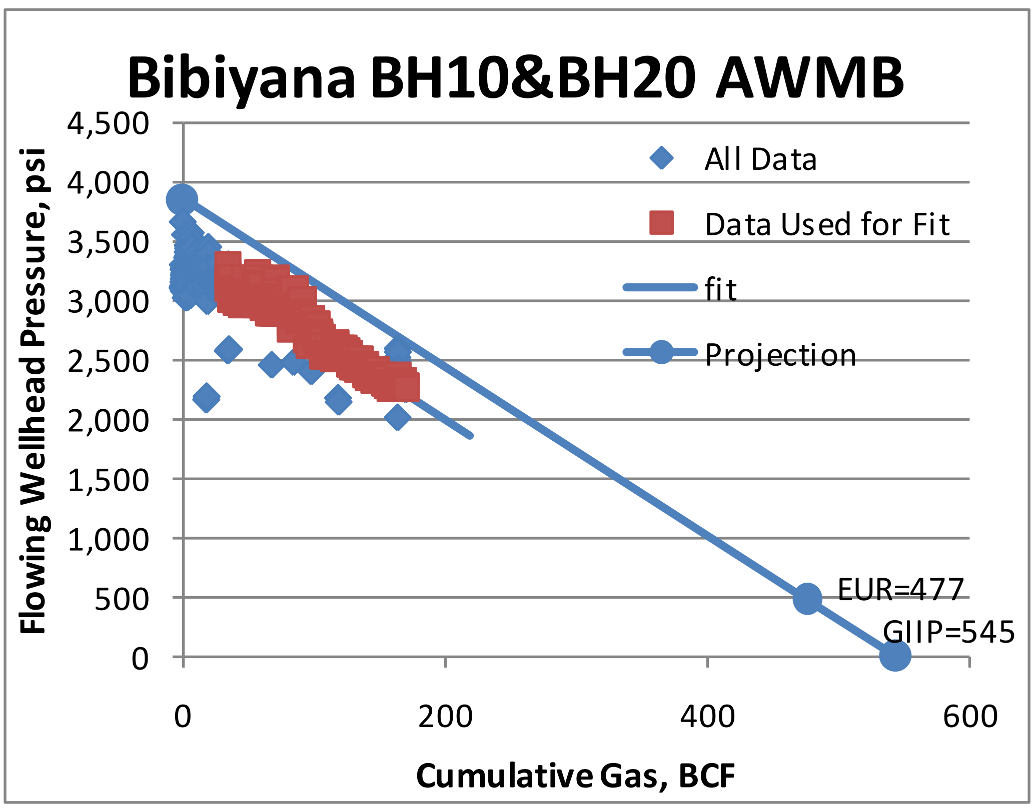



**Figure 6-53 Bibiyana BH10 and BH20 AWMB Plot**

All Gustavson's estimates are summarized below, using mean estimates from the probabilistic volumetric analysis:

| **Reservoir** | **BB60 & BB65 Sand** | | | **BB70** | | **BH25** | | **BH10& BH20** | |
|---|---|---|---|---|---|---|---|---|---|
| | **Volu-** | **Mat Bal** | | **Volu-** | **Mat Bal** | **Volu-** | **Mat Bal** | **Volu-** | **Mat Bal** |
| **Method** | **metric** | **p/z** | **AWMB** | **metric** | **AWMB** | **metric** | **AWMB** | **metric** | **AWMB** |
| GIIP, BCF | 3,380 | 3,960 | 1,236 | 901 | 412 | 76 | 193 | 1,317 | 545 |
| EUR, BCF | 2,923 | 3,446 | 1,099 | 784 | 369 | 64 | 169 | 1,118 | 477 |
| Cum. Gas, BCF | 173 | 173 | 173 | 94 | 94 | 38 | 38 | 170 | 170 |
| **Reserves, BCF** | **2,750** | **3,273** | **926** | **690** | **275** | **26** | **131** | **948** | **307** |

In general, performance-based material balance techniques are more reliable, and conventional p/z would be more reliable than AWMB.  The AWMB analysis judged least reliable of these presented for Bibiyana is for the BH25, due to the obvious variations in the flowing pressure levels.  The volumetric analysis for Bibiyana was based on rather old geologic maps.

### 6.3.7 Fenchuganj (12)

#### 6.3.7.1 Geologic Setting

Fenchuganj gas field is located near the western margin of the folded belt. The gas field is surrounded by Beani Bazar on the northeast, Bibiyana on the west, Moulavi Bazar on the southwest and Kailash Tila on the north (Figure 6-3).

#### 6.3.7.2 Structure

Fenchuganj structure was mapped by geologists of PPL, Geological Survey, and OGDC. It is an exposed anticline represented by low hills. Surface of the area is represented by outcrop of Tipam Sandstone and Dupi Tila Formation. Lithologically, outcrops are represented by sandstone and shale/clay.  In areal photos and satellite imageries the structure is quite well pronounced. The subsurface geometry of the structure was delineated by PPL in 1957 on the basis of singlefold analog seismic data.  An exploratory well was drilled to a depth of 2438m in 1960. It was a dry hole.

The structure is an elongated anticline with an axial trend oriented NNE-SSW. On the eastern flank of the structure, a major fault runs parallel to the axis and extends all along the structure. At the top of reservoir zone 3, the structure is about 7 km long and 1.55 km wide with amplitude of 38m. Figure 6-54 is a time structure map on an undisclosed horizon for Fenchuganj gas field.

#### 6.3.7.3 Reservoir

Like all other gas fields of the country the reservoir rock in Fenchuganj is sandstone of Miocene-Upper Miocene to Pliocene age. Reservoir parameter is evaluated on the basis of wireline log. From surface to a depth of 3240 meters, logging was conducted using vintage tool of former Soviet Union. Schlumberger tool was used for logging in the deeper part of the well. Except the lower most zone, all other zones are not covered by vintage tool. A graph of Log porosity and Core porosity Vs. Depth is shown in Figure 6-55 below.

Log porosity of the lowermost zone is 7- 9%. This interval was logged using Schlumberger tool. Rest of the interval was logged by logging tool from former USSR.

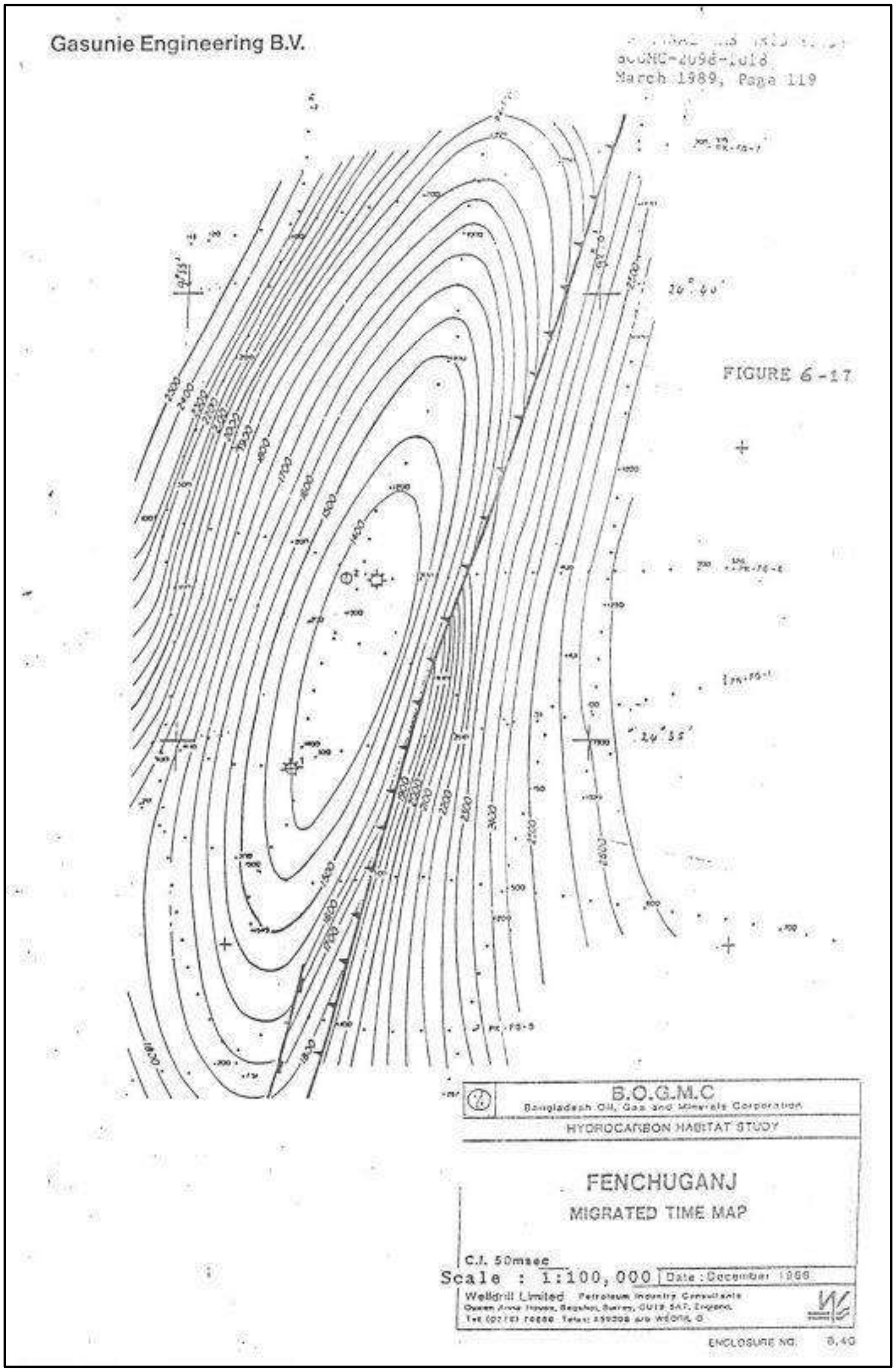



**Figure 6-54 Migrated Time Structure Map – Fenchuganj Gas Field**

Fenchuganj gas field has only two productive wells, Fenchuganj #2 and #3. The field was never developed with additional wells. The two wells produce from the Upper and Lower Gas Sands of the Bokabil Formation (after BOGMC, *in* Gasunie Engineering B.V., 1989).

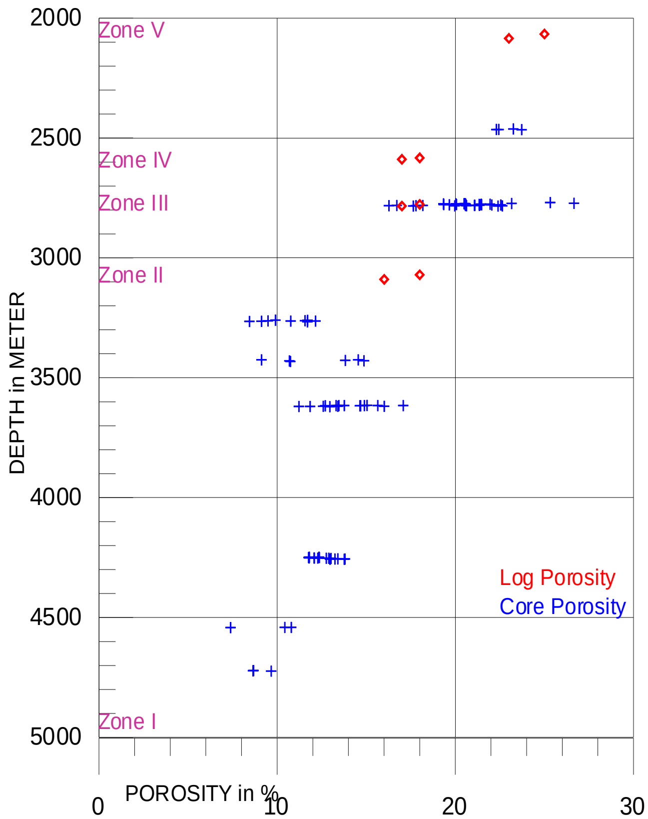



**Figure 6-55 Fenchuganj Well #1 – Depth vs. Porosity Plot**

6.3.7.4 Exploration and Field Development

During early 80's, Petrobangla, with German technical assistance, conducted digital multifold seismic survey over the area. The structure was remapped and a location for drilling of an exploratory well was selected. During 1985-86, Petrobangla with financial and technical assistance from France drilled Fenchuganj well #2. The well was terminated at 4977m. This is the deepest well in all of the country. The well opened seven hydrocarbon bearing horizons. Deeper two zones were evaluated as oil-bearing. Remaining five zones are gas-saturated.

Due to technical problems, DST for testing of the lowermost zone was abandoned. The next zone, containing a two meter oil column, overlain by gas and underlain by water was tested.

From commercial point of view, test result was not that interesting. Zone 4 and 5 were tested separately and both flowed dry gas.

Production records indicate some initial production from the Upper Gas Sand in Well #2 from February through May 2003. Continuous production from the Upper Gas Sand zone in Well #2 started in May 2004. At the beginning, and for about 8 months, production rate from Well #2 was quite uniform at 21-22 MMscfd. In May 2007, production from Well #2 was stopped. There was no drop in FWHP. Flow rate was quite uniform throughout the production period. Cumulative production was 31.2 Bscf from the Upper Gas Sand.

Well #2 was recompleted in Lower Gas Sand zone and opened for production in October 2008. Until April 2009, production rate was about 14 MMscfd but FWHP came down to 2502 psig from 2960 psig. By June 2009, FWHP was reduced to 2720 from 2925 psig. After reducing production rate to 6 MMscfd no improvement was observed. FWHP gradually reduced to 2511 psig by December 2009. Cumulative production from Well #2 in Lower Gas Sand through December 2009 is only 4.7 Bscf. Water production rate registered sharp increase from 0.1 bbl/MMscf gas to nearly 2 bbl/MMscf of gas.

Well #3 was opened in the Upper Gas Sand in January 2005 and the field's production increased to 43-44 MMscfd. From March 2007, production quite rapidly decreased to 20 MMscfd from 44 MMscfd. In October 2008 Well #2 was put back into production from the Lower Gas Sand and the total field production rate increased to 33 MMscfd and then gradually reduced to 24 MMscfd.

Detailed individual well histories and accompanying production charts for Fenchuganj wells are included in The Annex.

6.3.7.5 Well-wise and Sand-wise Production History

Figure 6-56 and Figure 6-57 present the well-wise and sand-wise daily historic production data for Fenchuganj gas field. Each of the wells at Fenchuganj has produced nearly 36 Bscf of gas through December 2009. However, Fenchuganj Well #2 has produced its gas from both the Upper and Lower Gas Sands whereas all of the gas production from Fenchuganj Well #3 has come from the Upper Gas Sand. Figure 6-56 confirms that both wells have produced similar volumes on a daily basis. However, as shown in Figure 6-57, the Upper Gas Sand accounts for the bulk of the gas production.

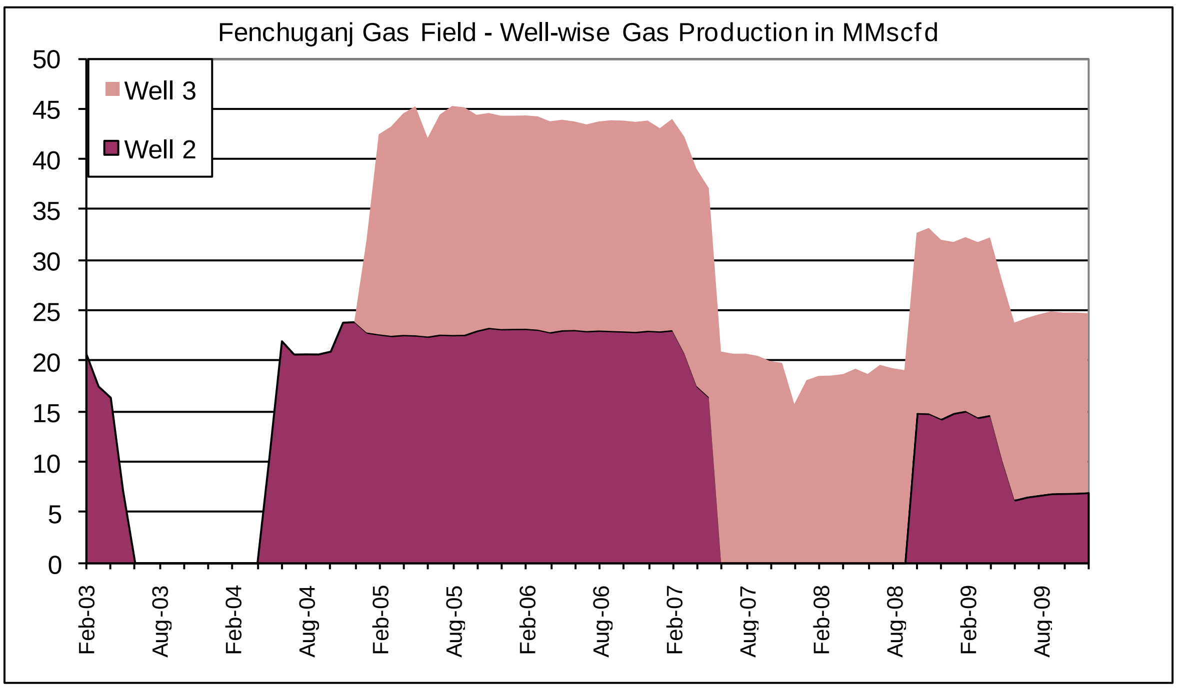



**Figure 6-56 Well-wise Gas Production – Fenchuganj Gas Field**

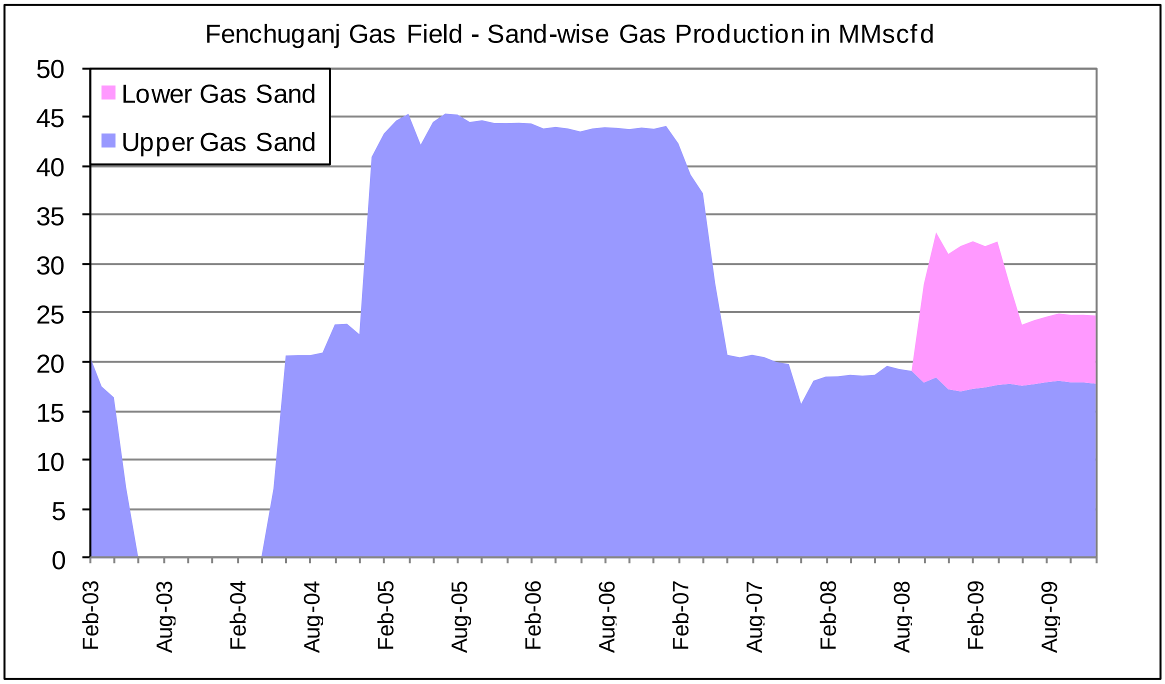



**Figure 6-57 Sand-wise Gas Production – Fenchuganj Gas Field**

6.3.7.6 Field-wise Cumulative Production

Cumulative production for Fenchuganj gas field is shown in Table 6-18 below, both by sand and for the total field. As with daily production, the Upper Gas Sand has been the largest contributor to gas production for this field, accounting for over 93% of the total produced gas through the end of 2009.

**Table 6-18 Sand-wise Cumulative Gas Production – Fenchuganj Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Upper Gas Sand | 66.9 |
| Lower Gas Sand | 4.7 |
| **Total** | **71.6** |

1 Production through end of December 2009
HCU production database

### 6.3.7.7 Earlier Reserve Estimates

Post-discovery estimate by Petrobangla (1988) placed the GIIP (Proven and Probable) at 404 Bscf. The results are shown in Table 6-19.

**Table 6-19 Petrobangla 1988 Reserve Estimate – Fenchuganj Gas Field**

| Petrobangla, 1988 | GIIP in Bscf | | |
|---|---|---|---|
| Zone | Proven | Probable | Total |
| Upper | 49 | 160 | 209 |
| Middle | 12 | 62 | 74 |
| Lower | 24 | 97 | 121 |
| Total | 85 | 319 | 404 |

In 1999, Gasunie re-estimated the gas reserve of Fenchuganj. Only recoverable volume was reported. This estimate included two shallow sands above 2034m. According to this estimate Proven reserve of the field was 50 Bscf. Expected value was 200 Bscf and 400 Bscf was placed under High category.

In 2003, HCU–NPD re-estimated the GIIP of Fenchuganj gas field. Results of this study are provided in Table 6-20.

**Table 6-20 HCU-NPD 2003 Reserve Estimate – Fenchuganj Gas Field**

| HCU–NPD, 2003 | GIIP in Bscf | | |
|---|---|---|---|
| Zone | Proven | Probable | Total |
| Upper | 42.4 | 137.2 | 179.6 |
| Middle | 12.9 | 63.7 | 76.6 |
| Lower | 26.4 | 105.5 | 131.9 |
| Total | 81.7 | 306.4 | 388.1 |

The last formal reserve study was conducted by RPS Energy and released in a final report in 2009. They used both ECLIPSE™ and Petrel ™ software. Results of this study are given below in Table 6-21.

**Table 6-21 RPS Energy 2009 Reserve Estimate – Fenchuganj Gas Field**

| RPS Energy, 2009 | GIIP in Bscf | |
|---|---|---|
| Reservoir | ECLIPSE | Petrel |
| Upper Sand | 284 | 297 |
| Middle Sand | 108 | 96 |
| Lower Sand | 58 | 53 |
| Total | 450 | 447 |

RPS, 2009d

6.3.7.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Fenchuganj field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C. Gustavson has insufficient data to estimate reserves for an additional reservoir, the New Gas Sand, and so has included the volumes of reserves for this sand based on the volumes reported by RPS in their 2010 report.

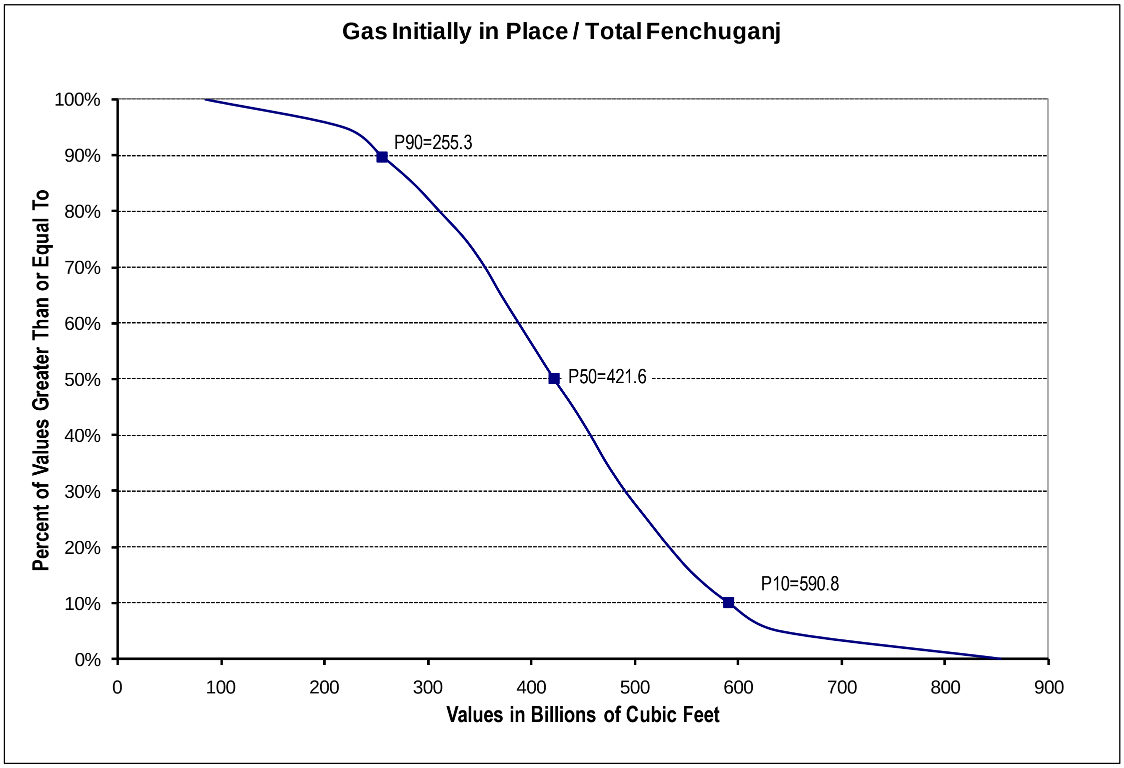



**Figure 6-58 Distribution of GIIP, Fenchuganj**

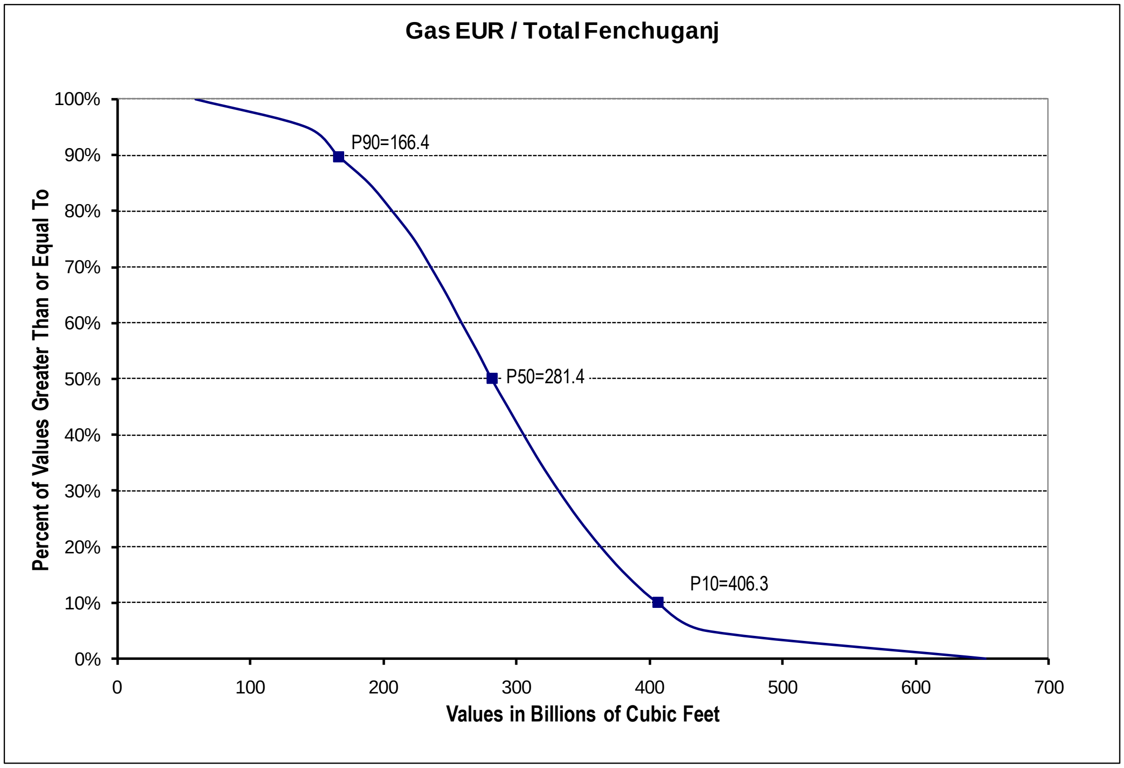



**Figure 6-59 Distribution of Gas EUR, Fenchuganj**

**Table 6-22 Summary of Estimated Ultimate Recovery at Fenchuganj**

| Reservoir | Mean Gas EUR, BCF |
|---|---|
| Upper Gas Sand | 193 |
| Middle Gas Sand | 53 |
| Lower Gas Sand | 41 |
| New Gas Sand | 50 |
| TOTAL | 337 |

### 6.3.8 Feni

#### 6.3.8.1 Geologic Setting

The Feni structure is located in the southern portion of the Eastern Foldbelt of eastern Bangladesh in the northeastern portion of the Hatia Trough (Figures 6-2 and 6-4). It is located approximately 40 km to the west-northwest of the undeveloped Semutang gas field.

#### 6.3.8.2 Structure

Feni structure was mapped as an oval shaped anticline on the basis of single fold analog seismic data. First well was drilled on the basis of this map. In 1981, two multifold analog lines were recorded, one across and another along the structure.

A twenty-four fold digital seismic survey was conducted during 1986 under HHSPP. Welldrill, consultant for the project, prepared a new map on the basis of this new seismic data. According to Welldrill, there is a possible flank prospect, which occurs on line FE-12 between the intersections of lines FE-04 and FE-06. According to Welldrill, the drainage area of the structure could not be determined because of short length of the lines.

BAPEX did a study on this field in 1991 when two maps, one on top of Lower Gas Sand (Figure 6-60) and another on top of Upper Gas sand, were prepared. These maps showed that the anticline is an elongated one with relatively slightly steeper west flank. The BAPEX map also indicated a flat spot on line FE-12, which was considered for estimation of reserve under the Possible category.

Maps prepared under SAPS study in 1993 show minor difference in structural pattern. However the map on top of Lower Gas Sand (Figure 6-61) indicates possible change of lithology from reservoir to non reservoir on the south and south-east.

According to SAPS study, the strong seismic reflector corresponding to Lower Gas sand becomes obscure towards south. According to their interpretation, this was due to a change in lithology. For the estimation of gas bearing area, SAPS Team did not consider this part. This resulted in significant reduction of GIIP of Lower Sand.

When Niko Resources (Bangladesh) Ltd. (NIKO), under a joint study program with BAPEX reprocessed seismic lines and prepared new maps on top of both Upper and Lower Gas Sands (Figure 6-62 and Figure 6-63). Logs were also re-evaluated. This study did not consider the Middle Gas Sand. Maps prepared by the NIKO-BAPEX Joint Study shows Feni as a flat crested anticline. All earlier maps show both the flanks gently dipping. The joint study map limited the aerial extension of the structure towards the north and this is on the basis of the result obtained in Well # 2.

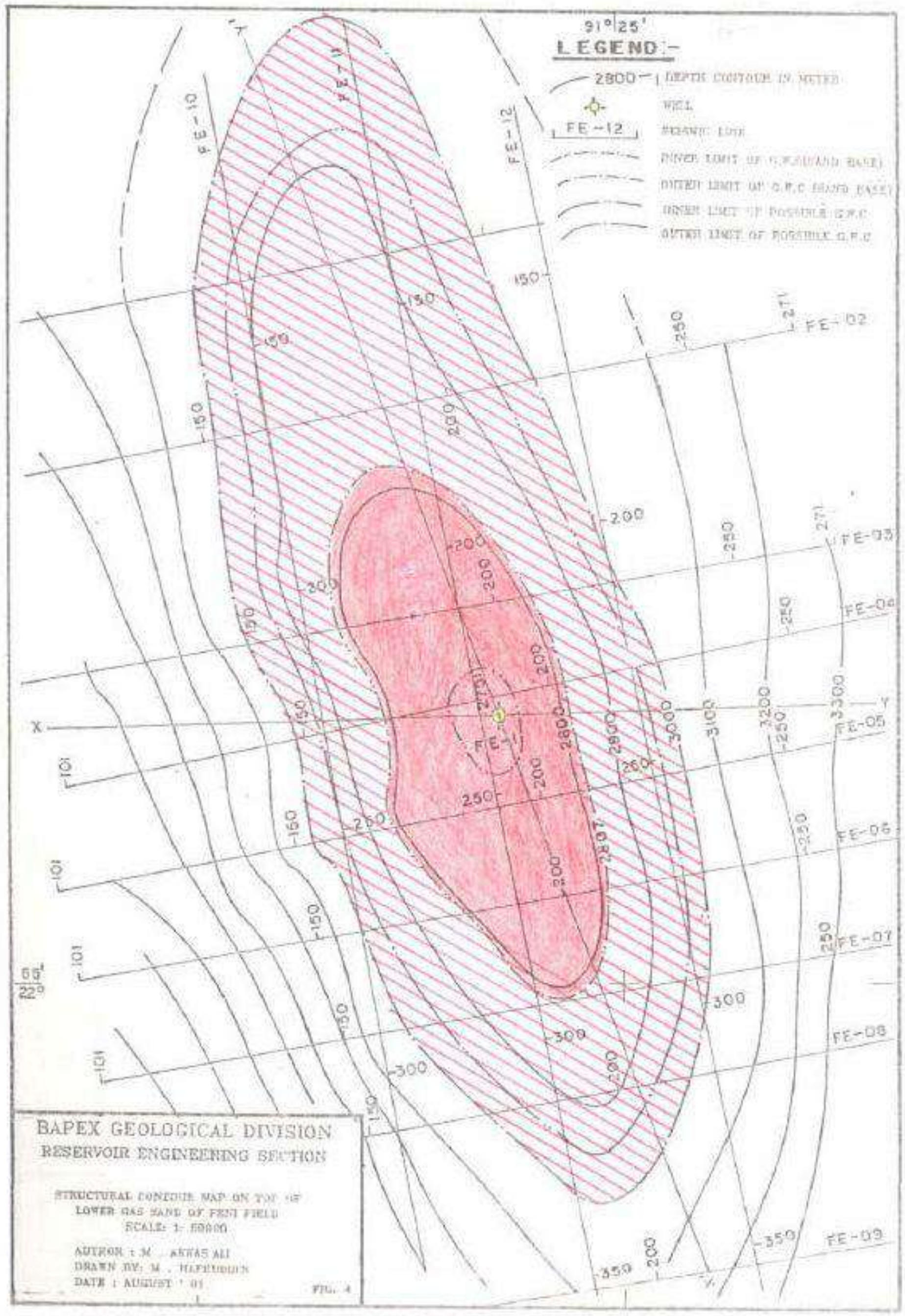



**Figure 6-60 Depth Structure Map on Top of Lower Gas Sand – Feni Gas Field, 1991**
Map drawn after drilling of Feni #1 well but prior to the drilling of Feni #2 well (after BAPEX, 1991).

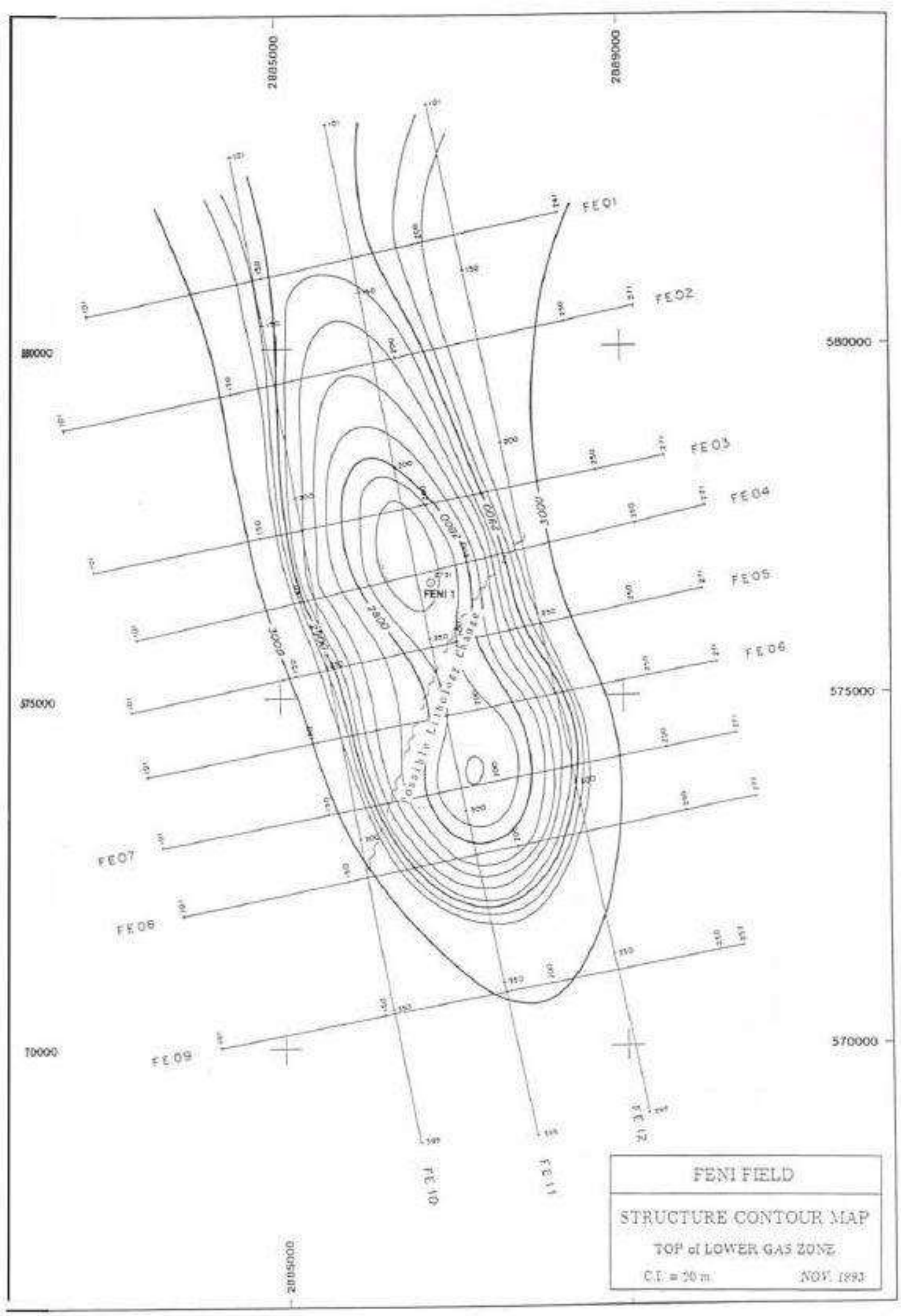



**Figure 6-61 Structure on Top of Lower Gas Sand – Feni Gas Field, 1993**
Map drawn after drilling of Feni #1 well but prior to the drilling of Feni #2 well (after SAPS, 1993).

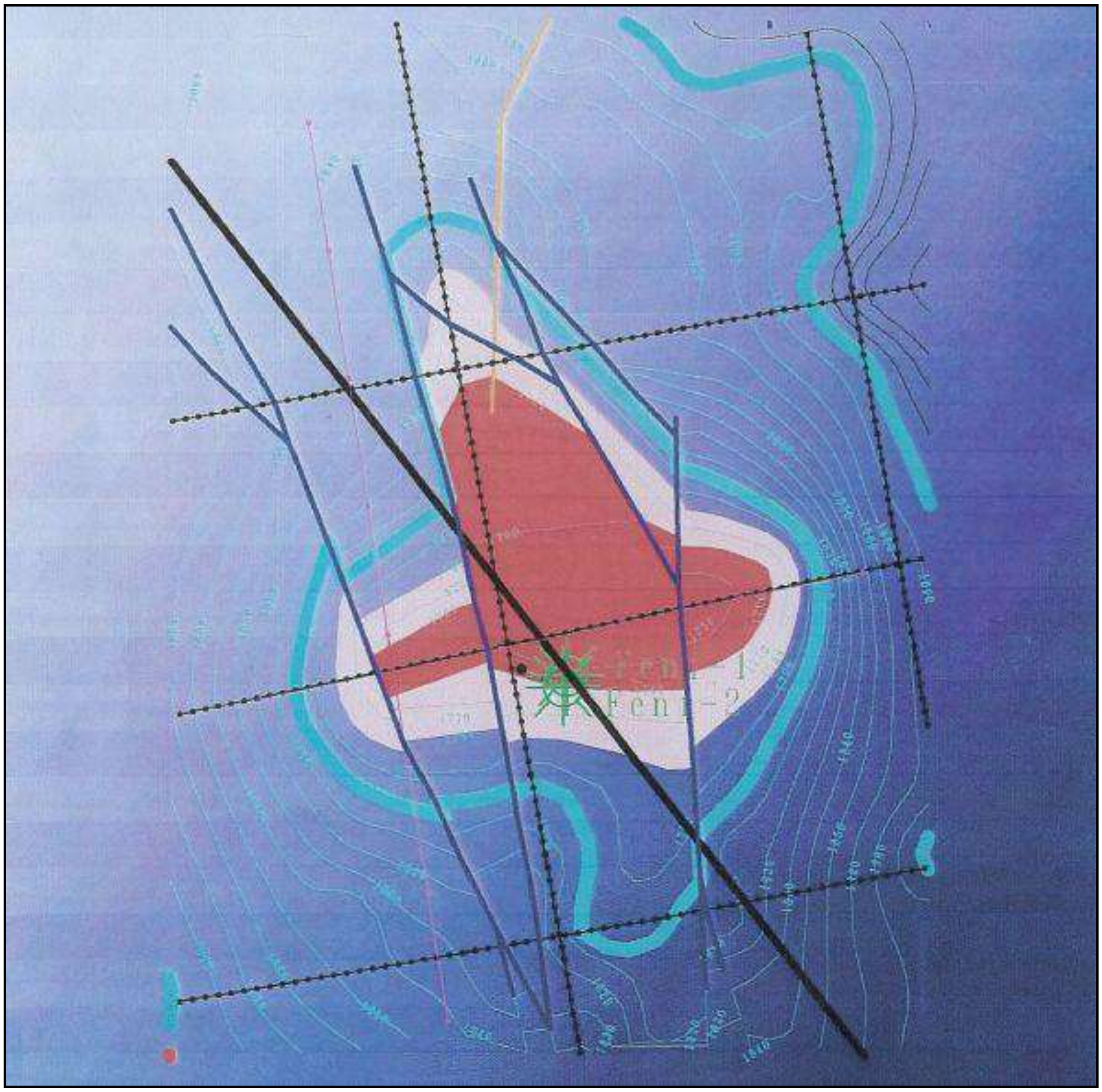



**Figure 6-62 Structure Map on Top of Upper Gas Sand – Feni Gas Field, 2000**
Interpretation by NIKO/BAPEX after the drilling of Feni #2 well (after NIKO/BAPEX, 2000).

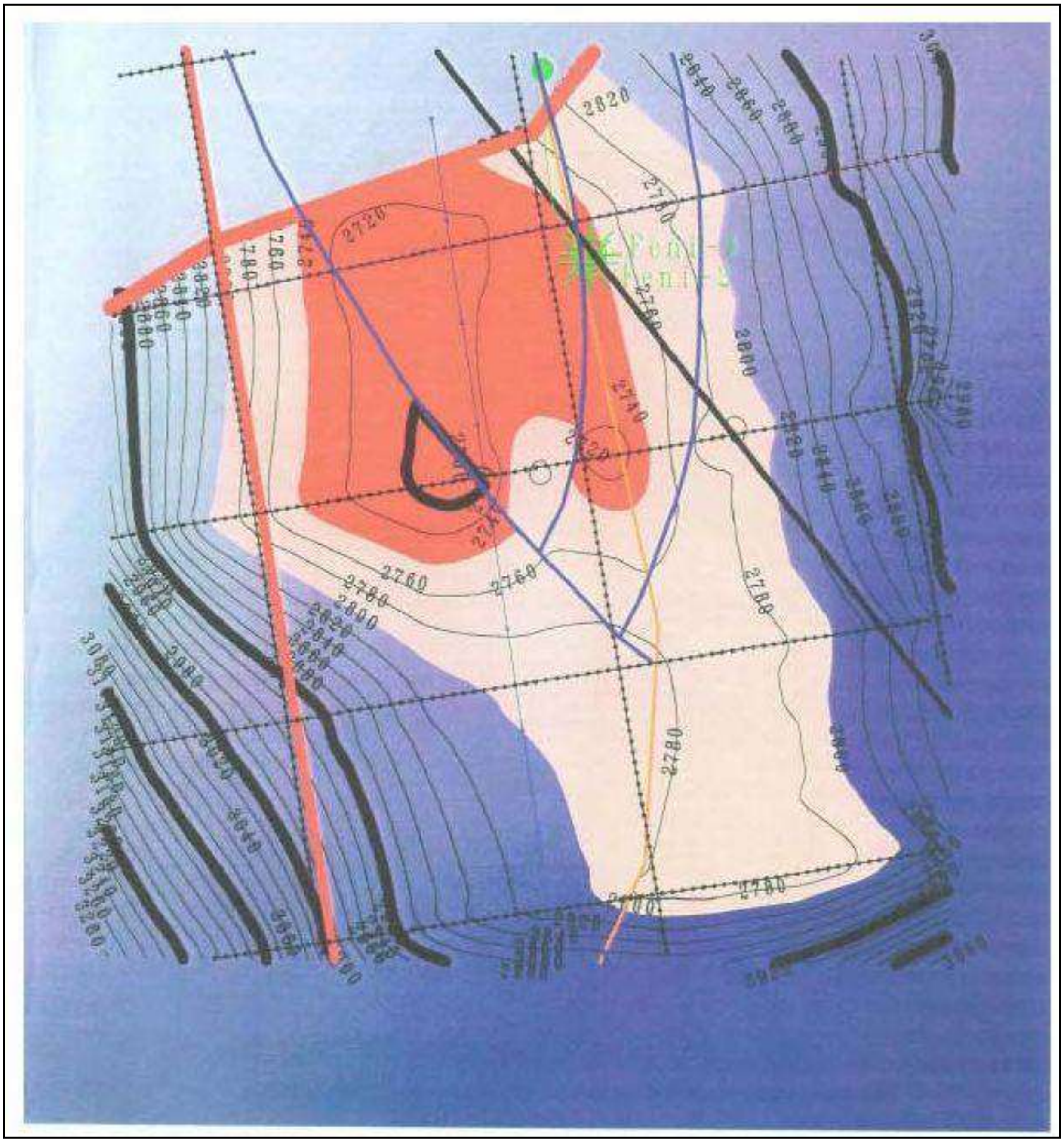


**Figure 6-63 Structure Map on Lower Gas Sand – Feni Gas Field, 2000**
Interpretation by NIKO/BAPEX after the drilling of Feni #2 well (after NIKO/BAPEX, 2000)

6.3.8.3 Reservoir

Only two gas-bearing reservoir sands were identified in the Feni #1 discovery well. The Upper Gas Sand extends from 1756 to 1829m with GWC (gas-water contact) at 1795m. This GWC is also quite well pronounced in seismic line. In some of the studies, the Middle Sand was also considered with a very small reserve.

The gross thickness of Lower Sand is 56m. GCW was observed in log at 2803m. Reservoir parameter was evaluated on the basis of log data.

Well #2 did not encounter the Lower Gas Sand. The well was drilled from the location of Well #1 and deviated about a kilometer towards north. The Well #2 is at a critical depth for drawing a conclusion on the presence or absence of Lower Gas Sand.

In all the earlier studies, the reservoirs were considered to be evenly distributed over the anticline. On the basis of seismic data, the SAPS report mentioned that the GWC for the upper zone is at 1.52 sec. For the Lower Sand, a horizontal refection at 2.06 sec can be considered as GWC. The report also mentioned that the log signature shows a decrease in formation resistivity at -2795m (ss), and GWC was anticipated at this level. The SAPS report also mentioned that the reflector corresponding to the Lower Gas Sand becomes obscure in the south and this might be due to the change in lithology from sandstone to shale. They assumed that reservoir extends only to the north of this area. SAPS structural map on top of Lower Gas Sand shows twin crest. This has largely reduced the gas- bearing area. The area was further reduced due to possible shale-out of the reservoir towards south.

On the other hand, NIKO-BAPEX joint study (2000) showed that the reservoir extends towards south and its extension towards north is terminated by a fault. In well #2, Lower Gas Sand was not encountered and this might lead the joint study team to consider a fault.

On Feni structure, two wells were drilled and cores were cut only in Well # 1 but none from the reservoir section. Porosity and saturation data was based on log evaluation.

The Upper Gas Sand was encountered in both the wells. In well #1, Upper Gas Sand is about 32m thick, and in well# 2 thickness of this sand is only 15m.

In the reserve estimation reports of 1980s, porosity for the upper and lower sands was estimated at 17.5–18.5% and 16–18%, respectively. Water saturation was found to be ranging between 62 and 65% for the upper sand and 52 to 56% for the lower sand. BAPEX estimate used porosity value at 21% for the upper sand and 15.85% for the lower sand. In this estimate water saturation was considered at 56% for Upper and 37% for the Lower sand.

SAPS study re-evaluated logs and used 25% porosity and 45% water saturation for the Upper sand and 16% porosity and 53% water saturation for the lower sand.

NIKO-BAPEX joint study estimated average porosity at 18% and water saturation at 23% for the Upper Gas Sand, and porosity of 12% and 49% water saturation for the Lower Gas Sand.

#### 6.3.8.4 Exploration and Field Development

Taila Sandhani Company defined Feni structure, (earlier known as Sonagazi) after acquiring single fold seismic data during 1975-76 field season and prepared structural contour map. The prospect was selected for exploratory drilling. During this time the name of the structure was changed to Feni. During 1979-80 two multifold analog seismic lines were recorded over the structure and new maps were drawn. The structure was interpreted as an elongated anticline with relatively gentler northern pitch. The west flank was also interpreted to be relatively steeper than the east flank. The closure height at the level of Lower Gas Sand is about 230m.

First well was spudded on 17 June 1980 and terminated at 3200m after encountering high pressure zone. Two gas sands were identified in well logs. In Well #1, in addition to vintage BKZ (Set of resistivity tool) logs, Schlumberger log was also recorded. Both the zones were tested and both flowed gas. The well was completed as a dual producer.

NIKO drilled three new wells in Feni gas field under their joint venture agreement with BAPEX in 2004. The Feni #3, #4, and #5 wells began producing from the deeper K and R Sands in November 2004. The M Sand was produced briefly during February and March 2005 but quickly depleted.

### 6.3.8.5 Well-wise and Sand-wise Production History

Figure 6-64 and Figure 6-65 graphically display the well-wise and sand-wise gas production history of Feni gas field. As the charts show, the first phase of production from Feni gas field ran from September 1991 through mid-1997 when gas was produced from the Upper and Lower Gas Sands. A long hiatus in production occurred from mid-1997 until November 2004. This hiatus was caused by the realization that Feni, along with Chhatak gas field, were only economically marginal. Following the NIKO/BAPEX study in 2000 and the commencement of their JVA, the second phase of gas production at Feni began in 2004 from the deeper K, M, and R Sands. As Figure 6-64 and Figure 6-65 illustrate, production from those deeper sands also began to decline quickly during the period from November 2004 through September 2007.

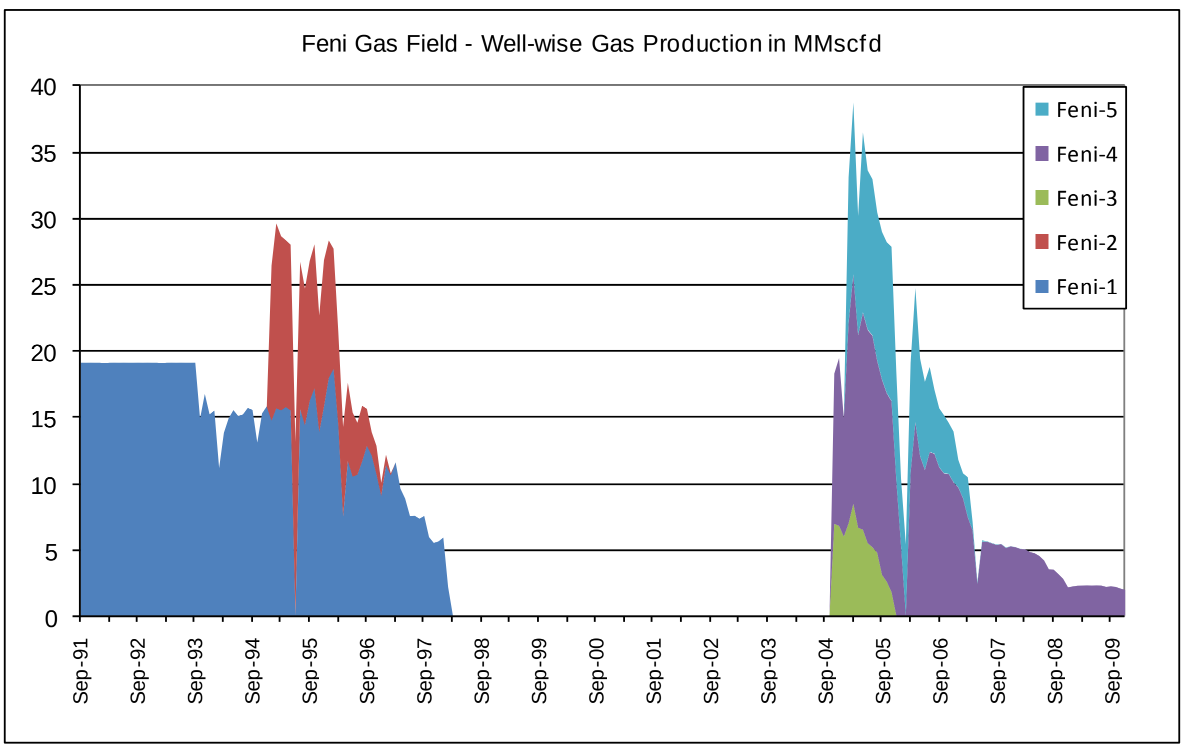



**Figure 6-64 Well-wise Gas Production – Feni Gas Field**

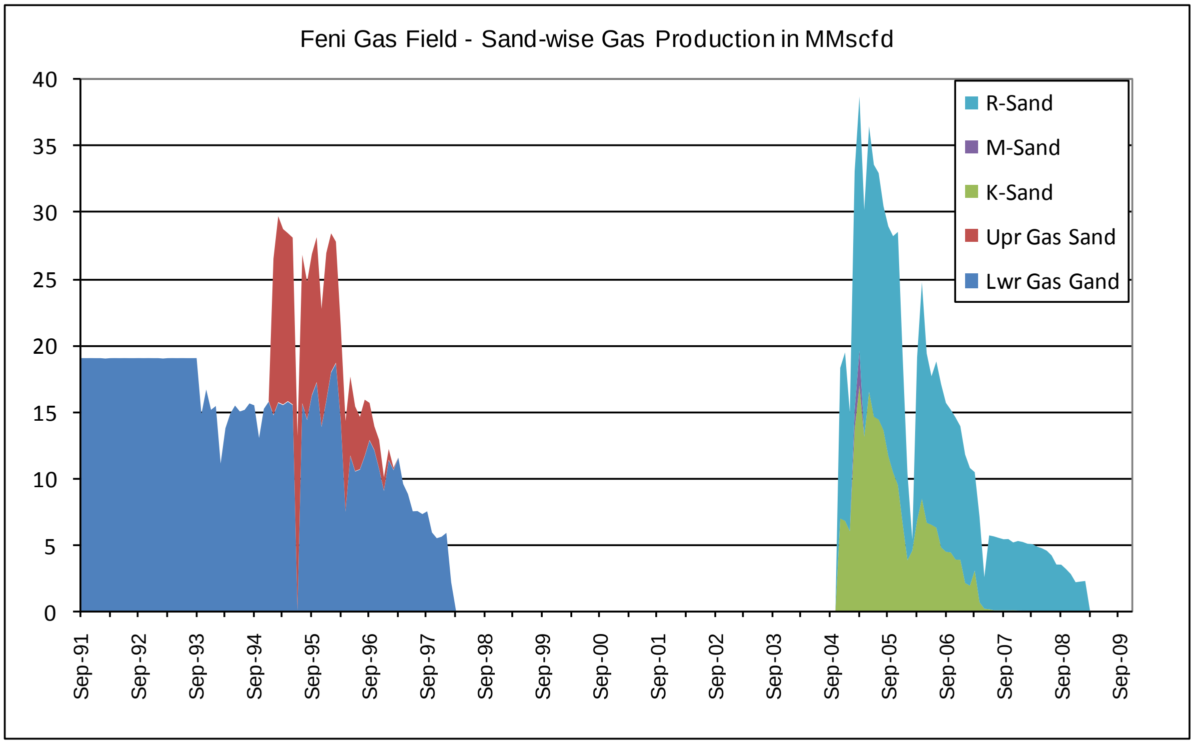



**Figure 6-65 Sand-wise Gas Production – Feni Gas Field**

6.3.8.6 Field-wise Cumulative Production

Table 6-23 summarizes the cumulative production for Feni gas field by reservoir and total field volume. The Lower Gas Sand accounts for slightly less than 55% of the field's total cumulative production, but this zone ceased producing in February 1998. The deeper R Sand, which began producing gas along with the K Sand in November 2004, is the next most important reservoir in the field. The M Sand only produced gas for two months in early 2005 and quickly depleted.

As briefly discussed above, the K, M, and R Sands have been produced by NIKO under their joint venture agreement (JVA) with BAPEX. Production ceased from the K Sand in March 2008 by natural depletion. However, the R Sand was still capable of economic production when it ceased producing in February 2009 following a dispute with the Bangladesh government over paying for lost gas at their other JV field, Chhatak. When production from the R Sand ceased, it was still producing at an average daily rate of 2.2 MMscfd although the daily flow rates were dropping dramatically from a high of 20 MMscfd in May 2005.

**Table 6-23 Sand-wise Cumulative Gas Production – Feni Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Upper Gas Sand | 6.1 |
| Lower Gas Sand | 34.2 |
| K Sand | 7.1 |
| M Sand | 0.1 |
| R Sand | 15.3 |
| **Total** | **62.8** |

1 Production through end of December 2009
HCU production database

### 6.3.8.7 Earlier Reserve Estimates

The First post discovery estimate by Pavlov et al. (1981) placed the GIIP at 244 Bscf with 67 Bscf under proven and 177 Bscf under probable reserve. No possible reserve was indicated.

Second estimate (1985) placed the GIIP at 454 Bscf out of which proven category accounted for 38 Bscf in the Upper Zone and 77 Bscf in the Lower zone. Probable GIIP in the Upper zone was estimated at 110 Bscf and that for Lower zone was 229 Bscf. Total condensate reserve was estimated at 1.011 MMbbl of which 0.342 MMbbl is under proven category. No possible reserve was indicated. According to the authors, reservoir thickness and area were the two main factors for upside revision of the reserve.

The German Geological Advisory Group in Petrobangla studied the discovered gas fields including Feni. According to this study, the most likely GIIP of the Upper zone was 93 Bscf and that for the Lower zone was 195 Bscf. The condensate reserve was estimated at 0.78 MMbbl with Lower Sand accounting for 0.53 MMbbl. GGAG followed both probabilistic and deterministic methods. Details of the result of this study are given as Table 6-24.

**Table 6-24 German Geological Advisory Group Reserve Estimate**

| Gas Sand | Probabilistic Method | | | Deterministic Method | |
|---|---|---|---|---|---|
| | Maximum | Most Likely | Minimum | Mean | RMS |
| Upper Zone | 108.2 | 92.5 | 78.2 | 92.4 | 92.4 |
| Lower Zone | 271.5 | 195.2 | 150.2 | 201.4 | 201.8 |
| Total GIIP | 379.7 | 287.7 | 228.4 | 293.8 | 294.2 |
| Reserve Up | 86.5 | 69.4 | 56.0 | 69.9 | 70.0 |
| Reserve Lr | 211.8 | 146.4 | 109.7 | 151.4 | 152.0 |
| Total Reserve | 298.3 | 215.8 | 165.7 | 221.3 | 221.9 |

In the same year, HHSP estimated GIIP of Feni at 19.8 Bscf under undifferentiated proven and probable category. According to this estimate, Lower Sand accounted for 16.5 Bscf and the Upper Sand accounted for 2.4 Bscf. HHSP considered one Middle Sand with a GIIP of 0.9 Bscf. According to this study condensate reserve was 0.076 MMbbl. This study used 24 fold digital seismic data recorded over the structure.

In 1989, Gasunie Engineering did a study on the gas reserve of the country. According to this study recoverable reserve of Feni was 50 Bscf under proven, 106 Bscf under expected and 135 Bscf under high category. Upper Sand contained 15 Bscf and the Lower sand 35 Bscf of proven reserve. No proven reserve was estimated for the third sand. Under expected category reserve of Upper Sand was 25 Bscf and that for Lower sand it was 80 Bscf. Third Sand accounted for 1 Bscf only. According to the author/s expected category included both Proven and probable reserve. Under High category the reserve increases to 135 Bscf with 100 Bscf in the Lower Sand and 30 Bscf in the Upper sand.

In 1991, BAPEX prepared new structural maps on top of Upper and Lower gas sands (Figure 6-60) and re-estimated the reserves of Feni field. This study placed the Proved GIIP of Upper Sand at 22.1 Bscf and that for Lower Sand at 42.7 Bscf. Probable GIIP of Upper Sand was estimated to be 22 Bscf and that for Lower Sand at 45.1 Bscf. No possible GIIP was assigned to the Upper Sand. However based on seismic data 455.4 Bscf of GIIP under possible category was estimated for the Lower Sand. Total GIIP under proven and probable category amounted to 131.9 Bscf. In September 1991, Feni Gas Field started production.

SAPS Team for the Overseas Economic Cooperation Fund, Japan (OECF) in 1993 studied Feni and Bakhrabad gas fields. They prepared a new map of Feni structure (Figure 6-61) and according to this study GIIP of Upper Sand was 53.4 Bscf and that for Lower Sand is 55.7 Bscf. Condensate reserve was estimated to 0.132 MMbbl under proven and probable category. Possible GIIP accounted for another 1.51 MMbbl condensate. SAPS Team prepared new maps on both the gas sands. According to them, the strong seismic reflector corresponding to Lower Gas sand becomes obscure towards south and it was due to change of lithology. For the estimation of gas bearing area, SAPS Team did not consider this part. This resulted in significant reduction of GIIP of Lower Sand.

Comparison of all these estimates is given in Table 5-25 below. The table shows that estimate made by HHSP (1986) is the lowest one. However, this can be considered not valid as cumulative production logged 6.12 Bscf from Upper sand and 32.08 Bscf from Lower Sand. It also appears that the estimates made in 1989 and afterward has some consistency as far as proven and probable GIIP are concerned.

Feni Well #2 was drilled in 1994 and the well went into production in 1995. Production from this field was suspended in 1998 due to high water production rate. At this time cumulative production logged 39.5 Bscf.

**Table 6-25 Comparison of Previous Reserve Estimates – Feni Gas Field (in Bscf)**

| Zone | Reserve Category | Authors | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | PB 81 | PB 85 | GGAG 68 | HHSPP, 86 | Gasunie*, 89 | BAPEX 91 | Gasunie*, 92 | SAPS 93 |
| Upper | Proven | 25 | 38 | | 2.4 | 15 | 22.1 | | 53.4 |
| | Probable | 50 | 110 | | | 10 | 22.0 | | |
| | Possible | | | | | 5 | | | |
| | Total | 75 | 148 | 92 | 2.4 | 30 | 44.1 | | 53.4 |
| Middle | Proven | | | | 0.9 | | | | |
| | Probable | | | | | 1 | | | |
| | Possible | | | | | 4 | | | |
| | Total | | | | 0.9 | 5 | | | |
| Lower | Proven | 42 | 77 | | 16.5 | 35 | 42.7 | | 55.7 |
| | Probable | 127 | 229 | | | 45 | 45.1 | | |
| | Possible | | | | | 20 | 455.4 | | |
| | Total | 169 | 306 | 201 | 16.5 | 100 | 543.2 | | 55.7 |
| Field Total (2p) | | 244 | 454 | 293 | 19.8 | 106 | 131.9 | 132 | 109.1 |
| Field Total (3p) | | | | | | 135 | 587.3 | | |

HCU-NPD 2003 *Recoverable

NIKO Resources of Canada did a study on Feni field jointly with BAPEX and the result of that study is given in Table 6-26.

**Table 6-26 NIKO-BAPEX 2000 Reserve Estimate - Feni Gas Field (in Bscf)**

| Gas Sand | P 10 | P 50 | Mean | P 90 | Remarks |
|---|---|---|---|---|---|
| Upper Zone | 6 | 9 | 10 | 14 | |
| Lower Zone | 54 | 102 | 115 | 193 | |
| Total | 60 | 111 | 125 | 207 | Unrisked |
| | 36 | 66.6 | 75 | 124.2 | Risked |
| Remaining Reserve | 20.5 | 72 | 86 | 168 | Unrisked |
| | | 27.6 | 36 | 85 | Risked |
| NIKO-BAPEX 2000 | | | | | |

All the studies, except the last one, i.e. NIKO-BAPEX joint study, were based on single well data. Probabilistic approach was followed for the studies by GGAG (1986), Gasunie (1989) and NIKO-BAPEX (2000).

The difference between BAPEX '91 and SAPS study for the Upper Zone is mainly because of difference in area, net thickness and saturation. In all the three cases BAPEX parameters are conservative than that of SAPS study. Considering produced volume it appears that the estimate for the Upper Sand by BAPEX and SAPS are on the low side. Same is the case with NIKO-BAPEX Joint study. If risked volume is considered then the reserve figures for Upper Sand (NIKO-BAPEX) becomes impractical.

For Lower Sand BAPEX used TDT log together with openhole logs for determining gas water contact and settled for the TDT result, which indicates no water contact. SAPS study used openhole log only and they anticipated from decrease in formation water resistivity that the GWC could be at 2795m. NIKO-BAPEX considered GWC at 2805m.

In 2003, the HCU-NPD re-estimated the reserves for Feni gas field. The GIIP was re-estimated after modifying maps prepared by the authors of SAPS report. GIIP (2P) of Upper Gas Sand was estimated at 52.6 Bscf, and Lower Gas Sand the GIIP (2P) was estimated at 132.6 Bscf for a combined Total GIIP (2P) of the field of 185.2 Bscf. The study estimated that a Recovery factor at 70% would result in a recoverable reserve of 129.64 Bscf gas.

#### 6.3.8.8 2010 Reserve Re-Estimation (This Report)

For this report, the previous estimates were reviewed, and the 2003 estimate was judged to be reliable.

### 6.3.9 Habiganj (3)

#### 6.3.9.1 Geologic Setting

Habiganj gas field is located on the northernmost culmination of Baramura anticline of the Eastern Foldbelt within Block 12. The field lies between Titas gas field to the southwest and Rashidpur gas field to the northeast (Figure 6-3). The Baramura anticline extends into the Indian State of Tripura. Habiganj structure is separated from Baramura gas field by a saddle along the fold axis. In the Indian part, the Upper Gas Sand of Habiganj is exposed. Habiganj field was discovered in 1963.

#### 6.3.9.2 Structure

The Habiganj structure was first defined by seismic survey shot during 1962 by PSOC. The area is represented by low hills covered by arenaceous rocks of Tipam Sand Stone and Dupi Tila formation of Plio-Pleistocene age. Subsurface structure is mapped as an elongated egg-shaped structure with a relatively steeper east flank. Gas-water contact was observed in the singlefold seismic data. This is believed to be due to high porosity (30%) and high gas saturation.

Figure 6-66 and Figure 6-67 are depth structure maps on the top of the Upper Gas Sand and Lower Gas Sand, respectively. Both maps are late vintage maps dating from 2001 to 2007.

#### 6.3.9.3 Reservoir

The reservoir rocks of the gas field are sandstones that can be divided into two units, Upper Gas Sand and Lower Gas Sand. The Lower Gas Sand is further divided into two units.

The Upper Gas sand is represented by a thick massive sandstone sequence. The gas column in the Upper Gas Sand is over 250m. The sandstone is an ideal reservoir with porosity ranging from 29% to 33% and permeability measured in Darcies. The reservoir rock is poorly cemented as observed in core samples.

The depositional model of the Upper Gas Sand is one of high-energy beach and barrier bars stacked on top of another during the course of marine transgression. The rate of deposition kept pace with the rising sea level.

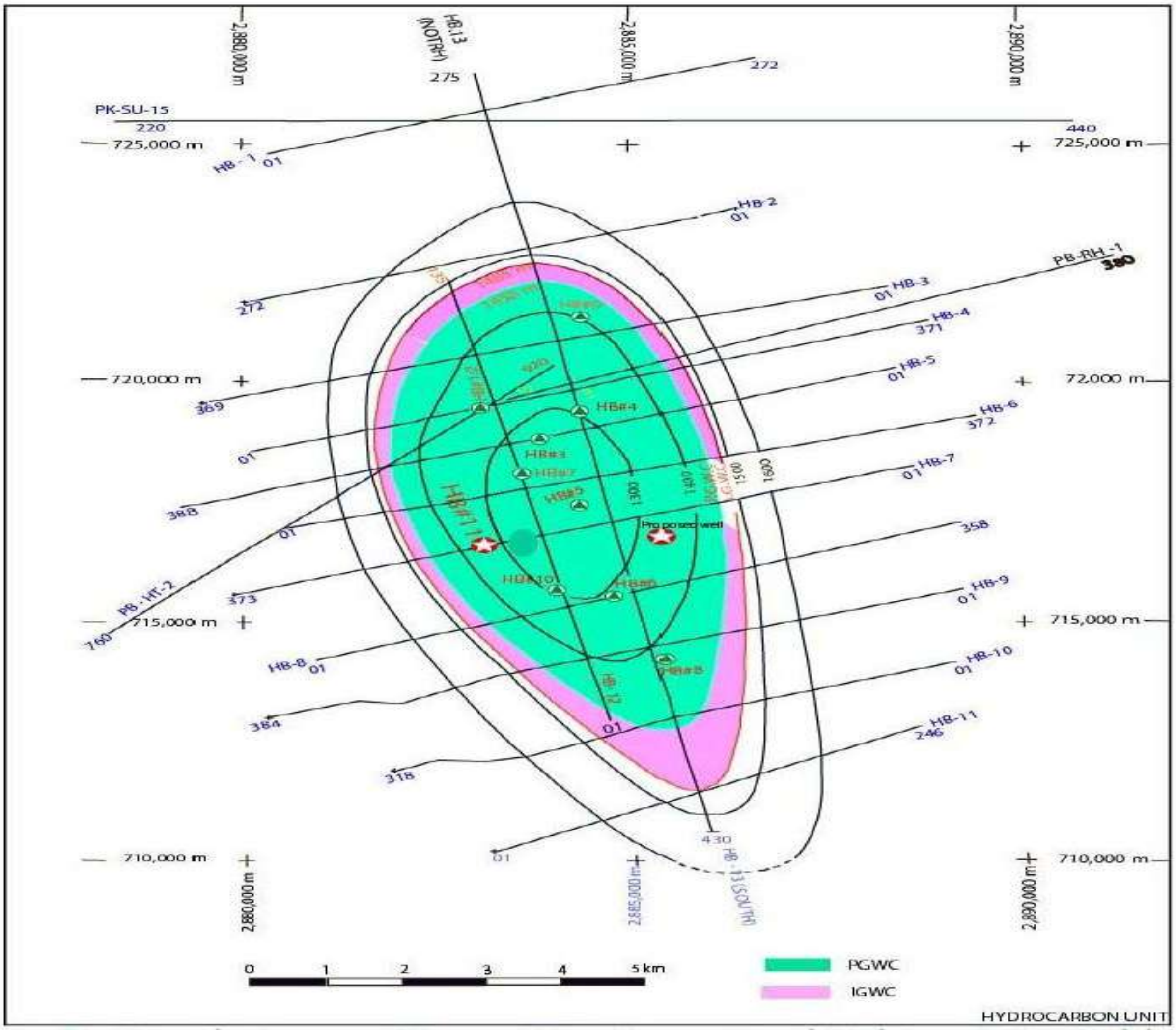



**Figure 6-66 Depth Structure on Top of Upper Gas Sand – Habiganj Gas Field**

Map based on results of the first ten wells. Original GWC (-1485m) is shown in magenta. The GWC at time map was constructed (vintage 2001) is shown in green at elevation of -1458m. Proposed locations for HBG #11 and another future well are shown by red circles enclosing white stars. Wells 1-10 are completed in the Upper Gas Sand. Well #11 is completed in the Lower Gas Sand (courtesy BGFCL, HCU, 2001).

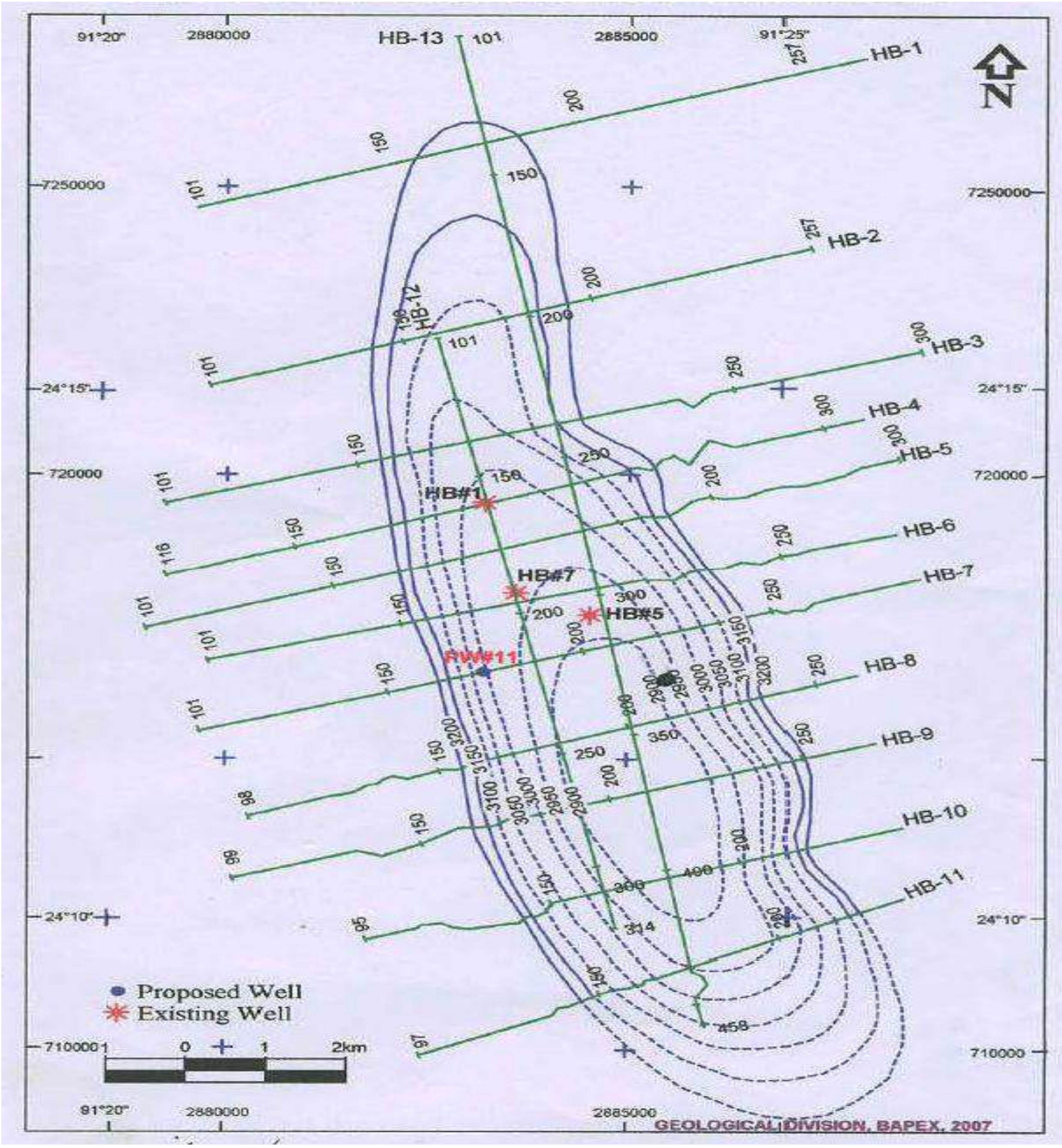



**Figure 6-67 Depth Structure on Top of Lower Gas Sand – Habiganj Gas Field**

Map based on the results of the first 11 wells following the drilling of Habiganj #11 well (shown by red label). Well #11 is the only well completed in the Lower Gas Sand. Proposed future location shown by black circle on east flank of the structure (after BAPEX, 2007).

#### 6.3.9.4 Exploration and Field Development

Two gas sands were discovered by the first well (Habiganj #1) and both were tested. During the test, Lower Gas Sand flowed gas at a rate of 15.8 MMscfd and the Upper sand flowed at a rate of 17.3 MMscfd. Habiganj 2, located only 30 meters from Well 1, was drilled to 1555m. The Upper Gas Sand was also tested in this well. In both of the wells the gas water contact was found and is also quite prominent in singlefold analog seismic data. According to PSOC, the GIIP of the field was 1280 Bscf. Both Well #1 and #2 were completed in the Upper Gas Sand.

Gas production from Habiganj started in February 1969. During the first decade, production was quite low and fluctuated. From the beginning of 1981, production rate was increased to about 25 MMscfd from both Wells #1 and #2. Due to close distance, Well #1 and #2 practically functioned as a single well and each had a similar production history.

Second phase of development of the field was implemented by Petrobangla during 1984 when Well #3 and #4 were drilled. In 1985, both wells started production from the Upper Gas Sand. Well #5 was drilled to a depth of 3521m. As the log response from the Lower Gas Sand was not encouraging, the well was completed in the Upper Gas Sand. In July 1992, the number of producing wells increased to 7 and daily production increased to 164 MMscfd. Another three wells were drilled and those started production in April/May 2000 and as a result, the field production crossed 200 MMscfd mark. By the year 2000, the total number of development wells increased to 11. In May 2004, production crossed 300 MMscfd mark and this rate continued for about six months and then it started to decline. In December 2009, field production was 226 MMscfd and a total of 1671 Bscf had been produced from the field.

#### 6.3.9.5 Well-wise and Sand-wise Production History

Well-wise production for Habiganj gas field is graphically provided in Figure 6-68. Wells #1 through #10 produce from the Upper Gas Sand. Only well #11 produces from the Lower Gas Sand. Sand-wise production for Habiganj gas field is shown in Figure 6-69, which graphically shows that the Lower Gas Sand accounts for only a minor fraction of total field gas production.

Detailed individual well histories and accompanying production charts for Habiganj wells are included in The Annex.

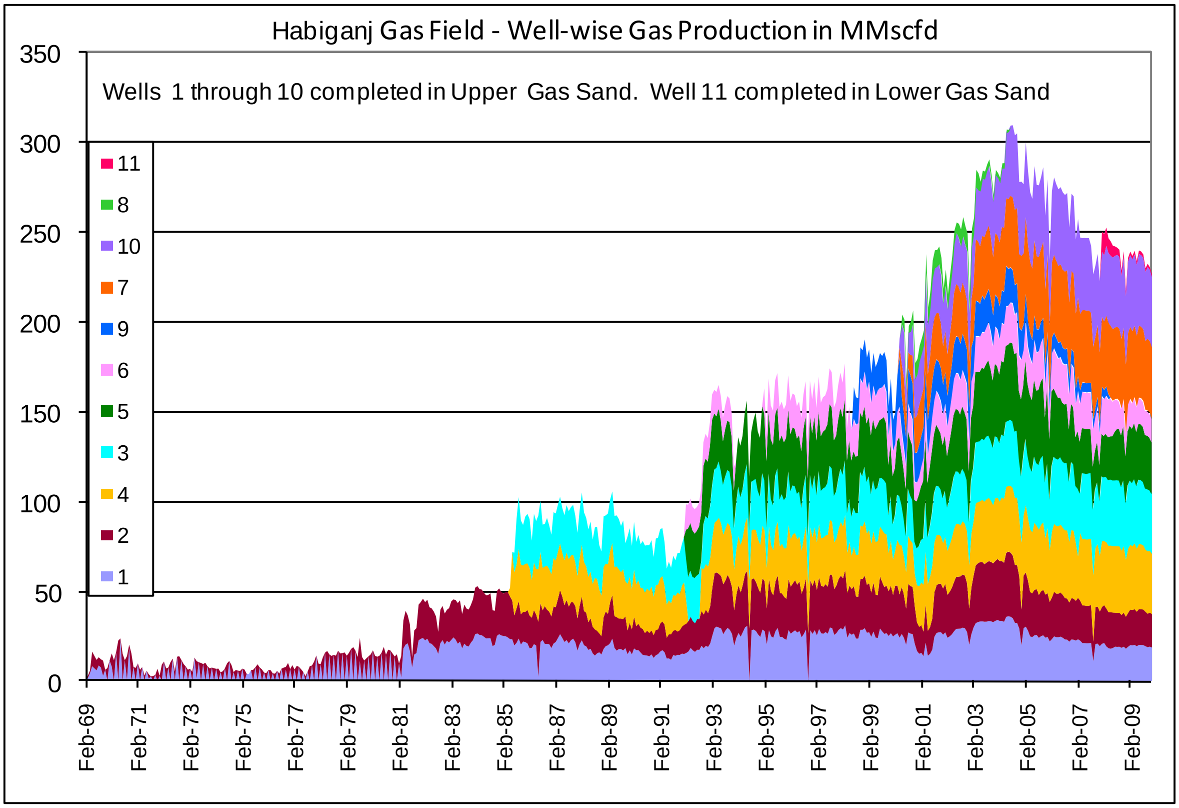



**Figure 6-68 Well-wise Gas Production – Habiganj Gas Field**

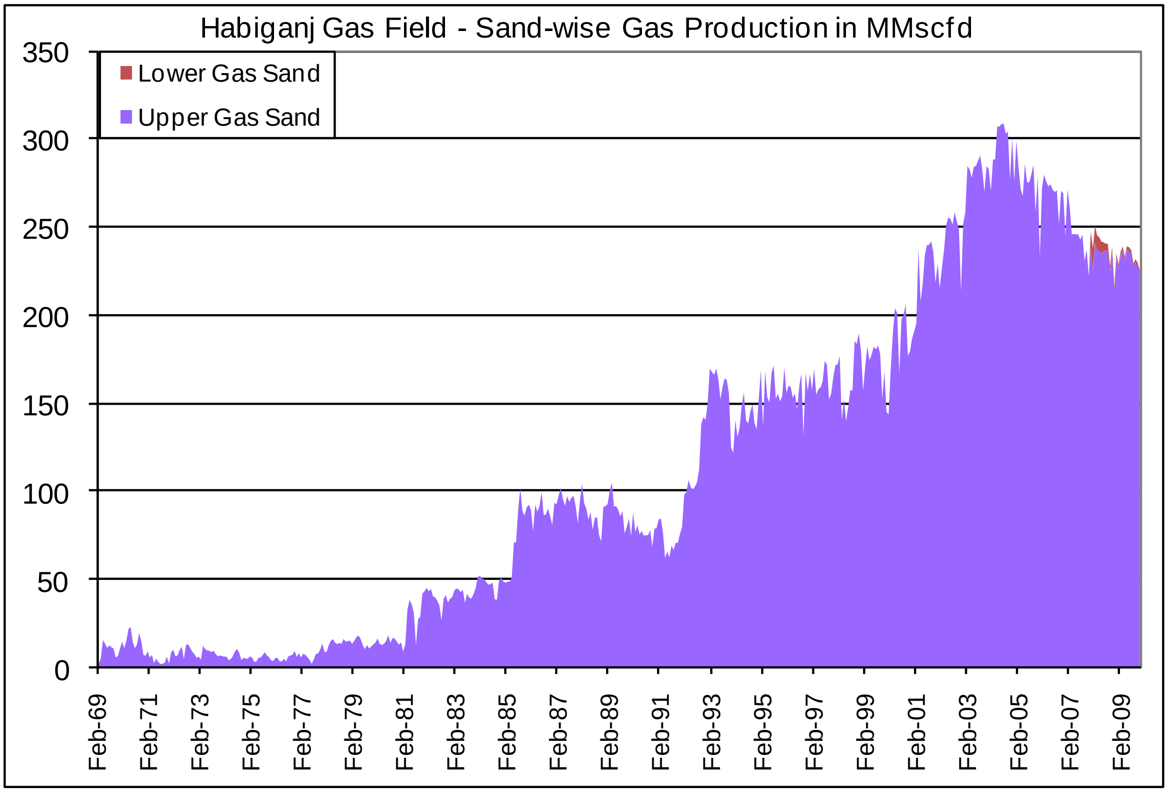



**Figure 6-69 Sand-wise Gas Production – Habiganj Gas Field**

6.3.9.6 Field-wise Cumulative Production

Over its 41-year productive life, Habiganj gas field has produced 1,671 Bscf of gas, 90 thousand barrels of condensate, and 8.1 million barrels of water from five separate sandstone intervals. The field is currently (December 2009) producing at a daily rate of 226 MMscfd of gas, 12 barrels of condensate, and 120 barrels of water.

As summarized in Table 6-27 over 99% of the reserves have been produced from the Upper Gas Sand with only 3 Bscf coming from the Lower Gas Sand through the end of 2009.

**Table 6-27 Sand-wise Cumulative Gas Production – Habiganj Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Upper Gas Sand | 1667.9 |
| Lower Gas Sand | 3.0 |
| **Total** | **1670.9** |

1 Production through end of December 2009
HCU production database

### 6.3.9.7 Earlier Reserve Estimates

PSOC initially estimated the gas reserve of Habiganj field after discovery of gas in 1963. Since then a number of reserve studies were conducted by a number of workers. Results of these estimates are provided in Table 6-28.

**Table 6-28 Comparison of Previous Reserve Estimates – Habiganj Gas Field**

| **Murtaza et. al. 1984 ( Bscf)** | | | | | |
|---|---|---|---|---|---|
| Reservoir | Proven | Probable | Possible | Total | |
| UGS | 170 | 1220 | 860 | 2250 | |
| LGS | 10 | 90 | 370 | 470 | |
| Total | 180 | 1310 | 1230 | 2720 | |

| **Eder & Taolad, 1984 (Bscf)** | | | | | |
|---|---|---|---|---|---|
| Field Total | Min | Most Likely | Max | Mean | RMS |
| Gas | 784 | 1437 | 2017 | 1315 | 1321 |
| Condensate | 26.6 | 51.4 | 72.2 | | |

| **GGAG, 1986 (Bscf)** | | | | | |
|---|---|---|---|---|---|
| Reservoir | | Min | Most Likely | Max | Mean |
| UGS | GIIP | 1063 | 1926 | 2522 | 1757 |
| | Reserve | 744 | 1445 | 2017 | 1318 |
| LGS | GIIP | 0* | 368 | 776 | 517 |
| | Reserve | 251 | 386 | 605 | 388 |

*per "Bangladesh Gas Reserve Estimation 2003."

| **HHSP, 1986 (Bscf)** | | | | |
|---|---|---|---|---|
| Reservoir | GIIP | | | |
| UGS | 2677 | | | |
| LGS | 308 | | | |
| Total | 2985 | | | |

| Gasunie Engineering B.V. , 1989 (Bscf) | | | | |
|---|---|---|---|---|
| | Proven | Expected | High | |
| Reserve | 1200 | 2600 | 3300 | |
| IKM, 1991 (Bscf) | | | | |
| | Proven | Expected | High | |
| GIIP | 1200 | 2600 | 3300 | |
| **Welldrill, 1991 (Bscf)** | | | | |
| GIIP | UGS | 3630 | | |
| GIIP | LGS | 80 | | |
| GIIP | Total | 3710 | | |
| **HCU-NPD, 2003 (Bscf)** | | | | |
| GIIP | UGS | Proven | 5105 | |
| | LGS | Proven | 39 | |
| GIIP | Total | Proven | 5144 | |

| RPS-Petrobangla, 2009[1] (Bscf) | | | |
|---|---|---|---|
| Reservoir | Petrel (static-volumetric) | Eclipse (Dynamic Flow Simulation Model) | |
| | (P50) GIIP | GIIP | Remaining Reserves (end 08) |
| UGS | 2985 | 3543 | 1037 |
| LGS1 | 85 | 101 | 30 |
| LGS2 | 33 | 39 | |
| Total | 3103 | 3684 | 1067 |

[1] RPS, 2009e

### 6.3.9.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Habiganj field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

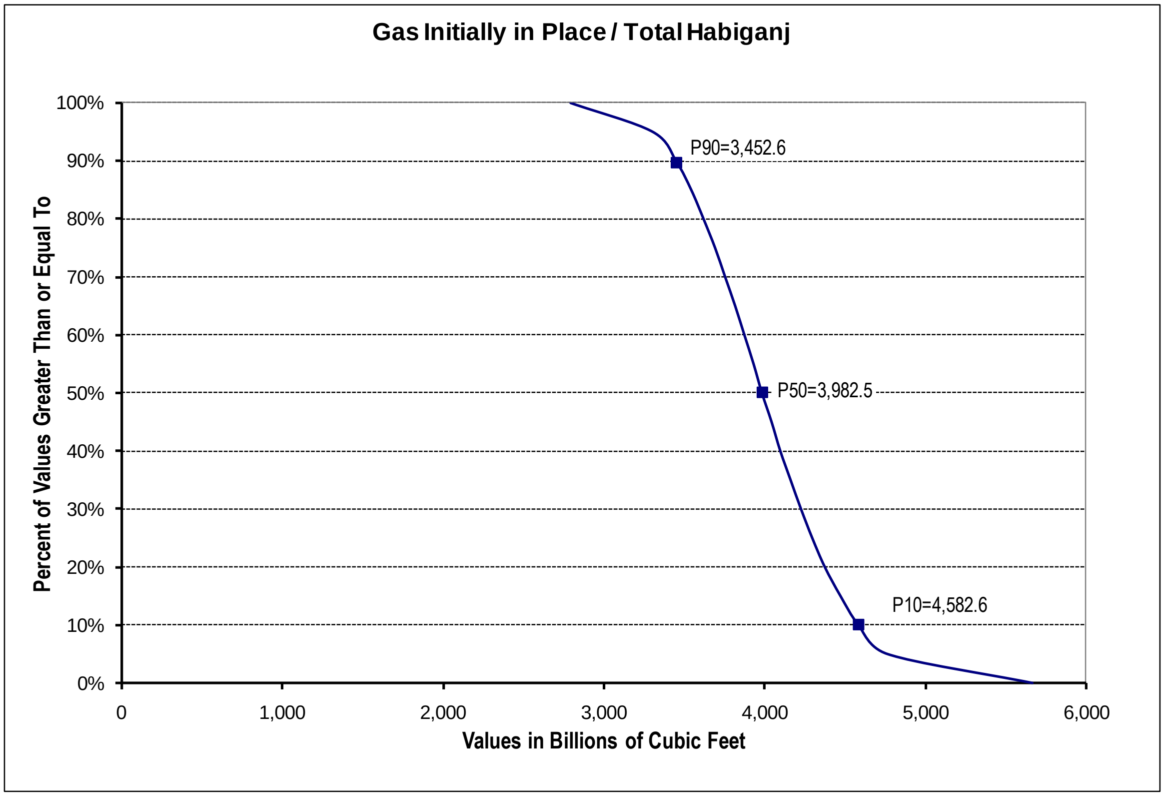



**Figure 6-70 Distribution of GIIP, Habiganj**

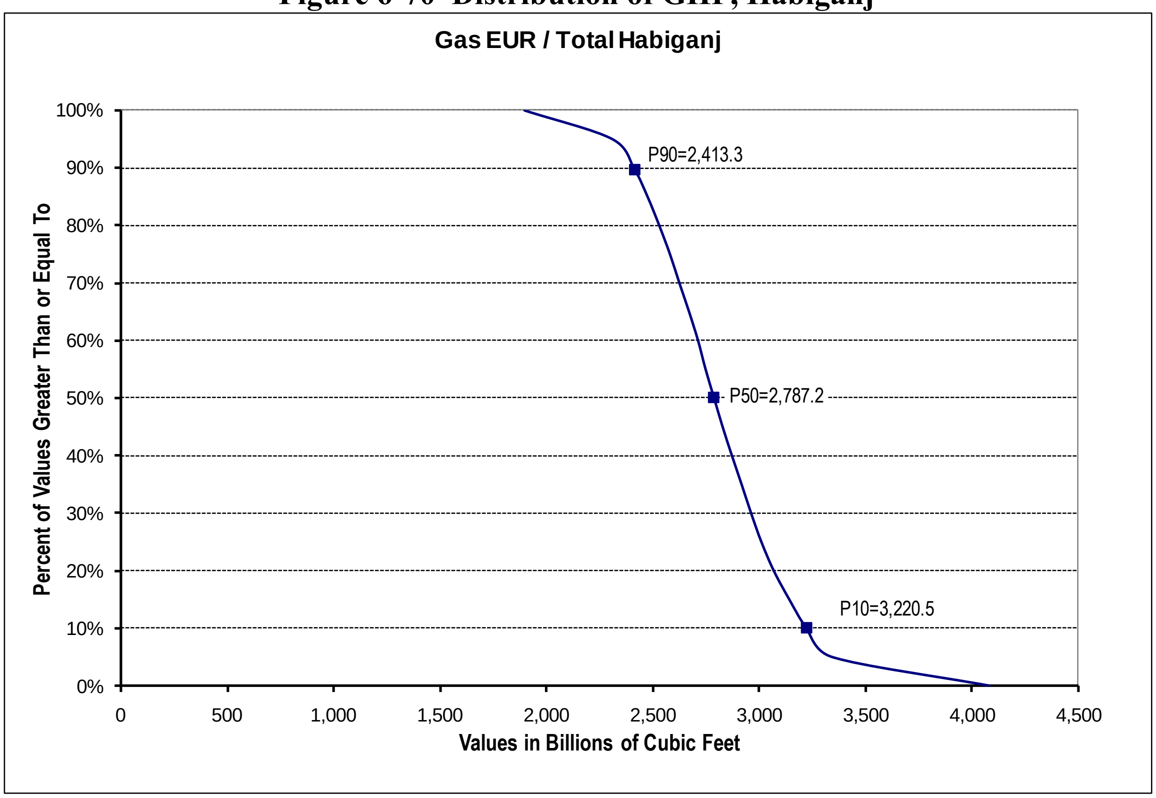



**Figure 6-71 Distribution of Gas EUR, Habiganj**

**Table 6-29 Summary of Estimated Ultimate Recovery at Habiganj**

| Reservoir | Mean Gas EUR, BCF | Cumulative Gas Production, BCF | Reserves, at 1/1/2010, BCF |
|---|---|---|---|
| Upper Sand | 2,643 | 1,668 | 975 |
| Lower Sand | 159 | 3 | 156 |
| **TOTAL** | **2,802** | **1,671** | **1,131** |

For the Upper Sand at Habiganj, reservoir pressure data were available and a p/z analysis was conducted. This analysis indicated a much higher gas in place and Estimated Ultimate Recovery (EUR) than the volumetric analysis for the reservoir, 11.7 TCF as compared to 2.6 TCF (Figure 6-72). This is as expected due to the water drive mechanism for this reservoir. **This method is not considered reliable for this reservoir.**

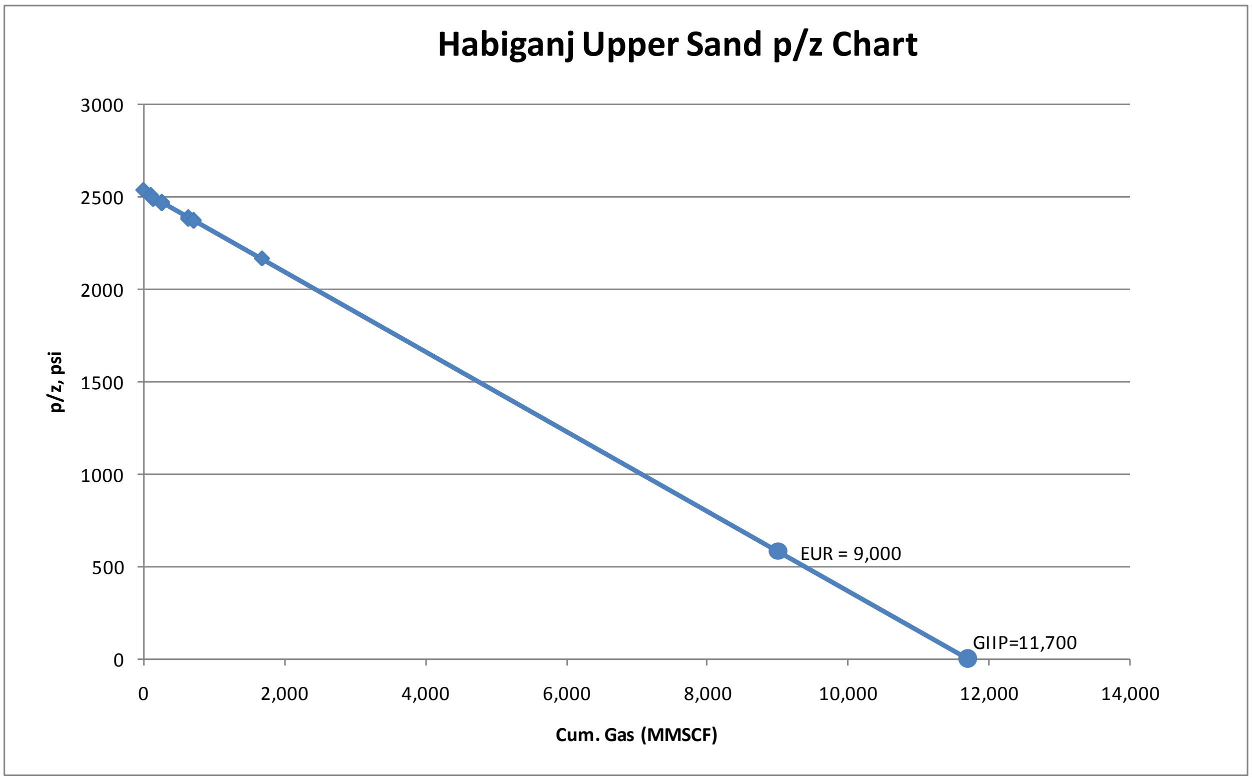



**Figure 6-72 p/z Chart for Habiganj Upper Sand**

An alternate formulation of the gas material balance was also attempted using this data, which accounts for water influx. This method also resulted in an unrealistically high estimate of GIIP, indicating that the ratio of the effective radius of the aquifer to the radius of the gas reservoir is very large.  In this case, this methodology is also invalid.  The Approximate Wellhead Flowing Material Balance method is also invalid for a strong water drive reservoir.  A history match of field performance using a finite-difference reservoir simulator would be a valid method of reserve estimation for this field, but is beyond the scope of this study.  We have compared our volumetric estimates of GIIP to those documented by RPS in 2010 for this field, and found them to compare reasonably well to RPS's estimates using both the volumetric and reservoir simulation estimates.

We note that Well HB #11 is the only well that has been completed in the LGS, and that this well has been producing lower gas rates and higher water rates in recent time.  We suggest that to produce all the remaining reserves in the LGS, it may be necessary to perform diagnostic measures such as cased hole logging on this well to identify possible remedial actions to reduce water production.  Alternatively, it should be possible to recomplete this reservoir in additional wells located higher on the structure.

### 6.3.10 Jalalabad (4)

#### 6.3.10.1 Geologic Setting

The Jalalabad gas field is located in the Surma basin of northeastern Bangladesh in the eastern part of the Eastern Foldbelt, about 200 km northeast of Dhaka (Figures 6-2 and 6-3).  It is located in a cluster of three gas fields that include Sylhet and Kailash Tila.  Jalalabad is located just to the west of Sylhet and to the northwest of Kailash Tila.  The Jalalabad structure is the southwestern most dip-closed feature within the Jalalabad-Sylhet-Dupi Tila anticlinorium (DeGolyer and MacNaughton, 1999).

The Surma basin occupies the northeastern part of the Bengal foredeep basin.  At the beginning of Eocene Time, deltaic sands and shales prograded into the Bengal basin as the region subsided.  Clastic sediments accumulated in a shallow marine environment during this period that persisted until the Pliocene.  Alluvial deposits covered the older shallow marine sediments during the

Pliocene-Pleistocene. Sandstones of Middle Miocene Bhuban and Upper Miocene Bokabil Formations constitute the primary gas reservoirs of the Jalalabad field.

### 6.3.10.2 Structure

The Jalalabad structure was delineated by Petrobangla with German technical assistance prior to 1987. Two-dimensional (2-D) seismic data obtained over the Jalalabad anticline in 1980 was used to identify a large elongated anticline with a NW-SE trend, with associated longitudinal normal and reverse faults near the crest. The productive area of the field follows the trend of the anticline for about eight kilometers. A major south-dipping thrust fault trends NE-SW within the field. The structure plunges to the southwest. Figure 6-74 through Figure 6-75 are structure and net gas isopach maps drawn on top of the three main reservoirs.

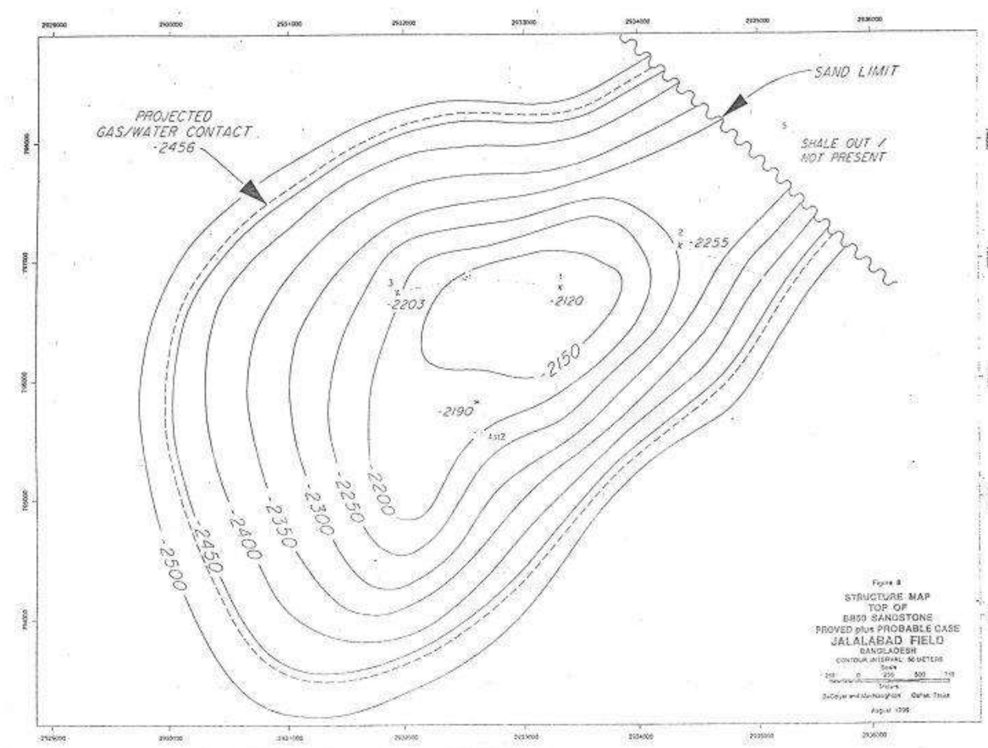
Folding of strata in the Surma basin started at the end of the Oligocene due to collision of the Indian and Arabian plates. Four periods of folding and faulting took place in the Bengal/Surma basin during the Alpine orogeny resulting in elongated narrow folds in the Surma basin strata.

### 6.3.10.3 Reservoir

Exploratory drilling in the Jalalabad field between 1989 and 1999 identified several sandstone gas reservoirs in the Bokabil Formation. The BB20, BB50, BB60, and BB70 sands are the major producing reservoirs. The BB80 sand was tested but no flow was recorded. Test results for sand in the underlying Bhuban Formation (BH40) are unknown. Minor Bokabil sands of questionable gas production potential are also present (BB30, BB35).

In the vicinity of the Jalalabad #5 well, 200 meters of strata in the BB50 and BB60 intervals has been eroded and replaced with so-called “valley fill” sediments. Petrophysical analyses indicate that the valley fill sediments are not hydrocarbon-bearing. Lower sand horizons may grade laterally into shale towards the northeast.

Net reservoir thickness, porosity, and water saturation were determined from petrophysical analyses of available wireline geophysical logs and well test data. Average porosity of the reservoir sands in the Jalalabad field ranges from 16.6% to 22.6%. Porosity is fairly uniform but tends to decrease down section. Water saturation in the reservoirs ranges from 27.2% to 46.9%.



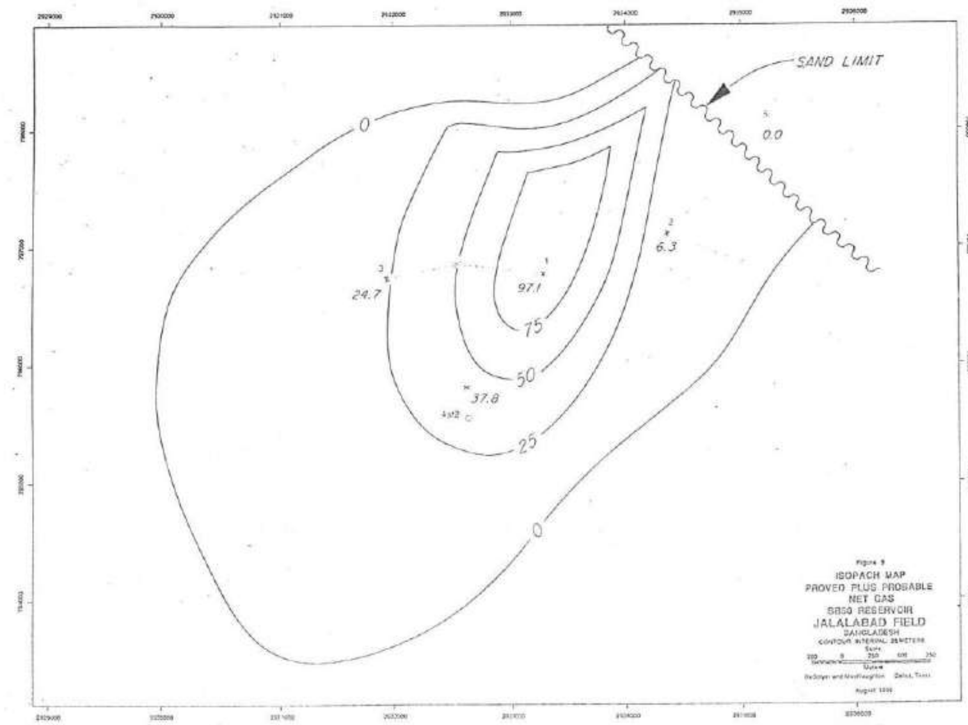
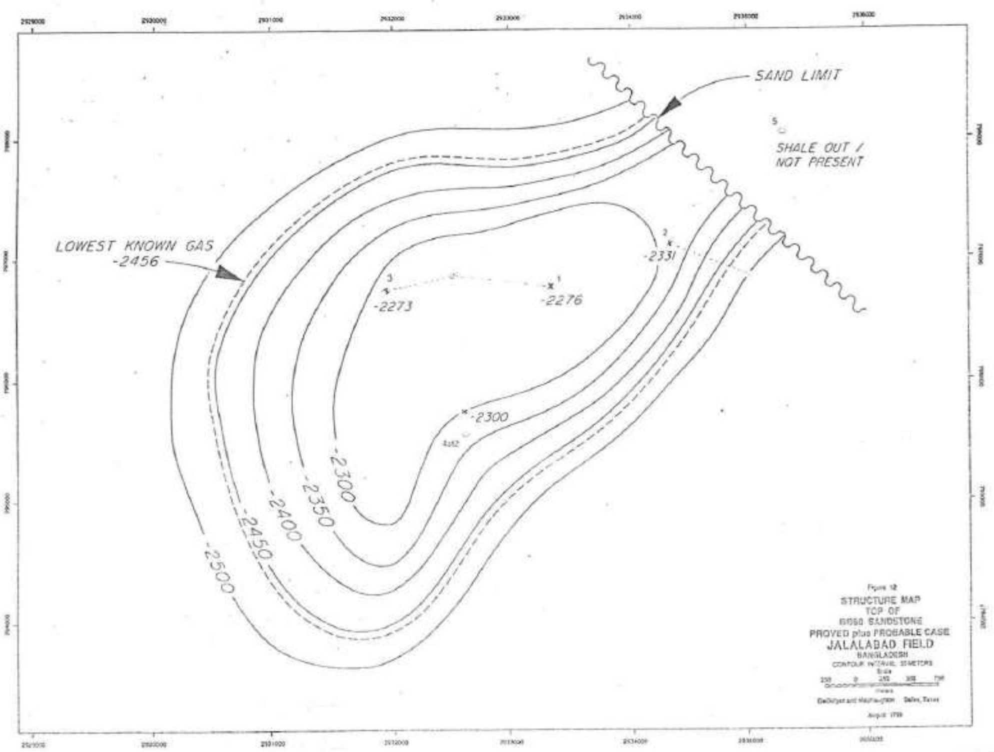



**Figure 6-73 Structure and Net Gas Isopach Maps – BB50 Reservoir – Jalalabad Gas Field**
Based on 2P Reserves (after DeGolyer and MacNaughton, 1999).



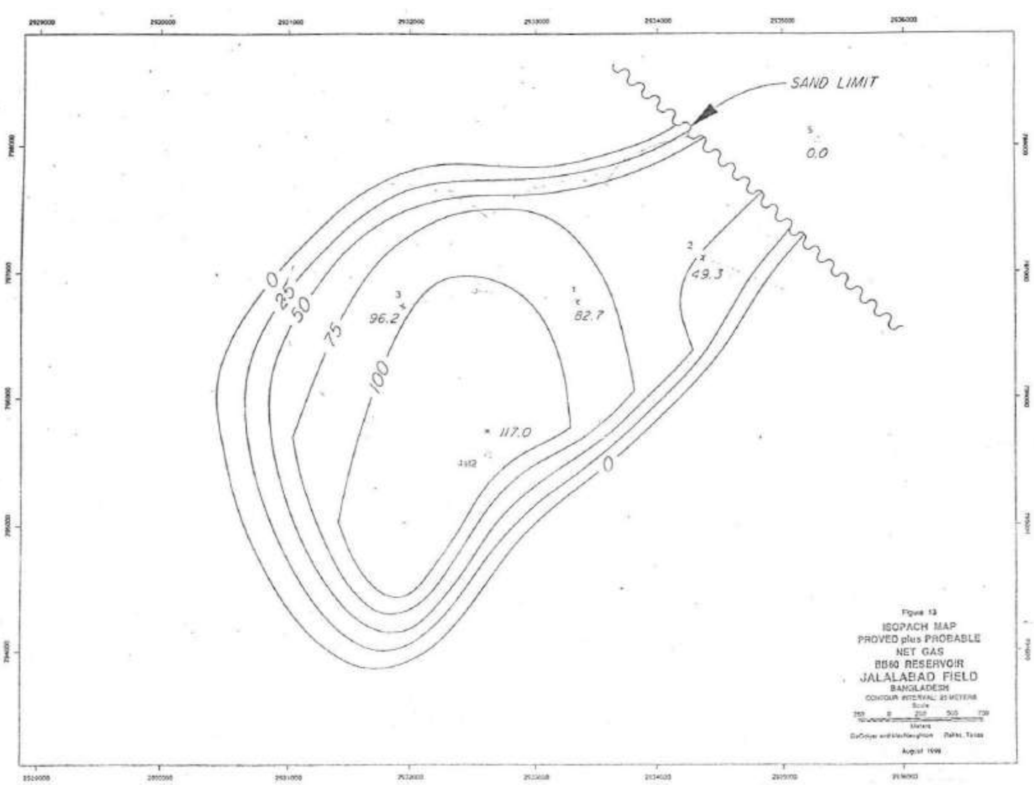




**Figure 6-74 Structure and Net Gas Isopach Maps – BB60 Reservoir – Jalalabad Gas Field**
Based on 2P Reserves (after DeGolyer and MacNaughton, 1999).

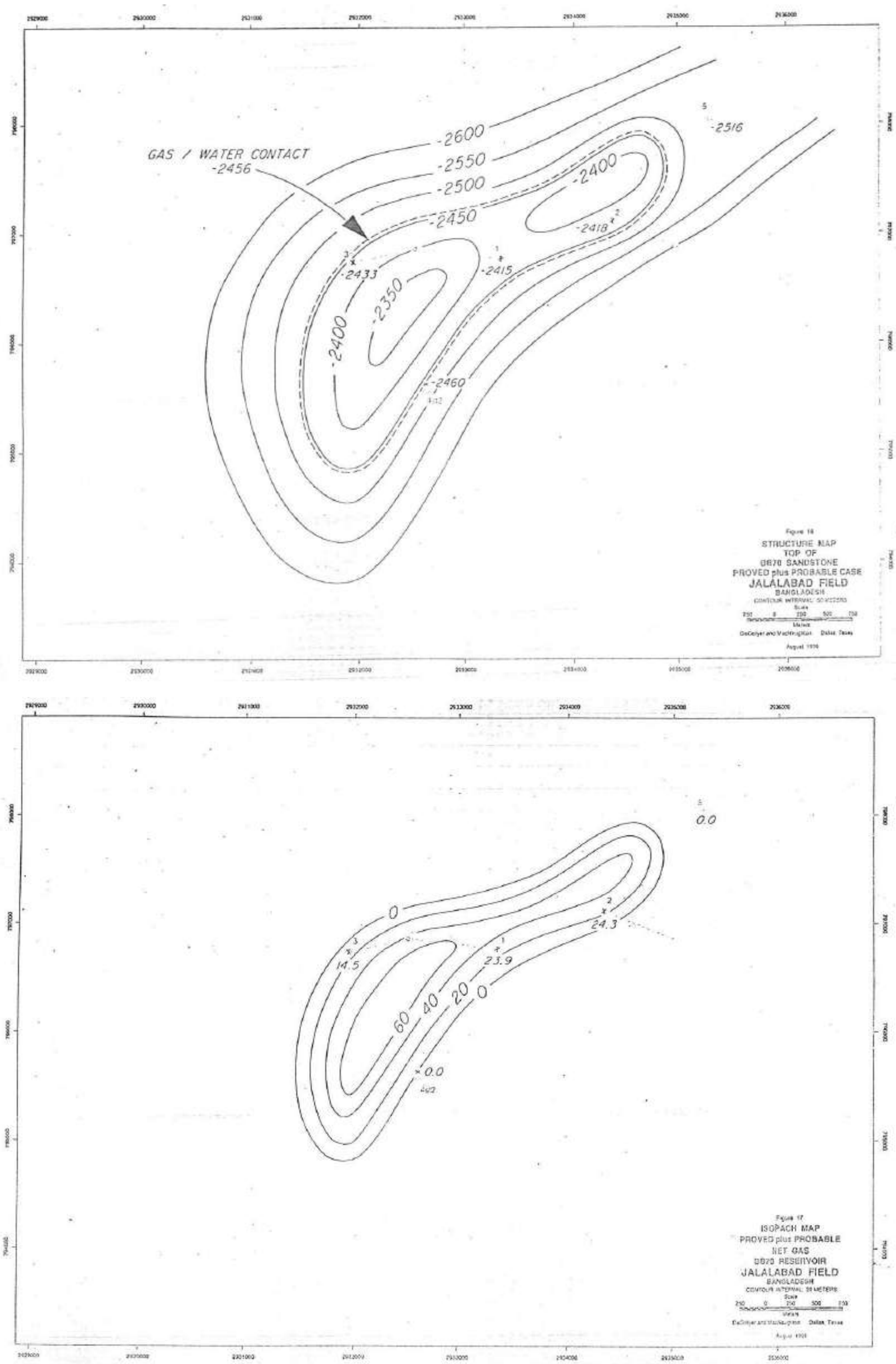



**Figure 6-75 Structure and Net Gas Isopach Maps – BB70 Reservoir – Jalalabad Gas Field**
Based on 2P Reserves (after DeGolyer and MacNaughton, 1999).

### 6.3.10.4 Exploration and Field Development

Scimitar Oil (Scimitar Exploration Limited) was awarded the Block 13 area that included the Jalalabad prospect under a PSC in 1987. The Jalalabad #1 well, drilled in 1989, found gas in three out of four sands tested in the Bokabil Formation (BB50, BB60, and BB70). This directional well reached a depth of 2,626 meters true vertical depth subsea (TVDSS).

Occidental Petroleum Corporation (Occidental) became the operator of Block 13 PSC in January, 1995. Occidental continued exploration with completion of Jalalabad #2 well in March, 1998. This well was directionally drilled to a depth of 2,768 meters TVDSS, and penetrated the BB20, BB50, BB60, and BB70 sandstone intervals.

The Jalalabad #3 well was spudded by Occidental in March, 1998. Drilling was temporarily suspended, and the well was reentered in July, 1998. Another directionally drilled well, JB #3 reached a depth of 2,771 meters TVDSS and encountered the BB60 sandstone.

Occidental spudded the Jalalabad #4 well in March, 1998, and ultimately directionally drilled to a depth of 2,606 meters TVDSS. JB #4 also encountered the BB60 sandstone interval.

Jalalabad #5, a vertical well, was drilled by Occidental in February, 1999, to a depth of 3,556 meters MD. This well encountered 200 meters of valley fill that replaced the eroded BB50 and BB60 sandstone intervals. The BH40 sand in the Bhuban Formation was tested through perforations between 3,385 and 3,395 meters MD. Jalalabad #5 was categorized as a dry hole.

Jalalabad #6 was drilled in 2005 and produced 22.7 MMscf of gas in January, 2006. The well has not produced since that time.

Unocal obtained Occidental's interest in Block 13 PSC in 1999 to become operator of the Jalalabad field. Chevron subsequently acquired Unocal. Chevron is the current operator and has a 98% interest in the production-sharing contract covering the Jalalabad field. Processed natural gas is transported via pipeline to Petrobangla.

6.3.10.5 Well-wise and Sand-wise Production History

Figure 6-76 and Figure 6-77 graphically display the average daily well-wise and sand-wise gas production for Jalalabad gas field. Figure 6-77 clearly shows that the BB60 Sand is the most important gas reservoir in the field. At the end of December 2009, the BB60 reservoir accounted for nearly 80% of the field's daily production of 167 MMscfd.

Detailed individual well histories and accompanying production charts for Jalalabad wells are included in The Annex.

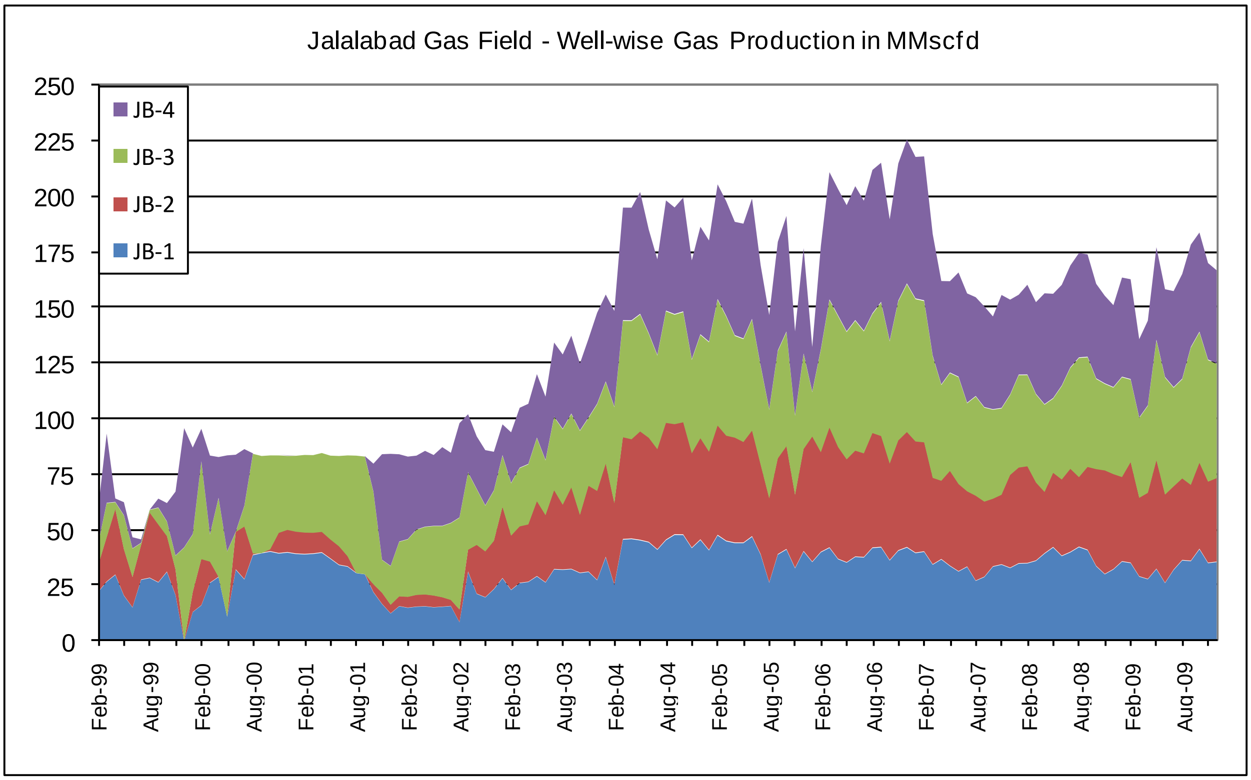



**Figure 6-76 Well-wise Gas Production – Jalalabad Gas Field**

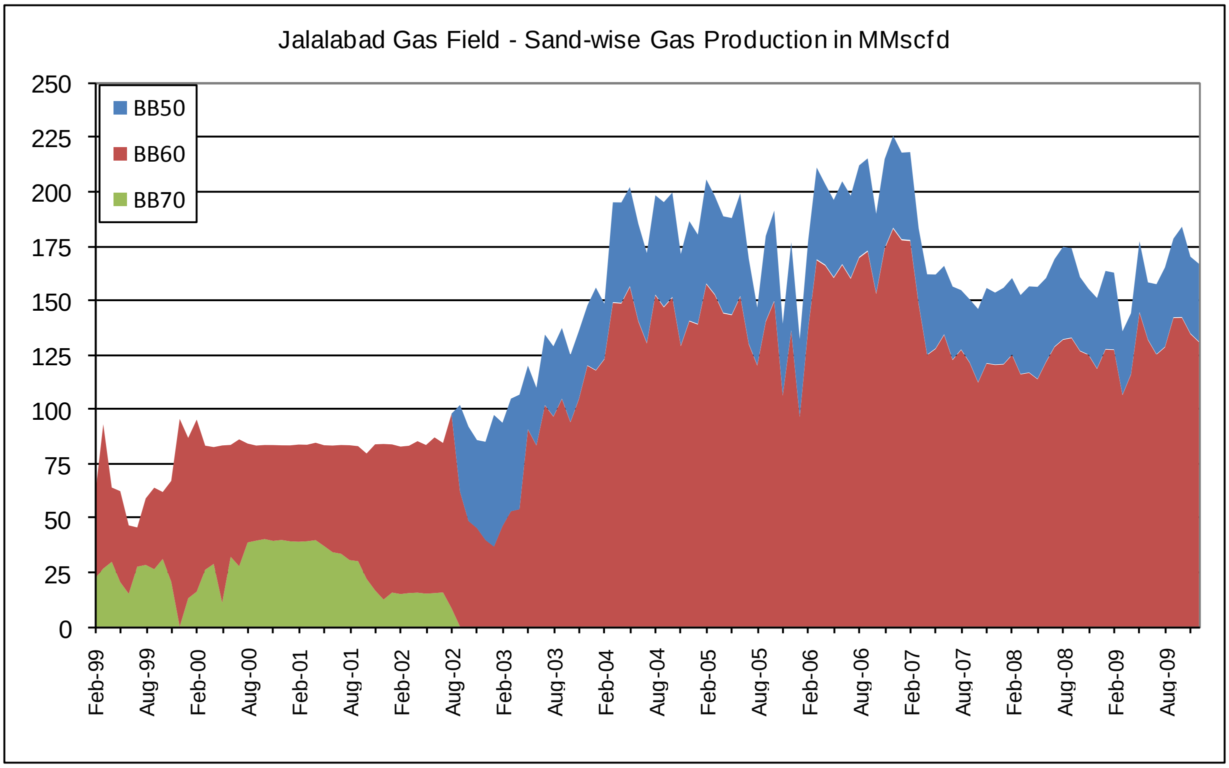



**Figure 6-77 Sand-wise Gas Production – Jalalabad Gas Field**

6.3.10.6 Field-wise Cumulative Production

Table 5-24 summarizes the cumulative gas production for Jalalabad gas field on both a sand-wise basis and a total field basis. Jalalabad has produced a total of nearly 545 Bscf of gas during its nearly 11-year productive life through the end of 2009. The BB60 reservoir has yielded a total of 410 Bscf or approximately 75% of the field's total cumulative production. Note that there is uncertainty in this allocation of production among the reservoirs, since two wells are commingled: Well #1 produces from the BB50 and BB70, while Well #2 produces from the BB50 and BB60.

**Table 6-30 Sand-wise Cumulative Gas Production – Jalalabad Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| B50 | 101.7 |
| B60 | 409.8 |
| B70 | 33.2 |
| **Total** | **544.8** |

1 Production through end of December 2009
HCU production database

6.3.10.7 Earlier Reserve Estimates

The D & M reserve report (1999) included proved and probable reserved estimated by the deterministic method. Proved reserves have less uncertainty than probable reserves. No possible reserves were calculated. Values listed in Table 6-31 are for separator gas (before fuel usage and flare losses). Total condensate reserves were estimated at 6,636 Mbbl proved and 2,859 Mbbl probable.

**Table 6-31 Previous Reserve Estimates – Jalalabad Gas Field**

| DeGolyer and MacNaughton 1999 ( MMscf) | | | | | |
|---|---|---|---|---|---|
| Reservoir | BB20 | BB50 | BB60 | BB70 | Total |
| Proved | ND | 187,549 | 599,040 | 36,947 | 823,536 |
| Probable | 45,687 | 159,690 | 107,851 | 47,987 | 361,215 |

No re-estimate was attempted for Jalalabad in the HCU-NDP 2003 reserve report (2004). For the purpose of the 2003 report Petrobangla's reserve table was used. Unlike D & M report, the Petrobangla table does not differentiate between proved and probable reserves. Petrobangla used 1195 Bscf as GIIP and 837 Bscf as recoverable reserve (recovery factor of 70%).

6.3.10.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Jalalabad field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

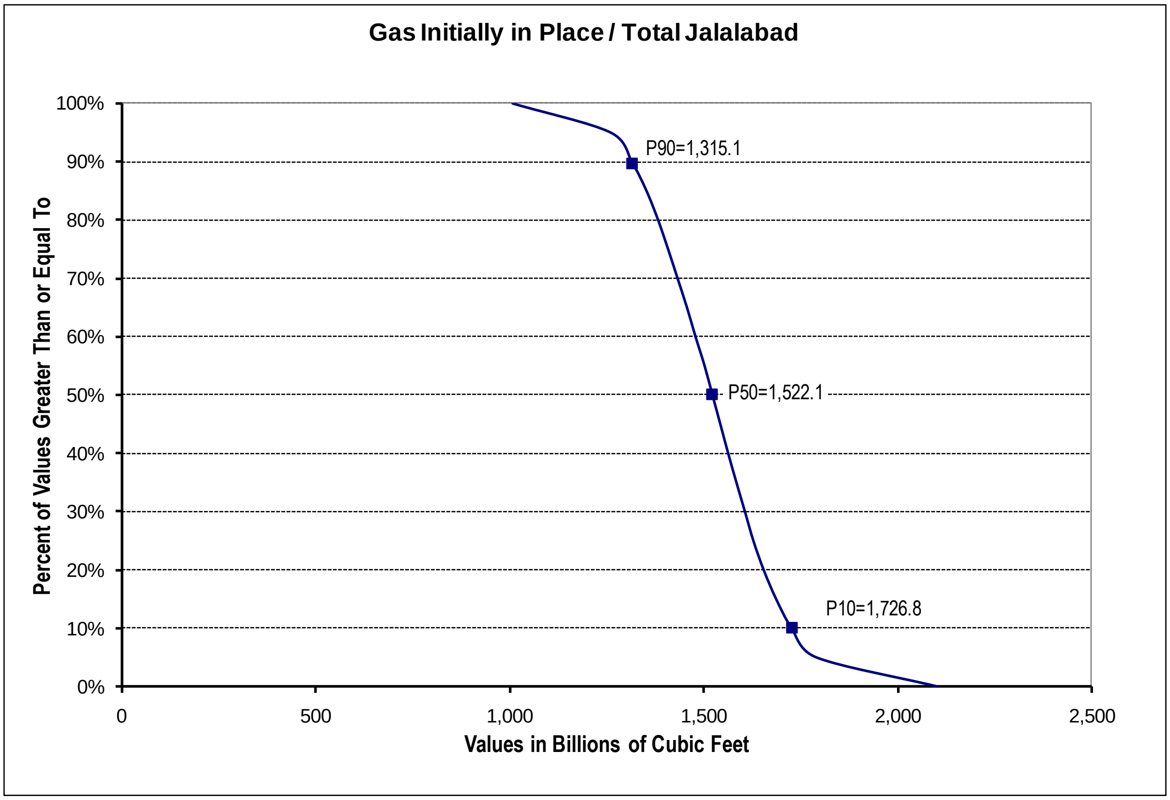



**Figure 6-78 Distribution of GIIP, Jalalabad**

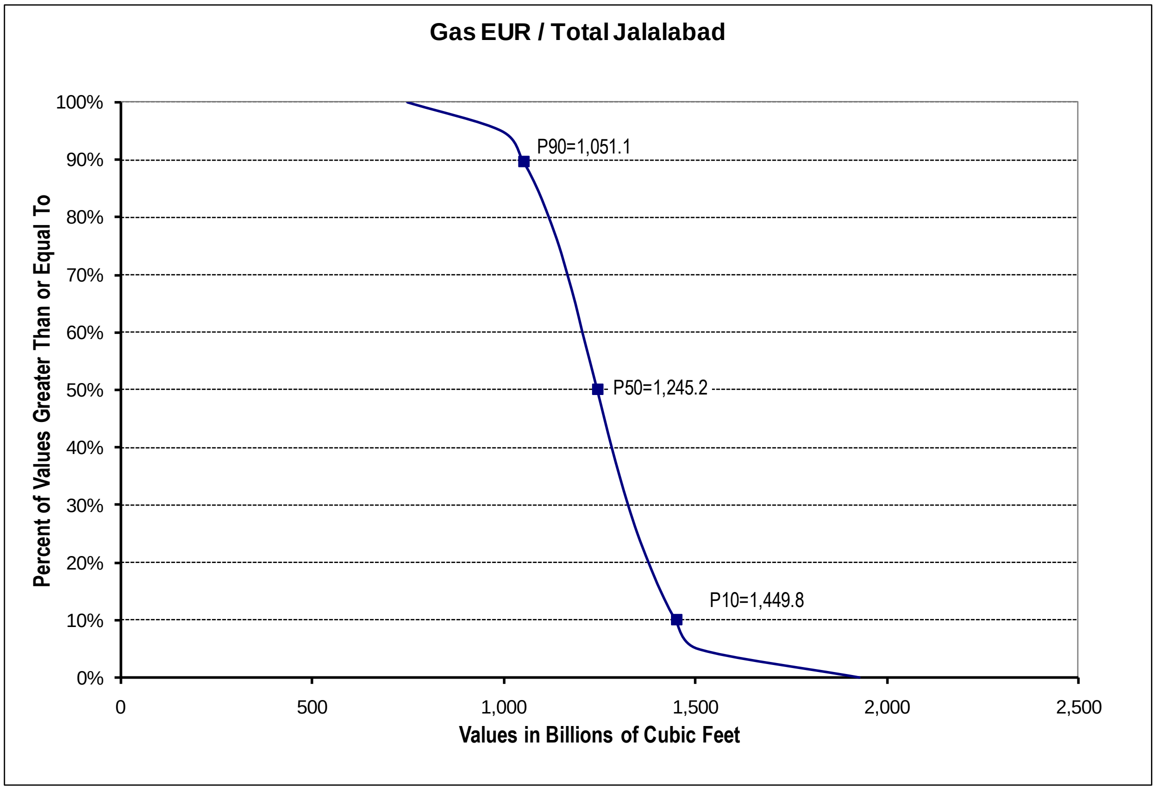



**Figure 6-79 Distribution of Gas EUR, Jalalabad**

**Table 6-32 Summary of Estimated Ultimate Recovery at Jalalabad**

| Reservoir | Mean Gas EUR, BCF | Cumulative Gas Production, 1/1/2010, BCF | Reserves, 1/1/2010, BCF |
|---|---|---|---|
| BB20 | 34 | 0 | 34 |
| BB50 | 344 | 102 | 242 |
| BB60 | 815 | 410 | 405 |
| BB70 | 56 | 33 | 23 |
| **TOTAL** | **1,249** | **545** | **704** |

Material balance reserve estimates were made in two ways for the Jalalabad Field: conventional p/z analysis and AWMB analysis[6]. For the p/z analysis, reservoir pressure was calculated from several data points during the life of each well when the well was shut in and shut-in well head pressure was recorded. In calculating the bottom-hole pressure, it was assumed that no liquid was present in the wellbore. This is likely a reasonable assumption since no water production has been reported and the condensate would be expected to be in the gas phase at reservoir conditions. Because two well produce from two reservoirs commingled, it was decided to add the cumulative production from all wells and average the pressures, which were reasonably close to each other throughout the history.

Because the last shut in pressure data was from October 2006, the AWMB method[7] was also used. For this method, again, all wells' production was summed and pressures were averaged. The results for the p/z method are shown in Figure 6-80 and for the AWMB in Figure 6-81.

[6] Mattar and McNeil, 1998.

[7] Mattar and McNeil, 1998.

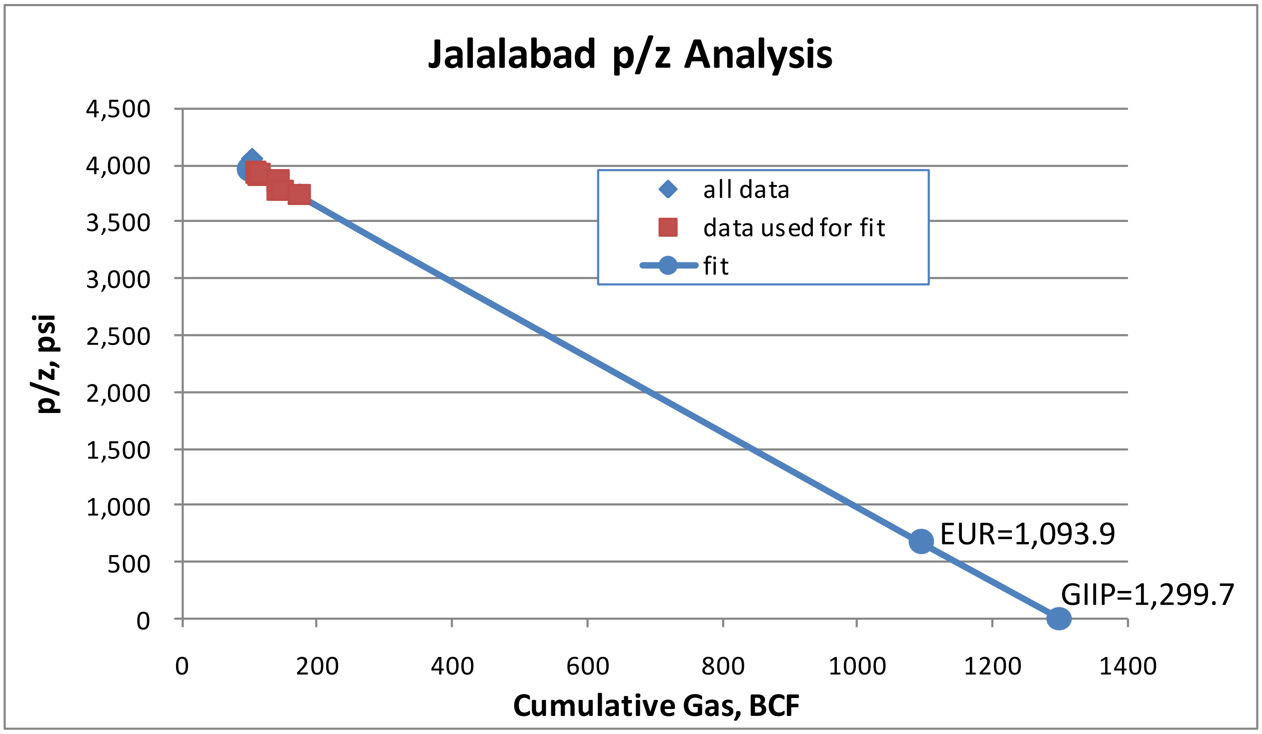



**Figure 6-80 Jalalabad p/z Analysis**

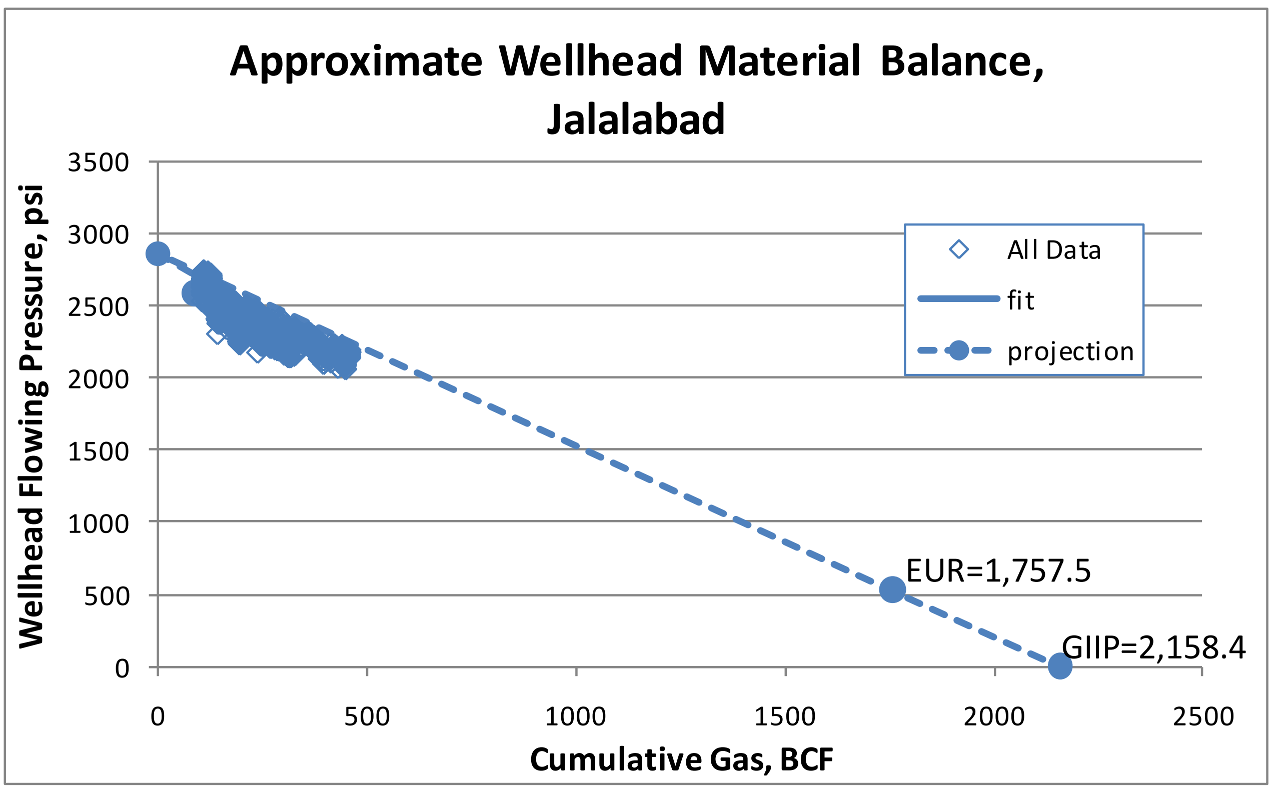



**Figure 6-81 Jalalabad AWMB Analysis**

These results compare with the mean volumetric calculations as follows, for the total of BB50, BB60, and BB70 reservoirs:

| **Method** | **Volumetric** | **p/z** | **AWMB** |
|---|---|---|---|
| GIIP, BCF | 1,475 | 1,300 | 2,158 |
| EUR, BCF | 1,215 | 1,094 | 1,758 |
| Cum. Gas, BCF | 545 | 545 | 545 |
| **Reserves, BCF** | **670** | **549** | **1,213** |

It is not clear why the AWMB method yielded such large estimates. The conventional p/z is generally considered the most accurate, although this method is complicated for this field due to the commingled production. The fact that the volumetric estimates are relatively close to the p/z results lends confidence to these two methods.

### 6.3.11 Kailash Tila (5)

#### 6.3.11.1 Geologic Setting

Kailash Tila structure is located in northeastern most Bangladesh within the eastern part of the Eastern Foldbelt in Block 14. On the surface, the structure is represented by isolated low hillocks with outcrops of Dupi Tila Formation. The area was covered by singlefold seismic survey in 1959. Based on the result of the survey, PSOC mapped the structure in 1960. The structure is surrounded by Beani Bazar anticline to the southeast, Fenchuganj on the south, Sylhet structure on the north, and Jalalabad to the northwest (Figure 6-3). A fault on the north separates Kailash Tila anticline from Sylhet anticline. Kailash Tila gas field was discovered in 1961 by PSOC.

#### 6.3.11.2 Structure

Kailash Tila is an elongated oval-shaped elongated anticline with slightly steeper west flank and with four-way dip closure. The structure is a four-way dip closure. One interpretation by IKM (1992) considered Kailash Tila to be an open structure on the north with the seal on the north provided by one east-west oriented fault (Figure 6-82). However, this idea was not supported by any other workers. The structure map produced by BAPEX in 2001 is the more accepted structural interpretation (Figure 6-83). Most of the authors interpreted the structure to be separated from Sylhet structure by a saddle. Kapna #1 well, drilled on the north of the saddle, was a dry hole (Figure 6-83).

#### 6.3.11.3 Reservoir

Reservoir rock of Kailash Tila is sandstones of Miocene or younger age. Distribution of reservoir rock over the structure is fairly uniform. Earlier workers identified three reservoir sandstones named the Upper, Middle and Lower Gas Sands. In 1986 HHSP divided Upper Gas Sand as Upper and Upper-Upper. IKM in 1989 used the names Upper, Middle and Lower Sands. Welldrill in 1991 added one additional sand named the New Sand. This sand is of limited areal extension. HCU-NPD study of 2003 used this sand in their estimate. RPS Energy (2009) considered six reservoir sands named: (1) UGS, (2) Sand A, (3) HRZ ("High Resistivity Zone"), (4) Sand B, (5) MGS, and (6) LGS. Except HRZ, all other reservoirs are distributed over the structure. HRZ sand is found in well #5 only. According to RPS Energy, GWC was encountered only in UGS. Porosity of the reservoir rock can be seen in Figure 6-84.

Log porosity of the Upper, Middle and Lower Gas sand is slightly lower than the core porosity. For the two oil sands, core porosity data is too little to compare with log porosity.

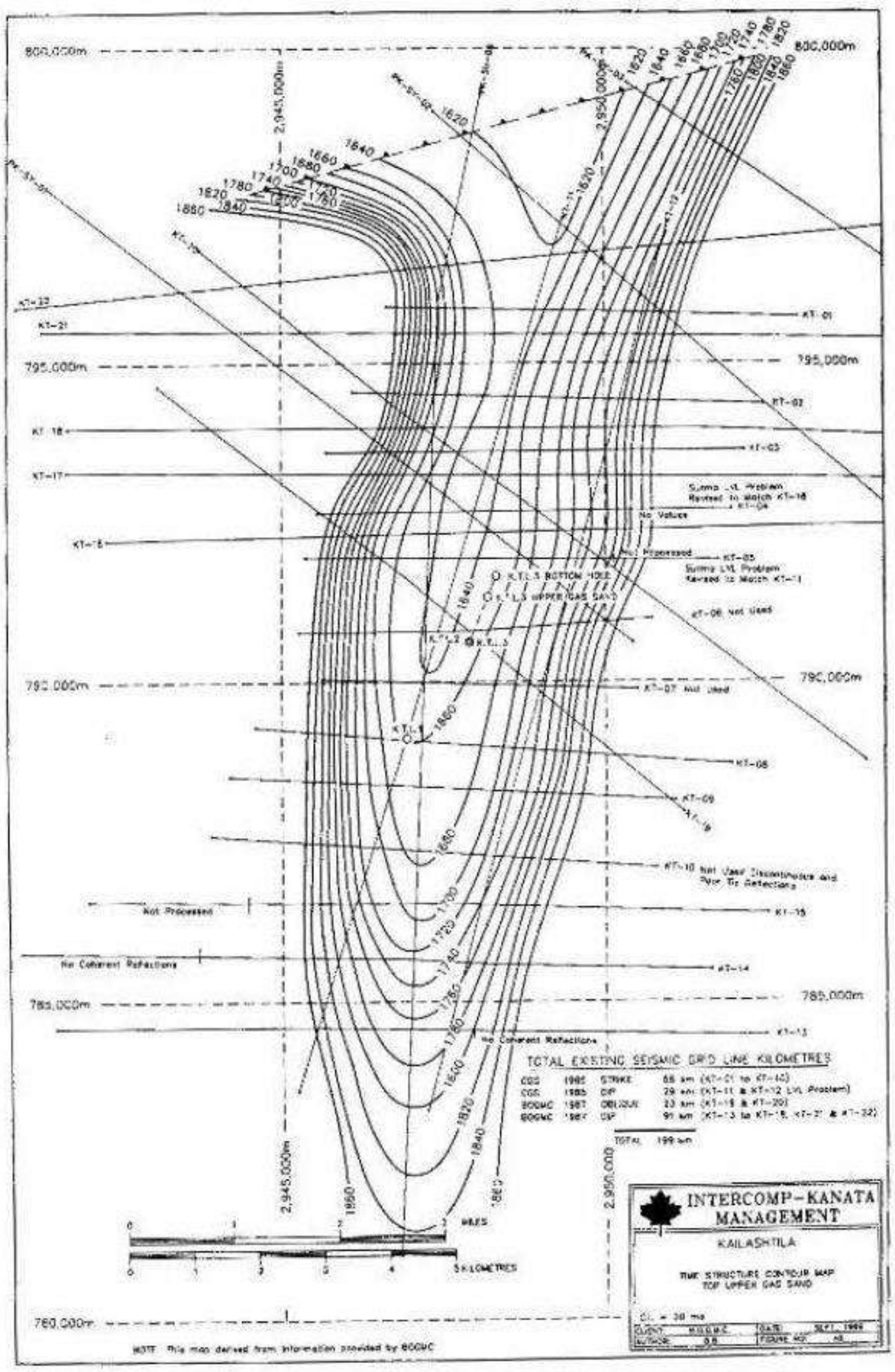



**Figure 6-82 Depth Structure Map on Top of Upper Gas Sand – Kailash Tila Field, 1992**
Map based on information from the first three wells (Kailash Tila #1, #2, and #3) (IKM, 1992)

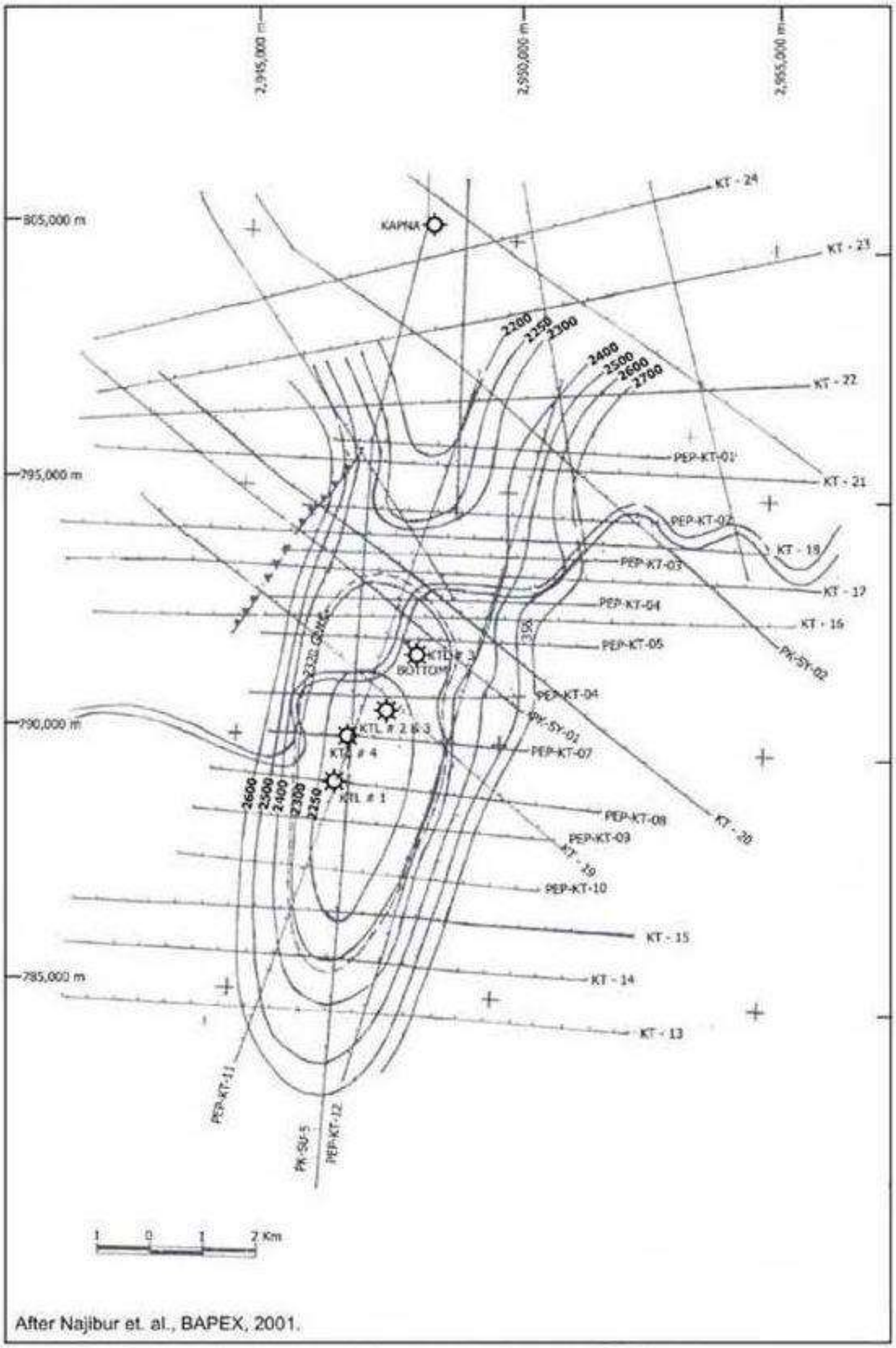



**Figure 6-83 Depth Structure Map on Top of Upper Gas Sand – Kailash Tila Field, 2001**
Map based on additional information from Kailash Tila #4 well (BAPEX, 2001).

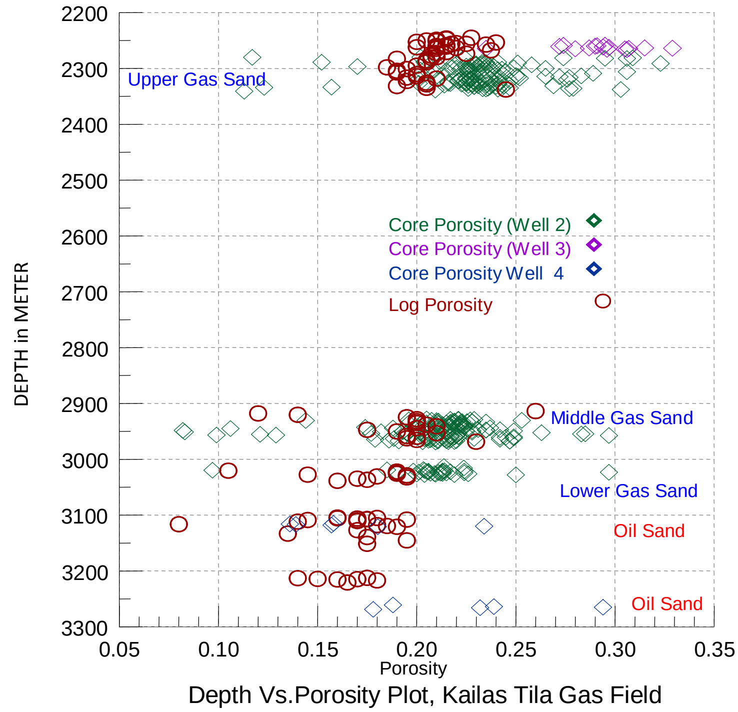



**Figure 6-84 Depth vs. Porosity Plot, Kailash Tila Gas Field**

6.3.11.4 Exploration and Field Development

In 1961, an exploratory well, Kailash Tila #1, was drilled to a depth of 4138m. This well discovered four gas sands. Only Upper and Lower Gas Sand were tested. During the test, both zones flowed gas and the rate was over 9 MMscfd. According to PSOC, GIIP of the field was 600 Bscf. This included 380 Bscf under Proven, 150 Bscf under Probable and remaining 70 Bscf under Possible category.

For nearly 20 years the well remained shut-in. During this period a number of studies on gas reserve of the field were carried out.

During the winter of 1979-80, under a German technical and financial assistance program Prakla Seismos was engaged to record multifold digital seismic data over a large part if the country. Kailash Tila gas field was included in the program.

In 1983, Kailash Tila well #1 was completed as a gas producer. The completion string consists of two strings to produce from two zones (Upper and Lower Gas Sands). In July 1983, Kailash Tila field started gas production.

During 1988-89, two wells were drilled in Kailash Tila. Earlier BAPEX, together with consultant from former USSR, re-evaluated old logs of this well and identified oil in two intervals below the discovered gas sands.  Well #3 was drilled deeper and confirmed presence of two oil horizons. An attempt to test both the zones was made, but due to cement problem water broke in and the test was terminated.  During the DST, the Lower Oil Zone flowed at a rate of 166 bbl/day and the Upper Oil Zone flowed at a rate of 488 bbl/day.  In well #4, oil sand was cored. Attempt to test the oil sand was not conclusive as DST was terminated due to water flow, presumably from overlying water sand.

Kapna well 1 was drilled on the north of the saddle.  It had oil and gas shows but was plugged and abandoned.

#### 6.3.11.5 Well-wise and Sand-wise Production History

Gas production from Kailash Tila field started in the middle of 1983. At the beginning only Well #1 was producing at an average rate was fluctuating from almost nil to 10 MMscfd. Production was gradually increased gradually to 14 MMscfd. Well #1 was re-completed in Middle sand. From the middle of 1995, Well #2 and Well #3 were added to production. Re-completed well #1 started production from the middle of 1997. During 1998- 2001, four wells were producing 80-90 MMscfd. During 2003-04, both Well #3 and Well #4 were re-completed in Upper and Middle Gas Sands, respectively. At the same time, Wells #5 and #6 were completed in High Resistivity Zone (HRZ) and Upper Gas Sand (UGS), respectively, and started production. This increased production to over 90 MMscfd.  However, at the end of 2009 production started to decline.

Figure 6-85 and Figure 6-86 graphically display the well-wise and sand-wise production from Kailash Tila gas field.  The Upper and Middle Gas Sands are the most important reservoirs in the field based on contribution to daily flow rate.

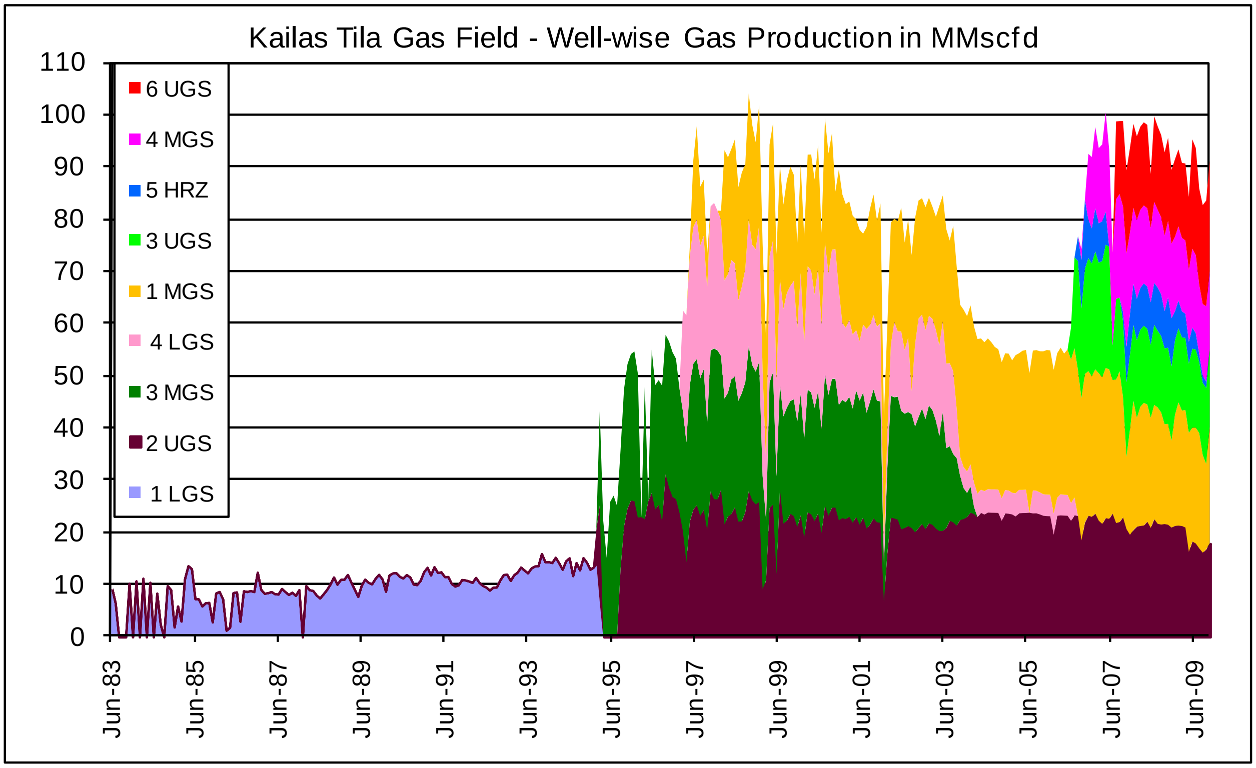



**Figure 6-85 Well-wise Gas Production – Kailash Tila Gas Field**

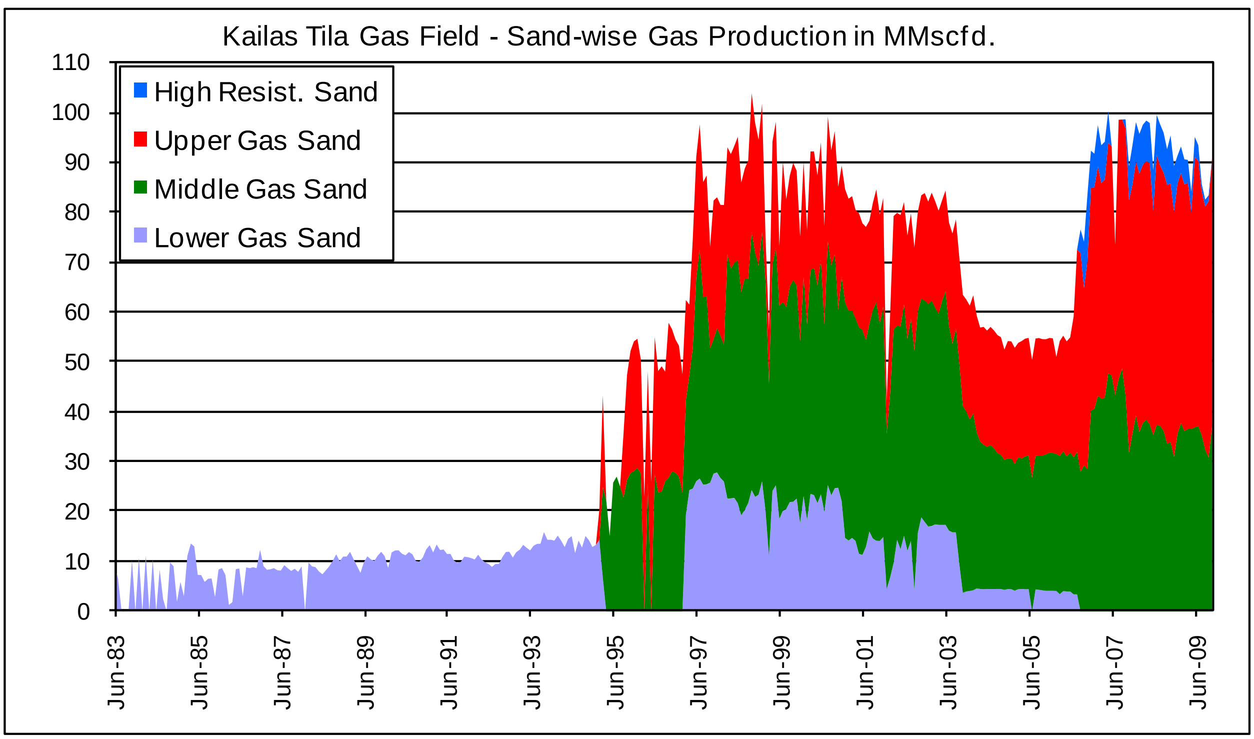



**Figure 6-86 Sand-wise Gas Production – Kailash Tila Gas Field**

Detailed individual well histories and accompanying production charts for Kailash Tila wells are included in The Annex.

### 6.3.11.6 Field-wise Cumulative Production

Table 6-33 summarizes the cumulative production from Kailash Tila field through the end of 2009 on both a reservoir basis as well as a total field basis. It is apparent that the Upper and Middle Gas Sands are also the two most important gas producers in the field based on cumulative production. The two main reservoirs account for nearly 80% of the field's total gas production through 2009 with the Middle Gas Sand producing slightly more than the Upper Gas Sand.

**Table 6-33 Sand-wise Cumulative Gas Production – Kailash Tila Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Upper Gas Sand | 188.2 |
| Middle Gas Sand | 192.1 |
| Middle (High Resist.) Zone | 6.3 |
| Lower Gas Sand | 93.4 |
| **Total** | **480.0** |

1 Production through end of December 2009
HCU production database

### 6.3.11.7 Earlier Reserve Estimates

Reserve estimation of Kailash Tila Gas Field was conducted by a number of authors. First estimation was carried out by PSOS and the result of this study is mentioned at the beginning. Since then a number of studies were conducted by a number of workers.

Earlier workers had access to limited data as there was only analog single fold seismic data, information from one well. Later on additional data was collected. Results of reserve estimations carried out by different workers are provided in Table 6-34, including the most recent 2009 estimate by RPS Energy-Petrobangla.

## Table 6-34 Comparison of Previous Reserve Estimates – Kailash Tila Gas Field

Kailas Tila Gas Field

Reserve Estimation (Probabilistic Method) Figure in Bscf

| Petrol Consult, 1979 | | | | German Geological Advisory Group, 1986 | | | | |
|---|---|---|---|---|---|---|---|---|
| Sand | P90 | P 50 | P 0 | Maximum | Most Likely | Min | Mean | RMS |
| Upper | 34 | 170 | 1018 | 1100 | 655 | 375 | 686 | 695 |
| Middle | 9 | 66 | 480 | 464 | 265 | 140 | 273 | 277 |
| Lower | 70 | 216 | 806 | 1048 | 622 | 438 | 679 | 684 |
| Total | 113 | 452 | 2304 | 2612 | 1542 | 953 | 1638 | 1656 |

Reserve Estimation (Deterministic Method) Figures in Bscf

| HHSP 1986 | | | Welldrill 1991 | | | |
|---|---|---|---|---|---|---|
| GIIP (Proved +Probable) B scf | | | | | GIIP Bscf | Rec |
| Upper Sand | | 643 | Upper Sand | | 2380 | 1980 |
| Up. Upper Sand | | 783 | New Sand | | 60 | 50 |
| Middle Sand | | 367 | Middle Sand | | 1050 | 900 |
| Lower Sand | | 546 | Lower Sand | | 300 | 260 |
| Total | | 2339 | Total | | 3790 | 3190 |

IKM 1989, Bscf

| Sand | Developed | Undeveloped | Total | Probable | GIIP, Bscf |
|---|---|---|---|---|---|
| Upper | 151 | 926 | 1077 | 1301 | 2378 |
| Middle | | 283 | 283 | 748 | 1031 |
| Lower | 169 | 79 | 248 | | 248 |
| Total | 320 | 1288 | 1608 | 2049 | 3657 |

HCU-NPD 2002, Bscf

| Sand | GIIP (Proved + Probable) | Recoverable |
|---|---|---|
| Upper | 1381 | 967 |
| New Sand | 142 | 99 |
| Middle | 704 | 493 |
| Lower | 493 | 345 |
| Total | 2720 | 1904 |

| Sand | Eclipse | Petrel |
|---|---|---|
| Upper | 1.79 | 1.89 |
| Middle | 0.72 | 0.66 |
| Lower | 1.10 | 0.99 |
| Total | 3.61 | 3.54 |

[1] RPS, 2009f

### 6.3.11.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Kailash Tila field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

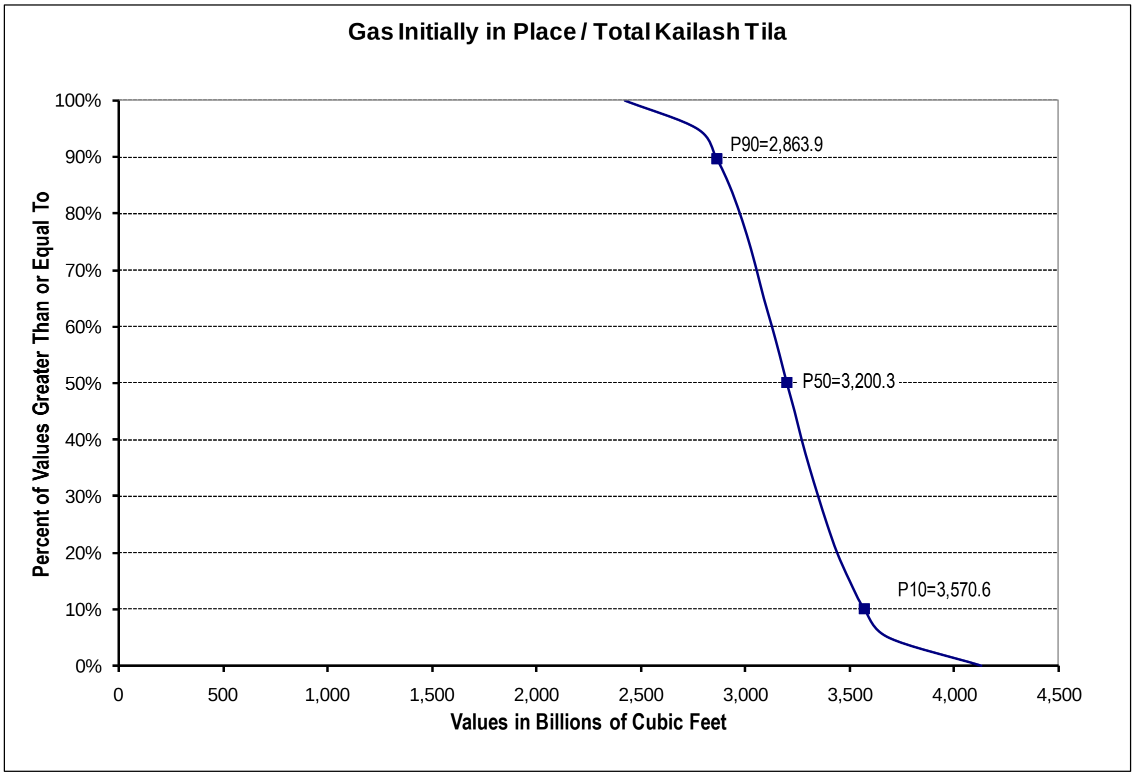



**Figure 6-87 Distribution of GIIP, Kailash Tila**

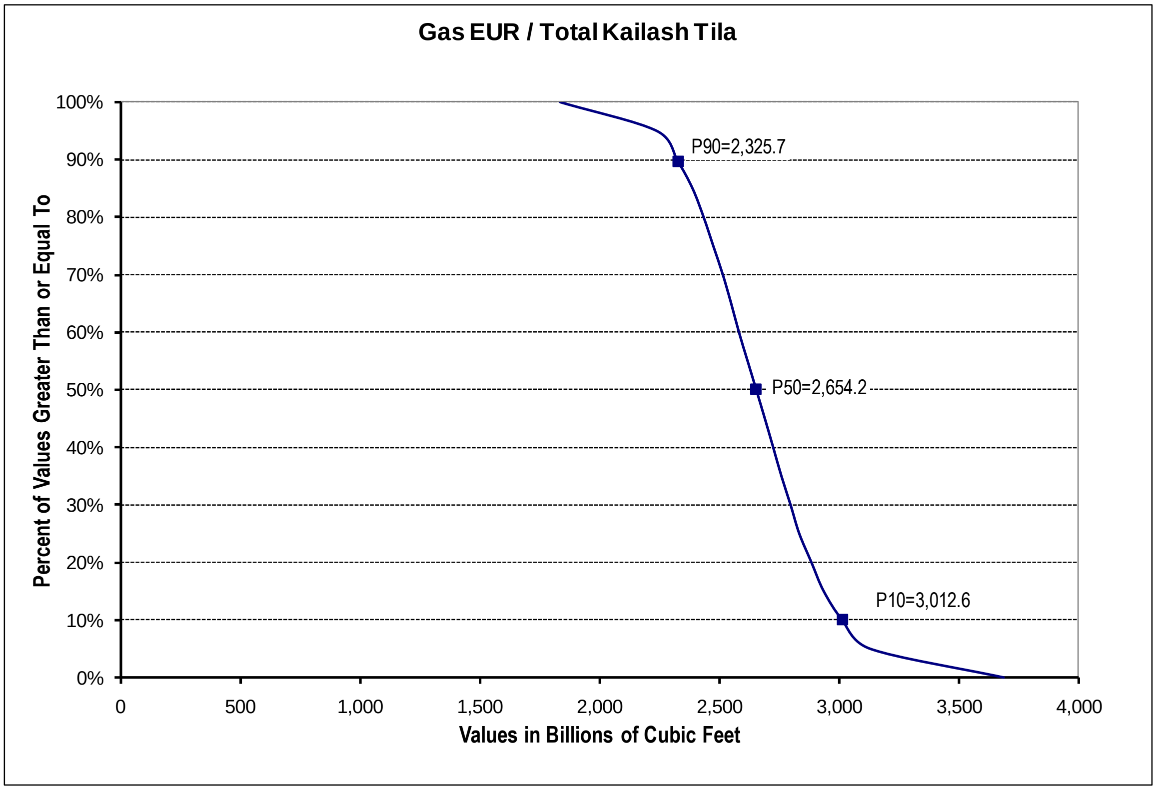



**Figure 6-88 Distribution of Gas EUR, Kailash Tila**

**Table 6-35 Summary of Estimated Ultimate Recovery at Kailash Tila**

| **Reservoir** | **Mean Gas EUR, BCF** | **Cumulative Gas, 1/1/2010, BCF** | **Reserves, 1/1/2010, BCF** |
|---|---|---|---|
| Upper Gas Sand | 1,372 | 188 | 1,184 |
| A Sand | 38 | 0 | 38 |
| HRZ Sand | 88 | 6 | 82 |
| Middle Gas Sand | 509 | 192 | 317 |
| Lower Gas Sand | 647 | 93 | 554 |
| **TOTAL** | **2,655** | **479** | **2,175** |

Available shut-in pressure data were reviewed for Kailash Tila. These data were found to be of insufficient quantity and / or too erratic to perform a conventional p/z material balance analysis for this field.

Additionally, reserves and GIIP were estimated for the producing sands at Kailash Tila using the Approximate Wellhead Material Balance (AWMB) technique.[8] For this technique, where more than one well is producing from a reservoir, the FWHP values are averaged. Any data deviating significantly from the established trend were excluded. The data from all three wells completed in the Upper Sand proved to be unsuitable for this analysis, as no definable downward trend in flowing wellhead pressure could be extracted from the data (example, Figure 6-89).

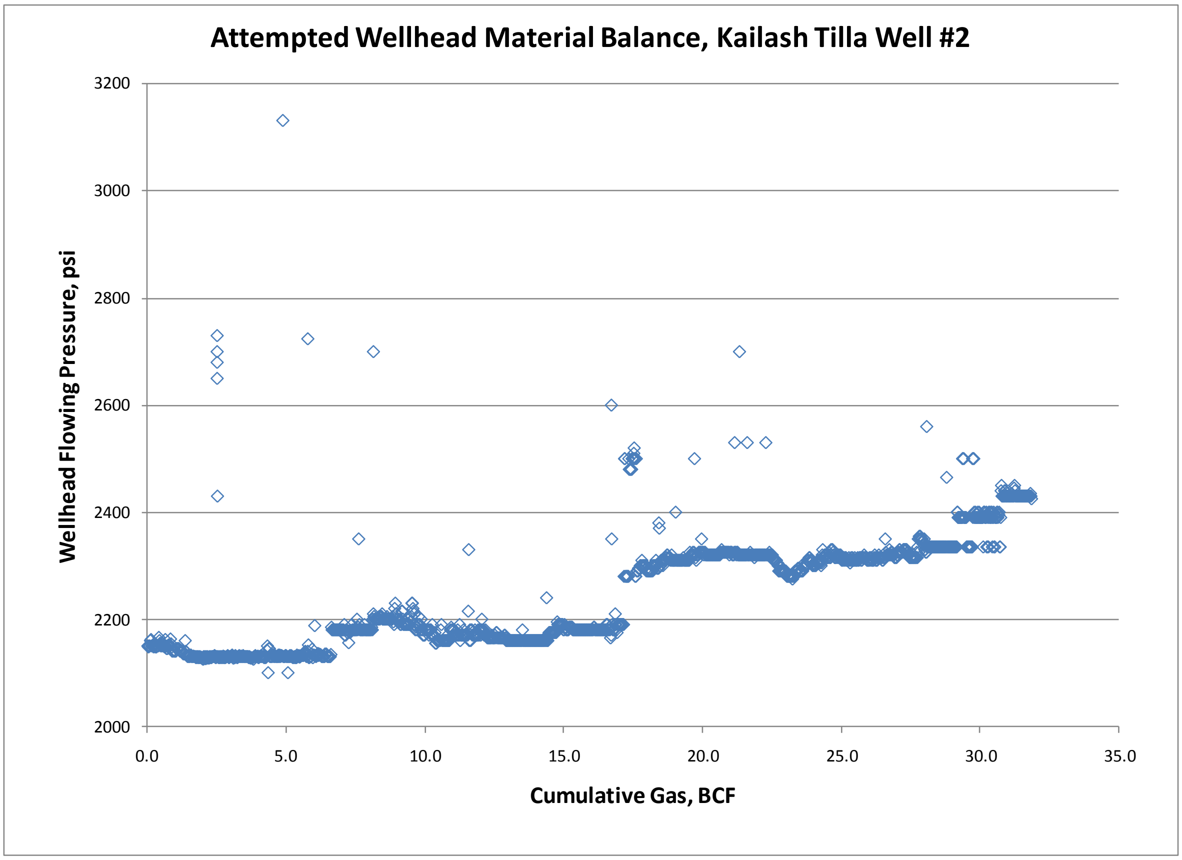



**Figure 6-89 Attempted Material Balance Plot, Kailash Tila Well #2**

Well #5, completed in the High Resistivity Zone, appears from its pressure history to have been functioning under a strong water drive, and in more recent time has apparently been loading up with water (Figure 6-90). Recent production rates declined steeply, similar to the pressure. In order to recover the remaining reserves in this sand, we suggest that it may be necessary to perform diagnostic measures such as cased-hole logging on this well to identify possible

[8] Mattar and McNeil, 1998.

remedial actions to reduce water production. Alternatively, it should be possible to recomplete this reservoir in additional wells located higher on the structure.

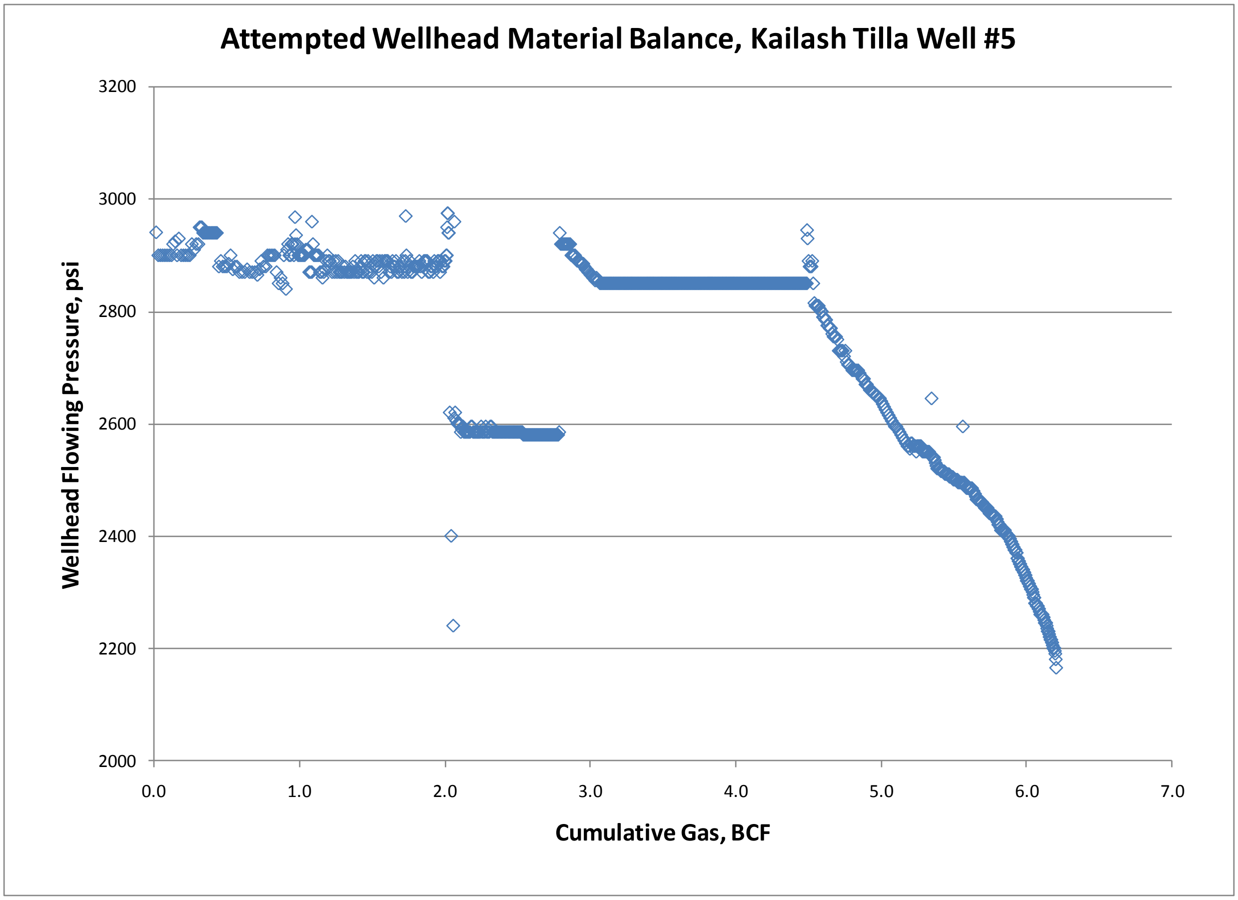



**Figure 6-90 Attempted Material Balance Plot, Kailash Tila Well #5**

AWMB analysis was completed for the Middle and Lower Sands. The results are shown in Figure 6-91 and Figure 6-92. These results compare with the mean volumetric calculations as follows:

| **Reservoir** | **Middle Sand** | | **Lower Sand** | |
|---|---|---|---|---|
| **Method** | **Volumetric** | **Mat Bal** | **Volumetric** | **Mat Bal** |
| GIIP, BCF | 609 | 416 | 781 | 1,046 |
| EUR, BCF | 513 | 350 | 651 | 883 |
| Cum. Gas, BCF | 192 | 192 | 93 | 93 |
| **Reserves, BCF** | **321** | **168** | **558** | **790** |

The large reserves indicated by the AWMB for the Lower Sand may be due to pressure support from water drive, and thus may be overestimated. However, the material balance estimate of GIIP is close to the RPS estimate using ECLIPSE for this sand of 1,100 BCF. It is unclear why the AWMB indicated lower reserves for the Middle Sand than the volumetric analysis, and the RPS analysis of 720 BCF. Given the generally erratic nature of the pressure data at this field, the volumetric analysis is considered more reliable.

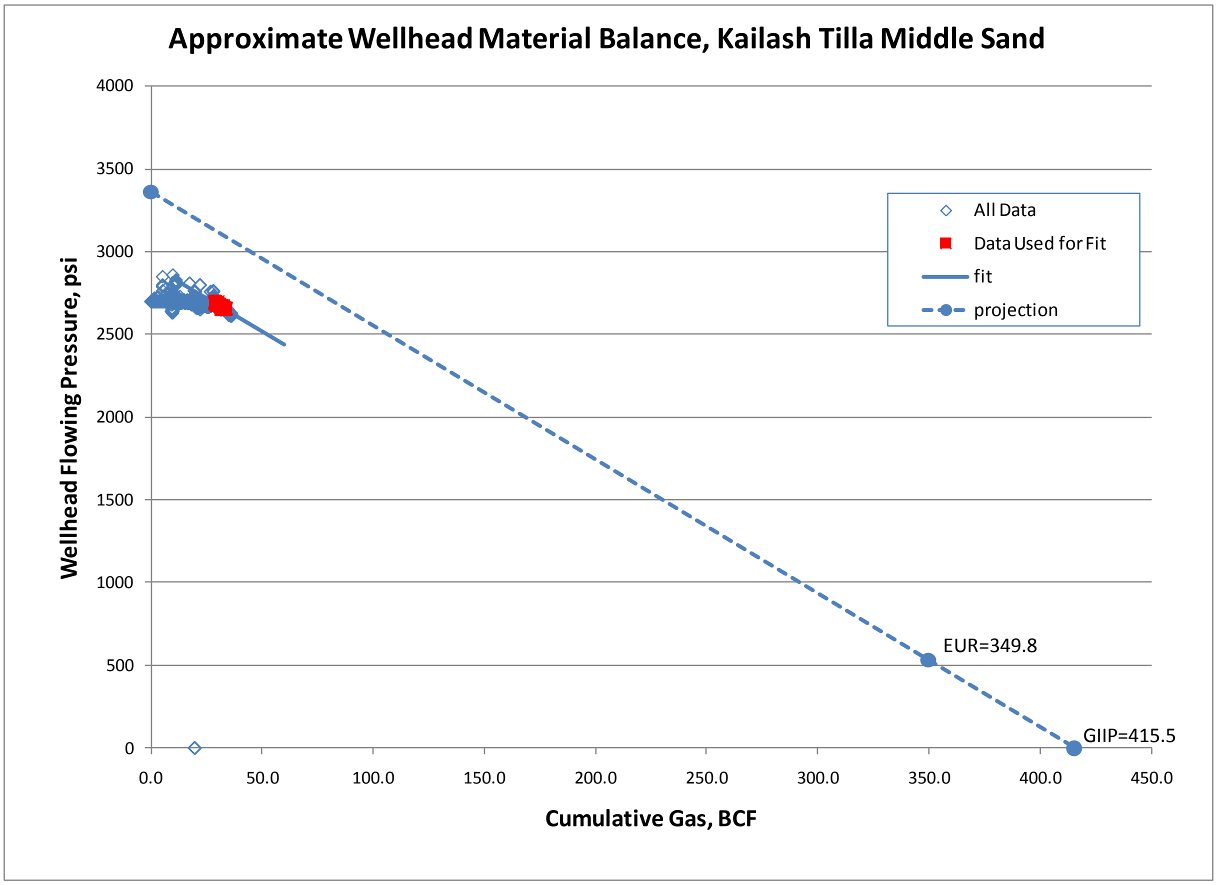



**Figure 6-91 AWMB Plot, Kailash Tila Middle Sand**

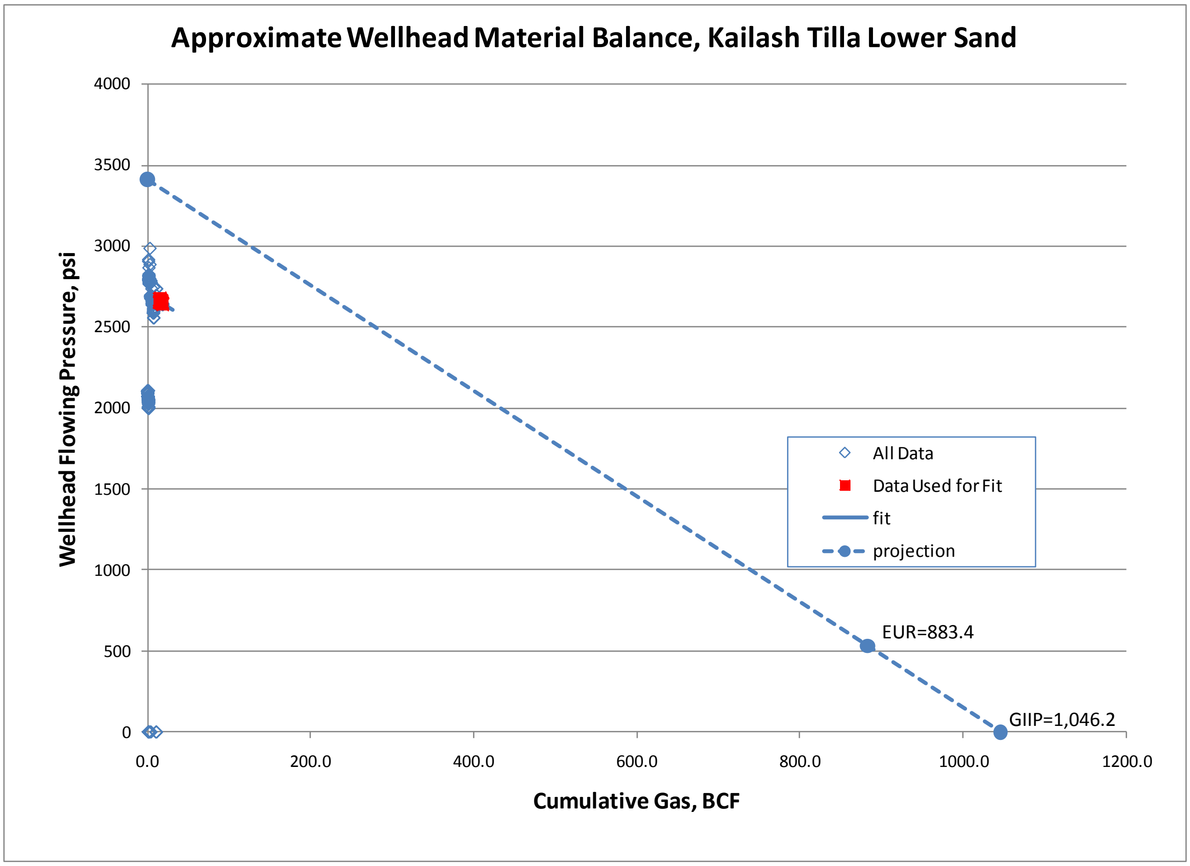



**Figure 6-92 AWMB Plot, Kailash Tila Lower Sand**

## 6.3.12 Moulavi Bazar (7)

### 6.3.12.1 Geologic Setting

Moulavi Bazar is located in northeastern Bangladesh in the eastern part of the Eastern Foldbelt near the southwestern corner of Block 14. It is located to the east of Rashidpur gas field (Figures 6-2 and 6-3).

A number of geologists conducted geological mapping of the structure at different times. Earlier, the structure was known as Kathalkandi. The southern part of the anticline extends to the Indian State of Tripura. As the southern part of the structure is located in India, the closure within Bangladesh territory was not delineated and it was not considered as an attractive exploration target.

6.3.12.2 Structure

The Moulavi Bazar structure is an elongated NS trending anticline that is bounded on the east by a high-angle reverse fault. This anticlinal closure is approximately 23 km. long by about 3.5 km. wide. Figure 6-93 and Figure 6-94 are depth structure maps of Moulavi Bazar drawn on the tops of the BB20 and BB70 reservoirs respectively, illustrating the structural style of this anticline.

6.3.12.3 Reservoir

The four productive gas reservoirs at Moulavi Bazar are, from youngest to oldest, the BB20, BB60, BB70, and BB80 Sands. The nomenclature for these sand intervals is the same as used for the sands at the other Unocal/Chevron gas fields - Bibiyana and Jalalabad (Figure 6-6).

The depositional environments of the sands at Moulavi Bazar are generally considered to be similar to those at Bibiyana and Jalalabad (Chevron, personal communication). Although the Unocal 2003 Moulavi Bazar Field Appraisal Report Table of Contents lists a discussion on sequence stratigraphy of the pay sands, no detailed discussion of the depositional environments of the correlative sands at Moulavi Bazar was available for this report. The copy in the HCU library did not contain the full text of this report and therefore this discussion was not available for our review. However, the reader is referred to Section 6.3.6.3 for a discussion of these sand intervals.

Net reservoir thickness, porosity, and water saturation for the BB70 Sand were determined from petrophysical analyses of available wireline geophysical logs and well test data from the first two wells in the field (MB #2 and MB #3) (Unocal, 2003). Porosity of the BB70 reservoir sands in the Moulavi Bazar field ranges from 16.3% to 24.4%. Water saturation in the gas-productive portions of the reservoirs ranges from 25.5% to 52.2%.

Figure 6-95 and Figure 6-96 are net pay isopach maps for the Upper and Lower BB70 Sands that together comprise the main reservoir in the field.

6.3.12.4 Exploration and Field Development

Under German Technical Assistance, digital multifold seismic survey over the area was carried out and new maps were prepared. These maps indicated presence of closure on the south. After detailed study this was considered as a good exploration target and well proposal was prepared. This prospect was selected as an exploration target under Multi-Well drilling Program financed by German Government. However this did not materialized. BAPEX during 1990-91 recorded additional seismic lines over the structure.

In 1995, Blocks 12, 13, and 14 was awarded to Occidental. Moulavi Bazar prospect located in Block 14 went along with the block. Occidental spudded their first well in June 1997, which blew out at 840m after encountering one gas sand. In 1999 after Unocal took over Occidental of Bangladesh, a second well was drilled to 3510m and several gas sands were discovered. A third well was also drilled in the same year to appraise the field.

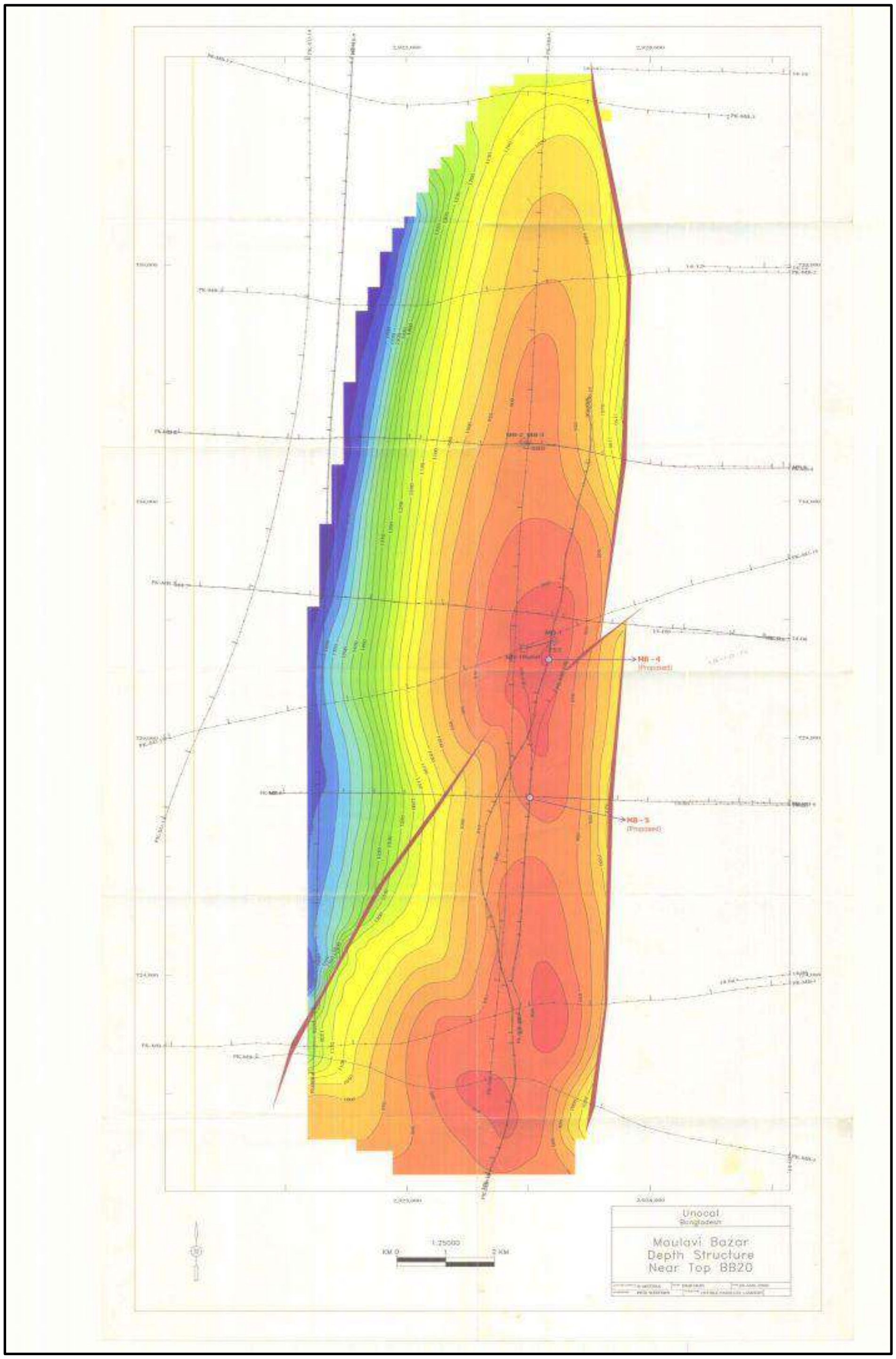



**Figure 6-93 Depth Structure Map Near Top of BB20 Reservoir – Moulavi Bazar Gas Field**
(after Unocal, 2003).

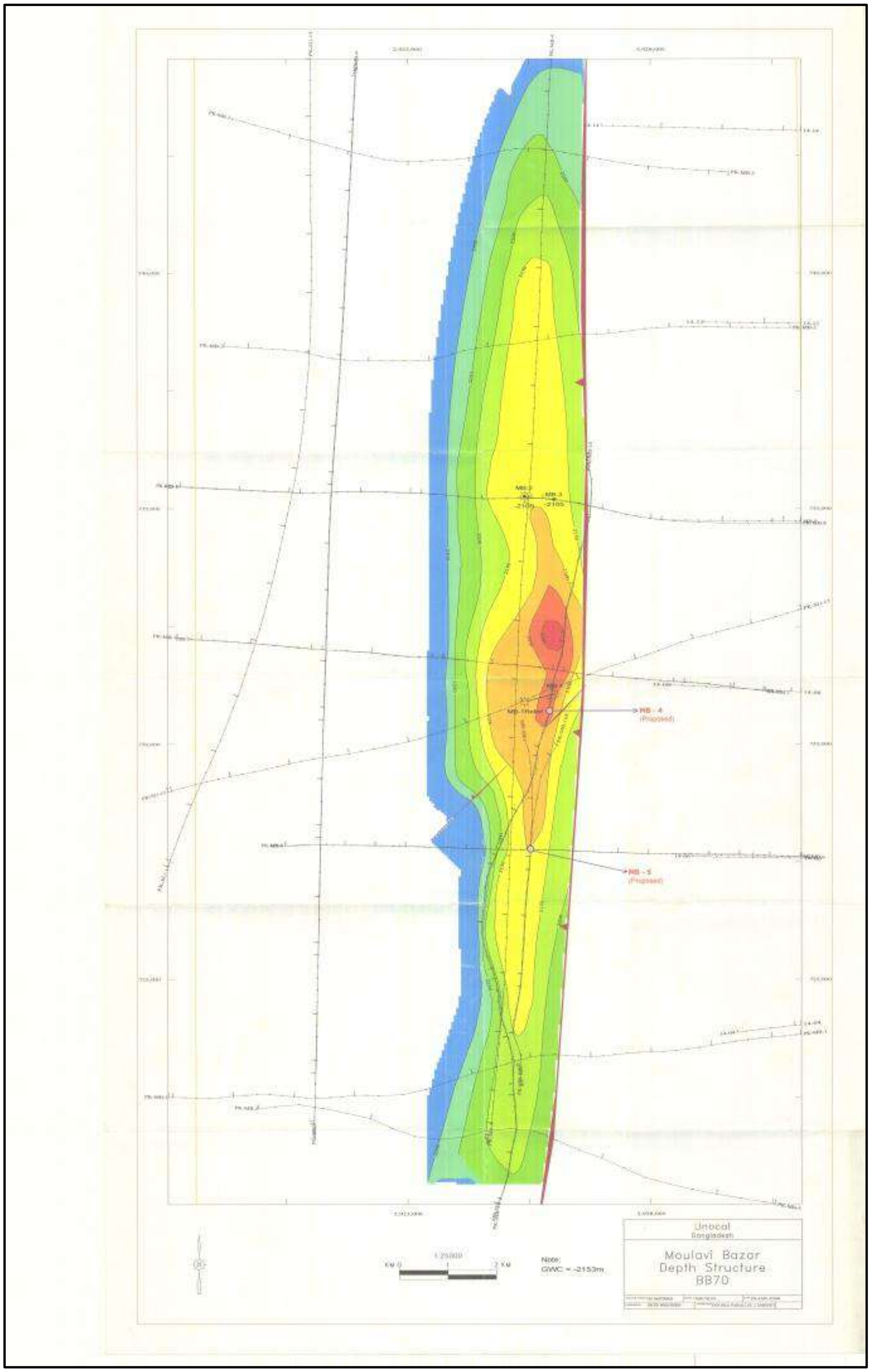



**Figure 6-94 Depth Structure Map on Top of BB70 Reservoir – Moulavi Bazar Gas Field**
Main pay interval at Moulavi Bazar field (after Unocal, 2003).

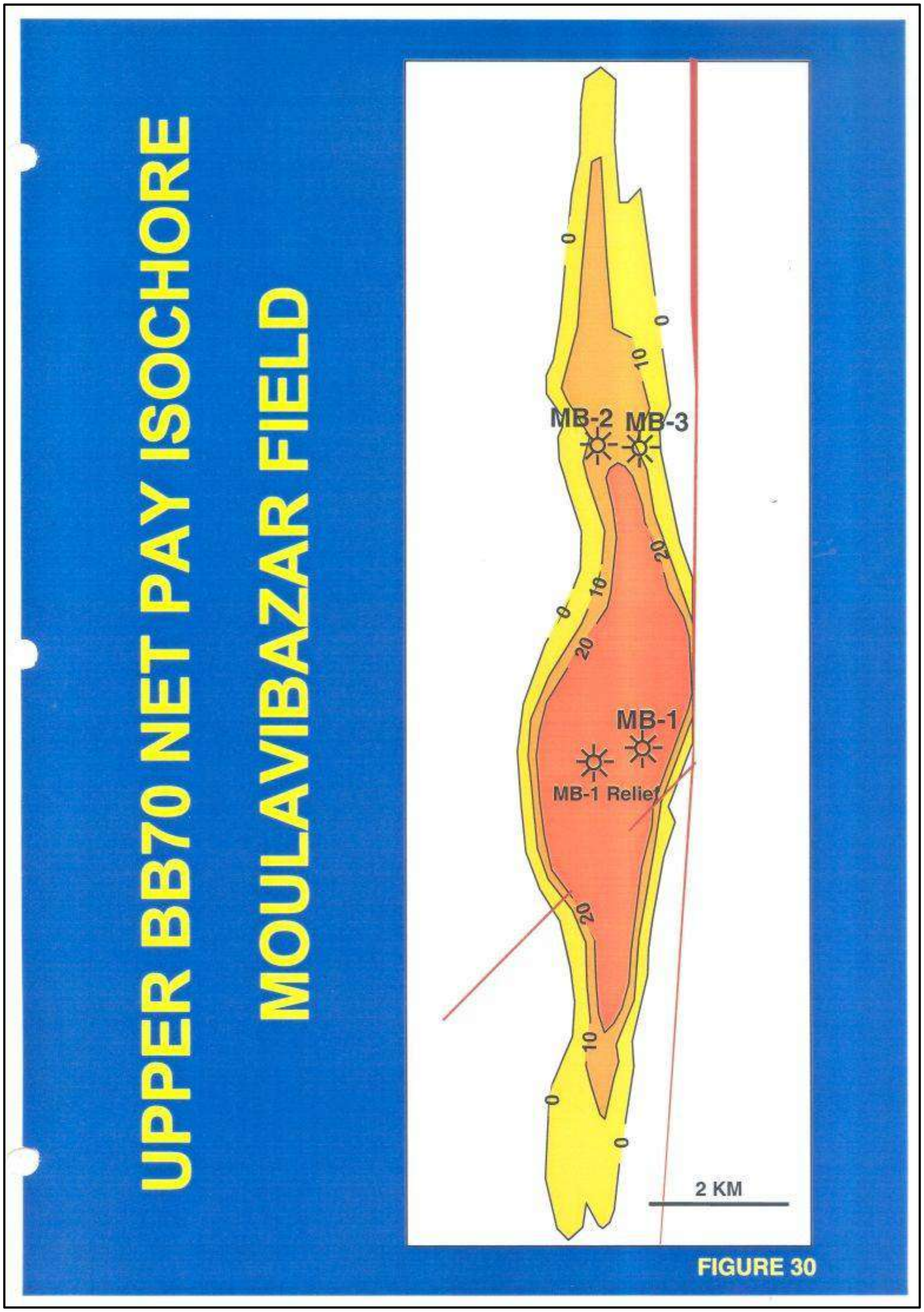



**Figure 6-95 Upper BB70 Net Pay Isopach – Moulavi Bazar Gas Field**
Upper main pay at Moulavi Bazar field (after Unocal, 2003).

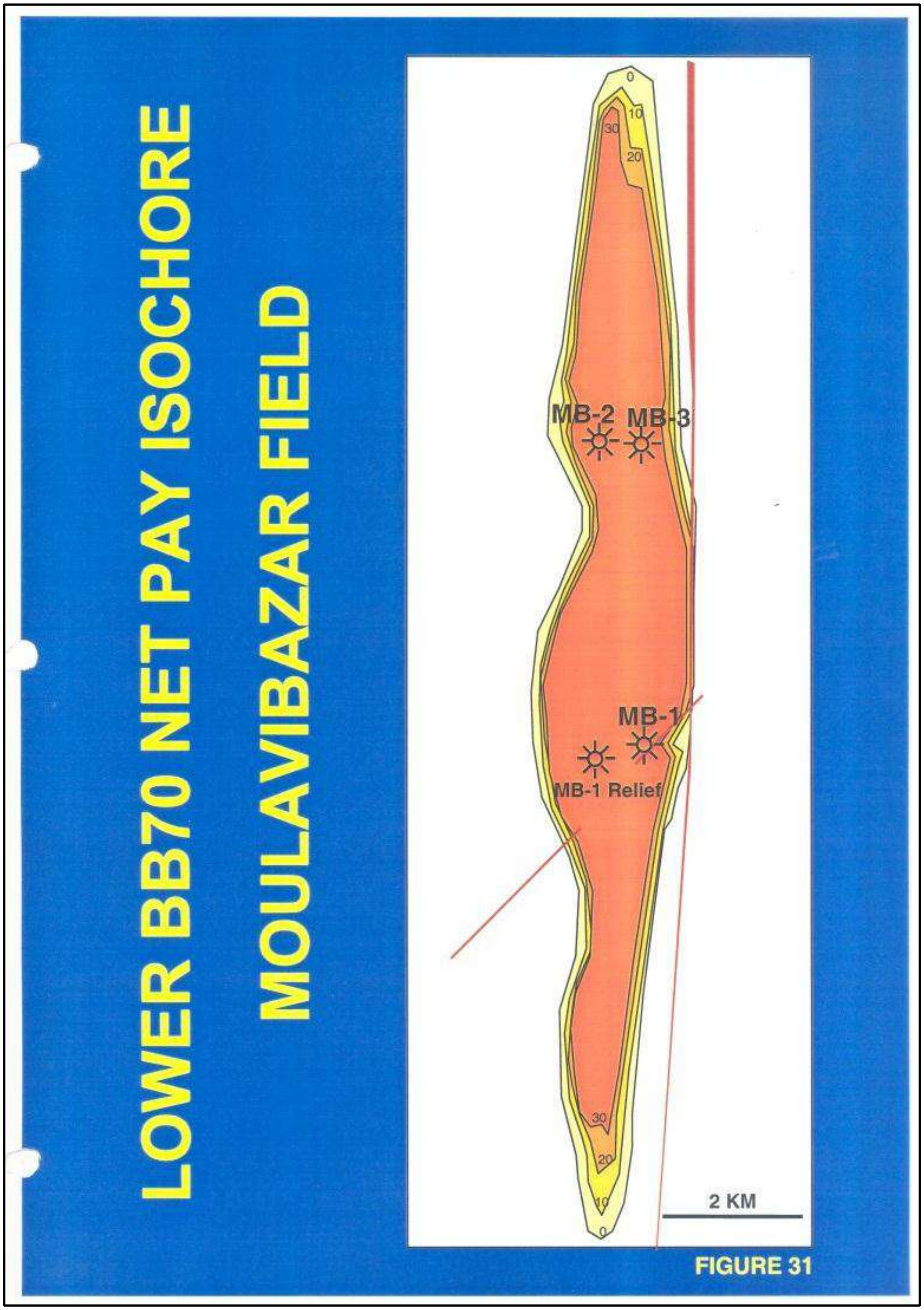



**Figure 6-96 Lower BB70 Net Pay Isopach – Moulavi Bazar Gas Field**
Lower main pay at Moulavi Bazar field (after Unocal, 2003).

### 6.3.12.5 Well-wise and Sand-wise Production History

Figure 6-97 and Figure 6-98 graphically display the well-wise and sand-wise production history of Moulavi Bazar gas field. MVB Well #3 has been the best producer in Moulavi Bazar throughout the field's history. The BB70 reservoir has been the most important reservoir in the field both in terms of contribution to the field's total average daily flow rate as well as to the field's cumulative gas production (Table 6-36).

Detailed individual well histories and accompanying production charts for Moulavi Bazar wells are included in the Annex.

### 6.3.12.6 Field-wise Cumulative Production

Table 6-36 summarizes the cumulative gas production by both a reservoir and a total field basis. Through the end of 2009, Moulavi Bazar gas field has produced 152 Bscf, of which the BB70 reservoir accounts for over 77% of the total or 117.5 Bscf. The BB80 Sand is the second most important reservoir in the field, having produced 32.6 Bscf or just over 21% of the field's total cumulative production through the end of 2009.

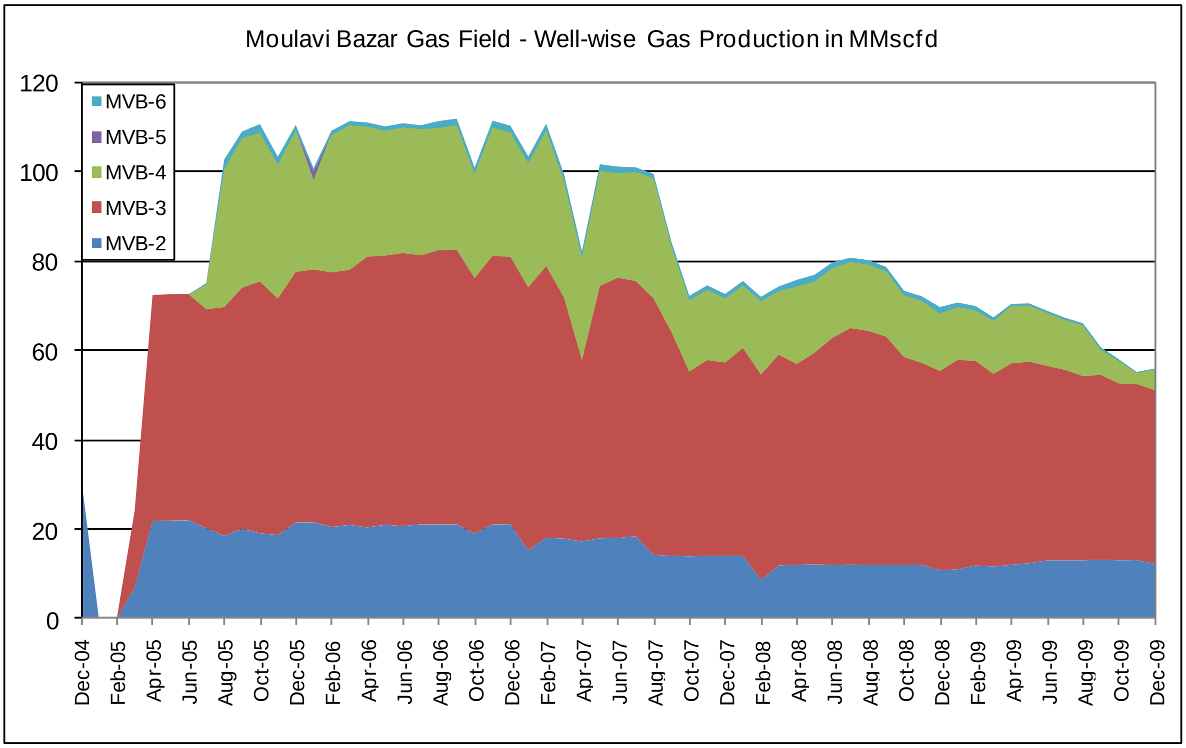



**Figure 6-97 Well-wise Gas Production – Moulavi Bazar Gas Field**

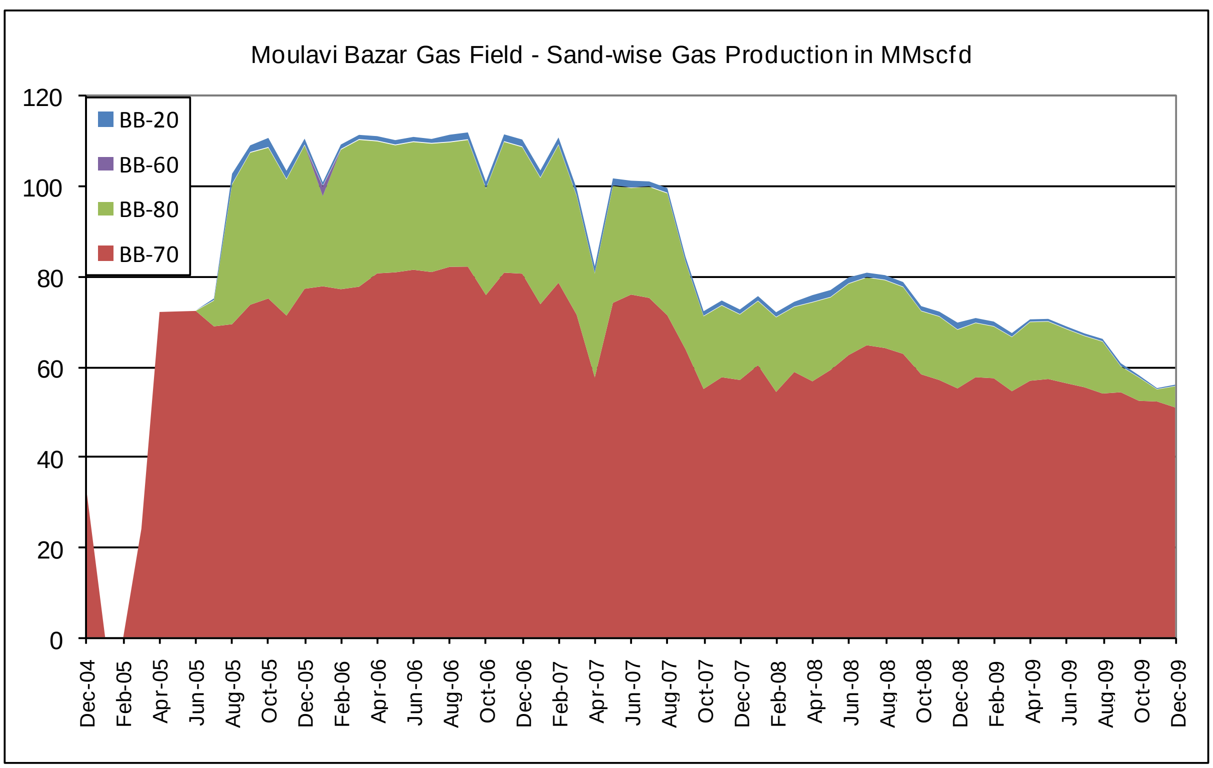



**Figure 6-98 Sand-wise Gas Production – Moulavi Bazar Gas Field**

**Table 6-36 Sand-wise Cumulative Gas Production – Moulavi Bazar Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| BB20 | 1.8 |
| BB60 | 0.1 |
| BB70 | 117.5 |
| BB80 | 32.6 |
| **Total** | **152.0** |

1 Production through end of December 2009
HCU production database

6.3.12.7 Earlier Reserve Estimates

Post-discovery volumetric estimate by Unocal placed the GIIP at 1053.29 Bscf. Proved GIIP was only 505.56 Bscf and 35.08 Bscf was assigned under Probable category. Possible category GIIP amounted to 512.65 Bscf. Details of the estimate can be seen below in Table 6-37.

**Table 6-37 Unocal Post-Discovery Reserve Estimate – Moulavi Bazar Gas Field**

| GIIP (Bscf) | | | | | Reserves (Bscf) | | | |
|---|---|---|---|---|---|---|---|---|
| Proven | Probable | Possible | Total | Sand | Proven | Probable | Possible | Total |
| | 35.1 | 141.2 | 176.3 | BB 20 | | 23.5 | 94.6 | 118.1 |
| | | 157.7 | 157.7 | BB 50 | | | 121.0 | 121.0 |
| | | 213.8 | 213.8 | BB 60 | | | 168.7 | 168.7 |
| 505.6 | | | 505.6 | BB 70 | 404.6 | | | 404.6 |
| 505.6 | 35.1 | 512.7 | 1053.3 | Total | 404.6 | 23.5 | 384.2 | 812.4 |

It should be observed in this report that the Proven reserve estimate is not dependent on a gas sales agreement. Petrobangla reviewed the report and came up with a new GIIP and recoverable 2P reserve (undifferentiated Proven and Probable) of 448.86 Bscf and 359.50 Bscf, respectively.

6.3.12.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Moulavi Bazar field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

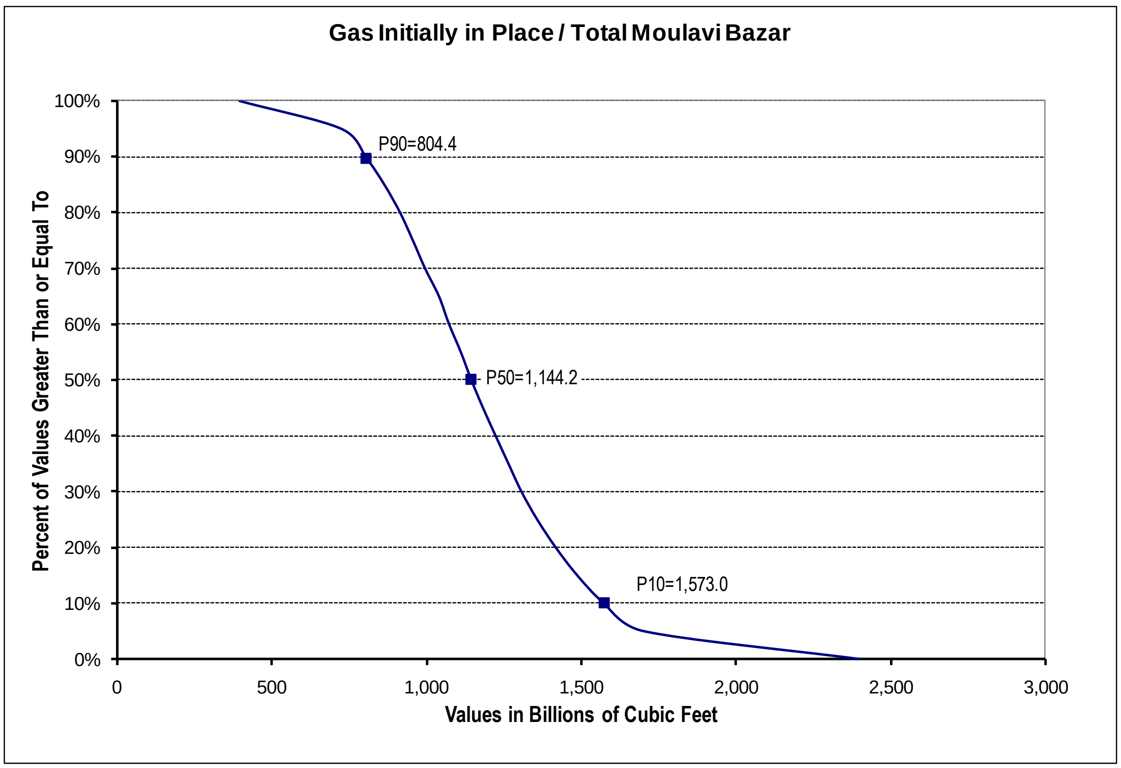



**Figure 6-99 Distribution of GIIP, Moulavi Bazar**

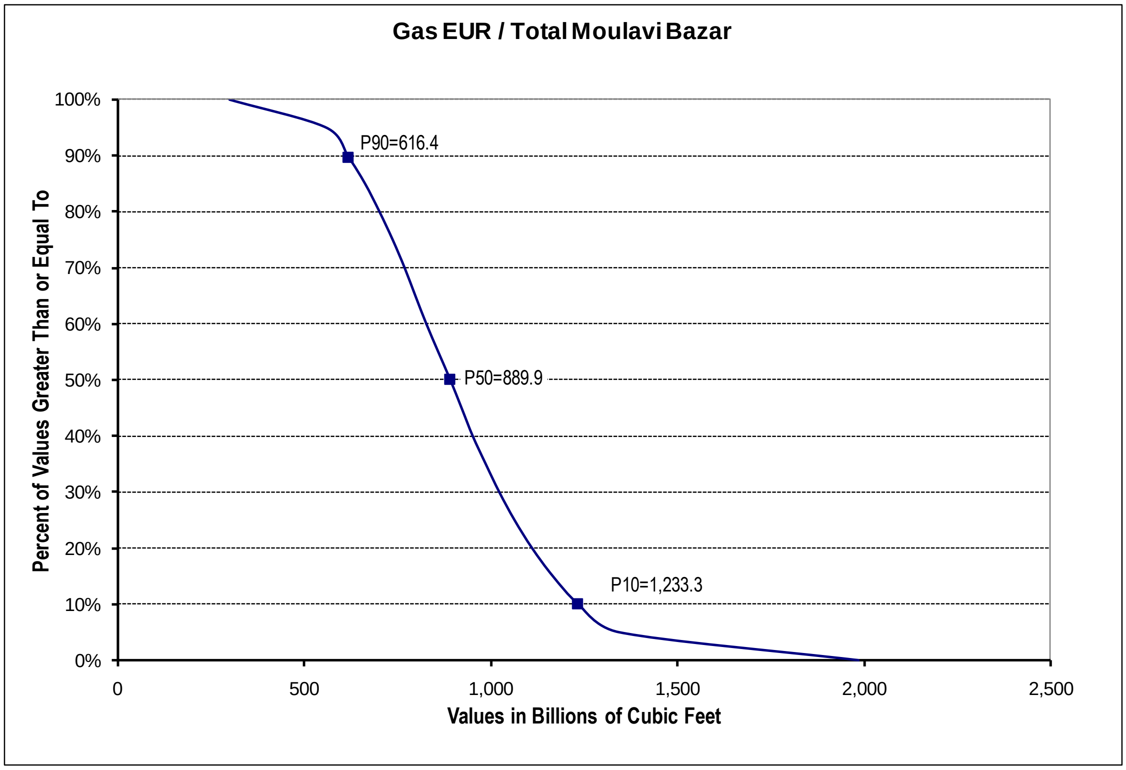



**Figure 6-100 Distribution of Gas EUR, Moulavi Bazar**

**Table 6-38 Summary of Estimated Ultimate Recovery at Moulavi Bazar**

| **Reservoir** | **Mean Gas EUR, BCF** | **Cumulative Gas, 1/1/2010, BCF** | **Reserves, 1/1/2010, BCF** |
|---|---|---|---|
| BB20 | 26.6 | 1.8 | 24.8 |
| BB50 | 42.3 | 0.0 | 42.3 |
| BB60 | 163.9 | 0.1 | 163.8 |
| BB70 | 537.5 | 117.5 | 420.0 |
| BB80 | 139.9 | 32.6 | 107.3 |
| **TOTAL** | **910.2** | **152.0** | **758.2** |

In addition, material balance calculations were made for Moulavi Bazaar using conventional p/z analysis. Bottom-hole shut-in pressures were calculated from reported surface shut-in pressures and gas properties, assuming no liquid accumulation above the reservoir in the wellbore. This is considered a valid assumption, since the low water and condensate volumes would be expected to be in the gaseous state at reservoir conditions. For the BB70, with two producing wells, the pressure data were reviewed and found to be in close agreement between the two wells (#2 and

#3). Therefore, the pressure data were averaged and the cumulative production was summed for these wells to analyze the reservoir as a whole (Figure 6-101).

Only one well produces from the BB80 reservoir, Well #4. This well also showed a good fit straight line for its p/z data (Figure 6-102). The BB20 reservoir also has one producing well, #6. This well showed a reasonable fit if certain earlier pressure points that did not fit the trend were excluded (Figure 6-103). These results compare with the mean volumetric calculations as follows:

| **Reservoir** | **BB70** | | **BB80** | | **BB20** | |
|---|---|---|---|---|---|---|
| **Method** | **Volumetric** | **Mat Bal** | **Volumetric** | **Mat Bal** | **Volumetric** | **Mat Bal** |
| GIIP, BCF | 682.2 | 253.2 | 171.3 | 79.3 | 53.9 | 35.2 |
| EUR, BCF | 537.5 | 206.2 | 139.9 | 63.1 | 26.6 | 19.7 |
| Cum. Gas, BCF | 117.5 | 117.5 | 32.6 | 32.6 | 1.8 | 1.8 |
| **Reserves, BCF** | **420.0** | **88.7** | **107.3** | **30.5** | **24.8** | **17.9** |

The material balance in each case yielded lower estimates of gas in place and reserves. Since the volumetrics are based on older maps, and the material balance honors well performance, the material balance estimates are considered more reliable.

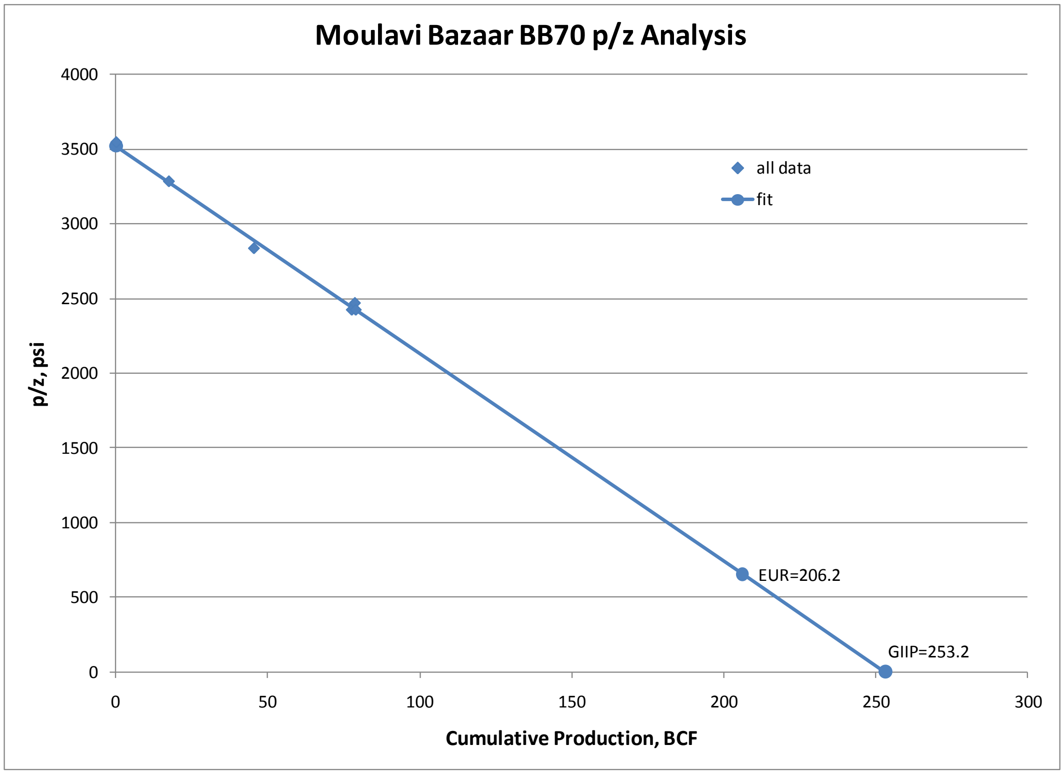



**Figure 6-101  Moulavi Bazaar BB70 p/z Analysis**

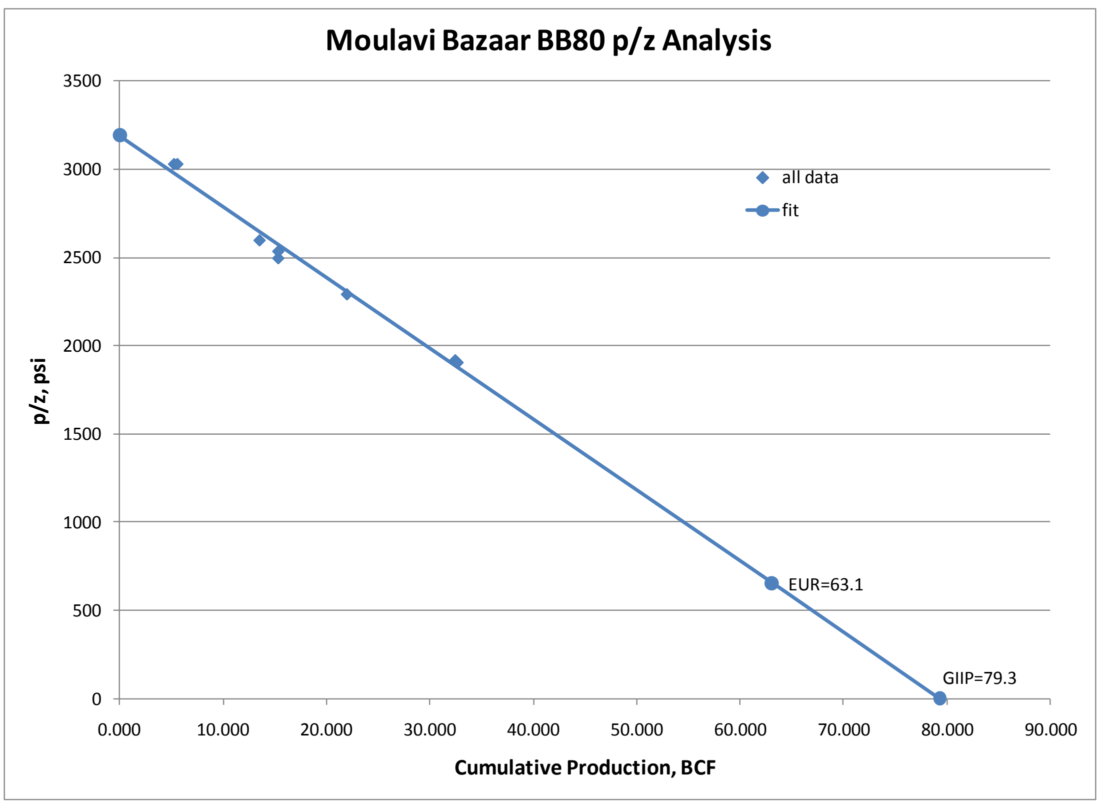



**Figure 6-102  Moulavi Bazaar BB80 p/z Analysis**

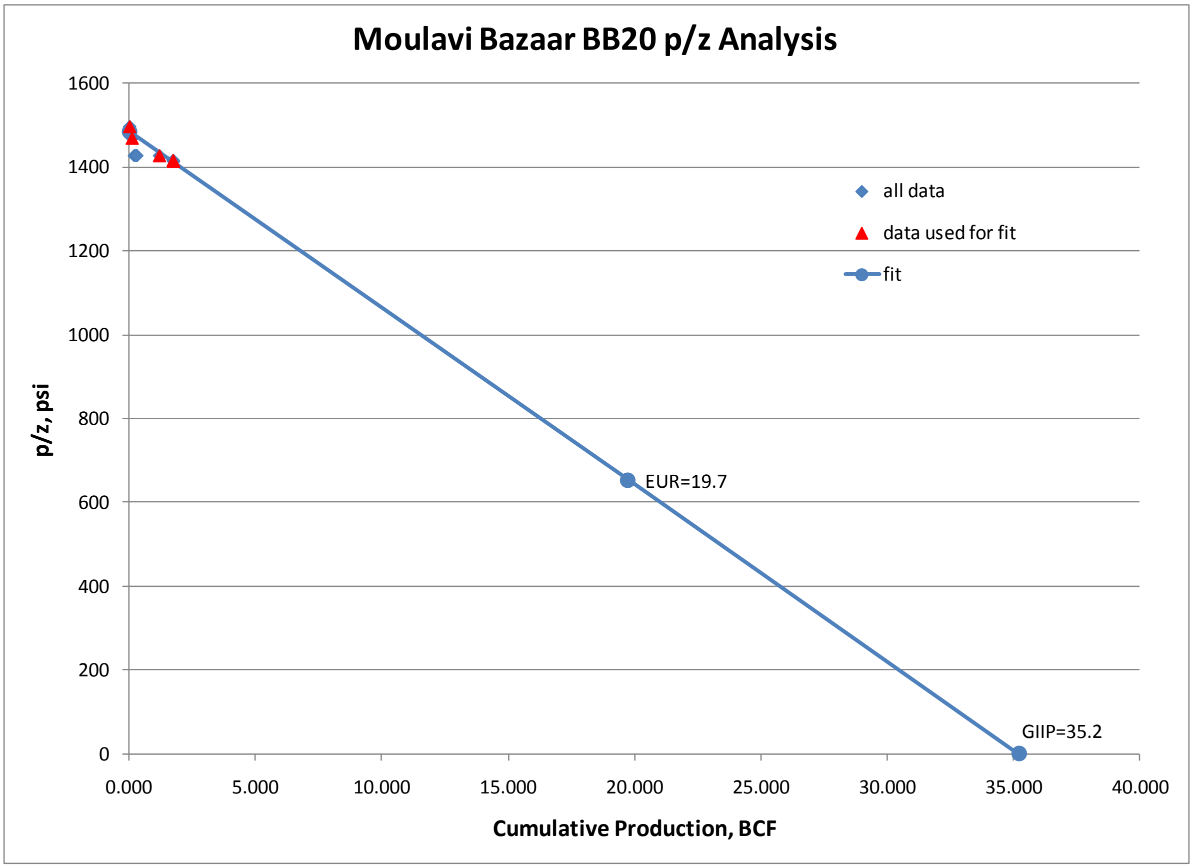



**Figure 6-103  Moulavi Bazaar BB20 p/z Analysis**

Well #5, despite not having produced since January 19, 2006, has had a varied reported pressure history since that time (Figure 6-104).  These data were not considered reliable for a material balance analysis of any type.

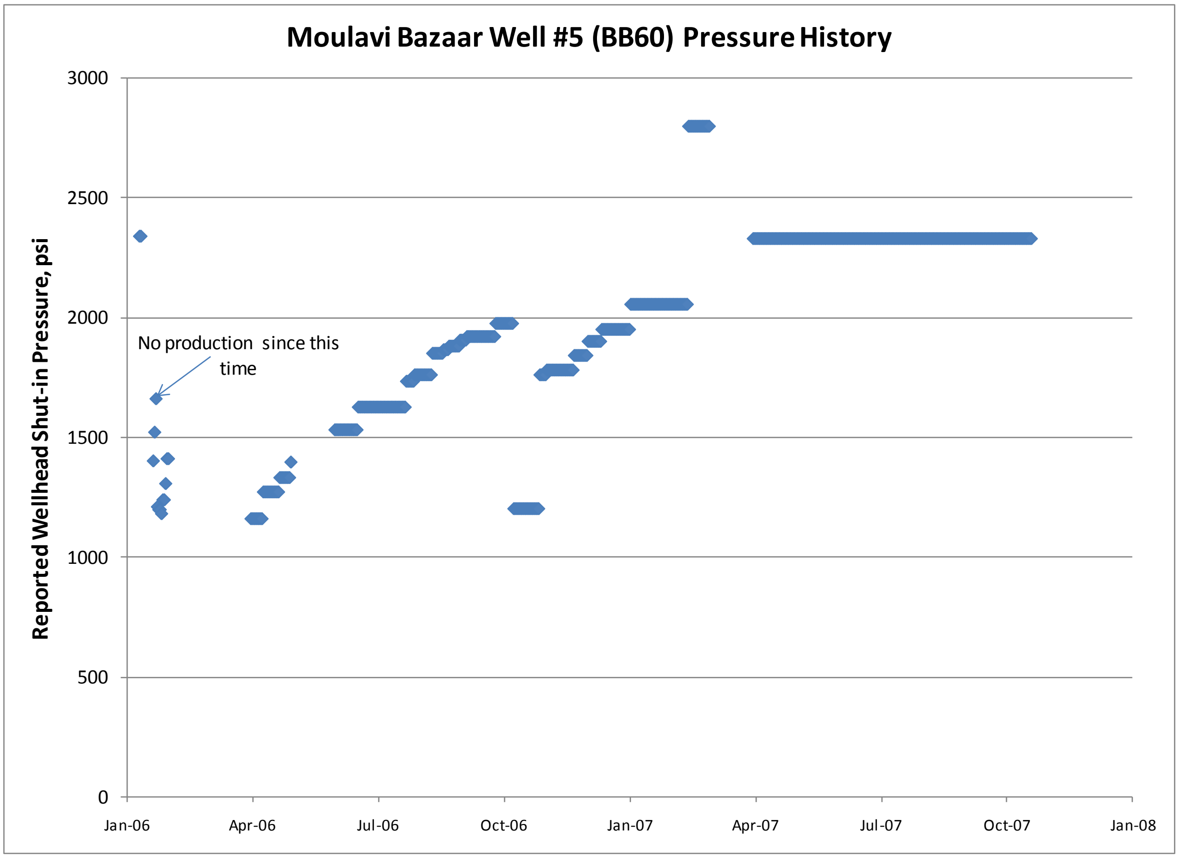



**Figure 6-104 Pressure History, Moulavi Bazaar Well #5**

## 6.3.13 <u>Narshingdi</u>

### 6.3.13.1 Geologic Setting

Narshingdi gas field is located in northeastern Bangladesh in the western edge of the Eastern Foldbelt in the northern portion of Block 9 (Figure 6-2). The field is located on the northernmost culmination of greater Bakhrabad structure that includes the Meghna and Bakhrabad gas fields to the south. The field is some 40 km. north of Bakhrabad field and approximately 32 km. west of Titas gas field.

### 6.3.13.2 Structure

The Narshingdi structure is a NNE trending anticlinal closure that exhibits approximately 12m of independent four-way dip closure along the crest of the structure as mapped on the top of the

Upper Gas Sand (Figure 6-105). At the level of the Lower Gas Sand, the mapped independent fold closure is somewhat larger at about 20m (Figure 6-106). As mapped in the 2003 versions, the area of independent closure is about 9 km. by 5 km. The two maps in Figure 6-105 and Figure 6-106 are based on a 2-D seismic grid and the results of the drilling of the NAR #1 (BK #10) discovery well. A GWC at -2907m was identified in the Upper Gas Sand (IKM, 1991, 1992). The GWC was also detectable on the seismic lines and could be traced around the structure.

The IKM study did not detect a GWC in the Lower Gas Sand in the NAR #1 well or on the seismic data. However, this study interpreted the presence of a down-to-the-south, WNW trending transverse fault located immediately to the north of the NAR #1 well at the Lower Gas Sand horizon. They believed that this fault formed the northern boundary of the Lower Gas Sand productive reservoir. The IKM study stated that the presence of this fault was confirmed through pressure transient testing that detected a boundary condition (IKM, 1991).

In a 2004, BAPEX produced a depth structure map of Narshingdi contoured on the top of the Lower Gas Sand. This map is shown in Figure 6-107. It shows a closed structure of similar structural style, size, and orientation as the maps in Figure 6-105 and Figure 6-106. However, this interpretation shows the structure to be asymmetrical with a steeper west limb and a gentler east limb. This map was also constructed using 2-D seismic and the results of NAR#1.

A similar depth structure map on top of the Lower Gas Sand was constructed by the Reservoir Management Study Cell of Petrobangla in their March 2003 study (Petrobangla, 2003: HCU document #74).

The fault interpreted at the Lower Gas Sand level in the 1991/1992 IKM study is not shown on any of the later maps.

All of the maps displayed in this report pre-date the drilling of the NAR #2 well, which was drilled in 2007. This latter well encountered the Upper Gas Sand at -2902.5m (5.5m low to NAR #1). Similarly, it encountered the Lower Gas Sand at -3153m (4m low to NAR #1) (BGFCL

Reservoir Engineering Section, PowerPoint presentation, J. Kabir, unlisted date). These results would not have been predicted by the structure maps shown in Figure 6-105 through Figure 6-107 and, most specifically, by the 2004 BAPEX map included as Figure 6-107.

6.3.13.3 Reservoir

Only two gas-bearing sands were encountered in NAR #1 (Bakhrabad #10) and were named as Upper Gas Sand and Lower Gas Sand. The two gas sands and other associated nonproductive sands in this gross stratigraphic interval were interpreted to be (bay)mouth bar sands in the IKM study on the basis of connate water salinity and position in the Middle/Late Miocene depositional basin (IKM, 1991).

The Upper Gas Sand in the NAR #1 well is about 17m thick with the gas-saturated portion being about 9.4m thick (gross sand) and containing 7.3m of net sand. The Upper Gas Sand interval contains interlaminated shales and siltstones along with the sands. The Lower Gas Sand is about 13.7m thick (completed gas-bearing interval) and contains 12.5m of net sand. The two productive intervals are separated stratigraphically by 266m of non-reservoir section (IKM, 1991).

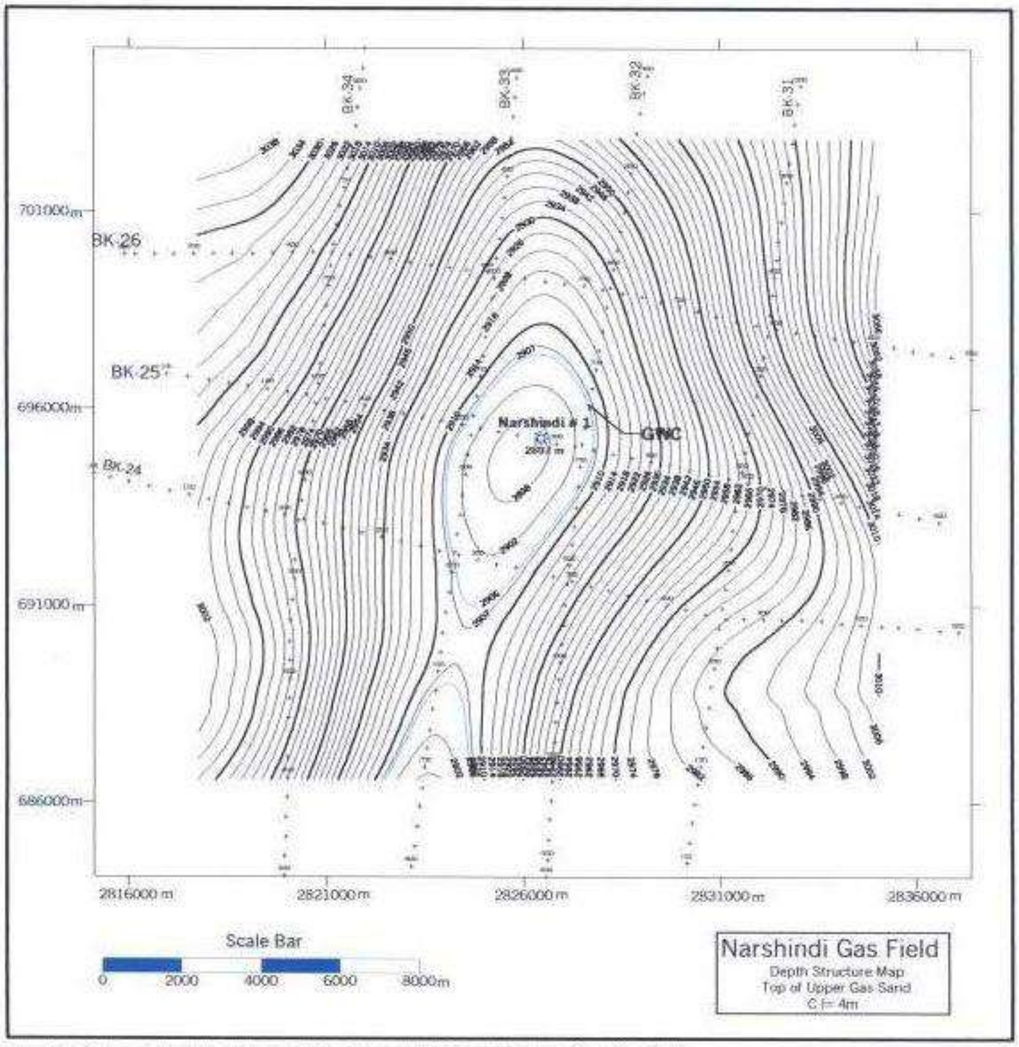



**Figure 6-105 Depth Structure Map on Top of Upper Gas Sand – Narshingdi Gas Field**
Map based on the results of Narshingdi #1 well (after HCU, 2003).

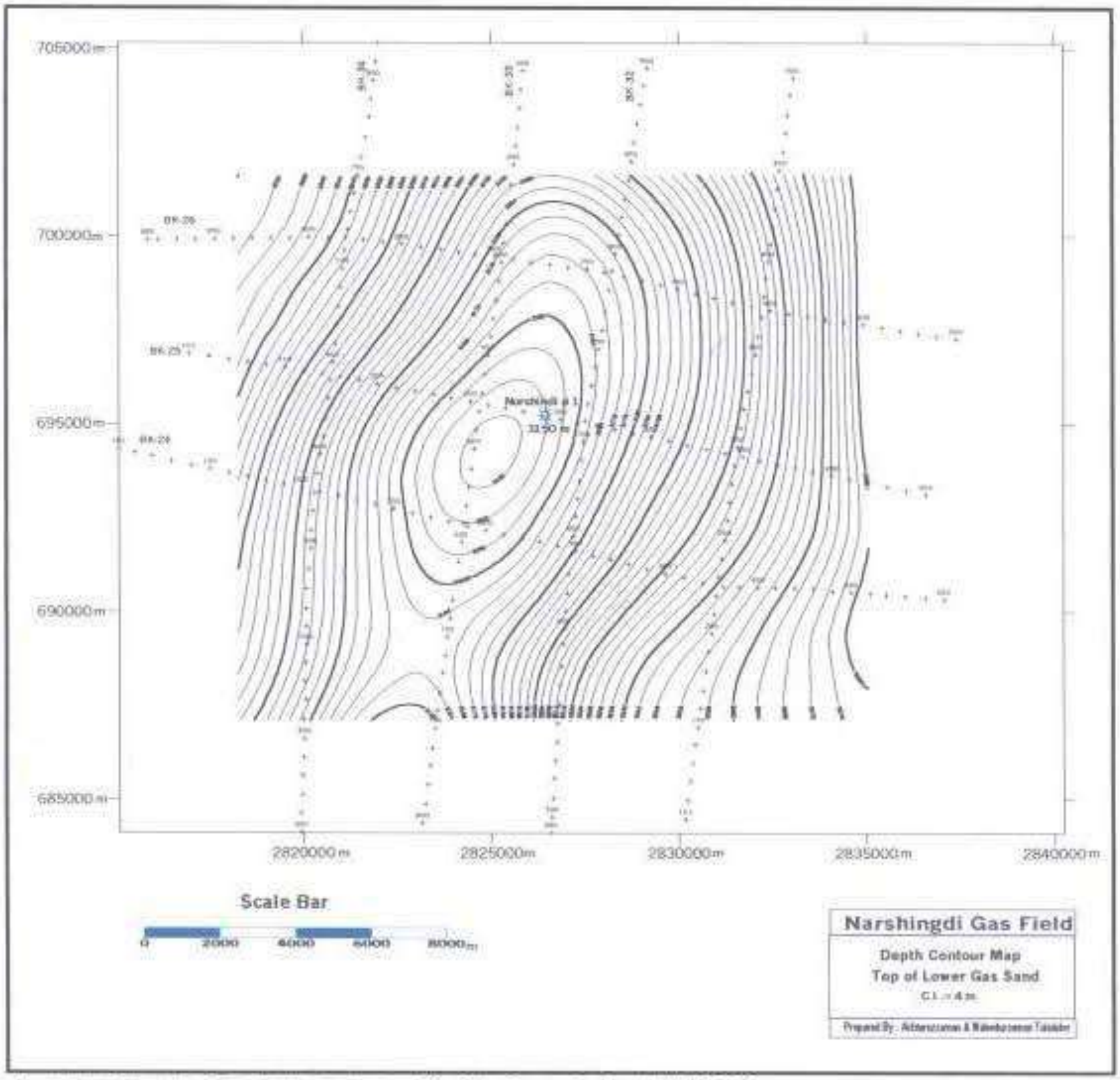



**Figure 6-106 Depth Structure Map on Top of Lower Gas Sand – Narshingdi Gas Field**
Map based on the results of Narshingdi #1 well (after HCU, 2003).

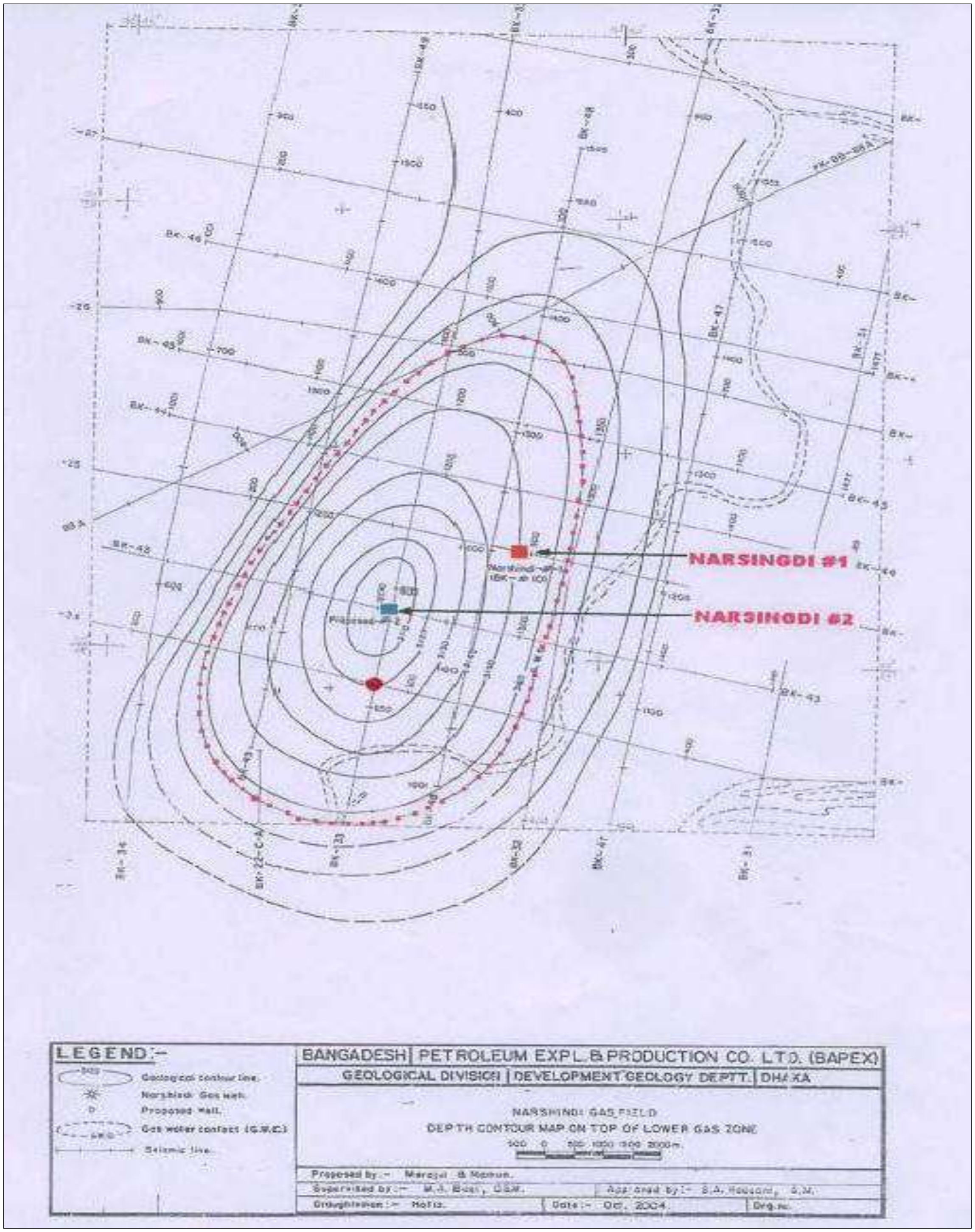



**Figure 6-107 Depth Structure Map on Top of Lower Gas Sand – Narshingdi Gas Field, 2004**

Map shows location of Narshingdi #1 (red rectangle) and the proposed location of Narshingdi #2 (blue rectangle). Additional proposed location for a third well shown with red circle. Only two wells were ultimately drilled and completed as gas wells in the field (BAPEX, 2004).

Lithologically, the productive sands range in grain size from coarse silts to medium-grained sands and are composed predominantly of quartz with secondary amounts of feldspar and rock fragments. Porosity averages 15-16% and permeability ranges from 85 to 150 md. In general, the reservoir quality is considered to be poor to moderate. (IKM, 1991).

#### 6.3.13.4 Exploration and Field Development

Narshingdi structure was identified by PSOC and named as Prospect A2 (Carmichael, 1994). Prospect A2 was mapped in detail and named as Belabo. However, the first well drilled in this prospect was named as Bakhrabad #10. After discovery of gas, the field was named as Belabo. Later, the name was changed to Narshingdi. Only two gas-bearing sands were encountered in Well #1 and were named as Upper Gas Sand and Lower Gas Sand.

Production from this field commenced on 25 July, 1996 from Lower Gas Sand. At the start of production, daily flow rate was about 25 MMscfd. However the rate was reduced to about 20 MMscfd within a year. Daily gas production from the single well remained relatively constant for the next several years and was still at a level of about 20 MMscfd when Narshingdi #2 well was completed in the Lower Gas Sand and began production in February 2007. With the addition of gas from Narshingdi #2, the total daily production from the field jumped to about 35 MMscfd. At the end of December 2009, combined daily production from the two wells was still at about 34 MMscfd.

#### 6.3.13.5 Well-wise and Sand-wise Production History

Figure 6-108 and Figure 6-109 graphically present the well-wise and sand-wise production history for Narshingdi gas field. Figure 6-108 clearly shows that the NAR Well #1 accounts for the lion's share of the gas that has been produced from this field through the end of 2009. NAR Well #2 began producing in February 2007 and is flowing gas at a rate only slightly less than the NAR #3 well (Figure 6-108). As shown in Figure 6-109 and in Table 6-39, all of the field's production comes from the Lower Gas Sand.

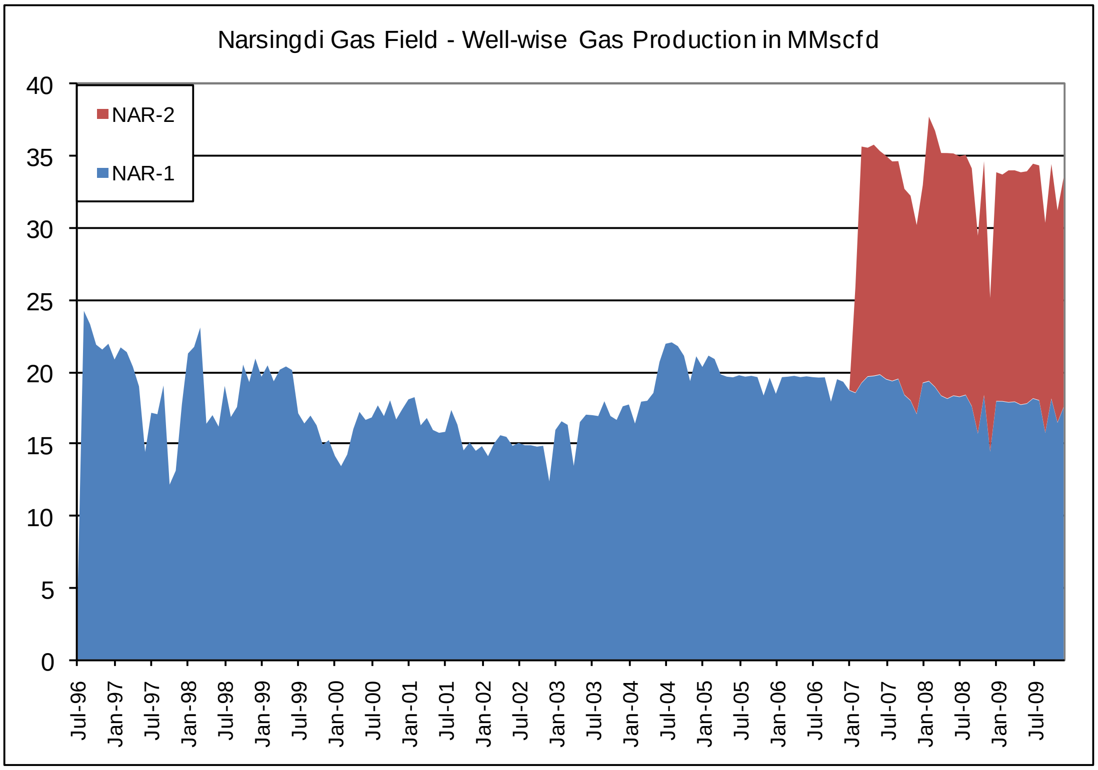



**Figure 6-108 Well-wise Gas Production - Narshingdi Gas Field**

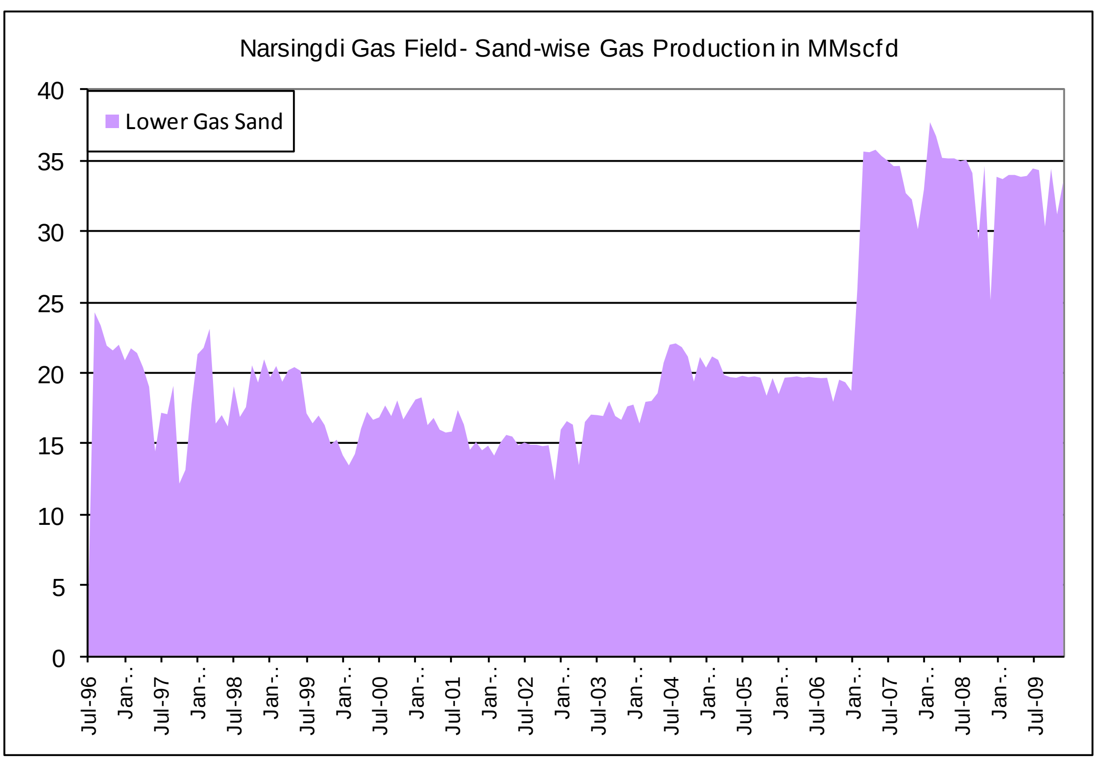



**Figure 6-109 Sand-wise Gas Production – Narshingdi Gas Field**

6.3.13.6 Field-wise Cumulative Production

The cumulative production from Lower Gas Sand was 104.4 Bscf at the end of December 2009 Table 6-39). All of the field's production is from this sand. The Upper Gas Sand has not been produced. Well #3 has produced nearly 88 Bscf of gas or approximately 96% of the field's total cumulative production through the end of 2009; however, the NAR #2 will be an important contributor to future production as well as to the field's ultimate cumulative recovery.

**Table 6-39 Sand-wise Cumulative Gas Production – Narshingdi Gas Field**

| Reservoir Sand | Cum. Prod. (Bscf)[9] |
|---|---|
| Lower Gas Sand | 106.2 |
| **Total** | **106.2** |

from HCU production database

6.3.13.7 Earlier Reserve Estimates

A number of pre-drill and post-drill reserve estimates of Narshingdi have been made over the years.

A pre-drill GIIP estimate was made by BOGMC based on a seismic interpretation and sand thicknesses from nearby fields (IKM, 1991). They estimated the potential for 2.1 Tscf of in-place gas on the Narshingdi structure - a far greater estimate than any of the post-drill estimates.

In 1992, IKM estimated the 2P and 3P GIIP for the Upper Gas Sand and 1P GIIP for the Lower Gas Sand. They used a deterministic volumetric methodology. Their results are listed below in Table 6-40.

[9] Production through end of December 2009

**Table 6-40 IKM 1992 Reserve Estimate – Narshingdi Gas Field**

| IKM, 1992 - GIIP (in Bscf) | | | |
|---|---|---|---|
| Reservoir | Proved (1P) | Probable (2P) | Possible (3P) |
| Upper Gas Sand | - | 45.9 | 83.7 |
| Lower Gas Sand | 64.8 | - | - |
| Total | 64.8 | 110.7 | 148.5 |

IKM, 1992

In 2003, Petrobangla's Reservoir Study Cell estimated GIIP and Recoverable Reserves for the Lower Gas Sand using both deterministic volumetric and material balance methodologies. The results of this study are presented in Table 6-41. The two methodologies result in similar values of GIIP that are within 20% of each other. The Material Balance methodology using actual production and pressure decline produced a slightly higher estimate of GIIP for this reservoir, although it was based on only three pressure measurements.

In its 2003 reserve report, the HCU-NPD study estimated GIIP for both reservoir zones at Narshingdi gas field using a deterministic volumetric methodology. The results of that estimation are presented in Table 6-42. In addition, the study also performed a material balance estimate of the GIIP for the Lower Gas Sand using the MBAL software package. This material balance study used shut-in wellhead pressure (SWHP) data and converted that data to shut-in bottomhole pressure (SBHP) using pressure gradient information. The material balance study indicated a GIIP of 315 Bscf for the Lower Gas Sand. That estimate is included in Table 6-42.

The HCU-NPD 2003 estimate is the first to include an estimate of 2P and 3P GIIP for both reservoir sands. It resulted in a 14% decrease in the 3P GIIP for the Upper Gas Sand over the 1992 IKM estimate. However, the HCU-NPD 2003 study resulted in a 7% increase in the 3P GIIP estimate for the Lower Gas Sand over the Petrobangla Reservoir Study Cell 2003 estimate for the same zone – both studies employing the material balance methodology.

**Table 6-41 Petrobangla Reservoir Study Cell 2003 Reserve Estimate – Narshingdi Gas Field**

| Petrobangla Reservoir Study Cell, 2003 (in Bscf) | | | | |
|---|---|---|---|---|
| Lower Gas Sand | | | | |
| Estimated Volume | Volumetric | | | Material Balance (p/z) |
| | Proved (1P) | Probable | Proved + Probable (2P) | |
| GIIP | 137.25 | 111.21 | 248.46 | 295 |
| Recoverable (60% R.F.) | 82.35 | 66.73 | 149.08 | |

Petrobangla, 2003

**Table 6-42 HCU-NPD 2003 Reserve Estimate – Narshingdi Gas Field**

| | GIIP | | | | |
|---|---|---|---|---|---|
| Sand | Proved | Probable | Possible | Total 2P | Total 3P |
| Upper Sand | | 71.7 | | 71.7 | 71.7 |
| Lower Sand | 46.46 | 189.04 | 79.8 | 235.5 | 315.3 |
| Field Total | 46.46 | 260.74 | 79.8 | 307.2 | 387 |

HCU-NPD 2003

The most recent reserve estimate for Narshingdi gas field is that done by RPS Energy for Petrobangla and released in late 2009 (RPS, 2009h). The results of that estimate are presented on Table 6-43. This study incorporated 3-D modeling and reservoir simulation using the Petrel and Eclipse software packages of Schlumberger. It also used a probabilistic volumetric methodology using the REP software. This estimate is very similar to the HCU-NPD 2003 and the Petrobangla Reservoir Study Cell 2003 estimates for the field. All three studies estimated GIIP for the Lower Gas Sand in the range of 285-315 Bscf. The HCU-NPD and the RPS Energy estimates for total field GIIP are within 22 Bscf of each other and in the range of 365 Bscf to 387

Bscf. This should be considered excellent confirmation of the GIIP for the field, approaching the same conclusion using much different methodologies.

**Table 6-43 RPS Energy 2009 Reserve Estimate – Narshingdi Gas Field**

| GIIP | Volumetric Calculation (Bcf) | | Material Balance (Bcf) | History Match Model (Bcf) |
|---|---|---|---|---|
| | Petrel™ | †REP™ (P50) | | |
| Upper Gas Sand | 81 | 49 | No production | 84 |
| Lower Gas Sand | 284 | 151 | 235 - 290 | 285 |
| **Total** | **365** | **200** | **-** | **369** |

RPS Energy, 2009h

### 6.3.13.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Narshingdi field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

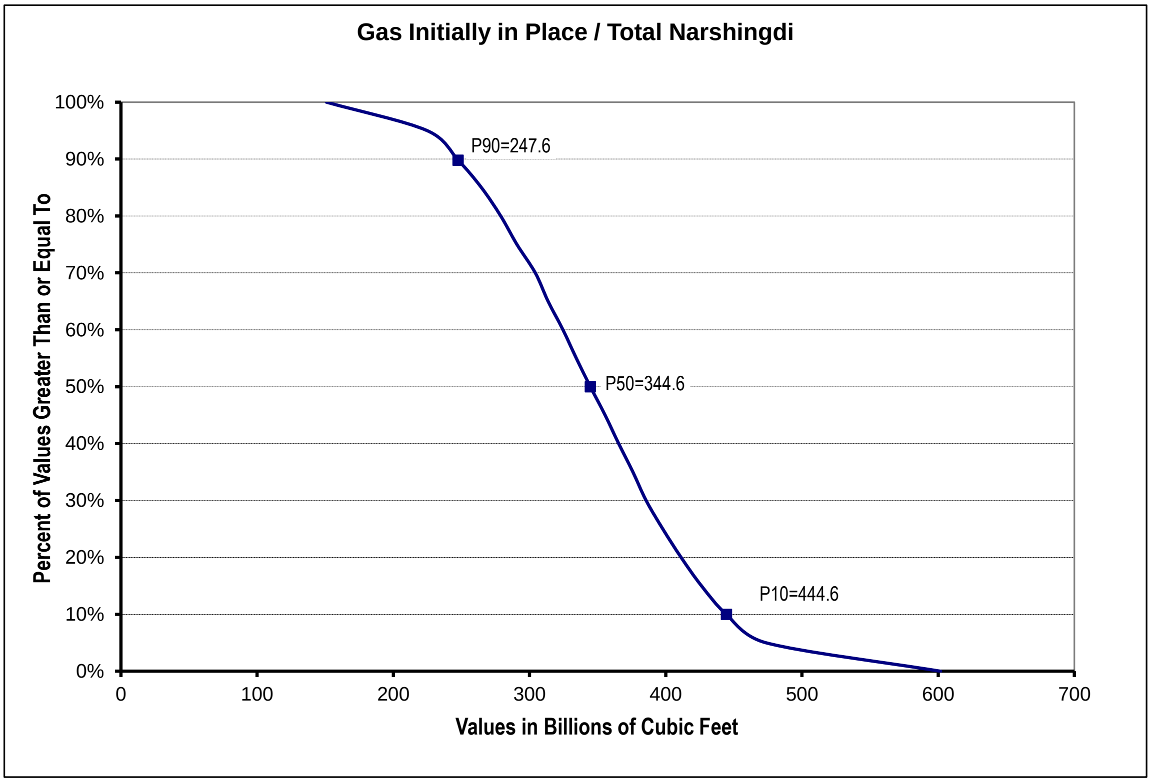



**Figure 6-110 Distribution of GIIP, Narshingdi**

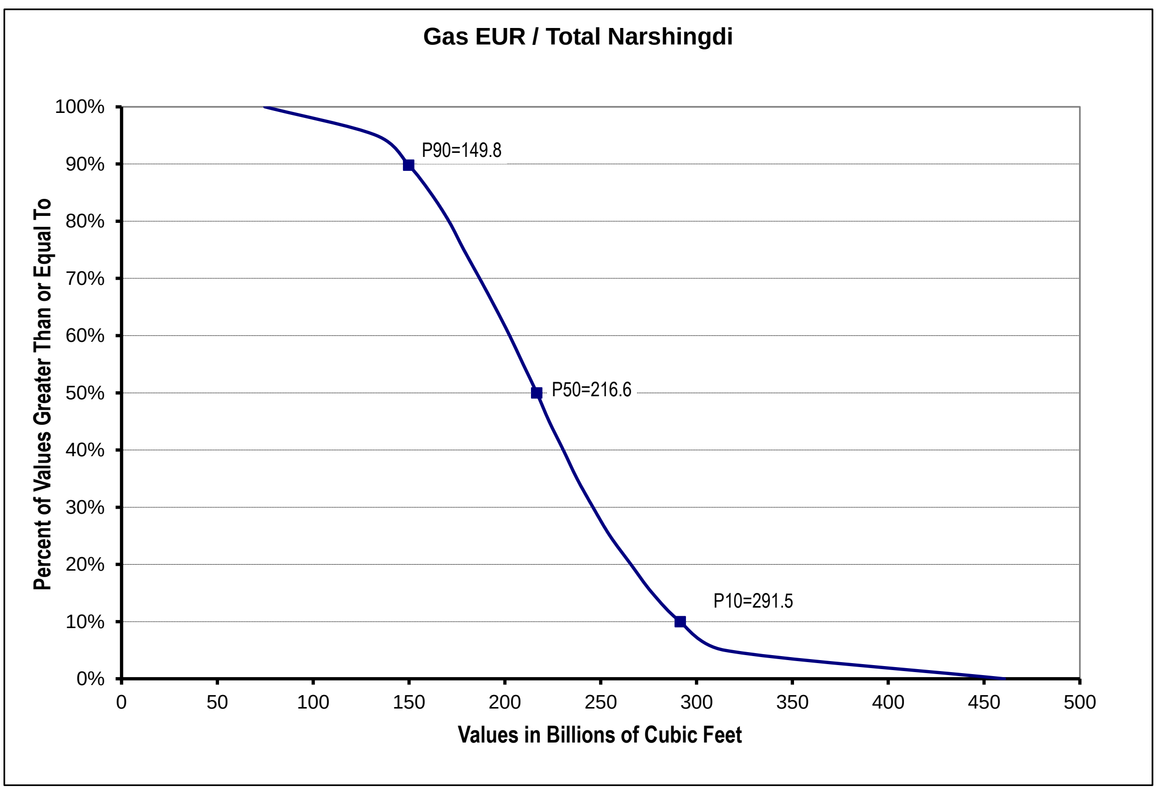



**Figure 6-111 Distribution of Gas EUR, Narshingdi**

**Table 6-44 Summary of Estimated Ultimate Recovery at Narshingdi**

| Reservoir | Mean Gas EUR, BCF | Cumulative Gas, 1/1/2010, BCF | Reserves, 1/1/2010, BCF |
|---|---|---|---|
| Upper Gas Sand | 61 | 0 | 61 |
| Lower Gas Sand | 159 | 106 | 53 |
| **TOTAL** | **220** | **106** | **114** |

In addition, material balance calculations were made for Narshingdi using conventional p/z analysis. Bottom-hole shut-in pressures were calculated from reported surface shut-in pressures and gas properties, assuming no liquid accumulation above the reservoir in the wellbore. This is considered a valid assumption, since the low water and condensate volumes would be expected to be in the gaseous state at reservoir conditions. The pressure data were reviewed and found to be in close agreement between the two wells (#1 and #2). Therefore, the pressure data were averaged and the cumulative production was summed for these wells to analyze the Lower Gas Sand reservoir as a whole (Figure 6-112).

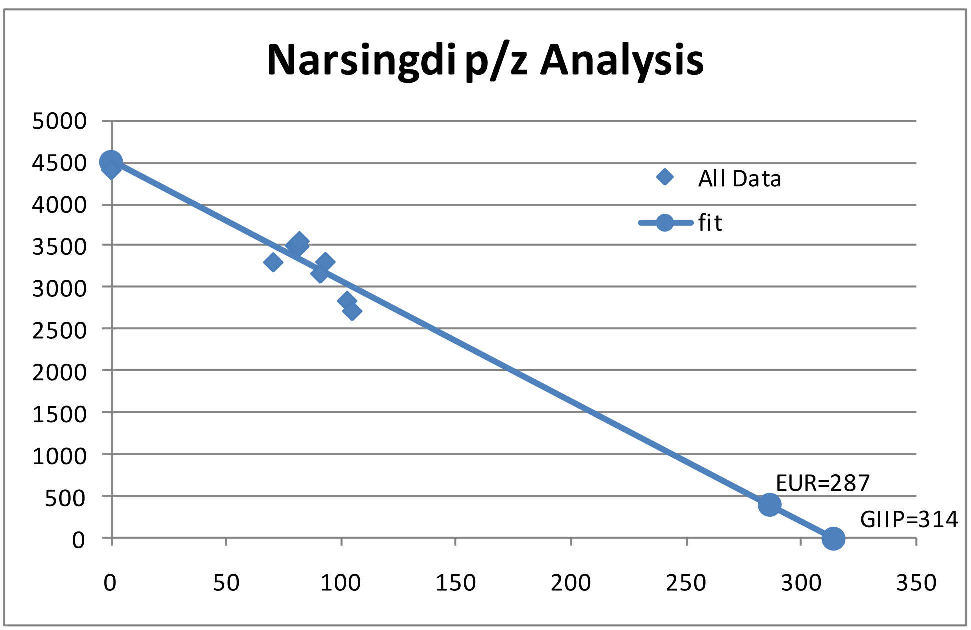



**Figure 6-112 Narshingdi p/z Analysis**

Because the GIIP estimated from this analysis was materially higher than that calculated volumetrically, and because the last two pressure points showed a downward variation from the trend line, the AWMB method[10] was also used. For this method, again, both wells' production was summed and pressures were averaged. The results for the AWMB are shown in Figure 6-113.

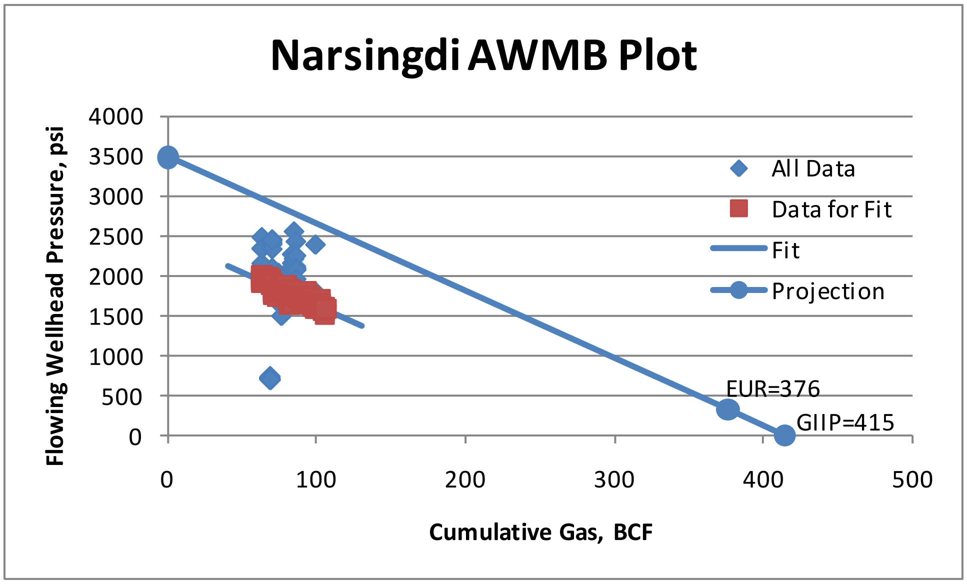



**Figure 6-113 Narshingdi AWMB Plot**

The material balance results compare with the mean volumetric calculations as follows:

| | | Mat Bal | |
|---|---|---|---|
| **Method** | **Volumetric** | **p/z** | **AWMB** |
| GIIP, BCF | 252 | 314 | 415 |
| EUR, BCF | 159 | 287 | 376 |
| Cum. Gas, BCF | 106 | 106 | 106 |
| **Reserves, BCF** | **53** | **181** | **270** |

The performance-based material balance analysis is generally more reliable, and the p/z analysis is more reliable than the AWMB. Since the AWMB analysis for Narshingdi supports an even higher GIIP than the p/z analysis, the p/z is judged to be reliable despite the two points late in time that deviating from the trend line.

[10] Mattar and McNeil, 1998.

### 6.3.14 Rashidpur

#### 6.3.14.1 Geologic Setting

Rashidpur Anticline is located in the southeastern part of the Surma Basin and within the Eastern Foldbelt to the south of and on trend with the Bibiyana gas field structure (Figure 6-3). The anticline is exposed on surface and mapped by a number of geologists. The structure was delineated on the basis of singlefold analog seismic data acquired during 1959-60 by PSOC. According to the PSOC interpretation, the structure is an elongated, north-south trending anticline with relatively steeper eastern flank. The structure is quite pronounced in aerial photographs. Rashidpur gas field was discovered in 1960 with the drilling of the Rashidpur Well #1.

#### 6.3.14.2 Structure

Rashidpur is an elongated narrow asymmetrical anticline with a north-south oriented axis. On the surface the structure is represented by outcrop of late Tertiary age. Since 1960 a number of structural maps were prepared by different workers. All these maps are quite similar. The main difference is the fault on the eastern flank, which is not shown in most of the interpretations.

Based on singlefold seismic data, PSOC mapped the structure as a narrow, elongated asymmetrical anticline with relatively steeper east flank. After acquiring additional 271 line-km of seismic data, HHSG in Petrobangla mapped the structure with three culminations. IPR in 1989 mapped the Upper Gas Sand only. This map showed two culminations.

After acquiring additional seismic data and drilling two new wells, IKM, (1990) prepared a map which divided the Upper Gas Sand into multiple blocks by three transverse faults. The Lower Gas Sand is also affected by four transverse faults. A longitudinal fault is also present in this map interpretation (Figure 6-114).

In 1995, BAPEX, after reviewing available data, prepared two maps, one on top of the Upper Gas Sand and another on top of the Lower Gas Sand. Figure 6-115 shows structure maps on the Upper Gas Sand, zones A and B, from this mapping effort. According to BAPEX, the Upper Gas Sand in the south is underlain by another sand bed which is gas-bearing. This sand does not continue on the north. Vertical distance between these two sands is about 100m.

During 1999, three more wells were drilled in Rashidpur and the new well data supported the findings of BAPEX's earlier mapping. Figure 6-116 is the latest seismically based structural interpretation of the Rashidpur structure (Kabir and Hussain, 2009).

#### 6.3.14.3 Reservoir

Reservoir sands of Rashidpur gas field were evaluated by earlier workers with the help of seismic, well logs, and other well data including limited core data.

Rashidpur Wells #1 and #2 confirmed the presence of two main gas sands named as Upper Gas Sand and Lower Gas Sand. During 1989, three more wells (#3, #4, and #5) were drilled and additional gas sands of limited extension were identified. New wells also provided data for better understanding on distribution of Upper and Lower Gas Sands. Wells drilled during 1999 identified additional gas sands of limited extension and further New wells also provided additional data for better understanding of distribution of Upper and Lower Gas Sands (UGS and LGS).

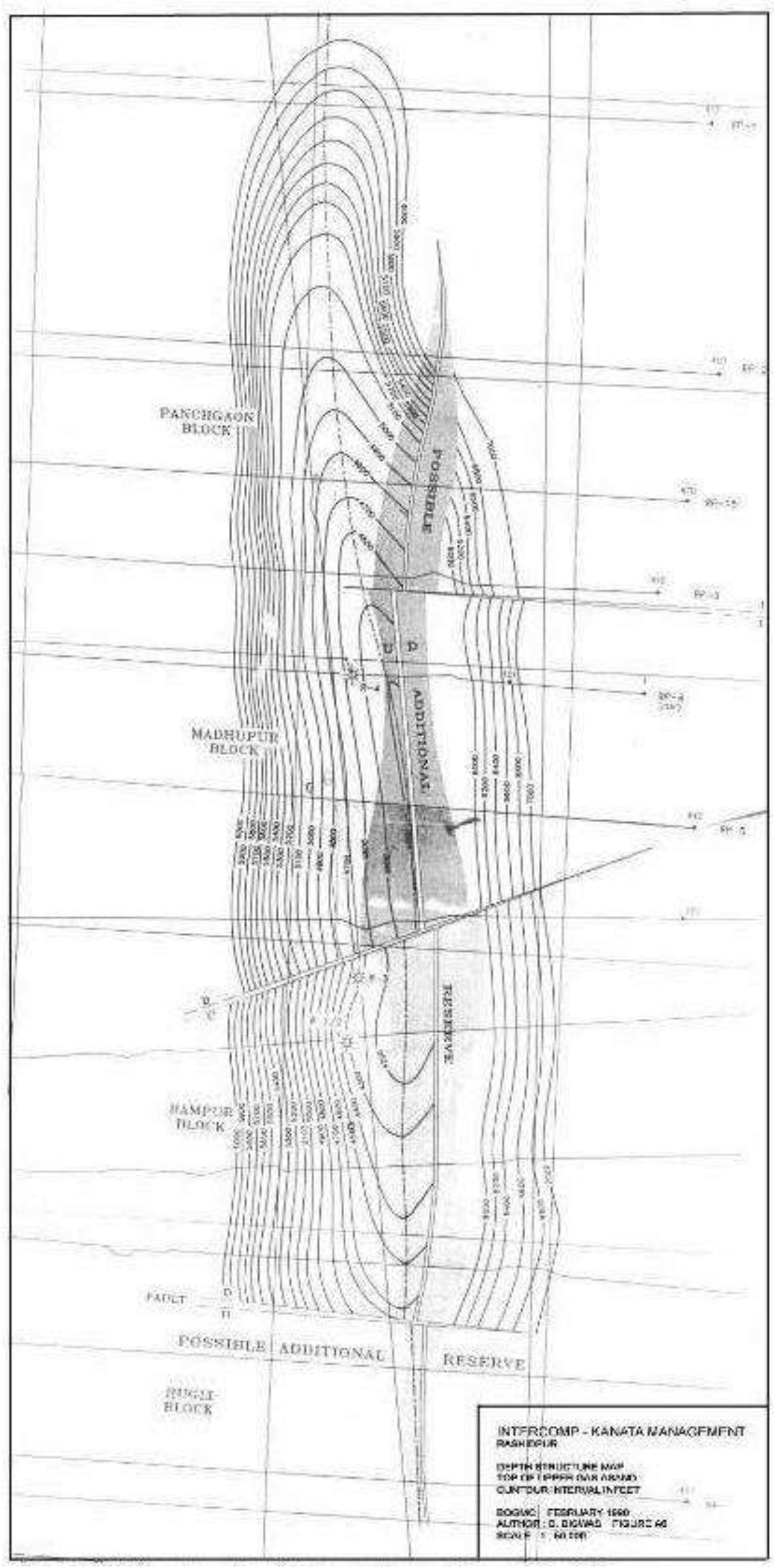



**Figure 6-114 Depth Structure Map on Top of Upper Gas Sand – Rashidpur Gas Field**
(IKM, 1990)

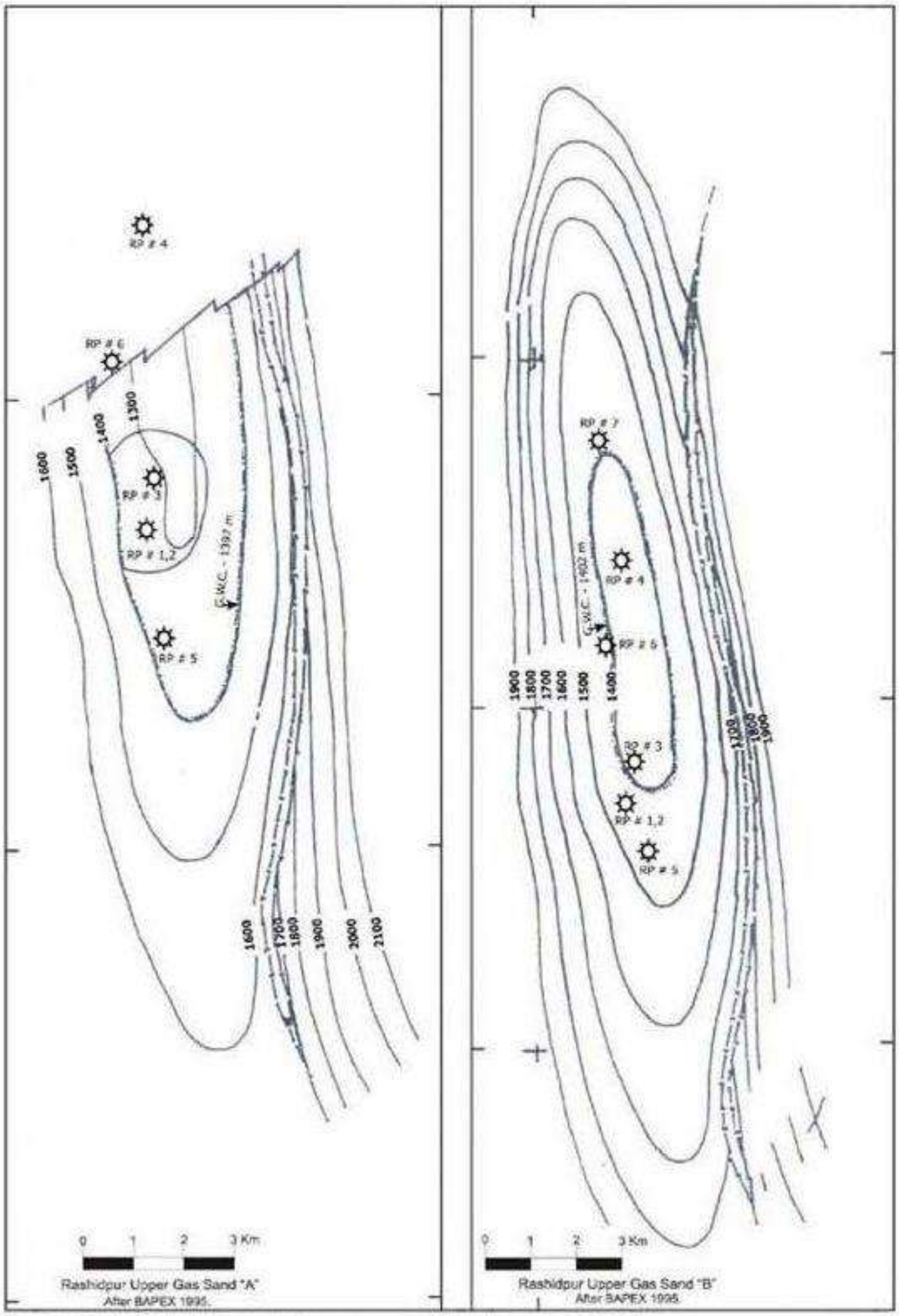



**Figure 6-115 Structure Maps on Top of Upper Gas Sands A and B, Rashidpur Field**
(BAPEX, 1995)

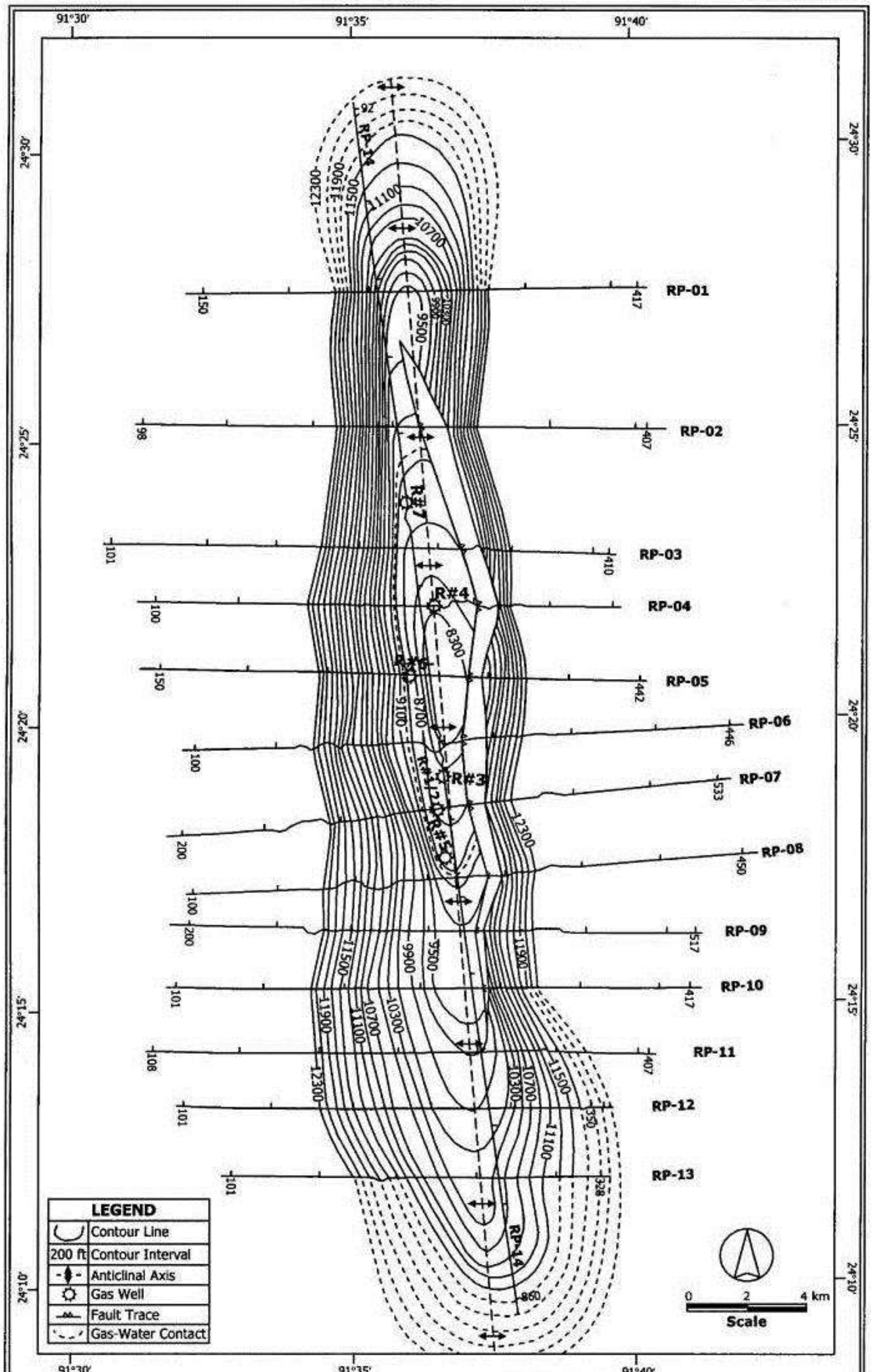



**Figure 6-116 Depth Structure Map on Top of Lower Gas Sand – Rashidpur Gas Field**
Seismically-derived structure map (in feet) (after Kabir and Hussain, 2009).

Well #5 drilled to the south of Wells #1 and #2, confirmed that the Upper Gas Sand is divided into sub-units separated by a shale bed of about 50m thick. The discovery well drilled through the gas water contact of the upper layer, and drilled through the lower layer, just outside the gas water contact. Well #5 opened a new gas sand at the interval 2730-2750m named the Bhuban Thin Alternation (BTA) Sand. The Lower Gas Sand was encountered at a greater depth than anticipated. Well #5 was completed in the BTA Sand. This well has apparently watered out and is located at or near the crest of the structure; therefore, this reservoir has no significant remaining reserves. RPS did not model this sand in their 2009/2010 study. With our limited data, we were also unable to estimate reserves for this sand. With better mapping, it may be possible to include this reservoir in future updates; however, its contribution is expected to be minor.

Well #6 narrowly missed the gas column of the Upper Gas Sand as the location is slightly down dip from the gas-water contact. The well drilled entirely through wet sand. However, this well opened two other gas sands at 2738m and 2779m, separated by a 24-meter shale bed. These sands were named the Bhuban ‘A’ and Bhuban ‘B’. The Lower Gas Sand was found wet in this well. Well #6 was completed in the Bhuban ‘A’ (BHA) Sand. This well has apparently watered out. Some minor reserves may remain in the BHA Sand updip of this well, but insufficient data are available to estimate these reserves. RPS did not model this sand in their 2009/2010 study. With better mapping, it may be possible to include this reservoir in future updates; however, its contribution is expected to be minor.

In Well #7, the northernmost well of the field, one 9m gas sand was found at interval 1293-1302m. This gas sand is within the Upper Marine Shale and appears to be of limited extent. The Upper Gas sand was found to be wet in well #7. However, well #7 opened a new gas sand named the Middle Gas Sand (MGS). This sand is located at the depth of 2177–2215m. The Lower Gas Sand is observed to be divided into two units. The upper one extends from 2746 to 2770m and the lower one from 2789 to 2807m. According to log data, the GWC is observed at 2802m. The second unit of the Lower Gas Sand extends from 2844 to 2861m and water saturation is rather high (75%).

In the Rashidpur field, cores were cut in wells #1 and #2. According to PSOC core was cut at every 305m (1000ft) in well #1, and in well #2 core was cut at a depth below Lower Gas Sand. No core reports are available. In both well #3 and 4#, Upper Gas Sand is continuously cored, from 1375 to 1440m in well #3 and 1450 to 1511m in well #4. The Lower Gas Sand was also cored in both the wells. Reservoir parameters are based on core as well as log data. A porosity vs. depth plot can be seen in Figure 6-117 below. The plot shows that log porosity is lower than the core porosity for both Upper and Lower Gas Sands.

Porosity is considered to be 22% for the UGS, 20% for both the Middle Sand and the BTA Sand, and 17% for the LGS. Water saturation is considered to be within a range between 27 and 32% (32% for the UGS, 30% for both Middle and BTA and 27% for LGS).

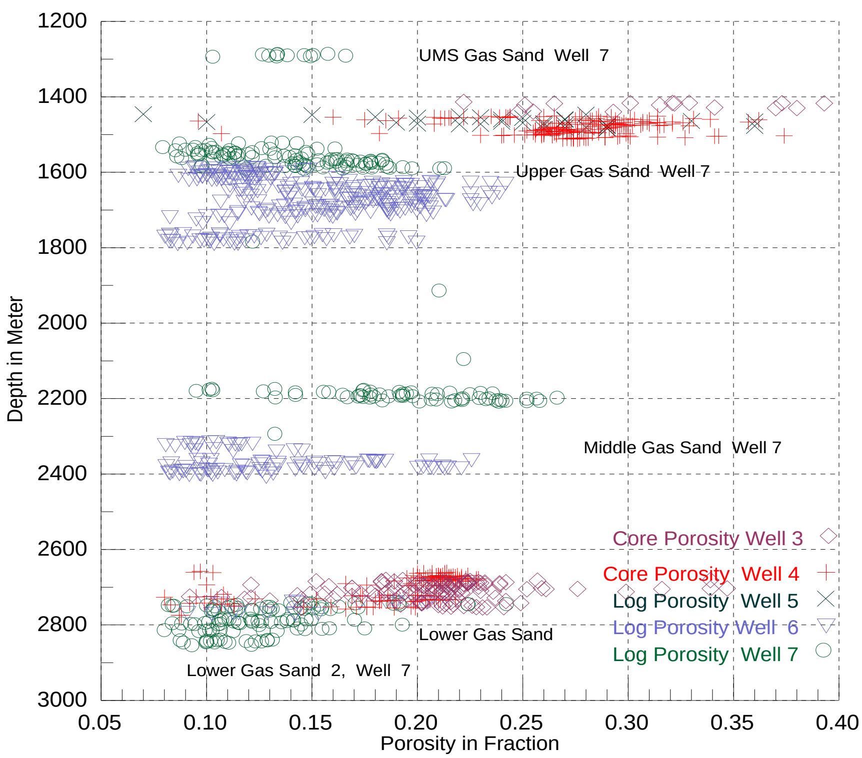



**Figure 6-117 Porosity vs. Depth Plot, Rashidpur**

### 6.3.14.4 Exploration and Field Development

The Rashidpur discovery well (Well #1) was drilled to 3860m by PSOC in 1960. The well discovered two gas horizons and both zones were tested. The sands were named the Upper Gas Sand and the Lower Gas Sand. During well testing, the Upper Sand flowed gas at the rate of 4.7 MMscfd and the Lower Gas Sand flowed at the rate of 7 MMscfd. In 1961, Well #2, located about 30 meters from Well #1, was drilled to 4593m. Only the Lower Gas Sand was tested in Well #2. Rashidpur Well #2 was the deepest well of the country until 1986, when Fenchuganj Well #2 was terminated at 4977m. Wells #1 and #2 remained shut down for nearly 30 years until production began in 1993. During 1989, three more wells (#3, #4, and #5) were drilled.

Gas production from Rashidpur started in September 1993. Well #1 was opened first and at the beginning, the flow rate was 16-22 MMscfd from the Upper Gas Sand (UGS). In February 1994, wells #2 and #3 were opened for production. Both of the wells were completed in the Lower Gas Sand (LGS). This increased field production to 60 MMscfd. Two months later in April 1994, well #4 was opened for production from the LGS. Production from these four wells was about 80 MMscfd. In November 1999, production sharply dropped to 35 MMscfd. However, production was gradually increased but it did not return to the earlier rate.

In January 2000, well #5 and well #6, completed in the BTA Sand, and well #7, completed in the LGS, were open for production. The addition of three more wells in January 2000 increased daily production to about 90 MMscfd over the next few months. There were some peaks showing production rates above 100 MMscfd. From January 2004, total field production started to decline. Within 5 years, daily production decreased to 50-51 MMscfd. After cutting back production to about 45-50 MMscfd, the decline rate was arrested. For the last 18 months, the production decline rate was reduced but total production came down to about 50 MMscfd. This reduction is shown in Figure 6-118.

This increased the field production rate to 100 MMscfd. Production rate was maintained at this level for about four years. From then on field production started to decline.

6.3.14.5 Well-wise and Sand-wise Production History

Production histories, both well-wise and sand-wise, are shown below in Figure 6-118 and Figure 6-119, respectively. Figure 6-119 clearly shows that the Lower Gas Sand is by far the most important pay interval in Rashidpur gas field and has consistently accounted for the largest percentage of gas field's daily production.

Detailed individual well histories and accompanying production charts for Rashidpur wells are included in The Annex.

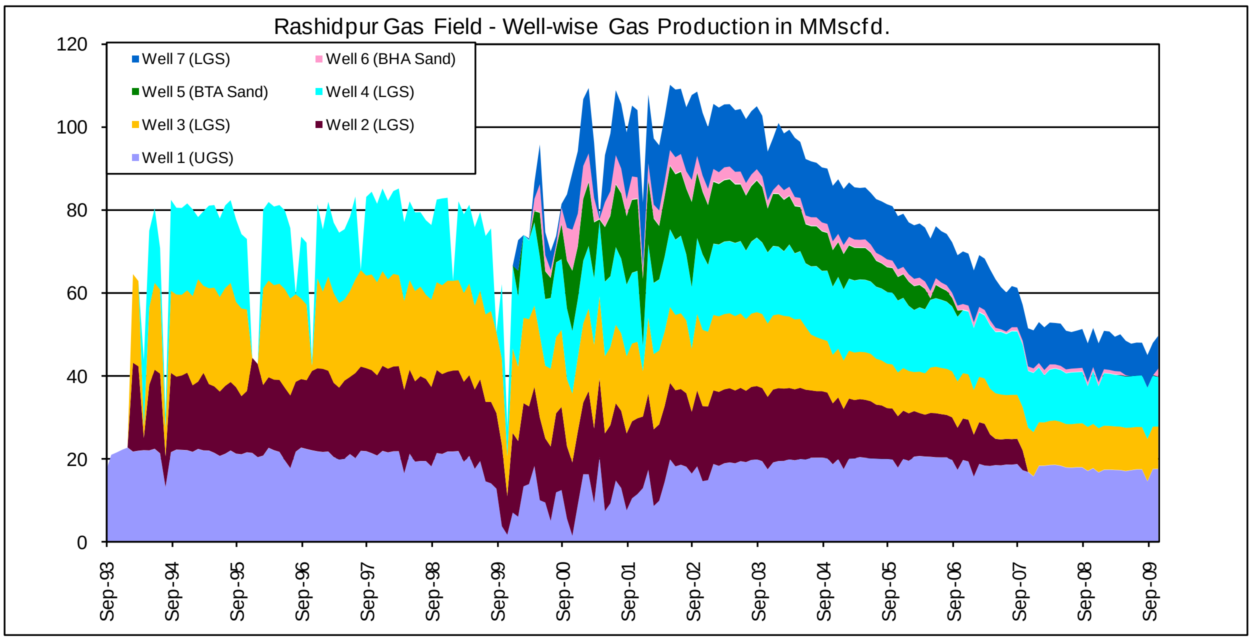



**Figure 6-118 Well-wise Gas Production – Rashidpur Gas Field**

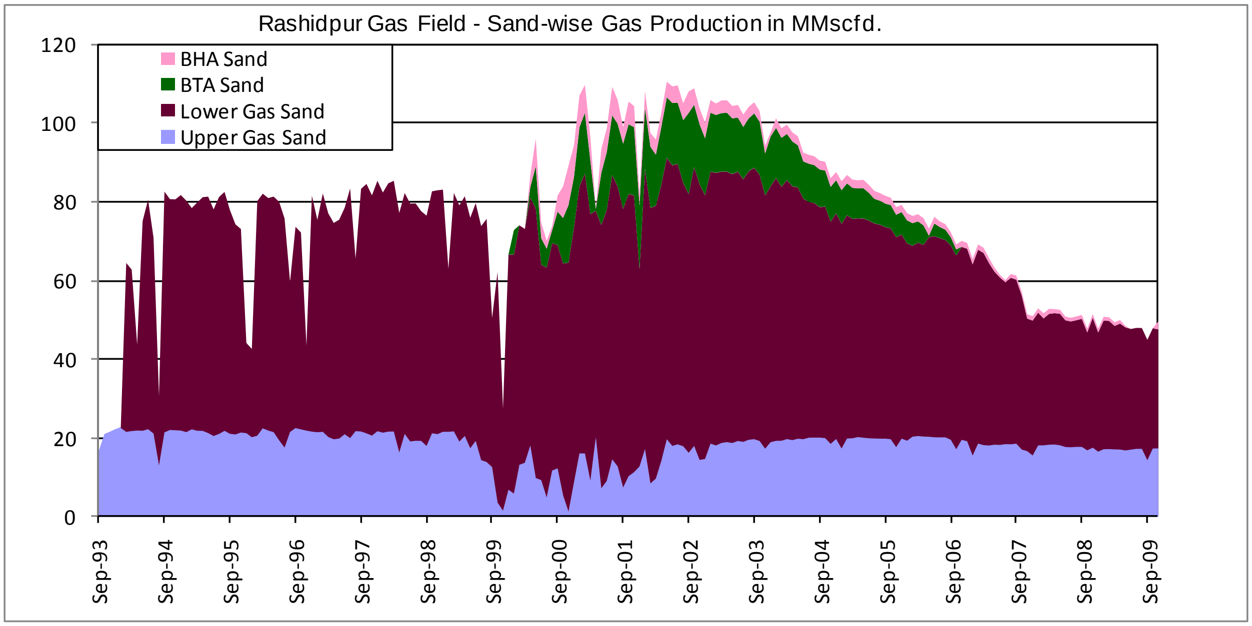



**Figure 6-119 Sand-wise Gas Production – Rashidpur Gas Field**

6.3.14.6 Field-wise Cumulative Production

Over its 16-year productive life, Rashidpur gas field has produced 457 Bscf of gas, 623,000 barrels of condensate, and 619,000 barrels of water from four separate sandstone intervals. At the end of 2009, the field was producing at an average daily rate of 50.3 MMscf of gas, 66 barrels of condensate, and 160 barrels of water.

Sand-wise cumulative production for Rashidpur gas field at end of December 2009 is summarized in Table 6-45 below.

Cumulative production from the LGS as of November 2009 was 314 Bscf. Contribution from well #7 was 43 Bscf. Wells #2, #3 and #4 produced 82, 95 and 94 Bscf, respectively. The LGS is the most important producing interval in the field, accounting for approximately 75% of the field's cumulative production.

The UGS, BTA, and BHA zones are each produced from single wells.

**Table 6-45 Sand-wise Cumulative Gas Production – Rashidpur Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Upper Gas Sand | 107.2 |
| Lower Gas Sand | 314.4 |
| BTA Sand | 25.6 |
| BHA Sand | 9.4 |
| **Total** | **456.6** |

1 Production through end of December 2009
HCU production database

### 6.3.14.7 Earlier Reserve Estimates

According to the original post-discovery PSOC estimate, the GIIP of Rashidpur gas field was 1060 Bscf. From 1977, Rashidpur started to attract attention of policy makers. Since then a number of reserve estimation reports were prepared by different agencies/authors. All these are based on old seismic data and essentially data from one well. Findings of these reports are discussed in detail in the "Gas Reserve Estimation 2003" report of Hydrocarbon Unit and are briefly reviewed here.

Under a German technical and financial assistance, a large area of the country was covered by a digital multifold seismic survey. Rashidpur was included in this program. Based on this data, new maps were prepared by the German Geological Advisory Group (GGAG) in Petrobangla. This group prepared new maps on Rashidpur and re-estimated gas reserve following both deterministic and probabilistic methods. According to this 1986 study, GIIP of Rashidpur was 2505 Bscf under Most Likely scenario (Deterministic Method) and it was 2823 Bscf at mean (probabilistic method). Results of this estimate are shown in Table 6-46.

**Table 6-46 GGAG 1986 Reserve Estimate - GIIP and Reserves in Bscf - Rashidpur**

| | | GIIP MMscf | Recovery Factor | Reserve MMscf | Condensate Reserve MMbbl |
|---|---|---|---|---|---|
| Probabilistic Method | Maximum | 6191.7 | 80 | 4953.35 | 1.48 |
| | Most Likely | 2505.4 | 75 | 1879.08 | 0.56 |
| | Minimum | 1217.9 | 70 | 852.53 | 0.26 |
| Deterministic | Mean | 2823.1 | 75 | 2117.30 | |
| | RMS | 2864.5 | 75 | 2148.40 | |

GGAG 1986

In 1986, under Hydrocarbon Habitat Study Program (HHSP), additional 271 km. of new seismic data was recorded. This group also estimated gas reserve of Rashidpur. According to this estimate, Proven and Probable (2P) GIIP of the field was 373 Bscf and another 2083 Bscf was placed under Possible category giving a 3P GIIP of 2456 Bscf. Results of this estimate are shown in Table 6-47.

**Table 6-47 HHSP 1986 Reserve Estimate – GIIP in Bscf – Rashidpur Gas Field**

| Reservoir | | Gas in Bscf | | | Condensate in MMbbl | | |
|---|---|---|---|---|---|---|---|
| | | Proven+ Probable | Possible | Total | Proven+ Probable | Possible | Total |
| Upper | North | 147.1 | | 147.1 | 0.044 | | 0.044 |
| | Central | | 109.3 | 109.3 | | 0.033 | 0.033 |
| | South | 171.7 | | 171.7 | 0.052 | | 0.052 |
| Lower | North | | 16.8 | 16.8 | | 0.005 | 0.005 |
| | Central | | 1956.6 | 1956.6 | | 0.586 | 0.586 |
| | South | 54.6 | | 54.6 | 0.016 | | 0.016 |
| Field Total | | 373.4 | 2082.7 | 2456.1 | 0.112 | 0.624 | 0.736 |

HHSP, 1986

During 1989-1990, additional seismic data was recorded over Rashidpur and new maps were prepared. Based on the result of seismic interpretation, two wells were drilled in Rashidpur. IKM of Canada estimated the 2P GIIP at 2243 Bscf (Proved+Probable). No Possible GIIP was indicated. Results of the IKM estimate are shown in Table 6-48.

**Table 6-48 IKM 1990 Reserve Estimate – GIIP in Bscf – Rashidpur Gas Field**

| Sand | Proved | Probable | Total 2P |
|---|---|---|---|
| Upper | 480.3 | 353.6 | 833.9 |
| Lower | 634.1 | 775.0 | 1409.1 |
| Total | 1114.4 | 1128.6 | 2243.0 |

IKM 1990

In 1995, BAPEX estimated the GIIP of Rashidpur at 1642 Bscf. Another estimate by PMRE of BUET placed the GIIP of this field at 3183 Bscf. PMRE used flowing wellhead pressure (FWHP) for the study. The 2003 HCU-NPD reserve report estimated GIIP figure was 2002 Bscf.

The HCU-NPD 2003 Gas Reserve Estimate Report results for Rashidpur gas field are shown in Table 6-49 below. This earlier HCU-NPD study estimated 1P GIIP at 1398 Bscf and 2P GIIP at 2002 Bscf with a recoverable 2P reserve of 1401 Bscf.

**Table 6-49 HCU-NPD 2003 Reserve Estimate – GIIP in Bscf – Rashidpur Gas Field**

| | GIIP | | | Recoverable |
|---|---|---|---|---|
| Sand | Proved | Probable | Total 2P | |
| Upper | 349.18 | 139.33 | 488.5 | 341.95 |
| Middle | 307.77 | | 307.77 | 215.44 |
| BTA | 48.48 | | 48.48 | 33.94 |
| Lower | 646.61 | 464.4 | 1110.98 | 777.69 |
| Bhuban | 45.93 | | 45.93 | 32.15 |
| Total | 1397.97 | 603.7 | 2001.7 | 1401.16 |

HCU-NPD 2003

In 2009, the Reservoir Study Cell of Petrobangla and RPS Energy conducted another study on reserve estimation of Rashidpur gas field. The Petrel deterministic volumetric modeling estimated GIIP at 4191 Bscf and RPS's probabilistic volumetric estimate of GIIP was 4100 Bscf.

The RPS study reported a prior published 2P GIIP of 2002 Bscf, attributed to Petrobangla from their 2007 Annual Report, which RPS believes did not include all gas-bearing zones. However, this figure is identical to that reported in the 2003 HCU-NPD estimate shown in Table 6-50 above for all four producing sands as well as for the Middle Gas Sand. It is unclear to us what additional sands RPS Energy is referring to in their footnote to Table 6-50 below which presents their results. The RPS nomenclature is somewhat different from that shown by HCU-NPD in Table 6-49 so it is somewhat uncertain how to compare the results of the two estimates.

**Table 6-50 RPS Energy 2009 Reserve Estimate – Rashidpur Gas Field**

| Sand | Volumetric Calculation | | Simulation Model | | Estimated Connected Volume | | Published GIIP[1] (2P) |
|---|---|---|---|---|---|---|---|
| | Petrel™ | REP™ (P50) | Before History Match | After History Match | Production Analysis | Material Balance | |
| UGS1 | 268 | 261 | 302 | 302 | Inadequate pressure data | | - |
| UGS2 | 12 | 13 | 64 | 64 | No production yet | | - |
| MGS1 | 3,190 | 3,112 | 2,024 | 2,024 | No production yet | | - |
| MGS2 | 162 | 160 | 149 | 149 | No production yet | | - |
| LGS | 559 | 554 | 374 | 1,111 | 1,213 | 1,200 | - |
| **Total** | **4,191** | **4,100** | **2,913** | **3,650** | **-** | **-** | **2,002** |

RPS Energy 2009i

[1]Source: Petrobangla Annual Report 2007 (RPS does not believe that this includes all gas-bearing zones)

### 6.3.14.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Rashidpur field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

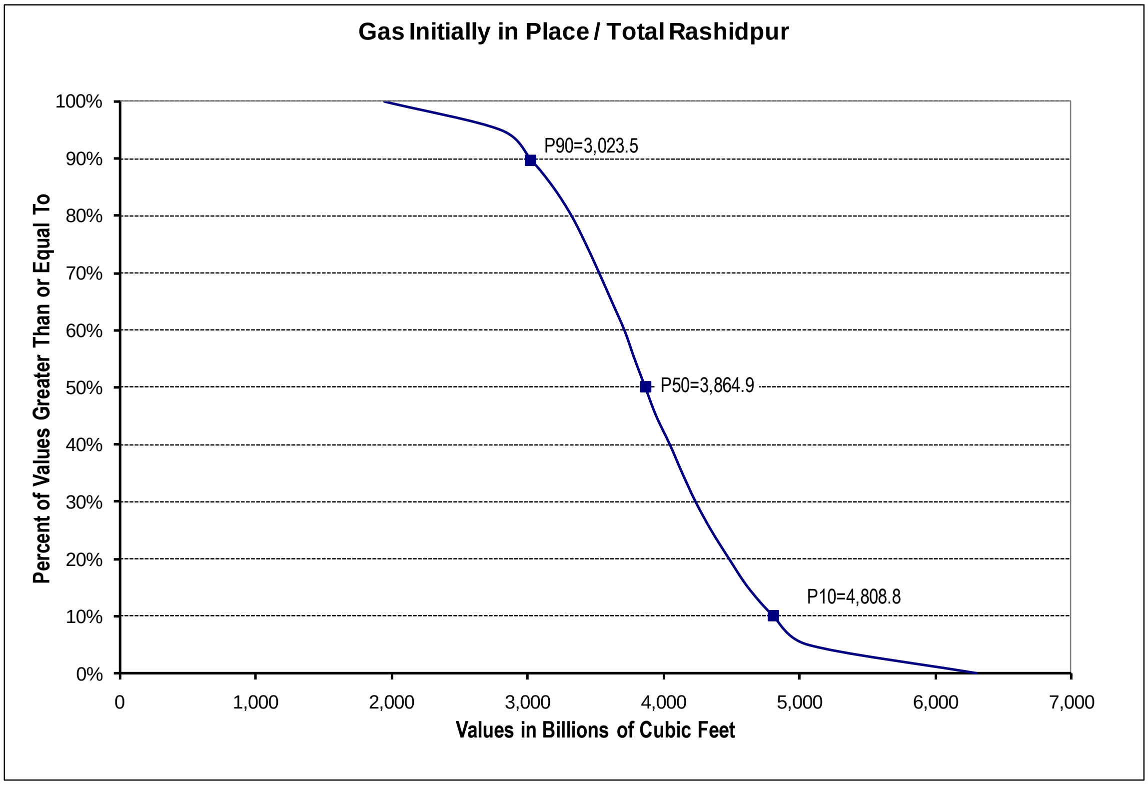



**Figure 6-120 Distribution of GIIP, Rashidpur**

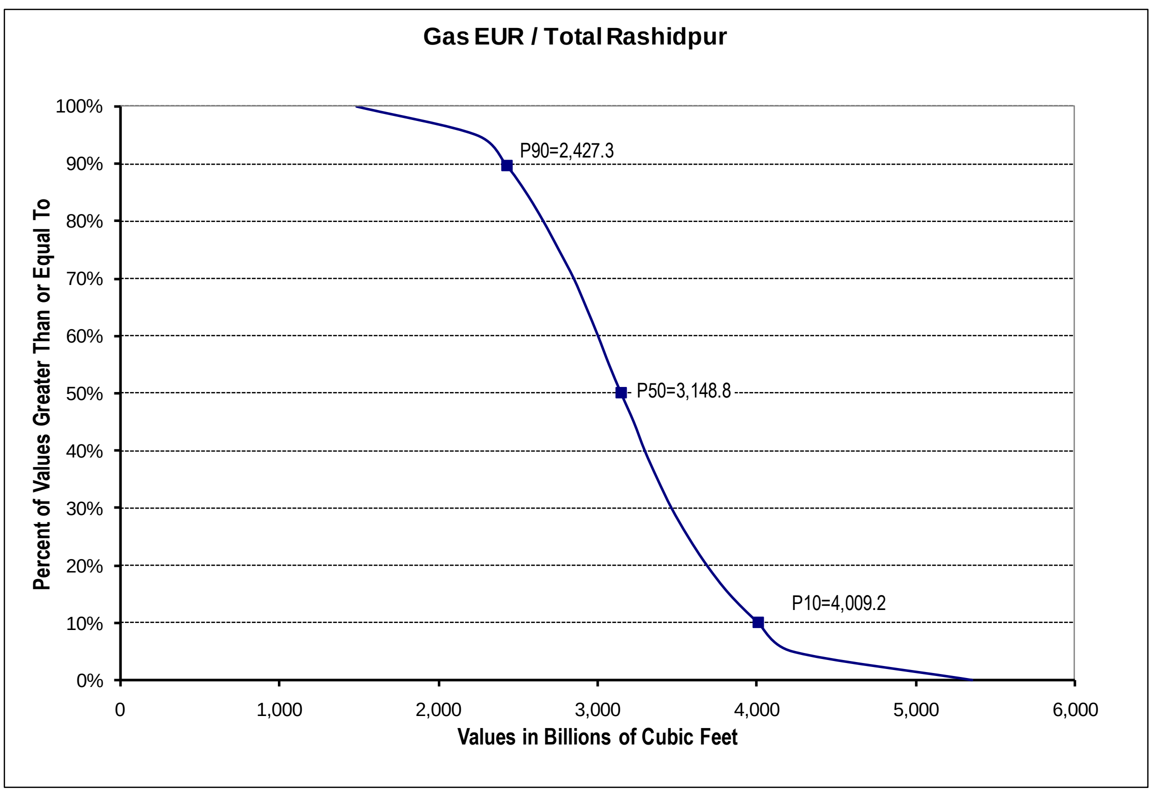



**Figure 6-121 Distribution of Gas EUR, Rashidpur**

**Table 6-51 Summary of Estimated Ultimate Recovery at Rashidpur**

| Reservoir | Mean Gas EUR, BCF |
|---|---|
| Upper Sand | 408 |
| Middle Sand | 1,779 |
| Lower Sand | 994 |
| **TOTAL** | **3,181** |

### 6.3.15 <u>Salda Nadi</u>

#### 6.3.15.1 Geologic Setting

Salda Nadi is located within the Eastern Foldbelt near the eastern border of Bangladesh and the eastern boundary of Block 9 (Figure 6-2). Salda Nadi gas field is located along the greater Rukhia structural trend that extends into the neighboring Indian state of Tripura both to the north and to the south from Salda Nadi field.

#### 6.3.15.2 Structure

The Salda Nadi anticline is a NNW-SSE trending fold that is bounded on the east by a high-angle NW-trending fault. The two-well gas field is located along the crest of the structure. Figure 6-122 through Figure 6-124 are depth structure maps drawn on the tops of the Upper, Middle, and Lower Gas Sand reservoirs. The productive portion of the anticline is approximately 3.75 km. long by about 1 km. wide as defined by the closing contours and the GWC as mapped on the top of the Middle Gas Sand horizon (Figure 6-123).

As can be seen in Figure 6-122 and Figure 6-124 the Upper and Lower Gas Sands are only present on the western limb and crest of the anticline and are missing on the eastern flank by either pinchout or truncation. As a result, those sands were missing in the Salda Nadi #2 well.

Only the Middle Gas Sand extends across the entire structure as evidenced by the results of both Well #1 and Well #2. However, Well #1 penetrated the Middle Gas Sand structurally below the GWC, and therefore only Well #2 is productive from this sand.

#### 6.3.15.3 Reservoir

The three gas-bearing reservoirs at Salda Nadi are designated the Upper, Middle, and Lower Gas Sands. The following reservoir parameters for the three productive sands are based on log analysis (BAPEX, 2001).

The Upper Gas Sand has a maximum gross thickness of 45m with an average gross thickness of 38.7m and an average net effective thickness of 25.5m. Porosity ranges from 11.0-17.0% and calculated water saturation (Sw) varies from 31.8-48.9%. Based on DST pressure measurements, the Upper Gas Sand reservoir is nearly normally pressured to perhaps very slightly overpressured with a calculated pressure gradient of 0.47 psi/ft (1.54 psi/m).

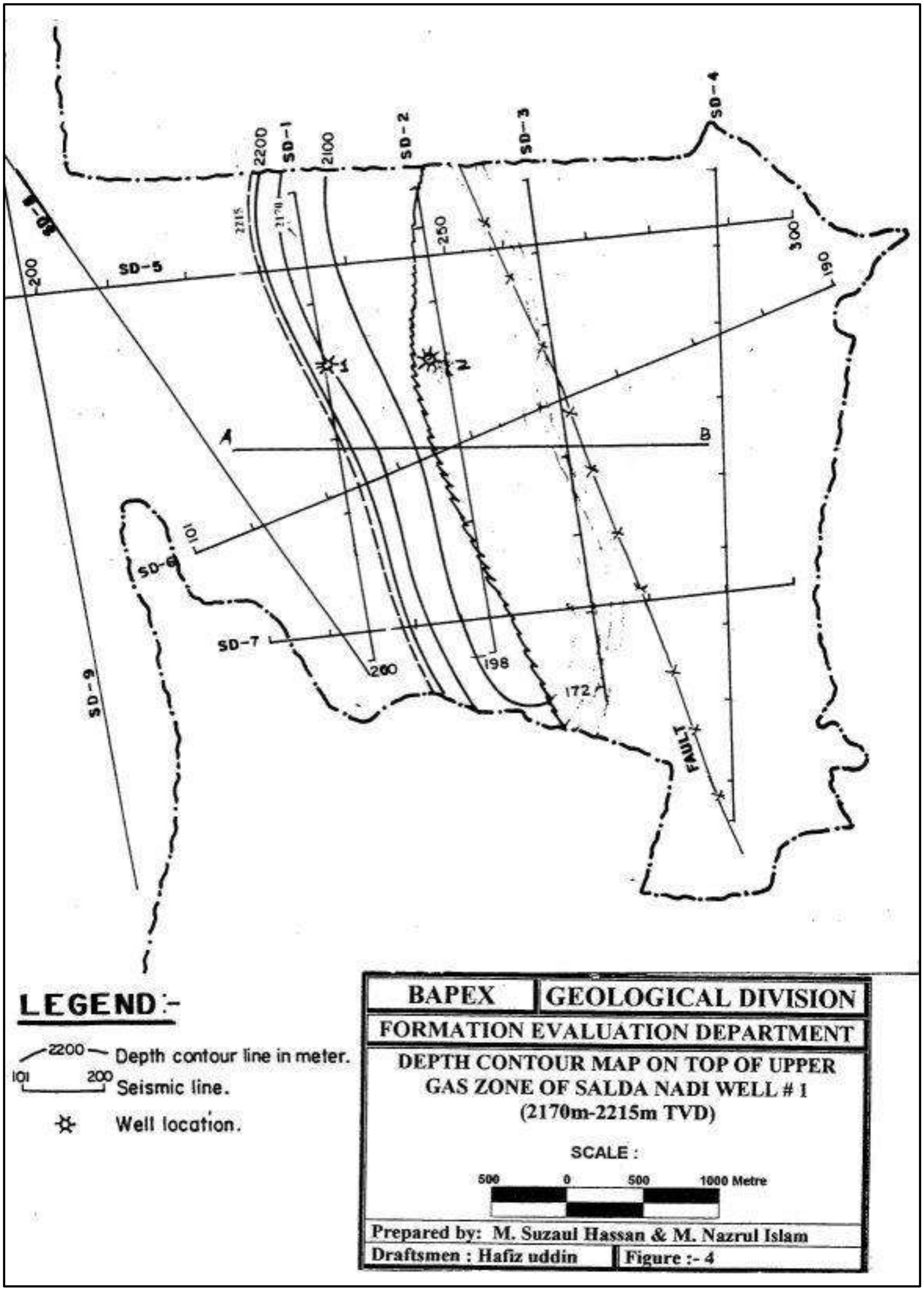



**Figure 6-122 Depth Structure Map on Top of Upper Gas Sand – Salda Nadi Gas Field** (after BAPEX, 2001).

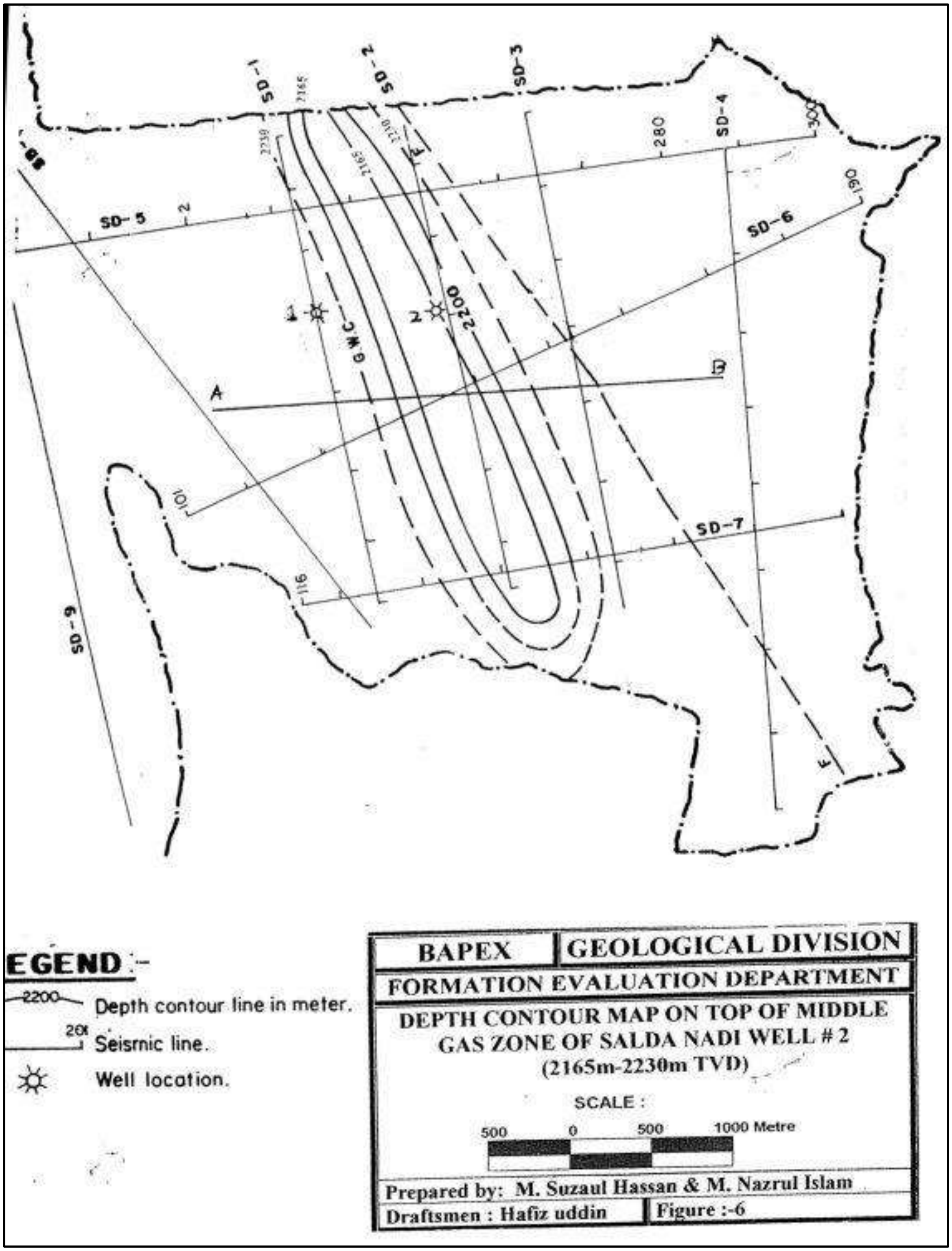



**Figure 6-123 Depth Structure Map on Top of Middle Gas Sand – Salda Nadi Gas Field** (after BAPEX, 2001).

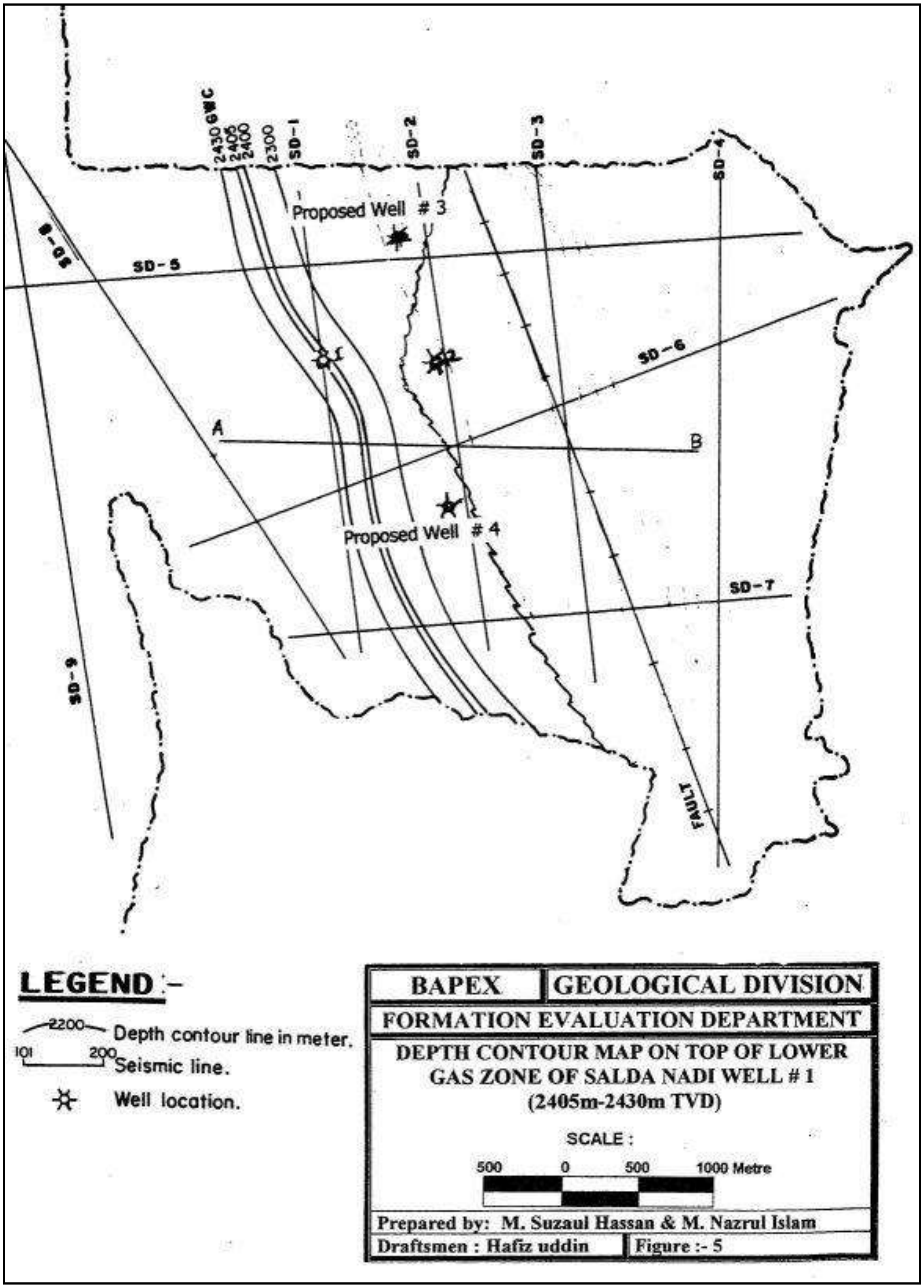



**Figure 6-124 Depth Structure Map on Top of Lower Gas Sand – Salda Nadi Gas Field**
(after BAPEX, 2001)

The Middle Gas Sand has a maximum gross thickness of 65m an average gross thickness of 42.4m and an average net effective thickness of 29.7m. Porosity ranges from 14.3-17.40% and calculated water saturation (Sw) varies from 42.0-53.4%.

The Lower Gas Sand has a maximum gross thickness of 25m with an average gross thickness of 15.3m and an average net effective thickness of 11.0m. Porosity ranges from 15.2-20.3% and calculated water saturation (Sw) varies from 26.7-36.2%. Based on DST pressure measurements, the Lower Gas Sand reservoir is nearly normally pressured to perhaps very slightly overpressured with a calculated pressure gradient of 0.46 psi/ft (1.51 psi/m).

#### 6.3.15.4 Exploration and Field Development

Oil and Natural Gas Corporation (ONGC) of India drilled the first exploratory well in Rukhia during 1980-83 and it was a gas discovery. Since then ONGC drilled about 40 wells. Salda Nadi is a part of greater Rukhia structure. According to information received only a few of these wells were put into production stream. Salda Nadi Well # 1 was drilled in 1996 by BAPEX and it was a gas discovery. The well discovered two gas bearing zones named as Upper Gas Sand and Lower Gas Sand. The well was completed as a dual producer and production started from 28 March 1998. Salda Nadi # 2 was drilled in 1999. The well was completed as a single producer from Middle Gas Sand on 3 May 2001.

Salda Nadi gas field has been producing since 1998 and there has only been a slight increase in water production rate from less than 1 bbl/MMscf gas in 1998 to about 6.5 bbl/MMscf at the end of 2009. However, the flowing wellhead pressure (FWHP) indicates gradual depletion of all the reservoirs. Initial FWHP was approximately 2000-2100 psig in 1998 and has declined to between 950-1000 psig by November 2009.

6.3.15.5 Well-wise and Sand-wise Production History

The well-wise and sand-wise gas production of Salda Nadi gas field can be seen in the Figure 6-125 and Figure 6-126. As seen in Figure 6-126, most of the daily production from the field is attributable to the Middle and Lower Gas Sands. The Upper Gas Sand is only a minor contributor to gas production from this field.

6.3.15.6 Field-wise Cumulative Production

Cumulative production of the field was 60.2 Bscf at the end of December 2009 and annual production for 2009 was 3.3 Bscf with an average daily production of 9.1 MMscfd, or approximately 53% of the annual production in 2003 when the previous HCU-NPD reserve report was published.

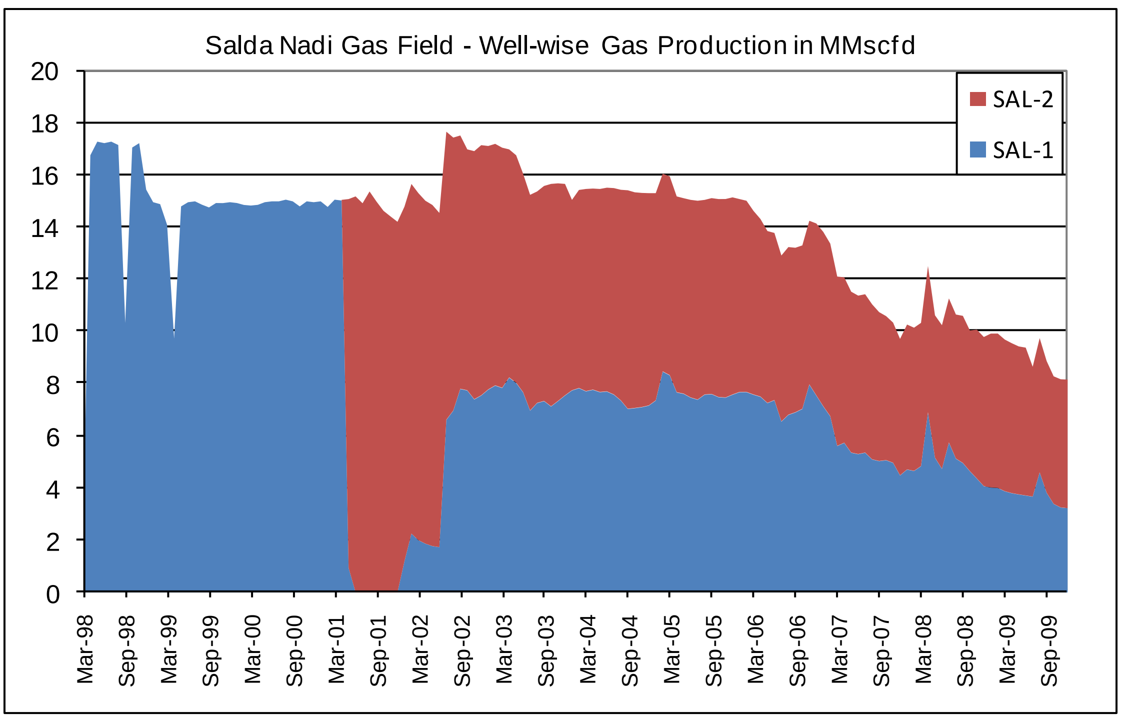



**Figure 6-125 Well-wise Gas Production – Salda Nadi Gas Field**

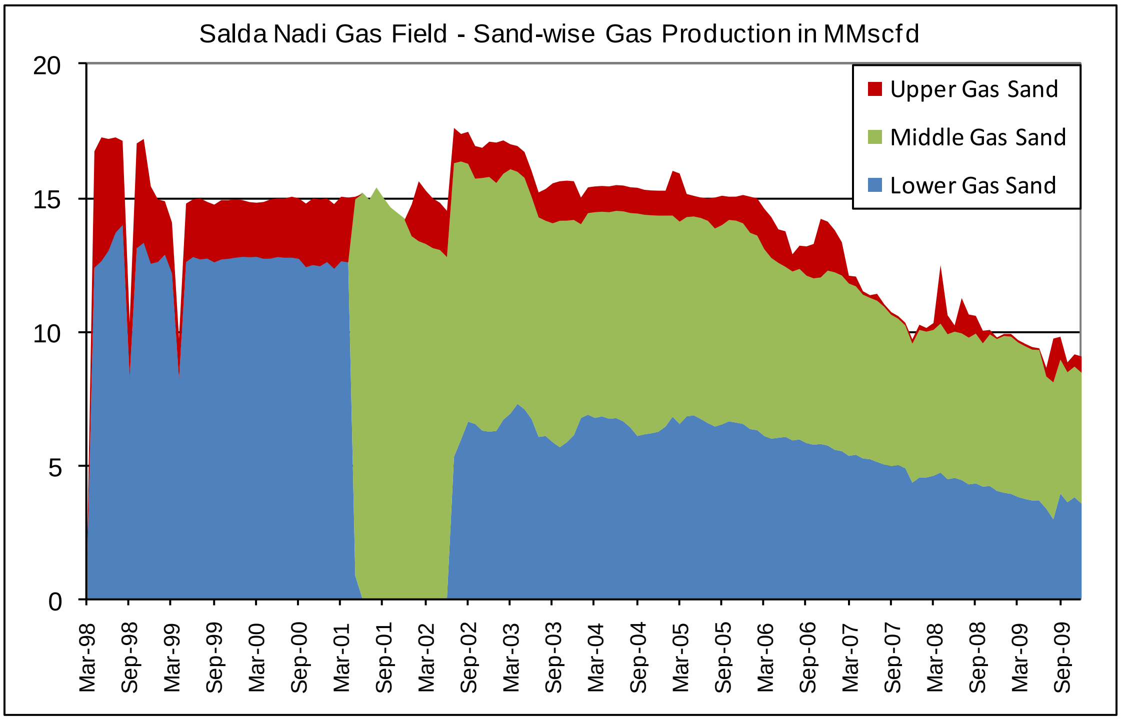



**Figure 6-126 Sand-wise Gas Production – Salda Nadi Gas Field**

Table 6-52 summarizes the sand-wise and field-wise cumulative gas production from the field. As reflected in the daily gas production in Figure 6-126, the Middle and Lower Gas Sands are the main gas reservoirs in the field and have contributed about equal amounts to the field's cumulative production. The Upper Gas Sand has produced less than 6 Bscf of gas, or about 10% of the total field cumulative production, since it was opened in 1998.

**Table 6-52 Sand-wise Cumulative Gas Production – Salda Nadi Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Upper Gas Sand | 5.7 |
| Middle Gas Sand | 25.2 |
| Lower Gas Sand | 29.3 |
| **Total** | **60.2** |

1 Production through end of December 2009
HCU production database

6.3.15.7 Earlier Reserve Estimates

After completion of Well #2, GIIP was re-estimated by BAPEX at 165.80 Bscf (2001). GIIP by sand is given as Table 6-53. The field's 1P GIIP was estimated at 75.4 Bscf and the 2P GIIP at 165.8 Bscf. The estimate assigned roughly equally distributed in-place gas volumes to all three reservoirs with the Middle Gas Sand containing the largest volume of gas. No Possible reserves were indicated in the 2001 report and recovery factor was considered at 70%.

**Table 6-53 BAPEX 2001 Reserve Estimate – GIIP in Bscf – Salda Nadi Gas Field**

| | Proven | Probable | Total |
|---|---|---|---|
| Upper Sand | 19.77 | 22.94 | 42.71 |
| Middle Sand | 32.92 | 37.76 | 70.68 |
| Lower Sand | 22.72 | 29.69 | 52.41 |
| Total | 75.41 | 90.39 | 165.8 |

BAPEX 2001

The HCU-NPD 2003 Gas Reserve Estimation Report re-estimated the GIIP for Salda Nadi field using the GeoX software program. This estimate reported the GIIP reserve as Proven + Possible with no Probable category. Essentially this is a 3P estimate, resulting in total GIIP of 185.7 Bscf, or about a 12% increase over the 2P GIIP BAPEX estimate of 165.8 Bscf. The HCU acknowledged that due to uncertainty in estimating rock volume and the reasonably close volumes between the two estimates, they would accept the BAPEX 2001 estimate for the 2003 reserve report. The results of the HCU-NPD 2003 estimate are presented in Table 6-54.

**Table 6-54 HCU-NPD 2003 Reserve Estimate-GIIP in Bscf – Salda Nadi Gas Field**

| | Proven + Possible | Total |
|---|---|---|
| Upper Sand | 47.9 | 47.9 |
| Middle Sand | 91.4 | 91.7 |
| Lower Sand | 46.4 | 46.4 |
| Total | 185.7 | 185.7 |

HCU-NPD 2003

The most recent GIIP estimate for Salda Nadi was the recently released Reservoir Study Cell of Petrobangla and RPS Energy estimate that was released in late 2009 (Table 6-55). They estimated GIIP for Salda Nadi using two volumetric methodologies, one deterministic (Petrel) and a second probabilistic (REP). The Petrel deterministic volumetric modeling resulted in an estimated GIIP of 383.7 Bscf. RPS's probabilistic volumetric estimate of GIIP was 383 Bscf. The close match in the two methodologies provides a good level of confidence in the GIIP estimate for this gas field. This most recent estimate doubles the earlier GIIP estimate of the HCU-NPD 2003 report.

**Table 6-55 RPS Energy 2009 Reserve Estimate - GIIP in Bscf - Salda Nadi Gas Field**

| Pool | Volumetric Calculation (Bcf) | | Simulation Model (Bcf) | | Estimated Connected[1] Volume (Bcf) | |
|---|---|---|---|---|---|---|
| | Petrel™ | REP™ (P50) | Before History Match | After History Match | Production Analysis | Material Balance |
| Upper Sand | 274.5 | - | 273.2 | 273.2 | 12 | 6-16 |
| Middle Sand | 49.6 | - | 47.2 | 47.2 | 53 | - |
| Lower Sand | 59.6 | - | 59.6 | 59.6 | 60 | 40-60 |
| **Total** | **383.7** | **383.0** | **379.9** | **379.9** | **125** | **-** |

RPS Energy 2009

6.3.15.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Salda Nadi field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

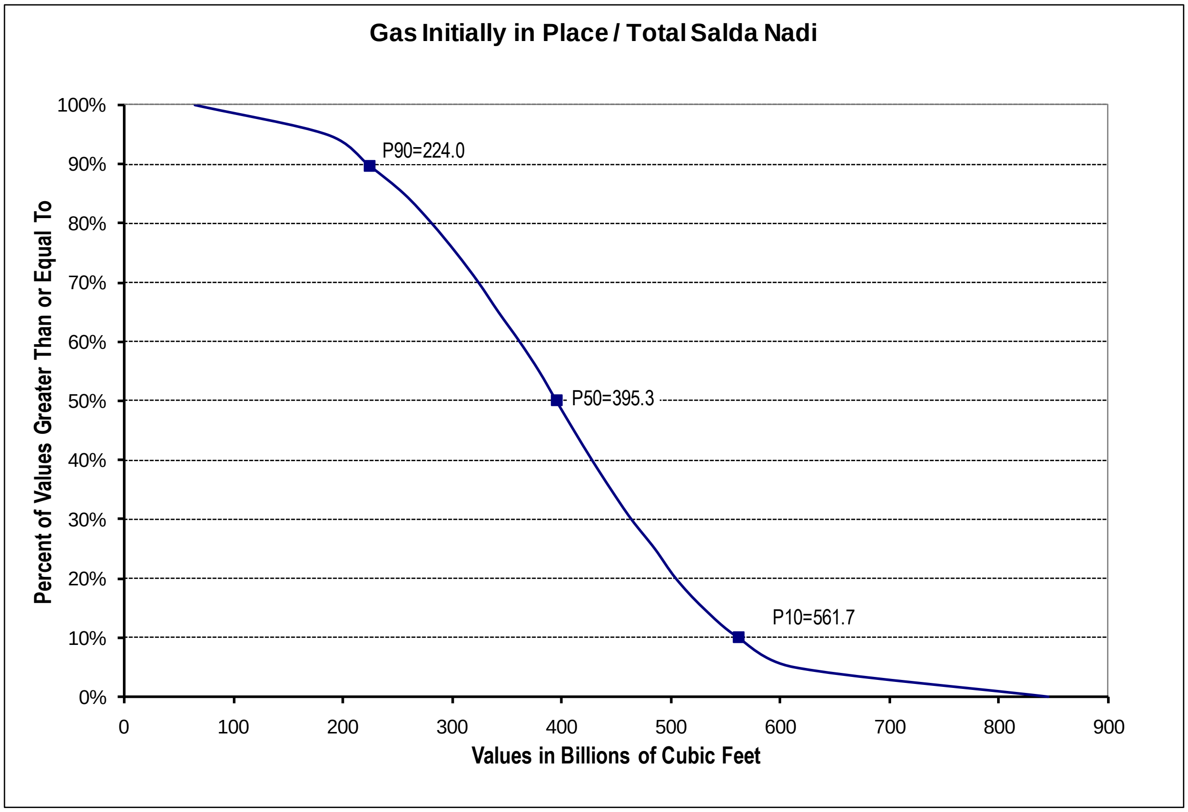



**Figure 6-127 Distribution of GIIP, Salda Nadi**

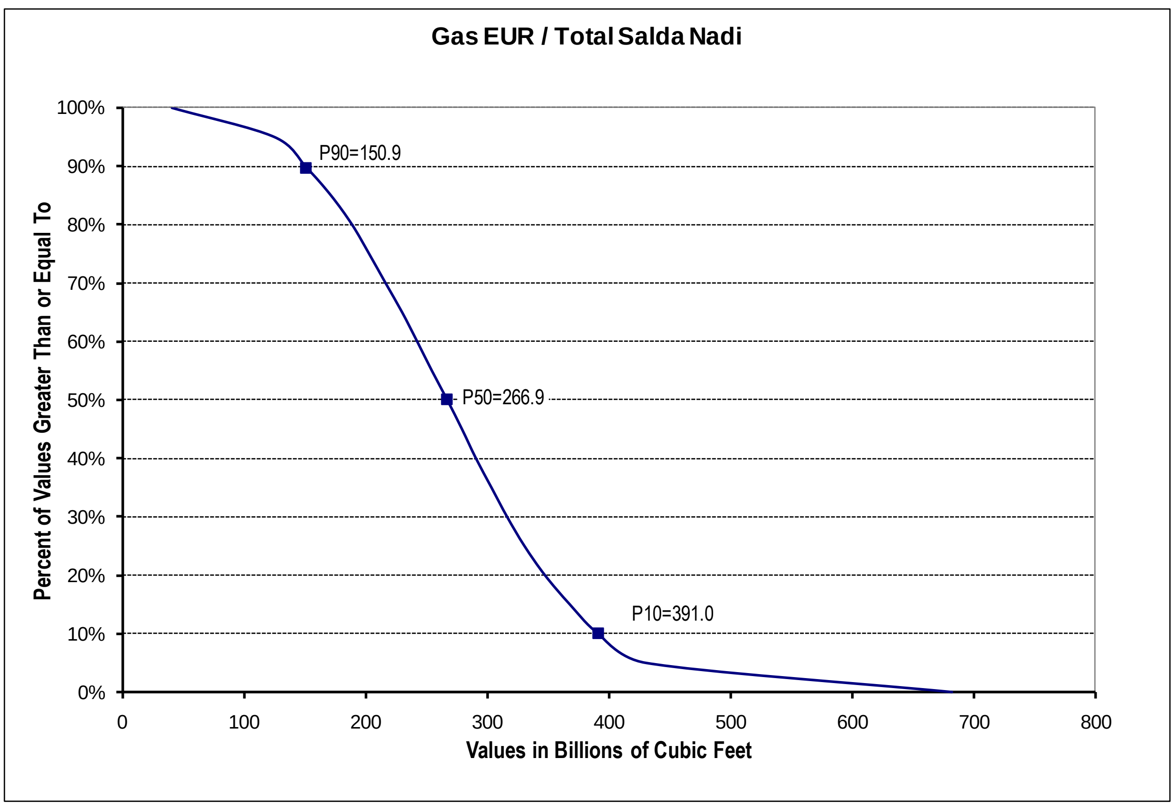



**Figure 6-128 Distribution of Gas EUR, Salda Nadi**

**Table 6-56 Summary of Estimated Ultimate Recovery at Salda Nadi**

| Reservoir | Mean Gas EUR, BCF |
|---|---|
| Upper Gas Sand | 205 |
| Middle Gas Sand | 15 |
| Lower Gas Sand | 49 |
| **TOTAL** | **270** |

### 6.3.16 Sangu (8)

#### 6.3.16.1 Geologic Setting

The Sangu gas field is located in the Bay of Bengal (Block 16), about 240 km off the southeastern coast of Bangladesh (Figure 6-2). Water depth in this area is about 10 meters. The general field structure is an anticline with gently dipping flanks that trends northeast-southwest.
The Sangu field was the first offshore gas field identified in the Patuakhali Depression or Hatia Trough of the Bengal foredeep. The Bengal foredeep, a large area generally to the south of the Surma Basin, contains the great volume of Tertiary sedimentary accumulation of the Ganges-Brahmaputra delta. These strata are more distal equivalents of the Oligocene Barail Group, the Miocene Surma Group, and the Pliocene Tipam Group found in the Surma Basin and in the Eastern Foldbelt (see Figure 6-6). The rocks consist of sandstones, siltstones, and shales that commonly contain plant-derived organic matter. Overall, the strata are as thick as 20,000m in the Patuakhali Depression or Hatia Trough, a depocenter located in the southeastern side of the delta (U.S. Geological Survey, 2001).

Cairn Energy and Shell Bangladesh devised an informal classification for the strata in the southern and offshore regions of Bangladesh ("megasequence"). These megasequences are identified on seismic cross sections and are based upon gross characteristics of recognizable bed forms. Megasequence 1 (MS 1), at the base of seismically imaged section lines, consists of major progradational bed forms overlain by generally subhorizontal aggradational bed forms. MS 1 is overlain by the highly dissected erosional bed forms (valley fill deposits) of megasequence 2

(MS 2). In Block 16, MS 2 may represent deeply eroded submarine canyon fill in the more distal, southern part of the delta. The upper part of the section, represented by megasequence 3 (MS 3), consists of progradational and aggradational bed forms similar to those of MS 1.

In the nearshore and offshore areas of southeastern Bangladesh, MS 1 imaged at the base of the seismic sections is 1 to 1.5 km thick and MS 2 is about 2.5 km thick. MS 3 at the top of the seismic sections may be as thick as 1 km. The Miocene-Pliocene boundary has been identified at about the middle of MS 2 using biostratigraphic markers. If this is correct, then the Tipam and Dupi Tila Groups to the east would be approximately equivalent to MS 2.

6.3.16.2 Structure

The Sangu field lies in the Eastern Foldbelt of southeastern Bangladesh, and consists of a large NNW-SSE trending anticline situated at a depth of about 3,000 meters subsea. Figure 6-129 and Figure 6-130 are depth structure maps drawn on top of two of the main gas-bearing reservoir sands in the field. Gas is trapped in stacked marginal marine sands of Upper Miocene age (MS 1). Marine to marginal marine shales form the seal. Deep erosional channels on the flanks of the anticline contain a lithologically varied stratigraphic fill that serves as a secondary trapping mechanism (MS 2). The result is numerous stacked reservoirs within the structure that have different gas water contacts

6.3.16.3 Reservoir

Reservoir rocks are deltaic, littoral, and marine sandstones in the upper part of MS 1 and possibly sandstone channel-fill deposits in MS 2. Ten gas-bearing sands have been identified by exploratory drilling. Designation of identified reservoir zones follows (stratigraphically descending order): SG1.1860, SG1.2585, SG3.2635, SG1.2970, SG1.3085, SG1.3155, SG1.3255, SG2.3480, SG2.3590, and SG2.3710. The main gas producing reservoir is the SG1.3155 zone.

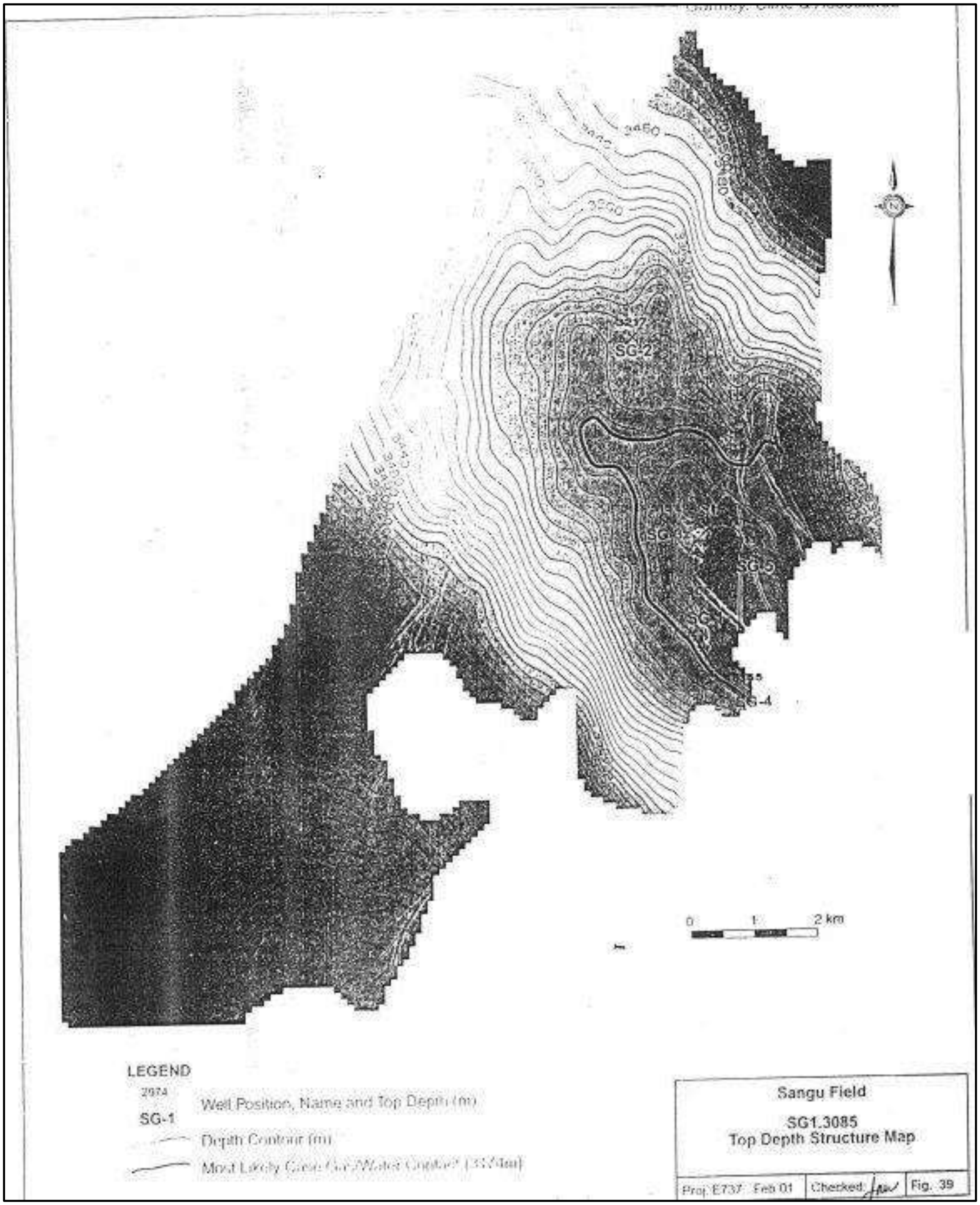



**Figure 6-129 Depth Structure Map on Top of SG1.3085 Reservoir – Sangu Gas Field**

This reservoir is a secondary producer at Sangu field with only limited cumulative production (after Gaffney, Cline, & Assoc., 2001).

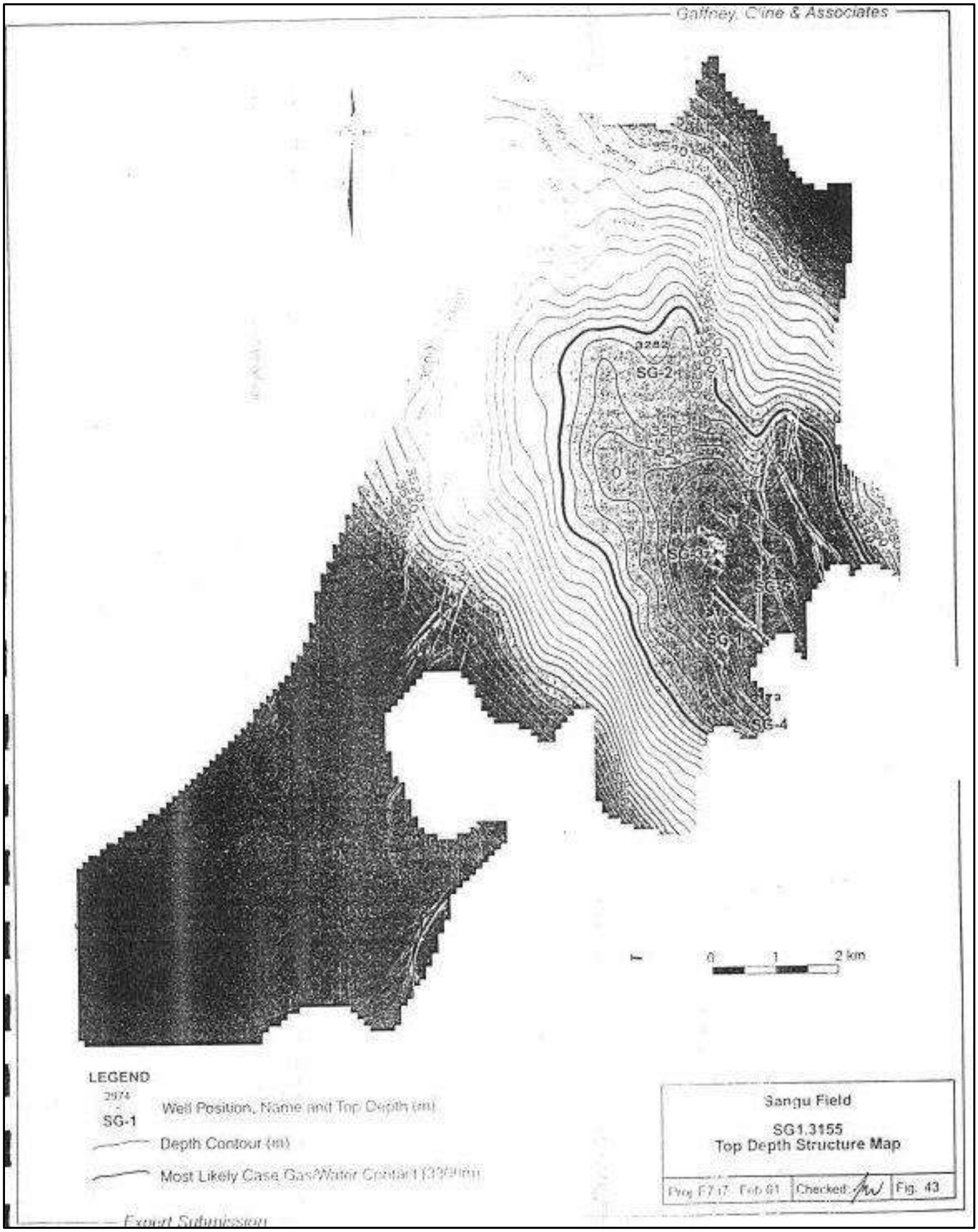



**Figure 6-130 Depth Structure Map on Top of SG1.3155 Reservoir – Sangu Gas Field**
Main pay at Sangu field (after Gaffney, Cline, & Assoc., 2001).

Net reservoir thickness, porosity, and water saturation were determined from wireline geophysical logs, petrophysical analyses, and well test data. Average porosity of the reservoir sands in the Sangu field ranges from 6.0% to 24.5%. Water saturation in the reservoirs ranges from 30% to 40% in the major sands and 60-70% in some minor sands (HCU-NPD, 2003).

#### 6.3.16.4 Exploration and Field Development

Cairn Energy plc discovered the Sangu field in 1996. The Sangu Development Area, defined in January, 1997, covers 419 square kilometers in offshore Block 16. Sangu #1 well found gas in several zones. The Sangu #2 appraisal well, also drilled in 1996, helped confirm the gas resource potential of the field. Target zones generally lie at depths from 3,000 to 4,500 meters subsea.

Cairn partnered with Royal Dutch/Shell Group (Shell Bangladesh) during 1997-2003. South Sangu #1 well was drilled by Shell on the southern flank of the Sangu structure and encountered the SG1.3155 reservoir (3360.5-3396 m AH). This appraisal well, drilled in 1999/2000 confirmed the extension of the Sangu field towards the southeast of this area.

The Sangu field has been in production since June 1998, following installation of the unmanned Sangu drilling platform. Gas has been produced from one or more zones in the Sangu #1, Sangu-#3z, Sangu #4, and Sangu #5 wells. Cairn currently operates the Sangu field and maintains a 50% exploration interest and 37.5% development area interest in Block 16. Joint venture partners in the Sangu field with Cairn are Santos and HBR Energy.

Sangu #6 was drilled to test sands in the northern part of the field. This well found gas in shallow sands (MS 2), but did not reach the main producing zones.

#### 6.3.16.5 Well-wise and Sand-wise Production History

Well-wise production for Sangu gas field is graphically provided in Figure 6-131. Production records at Sangu started in April, 1997 from Sangu #1. Production was suspended until June, 1998, when Sangu #3z, #4, and #5 wells were drilled. Sangu #1 resumed production in October

1998. During the spring of 2005, Sangu #7, #8, and #9 wells were added to production. In March 2008, the number of producing wells increased to eight with completion of Sangu #10 well. Daily production exceeded 160 MMscfd for the last time in January 2006. Field production is currently in steep decline. In December 2009, total daily production from the field was only 35 MMscfd from four wells. In all four wells, the FWHP was below 200 psig.

Wells #1 through #7 produce from the SG1.3155 reservoir, Well #8 from the SG1.3085 reservoir, Well #9 from the SG1.2635 reservoir, and Well #10 from the MS 2.7 reservoir. Figure 6-132 is a chart of sand-wise production. From this chart it is evident that the SG1.3155 Sand is by far the most important contributor to daily gas production in the field.

Detailed individual well histories and accompanying production charts for Sangu wells are included in The Annex.

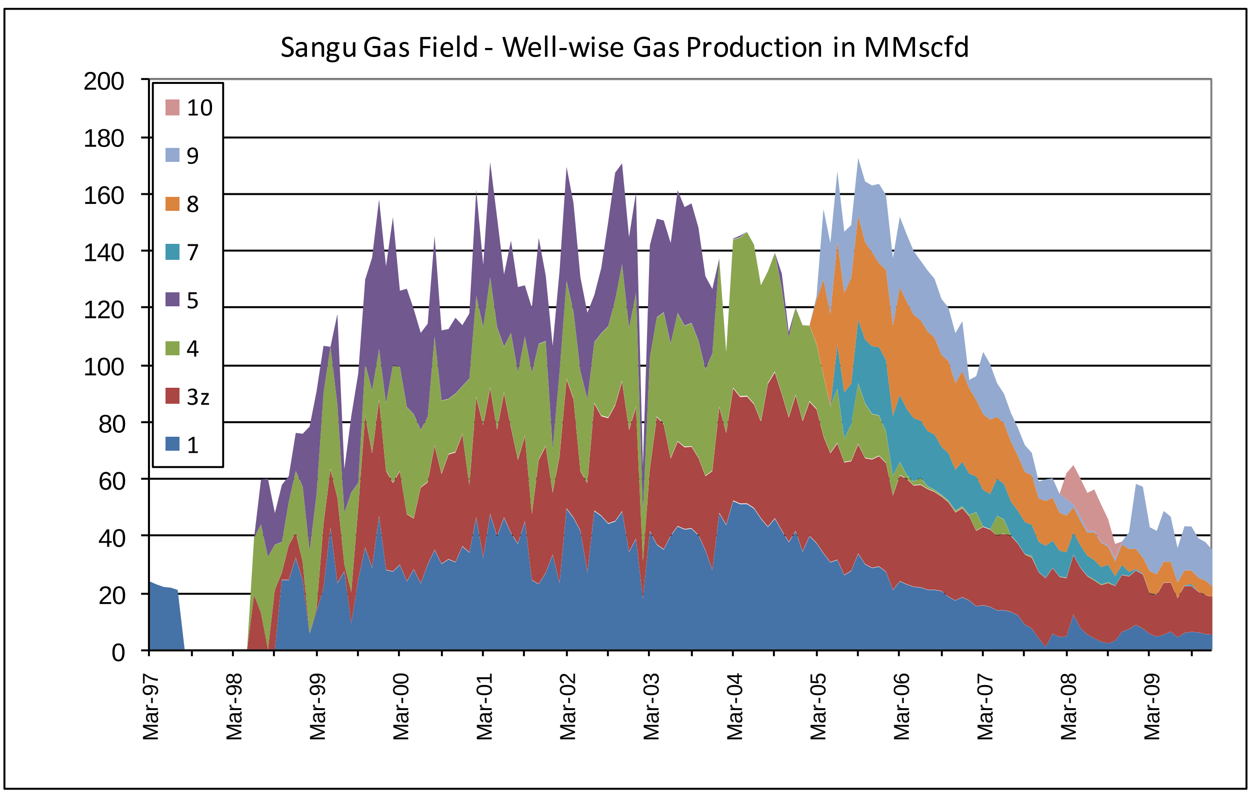



**Figure 6-131 Well-wise Gas Production – Sangu Gas Field**

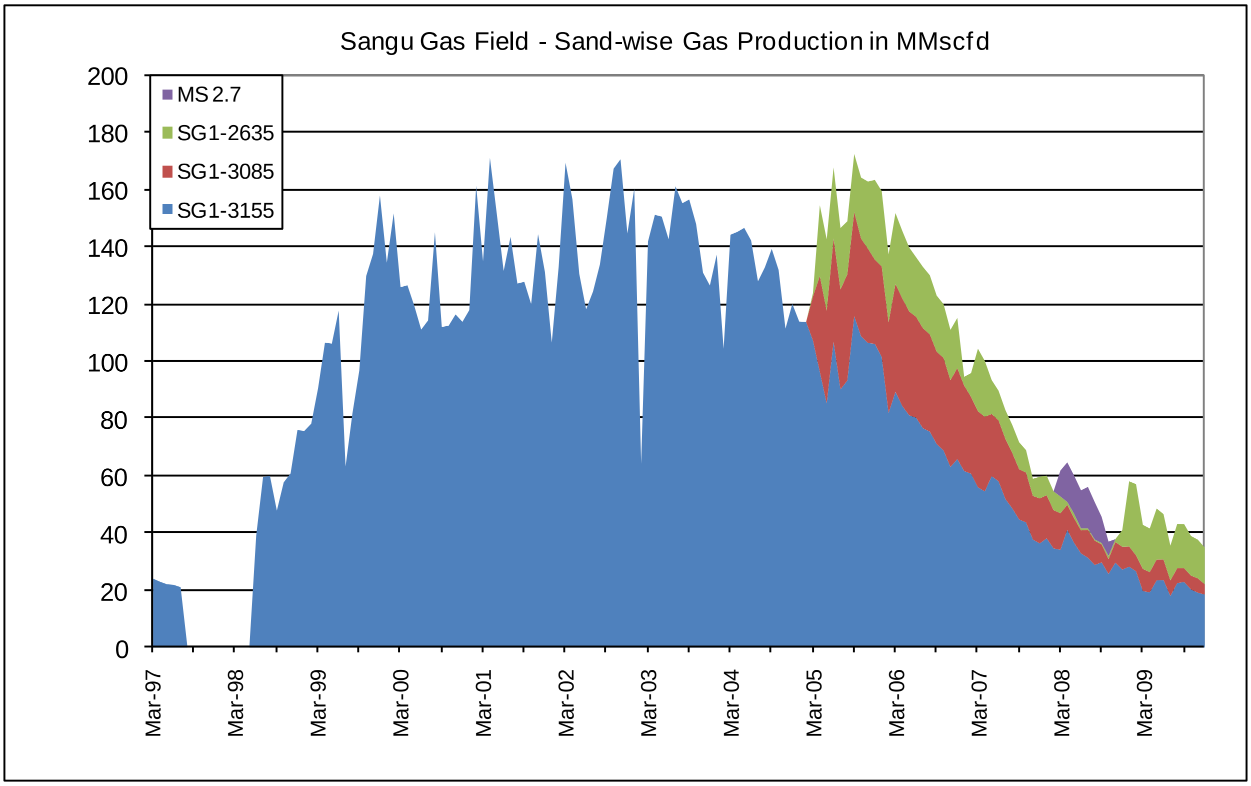



**Figure 6-132 Sand-wise Gas Production – Sangu Gas Field**

6.3.16.6 Field-wise Cumulative Production

During its 11-year productive life, Sangu gas field has produced 466 Bscf of gas, 33,000 barrels of condensate, and 566,000 barrels of water from the SG1.3155 sandstone interval. The field is currently (December 2009) producing at a daily rate of 35 MMscfd of gas, 8 barrels of condensate, and 276 barrels of water.

Sand-wise gas cumulative production for Sangu gas field at end of December 2009 is summarized in Table 6-57. As with daily production, it can be seen in this table that the SG1.3155 Sand has accounted for nearly 87% of the total field cumulative production through the end of 2009.

**Table 6-57 Sand-wise Cumulative Gas Production – Sangu Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| SG1.2635 Sand | 24.1 |
| SG1.3085 Sand | 35.3 |
| SG1.3155 | 404.0 |
| MS 2.7 Sand | 2.7 |
| **Total** | **466.1** |

1 Production through end of December 2009
HCU production database

### 6.3.16.7 Earlier Reserve Estimates

After discovery of gas, Cairn did an estimate of the gas reserve, and a gas sales agreement was signed in 1997, for which a reserve figure of 848 Bscf was used. This estimate was based on single well data. In 1997, four additional wells were drilled.

In June 1999, SBED estimated 2P reserve of the field at 1,103 Bscf. According to this report the mean estimated reserve of the main sand (SG1.3155) was 557 Bscf.

In June 2000, an SBED report on Sangu Field Reservoir Performance and Reserve update GIIP of the producing SG1.3155 (T1C) sand was estimated at 526 Bscf using material balance method. In this report a comparison between estimates of 1999 (deterministic method) and 2000 (probabilistic method) are tabulated. Field GIIP as per 1999 estimate was 1,581 Bscf and in 2000 it increased to 1,798 Bscf. Large increases of reserves were noted for SG1.2635, SG 1.2970, and SG2.3590. For the main sand (SG 1.3155) the expectation GIIP was 781 Bscf, a decrease of 14 Bscf. Table 6-58 summarizes the results of this estimate in tabular form.

Gaffney, Cline & Associates was assigned to estimate the reserve in 2001, and they placed GIIP (2P) of the field at 1,204 Bscf and reserve at 935 Bscf (Table 6-59).

**Table 6-58 SBED 2000 Reserve Estimate – Sangu Gas Field (in Bscf)**

| \Sangu Main | Expec. GIIP | Reserve | | |
|---|---|---|---|---|
| | | P90 | Expected | P10 |
| SG 1. 1860 | 12.7 | | | |
| SG 1. 2585 | 10.2 | 3.5 | 7.8 | 13.1 |
| SG 3. 2635 | 130.3 | 54.7 | 99 | 140.9 |
| SG 1. 2970 | 87.6 | 50.5 | 66.4 | 84.8 |
| SG 1. 3085 | 113.4 | 67.5 | 88.6 | 113.4 |
| SG 1. 3155 | 781.2 | 464.7 | 614.8 | 780.1 |
| SG 1. 3255 | 276.2 | 177.6 | 218.9 | 265.6 |
| SG 2. 3480 | 163.9 | 102.8 | 132.4 | 161.4 |
| SG 2. 3590 | 154.0 | | | |
| SG 2. 3710 | 68.5 | | | |
| South Sangu | | | | |
| SG 1. 3155 | 200.2 | 64.6 | 158.2 | 246.1 |
| Total | 1998.2 | 985.9 | 1386.1 | 1805.4 |

SBED 2000

**Table 6-59 Gaffney-Cline 2001 Reserve Estimate – Sangu Gas Field (in Bscf)**

| | GIIP | | | Reserve | | |
|---|---|---|---|---|---|---|
| Sand | P1 | 2P | 3P | P1 | 2P | 3P |
| SG 1. 1860 | 13.2 | 17.1 | 740 | 0 | 0 | 0 |
| SG 1. 2585 | 10.7 | 16.6 | 22.1 | 8.6 | 14.1 | 18.8 |
| SG 3. 2635 | 37.2 | 63.8 | 89.6 | 29.8 | 54.2 | 76.2 |
| SG 1. 2970 | 6.7 | 11.7 | 59.2 | 5.4 | 9.9 | 50.3 |
| SG 1. 3085 | 122.6 | 136.7 | 372.4 | 92 | 109.4 | 316.5 |
| SG 1. 3155 | 405 | 629.5 | 718.2 | 303.8 | 503.6 | 610.5 |
| SG 1. 3255 | 177.2 | 214.3 | 273.9 | 132.9 | 171.4 | 232.8 |
| SG 2. 3480 | 70.3 | 96.9 | 129 | 0 | 72.7 | 109.6 |
| SG 2. 3590 | 2.8 | 4.1 | 18 | 0 | 0 | 0 |
| SG 2. 3710 | 7.8 | 13.5 | 31 | 0 | 0 | 0 |
| Total | 853.5 | 1204.2 | 2453.4 | 572.5 | 935.3 | 1414.7 |

Gaffney, Cline & Associates, 2000

Petrobangla, after review of the Gaffney-Cline report, came up with a reserve figure of 839 Bscf. Petrobangla used a recovery factor of 80% and this places the GIIP at 1,049 Bscf. However, sand-wise distribution of GIIP or reserve could not be found. This reserve figure was further modified and used in Petrobangla publications including their website.

According to the Petrobangla report, a discrepancy exists between the material balance and volumetric GIIP (526 Bscf vs. 781 Bscf). One possible reason could be the depositional environment of the reservoir sequence, which suggests vertical compartmentalization within the reservoir by interbedded shales. All the sand bodies of SG1.3155 are not perforated, and the mass balance result is considered to be approximately equivalent to the Proven GIIP. Reservoir modeling by SBED simulated a recovery factor for the producing sand (SG1.3155) without compression at about 64% and increased this to 85% by installation of compression.

HCU-NPD used 1,049 Bscf as Proved + Probable GIIP in 2001, considering 70% as recovery factor. This provided a recoverable reserve of 734 Bscf. Additional recovery by use of compression was estimated at 105 Bscf.

SBED, in their monthly report for July 2002, provided an update of reserves from producing sand using pressure data. According to this study, GIIP of the producing horizon (SG1.3155) was 521 Bscf. In October, 2002, this figure was revised to 516 Bscf and in January, 2003, it was further revised to 518 Bscf.

No estimate was attempted for this field in the HCU-NPD 2003 Reserve Estimate Report (2004). GIIP and Reserve as used by Petrobangla was referred to in this report. Petrobangla used a GIIP of 1,031 Bscf and reserve of 848 Bscf. GIIP and reserve data by sand were not available from Petrobangla.

#### 6.3.16.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Sangu field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

Input parameters, particularly the maximum productive area for the SG 1.3155ABC and SG 1.3255 reservoirs, were adjusted upward from what was estimated from available maps in order to calculate EURs large enough to be reasonable considering cumulative production, and achieve reasonable agreement with Cairn's estimates (The Annex).

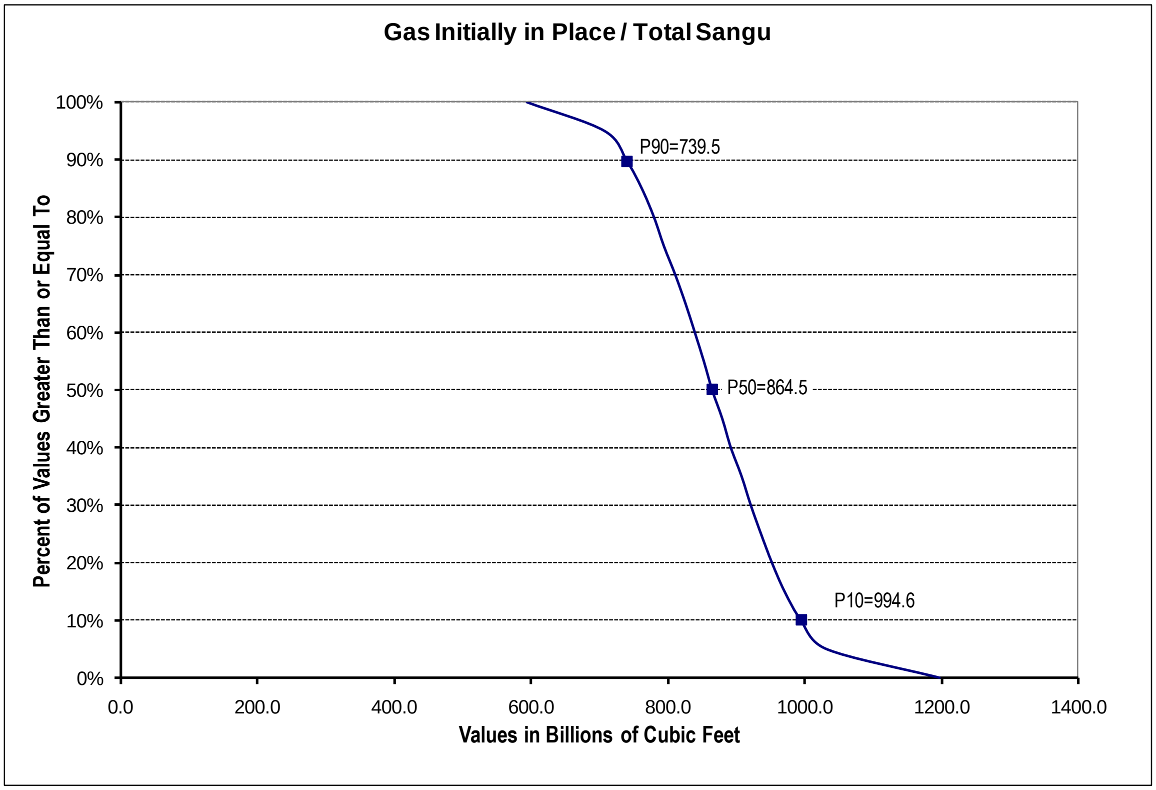



**Figure 6-133 Distribution of GIIP, Sangu**

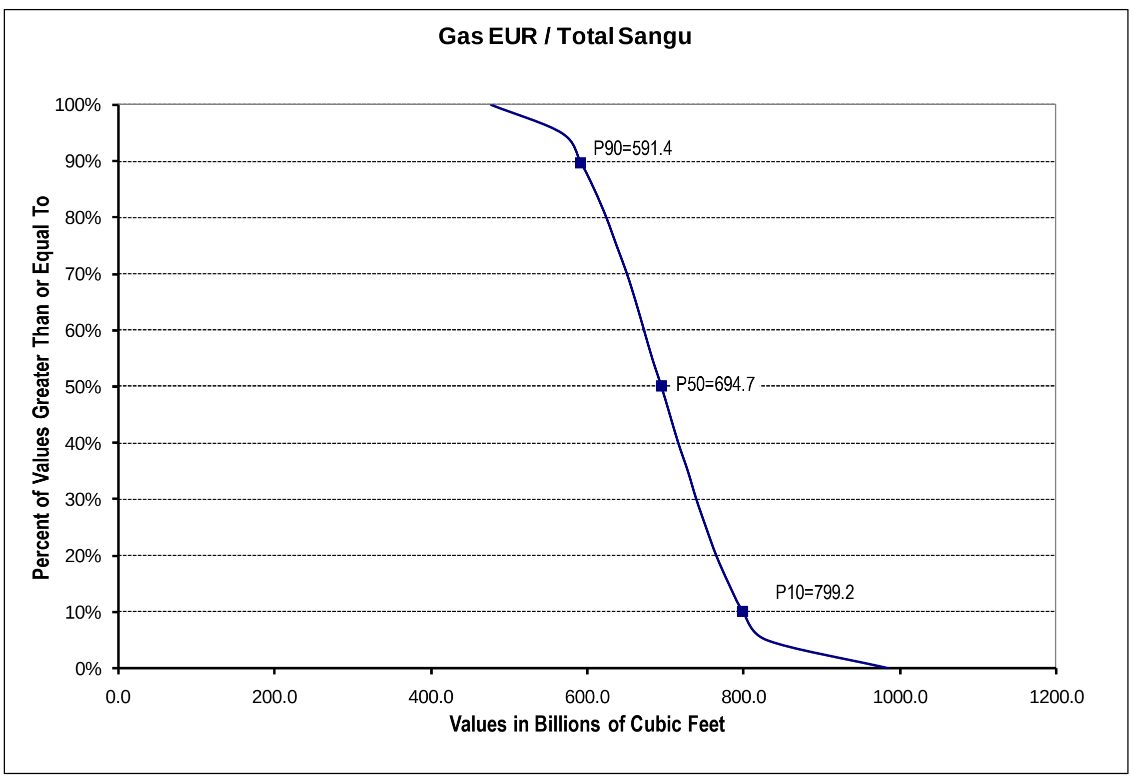



**Figure 6-134 Distribution of Gas EUR, Sangu**

**Table 6-60  Summary of Estimated Ultimate Recovery at Sangu**

| Reservoir | Mean Gas EUR, BCF | Cumulative Gas (1/1/2010), BCF | Gas Reserves (1/1/2010), BCF |
|---|---|---|---|
| SG 1.1860 | 74 | 0 | 74 |
| SG 1.2585 | 14 | 0 | 14 |
| SG 3.2635 | 26 | 24 | 2 |
| SG 1.2970 | 26 | 0 | 26 |
| SG 1.3085 | 38 | 35 | 3 |
| SG 1.3155ABC | 369 | 404 | -35 |
| SG 1.3255 | 106 | 0 | 106 |
| SG 2.3480 | 43 | 0 | 43 |
| **TOTAL** | **696** | **463** | **233** |

Additionally, reserves and GIIP were estimated for the currently producing sands at Sangu using the Approximate Wellhead Material Balance (AWMB) technique.[11] For this technique, where more than one well is producing from a reservoir, the FWHP values are averaged. Any data deviating significantly from the established trend were excluded. The results are shown in Figure 6-135 through Figure 6-138.

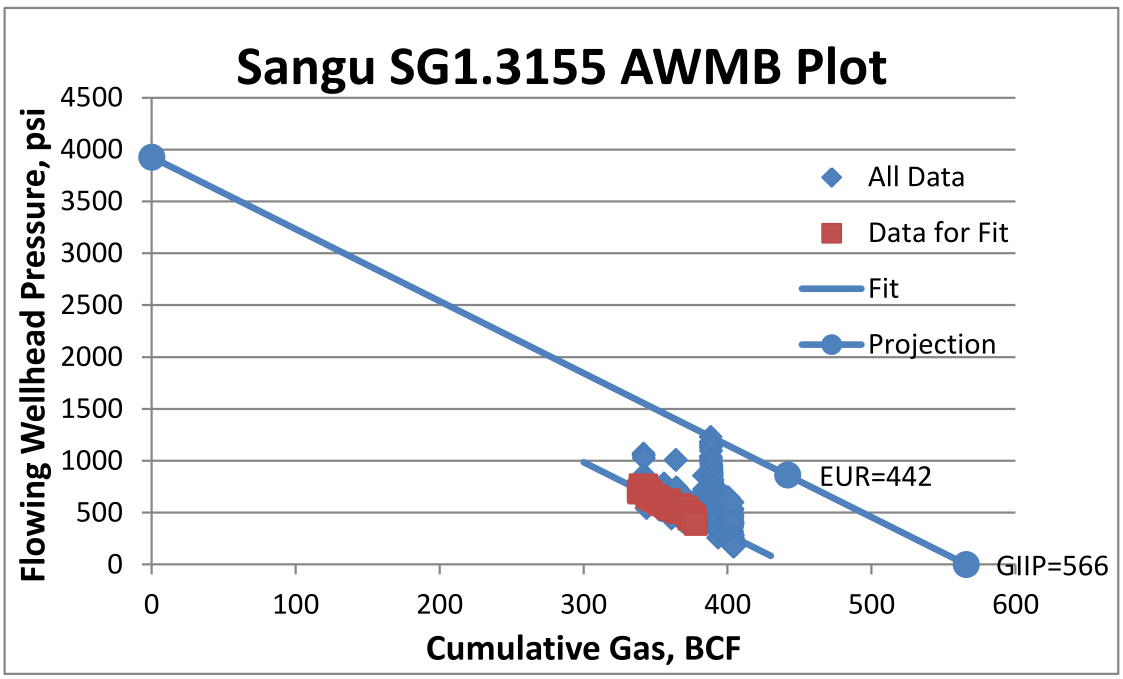



**Figure 6-135  Sangu SG1.3155 AWMB Plot**

[11] Mattar and McNeil, 1998.

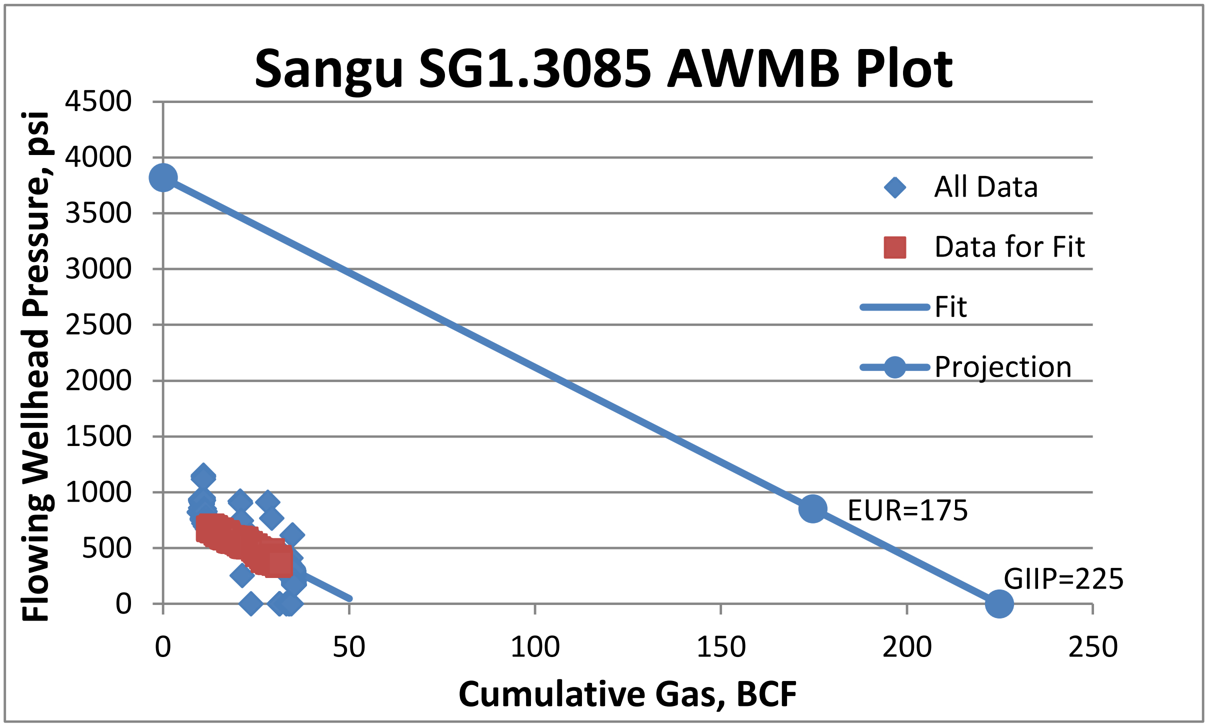



**Figure 6-136 Sangu SG1.3085 AWMB Plot**

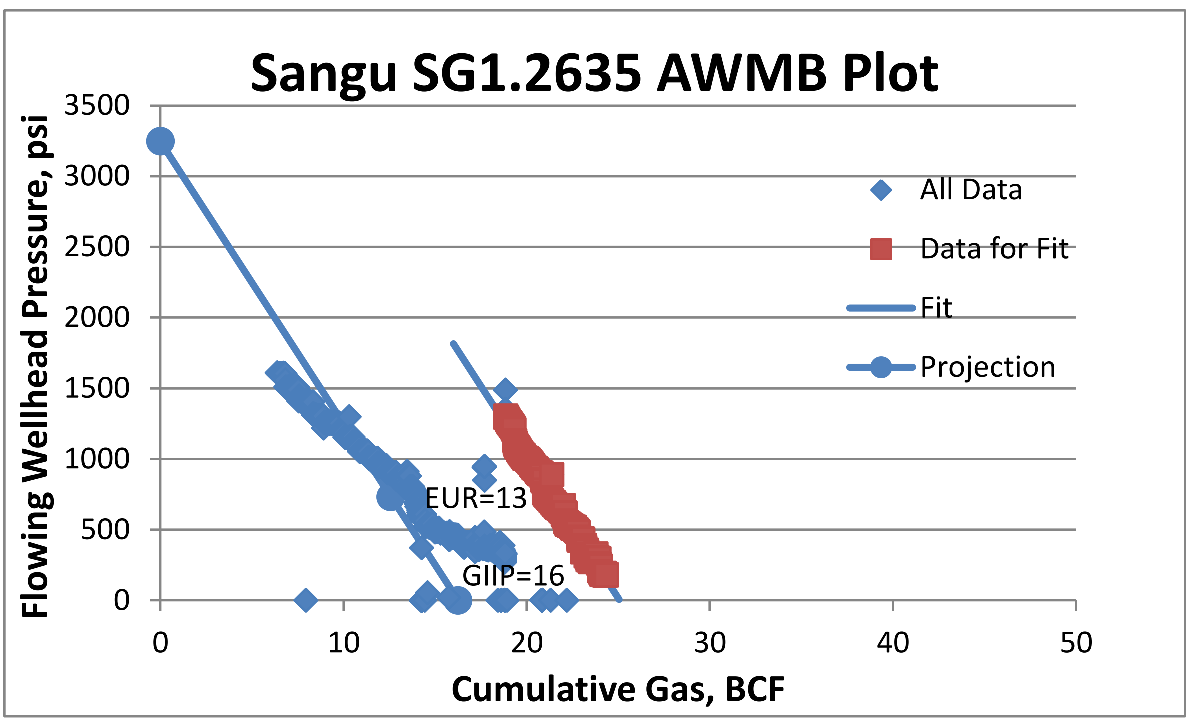



**Figure 6-137 Sangu SG1.2635 AWMB Plot**

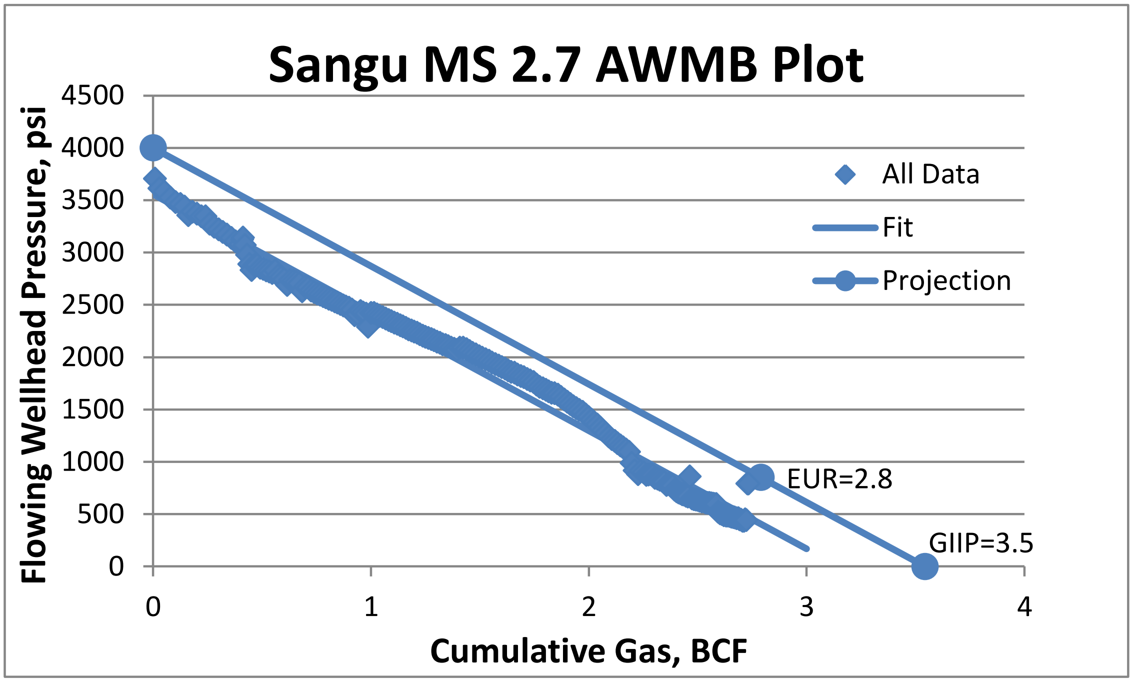



**Figure 6-138 Sangu MS 2.7 AWMB Plot**

These results compare with the mean volumetric calculations as follows:

| **Reservoir** | **SG1.3155** | | **SG1.3085** | | **SG1.2635** | | **MS 2.7** | |
|---|---|---|---|---|---|---|---|---|
| **Method** | **Volu-metric** | **Mat Bal** | **Volu-metric** | **Mat Bal** | **Volu-metric** | **Mat Bal** | **Volu-metric** | **Mat Bal** |
| GIIP, BCF | 458 | 566 | 48 | 225 | 33 | 16 | NA | 3.5 |
| EUR, BCF | 369 | 442 | 38 | 175 | 26 | 13 | NA | 2.8 |
| Cum. Gas, BCF | 404 | 404 | 35 | 35 | 24 | 24 | 2.7 | 2.7 |
| **Reserves, BCF** | **-35** | **38** | **3** | **140** | **2** | **-11** | **NA** | **0.1** |

The material balance method is considered most reliable for the SG1.3155 and MS 2.7 reservoirs. The volumetric estimate is considered most reliable for the SG1.3085 and the SG1.2635.

### 6.3.17 Shahbazpur

#### 6.3.17.1 Geologic Setting

Shahbazpur Structure is a subsurface anticline located in the Meghna delta in Block 10 (Figure 6-2). The nearest gas field is Begumganj situated about 80 km northeast. The offshore Kutubdia gas field is situated about 100 km south of Shahbazpur.

#### 6.3.17.2 Structure

Shahbazpur is an oval-shaped gentle anticline with almost symmetrical flanks. No fault was identified in BAPEX maps (Figure 6-139). Seismic data collected in 1995 indicate that the structure extends towards north. Additional survey is needed for full delineation of the structure. During 1996 under a joint study program with Unocal seismic data was reprocessed and new maps were prepared. The shape of the structure remained similar.

After discovery of gas additional seismic lines were recorded during 1995-96. New maps were prepared and the structural shape remained almost unchanged. However additional data indicated that there is a possibility of presence of another culmination on the north.

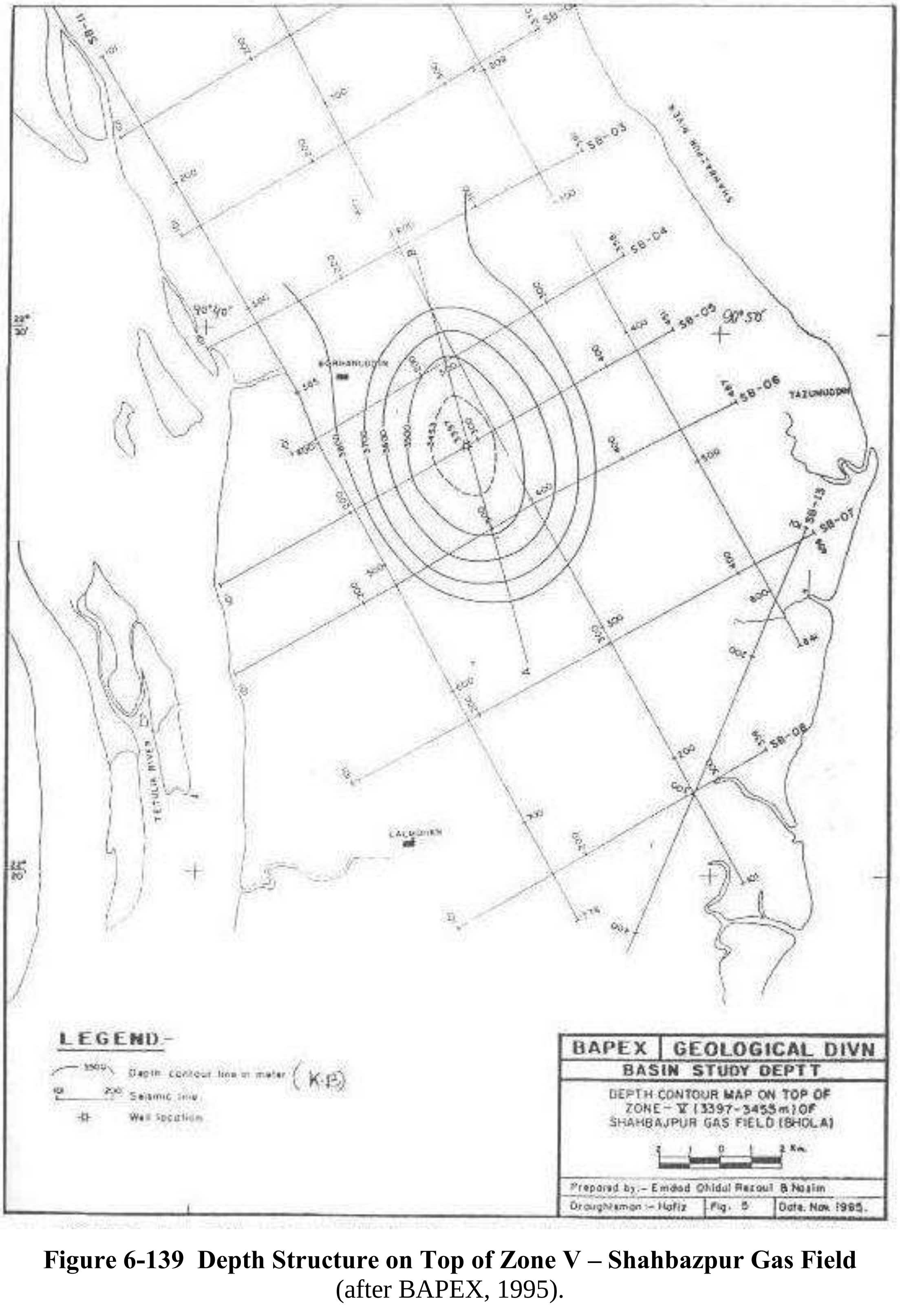



**Figure 6-139 Depth Structure on Top of Zone V – Shahbazpur Gas Field**
(after BAPEX, 1995).

6.3.17.3 Reservoir

In well #1 five gas sands within a depth range of 2587 – 3453m were identified from logs. In addition to this five, another four possible gas horizon within a depth ranging from 2755 to 2997m are evaluated. Two gas zones, one from mud log another below drilled depth identified from seismic data were included for reserve estimation by Unocal-BAPEX Joint Study team.

Depositional environment for the upper most reservoir was evaluated as prodelta-inner shelf. For the middle four gas sands the depositional environment was considered to be delta front/slope. Remaining reservoirs are considered to be deposited in prodelta–inner shelf environment.

Porosity of the shallowest reservoir was about 22% and this gradually decreases to 15-16% with increase of depth. Water saturation is depth independent and was found to range between 25 to 45%. A plot showing depth versus log and core porosity is provided in Figure 6-140.

As gas water contact was not seen in logs, BAPEX estimated reservoir thickness was the minimum possible thickness i.e. considering base of the sand in the well as GWC.

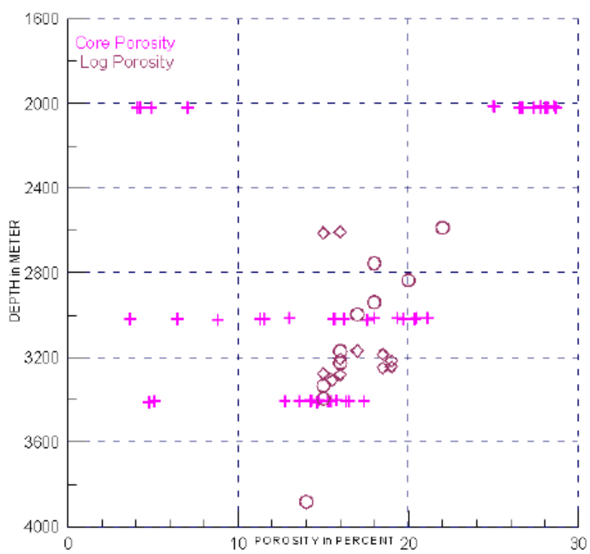



**Figure 6-140 Shahbazpur Well 1, Depth vs. Porosity Plot**

### 6.3.17.4 Exploration and Field Development

The area was first covered by seismic survey in early fifties by PSOC.

Atlantic Richfield Co. (ARCO) was awarded one offshore block covering Bhola Island. ARCO recorded shallow water seismic around the island and the structure was selected by as an alternate location for their first offshore well ARCO A-1. However after drilling the offshore well ARCO relinquished the area.

Petrobangla conducted seismic survey over the area during 1986-87 and prepared maps. The well location was selected on the basis of these maps.

During 1993–94 Shahbazpur well #1 was drilled to a depth of 3631m. The well encountered overpressure zone and during the process string got stuck. Prolonged operation for releasing string was unsuccessful and finally circulation was lost. Coiled Tubing Unit (CTU) was run to clean the well, restore circulation and release stuck string. This attempt could not be materialized as loss circulation material (LCM) blocked the annulus of drill string above bit. CTU was successfully used to test interval 3201-10m (Zone F/ll). This zone was perforated (stuck string) and dry gas flowed through CTU. Subsequently in 1995 a sidetrack hole was drilled to 3342m. Only one zone was tested in the sidetrack hole. At total depth (TD) horizontal displacement of side tracked well is about 250m from the original hole. All the gas sands except Zone 'A'/I sand is found present in the both the hole.

Recently BAPEX has taken up a development plan for this field, which includes drilling of one development well and completion of well #1. Shahbazpur #2 well was drilled in 2008 and completed in the Middle Gas Sand but has not yet been brought on stream. This well also encountered gas in a new reservoir called the New Gas Sand. Insufficient data are available to estimate reserves for this sand.

6.3.17.5 Well-wise and Sand-wise Production History

Only one well has produced gas at Shahbazpur field. Well #1 was completed in the Lower Gas Sand and has produced a total of 1.3 Bscf since if came on line in May 2009. The main reason for the restricted production is a lack of pipeline to transport gas to the regional gas transmission system of Bangladesh. Shahbazpur only supplies the local needs of a power generation plant on the island. No well-wise or sand-wise production charts have been constructed since the production is so limited.

6.3.17.6 Field-wise Cumulative Production

Table 6-61 summarizes the brief gas production history of Shahbazpur gas field. It shows that only a very small amount of gas has been produced to date and from only the Lower Gas Sand reservoir.

**Table 6-61 Sand-wise Cumulative Gas Production – Shahbazpur Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Middle Gas Sand | 0 |
| Lower Gas Sand | 1.3 |
| **Total** | **1.3** |

1 Production through end of December 2009
HCU production database

6.3.17.7 Earlier Reserve Estimates

Post-discovery estimate (BAPEX) placed GIIP of the field at 513.8 Bscf under undifferentiated Proven and Probable category. Sand-wise GIIP is given in Table 6-62.

**Table 6-62 BAPEX 1996 Post-Discovery Reserve Estimate – Shahbazpur Gas Field**

| Zone | GIIP (2P) |
|---|---|
| I | 22.4 |
| II | 72.1 |
| III | 306.6 |
| IV | 46.8 |
| V | 65.9 |
| Total in Bscf | 513.8 |

BAPEX 1996

Unocal Corporation together with BAPEX did a study (1996) on this field. Seismic data was reprocessed and reinterpreted and well log and test data were re-evaluated. This resulted in a new GIIP reserve figure, which is given below as Table 6-63. Of particular interest is the estimation that the 3P GIIP could be substantial at 2,041 Bscf, making this field a potentially important field for providing gas to meet future gas demand for Bangladesh if an economic connection to the regional gas transmission system can be implemented.

**Table 6-63 Unocal-BAPEX 1996 Reserve Estimate – Shahbazpur Gas Field (in Bscf)**

| Sand | Proven | Probable | Possible | Total |
|---|---|---|---|---|
| A Sand (I) | | 22.630 | | 22.630 |
| B Sand | | 168.226 | | 168.226 |
| C Sand | | 129.367 | | 129.367 |
| D Sand | | 115.096 | | 115.096 |
| E Sand | | 544.301 | | 544.301 |
| F Sand (II) | | 112.570 | | 112.570 |
| G Sand (III) | 252.871 | | | 252.871 |
| H Sand (IV) | | 33.946 | | 33.946 |
| I Sand (V) | | | 242.849 | 242.849 |
| J Sand | | | 418.900 | 418.900 |
| Total in Bscf | 252.871 | 1126.136 | 661.749 | 2040.756 |

Unocal-BAPEX 1996

In above two estimates A, F, G, H and I sands are common, and Proven+Probable GIIP of these five sands was 422.02 Bscf in Unocal-BAPEX Joint study. This is about 98 Bscf less than the estimate made by BAPEX. BAPEX study was limited to five gas sands only.

Zone III or ‘G’ was tested and Zone II or ‘F’ sand flowed dry gas through CTU. The estimated reserve of these two zones (III and II) can be considered as Proved on the basis of flow test. According to definition (SPEE 2002), in certain cases, Proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation test.

If Zone F/II and G/III are considered for Proven category, then GIIP of these two sands is 365.44 Bscf as per Unocal-BAPEX joint study and 378.7 Bscf according to earlier estimate by BAPEX.

In 2003, HCU-NPD produced an estimate of Shahbazpur’s GIIP (HCU-NPD, 2004). Between the last estimate by Unocal-BAPEX (1996) and the HCU-NPD 2003 estimate, no new data was collected or generated. For the 2003 estimate, the two earlier reserve estimation reports were reviewed and it was observed that the Unocal-BAPEX joint study report was more detailed. Seismic data was reprocessed and new maps were generated. Logs were also re-evaluated for that study.

It may be mentioned that in HCU-NPD Resource Study of 2002, the Unocal-BAPEX joint study report was used after redistribution of categories of GIIP. In their 2003 update, HCU and NPD followed the same path. Both the F (ll) and G (lll) Sands were considered as Proven as both flowed dry gas. The A (l) and I (v) sands were placed under Probable category on the basis of log evaluation results. The B through E sands were placed under the Possible category, also on the basis of wireline and mud log evaluation. The J sand was excluded as this reservoir was an undrilled horizon lying below T.D of the wells. Table 6-64 shows revised result after changing of reserve category for some of the sands. This table of results was used for the HCU-NPD 2003 study.

**Table 6-64  HCU-NPD 2003 Reserve Estimate – GIIP in Bscf – Shahbazpur Gas Field**

| Sand | Proven | Probable | Total (2P) | Possible | Total (3P) |
|---|---|---|---|---|---|
| A Sand (I) | | 23 | 23 | | 23 |
| B Sand | | | | 168 | 168 |
| C Sand | | | | 129 | 129 |
| D Sand | | | | 115 | 115 |
| E Sand | | | | 544 | 544 |
| F Sand (II) | 113 | | 113 | | 113 |
| G Sand (III) | 253 | | 253 | | 253 |
| H Sand (IV) | | 34 | 34 | | 34 |
| I Sand (V) | | 243 | 243 | | 243 |
| Total | 365 | 299 | 665 | 957 | 1622 |

HCU-NPD 2004

The HCU-NPD 2003 estimate of 3P GIIP of 1,622 Bscf for the field represents about a 21% reduction from the Unocal-BAPEX estimate of 3P GIIP.  However HCU's estimate of 365 Bscf for 1P GIIP represents about a 44% increase in the 1P GIIP over that of the previous study.

As with other National Company-operated fields, the RPS Energy-Petrobangla 2009 re-estimation study using both volumetric (deterministic and probabilistic) and reservoir simulation methodologies is the latest attempt to determine the most accurate GIIP for Shahbazpur gas field. The results of this latest study are presented below in Table 6-65.

**Table 6-65  RPS Energy 2009 Reserve Estimate – GIIP in Bscf – Shahbazpur Gas Field**

| GIIP | Volumetric Calculation (Bcf) | | Simulation Initialisation (Bcf) |
|---|---|---|---|
| | Petrel™ | REP™ (P50) | |
| Lower Gas Sand | 394 | 429 | 393 |

**RPS** Energy 2009

This latest estimate by RPS has drastically reduced the GIIP for the field from the range of 1,600 to 2,000 Bscf of previous studies to around 393 Bscf (Petrel deterministic volumetric methodology) to 429 Bscf (REP probabilistic volumetric methodology).  These latter GIIP levels are very similar to the 1P GIIP estimates from the previous studies.  It therefore appears that the latest RPS estimate does not give any significant credit for Probable or Possible GIIP categories as was done in the earlier estimates.

6.3.17.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Shahbazpur field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

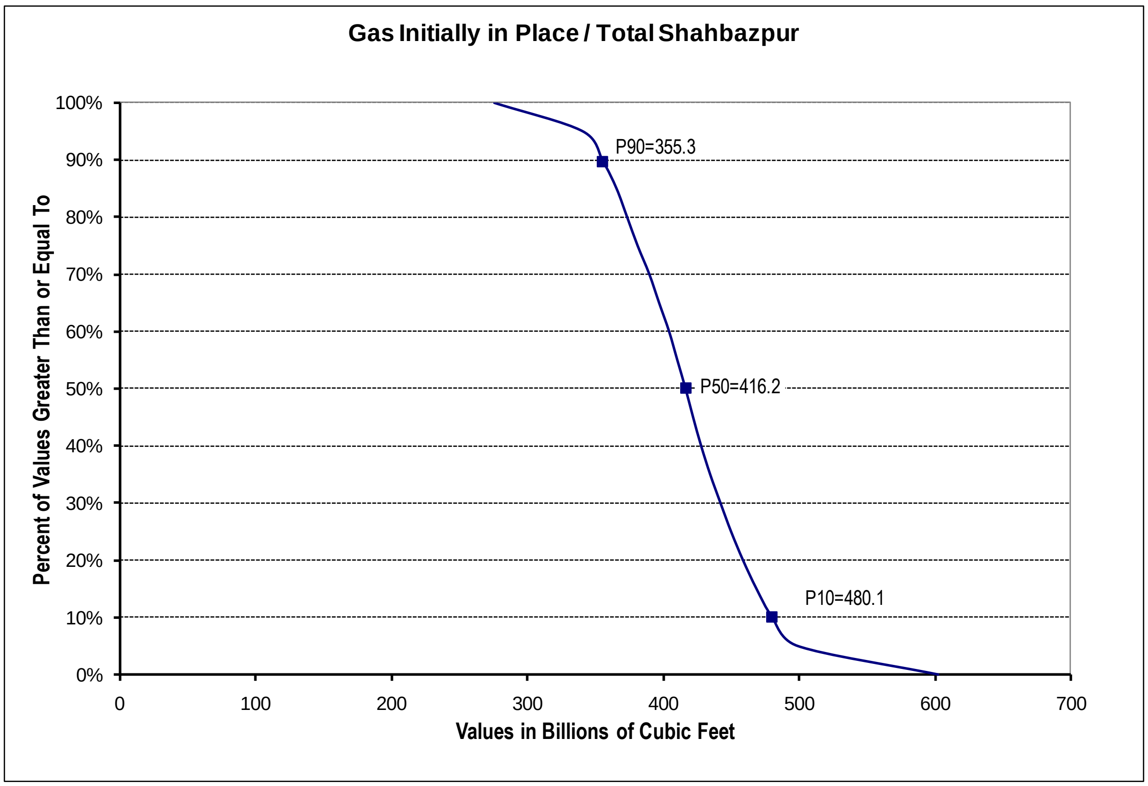



**Figure 6-141 Distribution of GIIP, Shahbazpur**

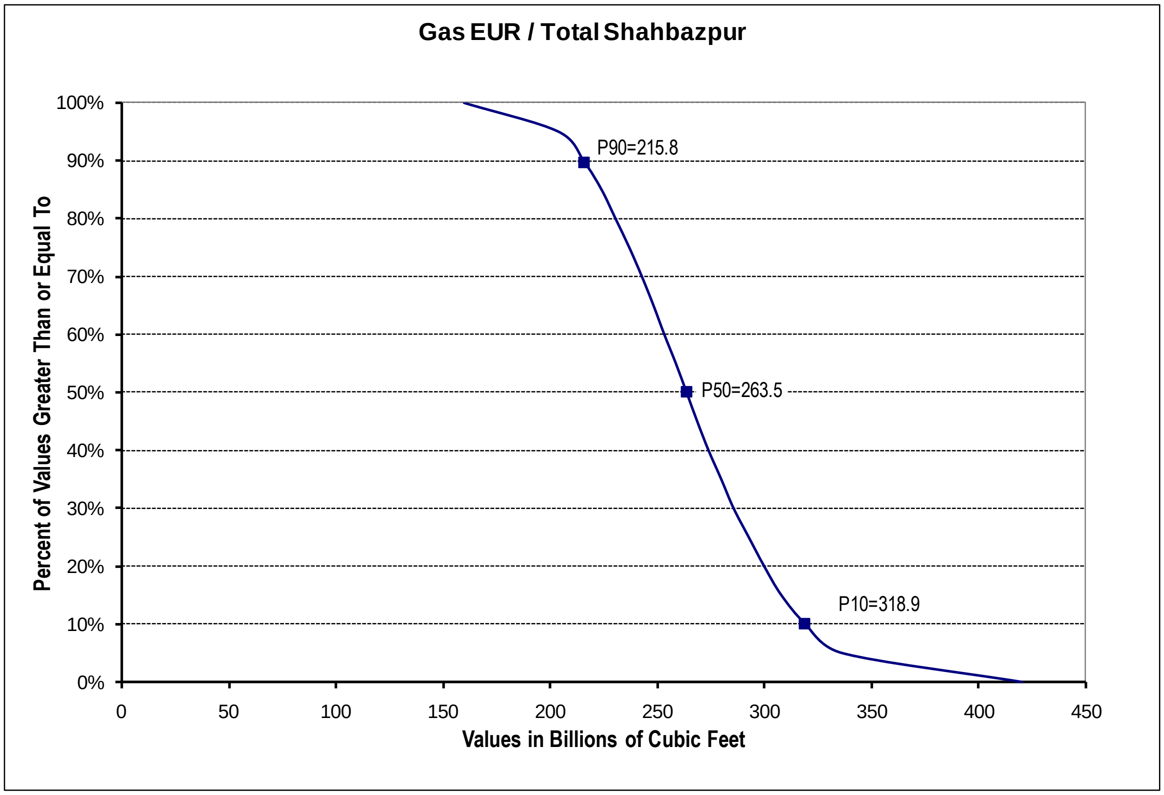



**Figure 6-142 Distribution of Gas EUR, Shahbazpur**

**Table 6-66 Summary of Estimated Ultimate Recovery at Shahbazpur**

| Reservoir | Mean Gas EUR, BCF |
|---|---|
| I Sand | 11 |
| II Sand | 37 |
| III Sand | 151 |
| IV Sand | 27 |
| V Sand | 40 |
| **TOTAL** | **266** |

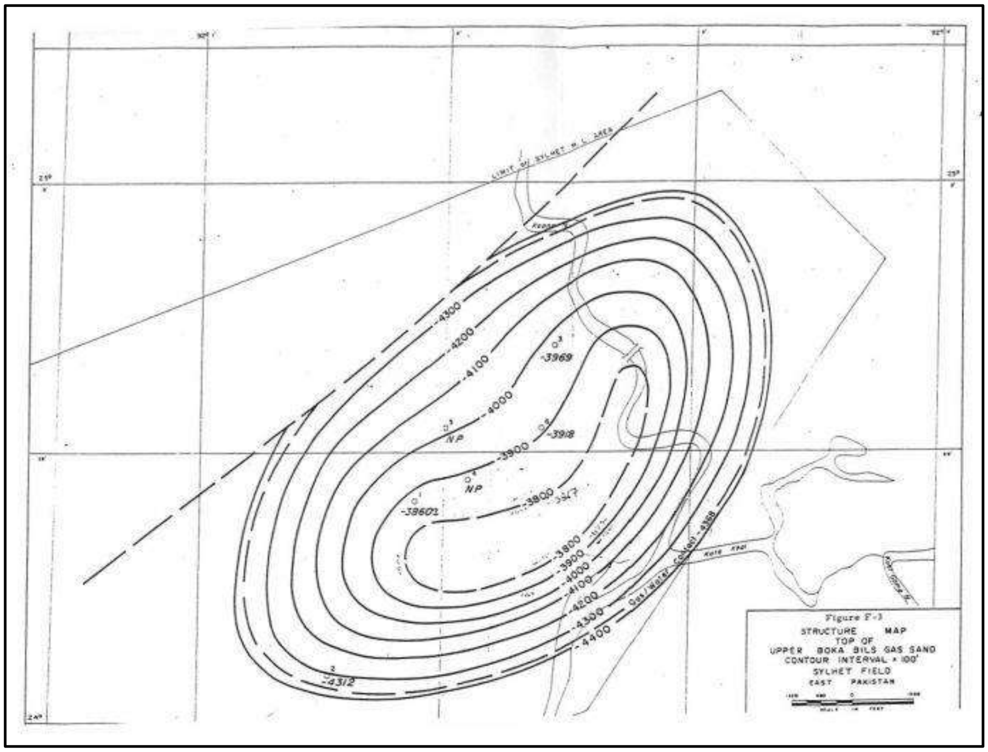
### 6.3.18 Sylhet

#### 6.3.18.1 Geologic Setting

Sylhet Anticline is located in the northeastern region of Bangladesh within the Eastern Foldbelt. It is located in Block 13 to the ENE of Jalalabad gas field and north of Kailash Tila gas field (Figure 6-3). It is the northeastern-most commercial gas field in the country.

#### 6.3.18.2 Structure

Sylhet structure is an anticline covered with outcrops of Tipam Sandstone and younger sediments. During early fifties PPL carried out surface geological as well as seismic survey. The structure is a brachi-anticlinal one with relatively steeper South East flank. The pitching alignment is NNW-SSW. No fault was observed by PPL. Figure 6-143 through Figure 6-145 are structure and gross sand isopachs for the Upper, Second, and Lower Bokabil Sand. The isopach maps show the amount of gross sand above the respective gas-water contacts (GWCs) for each reservoir.



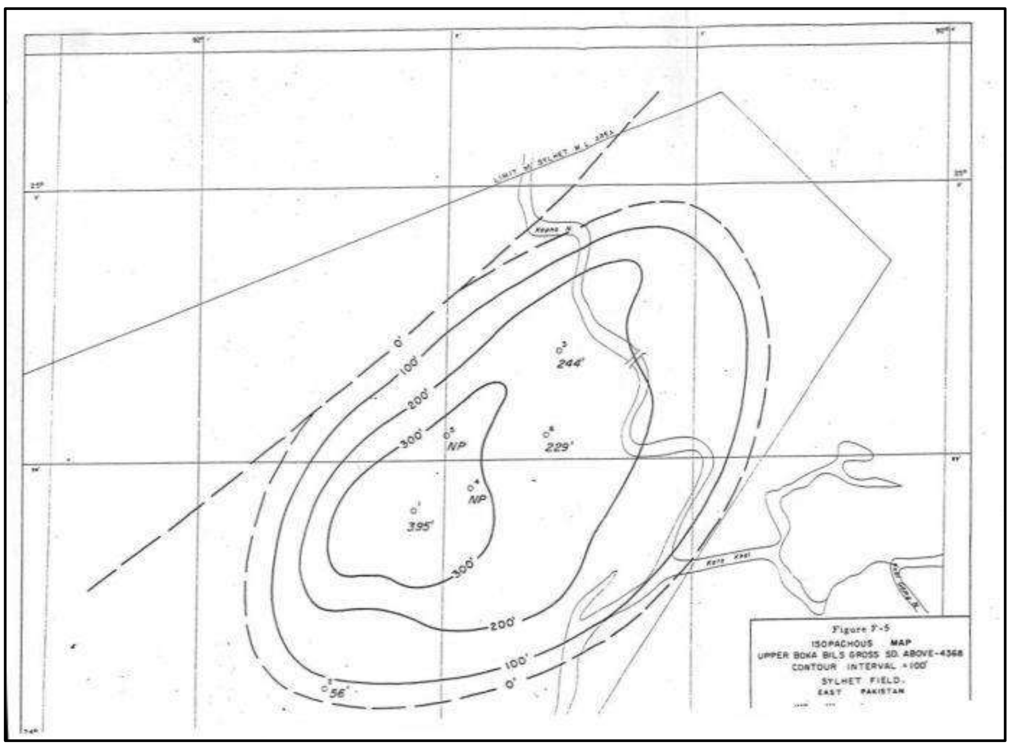
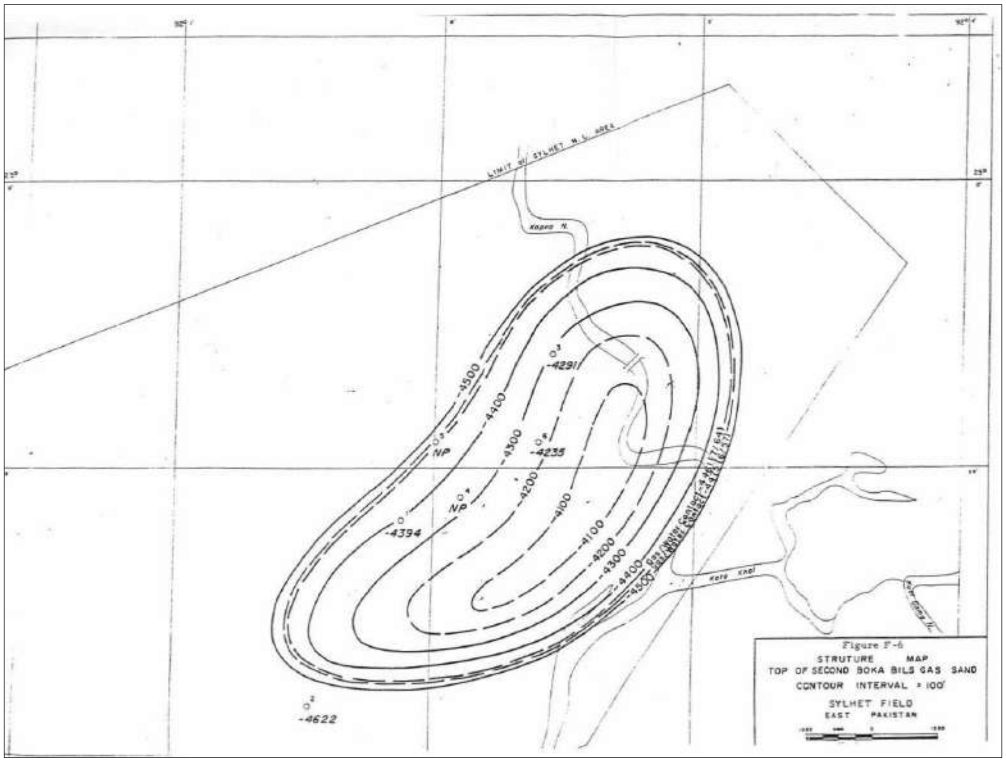




**Figure 6-143 Structure and Isopach Maps, Upper Bokabil Sand – Sylhet Gas Field**
Contoured in feet (after PPL, 1971)



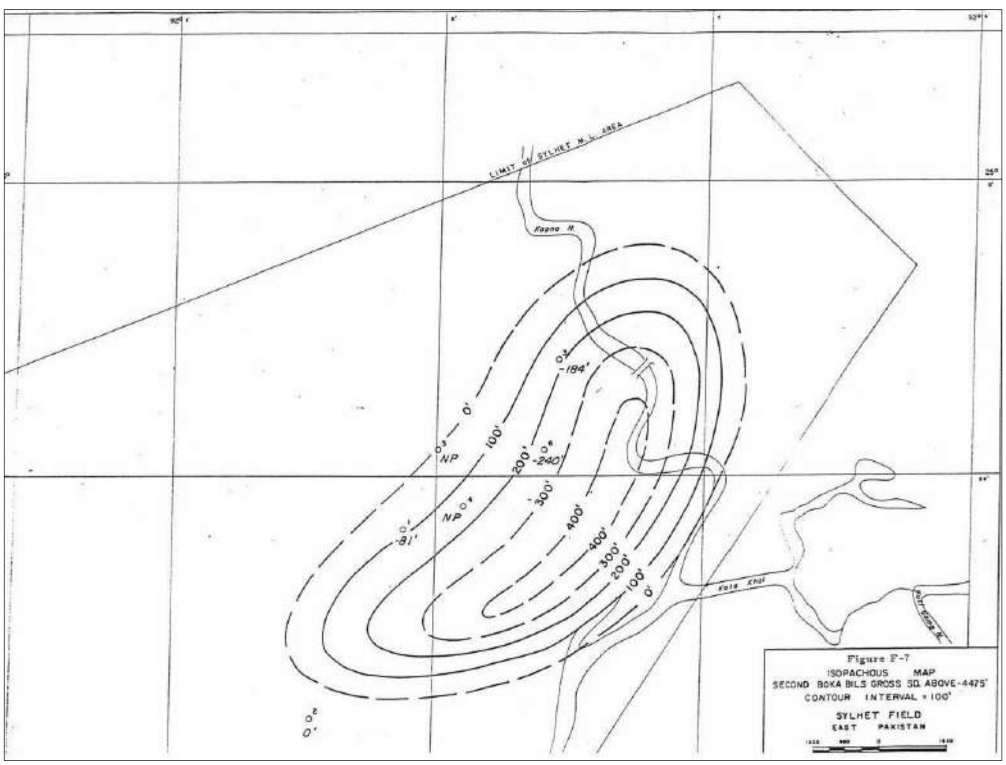
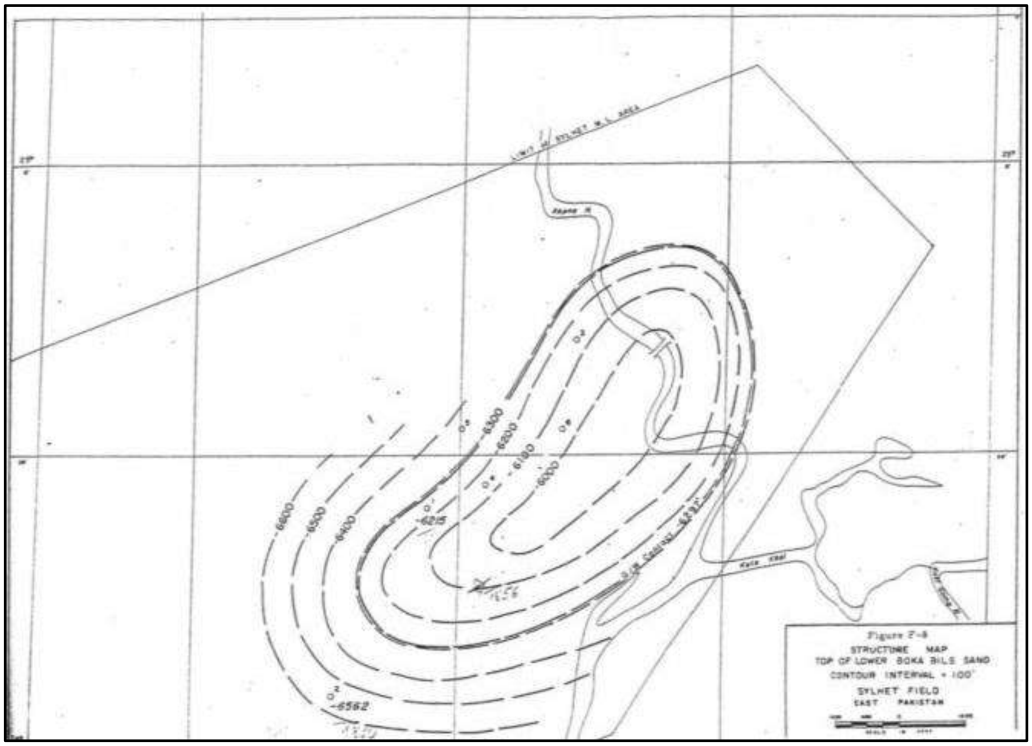




**Figure 6-144 Structure and Isopach Maps, Second Bokabil Sand - Sylhet Gas Field**
Contoured in feet (after PPL, 1971)



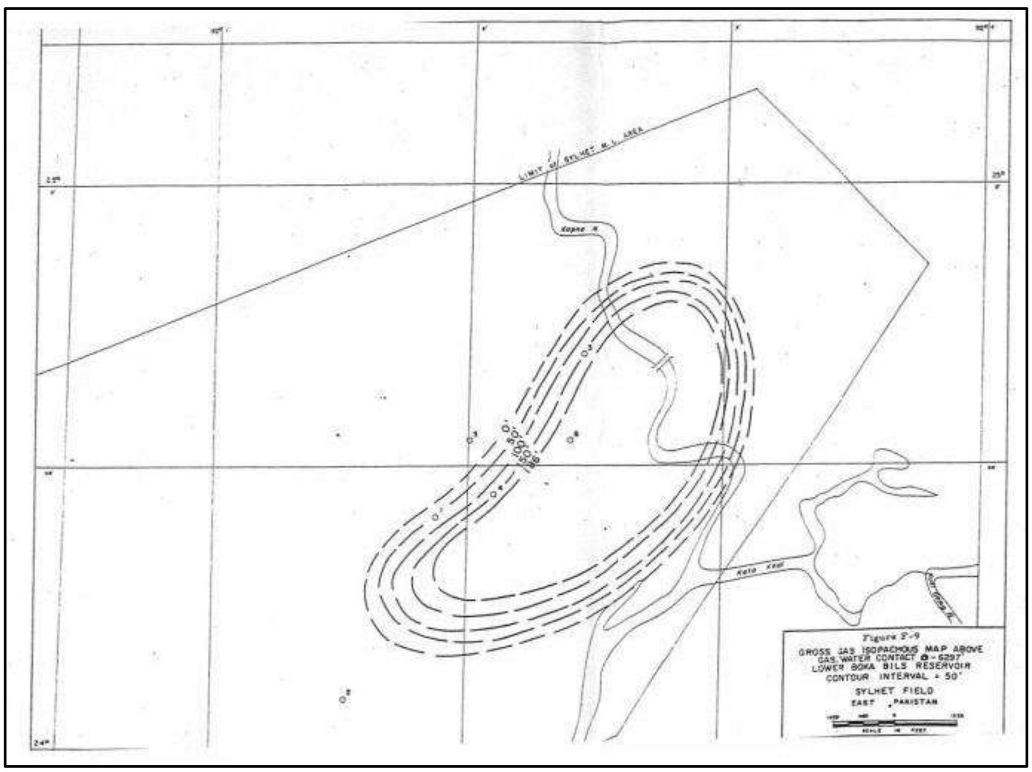




**Figure 6-145 Structure and Isopach Maps, Lower Bokabil Sand–Sylhet Gas Field**
Contoured in feet (after PPL, 1971).

### 6.3.18.3 Reservoir

In Sylhet structure, six gas sands were identified by drilling. In addition, one oil-bearing sand was discovered. The shallowest gas sand is encountered at 1665 ft (508m) and PPL named it as 1665 ft Tipam Sandstone. This sandstone was encountered in all of the wells. The Tipam Sandstone has never been produced.

The second gas sand named as Upper Boka Bokabil Sand was encountered in all the wells. In well #2, GWC was observed at -1331m (-4368 ft) for this reservoir.

Within Bokabil Formation, another gas sand, the Second Bokabil Sand, was encountered in all the wells. A GCW was observed in wells at -1364m (-4475 ft).

The lowest productive gas sand in the Bokabil is the Lower Bokabil Sand that was encountered in Well #7 along with a deeper oil sand. A GWC was noted in this lower gas sand at -1919m (-6297 ft). Following depletion of the oil sand, Well #7 was recompleted in the Lower Bokabil Gas Sand in 2005.

The oil reservoir at Sylhet gas field was encountered in Well #7 and Surma Well #1. This unnamed oil sand occurs beneath the Lower Bokabil Sand.

According to PPL, porosity in Upper Bokabil Sand and Second Bokabil Sand is 25%. A later Petrobangla study (1988) listed porosity of Tipam Sandstone as 21 to 28%, and the porosity of the Upper Bokabil Sandstone as 15 to 20%. Porosity of Second Bokabil Sandstone ranged from 12 to 19%.

In 2009, RPS Energy, under contract to Petrobangla, restudied and modeled Sylhet production. They renamed the three gas sands at Sylhet as follows: the BB3 (Upper Bokabil), the BB2 (Second or Middle Bokabil), and the BB1 (Lower Bokabil). In addition, they assigned the oil sand to the Upper Bhuban Formation. For the present report, we will continue to use the historic nomenclature for these sands.

### 6.3.18.4 Exploration and Field Development

Pakistan Petroleum Ltd (PPL) surveyed the area using both geological and geophysical methods. In 1955, first well was drilled to s depth of 2377m. The well discovered three gas sands. After cementation of 10¾ inch casing, pressure developed in the annulus and eventually well blew out through surface vents 60-100 meters away from well head and caught fire. The reason of blow out was attributed to poor cement job. Subsequently Well #1 cratered and killed itself. Gas continued to flow from the crater but its composition was quite different from that of the reservoir gas and it was believed to be coming from lignite bed near the surface. However, samples collected in December 1961 indicated that the gas was coming from the main reservoirs. This indicated that collapse of the well could not seal off the reservoir. Earlier workers opined that though the flow of gas at surface constitutes a minor loss, the fact that the reservoir gas might be lost to the massive sands overlying the reservoir. No study was undertaken since then. The crater is still burning. According to some workers, gas flow at the surface constitutes a minor loss as the reservoir gas might be lost into overlying massive sands.

In 1956, Well #2 was drilled to 2818m. This well faced problem with formation pressure and the well was junked. In the following year, well #3 was drilled and completed as a commingled dual producer in the Upper and Second Bokabil Sands. Following the drilling of Well #6 in 1964, Well #3 was recompleted as a dual producer from the two sands and production from each zone was isolated beginning in December 1964.

In 1962, Well #4 was spudded but it blew out at 315m. An observation well, it was an indication that the gas from the main reservoir could be leaking into sands at shallower depth causing excess pressure. In order to address this issue, an observation well (Well #5) was drilled to monitor pressure behavior at a shallow depth. Well #6 was drilled in 1964 and completed as a dual producer in the Upper and Second Bokabil Sands.

In 1986, with technical and financial assistance from Asian Development Bank, Well #7 was drilled. Target of the well was to open known gas sands. On insistence from Petrobangla, the well was deepened to check for presence of the Lower Gas Sand. The well discovered oil in an unnamed sand that was encountered below the Lower Gas Sand at a depth of 2020-2035m. The oil sand was tested and the test led to production.

After discovery of oil, the area covering the oil field along with a delineated structure (Jalalabad) was awarded to a company named Scimitar Oil. This company drilled the Surma #1 and Surma #1A wells but failed to test the oil and abandoned both wells. The company also drilled an exploratory well in Jalalabad and discovered gas. However, the company left the country without further work.

SGFL operated the oil well, which died in July 1994 after producing just over one-half million bbl of oil in six and one-half years. In 2005, it was re-completed in the overlying Lower Bokabil Gas Sand. The well produced gas for over three years and died again in July 2008. The production history was short. The well produced 7 Bscf of gas in about two and one-half years.

After Independence of Bangladesh, PPL left the country. As a result, gas fields operated by PPL, were taken over by the government. A new company, Sylhet Gas Field Ltd was formed to operate these gas fields.

With German technical assistance, Petrobangla recorded multifold digital seismic survey. On the basis of the result, new maps were prepared. For many years there was no re-evaluation of Sylhet gas field. In 2009, Petrobangla and its consultant RPS Energy completed a study on the 14 gas fields operated by Petrobangla including Sylhet.

6.3.18.5 Well-wise and Sand-wise Production History

Gas production from Sylhet gas field started in December 1960 from commingled Upper and Second Bokabil Gas Sands in Well #3. Production during its first year averaged about 4 MMscfd with some rates as high as 12-19 MMscfd during the early 1960s.

Well # 6 began producing in August 1964 with average rates around 6 MMscfd and rates as high as 10-17 MMscfd during its first four years of production. From October 1980 through May

1989, daily flow rates from Well #6 commonly exceeded 10 MMscfd. The daily rate gradually reduced unto this rate quite rapidly declined to less than 1 MMscfd in November and December 2008. During the same time, water production increased to over 200 bbl/MMscf of gas from less than one bbl/MMscf gas. FWHP also recorded a drop to 545 psig from 1040 psig. Cumulative production from this zone was 93 Bscf.

Oil Production from Sylhet well #7 started in December 1987. Oil production rate was 380 bbl/day. Production started to decline quite early. The FWHP was 725 psig at the beginning or production. This pressure came down to 62 psig when the well was shut down. During the entire production period, water production rate was quite insignificant. At the beginning it was zero during first 3 years of production. Then it started to increase quite slowly and at the end it was 0.28 bbl/MMbbl.

Gas production from Sylhet well #7, started in August 2005. For less than a year, the well flowed gas at the rate of 13-14 MMscfd. From January 2006 production started to decline and in August 2008 it stopped flowing. During this period, FWHP decreased to 950 psig from 1900 psig. Water production rate was less than one bbl/MMscf of gas. This rate jumped to10 bbl/MMscf on the last day of production. Cumulative production was only 7 Bscf.

Figure 6-146 and Figure 6-147 graphically display the well-wise and sand-wise gas production in Sylhet gas field. From Figure 6-147, it evident that the Upper Bokabil Sand has been the largest contributor to the daily gas flows over much of the field's productive history.

Detailed individual well histories and accompanying production charts for Sylhet wells are included in The Annex.

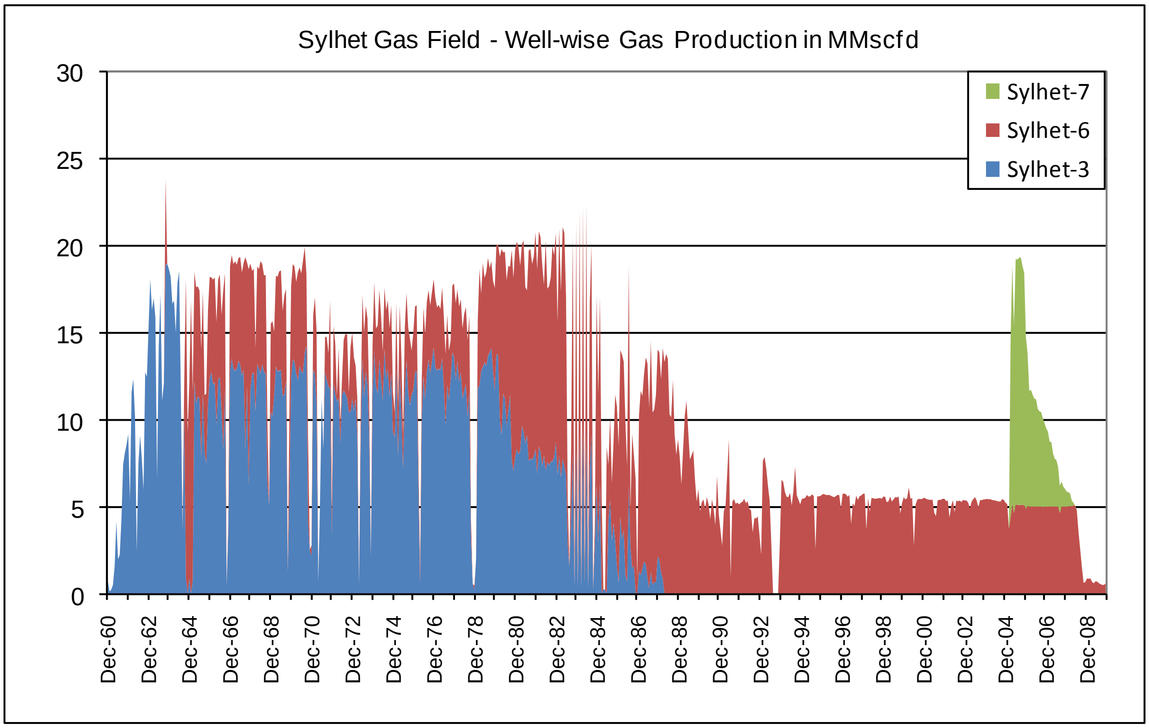



**Figure 6-146 Well-wise Gas Production – Sylhet Gas Field**

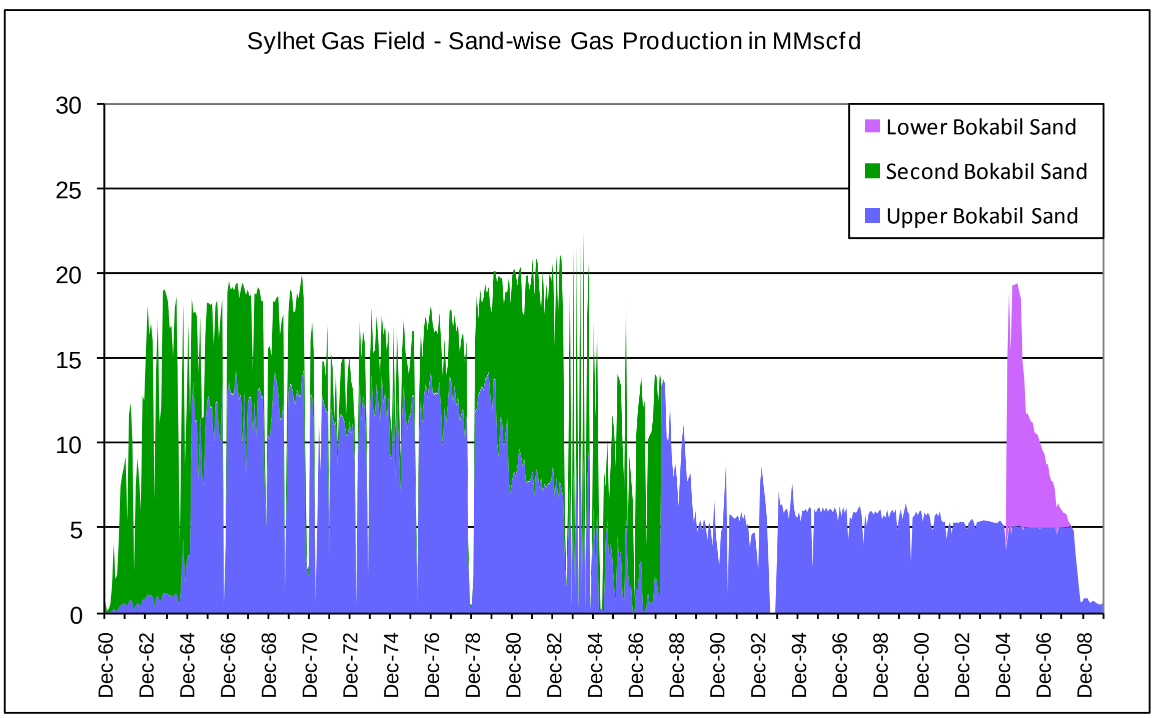



**Figure 6-147 Sand-wise Gas Production – Sylhet Gas Field**

### 6.3.18.6 Field-wise Cumulative Production

Table 6-67 summarizes production from the three gas reservoirs at Sylhet gas field. Table 6-67 confirms that the Upper Bokabil Sand has been the main contributor to Sylhet's cumulative gas production, accounting for 63% of the field's total historic production. The split between the Upper and Second Bokabil Sands is somewhat uncertain due to incomplete records as to when each sand was being produced from each of the two dually completed wells, Well #3 and Well #6. Additionally, the Upper and Second Bokabil Sands were commingled in Well #3 for the first four years of production until the well was recompleted as a dual producer from the same sands in 1964.

**Table 6-67 Sand-wise Cumulative Gas Production – Sylhet Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Upper Bokabil Gas Sand | 119.0 |
| Second Bokabil Gas Sand | 63.2 |
| Lower Bokabil Gas Sand | 7.1 |
| **Total** | **189.3** |

1 Production through end of December 2009
HCU production database

### 6.3.18.7 Earlier Reserve Estimates

Table 6-68 below summarizes early reserve estimates of the individual reservoir sands of Sylhet Gas Field for the period from 1955 through 1971. After independence of Bangladesh a number of studies were conducted. Results of these estimates are provided in the Table 6-69. They span a period from 1971 through 2000.

The most recent reserve estimate is that of RPS Energy, under contract to Petrobangla. This estimate was released in late 2009 and was based on 3-D static modeling, history matching, and reservoir simulation using the Petrel and ECLIPSE software packages. The results of this study for both gas and oil reserves are summarized in Tables 6-70 and 6-71, respectively.

## Table 6-68 Comparison of Early Reserve Estimates – Sylhet (in Bscf)

| Sand | PPL 1955 | PPL 1957 | A. H. Sweatman 1957 | Ralph Davies 1958 | MB Analysis 1965 | PPL Nov. 1966 | B. Bonnet 1967 (MB) | James Lewis 1971 |
|---|---|---|---|---|---|---|---|---|
| Tipam | | | | | | 29.25 | | 28.22 |
| Up.Boka Bil | 516.3 | 497 | 146 | 210.40 | 197.48 | 311.37 | 235.41 | 320.98 |
| Second Bokabil | 189.8 | 189 | 70 | 119.68 | 114.61 | 204.72 | | 203.07 |
| Lr. Boka Bil 1920 | | | | 16.13 | | | | 131.59 |
| Total | 706.1 | 686 | 216 | 346.21 | 312.09 | 545.34 | 235.41 | 683.85 |

## Table 6-69 Comparison of Post-Independence Reserve Estimates – Sylhet (in Bscf)

| Sand | Petrol Consult 1979 * | IMEG 1980 | GGAG 1986 | HHSPP 1986 | Weldeill 1991 | PMRE, BUET 2000 |
|---|---|---|---|---|---|---|
| Tipam | | | | | | |
| Upper Boka Bil | 130 | 291.5 | 245.08 | 291.5 | 400 | 840 |
| Second Bokabil | 34 | 155.2 | 230.18 | 152.5 | | |
| Lower Boka Bil 1920 | | | | | | |
| Total | 164 | 446.7 | 475.26 | 444.0 | 400 | 840 |

* Recoverable

## Table 6-70 RPS 2009 Reserve Estimate – Sylhet GIIP (in Bscf)

| Gas Sand | Volumetric Calculation (Bcf) | | Simulation Model (Bcf) | | Estimated Connected Volume (Bcf) | |
|---|---|---|---|---|---|---|
| | Petrel™ | REP™ (P50) | Before History Match | After History Match | Production Analysis | Material Balance Analysis |
| A | 323 | 349 | 322 | 242 | 275 -290 | Bottomhole pressure data are not available |
| B | 78 | 84 | 76 | 82 | 87 - 90 | |
| D | 127 | 134 | 127 | 46 | 13 | 15 - 105 |
| **Total** | **528** | **567** | **525** | **370** | **375 – 393** | **-** |

RPS, 2009m

**Table 6-71 RPS 2009 Reserve Estimate – Sylhet STOIIP (in MMSTB)**

| Oil Sand | Volumetric Calculation (MMSTB) | | Simulation Model (MMSTB) | | Estimated Connected Volume (MMSTB) | |
|---|---|---|---|---|---|---|
| | Petrel™ | REP™ (P50) | Before History Match | After History Match | Production Analysis | Material Balance Analysis |
| E | 31.2 | 30.0 | 31.0 | 10.2 | 3.2 | 8 -19 |
| **Total** | **31.2** | **30.0** | **31.0** | **10.2** | **3.2** | **8 -19** |

RPS, 2009m

6.3.18.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Sylhet field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

Additionally, insufficient data were available for a re-estimation of the reserves of the minor Tipam reservoir. Therefore, we have relied on the estimate presented in the 2003 Reserve Estimate report for this reservoir.

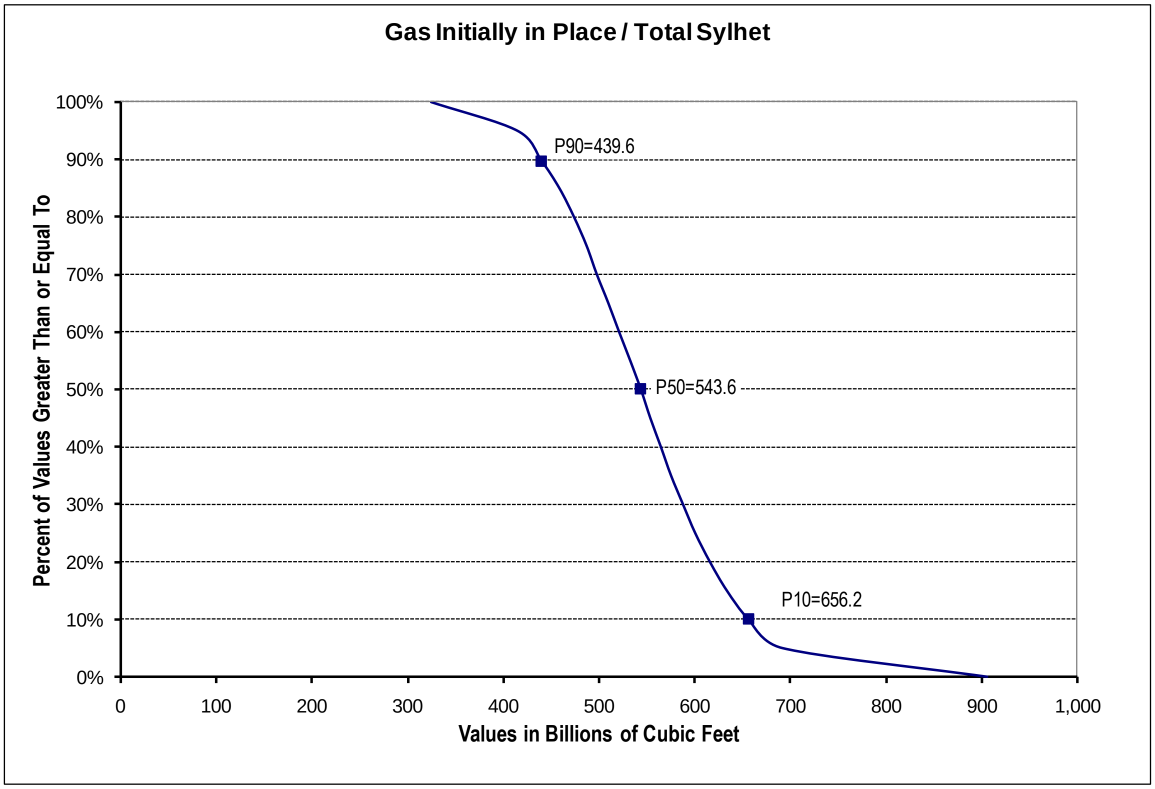



**Figure 6-148 Distribution of GIIP, Sylhet**

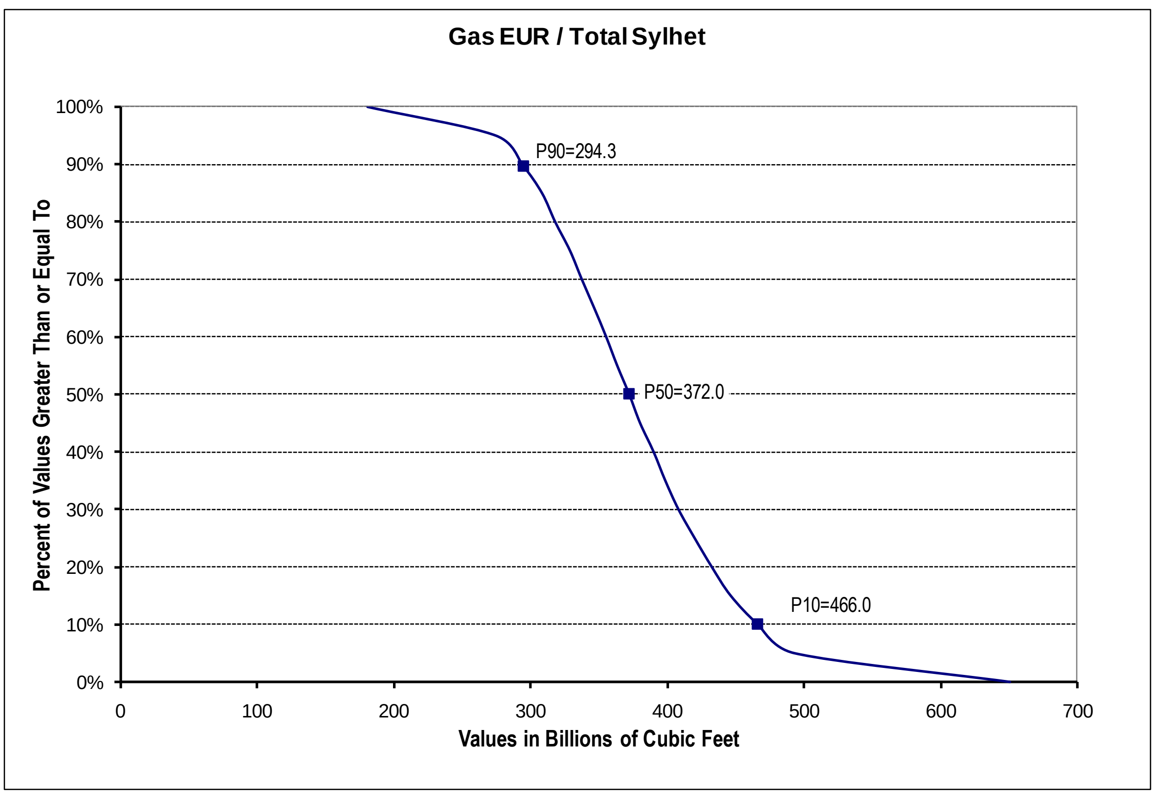



**Figure 6-149 Distribution of Gas EUR, Sylhet**

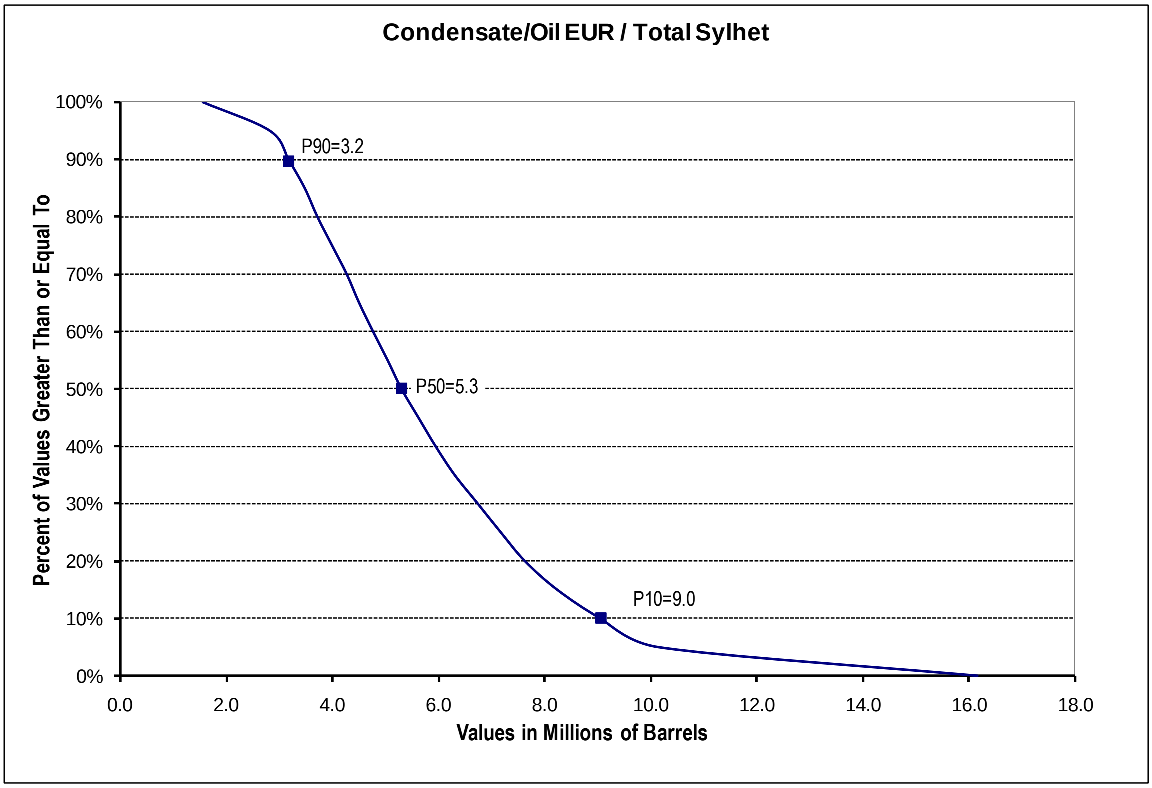



**Figure 6-150 Distribution of Oil/Condensate EUR, Sylhet**

**Table 6-72 Summary of Estimated Ultimate Recovery at Sylhet**

| **Reservoir** | **Mean Gas EUR, BCF** | **Mean Oil/Condensate EUR, BCF** |
|---|---|---|
| Tipam | 28 | 0.0 |
| Upper Bokabil | 235 | 0.8 |
| Middle Bokabil | 63 | 0.2 |
| Lower Bokabil | 86 | 0.6 |
| Upper Bhuban | 2 | 4.1 |
| **TOTAL** | **414** | **5.7** |

### 6.3.19 Titas (2)

#### 6.3.19.1 Geologic Setting

Titas structure is located within Chandina Deltaic Plain in the southwestern corner of Block 12 (Figure 6-2). The structure is located in the western part of the Eastern Foldbelt and lies to the southwest of Habiganj gas field (Figure 6-3). The area is covered by sediments deposited by Titas and Meghna rivers. The area is covered by Chandina Formation of Early Holocene age (Bakr, 1977). On the east, along the India – Bangladesh border, outcrop of Pleistocene sediments represented by Modhupur Clay is exposed along a narrow strip.

There is no surface expression of the Titas structure. PPL During early 1950s, PPL covered the area by gravity survey and initial indication of the structure was made. During late 1950s PSOC recorded widely spaced seismic survey and in 1960 confirmed the presence of a subsurface anticline. It was named as Titas structure after the river Titas. Titas gas field was discovered on the structure in 1962.

6.3.19.2 Structure

Titas structure is a low relief subsurface anticline. In the initial map prepared by PSOC the structure is a low relief asymmetrical anticline with a much broader west flank. Petrobangla recorded 63 km seismic line during 1982. Four years later CGG was engaged by Petrobangla to recorded 134 Km multi fold line. Based on this data, IKM prepared depth contour maps, which showed the asymmetrical nature of the anticline (Figure 6-151). The west flank of the anticline became narrower and steeper in comparison with the PSOC map. This set of maps incorporated the results of the first 11 wells drilled in the field.

Another set of depth contour maps were prepared in 1988 by Teknika using Seislog processing. The results of this technique largely depend on velocity-depth conversion and the control provided by a grid of velocity data. In this case, only one well log data was used.

In 2001, HCU prepared depth contour maps on top of A and B sands and conducted volumetric estimation. Figure 6-152 and Figure 6-153 are structure maps from this study and are based on the results of 14 wells.

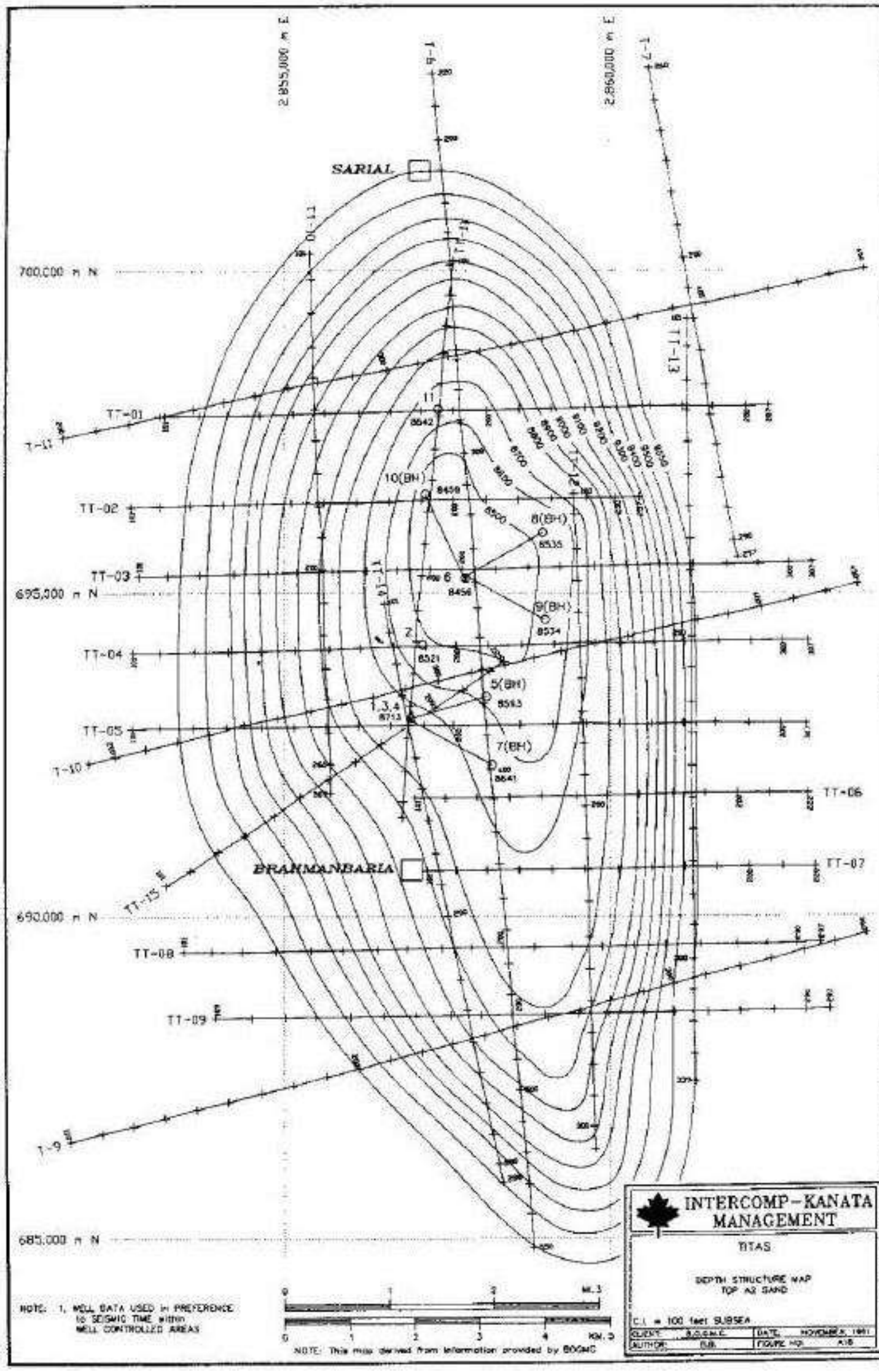



**Figure 6-151 Depth Structure Map on Top of A2 Sand – Titas Gas Field, 1992**
Map based on results of first 11 wells. C.I.=100 ft (after IKM, 1992).

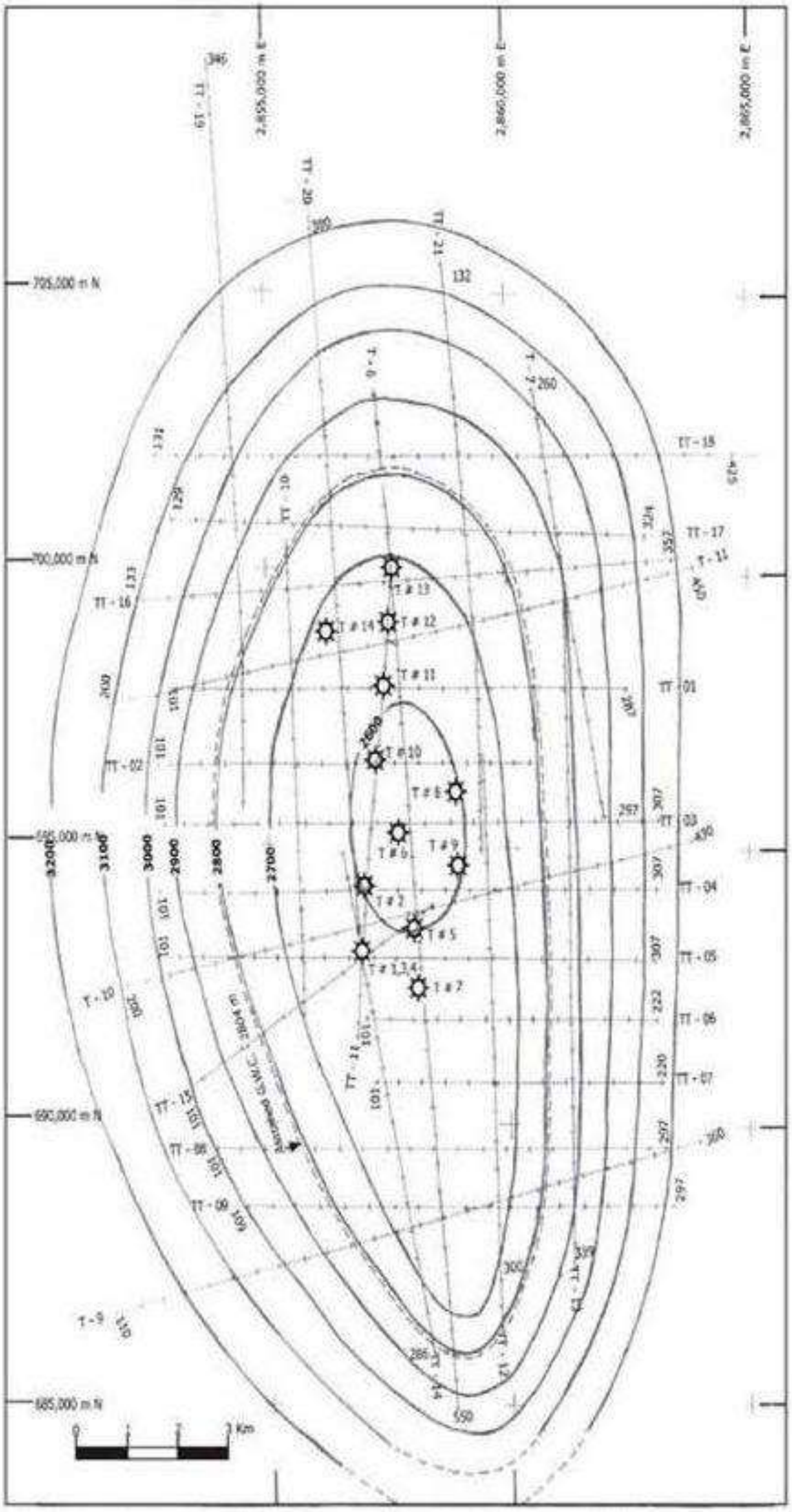



**Figure 6-152 Depth Structure Map on Top of A2 Sand – Titas Gas Field, 2001**
Map based on results or first 14 wells. C. I.=100 m (after HCU 2001)

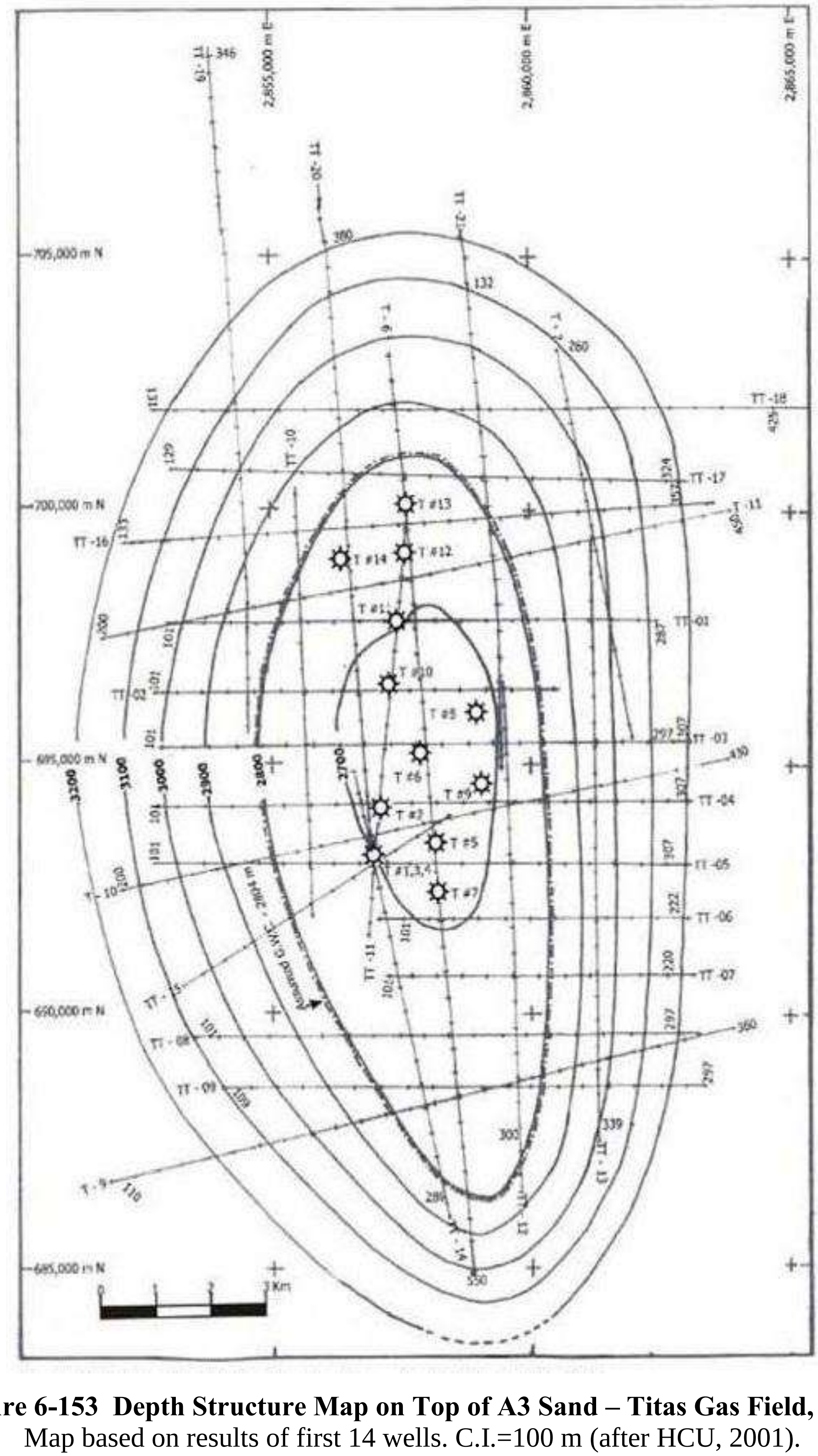


**Figure 6-153 Depth Structure Map on Top of A3 Sand – Titas Gas Field, 2001**
Map based on results of first 14 wells. C.I.=100 m (after HCU, 2001).

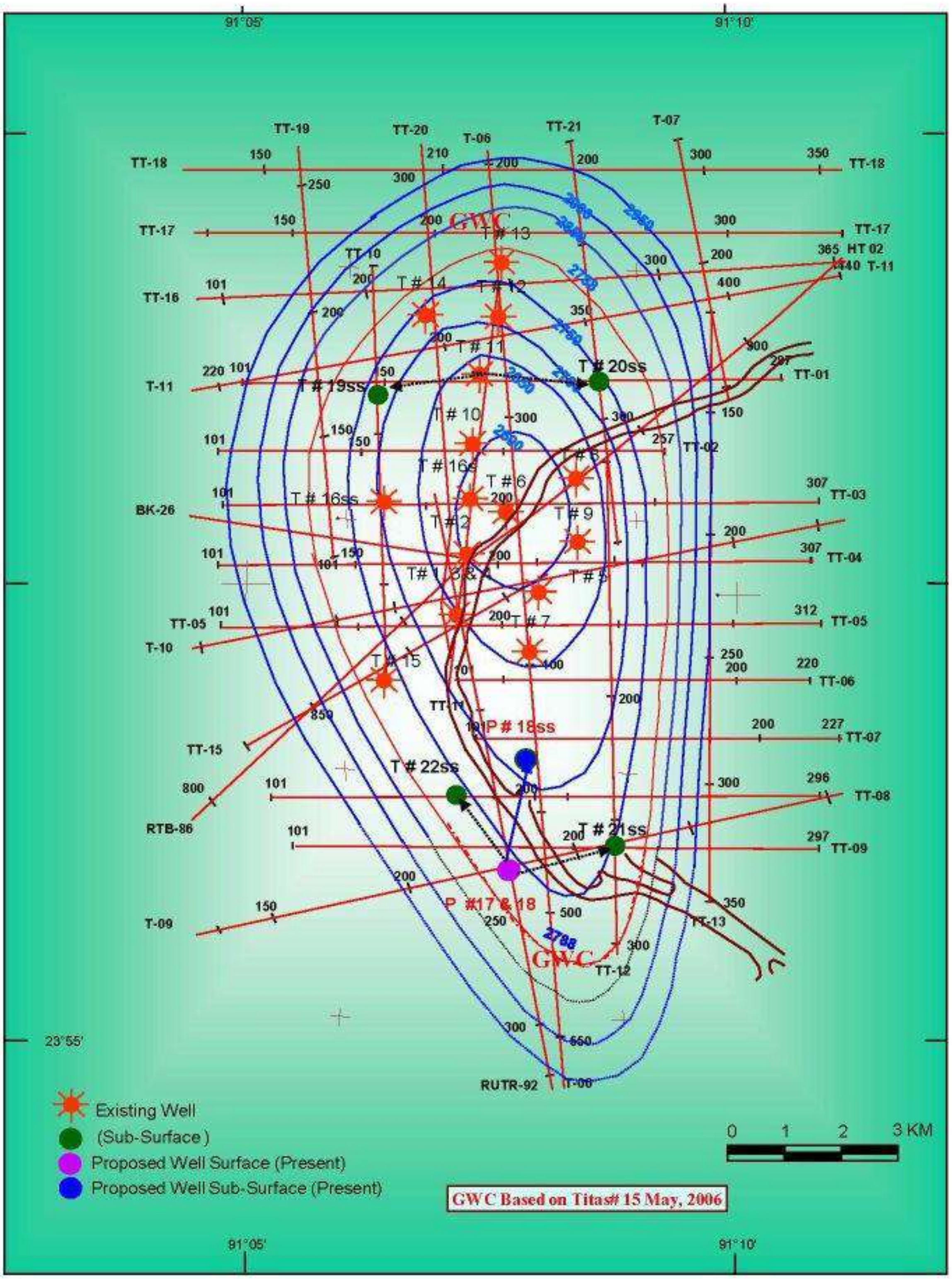

91°05'
91°10'
23°55'
Existing Well
(Sub-Surface)
Proposed Well Surface (Present)
Proposed Well Sub-Surface (Present)
0 1 2 3 KM
GWC Based on Titas# 15 May, 2006
GWC
T # 19ss
T # 20ss
T # 21ss
T # 22ss
P # 18ss
P #17 & 18
TT-18
TT-17
TT-16
T-11
BK-26
TT-05
T-10
TT-15
RTB-86
T-09
RUTR-92

Figure 6-154 is a post-2006 vintage structure map of Titas field constructed by BGFCL using data from all 16 wells in the field. This map also shows proposed new locations at the southern end of the field where there has been no drilling.

The most updated map was prepared by RPS Energy (2009) prepared for Petrobangla. These are computer-generated maps using the Schlumberger Petrel software. However, the seismic database is old and the only additions were a few new development wells.

### 6.3.19.3 Reservoir

In Titas Gas Field reservoir sands were named on the basis of the result of the discovery well. Major pay zone were named as ‘A’, ‘B’ and ‘C’ sands. Depending on the results of subsequent wells the gas sands were further subdivided.

‘A’ Sand is divided into six units and named as $A_1$, $A_2$, $A_{2B}$, $A_3$, $A_{4U}$ and $A_{4L}$. In the same way ‘B’ and ‘C’ sands are divided into $B_1$, $B_2$ $B_{3a}$ and $B_{3b}$ and $C_1$ and $C_2$ sands. Theses subdivision is expanded on the basis of the result of wells drilled later. Apart from the main gas sands, in some of the wells localized gas sands were encountered. Core control is quite limited. Conventional cores were cut from 6 wells. Out of these six wells, only two wells were extensively cored.

Porosity of A1 sand is 0.195. This was found in one well. A2 sand is quite extensive and its average porosity is estimated at 0.194. Table 6-73 below gives an idea on the distribution and average porosity of the reservoir sands. Among the sands listed in the table, A1, B1, B1-E, BO-E, B2-E, C1, C1-E, C-2, C-0E, C4, C4E, are considered as minor sands.

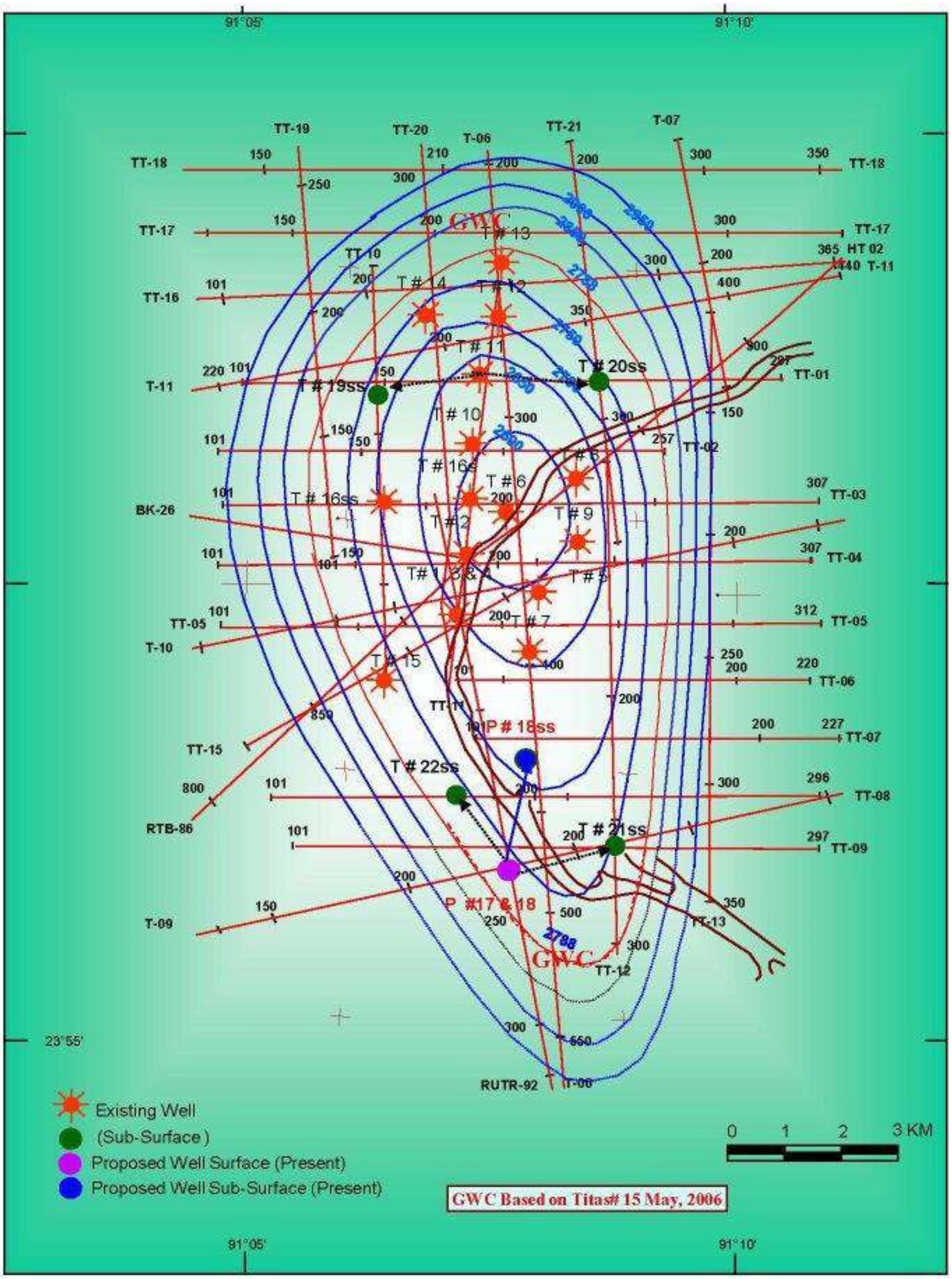



**Figure 6-154 Post-2006 Structure Map of Titas Gas Field**

Map shows locations of all sixteen existing wells and proposed locations for new development wells. C.I.= 50 m. (courtesy of BGFCL, 2009).

## Table 6-73 Average Porosities of Titas Reservoir Sands

**Log Porosity of Titas Wells (IKM Report)**

| | A1 | A2 | A3 | A4 | A4 Up | A4L | B1 | B 1E | B2 | B 2E | B3 | B OE | C1 | C 1E | C2 | C 2E | C3 | C4 | C 4E | C OE | C 4E |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Well 1 | 0.17 | 0.19 | 0.177 | | 0.131 | | 0.17 | | 0.13 | | 0.16 | | 0.17 | | 0.17 | | 0.15 | | | | |
| Well 2 | | 0.2 | 0.198 | 0.16 | | | | | | | 0.16 | | 0.16 | | 0.17 | | 0.17 | 0.16 | | | |
| Well 3 | | 0.18 | 0.174 | | 0.135 | 0.18 | | | | | | | | | | | | | | | |
| Well 4 | | 0.19 | 0.183 | | 0.149 | 0.19 | | | | | | | | | | | | | | | |
| Well 5 | | 0.18 | 0.187 | 0.17 | | | | | | | | | | | | | | | | | |
| Well 6 | | 0.19 | 0.194 | 0.18 | | | | | | | | | | | | | | | | | |
| Well 7 | | 0.19 | 0.198 | 0.21 | | | | | | | | | | | | | | | | | |
| Well 8 | | 0.2 | 0.198 | 0.18 | | | | 0.18 | | 0.17 | 0.16 | 0.15 | | 0.18 | | | 0.16 | | | 0.15 | 0.18 |
| Well 9 | | 0.2 | 0.199 | 0.19 | | | | 0.19 | | 0.18 | 0.17 | | | 0.18 | | 0.17 | 0.18 | | 0.21 | | |
| Well 10 | | 0.21 | 0.199 | 0.19 | | | | | | | 0.2 | | | | 0.16 | | 0.16 | | | | |
| Well 11 | | 0.21 | 0.195 | 0.17 | | | | | | | | | | | 0.15 | | 0.17 | | | | |
| Avg | 0.17 | 0.19 | 0.19 | 0.18 | 0.14 | 0.19 | 0.17 | 0.19 | 0.13 | 0.17 | 0.17 | 0.15 | 0.16 | 0.18 | 0.16 | 0.08 | 0.16 | 0.16 | 0.21 | 0.15 | 0.18 |

### 6.3.19.4 Exploration and Field Development

In 1962, an exploratory well, Titas # 1, was drilled to 3690m and drilling was terminated after opening overpressure zone. This well is the deepest well of Titas. The well tested gas in five zones within depth interval 2573 – 3072mt. PSOC divided the gas sands into three main groups, named as A, B and C Sand. Sands classified as "A" Sand is the main reservoir holding almost 85 % of the total reserves. No gas water contact was observed in the discovery well. After the discovery, PSOC drilled Well # 2, located about 1 km NNE of Titas Well #1. During 1970, PSOC drilled two more wells with surface location close to Well #1. These two wells were planned as directional well but this objective was not achieved. Maximum deviation of 116m was achieved.

Gas production from Titas field started in 1969. In 1970, well 3 and 4 were added to producing wells. In 1970 annual production was just below 1 Bscf. In 1971, during the war of liberation, production was reduced to about 0.5 Bscf. After independence of Bangladesh, PSOC sold their asset to the Government.

The first development well after independence was drilled in 1981 (Well #5). It was a deviated well, completed in the "A" group of sands. In 1983 Petrobangla drilled Well #6. In the 25 years since then, ten development wells were drilled. This resulted in increase of field production to over 400 MMscfd in 2005. Field development program was taken up considering gas demand. Until now, 16 wells have been drilled in Titas gas field.

Due to a poor cement job in four wells, water production rate increased in those wells, migrating into the wellbores from other water-bearing zones in the well. This also resulted in gas leakage from the reservoir (s) to surface. Some effort was taken to contain the gas seeps. In the process, well #3 was killed and permanently plugged back; however, this did not solve the problem. A program has already been taken up for remedial work in these wells. For the last couple of years production was slightly reduced. In addition to the remedial job, BGFCL is planning to drill three more wells to increase production.

6.3.19.5 Well-wise and Sand-wise Production History

Figure 6-155 and Figure 6-156 graphically display well-wise and sand-wise gas production from Titas gas field in MMscfd. As clearly shown in Figure 6-156, the A Sand reservoir is by far the most important contributor to the daily production of Titas field, with 13 of the 16 wells producing from this reservoir interval.

Water production rate of all producing sands of A Group is graphically displayed in Figure 6-157. Water production from well #12 can be considered as water break-in. The interval spanning the upper part of A Sand, the overlying water-bearing sand, and the intervening shale layer remains in communication due to poor cement bond. Similar situation was also observed in well #13. Increase in water production rate (bbl/MMscf) is due to influx from water-bearing reservoir overlying the gas sand and not from water beneath the gas column in the gas reservoir.

For B and C Sands, water production rate is quite low. Figure 6-158 shows the water production for these sands. The spike could be due to some sort of typographical or recording mistake. This type of peak in water is not expected during production.

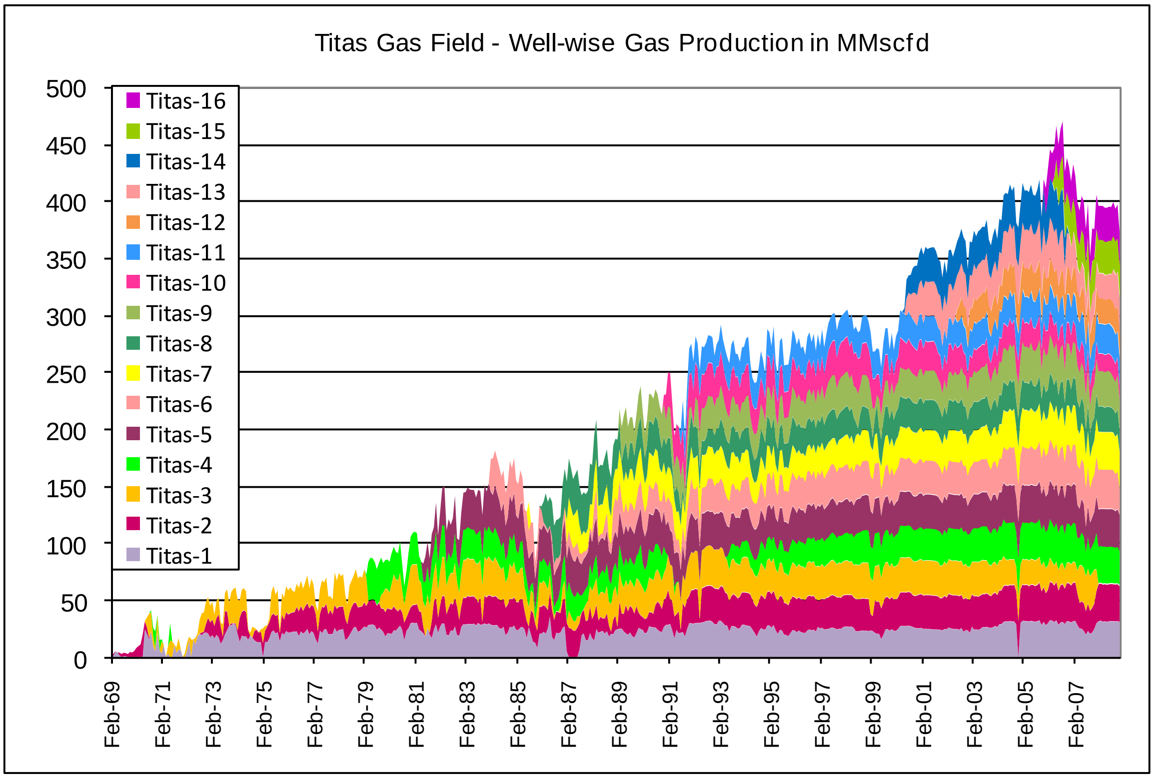



**Figure 6-155 Well-wise Gas Production – Titas Gas Field**

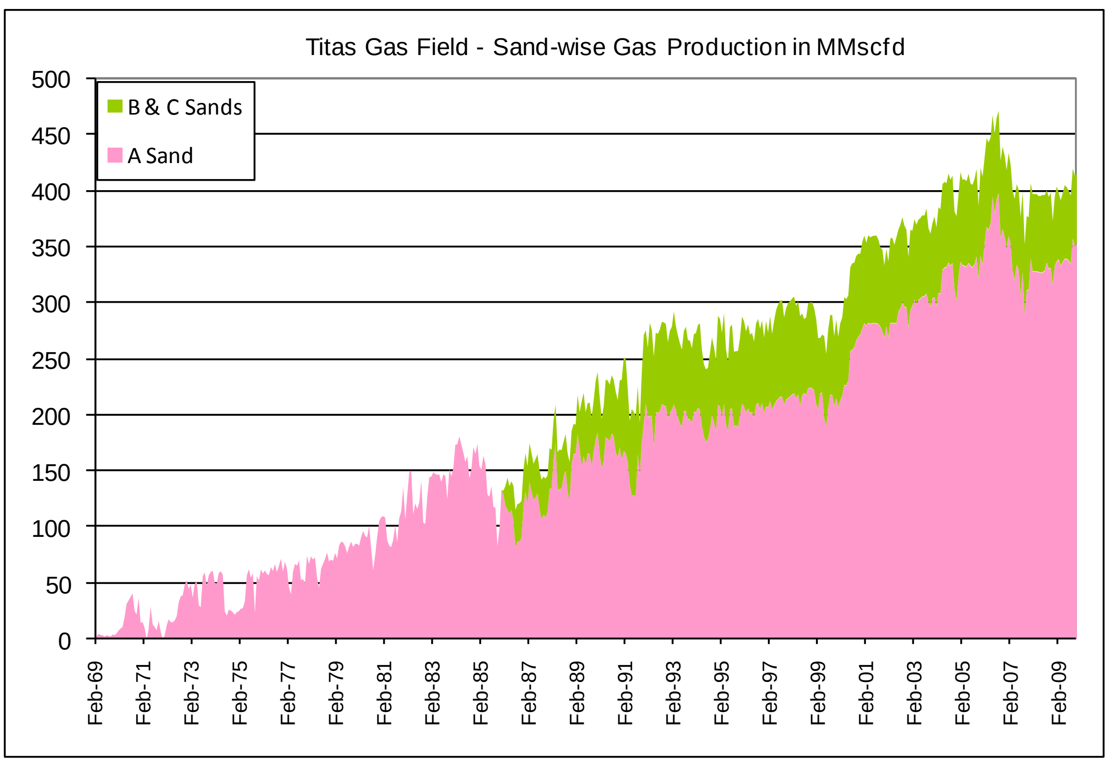



**Figure 6-156 Sand-wise Gas Production – Titas Gas Field**

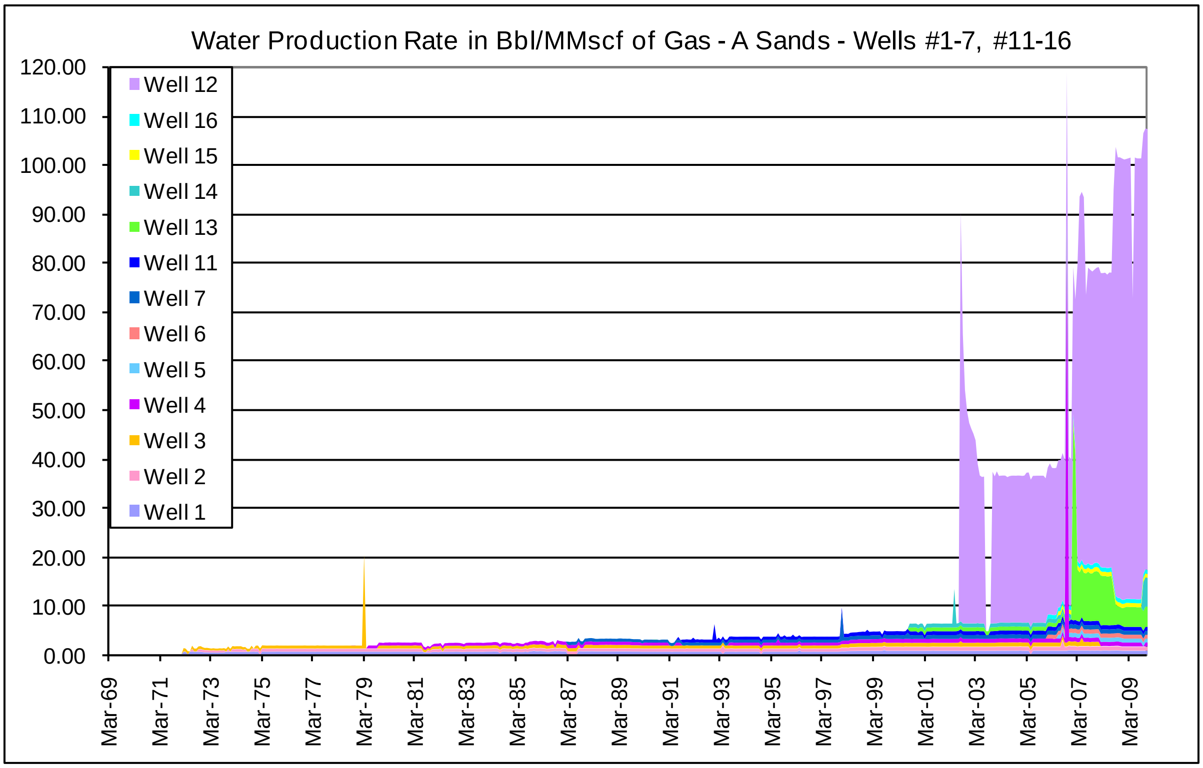



**Figure 6-157 Water Production Rates for A Sands - Titas Gas Field**

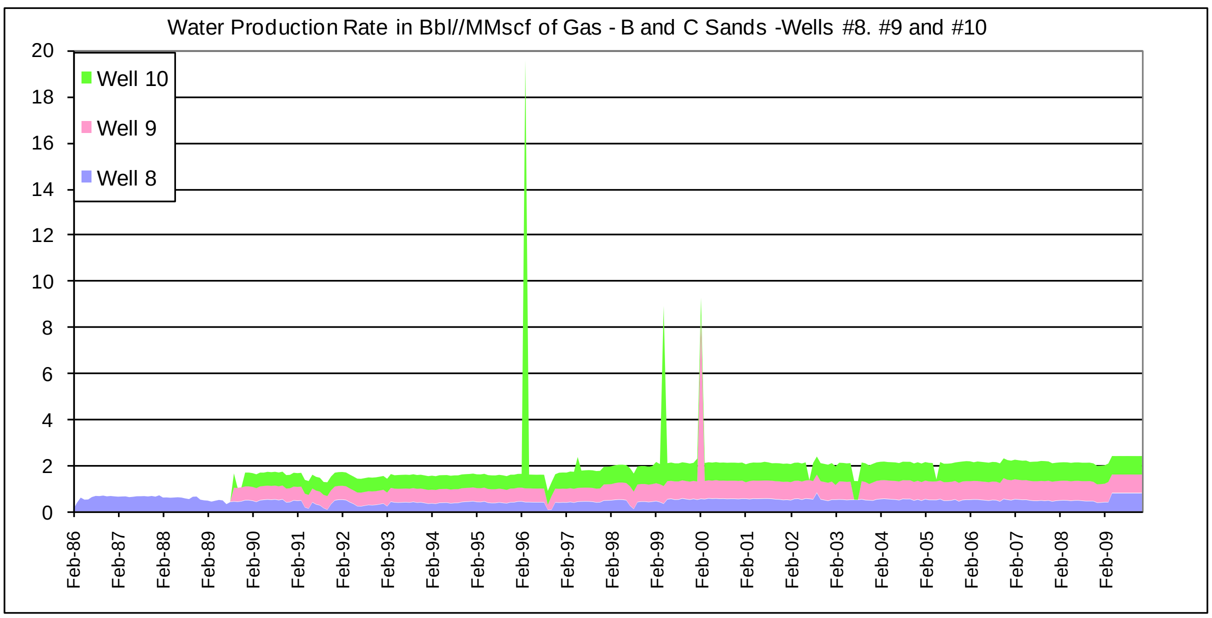



**Figure 6-158 Water Production Rates for B and C Sands - Titas Gas Field**

Detailed individual well histories and accompanying production charts for Bakhrabad wells are included in The Annex.

6.3.19.6 Field-wise Cumulative Production

Thirteen of the sixteen wells in Titas gas field (Wells #1-7 and #11-16) produce from the A group of sands. Wells #8-10 produce comingled gas from sands of the B and C groups. Table 6-74 summarizes the sand-wise cumulative gas production from the field through December 2009. The A sand group of reservoirs has accounted for approximately 81.6% of the field's cumulative production.

**Table 6-74 Sand-wise Cumulative Gas Production – Titas Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| A Sands | 2502.1 |
| B and C Sands comingled | 566.0 |
| **Total** | **3068.1** |

1 Production through end of December 2009
HCU production database

6.3.19.7 Earlier Reserve Estimates

A post-discovery reserve estimate was made by PSOC. According to this study, GIIP of the field was 2250 Bscf. During the following years this figure was refined by a number of workers.

In 1976, Federal Republic of Germany provided technical and financial assistance to Petrobangla. As a result, German Geological Advisory Group (GGAG), comprising of a geologist, geophysicist and petroleum engineer from BGR and Petrobangla, was formed in Petrobangla. This group conducted a study on the gas reserve of the country. The detailed sand-wise results of this study on Titas gas field are summarized below in Table 6-75.

In 1979, Petro-Consultants estimated the gas reserve of the country using probabilistic method. According to their study, recoverable reserve of Titas Gas field was 1,885 Bscf at P50 (50% probability). This figure increases to 5,617 Bscf at P10 category.

**Table 6-75 GGAG 1976 Reserve Estimate - Titas Gas Field (in Bscf)**

| Titas GIIP | Max | Most Likely | Minimum | Mean | RMS |
|---|---|---|---|---|---|
| A Sands | 3739.01 | 1620.13 | 779.89 | 1789.89 | 1819.70 |
| B Sands | 671.16 | 383.09 | 227.25 | 405.41 | 409.76 |
| C Sands | 1195.19 | 667.55 | 341.92 | 680.76 | 688.74 |
| Total | 5605.37 | 2670.78 | 1349.06 | 2876.06 | 2918.19 |

In 1980, IMEG conducted a study where GIIP of Titas gas field was estimated at 3,335 Bscf and the recoverable reserve was estimated at 1,793 Bscf. The recovery factor was 54%. The detailed sand-wise results of this study on Titas Gas field are provided below in Table 6-76.

**Table 6-76 IMEG 1980 Reserve Estimate - Titas Gas Field**

| Titas | GIIP in Bscf | Reserve |
|---|---|---|
| Sand A-1 | 47.17 | |
| Sand A-2 | 906.99 | |
| Sand A-3 | 955.05 | |
| Sand A-4 | 348.55 | |
| Sand B-3 | 592.38 | |
| Sand C-1 | 335.00 | |
| Sand C-2 | 150.05 | |
| Field Total | 3335.19 | 1792.8 |

In 1981, Petrobangla estimated the gas reserve of this field. This study considered only major sands in the A Group and came up with a figure of 3,448 Bscf as GIIP.

In 1986, Hydrocarbon Habitat Study Program (HHSP) with ODA assistance was launched. Under this program, Petrobangla, with technical and financial assistance from ODA, conducted seismic survey over a large area of the country. This study estimated both hydrocarbon resources and reserves with a 2P of 2,671 Bscf and an additional 143 Bscf of Ps (Possible) reserves. The detailed sand-wise results of this study for Titas gas field are listed below in Table 6-77.

**Table 6-77 HHSP 1988 Reserve Estimate – Titas (in Bscf)**

| | Upper | Blue | RED | A1 | A2 | A3 | A4 | A5 | A6 | B0 | B1 | B2 | B 3.1 | C0 | C1 | C2 | C3 | C4 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| P1+P2 | 74 | | | 176 | 557 | 414 | 457 | | | 11 | 168 | 50 | 57 | 5 | 56 | 114 | 413 | 69 | 2621 |
| P3 | | 61 | 82 | | | | | | | | | | | | | | | | 143 |

In 1988, with CIDA assistance, Seislog study over Titas gas field was conducted. The weak part of this study was mentioned earlier in Section 6.13.19.2. This study considered $A_1$, $A_2$, $A_3$, $A_4$,$A_5$, $A_6$, $B_1$, $B_{3.1}$ sands. According to this study, GIIP of the field was 8,486 Bscf. Bulk of the reserve (7,171 Bscf) is under Probable category.

In 1989, Gasunie Engineering conducted a study of Titas gas field. The results of their study for Titas Gas field are given below in Table 6-78. Their estimates incorporated an Expected case of 3140 Bscf with a high estimate of 7,000 Bscf. An additional 200 Bscf was considered Speculative.

**Table 6-78 Gasunie 1989 Reserve Estimate - Titas Gas Field (in Bscf)**

| Recoverable Reserve in Bscf | | | | |
|---|---|---|---|---|
| Name of Field | Proven | Expected | High | Speculative |
| Titas | 1500 | 3140 | 7000 | 200 |
| Gasunie, 1989 | | | | |

In 1991, WELLDRILL reviewed the gas reserve of the country and their estimate for Titas gas field was 5,122 Bscf. Sand-wise details of the estimate are given below in Table 6-79.

**Table 6-79 WELLDRILL 1991 Reserve Estimate - Titas Gas Field (in Bscf)**

| GIIP | P1+P2 | A1 | A2 | A3 | A4 | A5 | A6 | B0 | B1 | B2 | B 3.1 | C | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| WELLDRILL,91 | | 403 | 1660 | 1170 | 449 | | 131 | | 156 | | 480 | 673 | 5122 |
| | | | | | | | | | | | | | |

The first Material Balance estimate of Titas gas field was conducted by Oil & Mineral Services (OMS) of UK. According to this study, GIIP of the producing gas sands of the A group of Titas gas field was 8,363 Bscf.

In 1991, IKM conducted a study on selected gas fields of the country. IKM's volumetric estimates by sand are provided in Table 6-80.

**Table 6-80 IKM 1991 Reserve Estimate - Titas Gas Field**

**IKM 1991 Figures in Bscf**

| | A1 | A2 | A3 | A4 | B 0 | B1 | B2 | B 3.1 | C 0 | C 2 | C3 | C4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| P1 | 5 | 1141 | 827 | 165 | 1 | 4 | 15 | 247 | 1 | 46 | 52 | 93 | 18 | 2615 |
| P2 | | 880 | 52 | 98 | | | | | | | | 495 | | 1525 |
| Total | 5 | 2021 | 879 | 263 | 1 | 4 | 15 | 247 | 1 | 46 | 52 | 588 | 18 | 4140 |

IKM also did material balance estimate of the GIIP. According to IKM GIIP of the producing sands of A group was 9,580 Bscf and GIIP for B and C sand was 746 Bscf. According to volumetric estimate, GIIP of producing sands of A group was 3,168 Bscf and the same for B and C sand was 654 Bscf. IKM considered the result of volumetric estimate.

In 1993, BGFCL and PMRE Department of BUET conducted another study. They followed MB method. According to this study GIIP of the producing sands A group was 9210 Bscf. For B and C sands the result was 806 Bscf.

In 1995, Clyde Petroleum of UK conducted another MB study on Titas field. Acccording to this study, GIIP of the producing sands was likely to range from 6,496 to 10,064 Bscf. GIIP of A group of Sands ranged from 6039 to 9185 Bscf.

According to HCU-NPD study, GIIP of producing sands of A and B & C Group was 6,100 and 1,200 Bscf, respectively.

The most recent estimate was carried out in 2009 by RPS Energy engaged by Petrobangla. This study incorporated a reservoir simulation methodology using Schlumberger's proprietary Petrel and Eclipse modeling software suites. This methodology incorporates history matching of production and constructing 3-D geological and fluid flow models. According to this study, the GIIP of the field is 7,169 Bscf, split among 11 separate reservoirs in the A, B, and C zones. Results of this study are shown in Table 6-81.

**Table 6-81 RPS 2009 Reserve Estimate – Titas Gas Field**

**Petrel 2009, GIIP. Bscf**

| Sand | A1 | A2 | A2b | A3 | A4u | A4 L | B 1 | B3 | B3b | C1 | C2 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GIIP | 1151 | 3376 | 768 | 1089 | 172 | 75 | 23 | 127 | 147 | 143 | 98 | 7169 |

RPS Energy 2009n

6.3.19.8 2010 Reserve Re-Estimation (This Report)

As discussed in Section 6.2.1.2 of this report, updated estimates of gas reserves for the Titas field were prepared using a probabilistic approach to a volumetric calculation. The limited number and distribution of wells in the field contribute to the uncertainty in some of these parameters (e.g., reservoir volume, porosity, water saturation). Material balance was found to be a highly reliable method for estimating GIIP and reserves for the A Sands at Titas. Thus the B&C Sands were totaled separately in the volumetric analysis, and the total estimated volumes include material balance results for the A Sands and volumetric for the B and C Sands. The results are shown graphically and by reservoir in the figures and table below, and the input parameters are included in Appendix C.

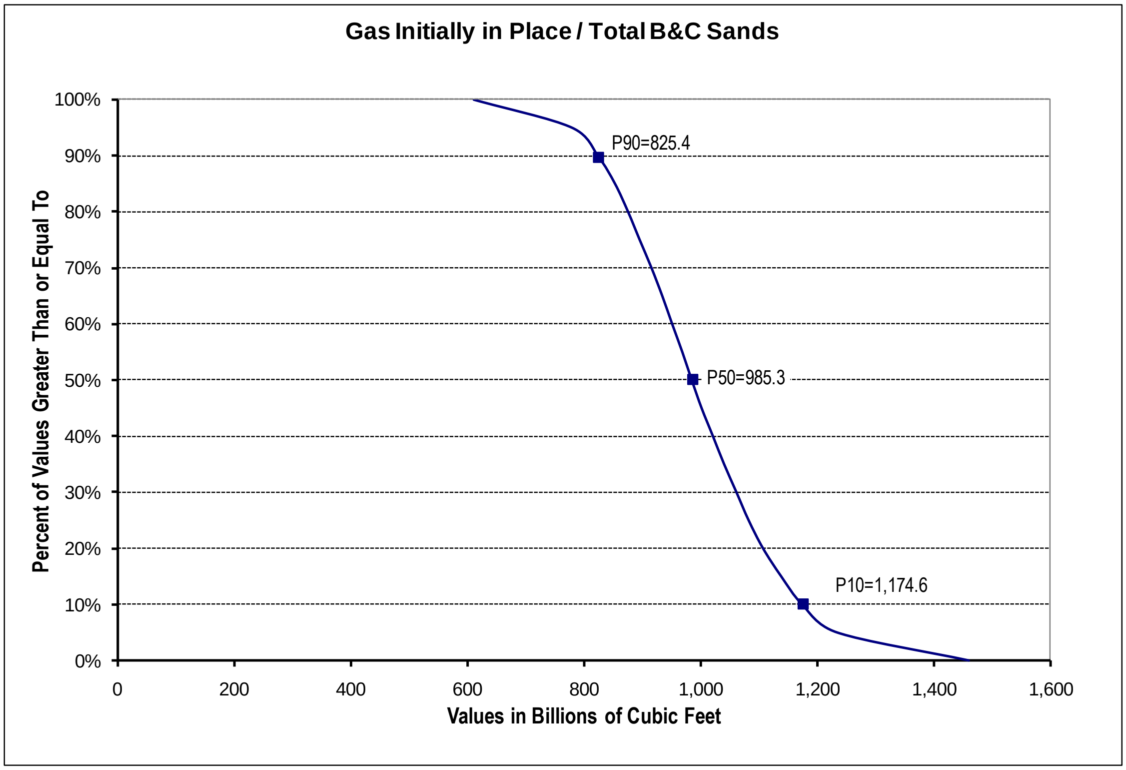



**Figure 6-159 Distribution of B&C Sand GIIP, Titas**

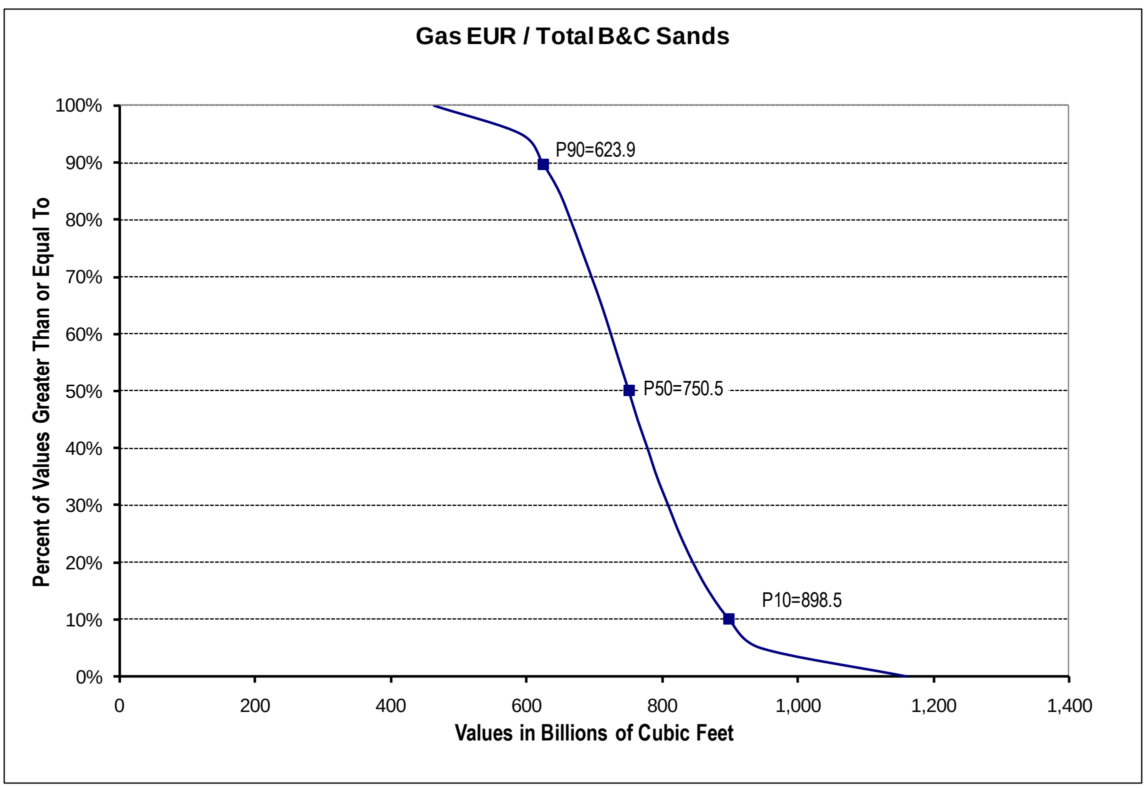



**Figure 6-160 Distribution of B&C Sand Gas EUR, Titas**

**Table 6-82 Summary of Estimated Ultimate Recovery at Titas, B&C Sands**

| Reservoir | Mean Gas EUR, BCF |
|---|---|
| B1,2 | 13 |
| B3a,3b | 617 |
| C1 | 107 |
| C2 | 19 |
| **TOTAL** | **756** |

Additionally, for the A Sands at Titas, reservoir pressure data were available and a p/z material balance analysis was performed (Figure 6-161). This analysis indicates GIIP and reserves (with varying abandonment pressure assumptions) as follows:

GIIP: 8.05 TCF
$P_{90}$: 6.33 TCF
$P_{50}$: 6.83 TCF
$P_{10}$: 7.40 TCF

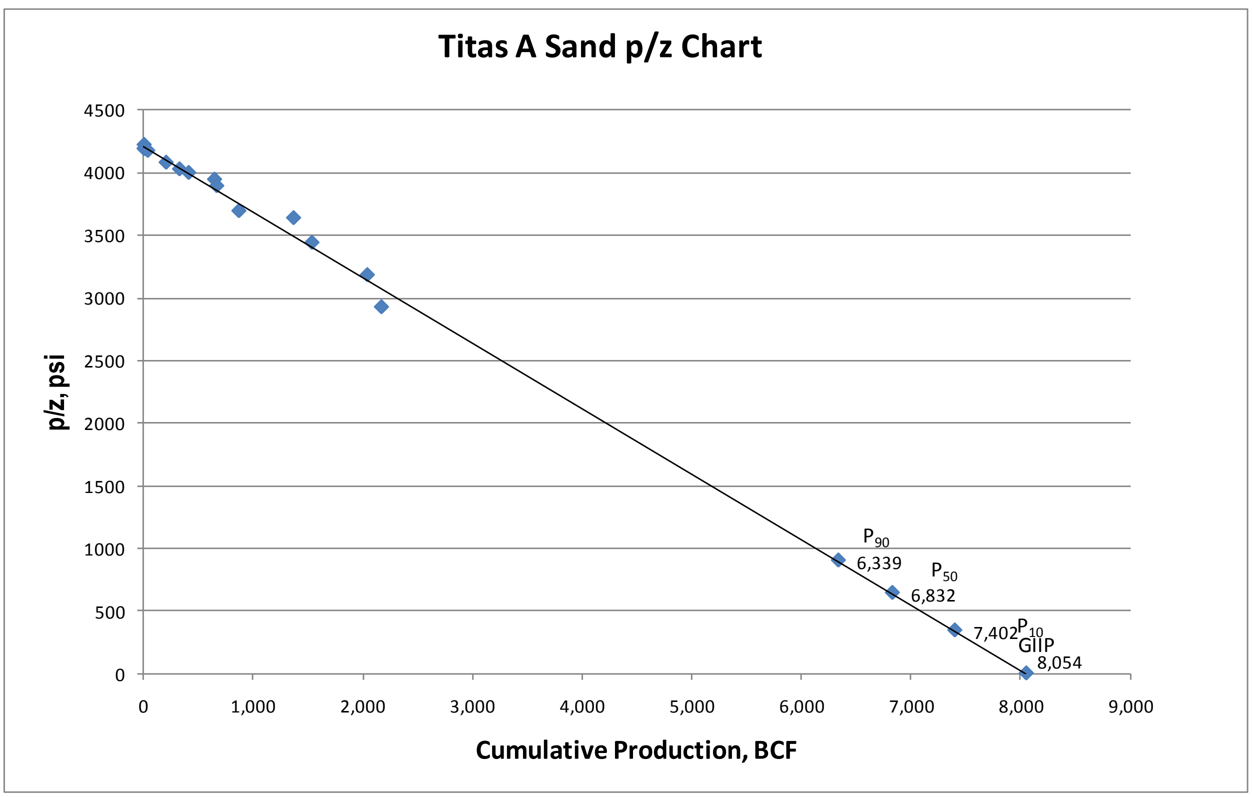



**Figure 6-161 p/z Analysis, Titas A Sand**

Because the p/z material balance analysis is performance-based, and the straight line fit is very good, this estimate is considered to be more reliable than a volumetric estimate. No bottomhole pressure data were available for the B and C sands; thus, our best estimate for reserves of these sands is the volumetric estimate. The blended most reliable estimates (material balance for A sands and volumetric for B&C sands) are summarized below:

| Reservoir | Probability | GIIP, BCF | EUR, BCF | Cumulative Production, BCF | Reserves, BCF |
|---|---|---|---|---|---|
| A | $P_{90}$ | 8,054 | 6,339 | 2,502 | 3,837 |
| | $P_{50}$ | | 6,832 | | 4,330 |
| | $P_{10}$ | | 7,402 | | 4,900 |
| B&C | $P_{90}$ | 825 | 624 | 566 | 58 |
| | $P_{50}$ | 985 | 751 | | 185 |
| | $P_{10}$ | 1,175 | 899 | | 333 |

We note that our volumetric estimate for the B and C sands exceeds previous volumetric estimates: this is because the reservoir bulk volume was adjusted upward to account for cumulative production that was larger than previous estimates of total recoverable gas.

## 6.4 SUSPENDED GAS FIELDS

Production from Chhatak, Kamta and Meghna gas fields has been suspended mainly due to high water production. A brief discussion of each of these three gas fields follows.

### 6.4.1 Chhatak

Chhatak structure is an ESE-WNW trending anticline with Dupi Tila sediments cropping out in places. On the surface, the structure can be traced from northeast of Chhatak Town to about 15 km WNW.

#### 6.4.1.1 Geologic Setting

Chhatak is located adjacent to a tectonically active and gently-folded foldbelt (Eastern Foldbelt) underlying the Indo-Burman ranges. Seismic evidence indicates that the Surma to Central Bangladesh basin originated in the Eocene as an array of pull-apart rift segments along the oceanic/cratonic transform zone between the Indian and Southeast Asian lithospheric plates. From Late Eocene to the present, the basin has been influenced by oblique subduction of the Indian plate oceanic crust beneath the Southeast Asia craton, and by dextral slip along an inter-cratonic transform fault that parallels the eastern margin of the basin, Tectonic movements have influenced both the stratigraphic and structural configuration of all reservoirs within the field.

The sediment fill within the Bangladesh basin is predominantly Cenozoic terrigenous clastics. Preserved sediments in the lower sequence are comprised of mainly continental to marine sediments from the Cretaceous to the Middle Eocene that were deposited during an extensional inter-cratonic, sub-basin development phase for the India plate. The upper sequence is predominantly continental sediment with interbedded terrigenous source beds of the Jenan, Bhuban, and Bokabil Formations with downslope fluvial (meandering and braided stream) sandstones, siltstones, and claystones. The final rapid influx of Pliocene to Recent sediments is composed of poorly sorted sandstones and siltstones with few interbedded shales and claystones.

#### 6.4.1.2 Structure

In 1956, Pakistan Petroleum Ltd. engaged G.S.I. to shoot about 75 km of singlefold 2-D seismic data over the structure. The first geological map of the structure, prepared by PPL, shows that the axis is bow-shaped and generally aligned NW-WSW, passing just north of Chhatak town. The map also indicates a N-S trending fault on the western flank of the anticline. The Chhatak-1 well is located to the west of the fault. This map is shown in Figure 6-162.

On the basis of the singlefold seismic data, A. J. Philipson of PPL delineated the structure as a faulted anticline. Two NE-SW trending faults divided the anticline into three segments. Both the eastern and western blocks are downthrown. The Chhatak-#1 well is located in the central block.

The central fault located on the west of the well is indicated on the geological map prepared by PPL geologists.

During the early 1980s Prakla Seismos was engaged to shoot digital seismic lines over the area. GGAG prepared new map on the basis of new data, which also shows multiple faults on both east and west of the well (Figure 6-163)

In 1988 Welldrill prepared another map, which also shows the faults.

BAPEX prepared another map in 1992 on which the faults were indicated. NIKO-BAPEX joint study (2000) reviewed seismic and geological data and new map was prepared. The new map is shown in Figure 6-164.

#### 6.4.1.3 Reservoir

The reservoir rock is sandstone of Bokabil Formation. A total of six reservoir horizons were identified in the Chhatak-1 well. No core was cut in the well, and very little is known about the reservoir intervals.

PPL log analysts evaluated porosity and water saturation from logs. Average porosity of the upper two zones is 30%. For the remaining four sands average porosity was 25%. Water saturation of different zones ranges from 26 to 40 %. Formation pressure was considered to be hydrostatic.

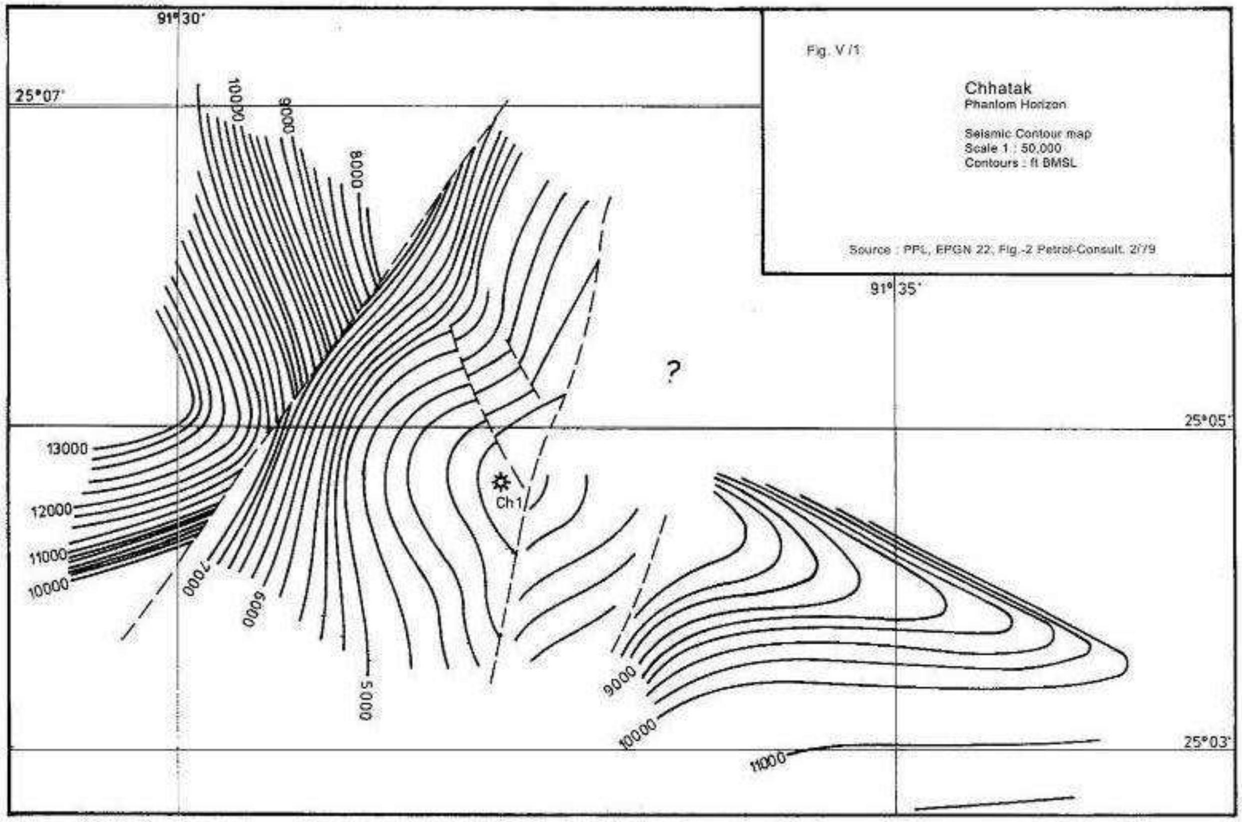



**Figure 6-162 Seismic Structure Map on a Phantom Horizon – Chhatak Gas Field**

Map derived from seismic interpretation by Petrol-Consult. for PPL in 1979. Map is contoured in feet below mean sea level. The location of the Chhatak #1 well drilled in 1959 is shown on the structural closure at the crest of the anticline (PPL, Petrol-Consult., 1979).

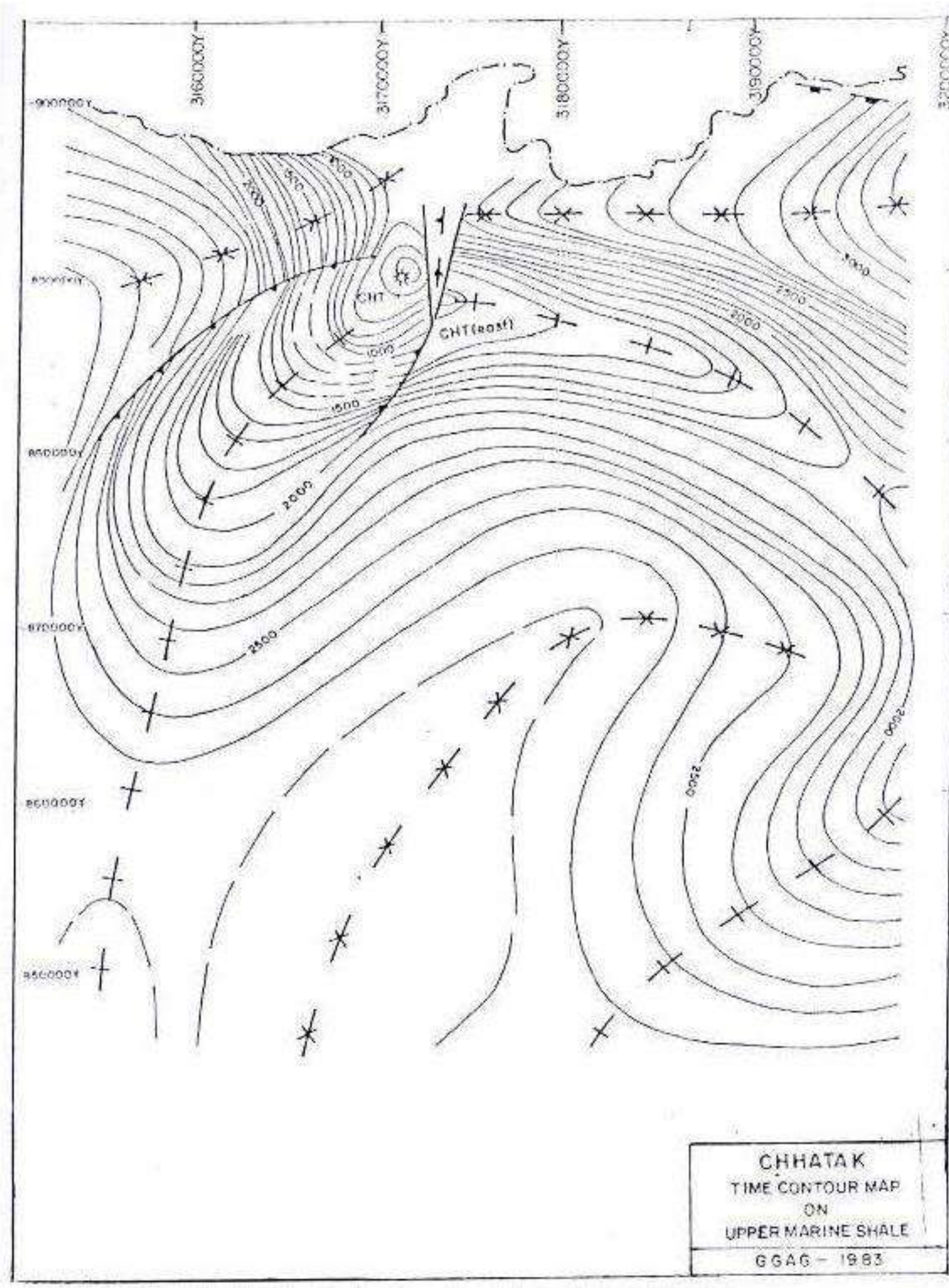



**Figure 6-163 Time Structure Map on Upper Marine Shale – Chhatak Gas Field**
Map is an interpretation by the German Geological Advisory Group (GGAG) and is based on multifold seismic data acquired by Prakla Seismos during the early 1980s (after GGAG, 1983).

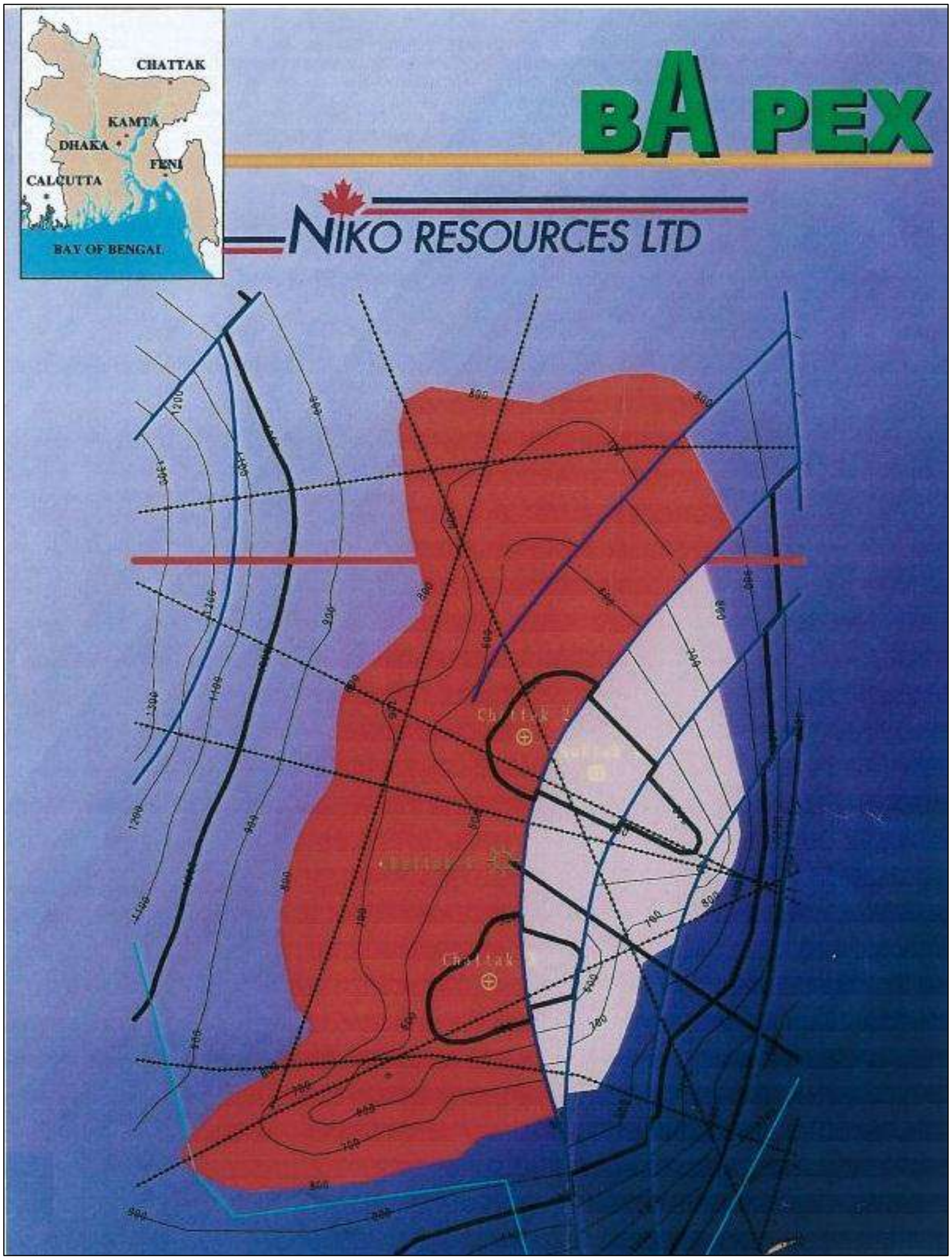



**Figure 6-164 Structure Map on Top of 1 & 2 Reservoir Sands – Chhatak Gas Field**
Seismic depth structure map derived from joint work program of Niko Resources and BAPEX as part of their Joint Venture Agreement. Location of Chhatak #1 discovery well and proposed locations for three new wells are shown along the crestal portion of the structure (after NIKO-BAPEX, 2001).

In their 1986 study, Welldrill considered porosity at 30% for the shallower sands and 25% for the lower three sands. Water saturation was considered at 30% for all the sands.

Niko Resources of Canada (NIKO) re-evaluated the logs, and concluded the porosity was less than that evaluated by PPL authors. NIKO-BAPEX study considered six sands in three groups. For the shallow sands (1&2), the porosity is estimated to be ranging between 20–25% and for Sand 3&4 it is ranging between 18–25 %. At greater depth (Sand 5&6) the porosity decreases to 15–20%.

#### 6.4.1.4 Exploration and Field Development

In 1959, Chhatak Well #1 was drilled to a depth of 2,135 m. The well encountered nine gas-bearing sandstone horizons within a depth ranging from 1,090 m to 1,975 m. Out of nine intervals tested, six flowed gas during testing at a rate ranging from 2.1 to 2.8 MMscfd. The well was completed in upper four gas sands (commingled) within a depth range of 1,090-1,255 m. During open flow potential test of these four sands the gas flow rates was 7.77 MMscfd on 16/64" inch choke, and on 24/64" choke the flow rate was 9.65 MMscfd.

In 1982, water production rate increased from 4 gal/MMscf to about 18 gal/MMscf. At later stage the well started to produce sand. In 1985 production stopped abruptly. The reason was considered to be blockage of tubing with sand. After a workover operation in 1985 the well was brought back to production. However the well again went dead after a very short period of production.

In 2000, NIKO showed interest in Chhatak Field and carried out a joint study with BAPEX. According to this study there are two gas sands at shallow depth, which were not tested. NIKO began a new exploration drilling project at Chhatak in 2004. Two separate blow-outs and ensuing fires during 2005 and subsequent litigation have suspended efforts to bring the field back into production.

6.4.1.5 Well-wise and Sand-wise Production History

Chhatak gas field is a one-well field that produced from two groups of commingled reservoirs over the period from January 1961 through January 1985. Producing intervals included the 3&4 and the 5&6 reservoir sands. The last daily flow rates from the Chhatak #1 well were between 5 and 6 MMscfd. Figure 6-165 is a combined well-wise/sand-wise production chart for Chhatak gas field.

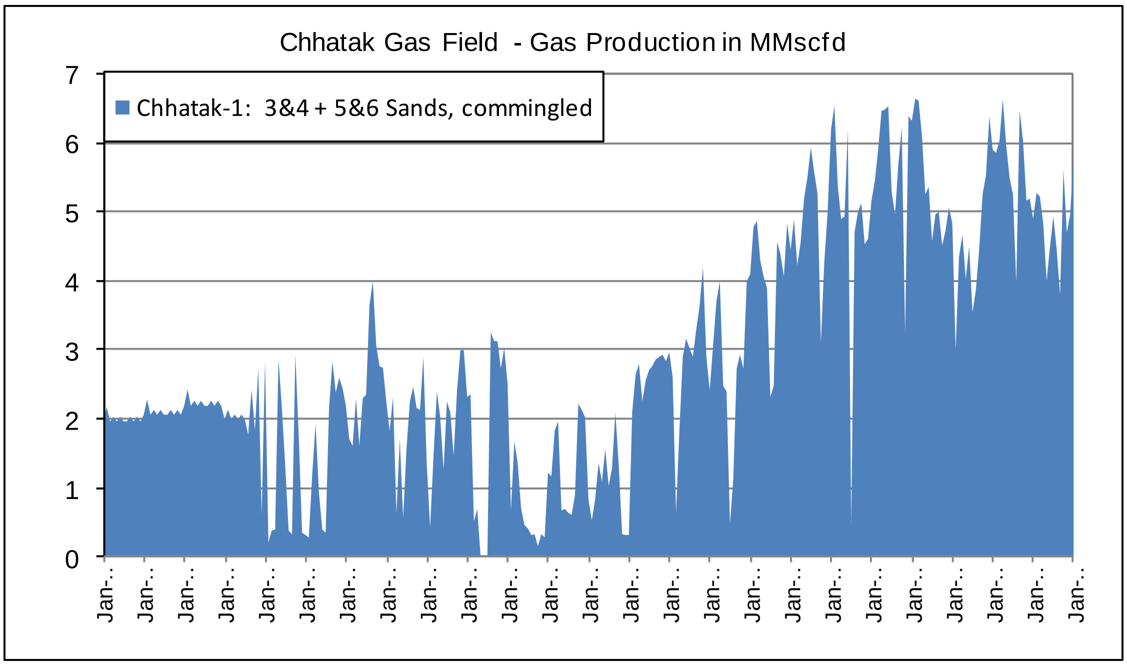



**Figure 6-165 Well-wise/Sand-wise Gas Production - Chhatak #1 Well – Chhatak Gas Field**

6.4.1.6 Field-wise Cumulative Production

Sand-wise gas cumulative production for Chhatak gas field at end of December 2009 is summarized below in Table 6-83. All gas production from the field came from the initial discovery well, Chhatak #1. The well's cumulative production from the two groups of reservoir sands was 25.8 Bscf.

**Table 6-83 Sand-wise Cumulative Gas Production – Chhatak Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Sands 3&4+5&6 | 25.8 |
| **Total** | **25.8** |

1 Production through end of December 2009
HCU production database

### 6.4.1.7 Earlier Reserve Estimates

Reservoir parameters, map of Chhatak, and the result obtained by NIKO-BAPEX joint study were reviewed and the result considered for the HCU 2003 (2004) study. However, the study report did not indicate GIIP or recovery factor and only recoverable reserve was shown. In order to obtain GIIP, recovery factor was considered to be 70% for all the sands. This resulted in GIIP of 677 Bscf. Detail is given in Table 6-84 below.

**Table 6-84 NIKO-BAPEX 2000 Reserve Estimate – Chhatak Gas Field (in Bscf)**

| Gas Sand | P 1 | P 50 | Mean | P 99 | Remarks |
|---|---|---|---|---|---|
| Zone 1&2 | 157 | 254 | 273 | 411 | Untested |
| Zone 3 & 4 | 119 | 190 | 201 | 301 | DST #14 |
| Zone 5 & 6 | 87 | 153 | 169 | 270 | DST # 7 & 8 |
| Zone 7 & 8 | 16 | 30 | 34 | 57 | DST # 4 & 5 |
| Total | 379 | 627 | 677 | 1039 | Unrisked |
| | 227 | 376 | 406 | 623 | Risked |

Modified by NIKO-BAPEX 2000

Risking of discovered reserve is not practiced in Bangladesh. As such this is not considered for HCU 2003 (2004) study. Average water saturation of the 1&2, 3&4, and 5&6 zones is estimated at 35.9%, 38.3%, and 47.7%, respectively. For HCU 2003 (2004) estimate porosity and saturation data from interpreted logs (NIKO-BAPEX) was used for probabilistic analysis using GeoX software. Net thickness was also taken from same logs. For the estimation of rock volume, maps prepared by NIKO-BAPEX study report were used.

#### 6.4.1.8 2010 Reserve Re-Estimation (This Report)

For this report, the previous estimates were reviewed, and the 2003 estimate was judged to be reliable.

### 6.4.2 Kamta

#### 6.4.2.1 Geologic Setting

Kamta gas field is located in Kaliganj upazila under Gazipur district about 17 km away to the north of Dhaka. Surface outcrops in the Kamta area are mainly Modhupur Clay of Quaternary age.

Kamta lies within the same tectonic regime as Chhatak, in the Bangladesh basin adjacent to the Indo-Burman ranges. Tectonic movements have influenced both the stratigraphic and structural configuration of all reservoirs within the field.

As noted for the Chhatak field, the sediment fill within the Bangladesh basin is predominantly Cenozoic terrigenous clastics. Preserved sediments in the lower sequence comprises principally continental to marine sediments from the Cretaceous to the Middle Eocene during an extensional inter-cratonic, sub-basin development phase for the India plate. The upper sequence is predominantly continental sediment with interbedded terrigenous source beds of the Jenan, Bhuban, and Bokabil Formations with downslope fluvial (meandering and braided stream) sandstones, siltstones, and claystones. The final rapid influx of Pliocene to Recent sediments is composed of poorly sorted sandstones and siltstones with few interbedded shales and claystones.

#### 6.4.2.2 Structure

Kamta is a low amplitude anticline with a closure height of just over 25m. The axial trend of the anticline is NW-SE. The well is located on the northwestern periphery of gas bearing area. In some of the old maps a saddle is indicated on the northern part dividing the structure into two culminations.

The NIKO-BAPEX joint study (2000) prepared another map using old seismic data. This map is shown in Figure 6-166. The map shows the structure as a low amplitude feature. The general outline of the structure is similar to the earlier maps. Because of low amplitude of the anticline, computer generated maps show some irregular lines on the flanks and pitching ends, which are not shown in hand drawn maps. This map also shows that the well is on the northwestern periphery of the gas water contact.

The anticline is simple in form and far enough away from the active Burma Foldbelt to be unfaulted. No apparent faults are present to serve as conduits for migration of hydrocarbons to shallow reservoirs. Numerous reservoirs have not been filled to spill point, reducing recoverable reserves in the field.

#### 6.4.2.3 Reservoir

The reservoir is sandstone and in the well section the gas column is about 6 m thick above gas water contact. Porosity is evaluated from log and average porosity for the reservoir section is 20.6%. Core porosity is available from a depth of 2,500 m.

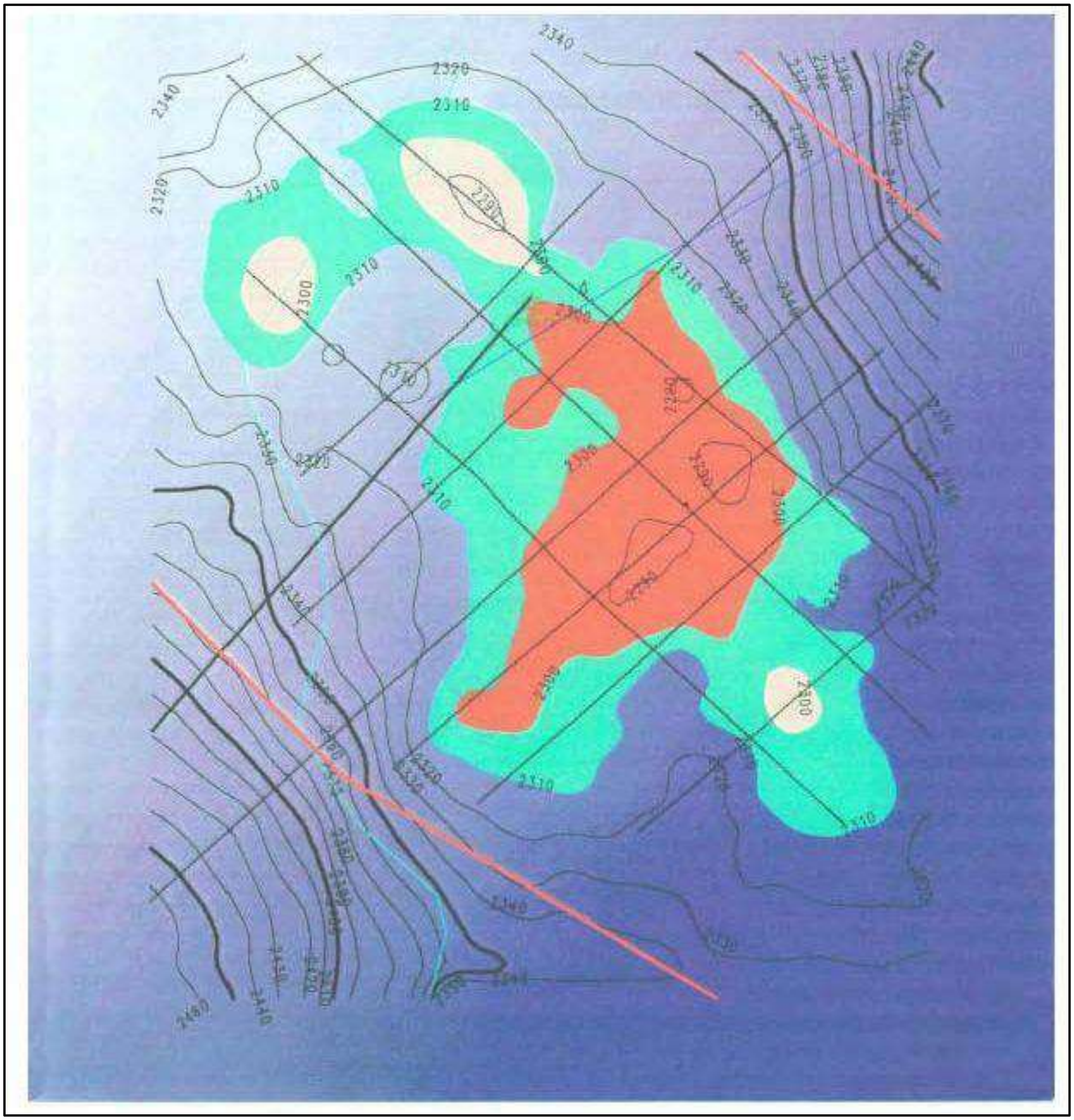



**Figure 6-166 Depth Structure Map – Kamta Gas Field**
Gas pool is shown in red (after NIKO/BAPEX, 2000).

### 6.4.2.4 Exploration and Field Development

Standard Vacuum Oil Co. (STANVAC) delineated the structure as a low amplitude one during their exploration campaign of 1960-66. After the departure of STANVAC there was no activity for over a decade.

Tailo Sandhani Company (TSC) recorded 32 Km. single fold data (two lines) in 1977-78. In the following year two more 12 fold lines were recorded. The structure was mapped as simple anticline with NW-SE axial trend. In 1979-80 two 12 fold lines were recorded and the data was processed by GSI (Singapore). Kamta Well #1 was drilled in 1981 to a depth of 3,618 m. Only one gas sand (2,294-2,297 m) was discovered in this well. Gross thickness of the zone was found to be about 12 m. Only top 3 m was perforated.

Kamta gas field was discovered by Petrobangla in 1982. After discovery of gas, Geological Evaluation Division (Murtaza et. al., 1982) prepared a map on top of gas sand for estimation of reserve. This map showed that the well was located on the northern pitching area of the anticline. The map also shows that the main culmination, with over 16m amplitude above the gas water contact, is located on the southeast of the well.

Fifty-three km of 12-fold digital data was recorded in 1983-84. Map prepared on the basis of digital data indicated that the well is located on the northwestern pitching area of the structure. According to this report a saddle separating the structure into two culminations, indicated in earlier report, could not be substantiated. The report also pointed out that it is very difficult to identify a saddle of 7 meter by standard processing.

Commercial gas production from this field was started in 1984. Average 20 million cubic feet of gas was produced daily since inception while it was reduced to 3 million cubic feet daily in 1988 due to excessive water production and for the same reason gas production was suspended from this field in 1991. NIKO-BAPEX joint study considered this field uneconomic in 2000.

#### 6.4.2.5 Well-wise and Sand-wise Production History

Sand-wise cumulative gas production for Kamta gas field at end of December 2009 is summarized in Table 6-85.  All production is from the Bokabil Sand.

**Table 6-85 Sand-wise Cumulative Gas Production – Kamta Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Bokabil Sand | 21.1 |
| **Total** | **21.1** |

1 Production through end of December 2009
HCU production database

### 6.4.2.6 Field-wise Cumulative Production

Total production from this field till 26th August, 1991, was 21.1 Bscf and 4,231 bbl condensate. Production was suspended in September 1991. The last production rate was 2.7 MMscfd in August 1991.

### 6.4.2.7 Earlier Reserve Estimates

The map generated by NIKO-BAPEX joint study was used to re-estimate rock volume by the HCU-NPD in their 2003 study (HCU-NPD, 2004). Porosity and saturation data was collected from the same NIKO-BAPEX joint study report and used for analysis by GeoX software. GIIP of the field was estimated at 71.8 Bscf in the Proven category. Recoverable reserve was estimated at 50.3 Bscf considering recovery factor of 70% and remaining reserve was 29.2 Bscf in 2003 based on production to that time. Based on this 2003 estimate by HCU-NPD, it appears that additional gas reserves of 29 Bscf remained unproduced from this field. The last average daily production rate before field suspension in September 1991 was 2.7 MMscfd in August 1991.

### 6.4.2.8 2010 Reserve Re-Estimation (This Report)

For this report, the previous estimates were reviewed, and the 2003 estimate was judged to be reliable.

### 6.4.3 Meghna

Meghna gas field is located in Bancharampur upzila under Brahmanbaria District some 40 km away of northern most east direction from Dhaka. There is no surface expression of the structure. The area is represented by numerous channels of Meghna River. The surface is represented by Holocene deposits of Meghna Flood Plain.

#### 6.4.3.1 Geologic Setting

In 1953, the structure was identified as a gravity anomaly. Later the structure was mapped by Shell as a prospect using single fold seismic data. It was named as culmination A.1 by Shell.

The pay and potential pay sands are represented by mouth bar and barrier bar sands. These sands, initially believed to correlate with pay zones in the nearby Bakhrabad field, are stratigraphically lower in the section by about 500 m and represent a different depositional facies than the Bakhrabad gas sands.

#### 6.4.3.2 Structure

The structure is a simple low relief anticline with a N-S running fault on the east flank. The structure is about 2.7 km long at the level of last closed contour for ‘C’ sand. The structure is flat topped with gently dipping flanks. Figure 6-167 is a structure map of Meghna field drawn on the top of the C Sand (IKM, 1992).

#### 6.4.3.3 Reservoir

The exploratory well encountered six gas sands within a depth range of 2,285–3,025 m. A total of five zones were tested and three flowed gas. Gross thickness of individual sands ranges from 4 to 10 m. For two main sands (‘A’ and ‘C’) and one minor gas sand (‘D’) gas water contact is not found in the well. GWC for ‘A’ is considered at the base of the sand.

Net thickness is maximum 9.15 m in 'C' sand and minimum is 2m in 'E' sand. Two unnamed sands with 5 and 2 m thickness within depth range of 2,736-2,893 m are also identified from log. In C and D sands gas water contact was not observed in log.

Porosity and saturation data are estimated from logs. Two cores in 'A' sand and one core in 'D' sand were cut. However laboratory analysis indicated a high porosity from Core 1 ranging from 40 to 27% with most of the reading above 40%.

Porosity of reservoir sands decreases with depth. At the top of the reservoir section (2,280 m) log porosity was evaluated at 0.23-0.24. This shows a gradual decrease of porosity from 0.239 to 0.228 in 'A' to 'C' sands. In 'D' sand the porosity is estimated at 0.18 and this gradually decreases to 0.167 in F sand.

Water saturation is found to be 0.34 in the 'A' sand. In other sands it ranges from 0.52 in 'E' sand to 0.46 in F sand.

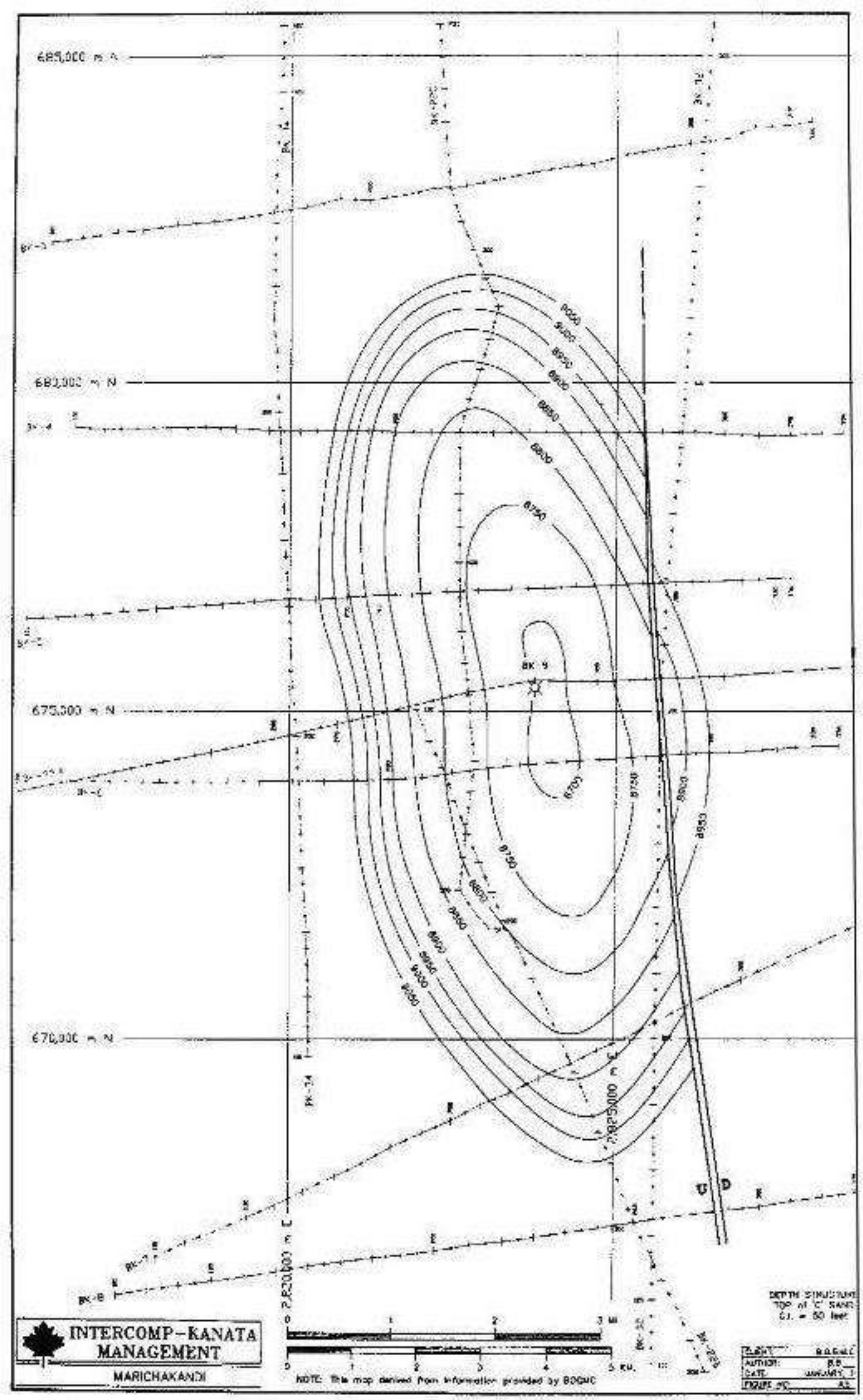



**Figure 6-167 Depth Structure Map on Top of C Sand – Meghna Gas Field**
Map is contoured in feet, C.I = 50 feet (after IKM, 1992).

### 6.4.3.4 Exploration and Field Development

In 1974, Shell estimated the resource potential of this prospect at 2,190 Bscf at 50% probability. In 1984-86 Petrobangla acquired 24 fold seismic lines over the area and new maps were prepared by HHSP. According to IKM, HHSP estimated the prospect's resource potential at 1730 Bscf. This could not be confirmed from HHSP report.

GGAG named the structure as Bakhrabad B2 structure and estimated its resource potential with 50% probability at 1118 Bscf (unrisked). The risk discounted resource potential was 335 Bscf. With 84% probability the figure reduces to 928 Bscf (unrisked) and risked discounted potential further reduces to 186 Bscf.

Meghna gas field was discovered by Petrobangla in 1990. The Bakhrabad # 9 exploratory well was drilled in 1990. It was named so that the structure can be considered as the northern most culmination of greater Bakhrabad anticline. The well encountered six gas bearing sands within a depth range of 2,285–3,020 m. The sands are named as A, B, C, D, E and F sands. The C, E and F sands were tested and flowed gas. After discovery of gas the prospect was named Marichakandi.

In 1997 the field started producing from 'C' Sand. The name of the field was changed to Meghna Gas Field. Gas production from one well of Meghna gas field was 20 million cubic feet daily since inception. Gas production from this field remains suspended since 10 August, 2007 due to excessive water production.

To sustain/increase production of natural gas in order to meet the country's growing demand and to determine actual reservoir condition and extent of various gas sands of Meghna gas field, re-completion of Meghna #1 well is now underway. Upon successful completion of the project additional daily 10 MMscf gas is expected to be produced and supplied to the national grid.

6.4.3.5 Well-wise and Sand-wise Production History

Sand-wise gas cumulative production for Meghna gas field at end of December 2009 is summarized in Table 6-86. All of the field's production has come from the Lower C Sand reservoir.

**Table 6-86 Sand-wise Cumulative Gas Production – Meghna Gas Field**

| Reservoir Sand | Cum. Prod. ( Bscf)[1] |
|---|---|
| Lower C Sand | 36.2 |
| **Total** | **36.2** |

1 Production through end of December, 2009
HCU production database

6.4.3.6 Field-wise Cumulative Production

A total 36.2 Bscf of gas has been produced from the Lower C Sand in Meghna gas field. Production was suspended in August 2007.

6.4.3.7 Earlier Reserve Estimates

Reservoir parameter was reviewed for the HCU 2003 study (2004) and reserve of 'A' to 'E' sands is re-estimated following deterministic approach. The result is 73.9 Bscf for the 'C' sand and 53.52 Bscf for the 'A' sand (Table 6-87). This is almost same as was estimated by IKM (1992).

**Table 6-87 HCU-NPD 2003 Reserve Estimate**

| | GIIP(Bscf) | | |
|---|---|---|---|
| Sand | Proved | Probable | Total 2P |
| A Sand | | 53.5 | 53.5 |
| B Sand | | 5.29 | 5.29 |
| C Sand | 73.9 | | 73.9 |
| D Sand | | 9.54 | 9.54 |
| E Sand | 13.1 | | 13.1 |
| F Sand | 15.3 | | 15.3 |
| Field Total | 102.3 | 68.33 | 170.63 |

HCU-NPD 2003

As the 'C', 'E' and 'F' sands were tested, GIIP estimates for these sands were placed under the Proven category. As the 'A' sand was not tested, the GIIP of this sand was placed under Probable category.

RPS Energy estimated GIIP and reserves for Meghna field in a report released in August 2009 using 3-D geologic modeling and reservoir simulation. Although several different GIIP estimates were contained in the RPS reports, their reconciled estimates appear to be those resulting from their ECLIPSE model reservoir simulation and history match as shown in Table 6-88. As seen by comparison with Table 6-88, this estimate is significantly lower than the HCU-NPD 2003 estimate, mainly in the A and C Sands. Since the RPS's estimate is supported by reservoir simulation history match, it is considered to be more reliable. RPS goes on to categorize their reserves estimates as shown in Table 6-89 below.

However, the RPS estimates indicates an additional 76 Bscf (Petrel) to 133 Bscf (REP probabilistic) of GIIP in the A, B, D, E, and F sands that were never produced. Using an 80% R.F., that would amount to about 60 Bscf of unproduced reserves that may be remaining in the reservoirs at Meghna. As stated above in Section 6.4.3.4, efforts are now underway to re-establish gas production from additional sands at Meghna gas field.

**Table 6-88 RPS Energy 2009 Reserve Estimate - Deterministic– Meghna Gas Field**

| Reservoir | STOIIP (Bcf) | Recovered at the end of HM (Bcf) | Recovered at the end of forecast scenario (Bcf) | Recovery ratio (%) |
|---|---|---|---|---|
| A | 5.8 | 0.0 | 0.0 | 0.0 |
| B | 1.5 | 0.0 | 0.0 | 0.0 |
| C | 51.8 | 36.7 | 49.1 | 94.8 |
| D | 25.5 | 0.0 | 20.8 | 81.6 |
| E | 15.5 | 0.0 | 13.2 | 85.2 |
| F | 22.1 | 0.0 | 18.1 | 82.0 |
| Field Total | 122.1 | 36.7 | 101.2 | 82.9 |

RPS Energy 2009g

**Table 6-89 RPS Categorization of Meghna Reserve Estimates**

| 1P (P90) | 2P (P50) | 3P (P10) |
|---|---|---|
| 36.7 | 49.1 | 101.2 |

RPS Energy 2009g

6.4.3.8 2010 Reserve Re-Estimation (This Report)

For this report, the RPS study and previous estimates were reviewed, and the RPS estimate was judged to be reliable. Note the implied recovery factor for the 2P reserves is only 40.2%. This is considered to be quite low, and is believed to be due to conservative assumptions made by RPS as to what further development of the non-producing zones may actually be undertaken and what production may result. Nonetheless, we rely on these assumptions.

## 6.5 UNDEVELOPED GAS FIELDS

Non-producing gas fields are the discovered gas fields that are awaiting development. Three small gas fields under this category are discussed in the following pages. The list includes Begumganj, Kutubdia, and Semutang fields. Most of this material is updated from the HCU/NPD 2003 Reserve Report (2004). The fields are arranged in alphabetical order.

### 6.5.1 Begumganj

#### 6.5.1.1 Geologic Setting

Begumganj is located in southern part of the country in Block 10 in the western part of the Eastern Foldbelt between the Bengal basin and the Indo-Burman ranges. The structure was delineated by PSOC in 1965 using singlefold analog seismic data. During 1967-68 OGDC carried out a gravity survey that was followed by a seismic campaign in 1970-71. The gas field is located on a north-south oriented anticline with moderate amplitude. No fault was identified.

The sedimentary succession is of Upper Paleozoic to recent age. A large proportion of the sediment has been deposited since Late Eocene. The basin infill consists mainly of clastic sediments that attain an estimated aggregate thickness of 20 to 22 km in the foredeep area. The foredeep follows a SW-NE trend parallel to the rifted continental margin. It also includes the Surma sub-basin in the northeast.

#### 6.5.1.2 Structure

Begumganj structure was originally mapped on the basis of singlefold analog seismic data. After drilling of two wells, two multifold analog cross profiles were recorded. The structural map (1982) was prepared on the basis of both the singlefold and multifold data and well data. According to this map, the structure trends NW-SE with gently dipping flanks and low relief. In 1984, a new map was prepared that shows a similar axial trend but with two culminations. The southern culmination is the main one and the first well was drilled there. The second well was drilled on the northern culmination.

The trend of the anticline is same as Kashimpur, Bakhrabad, and Lalmai anticlines to the north. Senbag-Chandina syncline separates Begumganj from Feni and Lalmai structures located on the east. The anticline is slightly asymmetric with a relatively steeper eastern flank.

No maps of this feature were available for inclusion in this report.

### 6.5.1.3 Reservoir

The reservoir rock is sandstones of Mio-Pliocene age. No detailed study of all the sandstone horizons selected for testing was done. In the tested zone no gas water contact was observed in the log. Gross thickness of the gas sand was greater than 10m, of which about 8 m was considered the effective thickness.

On the basis of log evaluation results of Begumganj well No. 1 eight zones were selected for testing. The zones arranged by depth follow:

VIII) 2887 – 2903m
VII) 2995 – 3012m
VI) 3033 – 3036m
V) 3441 – 3436m
IV) 3475 – 3478m
III) 3528 – 3532m & 3542 – 3547m
II) 3585 – 3588m
I) 3642 - 3646 m

Both porosity and water saturation were estimated from a set resistivity log (BKZ log). These logs were of vintage type recorded by tool from former Soviet Union. According to log evaluation based on a set of resistivity data porosity ranged from 14 to 18%. According to N. Golubev, porosity of Zone VII ranged between 10 and 15% and water saturation ranged from 31 to 22%.

Another evaluation placed water saturation within a range of 55 to 62%. The authors of 1988 report considered a GWC at the base of the gas sand in the well section. The area within 1 km radius of the well and GWC was considered for estimation of proven GIIP. For estimation of probable GIIP, GWC was considered at a depth between base of the sand as encountered in the well and spill point. They also estimated possible GIIP with an assumption that the GWC was at spill point.

Absence of quality seismic data had some effect on the dependability of seismic maps. The first map was prepared on the basis of single fold analog data and the second on the basis of two analog multifold lines recorded across and along the anticline.

Considering the number of sands that could not be tested in well # 1, some of these sands may be expected to flow gas in future well. However, these sands were not considered for reserve estimation.

#### 6.5.1.4 Exploration and Field Development

Begumganj well #1 was spudded in January, 1976, with a target depth of 4,400m. In April, 1977, the well was terminated at 3,656 m after encountering high pressure zone. During this period two analog 12 fold seismic lines were recorded across and along the structure. Out of eight horizons selected for test only two could be tested. Testing of the lowermost zone (I) within a high pressure sequence yielded formation water with little gas. After this testing, the pipe string got stuck during pull out, and due to a lengthy fishing job zones II to VI were lost. Well was made ready for further tests, but the first attempt to test Zone VII failed due to communication with zone I.

In 1978, the rig was released for drilling Begumganj Well #2, located about 4 km northwest of well #1. Second well was spudded in March, 1978, and this well drilled through six zones, all of which were tested. Only zone I flowed 106 Mscf gas along with water at a rate of 138 BPD. All the zones were found wet. After completion of Well #2 in 1980, the rig was moved back to Well #1 and Zone VII was retested. During testing the well flowed gas at rates ranging from 6.15 MMscfd to 12 MMscfd. Condensate ratio was found to be 12.8 gallon/MMscf and water rate was ranging from 1,500 to 3,000 gal/day.

A more detailed study was carried out in 1984. The authors prepared new maps for this study which showed that the anticline has two culminations.

### 6.5.1.5 Earlier Reserve Estimates

A preliminary estimate by PSOC in 1980 (Pavlov & Elahi. 1980) placed gas reserve of tested zone at 185 Bscf of which 60 Bscf was under proven category. No possible GIIP was indicated in the report. A more detailed study was carried out by Petrobangla in 1984, which placed GIIP of the tested interval at 154.4 Bscf. Out of this, only 14.1 Bscf was Proven and another 32.6 Bscf was Probable. Possible GIIP was estimated at 107.7 Bscf. Condensate reserve was estimated at 41.73 Mbbl. Results of this 1984 Petrobangla estimate are presented in Table 6-90.

**Table 6-90 1984 Petrobangla Reserve Estimate – Begumganj Gas Field (in Bscf)**

| GIIP in Bscf | | | | |
|---|---|---|---|---|
| Proven | Probable | Possible | Total 2P | Total 3P |
| 14.09 | 32.63 | 107.7 | 46.72 | 154.42 |

In 1986, under Hydrocarbon Habitat Study Project (HHSP), Begumganj reserve was reviewed. This time undifferentiated Proven and Probable reserve was estimated at 25 Bscf and another 30.3 Bscf was assigned under Possible category. Condensate reserve was also estimated. The figure was 0.005 MMbbl under Proven and Probable category and an additional 0.006 MMbbl under Possible category. HHSP identified gas sand at 2600m in Well #1. No attempt was made to estimate the GIIP of untested zones. Petrobangla used this result in the 'Exploration Opportunities of Bangladesh, 1989. However they used the term EURR instead of GIIP.

In 1989, Gasunie conducted a study on gas reserve and they studied 11 gas fields in detail. Table I of the report included all the discovered gas fields. The table showed remaining reserve under Proven, Expected and High categories, cumulative production and speculative reserve for the fields. Recoverable reserve of Begumganj was found to be 0.2 Tscf under expected category. This reduces to 0.01 Tscf under Proven and increases to 0.04 Tscf under High Case. Gasunie used Tscf as unit.

Table 6-91 shows results of all these estimates, including the original 1984 Petrobangla estimate for ease of comparison.

**Table 6-91 Comparison of Previous Reserve Estimates – Begumganj Gas Field**

| Estimated by | GIIP in Bscf | | | | Condensate in 1000 bbl |
|---|---|---|---|---|---|
| | Proven | Probable | Possible | Total | |
| Pavlov & Elahi. 1980 | 60.0 | 125.0 | | 185.0 | |
| Akkas Ali et.al. 1984 | 14.1 | 32.6 | 107.7 | 154.4 | 41.7 |
| HHSP, 1986 | 25.0 | | 30.3 | 55.3 | 11.0 |
| Gasunie, 1989 * | 10.0 | 20.0 | 40.0 | 70.0 | |

* Recoverable Reserve

Welldrill's report of 1991 used the GIIP as estimated by HHSP and used a Recovery Factor of 72%, which resulted in a recoverable reserve of 18 Bscf.

In the 1993 edition of the Exploration Opportunities of Bangladesh, GIIP and recoverable reserve were listed at 0.02 and 0.02 Tscf, respectively and recoverable condensate reserve remained unchanged at 0.01 MMbbl. Equal values for both GIIP and recoverable reserve were presumably due to rounding of figures to two digits after decimal. In the 1997 edition of Exploration Opportunity in Bangladesh, the figures were 0.025 Tscf and 0.015 Tscf as 2P GIIP and recoverable reserve, respectively. Condensate reserve remained unchanged. In May 2003, Petrobangla changed this figure on their website.

HCU-NPD study in 2001 used the reserve estimation report of Pavlov et al., 1980. The HCU-NPD 2003 (2004) reserve report used the deterministic method, and the GIIP was estimated at 16.3 Bscf as Proven, 37.8 Bscf as Probable and 124.6 Bscf as Possible category. This result is quite close to Petrobangla estimate of 1984. For the HCU/NPD 2003 (2004) study it was agreed to use the result of 1984 estimate provided in Table 6-90.

Uncertainty in the rock volume was the main factor behind large variation in different GIIP estimates. This, in turn, indicates that the level of confidence on structural map is rather low. Quality and volume of seismic data can be considered as the main factor for such uncertainty.

#### 6.5.1.6 2010 Reserve Re-Estimation (This Report)

For this report, the previous estimates were reviewed, and the 2003 estimate was judged to be reliable.

### 6.5.2 Kutubdia

#### 6.5.2.1 Geologic Setting

The Kutubdia field is situated southwest of the Sangu field offshore in the Bengal foredeep within Block 10. The Bengal foredeep, a large area generally to the south of the Surma Basin, contains the great volume of Tertiary sedimentary accumulation of the Ganges-Brahmaputra delta. These strata are more distal equivalents of the Oligocene Barail Group, the Miocene Surma Group, and the Pliocene Tipam Group found in the Surma Basin and in the folded belts to the east. The rocks consist of sandstones, siltstones, and shales that commonly contain plant-derived organic matter. Overall, the strata are as thick as 20,000m in the Patuakhali Depression or Hatia Trough, a depocenter located in the southeastern side of the delta (U.S. Geological Survey, 2001).

#### 6.5.2.2 Structure

The structure as it appears in Petrobangla map (1985) is an oval shaped four-way dip closure with a NNW-SSE trend. No fault was indicated on the map.

In 2000, Cairn/Shell shot seismic lines over the area and prepared new maps. One of these maps, the depth structure map drawn on top of Horizon 2.9.6, is shown in Figure 6-168. These maps indicate that the structure is NNW-SSE trending four-way dip closure, bifurcated into two highs by an east-west running saddle, which also marked a channel. The discovery well is located on the south side of the channel. The northern part of this structure is also a good target for drilling with certain degree of risk because the amplitude of the structure in the north is less than that observed on the south. The saddle has significantly reduced the gas-bearing area under probable category as considered by Petrobangla.

#### 6.5.2.3 Reservoir

Very little is known about the reservoir. As in other gas fields the reservoir is sandstone deposited in a fluvio-deltaic environment. According to Shell's map gas water contact is limited to the southern part of the structure. The northern part is separated by a saddle as well as by a channel and structural elevation is less than that in the southern culmination. All these factors resulted in uncertainty about the extension of gas pool to the north of the channel.

For reserve estimate, Petrobangla used porosity and saturation data from log evaluation. Porosity was found to be ranging between 0.14-0.24 with an average value of 0.20. Shell used a porosity ranging from 0.16 to 0.24 with a mean value of 0.20.

According to Petrobangla evaluation, gas saturation ranged from 100% to 64% with an average value of 76%. Shell used a range from 50 to 80% with a mean value of 75%.

Three zones were identified in the discovery well at 2,629-2,659m, 2,901-2,911m, and 3,166-3,179m. depth intervals.

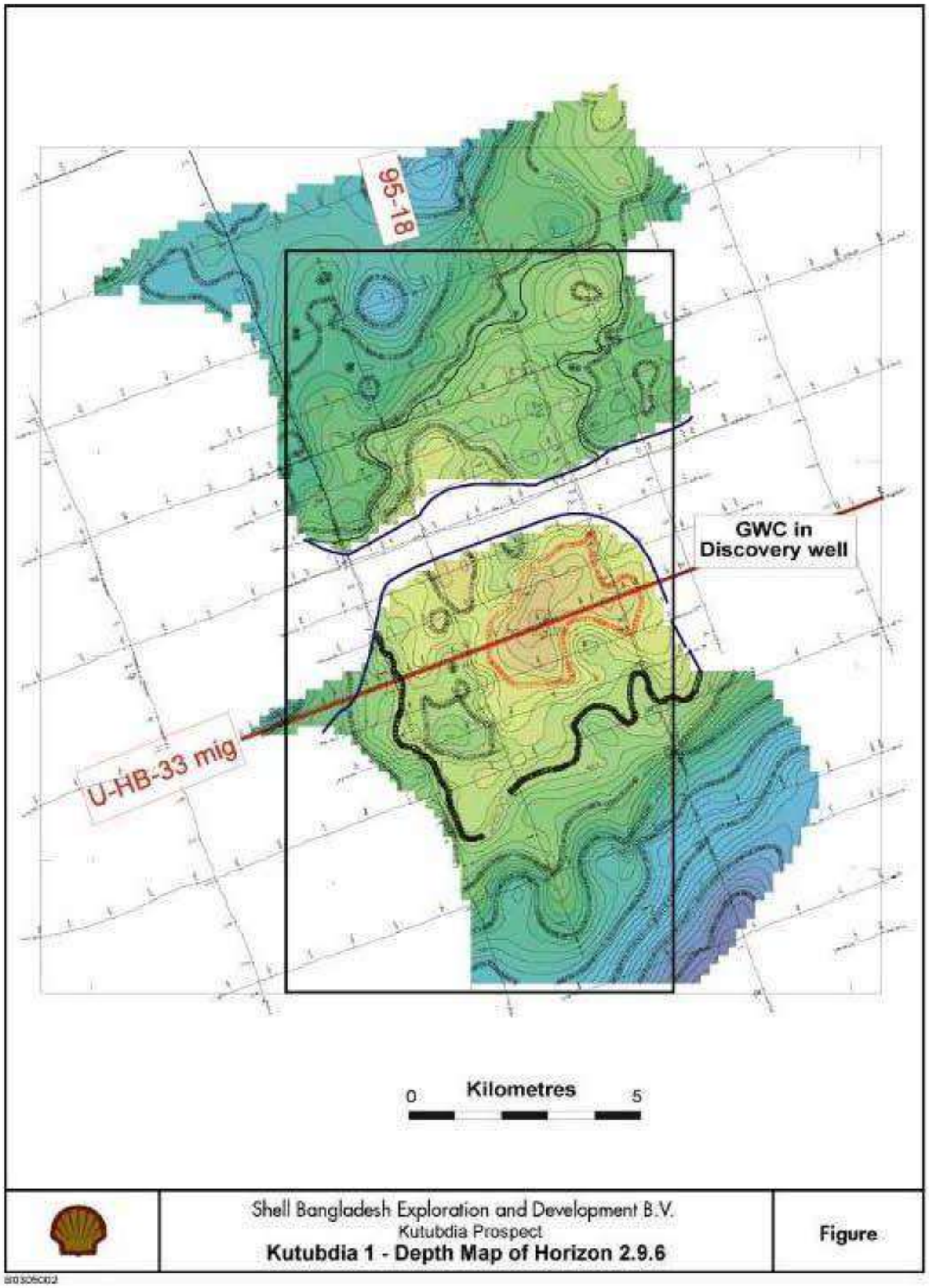



**Figure 6-168 Depth Structure Map of Horizon 2.9.6 – Kutubdia Gas Field**
Gas-water contact (GWC) is shown by red line. GCW based on fluid contacts in discovery well (after SBED, 2000).

#### 6.5.2.4 Exploration and Field Development

During the offshore exploration campaign of middle 1970s, Union Oil (which became Unocal) was awarded one block located south of coastal island of Shahbazpur, Hatia. After evaluation of seismic data acquired during 1975, Union Oil drilled an offshore prospect named Kutubdia, as it is located due west of Kutubdia Island.

The Union Oil discovery well was projected to drill down to 3,657m but was terminated at 3,505m upon encountering an overpressure zone below 3,414m. The well was drilled during January, 1977 and December, 1978. Although three horizons were found only one zone (2,629-2,659m) was tested. During DST the zone flowed gas at a rate of 17.9 MMscfd. Two additional zones are at intervals 2,901-2,911m and 3,166-3,179m.

The field is located in block 16 and this block along with the gas field was awarded to Cairn Energy Plc. and Holland Sea Search.  In 1995, Cairn shot seismic lines over the area and new maps were prepared (Figure 6-168). Shell later became a partner and subsequently became operator.

#### 6.5.2.5 Earlier Reserve Estimates

After discovery, Geological Division of Petrobangla estimated GIIP of the field. According to this estimate proven GIIP is about 61 Bscf, and another 800 Bscf was placed under Probable category. The authors considered a recovery factor of 90% and estimated recoverable reserve at 775 Bscf. Because of the uncertainty on the distribution of reservoir sand over the structure, proven GIIP accounted for only about 7% of the total.

In the 'Exploration Opportunities in Bangladesh 1989', a publication of Petrobangla, recoverable reserve was indicated at 0.78 Tscf. However, in the subsequent issues starting from 1993 this same figure labeled as GIIP (2P) and multiplied by a recovery factor of 60% to arrive at a new recoverable reserve of 0.468 Tscf. This figure was revised in 2003.

HCU-NPD study of 2001 used the result of Petrobangla report. In Estimate 1 of the National Committee Report, the reserve figures are same as in Petrobangla publications and in Estimate 2 the figures matched with the result of 1988 estimate.

On the basis of new maps, Shell estimated the GIIP for Horizon 2.9.6 at 65 Bscf and mean recoverable reserve at 41 Bscf (Table 6-92). Another 66 Bscf was assigned to a sand overlying the discovered gas sand (Horizon 2.8.0).

**Table 6-92 Shell Oil Reserve Estimate – Recoverable Reserve in Bscf - Kutubdia Gas Field**

| | Low | Mean | High |
|---|---|---|---|
| Horizon 2.9.6 | 28 | 41 | 62 |

6.5.2.6 2010 Reserve Re-Estimation (This Report)

For this report, the previous estimates were reviewed, and the 2003 estimate was judged to be reliable.

6.5.3 Semutang

6.5.3.1 Geologic Setting

Semutang is situated in Block 15 southeast of the Begumganj and Feni fields in the Eastern Foldbelt between Bengal basin and the Indo-Burman ranges. The structure is represented on surface by outcrops of Dupi Tila and Tipam Sandstones. The sedimentary succession is of Upper Paleozoic to recent age. A large proportion of the sediment has been deposited since Late Eocene. The basin infill consists mainly of clastic sediments that attain an estimated aggregate thickness of 20 to 22 km in the foredeep area. The foredeep follows a SW-NE trend parallel to the rifted continental margin. It also includes the Surma sub-basin in the northeast.

#### 6.5.3.2 Structure

The structure is a NNW-SSE trending anticline. In early maps it was interpreted as a simple anticline (Figure 6-169). In the maps prepared after recording additional seismic data, a number of faults were observed on both the flanks. Faulted nature of the structure has divided the reservoirs into multiple blocks. This has increased the risk as well as investment for the development of the field.

On the basis of latest multifold digital seismic data, Shell prepared new maps in 2000 (Figure 6-170). In these maps the structural trend remained unchanged but the anticline is found divided into several blocks by a number of longitudinal faults. Shell also identified a stratigraphic trap on the east flank. In addition to faults, cut and fill features were also identified. Shell has identified four fault blocks and one stratigraphic trap that could be possible targets for drilling. However, according to SBED estimates, the resource volumes of individual prospects are rather small.

#### 6.5.3.3 Reservoir

The reservoir rock is sandstone. Three named reservoirs are the Upper Gas Sand, Middle Gas Sand, and Lower Sand Gas Sand.

The porosity of the reservoir rock was found to be more than 30% at 900m depth. This gradually decreased to about 23% at 1,270m depth. For deeper horizons Shell data indicate a porosity of about 12%. Gas saturation in two horizons above 1,300m is around 70% and for the deeper horizons it is around 60%.

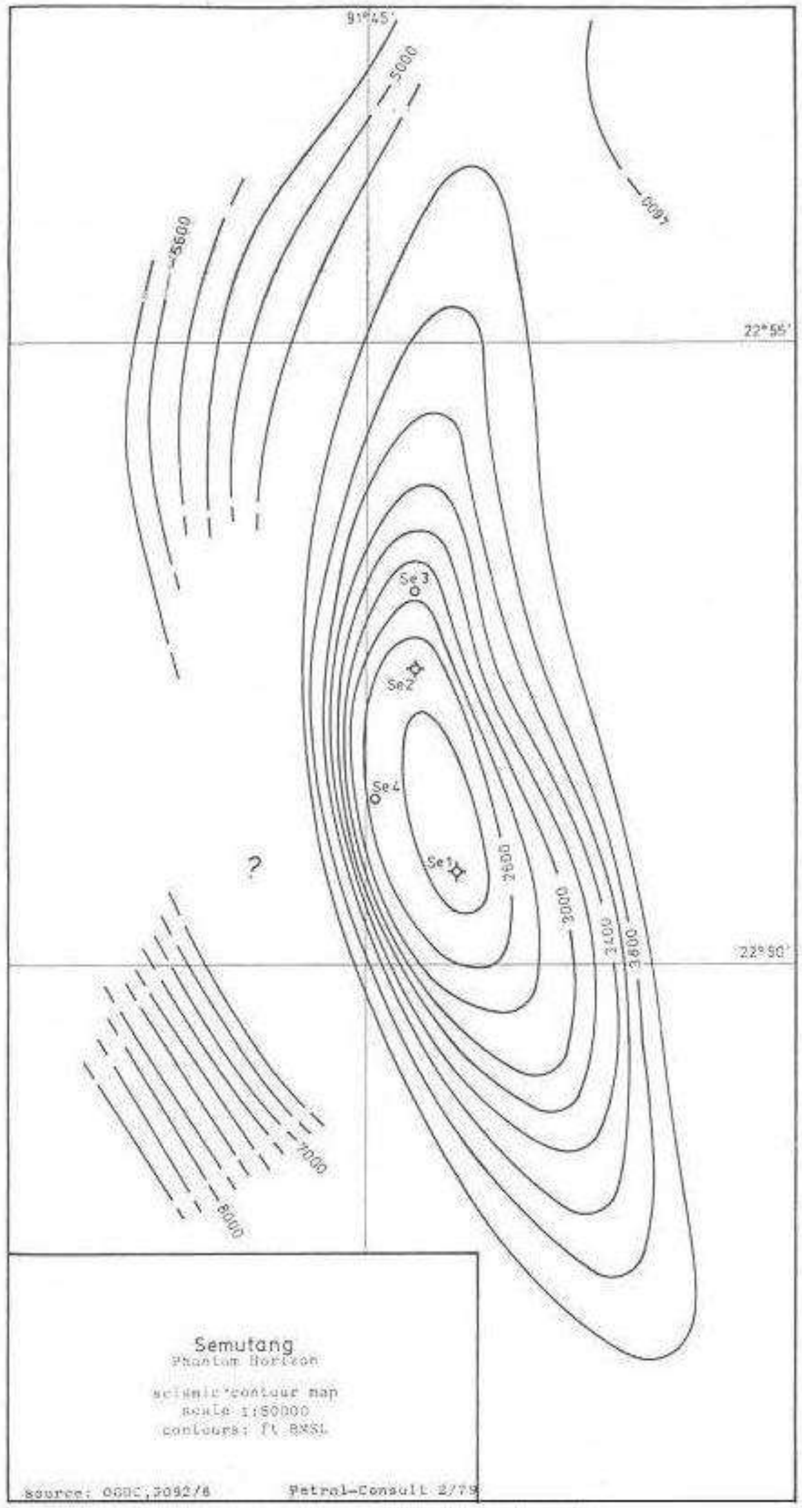



**Figure 6-169 Seismic Depth Structure Map on Phantom Horizon – Semutang Gas Field**
Map contoured in feet. C.I.=200 feet. Map shows locations of Semutang #1 and #2 wells and proposed locations of Semutang #3 and #4 wells (after OGDC, 1979).

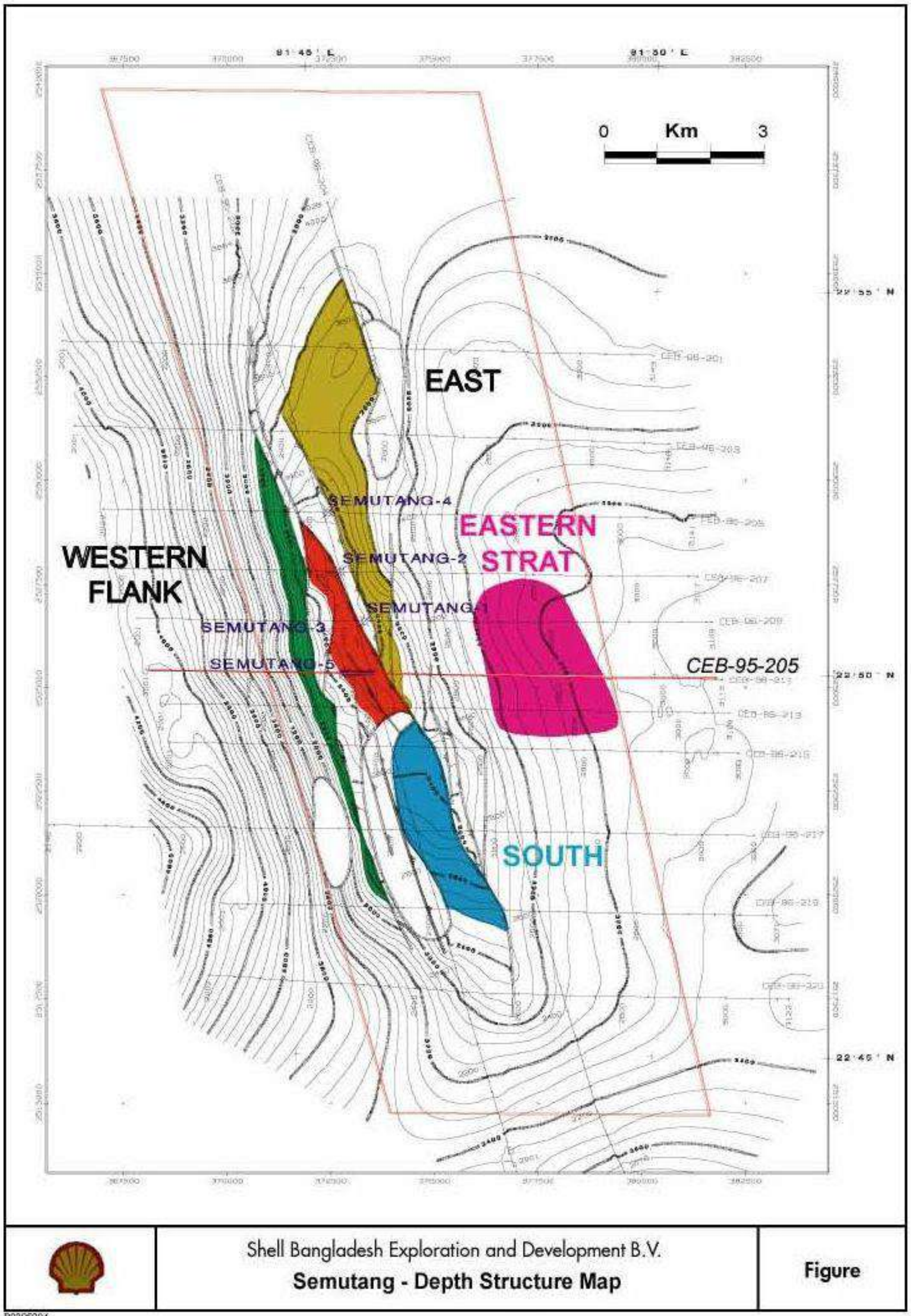



**Figure 6-170 Depth Structure Map – Semutang Gas Field**
Map shows four identified potentially productive fault traps and a mapped eastern stratigraphic target (after SBED, 2000).

### 6.5.3.4 Exploration and Field Development

Semutang anticline was surveyed by the geologists of Burmah Oil Company during late 1930s. PSOC in 1960 did photogeological study of the Chittagong and Chittagong Hill Tracts, which also included Semutang. A geological survey was carried out by OGDC geologists between 1962–64, and a detailed geological map of Semutang was prepared. During 1966-67 OGDC shot seismic lines over the structure. OGDC also prepared structural maps.

Semutang gas field was discovered by Oil and Gas Development Corporation (OGDC) in 1970. First well on this structure was a GIB (Geological Information Borehole) that resulted in blowout at a shallow depth (300m) in 1966. A deep well (4,088m) was drilled later, and three gas sands at a depth of 1,400m were discovered. The deep well was abandoned after lengthy fishing operation. Subsequently, three shallow wells were drilled by OGDC during 1967-70. In all these wells three gas sands within a depth range of 970-1,330m were encountered.

In 1981, Petrobangla recorded one strike and three dip lines (12 fold). New seismic maps and cross-sections were prepared by Petrobangla on the basis of these lines (N. Kabir). This maps and cross sections showed a number of faults on both the flanks.

Shell was awarded a block covering entire area of former Chittagong Hill Tract District and some part of Chittagong (current Block 22). Shell shot 24-fold digital seismic line over selected parts of the area including one dip line across Semutang structure. However, after drilling the Sitapahar structure (1988), Shell relinquished the area.

Shell returned to this country as a partner of Cairn Energy plc, operating in Blocks 15 and 16. Later on Shell became operator. New seismic data was recorded over the area including Semutang. Shell prepared new maps, which showed a number of faults dissecting the structure into several blocks. In addition to this, several stratigraphic traps were identified.

Semutang #5 was drilled in 1997 to a depth of 3,029m (MD). Two sands were tested (DST) between depths of 2,470-2,650m. The upper one flowed gas at a rate of 18 MMscfd and the lower one at a rate of 0.086 MMscfd. In addition to these two sands the well penetrated two gas sands at 950m and 1,270m. The gas zone at 950m was tested in wells #1 and #2.

BAPEX has plans to begin production in the Semutang field in 2011. Wells #1 and# 5 should be reconditioned in late 2010 in anticipation of producing gas to fuel a power plant. In addition, a pipeline is planned to carry gas 65 km to Chittagong.

#### 6.5.3.5 Earlier Reserve Estimates

In the paper presented in the national seminar on hydrocarbon resources of Bangladesh (1980) recoverable gas reserve of Semutang was quoted as 480 Bscf and D.K.Guha was quoted as source for the estimate. In the same paper recoverable reserve of Semutang was also quoted as 100 Bscf and this was after Schmidt and Haque. A preliminary estimate by Petrobangla (1981) placed the GIIP (2P) at 257 Bscf. Out of this, 164 Bscf was in the Lower zone.

In 1986 under HHSP, reserve of this field was re-estimated. According to this estimate GIIP of the field was 164.2 Bscf and condensate reserve was 0.033 MMbbl. The Middle Sand is the main reservoir with 112.1 Bscf gas followed by the Lower Sand with 37.6 Bscf gas. The GIIP of Upper Sand is only 14.5 Bscf. No recoverable reserve was indicated in the report.

In the same year, GGAG did another study where the GIIP of Semutang was estimated at 109 Bscf under most likely case.

Gasunie (1989) considered a recoverable reserve of 150 Bscf under high scenario. According to Welldrill (1991) GIIP of the field was 164 Bscf of which 112 Bscf could be recoverable reserve. Gasunie (1992) considered the reserve figure of 164 Bscf for their study.

A new estimate was made by Shell in 2001 and they followed probabilistic method. According to SBED at 50% probability recoverable reserve of the shallow zones is 40 Bscf, of which 33 Bscf is in the shallowest zone above 900m. Additional 110 Bscf recoverable reserves estimated for two deeper horizons at 2,300 and 2,600m. Another 313 Bscf of undiscovered reserve

(Unrisked) is estimated in several faulted blocks within a depth range of 2,300-2,630m. According to SBED the possibility of success in finding this volume is 20%. This has resulted in expected undiscovered recoverable reserve of only 22 Bscf.

After reviewing Shell data it was decided to use their estimated reserve figures for the HCU/NPD 2003 (2004) report. According to SBED estimate, recoverable reserve of the field is 150 Bscf. The largest reserve, 65 Bscf, is in Sm5-2300 Sand. Sm5-2630 Sand follows this, where the reserve is 45 Bscf. Petrobangla estimated the reserves of two shallow sands at 40 Bscf. SBED used 50% recovery factor for Sm5-950 and Sm5-1270 and 75 % for Sm-2300 and Sm-2630 sand horizons. The filed GIIP is 226.7 Bscf only.

RPS Energy released its estimate of GIIP for Semutang field in August 2009. Its study was based on 3-D geologic modeling using Petrel software and reservoir simulation using Eclipse software. The results of this study are presented in Table 6-93. According to this estimate, a substantial recoverable gas reserve is present at Samutang using reasonable Recovery Factors.

**Table 6-93 RPS Energy 2009 Reserve Estimate – Samutang Gas Field**

| Reservoir | GIIP (Bcf) | | Difference |
|---|---|---|---|
| | ECLIPSE™ | Petrel™ | (%) |
| Upper Sand | 121 | 118 | 2.5 |
| Middle Sand | 65.8 | 62.0 | 5.8 |
| Lower Sand 1 | 278 | 283 | -1.8 |
| Lower Sand 2 | 189 | 191 | -1.1 |
| Total | 564 | 654 | 0 |

RPS Energy 2009k

6.5.3.6 2010 Reserve Re-Estimation (This Report)

For this report, the RPS study and previous estimates were reviewed, and the RPS estimate was judged to be reliable.

## 7. SUMMARY OF GAS RESERVES AND PRODUCTION

The GIIP, EUR, cumulative production, and reserve estimates are presented in various ways in the following tables and figures.

**Table 7-1 Summary of Bangladesh Gas Reserves – 2010**

(Figures in Bscf)

| Sl no. | Field | Operator | GIIP Proved + Probable | Expected Ultimate Recovery | Recovery Factor % | Cumulative Production, 12/09 | Remaining Reserves, 12/09 | Possible Reserves |
|---|---|---|---|---|---|---|---|---|
| **A. Developed Reserve** | | | | | | | | |
| **a. Producing** | | | | | | | | |
| 1 | Bakhrabad | BGFCL | 1,825 | 1,387 | 76.0% | 698 | 689 | 65 |
| 2 | Bangora | Tullow | 730 | 621 | 85.1% | 99 | 522 | 207 |
| 3 | Beani Bazar | SGFL | 225 | 137 | 60.9% | 60 | 77 | 32 |
| 4 | Bibiyana | Chevron | 5,321 | 4,532 | 85.2% | 476 | 4,056 | 457 |
| 5 | Fenchuganj | BAPEX | 483 | 329 | 68.1% | 72 | 258 | 146 |
| 6 | Habiganj | BGFCL | 3,981 | 2,787 | 70.0% | 1,671 | 1,116 | 434 |
| 7 | Jalalabad | Chevron | 1,346 | 1,128 | 83.8% | 545 | 583 | 122 |
| 8 | Kailas Tila | SGFL | 3,463 | 2,880 | 83.2% | 480 | 2,400 | 346 |
| 9 | Moulavi Bazar | Chevron | 630 | 494 | 78.3% | 152 | 342 | 108 |
| 10 | Narshingdi | BGFCL | 405 | 345 | 85.1% | 106 | 239 | 27 |
| 11 | Rashidpur | SGFL | 3,887 | 3,134 | 80.6% | 457 | 2,677 | 856 |
| 12 | Salda Nadi | BAPEX | 393 | 275 | 70.0% | 60 | 215 | 128 |
| 13 | Sangu | Cairn | 976 | 771 | 78.9% | 466 | 304 | 93 |
| 14 | Shahbazpur | BAPEX | 415 | 261 | 63.0% | 1 | 260 | 54 |
| 15 | Sylhet | SGFL | 580 | 408 | 70.4% | 189 | 219 | 103 |
| 16 | Titas | BGFCL | 9,039 | 7,582 | 83.9% | 3,068 | 4,514 | 754 |
| **b. Production Suspended** | | | | | | | | |
| 17 | Chattak (West) | SGFL | 677 | 474 | 70.0% | 26 | 448 | 253 |
| 18 | Feni | BAPEX-NIKO | 185 | 130 | 70.0% | 63 | 67 | 72 |
| 19 | Kamta | BGFCL | 72 | 50 | 70.1% | 21 | 29 | - |
| 20 | Meghna | BGFCL | 122 | 101 | 82.8% | 36 | 65 | 0 |
| Total Developed Reserve: | | | 34,757 | 27,826 | 80.1% | 8,746 | 19,080 | 4,258 |
| **B. Undeveloped Reserve** | | | | | | | | |
| 21 | Begumganj | BAPEX | 47 | 33 | 70.0% | 0 | 33 | 76 |
| 22 | Kutubdia | BAPEX | 65 | 46 | 70.0% | 0 | 46 | - |
| 23 | Semutang | BAPEX | 654 | 318 | 48.6% | 0 | 318 | 51 |
| Total Undeveloped Reserve: | | | 766 | 396 | 51.8% | 0 | 396 | 127 |
| **Total Reserves in BCF:** | | | **35,522** | **28,222** | 79.4% | **8,746** | **19,476** | **4,385** |
| **Total Reserve in Tcf:** | | | 35.5 | 28.2 | 79.4% | 8.7 | 19.5 | 4.4 |

*Best reconciled estimates. Note that the total reserves may not equal the total of the numbers shown above due to rounding.*

## Table 7-2 Summary of Bangladesh Gas Reserves (Probabilistic Volumetric Estimates), by Category

| Figures in bcf | | GIIP | | | | | Recoverable | | | | | Recovery |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Field | Proved | Probable | | Possible | | | | | | | |
| | | P 1 | P2 | P1 + P2 | P3 | P1+P2+P3 | P1 | P2 | P1 + P2 | P3 | P1+P2+P3 | Factor |
| 1 | Bakhrabad | 1,623 | 202 | 1,825 | 231 | 2,055 | 1,201 | 186 | 1,387 | 207 | 1,594 | 76.0% |
| 2 | Bangora | 690 | 40 | 730 | 42 | 772 | 558 | 64 | 621 | 65 | 686 | 85.1% |
| 3 | Beani Bazar | 193 | 31 | 225 | 33 | 258 | 108 | 29 | 137 | 32 | 169 | 60.9% |
| 4 | Bibiyana | 5,036 | 285 | 5,321 | 286 | 5,608 | 4,075 | 456 | 4,532 | 457 | 4,988 | 85.2% |
| 5 | Fenchuganj | 292 | 191 | 483 | 194 | 677 | 195 | 135 | 329 | 146 | 476 | 68.1% |
| 6 | Habiganj | 3,451 | 530 | 3,981 | 600 | 4,581 | 2,413 | 374 | 2,787 | 434 | 3,221 | 70.0% |
| 7 | Jalalabad | 1,275 | 71 | 1,346 | 71 | 1,417 | 1,013 | 115 | 1,128 | 122 | 1,250 | 83.8% |
| 8 | Kailash Tila | 3,180 | 283 | 3,463 | 305 | 3,768 | 2,553 | 327 | 2,880 | 346 | 3,226 | 83.2% |
| 9 | Moulavi Bazar | 534 | 96 | 630 | 117 | 747 | 402 | 92 | 494 | 108 | 602 | 78.3% |
| 10 | Narshingdi | 387 | 18 | 405 | 18 | 423 | 317 | 28 | 345 | 27 | 371 | 85.1% |
| 11 | Rashidpur | 3,041 | 846 | 3,887 | 949 | 4,837 | 2,415 | 719 | 3,134 | 856 | 3,990 | 80.6% |
| 12 | Salda Nadi | 223 | 170 | 393 | 166 | 559 | 156 | 120 | 275 | 128 | 403 | 70.0% |
| 13 | Sangu | 888 | 88 | 976 | 90 | 1,066 | 677 | 93 | 771 | 93 | 864 | 78.9% |
| 14 | Shahbazpur | 354 | 61 | 415 | 64 | 479 | 214 | 47 | 261 | 54 | 316 | 63.0% |
| 15 | Sylhet | 469 | 111 | 580 | 119 | 700 | 323 | 86 | 408 | 103 | 512 | 70.4% |
| 16 | Titas | 8,619 | 420 | 9,039 | 424 | 9,463 | 6,838 | 744 | 7,582 | 754 | 8,336 | 83.9% |
| 17 | Chhatak (West | 379 | 298 | 677 | 362 | 1,039 | 265 | 209 | 474 | 253 | 727 | 70.0% |
| 18 | Feni | 39 | 146 | 185 | 103 | 288 | 63 | 67 | 130 | 72 | 202 | 70.0% |
| 19 | Kamta | 21 | 51 | 72 | 0 | 72 | 21 | 29 | 50 | 0 | 50 | 70.1% |
| 20 | Meghna | 110 | 12 | 122 | 12 | 134 | 76 | 25 | 101 | 107 | 209 | 82.8% |
| 21 | Begumganj | 14 | 33 | 47 | 107 | 154 | 10 | 23 | 33 | 75 | 108 | 70.0% |
| 22 | Kutubdia | | | 65 | | | 46 | | 46 | | 46 | 70.0% |
| 23 | Semutang | | | 654 | | | 318 | | 318 | | 318 | 48.6% |
| Total in Bcf | | 30,819 | 4,703 | 35,522 | 4,293 | 39,815 | 24,255 | 3,967 | 28,222 | 4,442 | 32,664 | 79.4% |
| Total in Tcf | | 30.8 | 4.7 | 35.5 | 4.3 | 39.8 | 24.3 | 4.0 | 28.2 | 4.4 | 32.7 | |

# Table 7-3 Reserve Estimates by Reservoir, Part 1

Figures in Bcf

| SI no. | Field | Gas Sand | GIIP Proven + Probable | GIIP Total | EUR by Sand | Total EUR | Recovery Factor % | Cumulative Production, 12/09 By Sand | Cumulative Production, 12/09 Total | Reserves, 12/09 By Sand | Reserves, 12/09 Total | Production Status |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Bakhrabad | B | 158.1 | 1,824.9 | 110.2 | 1,387.2 | 69.7% | 42.2 | 698.1 | 68.0 | 689.1 | Suspended |
| | | D Upper | 212.8 | | 153.4 | | 72.1% | 42.4 | | 111.0 | | Suspended |
| | | D Lower | 180.0 | | 135.4 | | 75.2% | 87.9 | | 47.5 | | Suspended |
| | | G | 288.0 | | 240.0 | | 83.3% | 153.7 | | 86.3 | | Producing |
| | | J | 563.0 | | 460.0 | | 81.7% | 371.9 | | 88.1 | | Producing |
| | | C | 34.9 | | 24.4 | | 69.9% | 0.0 | | 24.4 | | Non-producing |
| | | F | 47.5 | | 35.3 | | 74.2% | 0.0 | | 35.3 | | Non-producing |
| | | K | 195.7 | | 130.3 | | 66.6% | 0.0 | | 130.3 | | Non-producing |
| | | L | 144.8 | | 98.3 | | 67.9% | 0.0 | | 98.3 | | Non-producing |
| 2 | Bangora | A | 24.7 | 730.2 | 19.4 | 621.4 | 78.3% | 0.0 | 99.4 | 19.4 | 522.0 | Non-producing |
| | | B | 18.3 | | 14.8 | | 80.7% | 0.0 | | 14.8 | | Non-producing |
| | | C | 24.9 | | 19.1 | | 76.7% | 0.0 | | 19.1 | | Non-producing |
| | | D | 655.0 | | 562.0 | | 85.8% | 97.9 | | 464.1 | | Producing |
| | | E | 7.2 | | 6.1 | | 84.7% | 1.5 | | 4.6 | | Producing |
| 3 | Beani Bazar | Upper | 172.8 | 224.5 | 105.4 | 136.6 | 61.0% | 28.6 | 59.8 | 76.8 | 76.8 | Producing |
| | | Lower | 51.7 | | 31.2 | | 60.4% | 31.2 | | 0.0 | | Producing |
| 4 | Bibiyana | BB 60ab | 3,364.6 | 5,321.4 | 2,927.9 | 4,531.7 | 87.0% | 173.2 | 475.7 | 3,272.8 | 4,056.0 | Producing |
| | | BB 65 | 595.4 | | 518.1 | | 87.0% | | | | | Producing |
| | | BB 70 | 412.0 | | 369.0 | | 89.6% | 94.3 | | 274.7 | | Producing |
| | | BH 10 | 182.9 | | 123.9 | | 67.7% | 170.5 | | 198.5 | | Producing |
| | | BH20ab | 205.1 | | 138.9 | | 67.7% | | | | | Producing |
| | | BH 20c | 109.3 | | 74.0 | | 67.7% | | | | | Producing |
| | | BH 20d | 47.6 | | 32.2 | | 67.7% | | | | | Producing |
| | | BH25 | 193.0 | | 169.0 | | 87.6% | 37.7 | | 131.3 | | Producing |
| | | BH 50a | 75.9 | | 64.1 | | 84.4% | 0.0 | | 64.1 | | Non-producing |
| | | BH 50b | 98.0 | | 82.1 | | 83.8% | 0.0 | | 82.1 | | Non-producing |
| | | BH 60 | 37.5 | | 32.5 | | 86.7% | 0.0 | | 32.5 | | Non-producing |
| 5 | Fenchuganj | Upper | 283.7 | 483.3 | 189.6 | 329.3 | 66.8% | 66.9 | 71.6 | 122.7 | 257.7 | Producing |
| | | Middle | 75.7 | | 50.3 | | 66.4% | 0.0 | | 50.3 | | Non-producing |
| | | Lower | 61.8 | | 39.8 | | 64.3% | 4.7 | | 35.1 | | Producing |
| | | New Gas Sand | 62.0 | | 49.6 | | 80.0% | 0.0 | | 49.6 | | Non-producing |
| 6 | Habiganj | Upper | 3,756.3 | 3,981.1 | 2,629.7 | 2,786.8 | 70.0% | 1,667.9 | 1,670.9 | 961.8 | 1,115.9 | Producing |
| | | Lower | 224.8 | | 157.1 | | 69.9% | 3.0 | | 154.1 | | Non-producing |
| 7 | Jalalabad | BB20 | 46.1 | 1,346.1 | 33.8 | 1,127.8 | 73.3% | 0.0 | 544.7 | 33.8 | 583.1 | Non-producing |
| | | BB50 | 371.1 | | 312.3 | | 84.2% | 101.7 | | 210.6 | | Producing |
| | | BB60 | 868.7 | | 731.1 | | 84.2% | 409.8 | | 321.3 | | Producing |
| | | BB70 | 60.1 | | 50.6 | | 84.2% | 33.2 | | 17.4 | | Producing |
| 8 | Kailash Tila | UGS | 1,659.6 | 3,462.8 | 1,361.2 | 2,880.2 | 82.0% | 188.2 | 480.0 | 1,173.0 | 2,400.2 | Producing |
| | | MGS | 605.6 | | 509.4 | | 84.1% | 192.1 | | 317.3 | | Producing |
| | | LGS | 1,046.0 | | 883.0 | | 84.4% | 93.4 | | 789.6 | | Producing |
| | | A Sand | 46.2 | | 38.6 | | 83.6% | 0.0 | | 38.6 | | Non-producing |
| | | HRZ Sand | 105.5 | | 88.1 | | 83.5% | 6.3 | | 81.8 | | Producing |
| 9 | Moulavi Bazar | BB20 | 35.2 | 630.2 | 19.7 | 493.6 | 56.0% | 1.8 | 152.0 | 17.9 | 341.6 | Producing |
| | | BB50 | 59.0 | | 41.6 | | 70.5% | 0.0 | | 41.6 | | Non-producing |
| | | BB60 | 203.4 | | 163.0 | | 80.1% | 0.1 | | 162.9 | | Non-producing |
| | | BB70 | 253.2 | | 206.2 | | 81.4% | 117.5 | | 88.7 | | Producing |
| | | BB80 | 79.3 | | 63.1 | | 79.6% | 32.6 | | 30.5 | | Producing |
| 10 | Narshingdi | UGS | 91.2 | 405.2 | 57.7 | 344.7 | 63.3% | 0.0 | 106.2 | 57.7 | 238.5 | Non-producing |
| | | LGS | 314.0 | | 287.0 | | 91.4% | 106.2 | | 180.8 | | Producing |

Best reconciled estimates.

# Table 7-4 Reserve Estimates by Reservoir, Part 2

Figures in Bcf

| Sl no. | Field | Gas Sand | GIIP: Proved + Probable | GIIP: Total | EUR by Sand | Total EUR | Recovery Factor % | Cumulative Production, 12/09: By Sand | Cumulative Production, 12/09: Total | Reserves, 12/09: By Sand | Reserves, 12/09: Total | Production Status |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | | UGS | 561.5 | | 396.4 | | 70.6% | 107.2 | | 289.2 | | Producing |
| | Rashidpur | MGS | 2,185.1 | 3,887.2 | 1,767.1 | 3,134.0 | 80.9% | 0.0 | 456.6 | 1,767.1 | 2,677.4 | Non-producing |
| | | LGS | 1,140.7 | | 970.5 | | 85.1% | 349.4* | | 621.1 | | Producing |
| 12 | | Upper | 302.7 | | 203.8 | | 67.3% | 5.7 | | 198.1 | | Producing |
| | Salda Nadi | Middle | 22.1 | 393.1 | 25.2 | 275.3 | 113.8% | 25.2 | 60.2 | 0.0 | 215.1 | Producing |
| | | Lower | 68.3 | | 46.3 | | 67.8% | 29.3 | | 17.0 | | Producing |
| 13 | Sangu | 10 Gas Sands | 976.0 | 976.0 | 770.5 | 770.5 | 78.9% | 466.1 | 466.1 | 304.4 | 304.4 | Producing |
| 14 | | I Sand | 16.3 | | 10.5 | | 64.0% | 0.0 | | 10.5 | | Non-producing |
| | | II Sand | 57.0 | | 36.8 | | 64.5% | 0.0 | | 36.8 | | Non-producing |
| | Shahbazpur | III Sand | 241.2 | 414.8 | 147.8 | 261.2 | 61.3% | 0.0 | 1.3 | 147.8 | 259.9 | Non-producing |
| | | IV Sand | 41.5 | | 26.7 | | 64.3% | 0.0 | | 26.7 | | Non-producing |
| | | V Sand | 58.8 | | 39.5 | | 67.1% | 1.3 | | 38.2 | | Producing |
| 15 | | Tipam | 40.0 | | 28.2 | | 70.5% | 0.0 | | 28.2 | | Non-producing |
| | | Upper Bhuban | 13.2 | | 1.5 | | 11.7% | 0.0 | | 1.5 | | Non-producing |
| | Sylhet | Upper Bokabil | 325.2 | 580.1 | 230.3 | 408.3 | 70.8% | 119.0 | 189 | 111.3 | 219 | Producing |
| | | Mid Bokabil | 78.5 | | 63.2 | | 80.5% | 63.2 | | 0.0 | | Producing |
| | | Lower Bokabil | 123.2 | | 85.0 | | 69.0% | 7.1 | | 77.9 | | Non-producing |
| 16 | Titas | A Group | 8,054.0 | 9,039.3 | 6,831.7 | 7,582.2 | 84.8% | 2,502.0 | 3,068.0 | 4,329.7 | 4,514.2 | Producing |
| | | B and C Group | 985.3 | | 750.5 | | 76.2% | 566.0 | | 184.5 | | Producing |
| 17 | | Sand 1 and 2 | 272.9 | | 191.0 | | 70.0% | | | | | Non-producing |
| | Chattak (West) | Sand 3 and 4 | 201.4 | 677.2 | 141.0 | 474.0 | 70.0% | 25.8 | 25.8 | 448.2 | 448.2 | Suspended |
| | | Sand 5 and 6 | 168.6 | | 118.0 | | 70.0% | | | | | Suspended |
| | | Sand 7 and 8 | 34.3 | | 24.0 | | 70.0% | | | | | Non-producing |
| 18 | Feni | UGS | 52.6 | 185.2 | 36.8 | 129.6 | 70.0% | 6.1 | 62.8 | 30.7 | 66.8 | Suspended |
| | | LGS | 132.6 | | 92.8 | | 70.0% | 56.7** | | 36.1 | | Suspended |
| 19 | Kamta | 1 Gas Sand | 71.8 | 71.8 | 50.3 | 50.3 | 70.1% | 21.1 | 21.1 | 29.2 | 29.2 | Suspended |
| 20 | | C | 51.8 | | 49.1 | | 94.8% | 36.2 | | 12.9 | | Suspended |
| | | A | 5.8 | | 0.0 | | 0.0% | 0.0 | | 0.0 | | Non-producing |
| | Meghna | B | 1.5 | 122.2 | 0.0 | 101.2 | 0.0% | 0.0 | 36.2 | 0.0 | 65.0 | Non-producing |
| | | D | 25.5 | | 20.8 | | 81.6% | 0.0 | | 20.8 | | Non-producing |
| | | E | 15.5 | | 13.2 | | 85.2% | 0.0 | | 13.2 | | Non-producing |
| | | F | 22.1 | | 18.1 | | 81.9% | 0.0 | | 18.1 | | Non-producing |
| 21 | Begumganj | Zone-7 | 46.7 | 46.7 | 32.7 | 32.7 | 70.0% | 0.0 | | 32.7 | 32.7 | Non-producing |
| 22 | Kutubdia | 1 Gas Sand | 65.0 | 65.0 | 45.5 | 45.5 | 70.0% | 0.0 | | 45.5 | 45.5 | Non-producing |
| 23 | | Upper Sand | 121.0 | | 48.0 | | 39.7% | | | 48.0 | | |
| | Semutang | Middle Sand | 65.8 | 653.8 | 37.0 | 318.0 | 56.2% | 0.0 | 0.0 | 37.0 | 318.0 | Non-producing |
| | | Lower Sand 1 | 278.0 | | 207.0 | | 74.5% | | | 207.0 | | |
| | | Lower Sand 2 | 189.0 | | 26.0 | | 13.8% | | | 26.0 | | |
| | Total in Bcf | | 35,522.1 | 35,522.1 | 28,222.1 | 28,222.1 | 79.4% | 8,745.8 | 8,745.8 | 19,476.3 | 19,476.3 | |
| | Total in Tcf | | 35.5 | 35.5 | 28.2 | 28.2 | 79.4% | 8.7 | 8.7 | 19.5 | 19.5 | |

* includes BTA and BHA sand cums

** includes cum. from K, M, & R Sands

*Best reconciled estimates. Note that the total reserves may not equal the total of the numbers shown above due to rounding.*

**Table 7-5 Comparison of GIIP with Earlier Estimates**

| Field | GIIP, Bscf | | | | Maps Used for Areas | Vintage |
|---|---|---|---|---|---|---|
| | HCU/NPD 2003 2P | 2010 RPS Petrobangla | | 2010 GA Reconciled* | | |
| | | Volumetric | Sim/Mat Bal | | | |
| Bakhrabad | 1,499 | 1,418 | 1,700 | 1,825 | RPS Study | 2010 |
| Bangora | 637** | | | 730 | **Tullow estimate | 2005 |
| Beani Bazar | 243 | 231 | 231 | 225 | RPS Study | 2010 |
| Bibiyana | 3,145 | | | 5,321 | D&M (Ryder Scott 2P GIIP 5.9 TCF) | 2000 |
| Fenchuganj | 404 | 447 | 450 | 483 | Petrobangla Report | 1988 |
| Habiganj | 5,139 | 3,103 | 3,684 | 3,981 | RPS Study | 2010 |
| Jalalabad | 1,195 | | | 1,346 | Degolyer & McNaughton (1490 Bscf) | 1999 |
| Kailash Tila | 2,720 | 3,540 | 3,610 | 3,463 | RPS Study | 2010 |
| Moulavi Bazar | 449 | | | 630 | Unocal Report | 2003 |
| Narshingdi | 307 | 365 | 369 | 405 | RPS Study | 2010 |
| Rashidpur | 2,002 | 4,191 | 3,650 | 3,887 | RPS Study | 2010 |
| Salda Nadi | 166 | 384 | 380 | 393 | RPS Study | 2010 |
| Sangu | 1,031 | | | 976 | Shell (Cairn 814 Bscf, 2010) | 2000 |
| Shahbazpur | 665 | 394 | 393 | 415 | BAPEX report | 1996 |
| Sylhet | 684 | 528 | 370 | 580 | RPS Study | 2010 |
| Titas | 7,325 | 7,169 | 8,148 | 9,039 | RPS Study | 2010 |
| Chhatak (West) | 677 | | | 677 | previous studies audited and accepted | |
| Feni | 185 | | | 185 | previous studies audited and accepted | |
| Kamta | 72 | | | 72 | previous studies audited and accepted | |
| Begumganj | 47 | | | 47 | previous studies audited and accepted | |
| Meghna | 171 | 185 | 185 | 122 | previous studies audited and accepted | |
| Kutubdia | 65 | | | 65 | previous studies audited and accepted | |
| Semutang | 227 | 654 | 654 | 654 | previous studies audited and accepted | |
| **Total** | **28,418** | | | **35,522** | | |

*Note that the total reserves may not equal the total of the numbers shown above due to rounding.*

* These represent Gustavson's best estimate, and may be a combination of material balance and volumetric calculations

** Bangora Field was not included in the 2003 report. The numbers shown here are Tullow's estimates from 2005.

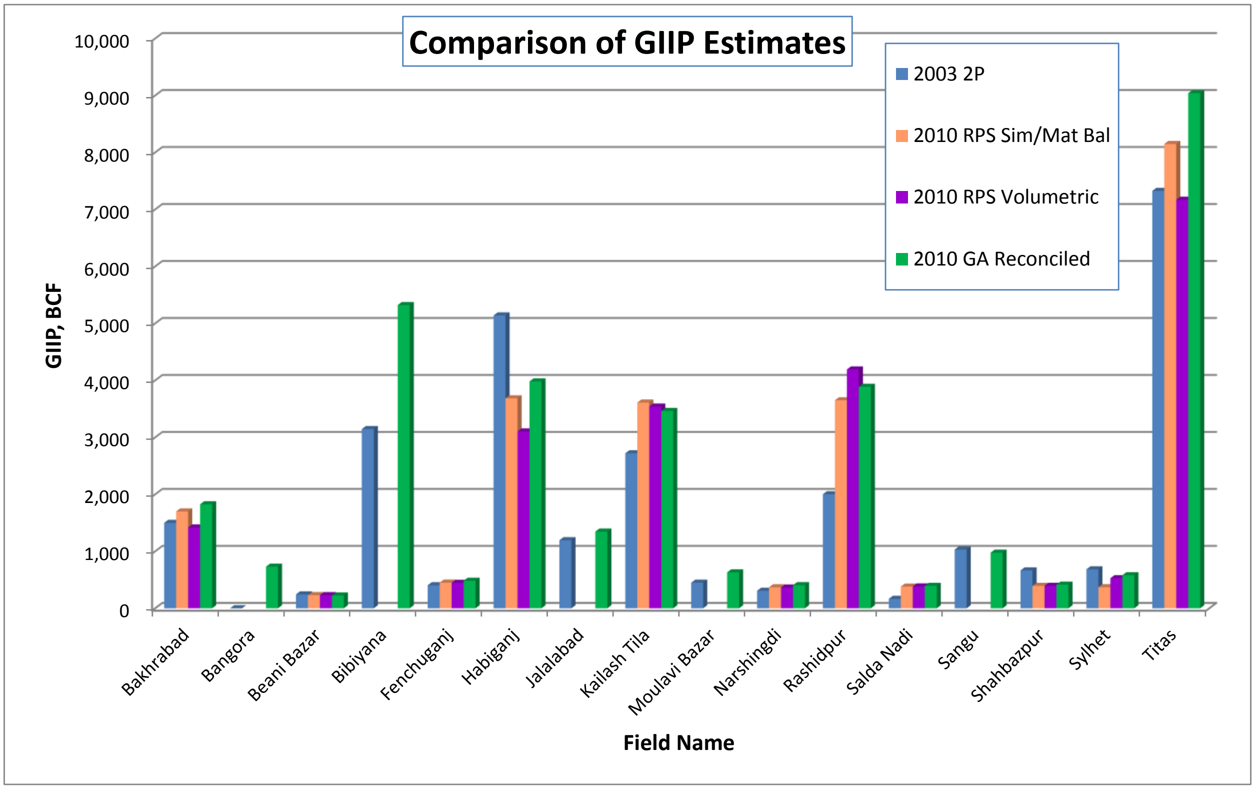



**Figure 7-1 Comparison of EUR Estimates**

# 8. ENHANCEMENT OF PRODUCTION AND RESERVE GROWTH

## 8.1 PRODUCTION ENHANCEMENT THROUGH IMPROVED RESERVOIR GROWTH

Companies are always seeking opportunities to enhance rates and reserves in a given reservoir. These efforts typically employ various techniques and involve an integrated reservoir management effort through the use of geological, geophysical, production, facilities, and reservoir engineering methods.

Opportunities for improved reservoir growth in Bangladesh include the use of thin bed logging tools to identify thin reservoirs that have reserve potential and the use of 3D seismic to map the fields in greater detail. Additionally, incremental reserves and higher production rates may be achieved by installing compression in order to reduce producing wellhead pressure. Production rates, and to some extent perhaps reserves, may be obtained by increasing the size of the production tubing string in certain wells, or by other well or field equipment optimization. These methods are discussed in more detail in the subsequent sections of this chapter.

## 8.2 PRODUCTION ENHANCEMENT THROUGH FACILITIES ENHANCEMENTS

### 8.2.1 Downhole Completion Equipment

IOCs operate seven wells at Bibiyana, one well at Moulavi Bazar and one well at Bangora that are producing, or have recently produced, at rates of 50 to 100 MMscfd per well. Compared to the IOC's, the wells of the National companies' are producing at much lower rates, even though the reservoir quality of Titas A2 & A3 sands and Habiganj Upper Gas Sands are much superior to Bibiyana, Moulavi Bazar, and Bangora in terms of important reservoir parameters like porosity, permeability, and net pay thickness. A combination of perforation design (interval, shots/foot, and penetration), restrictions in downhole completion equipment, and restrictions on surface facilities, are possibly the main reasons for lower production rates from the National companies' wells.

Also, all wells but one in Titas gas field were completed with 4 ½” production tubing. Titas well #11 was completed with 3 ½” production tubing, where the difference between the flowing bottom hole and wellhead pressure is much higher. The diameter of the production tubing at Bibiyana gas field is 5”. By larger diameter of the tubing and minimizing other restrictions in the completion equipment, the wells of the field are producing at much higher rates than wells in the National Companies’ operated fields. Nodal analysis shows that Titas 11 could increase production at the same wellhead pressure by tens of millions of cubic feet per day by changing out the tubing string from 3 ½ to 4 ½ ” (Figure 8-1). On this figure, the horizontal axis shows flow rate, while the vertical axis shows flowing bottomhole pressure. The red line represents reservoir performance at currently estimated reservoir pressure, while the red and green lines represent the performance of 3 ½ to 4 ½”, respectively, at the current wellhead flowing pressure. The points of intersection represent estimated performance of the well with the various tubing sizes. The intersection of the blue and red lines represents current production of about 23 MMCFD. The intersection of the green line with the blue line represents potential performance of the well with current reservoir pressure and surface flowing pressure, at about 75 MMCFD. This analysis is considered to be an approximation, since water and condensate production were ignored. Nevertheless, it is apparent that large rate increases could result from changing out tubing strings for larger sizes.

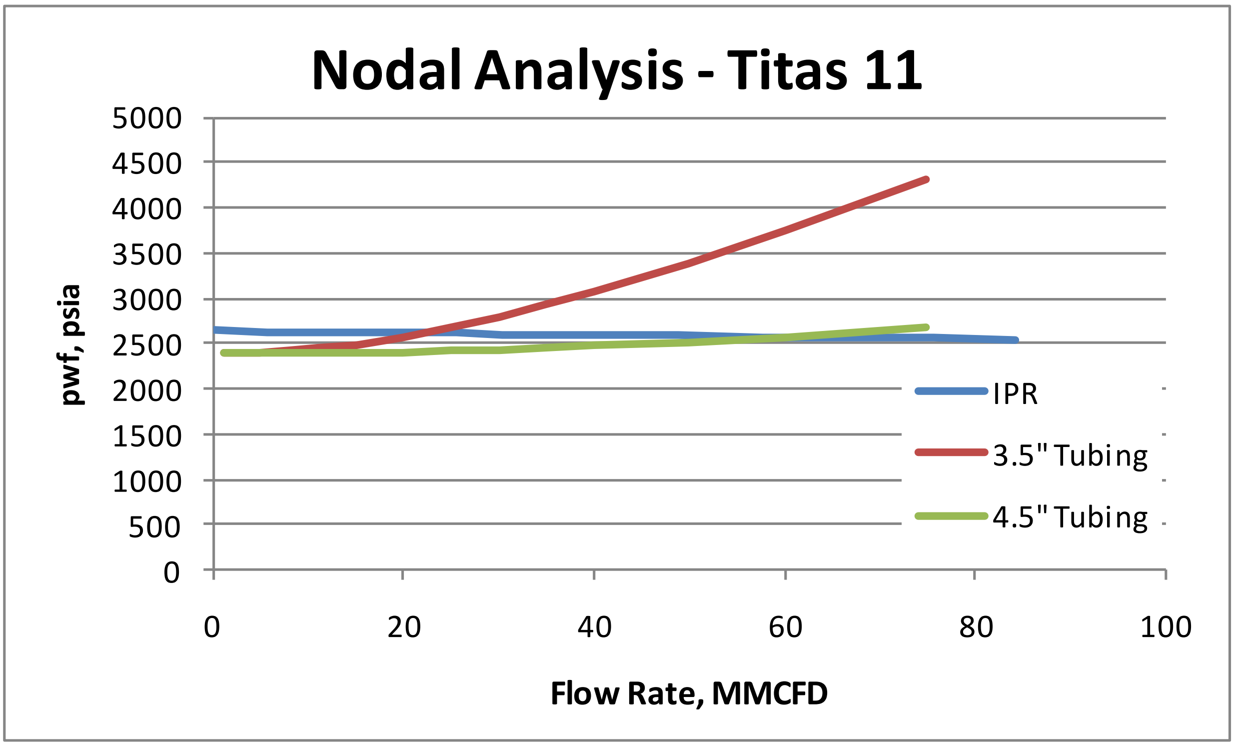



**Figure 8-1 Nodal Analysis – Titas Well #11**

The downside of increased tubing sizes is that the critical flow rate at which the well is able to lift a certain water/gas ratio is larger, meaning that if liquid production is a problem, the well may load up and die sooner. This could require returning to a smaller tubing string later in a well's life. Careful technical and economic analysis must be conducted for each well before undertaking such a program.

#### 8.2.2 Perforation

Most of the National Companies' wells were perforated with 4-6 shots/foot unidirectional holes (few wells used spiral guns) while completing the wells. In contrast, the IOC's in Bangladesh use spiral denser shot/foot and higher penetration shots in their wells. As a result, their wells are producing more gas from their wells having relatively inferior reservoir. National Companies should consider using higher density per foot and deeper penetration perforation shots at the time of completion of future wells to enhance gas production from these wells.

#### 8.2.3 Surface Facilities

It is observed that in some of gas fields, pressure losses between the well heads and the processing plant's inlet pressure are very high. This results in lower production from those wells compared to their ability to produce with a lower wellhead pressure. As an example, pressure difference between well head and process pressure inlet in wells # 3, #4, and #7 of Rashidpur gas field are about 117, 294 and 235 psi at distance of 1.5, 6, and 8 kilometers, respectively. Similarly, Habiganj wells #3, #4, #5, #6, #10, #11, and #7 had losses of 210, 180, 140 and 160 psi pressure, respectively between the flowing wellheads and the processing plant inlet over a distance of about 3 to 9 kilometers. It should be noted that wells #3 and #4 flow through a common line to process plant as do wells #5 and #6 and wells #10 and #11, so the pressure losses listed for each of the pairs of wells are combined into one reading for each pair, resulting in four listed pressure losses for the seven wells. If these pressure losses can be reduced, production from the field may be substantially increased. National Companies should make an inventory of those sorts of large pressure losses and evaluate the costs and benefits of optimizing the gathering facilities.

### 8.2.4 Compression

The previously estimated reserves of gas in Bangladesh gas fields were based on an average wellhead abandonment pressure of 1100 psi (NPD-HCU 2003). The wellhead abandonment pressure is determined from the transmission system delivery line pressure, allowing for pressure losses through the gas treatment plant and flow lines. By installing a compressor between wells and pipelines, the abandonment wellhead pressure can be reduced to 500 and even 200 psi, which also increases recovery efficiency significantly. For the reserves estimates in this report, wellhead flowing pressure of 250, 500, and 700 psi were considered for the minimum, most likely, and maximum values of the input distribution. Thus, in order to achieve the 2P and 3P reserves estimated in this report, compression would need to be added to most of the fields.

Compressors are being used in two Bangladesh gas fields, namely Bakhrabad and Sangu, and the wells are producing gas much below the previously accepted wellhead abandonment pressure of 1100 psi. A comparison of field studies conducted by Intercom-Kanata Management Ltd (1992) shows field reserves growth of at least 20-30% by reducing the average wellhead abandonment pressure from 1100 psi to 600 psi for five of the largest gas fields in Bangladesh.

## 8.3 PRODUCTION ENHANCEMENT THROUGH WORKOVERS

### 8.3.1 Work over of Suspended Wells

Under Petrobangla companies there are about 11 wells where production has been suspended due to depletion of gas from completed zone (s) or due to mechanical problem (s) or non availability of adequate water handling facilities, the wells can be brought to production at minimum risk, cost and time. Name of the Operator, field, well number and expected production are given below in Table 8-1.

**Table 8-1 Workover Candidates**

| Company | Work over (Field and Wells) | Production Enhancement (MMscfd) | Remarks |
|---|---|---|---|
| BGFCL | Bakhrabad # 2 & #5 | 20 – 35 | Gas has been depleted from the existing completed zone. Needs to recomplete to other zone(s) other than ‘J’ & ‘G’ sands to resume production. |
| BGFCL | Titas #12* | 20 – 35 | Mechanical problem. |
| SGFL | Sylhet #7* | 15 – 25 | Mechanical problem. |
| SGFL | Surma#1A (Sylhet #8) | 10 – 15 | Require adequate water handling facilities. |
| BGFCL | Meghna # 1 | 10 – 25 | Re-complete to other zone (s). |
| BAPEX | Semutang #1 & #5*<br>Begumganj #1 | 20 – 30<br>10- 15 | Work over, processing facilities and transmission would be required. |
| BGFCL | Habiganj # 11* | 30 – 45 | Redesign down hole equipment and perforation. |
| SGFL | Kailash Tila #5 | 10 – 25 | Recompletion to other zone. |
| SGFL | Rashidpur #5 | 10 – 15 | Recompletion to other zone or cement spotting across the water-bearing part of the perforation. |
| Total | | 155-260 | |

*Planned by BAPEX

To accomplish the above work in timely and cost efficient manner, these should be brought under a single project, or perhaps under a maximum of two projects. Work schedule will depend on the priority and convenience of the companies (Table 8-2).

**Table 8-2 Other Planned Workovers**

| Company | Work over (Field and Wells) | Production Enhancement (MMscfd) | Remarks |
|---|---|---|---|
| BGFCL | Titas #4 | - | Repair tubing leak – was in progress in Mar-10 |
| BGFCL | Meghna #1 | 15 | Mechanical problem and recompletion in upper zone. |
| TOTAL | | 15 | |

## 8.4 PRODUCTION ENHANCEMENT – RESERVOIR MANAGEMENT AND PRESSURE DATA

Reservoir management is the philosophy or process that incorporates all technologies in order to economically produce the maximum amount of hydrocarbons from any field area. In addition to using the latest technologies to identify and quantify the reserves and resource potential, reservoir management focuses on the completion and production technology to maximize recovery, as well as any ongoing operational considerations, such as maximum efficient rates or the benefits of increasing the number of wells or completions in the field. This is normally achieved by a combination of reservoir and production engineering, and frequently for reservoirs of the size and importance of these in Bangladesh, by reservoir simulation. Meaningful reservoir simulation requires accurate reservoir data, including both static reservoir description data, such as net pay thickness, porosity, saturation, and permeability data derived from logs, cores, and pressure transient analysis; and dynamic reservoir data including quantities of gas, oil/condensate, and water production for each producing zone/well and periodic measurements of reservoir flowing bottom hole (FBHP) and shut-in bottom hole (SIBHP) pressures. The static reservoir description is validated by running the model and adjusting these properties until calculated model performance matches actual production and pressure history data, a process called history matching.

Most of the gas fields of Bangladesh, especially the fields owned by the National Companies, are only partially appraised due to the relatively light drilling density. Routine pressure test data, production logs, and water/condensate data from the individual wells/zones are not available. Proper reservoir study is greatly complicated by this lack of data. Though most of the previous workers strongly recommended collecting such data, very little has been compiled. However, if proper reservoir management over the life of the fields in Bangladesh is carried out, another 10 to 20% of the initial Proved and Probable reserves base of the country could potentially be added.

## 8.5 RESERVE GROWTH THROUGH USE OF 3-D SEISMIC

Three-dimensional (3-D) seismic surveys have had an industry-wide positive impact on exploration success rates, discovery costs and field reserves growth when integrated with geological and engineering data. One case history documented that 42 producing fields fully covered with 3-D seismic demonstrated double reserve growth on average (Alyor, 1999). Another case study documented the impact of 3-D seismic on the overall success rate of exploration from 1990 through 1995. Success rate was 13% for wells drilled without 3-D seismic and 48% for those drilled with 3-D seismic survey evaluation (Alyor, 1998).

As such, for precise/improved delineation of the subsurface structure with a view to exploring the oil and gas resources, 3-D seismic surveys are being commonly conducted in most of the hydrocarbon-rich countries by the international oil companies (IOCs) using state of the art equipment and analysis techniques. Hydrocarbon exploration in Bangladesh is carried out by a number of IOCs on the one hand and by Bangladesh Petroleum Exploration and Production Company Ltd., (BAPEX) on the other hand. In addition to implementing its own exploration and production program, BAPEX also implements the field extension program (seismic and production/appraisal drilling) of the two national production companies Bangladesh Gas Fields Company Ltd., (BGFCL) and Sylhet Gas Fields Ltd., (SGFL). The national companies so far have not conducted any 3-D seismic surveys in the country. However, under a pending Asian Development Bank assistance program, 3-D seismic surveys over Titas and Bakhrabad gas fields (BGFCL) and Sylhet, Kailash Tila, and Rashidpur gas fields (SGFL) are planned during the current fiscal year. BAPEX, on behalf of BGFCL and SGFL, will conduct the 3-D surveys. One fundamental difference between the IOCs and the national exploration company BAPEX is that IOCs get their seismic survey and drilling operations done by reputable international contractors, while BAPEX itself conducts both seismic surveys and drilling operations.

Currently, four IOCs (Chevron, Tullow Bangladesh Ltd., Cairn Energy and Niko Bangladesh Ltd.) are working in Bangladesh. Chevron's predecessor Occidental (Oxy) was originally awarded Blocks 12, 13 and 14 in the north-eastern part of the country. After the discovery of Bibiyana gas field in Block 12, they conducted a 3-D seismic survey over the field in 1998. The 3-D survey helped demarcate the extent of all the pay sands, and thus the field is very well-defined. Bibiyana gas field is now the second largest gas field in terms of reserves and is the largest producer. It produces more than 700 MMscfd of gas that is more than 35% of the total daily gas production from 18 producing fields of the country, from just twelve effectively-placed wells. Additionally, the seismic data has defined additional targets on the flank of the structure.

Tullow conducted a 3-D seismic survey over certain selected areas of their leased Block 9. On the basis of the 2-D survey, they started drilling an exploration well over the Bangora structure. However, by the time the construction of the drilling pad was completed at the present Bangora #4 location, the interpretation results of the 3-D seismic started coming in, and it was realized that the drilling location was not appropriate. Consequently, they moved the rig to Lalmai. After completing the well in Lalmai, Tullow came back to Bangora and drilled the present Bangora #1 close to Srikail structure of BAPEX and it was a gas discovery. The most important information that Tullow gathered from the 3-D survey was that from the crest of the structure towards the west there is a channel elongated in the north-south direction, that eroded the gas-bearing sands thoroughly and that the western part of the Bangora structure has no prospect at all. Moreover, the 3-D seismic survey clearly resolved the spill points of the reservoir that helped them identify the extent of the reservoir and avoid drilling dry wells. All the wells drilled in Bangora, except Bangora #4 that was outside the gas-water contact, were successful.

Niko Bangladesh Ltd., under a Joint Venture Agreement (JVA) signed in 2003 with BAPEX, is working as the operator of the marginal and abandoned declared gas fields Feni and Chhatak. Before implementing any drilling program, Niko conducted a 3-D seismic survey over both of the structures. Feni gas field was originally discovered by Petrobangla in 1980. BGFCL started producing gas from this field in 1991 and produced until February 1998 when production from the field was suspended. The field produced more than 40 Bscf gas during that period. As a result of the 3-D seismic survey conducted by the JV, a number of new and thin sands were identified in the structure. In November 2004, the field re-started production and occasionally the field has produced at rates up to 50 MMscfd. However, since the producing sands were thin, production was not sustained for long. Currently the field is not producing. There are some more sands identified but their production is delayed since the two successive blow-outs in Chhatak gas field, which have temporarily stalled Niko's development program in the country.

Cairn Energy, another IOC operating in different gas blocks of Bangladesh, are conducting 3-D surveys over the two offshore structures Magnama and South Sangu in Block 16.

Two analog 12-fold seismic lines acquired in early 1990, delineated the Srikail structure as a gentle four-way closure. However, since the data quality was not very good, stratigraphic features like channels could not be identified there. BAPEX drilled an exploratory well there in 2004 on the top of the structure. Because noncommercial quantities of gas were found there, the well was abandoned. On the other hand, Bangora #1 well of Tullow is only about 5 km south of Srikail and was a producer. Later BAPEX, due to lack of 3-D seismic surveying capability, conducted a close-grid 60 and 30-fold 2-D seismic survey over Srikail. Interpretation of well results compared with the Bangora 3-D data confirms that the Srikail well was drilled into the channel-fill sands. Consequently, BAPEX is now planning to drill another well in Srikail in order to avoid the poorly productive channel-fill sands and encounter better producing sands down dip of the channel in similar fashion to Bangora.

The outcome of the 3-D seismic surveys conducted by the three IOCs operating in Bangladesh proves the worth of the investment in 3-D surveys. All three companies achieved good results from their 3-D seismic surveys by clearly delineating their gas fields. In brief, 3-D seismic surveys: (a) help delineate the extent of the gas sands of known gas fields clearly, (b) consequently help delineate the dimensions of the reservoir quite precisely and thus minimize the risk of drilling dry wells, (c) help gather precise information about the thickening, thinning, discontinuity, channeling, unconformities, faults and pinch-outs of the sands and their influence over the reserves, (d) help gather detailed information about the stratigraphic compartmentalization due to faults, pinch-outs, etc., (e) consequently help to precisely predict the reserve size, and (f) also help gather information about the lithology of the strata and nature of migration of fluids, the key information to knowing the history of development of the structure. Several of the fields operated by Petrobangla companies could benefit from acquisition of new 3-D seismic data, as detailed in the Recommendations section of this Report.

## 8.6 PRODUCTION AND RESERVE ENHANCEMENT THROUGH DRILLING TO PROVE UP PROBABLE AND POSSIBLE RESERVES

For some of the Bangladesh fields and reservoirs, all identified reservoirs have been completed and are producing. For these fields, additional wells may be required to optimize recovery and achieve the estimated levels of Probable and Possible reserves, or may serve as rate acceleration for reserves that would ultimately have been produced at a later date without such wells.

For many of the fields, however, from one to several sands were penetrated, logged and tested, but remain uncompleted in current producing wells. Exploitation of the reserves contained in these undeveloped and/or behind pipe reserves will require recompletion of exiting producers in these intervals and/or the drilling of additional wells. All such additional drilling and recompletion work will result in increased gas production rates.

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## 10. ABBREVIATIONS

| | |
|---|---|
| AAPG | American Association of Petroleum Geologists |
| BAPEX | Bangladesh Petroleum Exploration & Production Co. Ltd. |
| BBL (bbl) | Barrel |
| bbl/day | Flow rate of condensate and water in barrels per day |
| BCF, Bscf | Billion ($10^9$) Standard Cubic Feet |
| $B_g$ | Gas volume expansion factor |
| BGFCL | Bangladesh Gas Fields Co. Ltd. |
| BGR | Bundesansalt fur Geowissenschaften und Rohstoffe (Federal Institute for Geosciences and Mineral Resources), Hannover, Germany |
| BGSL | Bakhrabad Gas System Ltd. |
| BMSL | Below Mean Sea Level |
| BOC | Burmah Oil Company |
| BOGMC | Bangladesh Oil, Gas and Mineral Corporation (Petrobangla) |
| BPI | Bangladesh Petroleum Institute |
| BTA | Bhuban Thin Alternation of Sands |
| BUET | Bangladesh University of Engineering and Technology |
| $C_1$ | Methane |
| $C_2$ | Ethane |
| $C_3$ | Propane |
| CCOP | Committee for Coastal and Offshore Geoscience Programmes |
| CGG | Compagnie Generale Geophysique |
| CIDA | Canadian International Development Agency |
| CIMM | Canadian Institute of Mining, Metallurgy & Petroleum |
| CTU | Coil Tubing Unit |
| DST | Drill Stem Test |
| D & M | Degolyer and McNaughton |
| ESE | East-south-east |
| EUR | Estimated Ultimate Recovery (original reserves at time zero, including past production, in units of volume, e.g. Tscf, Bscf, MMscf, BBL, MMBBL) |
| E & P | Exploration and Production |
| ft | Feet |
| FWHP | Flowing Well Head Pressure |
| FBHP | Flowing Bottom Hole Pressure |

| | |
|---|---|
| G & E | Geological and Engineering |
| GFAP | Gas Field Appraisal Project |
| GGAG | German Geological Advisory Group |
| GIB | Geological Information Boring |
| GIIP | Gas Initially In-Place |
| GSI | Geophysical Services International |
| GWC | Gas- water Contact |
| HCU | Hydrocarbon Unit |
| HHSP | Hydrocarbon Habitat Study Project |
| IDA | International Development Agency |
| IKM | Intercomp-Kanata Management Ltd. |
| IMEG | International Management and Engineering Group Ltd. |
| IOC | International Oil Company |
| IPR | Improved Petroleum Recovery International. Ltd |
| JOE | Japan Oil Engineering Co. |
| JPT | Journal of Petroleum Technology |
| KB | Kelly Bushing |
| LGS | Lower Gas Sand |
| MBAL | Material Balance Software |
| MB | Material balance study |
| md | Millidarcy – a unit to measure permeability or the ability to flow fluids |
| MD | Measured Depth |
| Mbbl | Thousand ($10^3$) Barrel |
| MMbbl | Million ($10^6$) Barrel |
| MMscf | Million ($10^6$) Standard Cubic Feet |
| MMscfd | Flow rate: Million ($10^6$) Standard Cubic Feet per Day |
| NE | Northeast |
| NIKO | Niko Resources (Bangladesh) Ltd. |
| NNE | North-northeast |
| NNE-SSW | North-northeast-South-southwest |
| NPD | Norwegian Petroleum Directorate |
| NW-SE | Northwest- southeast |
| OECF | Overseas Economic Cooperation Fund, Japan |
| OGDC | Oil and Gas Development Corporation (Pakistan) |
| OIIP | Oil Initially in Place |

| | |
|---|---|
| OMS | Oil and Mining Services (UK) |
| ONGC | Oil & Natural Gas Corporation (India) |
| PEPP | Petroleum Exploration Promotional Project |
| PMRE | Petroleum and Mineral Resources Engineering Department of BUET |
| ppm | Parts per million |
| PPL | Pakistan Petroleum Ltd |
| PRMS | Petroleum Resource Management System ( |
| PSC | Production Sharing Contract |
| psi | Pounds per square inch |
| PSOC | Pakistan Shell Oil Company |
| PVD | Term used by D & M to indicate Proved Reserve as Probable (PVD) due to absence of sales contract for Bibiyana Gas Field |
| p/z | Pressure/ Z factor |
| P1 | Proven |
| P2 | Probable |
| P3 | Possible |
| 2P | Proven + Probable |
| 3P | Proven + Probable + Possible |
| RFT | Repeat Formation Tester |
| RMS | Root Mean Square |
| RPPN | Reservoir Physicist Pakistan Note |
| RPS | RPS Energy |
| RSC | Reservoir Study Cell of Petrobangla |
| SAPS | Special Assistance for Project Sustainability for OECF |
| SBED | Shell Bangladesh Exploration and Development B. V. |
| SBHP | Shut in Bottom Hole Pressure |
| SEAPEX | Southeast Asia Petroleum Exploration Society |
| SGFL | Sylhet Gas Fields Ltd. |
| SPE | Society of Petroleum Engineers |
| SPEE | Society of Petroleum Evaluation Engineers |
| SSW | South-south-west |
| STANVAC | Standard Vacuum Oil Company |
| SW | Southwest |
| SWHP | Shut-in Wellhead Pressure |
| TSC | Tailo Sandhani Company |

| | |
|---|---|
| Tscf | Trillion ($10^{12}$ ) Standard Cubic Feet |
| TDT | Thermal Decay Time log |
| TVD | Total Vertical Depth |
| TVDss | Total Vertical Depth, subsea |
| UGS | Upper Gas Sand |
| UNECAFE | United Nations Economic Commission for Asia and Far East |
| UNECE | United Nations Economic and Social Council, Economic Commission for Europe |
| UNFC | United Nations Task Force on International Framework Classification for Solid Fuels and Mineral Resources |
| UTP | Union Texas Petroleum |
| WNW | West- northwest |
| WPC | World Petroleum Congress |
| Z | Compressibility factor |

# APPENDIX A

# PETROLEUM RESOURCE MANAGEMENT SYSTEM
# (PRMS)

**A1. SPE - PRMS Guide for Non-Technical Users**

**A2. Petroleum Managemet System - 2007**

World Petroleum Council

# Petroleum
# Resources Management
# System

Sponsored by:

Society of Petroleum Engineers (SPE)
American Association of Petroleum Geologists (AAPG)
World Petroleum Council (WPC)
Society of Petroleum Evaluation Engineers (SPEE)

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# Petroleum Resources Management System

## Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

This document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information, and specific chapters are referenced herein. Appendix A is a consolidated glossary of terms used in resources evaluations and replaces those published in 2005.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

This SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, including its Appendix, may be referred to by the abbreviated term "SPE-PRMS" with the caveat that the full title, including clear recognition of the co-sponsoring organizations, has been initially stated.

# 1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

## 1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

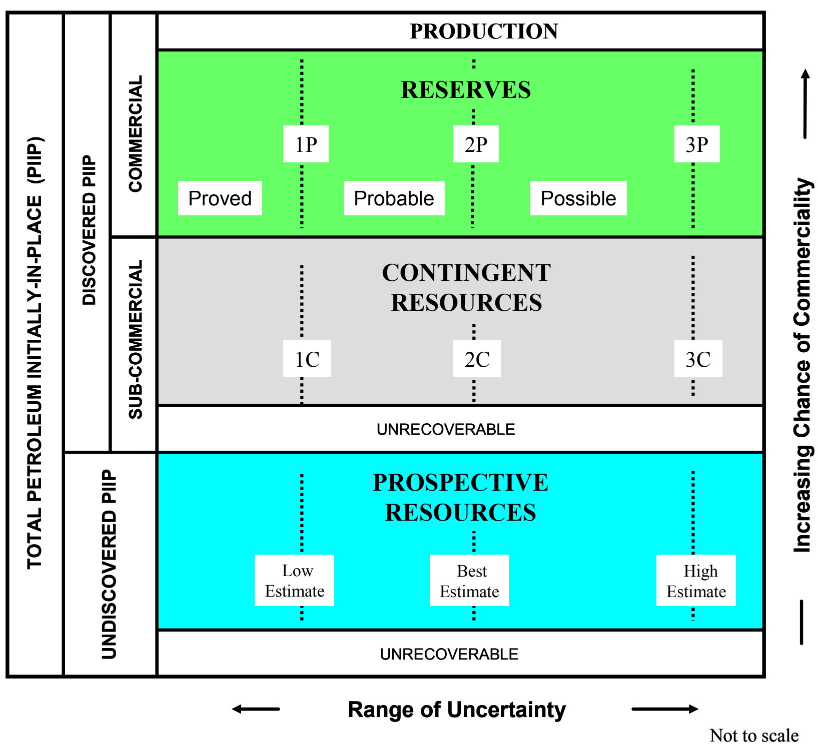


Figure 1-1: Resources Classification Framework.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

**TOTAL PETROLEUM INITIALLY-IN-PLACE** is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

**DISCOVERED PETROLEUM INITIALLY-IN-PLACE** is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

**PRODUCTION** is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

**RESERVES** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

**CONTINGENT RESOURCES** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

**UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

**PROSPECTIVE RESOURCES** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

**UNRECOVERABLE** is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

In specialized areas, such as basin potential studies, alternative terminology has been used; the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.

## 1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

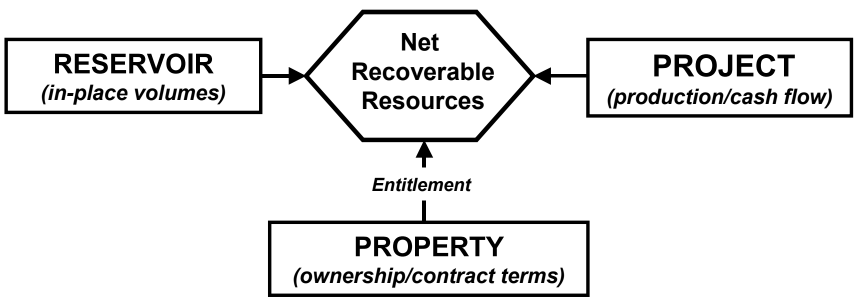


Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

# 2.0 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system as shown in Figure 1-1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality (the vertical axis) and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification vs. categorization varies with individual projects and is often an iterative analysis process leading to a final report. "Report," as used herein, refers to the presentation of evaluation results within the business entity conducting the assessment and should not be construed as replacing guidelines for public disclosures under guidelines established by regulatory and/or other government agencies.

Additional background information on resources classification issues can be found in Chapter 2 of the 2001 SPE/WPC/AAPG publication: "Guidelines for the Evaluation of Petroleum Reserves and Resources," hereafter referred to as the "2001 Supplemental Guidelines."

## 2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

### 2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

### 2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available:
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

### 2.1.3 Project Status and Commercial Risk

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized by standard project maturity level descriptions (qualitative) and/or by their associated chance of reaching producing status (quantitative).

As a project moves to a higher level of maturity, there will be an increasing chance that the accumulation will be commercially developed. For Contingent and Prospective Resources, this can further be expressed as a quantitative chance estimate that incorporates two key underlying risk components:

- The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the "chance of discovery."
- Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development."

Thus, for an undiscovered accumulation, the "chance of commerciality" is the product of these two risk components. For a discovered accumulation where the "chance of discovery" is 100%, the "chance of commerciality" becomes equivalent to the "chance of development."

#### 2.1.3.1 Project Maturity Sub-Classes

As illustrated in Figure 2-1, development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production.

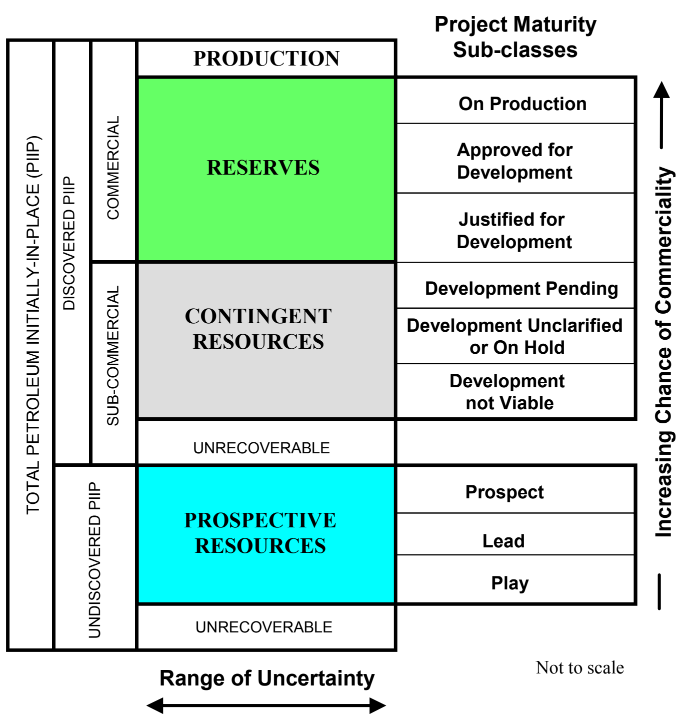


Figure 2-1: Sub-classes based on Project Maturity.

Project Maturity terminology and definitions have been modified from the example provided in the 2001 Supplemental Guidelines, Chapter 2. Detailed definitions and guidelines for each Project Maturity sub-class are provided in Table I. This approach supports managing portfolios of opportunities at various stages of exploration and development and may be supplemented by associated quantitative estimates of chance of commerciality. The boundaries between different levels of project maturity may be referred to as "decision gates."

Decisions within the Reserves class are based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. For Contingent Resources, supporting analysis should focus on gathering data and performing analyses to clarify and then mitigate those key conditions, or contingencies, that prevent commercial development.

For Prospective Resources, these potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under appropriate development projects. The decision at each phase is to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity where a decision can be made to proceed with exploration drilling.

Evaluators may adopt alternative sub-classes and project maturity modifiers, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management.

#### 2.1.3.2 Reserves Status

Once projects satisfy commercial risk criteria, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (detailed definitions and guidelines are provided in Table 2):

- Developed Reserves are expected quantities to be recovered from existing wells and facilities.
    - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
    - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.
- Undeveloped Reserves are quantities expected to be recovered through future investments**.**

Where Reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Determination of Commerciality, section 2.1.2) is justified, a reasonable time frame is generally considered to be less than 5 years.

Development and production status are of significant importance for project management. While Reserves Status has traditionally only been applied to Proved Reserves, the same concept of Developed and Undeveloped Status based on the funding and operational status of wells and producing facilities within the development project are applicable throughout the full range of Reserves uncertainty categories (Proved, Probable and Possible).

Quantities may be subdivided by Reserves Status independent of sub-classification by Project Maturity. If applied in combination, Developed and/or Undeveloped Reserves quantities may be identified separately within each Reserves sub-class (On Production, Approved for Development, and Justified for Development).

#### 2.1.3.3 Economic Status

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions (see Commercial Evaluations, section 3.1). Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.

- Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is "undetermined." Additional economic status modifiers may be applied to further characterize recoverable quantities; for example, non-sales (lease fuel, flare, and losses) may be separately identified and documented in addition to sales quantities for both production and recoverable resource estimates (see also Reference Point, section 3.2.1). Those discovered in-place volumes for which a feasible development project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Economic Status may be identified independently of, or applied in combination with, Project Maturity sub-classification to more completely describe the project and its associated resources.

## 2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

### 2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

### 2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods. (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Table III presents category definitions and provides guidelines designed to promote consistency in resource assessments. The following summarizes the definitions for each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

- Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

- Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

## 2.3 Incremental Projects

The initial resource assessment is based on application of a defined initial development project. Incremental projects are designed to increase recovery efficiency and/or to accelerate production through making changes to wells or facilities, infill drilling, or improved recovery. Such projects should be classified according to the same criteria as initial projects. Related incremental quantities are similarly categorized on certainty of recovery. The projected increased recovery can be included in estimated Reserves if the degree of commitment is such that the project will be developed and placed on production within a reasonable timeframe.

Circumstances where development will be significantly delayed should be clearly documented. If there is significant project risk, forecast incremental recoveries may be similarly categorized but should be classified as Contingent Resources (see Determination of Commerciality, section 2.1.2).

### 2.3.1 Workovers, Treatments, and Changes of Equipment

Incremental recovery associated with future workover, treatment (including hydraulic fracturing), re-treatment, changes of equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed or Undeveloped Reserves depending on the magnitude of associated costs required (see Reserves Status, section 2.1.3.2).

### 2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in Reserves estimates. If the eventual installation of compression was planned and approved as part of the original development plan, incremental recovery is included in Undeveloped Reserves. However, if the cost to implement compression is not significant (relative to the cost of a new well), the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

### 2.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the spacing beyond that utilized within the initial development plan, subject to government regulations (if such approvals are required). Infill drilling may have the combined effect of increasing recovery efficiency and accelerating production. Only the incremental recovery can be considered as additional Reserves; this additional recovery may need to be reallocated to individual wells with different interest ownerships.

### 2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir performance. It includes waterflooding, secondary or tertiary recovery processes, and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves commerciality criteria as primary recovery projects. There should be an expectation that the project will be economic and that the entity has committed to implement the project in a reasonable time frame (generally within 5 years; further delays should be clearly justified).

The judgment on commerciality is based on pilot testing within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

These incremental recoveries in commercial projects are categorized into Proved, Probable, and Possible Reserves based on certainty derived from engineering analysis and analogous applications in similar reservoirs.

## 2.4 Unconventional Resources

Two types of petroleum resources have been defined that may require different approaches for their evaluations:

- Conventional resources exist in discrete petroleum accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. The petroleum is recovered through wellbores and typically requires minimal processing prior to sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders).

For these petroleum accumulations that are not significantly affected by hydrodynamic influences, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum may not be possible. Thus, there typically is a need for increased sampling density to define uncertainty of in-place volumes, variations in quality of reservoir and hydrocarbons, and their detailed spatial distribution to support detailed design of specialized mining or in-situ extraction programs.

It is intended that the resources definitions, together with the classification system, will be appropriate for all types of petroleum accumulations regardless of their in-place characteristics, extraction method applied, or degree of processing required.

Similar to improved recovery projects applied to conventional reservoirs, successful pilots or operating projects in the subject reservoir or successful projects in analogous reservoirs may be required to establish a distribution of recovery efficiencies for non-conventional accumulations. Such pilot projects may evaluate both extraction efficiency and the efficiency of unconventional processing facilities to derive sales products prior to custody transfer.

# 3.0 Evaluation and Reporting Guidelines

The following guidelines are provided to promote consistency in project evaluations and reporting. "Reporting" refers to the presentation of evaluation results within the business entity conducting the evaluation and should not be construed as replacing guidelines for subsequent public disclosures under guidelines established by regulatory and/or other government agencies, or any current or future associated accounting standards.

## 3.1 Commercial Evaluations

Investment decisions are based on the entity's view of future commercial conditions that may impact the development feasibility (commitment to develop) and production/cash flow schedule of oil and gas projects. Commercial conditions include, but are not limited to, assumptions of financial conditions (costs, prices, fiscal terms, taxes), marketing, legal, environmental, social, and governmental factors. Project value may be assessed in several ways (e.g., historical costs, comparative market values); the guidelines herein apply only to evaluations based on cash flow analysis. Moreover, modifying factors such contractual or political risks that may additionally influence investment decisions are not addressed. (Additional detail on commercial issues can be found in the "2001 Supplemental Guidelines," Chapter 4.)

### 3.1.1 Cash-Flow-Based Resources Evaluations

Resources evaluations are based on estimates of future production and the associated cash flow schedules for each development project. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project. The calculation shall reflect:

- The expected quantities of production projected over identified time periods.
- The estimated costs associated with the project to develop, recover, and produce the quantities of production at its Reference Point (see section 3.2.1), including environmental, abandonment, and reclamation costs charged to the project, based on the evaluator's view of the costs expected to apply in future periods.
- The estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods including that portion of the costs and revenues accruing to the entity.
- Future projected production and revenue related taxes and royalties expected to be paid by the entity.
- A project life that is limited to the period of entitlement or reasonable expectation thereof.
- The application of an appropriate discount rate that reasonably reflects the weighted average cost of capital or the minimum acceptable rate of return applicable to the entity at the time of the evaluation.

While each organization may define specific investment criteria, a project is generally considered to be "economic" if its "best estimate" case has a positive net present value under the organization's standard discount rate, or if at least has a positive undiscounted cash flow.

### 3.1.2 Economic Criteria

Evaluators must clearly identify the assumptions on commercial conditions utilized in the evaluation and must document the basis for these assumptions.

The economic evaluation underlying the investment decision is based on the entity's reasonable forecast of future conditions, including costs and prices, which will exist during the life of the project (forecast case). Such forecasts are based on projected changes to current conditions; SPE defines current conditions as the average of those existing during the previous 12 months.

Alternative economic scenarios are considered in the decision process and, in some cases, to supplement reporting requirements. Evaluators may examine a case in which current conditions are held constant (no inflation or deflation) throughout the project life (constant case).

Evaluations may be modified to accommodate criteria imposed by regulatory agencies regarding external disclosures. For example, these criteria may include a specific requirement that, if the recovery were confined to the technically Proved Reserves estimate, the constant case should still generate a positive cash flow. External reporting requirements may also specify alternative guidance on current conditions (for example, year-end costs and prices).

There may be circumstances in which the project meets criteria to be classified as Reserves using the forecast case but does not meet the external criteria for Proved Reserves. In these specific circumstances, the entity may record 2P and 3P estimates without separately recording Proved. As costs are incurred and development proceeds, the low estimate may eventually satisfy external requirements, and Proved Reserves can then be assigned.

While SPE guidelines do not require that project financing be confirmed prior to classifying projects as Reserves, this may be another external requirement. In many cases, loans are conditional upon the same criteria as above; that is, the project must be economic based on Proved Reserves only. In general, if there is not a reasonable expectation that loans or other forms of financing (e.g., farm-outs) can be arranged such that the development will be initiated within a reasonable timeframe, then the project should be classified as Contingent Resources. If financing is reasonably expected but not yet confirmed, the project may be classified as Reserves, but no Proved Reserves may be reported as above.

### 3.1.3 Economic Limit

Economic limit is defined as the production rate beyond which the net operating cash flows from a project, which may be an individual well, lease, or entire field, are negative, a point in time that defines the project's economic life. Operating costs should be based on the same type of projections as used in price forecasting. Operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated (i.e., only those cash costs that will actually be eliminated if project production ceases should be considered in the calculation of economic limit). Operating costs should include fixed property-specific overhead charges if these are actual incremental costs attributable to the project and any production and property taxes but, for purposes of calculating economic limit, should exclude depreciation, abandonment and reclamation costs, and income tax, as well as any overhead above that required to operate the subject property itself. Operating costs may be reduced, and thus project life extended, by various cost-reduction and revenue-enhancement approaches, such as sharing of production facilities, pooling maintenance contracts, or marketing of associated non-hydrocarbons (see Associated Non-Hydrocarbon Components, section 3.2.4).

Interim negative project net cash flows may be accommodated in short periods of low product prices or major operational problems, provided that the longer-term forecasts must still indicate positive economics.

## 3.2 Production Measurement

In general, the marketable product, as measured according to delivery specifications at a defined Reference Point, provides the basis for production quantities and resources estimates. The following operational issues should be considered in defining and measuring production. While referenced specifically to Reserves, the same logic would be applied to projects forecast to develop Contingent and Prospective Resources conditional on discovery and development. (Additional detail on operational issues that impact resources estimation can be found in the "2001 Supplemental Guidelines," Chapter 3.)

### 3.2.1 Reference Point

Reference Point is a defined location(s) in the production chain where the produced quantities are measured or assessed. The Reference Point is typically the point of sale to third parties or where custody is transferred to the entity's downstream operations. Sales production and estimated Reserves are normally measured and reported in terms of quantities crossing this point over the period of interest.

The Reference Point may be defined by relevant accounting regulations in order to ensure that the Reference Point is the same for both the measurement of reported sales quantities and for the accounting treatment of sales revenues. This ensures that sales quantities are stated according to their delivery specifications at a defined price. In integrated projects, the appropriate price at the Reference Point may need to be determined using a netback calculation.

Sales quantities are equal to raw production less non-sales quantities, being those quantities produced at the wellhead but not available for sales at the Reference Point. Non-sales quantities include petroleum consumed as fuel, flared, or lost in processing, plus non-hydrocarbons that must be removed prior to sale; each of these may be allocated using separate Reference Points but when combined with sales, should sum to raw production. Sales quantities may need to be adjusted to exclude components added in processing but not derived from raw production. Raw production measurements are necessary and form the basis of engineering calculations (e.g., production performance analysis) based on total reservoir voidage.

### 3.2.2 Lease Fuel

Lease fuel is that portion of produced natural gas, crude oil, or condensate consumed as fuel in production and lease plant operations.

For consistency, lease fuel should be treated as shrinkage and is not included in sales quantities or resource estimates. However, some regulatory guidelines may allow lease fuel to be included in Reserves estimates where it replaces alternative sources of fuel and/or power that would be purchased in their absence. Where claimed as Reserves, such fuel quantities should be reported separately from sales, and their value must be included as an operating expense. Flared gas and oil and other losses are always treated as shrinkage and are not included in either product sales or Reserves.

### 3.2.3 Wet or Dry Natural Gas

The Reserves for wet or dry natural gas should be considered in the context of the specifications of the gas at the agreed Reference Point. Thus, for gas that is sold as wet gas, the volume of the wet gas would be reported, and there would be no associated or extracted hydrocarbon liquids reported separately. It would be expected that the corresponding enhanced value of the wet gas would be reflected in the sales price achieved for such gas.

When liquids are extracted from the gas prior to sale and the gas is sold in dry condition, then the dry gas volume and the extracted liquid volumes, whether condensate and/or natural gas liquids, should be accounted for separately in resource assessments. Any hydrocarbon liquids separated from the wet gas subsequent to the agreed Reference Point would not be reported as Reserves.

### 3.2.4 Associated Non-Hydrocarbon Components

In the event that non-hydrocarbon components are associated with production, the reported quantities should reflect the agreed specifications of the petroleum product at the Reference Point. Correspondingly, the accounts will reflect the value of the petroleum product at the Reference Point. If it is required to remove all or a portion of non-hydrocarbons prior to delivery, the Reserves and production should reflect only the residual hydrocarbon product.

Even if the associated non-hydrocarbon component (e.g., helium, sulfur) that is removed prior to the Reference Point is subsequently and separately marketed, these quantities are not included in petroleum production or Reserves. The revenue generated by the sale of non-hydrocarbon products may be included in the economic evaluation of a project.

### 3.2.5 Natural Gas Re-Injection

Natural gas production can be re-injected into a reservoir for a number of reasons and under a variety of conditions. It can be re-injected into the same reservoir or into other reservoirs located on the same property for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. In such cases, assuming that the gas will eventually be produced and sold, the gas volume estimated as eventually recoverable can be included as Reserves.

If gas volumes are to be included as Reserves, they must meet the normal criteria laid down in the definitions including the existence of a viable development, transportation, and sales marketing plan. Gas volumes should be reduced for losses associated with the re-injection and subsequent recovery process. Gas volumes injected into a reservoir for gas disposal with no committed plan for recovery are not classified as Reserves. Gas volumes purchased for injection and later recovered are not classified as Reserves.

### 3.2.6 Underground Natural Gas Storage

Natural gas injected into a gas storage reservoir to be recovered at a later period (e.g., to meet peak market demand periods) should not be included as Reserves.

The gas placed in the storage reservoir may be purchased or may originate from prior production. It is important to distinguish injected gas from any remaining native recoverable volumes in the reservoir. On commencing gas production, its allocation between native gas and injected gas may be subject to local regulatory and accounting rulings. Native gas production would be drawn against the original field Reserves. The uncertainty with respect to original field volumes remains with the native reservoir gas and not the injected gas.

There may be occasions, such as gas acquired through a production payment, in which gas is transferred from one lease or field to another without a sale or custody transfer occurring. In such cases, the re-injected gas could be included with the native reservoir gas as Reserves. The same principles regarding separation of native resources from injected quantities would apply to underground oil storage.

### 3.2.7 Production Balancing

Reserves estimates must be adjusted for production withdrawals. This may be a complex accounting process when the allocation of production among project participants is not aligned with their entitlement to Reserves. Production overlift or underlift can occur in oil production records because of the necessity for participants to lift their production in parcel sizes or cargo volumes to suit available shipping schedules as agreed among the parties. Similarly, an imbalance in gas deliveries can result from the participants having different operating or marketing arrangements that prevent gas volumes sold from being equal to entitlement share within a given time period.

Based on production matching the internal accounts, annual production should generally be equal to the liftings actually made by the participant and not on the production entitlement for the year. However, actual production and entitlements must be reconciled in Reserves assessments. Resulting imbalances must be monitored over time and eventually resolved before project abandonment.

## 3.3 Resources Entitlement and Recognition

While assessments are conducted to establish estimates of the total Petroleum Initially-in-Place and that portion recovered by defined projects, the allocation of sales quantities, costs, and revenues impacts the project economics and commerciality. This allocation is governed by the applicable contracts between the mineral owners (lessors) and contractors (lessees) and is generally referred to as "entitlement." For publicly traded companies, securities regulators may set criteria regarding the classes and categories that can be "recognized" in external disclosures.

Entitlements must ensure that the recoverable resources claimed/reported by individual stakeholders sum to the total recoverable resources; that is, there are none missing or duplicated in the allocation process. (The "2001 Supplemental Guidelines," Chapter 9, addresses issues of Reserves recognition under production-sharing and non-traditional agreements.)

### 3.3.1 Royalty

Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs by the producer (lessee/contractor) having access to the petroleum resources.

Many agreements allow for the lessee/contractor to lift the royalty volumes and sell them on behalf of, and pay the proceeds to, the royalty owner/lessor. Some agreements provide for the royalty to be taken only in-kind by the royalty owner. In either case, royalty volumes must be deducted from the lessee's entitlement to resources. In some agreements, royalties owned by the host government are actually treated as taxes to be paid in cash. In such cases, the equivalent royalty volumes are controlled by the contractor who may (subject to regulatory guidance) elect to report these volumes as Reserves and/or Contingent Resources with appropriate offsets (increase in operating expense) to recognize the financial liability of the royalty obligation.

Conversely, if a company owns a royalty or equivalent interest of any type in a project, the related quantities can be included in Resources entitlements.

### 3.3.2 Production-Sharing Contract Reserves

Production-Sharing Contracts (PSCs) of various types replace conventional tax-royalty systems in many countries. Under the PSC terms, the producers have an entitlement to a portion of the production. This entitlement, often referred to as "net entitlement" or "net economic interest," is estimated using a formula based on the contract terms incorporating project costs (cost oil) and project profits (profit oil).

Although ownership of the production invariably remains with the government authority up to the export point of the project, the producers may take title to their share of the net entitlement at that point and may claim that share as their Reserves.

Risked-Service Contracts (RSCs) are similar to PSCs, but in this case, the producers are paid in cash rather than in production. As with PSCs, the Reserves claimed are based on the parties' net economic interest. Care needs to be taken to distinguish between an RSC and a "Pure Service Contract." Reserves can be claimed in an RSC on the basis that the producers are exposed to capital at risk, whereas no Reserves can be claimed for Pure Service Contracts because there are no market risks and the producers act as contractors.

Unlike traditional royalty-lease agreements, the cost recovery system in production-sharing, risk-service, and other related contracts typically reduce the production share and hence Reserves obtained by a contractor in periods of high price and increase volumes in periods of low price. While this ensures cost recovery, it introduces a significant price-related volatility in annual Reserves estimates under cases using "current" economic conditions. Under a defined "forecast conditions case," the future relationship of price to Reserves entitlement is known.

The treatment of taxes and the accounting procedures used can also have a significant impact on the Reserves recognized and production reported from these contracts.

### 3.3.3 Contract Extensions or Renewals

As production-sharing or other types of agreements approach maturity, they can be extended by negotiation for contract extensions, by the exercise of options to extend, or by other means.

Reserves should not be claimed for those volumes that will be produced beyond the ending date of the current agreement unless there is reasonable expectation that an extension, a renewal, or a new contract will be granted. Such reasonable expectation may be based on the historical treatment of similar agreements by the license-issuing jurisdiction. Otherwise, forecast production beyond the contract term should be classified as Contingent Resources with an associated reduced chance of commercialization. Moreover, it may not be reasonable to assume that the fiscal terms in a negotiated extension will be similar to existing terms.

Similar logic should be applied where gas sales agreements are required to ensure adequate markets. Reserves should not be claimed for those quantities that will be produced beyond those specified in the current agreement or reasonably forecast to be included in future agreements.

In either of the above cases, where the risk of cessation of rights to produce or inability to secure gas contracts is not considered significant, evaluators may choose to incorporate the uncertainty by categorizing quantities to be recovered beyond the current contract as Probable or Possible Reserves.

# 4.0 Estimating Recoverable Quantities

Assuming that projects have been classified according to their project maturity, the estimation of associated recoverable quantities under a defined project and their assignment to uncertainty categories may be based on one or a combination of analytical procedures. Such procedures may be applied using an incremental (risk-based) and/or scenario approach; moreover, the method of assessing relative uncertainty in these estimates of recoverable quantities may employ both deterministic and probabilistic methods.

## 4.1 Analytical Procedures

The analytical procedures for estimating recoverable quantities fall into three broad categories: (a) analogy, (b) volumetric estimates, and (c) performance-based estimates, which include material balance, production decline, and other production performance analyses. Reservoir simulation may be used in either volumetric or performance-based analyses. Pre- and early post-discovery assessments are typically made with analog field/project data and volumetric estimation. After production commences and production rates and pressure information become available, performance-based methods can be applied. Generally, the range of EUR estimates is expected to decrease as more information becomes available, but this is not always the case.

In each procedural method, results are not a single quantity of remaining recoverable petroleum, but rather a range that reflects the underlying uncertainties in both the in-place volumes and the recovery efficiency of the applied development project. By applying consistent guidelines (see Resources Categorization, section 2.2.), evaluators can define remaining recoverable quantities using either the incremental or cumulative scenario approach. The confidence in assessment results generally increases when the estimates are supported by more than one analytical procedure.

### 4.1.1 Analogs

Analogs are widely used in resources estimation, particularly in the exploration and early development stages, when direct measurement information is limited. The methodology is based on the assumption that the analogous reservoir is comparable to the subject reservoir regarding reservoir and fluid properties that control ultimate recovery of petroleum. By selecting appropriate analogs, where performance data based on comparable development plans (including well type, well spacing and stimulation) are available, a similar production profile may be forecast.

Analogous reservoirs are defined by features and characteristics including, but not limited to, approximate depth, pressure, temperature, reservoir drive mechanism, original fluid content, reservoir fluid gravity, reservoir size, gross thickness, pay thickness, net-to-gross ratio, lithology, heterogeneity, porosity, permeability, and development plan. Analogous reservoirs are formed by the same, or very similar, processes with regard to sedimentation, diagenesis, pressure, temperature, chemical and mechanical history, and structural deformation.

Comparison to several analogs may improve the range of uncertainty in estimated recoverable quantities from the subject reservoir. While reservoirs in the same geographic area and of the same age typically provide better analogs, such proximity alone may not be the primary consideration. In all cases, evaluators should document the similarities and differences between the analog and the subject reservoir/project. Review of analog reservoir performance is useful in quality assurance of resource assessments at all stages of development.

### 4.1.2 Volumetric Estimate

This procedure uses reservoir rock and fluid properties to calculate hydrocarbons in-place and then estimate that portion that will be recovered by a specific development project(s). Key uncertainties affecting in-place volumes include:

- Reservoir geometry and trap limits that impact gross rock volume.
- Geological characteristics that define pore volume and permeability distribution.
- Elevation of fluid contacts.
- Combinations of reservoir quality, fluid types, and contacts that control fluid saturations.

The gross rock volume of interest is that for the total reservoir. While spatial distribution and reservoir quality impact recovery efficiency, the calculation of in-place petroleum often uses average net-to-gross ratio, porosity, and fluid saturations. In more heterogeneous reservoirs, increased well density may be required to confidently assess and categorize resources.

Given estimates of the in-place petroleum, that portion that can be recovered by a defined set of wells and operating conditions must then be estimated based on analog field performance and/or simulation studies using available reservoir information. Key assumptions must be made regarding reservoir drive mechanisms.

The estimates of recoverable quantities must reflect uncertainties not only in the petroleum in-place but also in the recovery efficiency of the development project(s) applied to the specific reservoir being studied.

Additionally, geostatistical methods can be used to preserve spatial distribution information and incorporate it in subsequent reservoir simulation applications. Such processes may yield improved estimates of the range of recoverable quantities. Incorporation of seismic analyses typically improves the underlying reservoir models and yields more reliable resource estimates. [Refer to the "2001 SPE Supplemental Guidelines" for more detailed discussion of geostatistics (Chapter 7) and seismic applications (Chapter 8)].

### 4.1.3 Material Balance

Material balance methods to estimate recoverable quantities involve the analysis of pressure behavior as reservoir fluids are withdrawn. In ideal situations, such as depletion-drive gas reservoirs in homogeneous, high-permeability reservoir rocks and where sufficient and high quality pressure data is available, estimation based on material balance may provide very reliable estimates of ultimate recovery at various abandonment pressures. In complex situations, such as those involving water influx, compartmentalization, multiphase behavior, and multilayered or low-permeability reservoirs, material balance estimates alone may provide erroneous results. Evaluators should take care to accommodate the complexity of the reservoir and its pressure response to depletion in developing uncertainty profiles for the applied recovery project.

Computer reservoir modeling or reservoir simulation can be considered a sophisticated form of material balance analysis. While such modeling can be a reliable predictor of reservoir behavior under a defined development program, the reliability of input rock properties, reservoir geometry, relative permeability functions, and fluid properties are critical. Predictive models are most reliable in estimating recoverable quantities when there is sufficient production history to validate the model through history matching.

### 4.1.4 Production Performance Analysis

Analysis of the change in production rates and production fluids ratios vs. time and vs. cumulative production as reservoir fluids are withdrawn provides valuable information to predict ultimate recoverable quantities. In some cases, before decline in production rates is apparent, trends in performance indicators such as gas/oil ratio (GOR), water/oil ratio (WOR), condensate/gas ratio (CGR), and bottomhole or flowing pressures can be extrapolated to an economic limit condition to estimate reserves.

Reliable results require a sufficient period of stable operating conditions after wells in a reservoir have established drainage areas. In estimating recoverable quantities, evaluators must consider complicating factors affecting production performance behavior, such as variable reservoir and fluid properties, transient vs. stabilized flow, changes in operating conditions, interference effects, and depletion mechanisms. In early stages of depletion, there may be significant uncertainty in both the ultimate performance profile and the commercial factors that impact abandonment rate. Such uncertainties should be reflected in the resources categorization. For very mature reservoirs, the future production forecast may be sufficiently well defined that the remaining uncertainty in the technical profile is not significant; in such cases, the "best estimate" 2P scenario may also be used for the 1P and 3P production forecasts. However, there may still be commercial uncertainties that will impact the abandonment rate, and these should be accommodated in the resources categorization.

## 4.2 Deterministic and Probabilistic Methods

Regardless of the analytical procedure used, resource estimates may be prepared using either deterministic or probabilistic methods. A deterministic estimate is a single discrete scenario within a range of outcomes that could be derived by probabilistic analysis.

In the deterministic method, a discrete value or array of values for each parameter is selected based on the estimator's choice of the values that are most appropriate for the corresponding resource category. A single outcome of recoverable quantities is derived for each deterministic increment or scenario.

In the probabilistic method, the estimator defines a distribution representing the full range of possible values for each input parameter. These distributions may be randomly sampled (typically using Monte Carlo simulation software) to compute a full range and distribution of potential outcome of results of recoverable quantities (see "2001 Supplemental Guidelines," Chapter 5, for more detailed discussion of probabilistic reserves estimation procedures). This approach is most often applied to volumetric resource calculations in the early phases of an exploitation and development projects. The Resources Categorization guidelines include criteria that provide specific limits to parameters associated with each category. Moreover, the resource analysis must consider commercial uncertainties. Accordingly, when probabilistic methods are used, constraints on parameters may be required to ensure that results are not outside the range imposed by the category deterministic guidelines and commercial uncertainties.

Deterministic volumes are estimated for discrete increments and defined scenarios. While deterministic estimates may have broadly inferred confidence levels, they do not have associated quantitatively defined probabilities. Nevertheless, the ranges of the probability guidelines established for the probabilistic method (see Range of Uncertainty, section 2.2.1) influence the amount of uncertainty generally inferred in the estimate derived from the deterministic method.

Both deterministic and probabilistic methods may be used in combination to ensure that results of either method are reasonable.

### 4.2.1 Aggregation Methods

Oil and gas quantities are generally estimated and categorized according to certainty of recovery within individual reservoirs or portions of reservoirs; this is referred to as the "reservoir level" assessment. These estimates are summed to arrive at estimates for fields, properties, and projects. Further summation is applied to yield totals for areas, countries, and companies; these are generally referred to as "resource reporting levels." The uncertainty distribution of the individual estimates at each of these levels may differ widely, depending on the geological settings and the maturity of the resources. This cumulative summation process is generally referred to as "aggregation."

Two general methods of aggregation may be applied: arithmetic summation of estimates by category and statistical aggregation of uncertainty distributions. There is typically significant divergence in results from applying these alternative methods. In statistical aggregation, except in the rare situation when all the reservoirs being aggregated are totally dependent, the P90 (high degree of certainty) quantities from the aggregate are always greater than the arithmetic sum of the reservoir level P90 quantities, and the P10 (low degree of certainty) of the aggregate is always less than the arithmetic sum P10 quantities assessed at the reservoir level. This "portfolio effect" is the result of the central limit theorem in statistical analysis. Note that the mean (arithmetic average) of the sums is equal to the sum of the means; that is, there is no portfolio effect in aggregating mean values.

In practice, there is likely to be a large degree of dependence between reservoirs in the same field, and such dependencies must be incorporated in the probabilistic calculation. When dependency is present and not accounted for, probabilistic aggregation will overestimate the low estimate result and underestimate the high estimate result. (Aggregation of Reserves is discussed in Chapter 6 of the "2001 Supplemental Guidelines.")

The aggregation methods utilized depends on the business purpose. It is recommended that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. Results reporting beyond this level should use arithmetic summation by category but should caution that the aggregate Proved may be a very conservative estimate and aggregate 3P may be very optimistic depending on the number of items in the aggregate. Aggregates of 2P results typically have less portfolio effect that may not be significant in mature properties where the statistical median approaches the mean of the resulting distribution.

Various techniques are available to aggregate deterministic and/or probabilistic field, property, or project assessment results for detailed business unit or corporate portfolio analyses where the results incorporate the benefits of portfolio size and diversification. Again, aggregation should incorporate degree of dependency. Where the underlying analyses are available, comparison of arithmetic and statistical aggregation results may be valuable in assessing impact of the portfolio effect. Whether deterministic or probabilistic methods are used, care should be taken to avoid systematic bias in the estimation process.

It is recognized that the monetary value associated with these recoveries is dependent on the production and cash flow schedules for each project; thus, aggregate distributions of recoverable quantities may not be a direct indication of corresponding uncertainty distributions of aggregate value.

#### 4.2.1.1 Aggregating Resources Classes

Petroleum quantities classified as Reserves, Contingent Resources, or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources and/ or Prospective Resources will not achieve commercial production.

Where the associated discovery and commerciality risks have been quantitatively defined, statistical techniques may be applied to incorporate individual project risk estimates in portfolio analysis of volume and value.

## Table 1: Recoverable Resources Classes and Sub-Classes

| **Class**/Sub-Class | **Definition** | **Guidelines** |
|---|---|---|
| **Reserves** | Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. | Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status.<br><br>To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame.<br><br>A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.<br><br>To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests. |
| On Production | The development project is currently producing and selling petroleum to market. | The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%.<br><br>The project "decision gate" is the decision to initiate commercial production from the project. |
| Approved for Development | All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way. | At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget.<br><br>The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells. |

| **Class**/Sub-Class | Definition | Guidelines |
|---|---|---|
| Justified for Development | Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained. | In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class).<br><br>The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time. |
| **Contingent Resources** | Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. | Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. |
| Development Pending | A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. | The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status.<br><br>The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production. |

| **Class**/Sub-Class | **Definition** | **Guidelines** |
|---|---|---|
| Development Unclarified or on Hold | A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. | The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a re-classification of the project to "Not Viable" status.<br><br>The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies. |
| Development Not Viable | A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. | The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.<br><br>The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future. |
| **Prospective Resources** | Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. | Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration. |
| Prospect | A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. | Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program. |
| Lead | A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. | Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios. |
| Play | A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. | Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios. |

## Table 2: Reserves Status Definitions and Guidelines

| Status | Definition | Guidelines |
|---|---|---|
| **Developed Reserves** | Developed Reserves are expected quantities to be recovered from existing wells and facilities. | Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing. |
| Developed Producing Reserves | Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. | Improved recovery reserves are considered producing only after the improved recovery project is in operation. |
| Developed Non-Producing Reserves | Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. | Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.<br><br>In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. |
| **Undeveloped Reserves** | Undeveloped Reserves are quantities expected to be recovered through future investments: | (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects. |

## Table 3: Reserves Category Definitions and Guidelines

| Category | Definition | Guidelines |
|---|---|---|
| **Proved Reserves** | Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. | If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.<br><br>The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.<br><br>In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8).<br><br>Reserves in undeveloped locations may be classified as Proved provided that:<br>• The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive.<br>• Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.<br><br>For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program. |
| **Probable Reserves** | Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. | It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.<br><br>Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria.<br><br>Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved. |

| Category | Definition | Guidelines |
|---|---|---|
| **Possible Reserves** | Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves. | The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.<br><br>Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project.<br><br>Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable. |
| **Probable and Possible Reserves** | (See above for separate criteria for Probable Reserves and Possible Reserves.) | The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.<br><br>In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.<br><br>Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.<br><br>In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations. |

## Appendix A: Glossary of Terms Used in Resources Evaluations

Originally published in January 2005, the SPE/WPC/AAPG Glossary has herein been revised to align with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System document. The glossary provides high-level definitions of terms use in resource evaluations. Where appropriate, sections and/or chapters within the 2007 and/or 2001 documents are referenced to best show the use of selected terms in context.

| TERM | Reference | DEFINITION |
|---|---|---|
| 1C | 2007 - 2.2.2 | Denotes low estimate scenario of Contingent Resources. |
| 2C | 2007 - 2.2.2 | Denotes best estimate scenario of Contingent Resources. |
| 3C | 2007 - 2.2.2 | Denotes high estimate scenario of Contingent Resources. |
| 1P | 2007 - 2.2.2 | Taken to be equivalent to Proved Reserves; denotes low estimate scenario of Reserves. |
| 2P | 2007 - 2.2.2 | Taken to be equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves. |
| 3P | 2007 - 2.2.2 | Taken to be equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of reserves. |
| Accumulation | 2001 - 2.3 | An individual body of naturally occurring petroleum in a reservoir. |
| Aggregation | 2007 - 3.5.1<br>2001 - 6 | The process of summing reservoir (or project) level estimates of resource quantities to higher levels or combinations such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions. |
| Approved for Development | 2007 - Table I | All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway. |
| Analogous Reservoir | 2007 - 3.4.1 | Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. |
| Assessment | 2007 - 1.2 | See Evaluation. |
| Associated Gas | | Associated Gas is a natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as Gas-Cap Gas or Solution Gas. |
| Barrels of Oil Equivalent (BOE) | 2001 - 3.7 | See Crude Oil Equivalent. |
| Basin-Centered Gas | 2007 - 2.4 | An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas saturated reservoirs and lack of a down-dip water leg. |

| | | |
|---|---|---|
| Behind-Pipe Reserves | 2007 - 2.1.3.1 | Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. |
| Best Estimate | 2007 - 2.2.2<br>2001 - 2.5 | With respect to resource categorization, this is considered to be the best estimate of the quantity that will actually be recovered from the accumulation by the project. It is the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate. |
| Bitumen | 2007 - 2.4 | See Natural Bitumen. |
| Buy Back Agreement | | An agreement between a host government and a contractor under which the host pays the contractor an agreed price for all volumes of hydrocarbons produced by the contractor. Pricing mechanisms typically provide the contractor with an opportunity to recover investment at an agreed level of profit. |
| Carried Interest | 2001 - 9.6.7 | A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the pre-production costs of another party (the carried party) on a license in which both own a portion of the working interest. |
| Chance | 2007 - 1.1 | Chance is 1- Risk. (See Risk) |
| Coalbed Methane (CBM) | 2007 - 2.4 | Natural gas contained in coal deposits, whether or not stored in gaseous phase. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. (Also termed Coal Seam Gas, CSG, or Natural Gas from Coal, NGC) |
| Commercial | 2007 - 2.1.2 and Table 1 | When a project is commercial, this implies that the essential social, environmental and economic conditions are met, including political, legal, regulatory and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. |
| Committed Project | 2007 - 2.1.2 and Table 1 | Projects are committed only when it can be demonstrated that there is a firm intention to develop them and bring them to production. Intention may be demonstrated with funding/financial plans and declaration of commerciality based on realistic expectations of regulatory approvals and reasonable satisfaction of other conditions that would otherwise prevent the project from being developed and brought to production. |

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| Completion | | Completion of a well. The process by which a well is brought to its final classification—basically dry hole, producer, injector, or monitor well. A dry hole is normally plugged and abandoned. A well deemed to be producible of petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir. Various methods are utilized to establish this connection, but they commonly involve the installation of some combination of borehole equipment, casing and tubing, and surface injection or production facilities. |
| Completion Interval | | The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes. |
| Concession | 2001 - 9.6.1 | A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an enterprise. The enterprise is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned. |
| Condensate | 2001 - 3.2 | Condensates are a mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from natural gas liquids (NGL) on two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensate. |
| Conditions | 2007 - 3.1 | The economic, marketing, legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated (also termed Contingencies). |
| Constant Case | 2007 - 3.1.1 | Modifier applied to project resources estimates and associated cash flows when such estimates are based on those conditions (including costs and product prices) that are fixed at a defined point in time (or period average) and are applied unchanged throughout the project life, other than those permitted contractually. In other words, no inflation or deflation adjustments are made to costs or revenues over the evaluation period. |
| Contingency | 2007 - 3.1 and Table 1 | See Conditions. |
| Contingent Project | 2007 - 2.1.2 | Development and production of recoverable quantities has not been committed due to conditions that may or may not be fulfilled. |
| Contingent Resources | 2007 - 1.1 and Table 1 | Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources. |
| Continuous-Type Deposit | 2007 - 2.4<br>2001 - 2.3 | A petroleum accumulation that is pervasive throughout a large area and which is not significantly affected by hydrodynamic influences. Such accumulations are included in Unconventional Resources. Examples of such deposits include "basin-centered" gas, shale gas, gas hydrates, natural bitumen and oil shale accumulations. |

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| Conventional Crude Oil | 2007 - 2.4 | Crude oil flowing naturally or capable of being pumped without further processing or dilution (see Crude Oil). |
| Conventional Gas | 2007 - 2.4 | Conventional Gas is a natural gas occurring in a normal porous and permeable reservoir rock, either in the gaseous phase or dissolved in crude oil, and which technically can be produced by normal production practices. |
| Conventional Resources | 2007 - 2.4 | Conventional resources exist in discrete petroleum accumulations related to localized geological structural features and/or stratigraphic conditions, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. |
| Conveyance | 2001 - 9.6.9 | Certain transactions that are in substance borrowings repayable in cash or its equivalent and shall be accounted for as borrowings and may not qualify for the recognition and reporting of oil and gas reserves. |
| Cost Recovery | 2001 - 9.6.2, 9.7.2 | Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the gross production stream. The contractor normally receives payment in oil production and is exposed to both technical and market risks. |
| Crude Oil | 2001 - 3.1 | Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature. Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas. |
| Crude Oil Equivalent | 2001 - 3.7 | Converting gas volumes to the oil equivalent is customarily done on the basis of the nominal heating content or calorific value of the fuel. There are a number of methodologies in common use. Before aggregating, the gas volumes first must be converted to the same temperature and pressure. Common industry gas conversion factors usually range between 1 barrel of oil equivalent (BOE) = 5,600 standard cubic feet (scf) of gas to 1 BOE = 6,000 scf. (Many operators use 1 BOE = 5,620 scf derived from the metric unit equivalent 1 $m^3$ crude oil = 1,000 $m^3$ natural gas ). (Also termed Barrels of Oil Equivalent.) |
| Cumulative Production | 2007 - 1.1 | The sum of production of oil and gas to date (see also Production). |
| Current Economic Conditions | 2007 - 3.1.1 | Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve a defined averaging period. The SPE guidelines recommend that a 1-year historical average of costs and prices should be used as the default basis of "constant case" resources estimates and associated project cash flows. |
| Cushion Gas Volume | | With respect to underground natural gas storage, Cushion Gas Volume (CGV) is the gas volume required in a storage field for reservoir management purposes and to maintain adequate minimum storage pressure for meeting working gas volume delivery with the required withdrawal profile. In caverns, the cushion gas volume is also required for stability reasons. The cushion gas volume may consist of recoverable and non-recoverable in-situ gas volumes and injected gas volumes. |
| Deposit | 2007 - 2.4 | Material laid down by a natural process. In resource evaluations, it identifies an accumulation of hydrocarbons in a reservoir (see Accumulation). |

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| Deterministic Estimate | 2007 - 3.5 | The method of estimation of Reserves or Resources is called deterministic if a discrete estimate(s) is made based on known geoscience, engineering, and economic data. |
| Developed Reserves | 2007 - 2.1.3.2 and Table 2 | Developed Reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered “developed” only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Developed Reserves may be further sub-classified as Producing or Non-Producing. |
| Developed Producing Reserves | 2007 - 2.1.3.2 and Table 2 | Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation. |
| Developed Non-Producing Reserves | 2007 - 2.1.3.2 and Table 2 | Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are also those expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. |
| Development Not Viable | 2007 - 2.1.3.1 and Table 1 | A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. A project maturity sub-class that reflects the actions required to move a project towards commercial production. |
| Development Pending | 2007 - 2.1.3.1 and Table 1 | A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class that reflects the actions required to move a project towards commercial production. |
| Development Plan | 2007 - 1.2 | The design specifications, timing and cost estimates of the development project including, but not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation and marketing. (See also Project.) |
| Development Unclarified or On Hold | 2007 - 2.1.3.1 and Table 1 | A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class that reflects the actions required to move a project toward commercial production. |
| Discovered | 2007 - 2.1.1 | A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. (See also Known Accumulations.) |

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| Discovered Petroleum Initially-in-Place | 2007 - 1.1 | Discovered Petroleum Initially-in-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. Discovered Petroleum Initially-in-Place may be subdivided into Commercial, Sub-Commercial, and Unrecoverable, with the estimated commercially recoverable portion being classified as Reserves and the estimated sub-commercial recoverable portion being classified as Contingent Resources. |
| Dry Gas | 2001 - 3.2 | Dry Gas is a natural gas remaining after hydrocarbon liquids have been removed prior to the reference point. The dry gas and removed hydrocarbon liquids are accounted for separately in resource assessments. It should be recognized that this is a resource assessment definition and not a phase behavior definition. (Also called Lean Gas.) |
| Dry Hole | 2001 - 2.5 | A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. |
| Economic | 2007 - 3.1.2<br>2001 - 4.3 | In relation to petroleum Reserves and Resources, economic refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation. |
| Economic Interest | 2001 - 9.4.1 | An Economic Interest is possessed in every case in which an investor has acquired any Interest in mineral in place and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return of his capital. |
| Economic Limit | 2007 - 3.1.2<br>2001 - 4.3 | Economic limit is defined as the production rate beyond which the net operating cash flows (after royalties or share of production owing to others) from a project, which may be an individual well, lease, or entire field, are negative. |
| Entitlement | 2007 - 3.3 | That portion of future production (and thus resources) legally accruing to a lessee or contractor under the terms of the development and production contract with a lessor. |
| Entity | 2007 - 3.0 | Entity is a legal construct capable of bearing legal rights and obligations. In resources evaluations this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies. |
| Estimated Ultimate Recovery (EUR) | 2007 - 1.1 | Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. |
| Evaluation | 2007- 3.0 | The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. Projects are classified and estimates of derived quantities are categorized according to applicable guidelines. (Also termed Assessment.) |

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| Evaluator | 2007 - 1.2, 2.1.2 | The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including Reserves and Resources and attributed value estimates. |
| Exploration | | Prospecting for undiscovered petroleum. |
| Field | 2001 - 2.3 | An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities. |
| Flare Gas | 2007 - 3.2.2<br>2001 - 3.1 | Total volume of gas vented or burned as part of production and processing operations. |
| Flow Test | 2007 - 2.1.1 | An operation on a well designed to demonstrate the existence of moveable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test). |
| Fluid Contacts | 2007 - 2.2.2 | The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal. |
| Forecast Case | 2007 - 3.1.1 | Modifier applied to project resources estimates and associated cash flow when such estimates are based on those conditions (including costs and product price schedules) forecast by the evaluator to reasonably exist throughout the life of the project. Inflation or deflation adjustments are made to costs and revenues over the evaluation period. |
| Forward Sales | 2001 - 9.6.6 | There are a variety of forms of transactions that involve the advance of funds to the owner of an interest in an oil and gas property in exchange for the right to receive the cash proceeds of production, or the production itself, arising from the future operation of the property. In such transactions, the owner almost invariably has a future performance obligation, the outcome of which is uncertain to some degree. Determination as to whether the transaction represents a sale or financing rests on the particular circumstances of each case. |
| Fuel Gas | 2007 - 3.2.2 | See Lease Fuel. |
| Gas Balance | 2007 - 3.2.7<br>2001 - 3.10 | In gas production operations involving multiple working interest owners, an imbalance in gas deliveries can occur. These imbalances must be monitored over time and eventually balanced in accordance with accepted accounting procedures. |

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| Gas Cap Gas | 2001 - 6.2.2 | Gas Cap Gas is a free natural gas which overlies and is in contact with crude oil in the reservoir. It is a subset of Associated Gas. |
| Gas Hydrates | 2007 - 2.4 | Gas hydrates are naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure, or clathrate. At conditions of standard temperature and pressure (STP), one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Because of this large gas-storage capacity, gas hydrates are thought to represent an important future source of natural gas. Gas hydrates are included in unconventional resources, but the technology to support commercial production has yet to be developed. |
| Gas Inventory | | With respect to underground natural gas storage, "gas inventory" is the sum of Working Gas Volume and Cushion Gas Volume. |
| Gas/Oil Ratio | 2007 - 3.4.4 | Gas to oil ratio in an oil field, calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil , symbol $R_s$; produced gas/oil ratio, symbol $R_p$; or another suitably defined ratio of gas production to oil production. |
| Gas Plant Products | | Gas Plant Products are natural gas liquids (or components) recovered from natural gas in gas processing plants and, in some situations, from field facilities. Gas Plant Products include ethane, propane, butanes, butanes/propane mixtures, natural gasoline and plant condensates, sulfur, carbon dioxide, nitrogen, and helium. |
| Gas-to-Liquids (GTL) Projects | | Gas-to-Liquids projects use specialized processing (e.g., Fischer-Tropsch synthesis) to convert natural gas into liquid petroleum products. Typically, these projects are applied to large gas accumulations where lack of adequate infrastructure or local markets would make conventional natural gas development projects uneconomic. |
| Geostatistical Methods | 2001 - 7.1 | A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of masses of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates, including the definition of (all) well and reservoir parameters in 1, 2, and 3 dimensions and the resultant modeling and potential prediction of various aspects of performance. |
| High Estimate | 2007 - 2.2.2<br>2001 - 2.5 | With respect to resource categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate. |
| Hydrocarbons | 2007 - 1.1 | Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon. |

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| Improved Recovery (IR) | 2007 - 2.3.4 | Improved Recovery is the extraction of additional petroleum, beyond Primary Recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called Enhanced Recovery.) |
| Injection | 2001 - 3.5<br>2007 - 3.2.5 | The forcing, pumping, or free flow under vacuum, of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids. |
| Justified for Development | 2007 - 2.1.3.1 and Table 1 | Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals/contracts will be obtained. A project maturity sub-class that reflects the actions required to move a project toward commercial production. |
| Kerogen | | The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.) |
| Known Accumulation | 2007 - 2.1.1<br>2001 - 2.2 | An accumulation is an individual body of petroleum-in-place. The key requirement to consider an accumulation as "known," and hence containing Reserves or Contingent Resources, is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling, or logging the existence of a significant quantity of recoverable hydrocarbons. |
| Lead | 2007 - 2.1.3.1 and Table 1 | A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. A project maturity sub-class that reflects the actions required to move a project toward commercial production. |
| Lease Condensate | | Lease Condensate is condensate recovered from produced natural gas in gas/liquid separators or field facilities. |
| Lease Fuel | 2007 - 3.2.2 | Oil and/or gas used for field and processing plant operations. For consistency, quantities consumed as lease fuel should be treated as shrinkage. However, regulatory guidelines may allow lease fuel to be included in Reserves estimates. Where claimed as Reserves, such fuel quantities should be reported separately from sales, and their value must be included as an operating expense. |
| Lease Plant | | A general term referring to processing facilities that are dedicated to one or more development projects and the petroleum is processed without prior custody transfer from the owners of the extraction project (for gas projects, also termed "Local Gas Plant"). |
| Liquefied Natural Gas (LNG) Project | | Liquefied Natural Gas projects use specialized cryogenic processing to convert natural gas into liquid form for tanker transport. LNG is about 1/614 the volume of natural gas at standard temperature and pressure. |
| Loan Agreement | 2001 - 9.6.5 | A loan agreement is typically used by a bank, other investor, or partner to finance all or part of an oil and gas project. Compensation for funds advanced is limited to a specified interest rate. |

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| Low/Best/High Estimates | 2007 - 2.2.1, 2.2.2 | The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes at varying degrees of uncertainty (using the cumulative scenario approach) for an individual accumulation or a project. |
| Low Estimate | 2007 - 2.2.2<br>2001 - 2.5 | With respect to resource categorization, this is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate. |
| Lowest Known Hydrocarbons | 2007 - 2.2.2. | The deepest occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, or core data. |
| Marginal Contingent Resources | 2007 - 2.1.3.3 | Known (discovered) accumulations for which a development project(s) has been evaluated as economic or reasonably expected to become economic but commitment is withheld because of one or more contingencies (e.g., lack of market and/or infrastructure). |
| Measurement | 2007 - 3.0 | The process of establishing quantity (volume or mass) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities. |
| Mineral Interest | 2001 - 9.3 | Mineral Interests in properties including (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer). |
| Monte Carlo Simulation | 2001 - 5<br>2007 - 3.5 | A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum volumes). |
| Natural Bitumen | 2007 - 2.4 | Natural Bitumen is the portion of petroleum that exists in the semisolid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non-hydrocarbons. Natural Bitumen has a viscosity greater than 10,000 milliPascals per second (mPa.s) (or centipoises) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural Bitumen generally requires upgrading prior to normal refining. (Also called Crude Bitumen.) |
| Natural Gas | 2007 - 3.2.3<br>2001 - 6.6, 9.4.4 | Natural Gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural Gas may include some amount of non-hydrocarbons. |

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| Natural Gas Inventory | | With respect to underground natural gas storage operations "inventory" is the total of working and cushion gas volumes. |
| Natural Gas Liquids | 2007 - A13<br>2001 - 3.2, 9.4.4 | Natural Gas Liquids (NGL) are a mixture of light hydrocarbons that exist in the gaseous phase and are recovered as liquids in gas processing plants. NGL differs from condensate in two principal respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensates. |
| Natural Gas Liquids to Gas Ratio | | Natural gas liquids to gas ratio in an oil or gas field, calculated using measured natural gas liquids and gas volumes at stated conditions. |
| Net-Back | 2007 - 3.2.1 | Linkage of input resource to the market price of the refined products. |
| Net Profits Interest | 2001 - 9.4.4 | An interest that receives a portion of the net proceeds from a well, typically after all costs have been paid. |
| Net Working Interest | 2001 - 9.6.1 | A company's working interest reduced by royalties or share of production owing to others under applicable lease and fiscal terms. (Also called Net Revenue Interest.) |
| Non-Hydrocarbon Gas | 2007 - 3.2.4<br>2001 - 3.3 | Natural occurring associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium. If non-hydrocarbon gases are present, the reported volumes should reflect the condition of the gas at the point of sale. Correspondingly, the accounts will reflect the value of the gas product at the point of sale. |
| Non-Associated Gas | | Non-Associated Gas is a natural gas found in a natural reservoir that does not contain crude oil. |
| Normal Production Practices | | Production practices that involve flow of fluids through wells to surface facilities that involve only physical separation of fluids and, if necessary, solids. Wells can be stimulated, using techniques including, but not limited to, hydraulic fracturing, acidization, various other chemical treatments, and thermal methods, and they can be artificially lifted (e.g., with pumps or gas lift). Transportation methods can include mixing with diluents to enable flow, as well as conventional methods of compression or pumping. Practices that involve chemical reforming of molecules of the produced fluids are considered manufacturing processes. |
| Oil Sands | | Sand deposits highly saturated with natural bitumen. Also called "Tar Sands." Note that in deposits such as the western Canada "oil sands," significant quantities of natural bitumen may be hosted in a range of lithologies including siltstones and carbonates. |
| Oil Shales | 2007 - 2.4 | Shale, siltstone and marl deposits highly saturated with kerogen. Whether extracted by mining or in situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil). |
| Offset Well Location | | Potential drill location adjacent to an existing well. The offset distance may be governed by well spacing regulations. In the absence of well spacing regulations, technical analysis of drainage areas may be used to define the spacing. For Proved volumes to be assigned to an offset well location there must be conclusive, unambiguous technical data which supports the reasonable certainty of production of hydrocarbon volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the lowest known hydrocarbon. |

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| On Production | 2007 - 2.1.3.1 and Table 1 | The development project is currently producing and selling petroleum to market. A project status/maturity sub-class that reflects the actions required to move a project toward commercial production. |
| Operator | | The company or individual responsible for managing an exploration, development, or production operation. |
| Overlift/Underlift | 2007 - 3.2.7 2001 - 3.9 | Production overlift or underlift can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed among the parties. At any given financial year-end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year, and not on the production entitlement for the year. |
| Penetration | 2007 - 1.2 | The intersection of a wellbore with a reservoir. |
| Petroleum | 2007 - 1.0 | Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%. |
| Petroleum Initially-in-Place | 2007 - 1.1 | Petroleum Initially-in-Place is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Crude Oil-in-place, Natural Gas-in-place and Natural Bitumen-in-place are defined in the same manner (see Resources). (Also referred as Total Resource Base or Hydrocarbon Endowment.) |
| Pilot Project | 2007 - 2.3.4, 2.4 | A small-scale test or trial operation that is used to assess the suitability of a method for commercial application. |
| Play | 2007 - 2.1.3.1 and Table 1 | A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. A project maturity sub-class that reflects the actions required to move a project toward commercial production. |
| Pool | | An individual and separate accumulation of petroleum in a reservoir. |
| Possible Reserves | 2007 - 2.2.2 and Table 3 | An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. |
| Primary Recovery | | Primary recovery is the extraction of petroleum from reservoirs utilizing only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery. |
| Probability | 2007 - 2.2.1 | The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. SPE convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.) |

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| Probabilistic Estimate | 2007 - 3.5 | The method of estimation of Resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities. |
| Probable Reserves | 2007 - 2.2.2 and Table 3 | An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. |
| Production | 2007 - 1.1 | Production is the cumulative quantity of petroleum that has been actually recovered over a defined time period. While all recoverable resource estimates and production are reported in terms of the sales product specifications, raw production quantities (sales and non-sales, including non-hydrocarbons) are also measured to support engineering analyses requiring reservoir voidage calculations. |
| Production-Sharing Contract | 2007 - 3.3.2<br>2001 - 9.6.2 | In a production-sharing contract between a contractor and a host government, the contractor typically bears all risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership is retained by the host government; however, the contractor normally receives title to the prescribed share of the volumes as they are produced. |
| Profit Split | 2001 - 9.6.2 | Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor is entitled to a share of the remaining profit oil or gas. The contractor receives payment in oil or gas production and is exposed to both technical and market risks. |
| Project | 2007 - 1.2<br>2001 - 2.3 | Represents the link between the petroleum accumulation and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership. In general, an individual project will represent a specific maturity level at which a decision is made on whether or not to proceed (i.e., spend money), and there should be an associated range of estimated recoverable resources for that project. (See also Development Plan.) |
| Property | 2007 - 1.2<br>2001 - 9.4 | A volume of the Earth's crust wherein a corporate entity or individual has contractual rights to extract, process, and market a defined portion of specified in-place minerals (including petroleum). Defined in general as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license. |
| Prorationing | | The allocation of production among reservoirs and wells or allocation of pipeline capacity among shippers, etc. |
| Prospect | 2007 - 2.1.3.1 and Table 1 | A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class that reflects the actions required to move a project toward commercial production. |

| | | |
|---|---|---|
| Prospective Resources | 2007 - 1.1 and Table 1 | Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. |
| Proved Economic | 2007 - 3.1.1 | In many cases, external regulatory reporting and/or financing requires that, even if only the Proved Reserves estimate for the project is actually recovered, the project will still meet minimum economic criteria; the project is then termed as "Proved Economic." |
| Proved Reserves | 2007 - 2.2.2 and Table 3 | An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as "Proven." |
| Purchase Contracts | 2001 - 9.6.8 | A contract to purchase oil and gas provides the right to purchase a specified volume of production at an agreed price for a defined term. |
| Pure-Service Contract | 2001 - 9.7.5 | A pure-service contract is an agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific period of time. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor's reimbursement is fixed by the terms of the contract with little exposure to either project performance or market factors. |
| Range of Uncertainty | 2007 - 2.2<br>2001 - 2.5 | The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. (See Resource Uncertainty Categories.) |
| Raw Natural Gas | 2007 - 3.2.1 | Raw Natural Gas is natural gas as it is produced from the reservoir. It includes water vapor and varying amounts of the heavier hydrocarbons that may liquefy in lease facilities or gas plants and may also contain sulfur compounds such as hydrogen sulfide and other non-hydrocarbon gases such as carbon dioxide, nitrogen, or helium, but which, nevertheless, is exploitable for its hydrocarbon content. Raw Natural Gas is often not suitable for direct utilization by most types of consumers. |
| Reasonable Certainty | 2007 - 2.2.2 | If deterministic methods for estimating recoverable resource quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. |
| Reasonable Expectation | 2007 - 2.1.2 | Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. |
| Reasonable Forecast | 2007 - 3.1.2 | Indicates a high degree of confidence in predictions of future events and commercial conditions. The basis of such forecasts includes, but is not limited to, analysis of historical records and published global economic models. |
| Recoverable Resources | 2007 - 1.2 | Those quantities of hydrocarbons that are estimated to be producible from discovered or undiscovered accumulations. |

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| Recovery Efficiency | 2007 - 2.2 | A numeric expression of that portion of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. |
| Reference Point | 2007 - 3.2.1 | A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions prior to custody transfer (or consumption). Also called Point of Sale or Custody Transfer Point. |
| Reserves | 2007 - 1.1 | Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied. |
| Reservoir | 2001 - 2.3 | A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rocks/formations and is characterized by a single-pressure system. |
| Resources | 2007 - 1.1 | The term “resources” as used herein is intended to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered “conventional” or “unconventional” (see Total Petroleum Initially-in-Place). (In basin potential studies, it may be referred to as Total Resource Base or Hydrocarbon Endowment.) |
| Resources Categories | 2007 - 2.2 and Table 3 | Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability, contractual changes) |
| Resources Classes | 2007 - 1.1, 2.1 and Table 1 | Subdivisions of Resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project’s estimated chance of reaching producing status. |
| Revenue-Sharing Contract | 2001 - 9.6.3 | Revenue-sharing contracts are very similar to the production-sharing contracts described earlier, with the exception of contractor payment. With these contracts, the contractor usually receives a defined share of revenue rather than a share of the production. |
| Reversionary Interest | | The right of future possession of an interest in a property when a specified condition has been met. |
| Risk | 2001 - 2.5 | The probability of loss or failure. As “risk” is generally associated with the negative outcome, the term “chance” is preferred for general usage to describe the probability of a discrete event occurring. |

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| Risk and Reward | 2001 - 9.4 | Risk and reward associated with oil and gas production activities stems primarily from the variation in revenues due to technical and economic risks. Technical risk affects a company's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors. |
| Risked-Service Contract | 2007 - 3.3.2<br>2001 - 9.7.4 | These agreements are very similar to the production-sharing agreements with the exception of contractor payment, but risk is borne by the contractor. With a risked-service contract, the contractor usually receives a defined share of revenue rather than a share of the production. |
| Royalty | 2007 - 3.3.1<br>2001 - 3.8 | Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs and the producer (lessee/contractor) for having access to the petroleum resources. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. Some agreements provide for the royalty to be taken only in kind by the royalty owner. |
| Sales | 2007 - 3.2 | The quantity of petroleum product delivered at the custody transfer (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities. All recoverable resources are estimated in terms of the product sales quantity measurements. |
| Shut-in Reserves | 2007 - 2.1.3.2 and Table 2 | Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not started producing; (2) wells which were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons. |
| Solution Gas | | Solution Gas is a natural gas which is dissolved in crude oil in the reservoir at the prevailing reservoir conditions of pressure and temperature. It is a subset of Associated Gas. |
| Sour Natural Gas | 2001 - 3.4 | Sour Natural Gas is a natural gas that contains sulfur, sulfur compounds, and/or carbon dioxide in quantities that may require removal for sales or effective use. |
| Stochastic | 2001 - 5 | Adjective defining a process involving or containing a random variable or variables or involving chance or probability such as a stochastic stimulation. |
| Sub-Commercial | 2007 - 2.1.2 | A project is Sub-Commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. Discovered sub-commercial projects are classified as Contingent Resources. |
| Sub-Marginal Contingent Resources | 2007 - 2.1.3.3 | Known (discovered) accumulations for which evaluation of development project(s) indicated they would not meet economic criteria, even considering reasonably expected improvements in conditions. |
| Sweet Natural Gas | 2001 - 3.3 | Sweet Natural Gas is a natural gas that contains no sulfur or sulfur compounds at all, or in such small quantities that no processing is necessary for their removal in order that the gas may be sold. |

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| Synthetic Crude Oil (SCO) | 2001 - A12, A13 | A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. SCO may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil. |
| Taxes | 2001 - 9.4.2 | Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority. |
| Technical Uncertainty | 2007 - 2.2 | Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied. |
| Total Petroleum Initially-in-Place | 2007 - 1.1 | Total Petroleum Initially-in-Place is generally accepted to be all those estimated quantities of petroleum contained in the subsurface, as well as those quantities already produced. This was defined previously by the WPC as "Petroleum-in-place" and has been termed "Resource Base" by others. Also termed "Original-in-Place" or "Hydrocarbon Endowment." |
| Uncertainty | 2007 - 2.2<br>2001 - 2.5 | The range of possible outcomes in a series of estimates. For recoverable resource assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.) |
| Unconventional Resources | 2007 - 2.4, | Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrate, natural bitumen (tar sands), and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders). (Also termed "Non-Conventional" Resources and "Continuous Deposits.") |
| Undeveloped Reserves | 2001 - 2.1.3.1 and Table 2 | Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects. |
| Unitization | | Process whereby owners group adjoining properties and divide reserves, production, costs, and other factors according to their respective entitlement to petroleum quantities to be recovered from the shared reservoir(s). |
| Unproved Reserves | 2001 - 5.1.1 | Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves. |
| Unrecoverable Resources | 2007 - 1.1 | That portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which are estimated, as of a given date, not to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data are acquired. |

| | | |
|---|---|---|
| Upgrader | 2007 - 2.4 | A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil (SCO). While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts. |
| Well Abandonment | | The permanent plugging of a dry hole, an injection well, an exploration well, or a well that no longer produces petroleum or is no longer capable of producing petroleum profitably. Several steps are involved in the abandonment of a well: permission for abandonment and procedural requirements are secured from official agencies; the casing is removed and salvaged if possible; and one or more cement plugs and/or mud are placed in the borehole to prevent migration of fluids between the different formations penetrated by the borehole. In some cases, wells may be temporarily abandoned where operations are suspended for extended periods pending future conversions to other applications such as reservoir monitoring, enhanced recovery, etc. |
| Wet Gas | 2001 - 3.2<br>2007 - 3.2.3 | Wet (Rich) Gas is natural gas from which no liquids have been removed prior to the reference point. The wet gas is accounted for in resource assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resource assessment definition and not a phase behavior definition. |
| Working Gas Volume | | With respect to underground natural gas storage, Working Gas Volume (WGV) is the volume of gas in storage above the designed level of cushion gas which can be withdrawn/injected with the installed subsurface and surface facilities (wells, flowlines, etc.) subject to legal and technical limitations (pressures, velocities, etc.). Depending on local site conditions (injection/withdrawal rates, utilization hours, etc.), the working gas volume may be cycled more than once a year. |
| Working Interest | 2001 - 9 | A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms. |

# APPENDIX B

# RESPONSES TO QUESTIONNAIRES ON OPERATIONS AND RESERVOIR PARAMETERS

# Questionnaire from Petrobangla for Field Operations

## Wellbore Equipment

Total 10 wells have been drilled so far in the Sangu main field, of which 4 wells are producing gas presently. Wellbore diagrams for the producing wells are given in Attachment-1.

## Facilities Equipment Layout

- Sangu offshore Process Flow Diagram (Attachment-2)
- Sangu Onshore Process Facilities Process Flow Diagram (Attachment-3)

## Production Rate Practices

Presently production is sustained with following 4 wells producing gas from Sangu field.

### Sangu-1

- 4" choke 100% open
- Producing from 3 Zones (SG1.2585, 2970 & 3155)
- Production $\simeq$ 5 MMscf/d - below critical rate, average FTHP 175 psi
- Sustaining production venting the well to atmosphere time to time for liquid unloading thus suppressing the critical rate

### Sangu-3Z

- 4" choke 100% open
- Producing from SG1.3155 since 1998, which was commingled with SG1.3255 at the end of 2003. Present gas production around 13 MMscf/d at FTHP around 200 psi
- Producing formation water since Q3 2009, LGR increasing to 10 bbl/MMscf at the end of March 2010.

### Sangu-8

- 4" choke 100% open
- Production from 2 zones (SG1.3085 & 3155)
- Production $\simeq$ 2.5 MMscfd which has increased to $\simeq$ 14 MMscfd after the recent intervention.
- Average LGR 3.5 bbl/MMscf

## Sangu-9

- 4" choke 100% open
- Production from 2 zones (SG1.3155 & SG3.2635)
- SG3.2635 prone to sand production thus maintained maximum sand face pressure drawdown up to 350 psi
- Production $\simeq$ 11 MMscfd
- Average LGR 11 bbl/MMscf

## Production Enhancement

1. **Facilities Enhancement**
   - Total gas processing capacity of two trains : 520 MMscf/d, no further enhancement required
   - Already installed onshore compressors,
     - present average suction pressure - 120 psi (compared to 300 psi plant inlet pressure in natural flow), designed for up to 80 psi

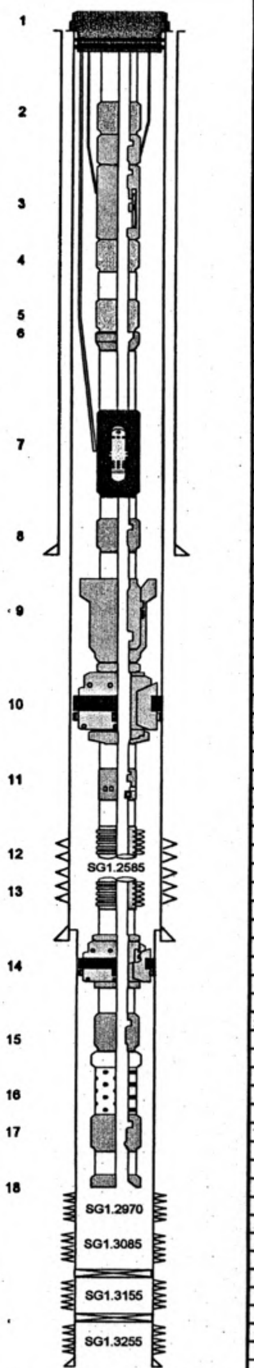
2. **Production Enhancement through Workovers and Recompletions**
   - Conducted total 6 (six) interventions since 2003.
   - Current Interventions :
     - Sand bailing and removal of mechanical obstruction, if any, in Sangu-7, 8 & 9 (additional recovery of around 3.4 bcf is anticipated) with an initial production increment of around 10 MMscf/d.
     - Isolating SG1.3255 & 3155 in Sangu-3Z and Opening SG3.2635 (additional recovery of around 17 bcf is anticipated considering 52 bcf GIIP for SG3.2635 reservoir) – due to adverse weather condition this operation is however deferred to November 2010.

3. **Reserves Growth with the use of 3D Seismic**
   - Presently 3D seismic survey is being conducted to confirm the mapping of South Sangu reservoir sands (Mean GIIP 124 bcf) and Sangu field (partially).

4. **Production and reserves enhancement through drilling to prove up probable and possible reserves**
   - Subject to positive outcome of 3D seismic survey well may be drilled to confirm expected 124 bcf Mean GIIP of South Sangu reservoirs.

**ATTACHMENT-1**

# Sangu 1 Wellbore Schematic




| OPERATOR | CAIRN ENERGY | CASING | | LINER | | TUBING | | |
|---|---|---|---|---|---|---|---|---|
| WELL# | SANGU 1 | SIZE | 9 5/8" | 7" | | 5 1/2" | 4 1/2" | |
| FIELD | SANGU | WEIGHT | 47PPF | 32PPF | | 17PPF | 12.6PPF | |
| COUNTRY | BANGLADESH | GRADE | | | | L80 13Cr. | L80 13Cr. | |
| Comp. DATE | Tuesday, February 10, 1998 | THREAD | SLX | SLX | | FOX-K | FOX-K | |
| Schem Update | Wednesday, April 22, 2009 | DEPTH(m) | 2898 | 3497 | | 2467.70 | 2890.84 | |
| Update by: | Babur Khan | MAX DEV | 4.5 | 8.25 | | | | |

| ITEM# | EQUIPMENT AND SERVICES | ID" | OD" | LENGTH | Top Depth | Bot. Depth |
|---|---|---|---|---|---|---|
| | RIG FLOOR ELEVATION TO RKB | | | 9.140 | 0.00 | |
| | | | | | | |
| 1 | CAMERON TUBING HANGER | 4.881 | 13.071 | 0.240 | 0.00 | 0.24 |
| | PUP JOINT 5 1/2" 13Cr. L80 17# FOX K PIN x PIN | 4.892 | 5.500 | 1.430 | 0.24 | 1.67 |
| | SPACER PUP JOINT 5 1/2" 13Cr. L80 17# FOX K | 4.892 | 5.500 | 2.972 | 1.67 | 4.64 |
| | SPACER PUP JOINT 5 1/2" 13Cr. L80 17# FOX K | 4.892 | 5.500 | 1.582 | 4.64 | 6.22 |
| | 9 x TUBING JOINTS 5 1/2" 13Cr. L80 17# Fox K | 4.892 | 5.500 | 110.909 | 6.22 | 117.13 |
| 2 | Baker 5-1/2" Flow Coupling | 4.892 | 6.050 | 1.379 | 117.13 | 118.51 |
| 3 | BAKER 5 1/2" T-5EMS Slimline TRSSV comp. w/upper 4.562" 'LS' WLRSSSV nipple. | 4.562 | 7.700 | 2.381 | 118.51 | 120.89 |
| 4 | Baker 5-1/2" Flow Coupling | 4.892 | 6.050 | 1.374 | 120.89 | 122.27 |
| | 5 1/2" PUP JOINT 13Cr. L80 17# FOX K | 4.892 | 5.500 | 2.492 | 122.27 | 124.76 |
| | 5 1/2" PUP JOINT 13Cr. L80 17# FOX K | 4.892 | 5.500 | 1.582 | 124.76 | 126.34 |
| | 193 x TUBING JOINTS 5 1/2" 13Cr. L80 17# FOX K | 4.892 | 5.500 | 2338.112 | 126.34 | 2464.45 |
| | 5 1/2" PUP JOINT 13Cr. L80 17# FOX K | 4.892 | 5.500 | 1.570 | 2464.45 | 2466.02 |
| 5 | Baker 5-1/2" Flow Coupling | 4.892 | 6.050 | 1.380 | 2466.02 | 2467.40 |
| 6 | CROSS-OVER PUP JOINT 5 1/2" box x 4-1/2" pin | 3.833 | 5.980 | 0.296 | 2467.40 | 2467.70 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.573 | 2467.70 | 2469.27 |
| | 2 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 22.554 | 2469.27 | 2491.83 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.557 | 2491.83 | 2493.38 |
| 7 | Exal permanent gauge carrier | 3.958 | 5.835 | 1.887 | 2493.38 | 2495.27 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.552 | 2495.27 | 2496.82 |
| | 2 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 22.574 | 2496.82 | 2519.40 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.518 | 2519.40 | 2520.91 |
| 8 | 4 1/2" x 3.813" AOF Nipple | 3.812 | 5.315 | 0.661 | 2520.91 | 2521.58 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.574 | 2521.58 | 2523.15 |
| | 1 x TUBING JOINT 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 11.287 | 2523.15 | 2534.44 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.558 | 2534.44 | 2535.99 |
| | 4 1/2" x 20' stroke PBR, size 80-48 | 3.958 | 5.910 | 8.254 | 2535.99 | 2544.25 |
| 9 | 4 1/2" KC-22S anchor tubing seal assy size 81 - 47 | 3.870 | 5.499 | 0.872 | 2544.25 | 2545.12 |
| 10 | 9 5/8" SABT packer 190-60-47 | 3.875 | 5.875 | 1.652 | 2545.12 | 2546.77 |
| | Mill out extension size 80-40 | 4.758 | 5.540 | 1.872 | 2546.77 | 2548.64 |
| | CROSS-OVER 5 1/2" box x 4-1/2" pin | 3.958 | 5.970 | 0.330 | 2548.64 | 2548.97 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.562 | 2548.97 | 2550.54 |
| | 3 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 33.842 | 2550.54 | 2584.38 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.562 | 2584.38 | 2585.94 |
| 11 | Baker 3.75" CMD SSD (Open) | 3.750 | 5.468 | 1.398 | 2585.94 | 2587.34 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.562 | 2587.34 | 2588.90 |
| | 2 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 22.554 | 2588.90 | 2611.45 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.577 | 2611.45 | 2613.03 |
| 12 | 14 x 4 1/2" Blast Joints | 3.948 | 4.921 | 41.720 | 2613.03 | 2654.75 |
| | 16 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 178.666 | 2654.75 | 2833.42 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.590 | 2833.42 | 2835.01 |
| 13 | 1 x 4 1/2" Blast Joints | 3.948 | 4.921 | 2.920 | 2835.01 | 2837.93 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.568 | 2837.93 | 2839.50 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.447 | 2839.50 | 2840.94 |
| | 4 1/2" E22 shear out seal assy size 81-47 | 3.875 | 5.487 | 0.794 | 2840.94 | 2841.74 |
| 14 | 7" SABLT packer 85-47-38 | 3.875 | 5.875 | 1.587 | 2841.74 | 2843.32 |
| | Mill out extension size 80-40 | 4.758 | 5.540 | 1.592 | 2843.32 | 2844.92 |
| | CROSS-OVER 5 1/2" box x 4-1/2" pin | 3.958 | 5.970 | 0.275 | 2844.92 | 2845.19 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.543 | 2845.19 | 2846.73 |
| | 2 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 22.114 | 2846.73 | 2868.85 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.567 | 2868.85 | 2870.41 |
| 15 | 4 1/2" x 3.688" AOF Nipple | 3.812 | 5.315 | 0.662 | 2870.41 | 2871.08 |
| 16 | 4 1/2" perforated pup joint | 3.958 | 4.530 | 3.097 | 2871.08 | 2874.17 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.574 | 2874.17 | 2875.75 |
| 17 | 4 1/2" x 3.688" R Nipple | 3.625 | 4.902 | 0.458 | 2875.75 | 2876.21 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.874 | 2876.21 | 2878.08 |
| | 1 x TUBING JOINT 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 11.187 | 2878.08 | 2889.27 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.572 | 2889.27 | 2890.84 |
| 18 | Baker Fluted Wireline re-entry guide | 3.975 | 5.938 | 0.431 | 2890.84 | 2891.27 |

**WELL FLUIDS**

| | |
|---|---|
| Pre Completion | 9.6PPG BRINE |
| Post Completion | 6.7PPG BASE OIL. |

| PREPARED BY | OFFICE | TELEPHONE |
|---|---|---|
| Mike Ross | Edinburgh | 0131 475 3221 |

**Notes:**

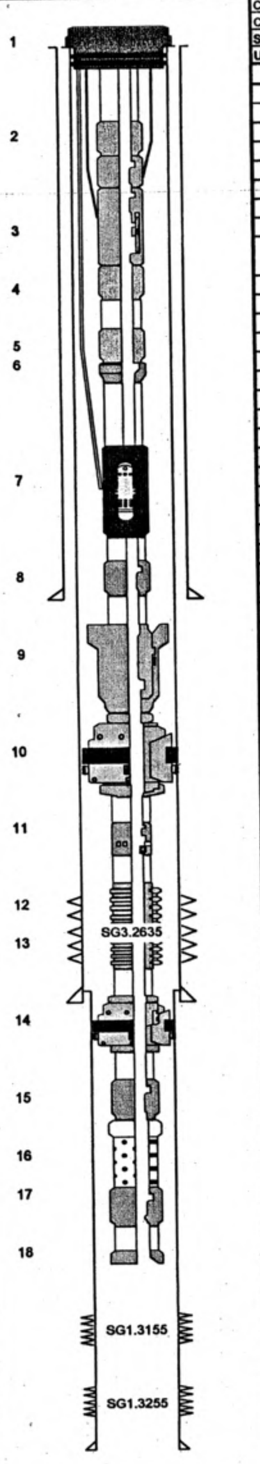
Perforation depths are reported as m MDBRT.
All lengths and depths reported in meters

| Interval | Perforations | Perforations | Perforations | Perforations | Perforations |
|---|---|---|---|---|---|
| *Date:* | Apr-98 | Dec-03 | Mar-08 | Oct-08 | Dec-08 |
| MS2 Sand | interval not present | | | | |
| SG1.2585 | 2622 - 2655m (Isolated with SSD) | 2622-2655m (Isolated with SSD) | 2622 - 2655m (Isolated with SSD) | 2622 - 2655m SSD open & commenced production | |
| SG1.2635 | interval not present | | | | |
| SG3z.2825 | interval not present | | | | |
| SG1.2970 | | | 3006 - 3035m | | |
| SG1.3085 | | | | | 3162.5 - 3170.5m<br>3151 - 3158.5m |
| SG1.3155 | 3208.3 - 3256.3m | 3191 - 3265m | Isolated with TTBP | | |
| SG1.3255 | | 3292 - 3320m | Isolated with TTBP | | |

ATTACHMENT-1

# Sangu 3z Wellbore Schematic

| | | | CASING | LINER | | TUBING | | |
|---|---|---|---|---|---|---|---|---|
| OPERATOR | CAIRN ENERGY | | | | | | | |
| WELL# | SANGU 3z | SIZE | 9 5/8" | 7" | | 5 1/2" | 4 1/2" | |
| FIELD | SANGU | WEIGHT | 47PPF | 29PPF | | 17PPF | 12.6PPF | |
| COUNTRY | BANGLADESH | GRADE | L80 | L80 | | L80 13Cr. | C95 13Cr. | |
| Comp. DATE | Thursday, December 18, 1997 | THREAD | Fox | Fox | | FOX-K | FOX-K | |
| Schem Update | Wednesday, July 02, 2008 | DEPTH(m) | 3242 | 2847 (top) | 3886 (bot) | 2777.37 | 3602.89 | |
| Update by: | Mike Ross | MAX DEV | 44.27 | 29 | | | | |




| ITEM# | EQUIPMENT AND SERVICES | ID" | OD" | LENGTH | Top Depth | Bot. Depth |
|---|---|---|---|---|---|---|
| | RIG FLOOR ELEVATION TO RKB | | | 9.140 | 0.00 | |
| 1 | CAMERON TUBING HANGER | 4.881 | 13.071 | 0.240 | 0.00 | 0.24 |
| | 5 1/2" PUP JOINT 13Cr. L80 17# FOX K PIN x PIN | 4.892 | 5.500 | 1.430 | 0.24 | 1.67 |
| | 1 x TUBING JOINTS 5 1/2" 13Cr. L80 17# Fox K | 4.892 | 5.500 | 12.192 | 1.67 | 13.86 |
| | 5 1/2" PUP JOINT 13Cr. L80 17# FOX K | 4.892 | 5.500 | 3.144 | 13.86 | 17.01 |
| | 8 x TUBING JOINTS 5 1/2" 13Cr. L80 17# Fox K | 4.892 | 5.500 | 97.487 | 17.01 | 114.49 |
| 2 | Baker 5-1/2" Flow Coupling | 4.892 | 6.050 | 1.400 | 114.49 | 115.89 |
| 3 | BAKER 5 1/2" T-5EMS Slimline TRSSV comp. w/upper 4.562" 'LS' WLRSSSV nipple & wireline retrievable insert valve. | 4.562 | 7.700 | 2.380 | 115.89 | 118.27 |
| 4 | Baker 5-1/2" Flow Coupling | 4.892 | 6.050 | 1.380 | 118.27 | 119.65 |
| | 220 x TUBING JOINTS 5 1/2" 13Cr. L80 17# FOX K | 4.892 | 5.500 | 2654.595 | 119.65 | 2774.25 |
| | 5 1/2" PUP JOINT 13Cr. L80 17# FOX K | 4.892 | 5.500 | 1.750 | 2774.25 | 2776.00 |
| 5 | Baker 5-1/2" Flow Coupling | 4.892 | 6.050 | 1.376 | 2776.00 | 2777.37 |
| 6 | CROSS-OVER PUP JOINT 5 1/2" box x 4-1/2" pin | 3.833 | 5.980 | 0.294 | 2777.37 | 2777.67 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.585 | 2777.67 | 2779.25 |
| | 18 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 200.976 | 2779.25 | 2980.23 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.560 | 2980.23 | 2981.79 |
| 7 | Exal permanent gauge carrier | 3.958 | 5.835 | 1.893 | 2981.79 | 2983.68 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.556 | 2983.68 | 2985.24 |
| | 6 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 67.162 | 2985.24 | 3052.40 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.610 | 3052.40 | 3054.01 |
| 8 | 4 1/2" x 3.813" AOF Nipple | 3.812 | 5.315 | 0.660 | 3054.01 | 3054.67 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.568 | 3054.67 | 3056.24 |
| | 1 x TUBING JOINT 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 11.177 | 3056.24 | 3067.42 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.580 | 3067.42 | 3069.00 |
| | 4 1/2" x 20' stroke PBR, size 80-48 | 3.958 | 5.910 | 8.270 | 3069.00 | 3077.27 |
| 9 | 4 1/2" KC-22S anchor tubing seal assy size 81 - 47 | 3.870 | 5.499 | 0.800 | 3077.27 | 3078.07 |
| 10 | 9 5/8" SABT packer 190-60-47 | 3.875 | 5.875 | 1.587 | 3078.07 | 3079.65 |
| | Mill out extension size 80-40 | 4.758 | 5.540 | 1.595 | 3079.65 | 3081.25 |
| | CROSS-OVER 5 1/2" box x 4-1/2" pin | 3.958 | 5.970 | 0.273 | 3081.25 | 3081.52 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.585 | 3081.52 | 3083.11 |
| | 1 x TUBING JOINT 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 11.287 | 3083.11 | 3094.39 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.585 | 3094.39 | 3095.98 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.587 | 3095.98 | 3097.56 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.519 | 3097.56 | 3099.08 |
| | 1 x TUBING JOINT 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 11.267 | 3099.08 | 3110.35 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.600 | 3110.35 | 3111.95 |
| 11 | Baker 3.75" CMD SSD (Closed) | 3.750 | 5.468 | 1.397 | 3111.95 | 3113.35 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.569 | 3113.35 | 3114.92 |
| | 2 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 22.317 | 3114.92 | 3137.23 |
| 12 | 12 x 4 1/2" Blast Joints | 3.948 | 4.921 | 35.760 | 3137.23 | 3172.99 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.577 | 3172.99 | 3174.57 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.567 | 3174.57 | 3176.14 |
| | 33 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 369.128 | 3176.14 | 3545.27 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.590 | 3545.27 | 3546.86 |
| 13 | 1 x 4 1/2" Blast Joints | 3.948 | 4.921 | 2.920 | 3546.86 | 3549.78 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.568 | 3549.78 | 3551.34 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.571 | 3551.34 | 3552.91 |
| | 4 1/2" E22 shear out seal assy size 81-47 | 3.875 | 5.487 | 0.800 | 3552.91 | 3553.71 |
| 14 | 7" SABLT packer 85-47-38 | 3.875 | 5.875 | 1.587 | 3553.71 | 3555.30 |
| | Mill out extension size 80-40 | 4.758 | 5.540 | 1.593 | 3555.30 | 3556.89 |
| | CROSS-OVER 5 1/2" box x 4-1/2" pin | 3.958 | 5.970 | 0.258 | 3556.89 | 3557.15 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.610 | 3557.15 | 3558.76 |
| | 2 x TUBING JOINTS 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 22.214 | 3558.76 | 3580.98 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.567 | 3580.98 | 3582.54 |
| 15 | 4 1/2" x 3.688" AOF Nipple | 3.812 | 5.315 | 0.660 | 3582.54 | 3583.20 |
| 16 | 4 1/2" perforated pup joint | 3.958 | 4.530 | 3.100 | 3583.20 | 3586.30 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.910 | 3586.30 | 3588.21 |
| 17 | 4 1/2" x 3.688" R Nipple | 3.625 | 4.902 | 0.457 | 3588.21 | 3588.67 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.563 | 3588.67 | 3590.23 |
| | 1 x TUBING JOINT 4 1/2" 13Cr. C95 12.6# FOX K | 3.958 | 4.500 | 10.657 | 3590.23 | 3600.89 |
| | 4 1/2" PUP JOINT 13Cr. L80 12.6# FOX K | 3.958 | 4.500 | 1.575 | 3600.89 | 3602.46 |
| 18 | Baker Fluted Wireline re-entry guide | 3.975 | 5.938 | 0.430 | 3602.46 | 3602.89 |

| PREPARED BY | OFFICE | TELEPHONE |
|---|---|---|
| Mike Ross | Edinburgh | 0131 475 3221 |

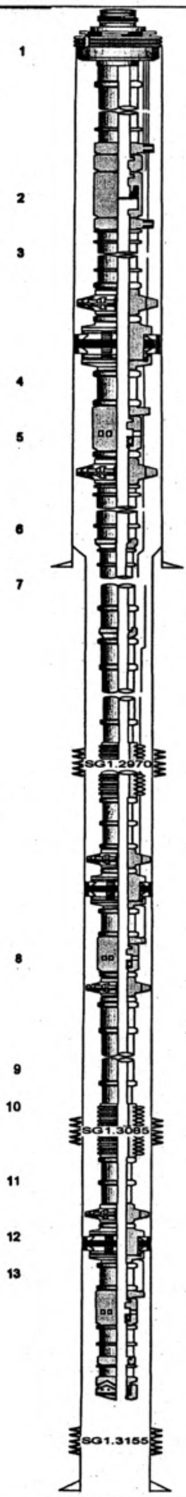
**Notes:**

Perforation depths are reported as m MDBRT.
All lengths and depths reported in meters

| Interval | Perforations | Perforations | Perforations | Perforations |
|---|---|---|---|---|
| *Date:* | Apr-98 | Dec-03 | | |
| MS2 Sand | interval not present | | | |
| SG1.2585 | interval not present | | | |
| SG3.2635 | 3145 - 3166m (Isolated with SSD) | 3145 - 3166m (Isolated with SSD) | | |
| SG3z.2825 | wet | | | |
| SG1.2970 | interval not present | | | |
| SG1.3085 | | | | |
| SG1.3155 | 3745 - 3790m | 3725 - 3800m | | |
| SG1.3255 | | 3823 - 3842m | | |

ATTACHMENT-1

# Sangu 8
# Wellbore Schematic




| OPERATOR | CAIRN ENERGY | CASING | | LINER | | TUBING | | |
|---|---|---|---|---|---|---|---|---|
| WELL# | SANGU 8 (D Well) | SIZE | 9 5/8" | 7" | | 5 1/2" | 4 1/2" | 3 1/2" |
| FIELD | SANGU | WEIGHT | 47PPF | 29PPF | | 17PPF | 12.6 PPF | 9.2PPF |
| COUNTRY | BANGLADESH | GRADE | L80 | L80 | | L80 13Cr. | L80 13 Cr. | L80 13Cr. |
| Comp. DATE | 8thMarch 2005 | THREAD | FOX | Fox | | BEAR | BEAR | BEAR |
| Schem Update | Friday, July 04, 2008 | DEPTH(m) | 3063 | 2956.86 | 3410 | 2940.000 | 3083.00 | 3263 |
| Update by: | Mike Ross | MAX DEV | 16 | 16 | | | | |

| ITEM# | EQUIPMENT AND SERVICES | ID" | OD" | LENGTH | Top Depth | Bot. Depth |
|---|---|---|---|---|---|---|
| | Ocean Soverign Rig Floor elevation to platform hangoff point | | | 19.560 | 0.00 | |
| | | | | | 19.56 | |
| 1 | CAMERON TUBING HANGER | | 13.625 | 0.221 | 19.56 | 19.56 |
| | 13 5/8" x 6.375" HN/B 38685 CC-RS-04 151992-01-03 REV 01 110283887-2 | | | | 19.78 | |
| | PUP JOINT 5 1/2" 13Cr. L80 17# FOX PIN x 5 1/2" 17# KS BEAR PIN | 4.892 | 5.500 | 1.452 | 19.78 | 21.23 |
| | SPACER PUP JOINT 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# KS BEAR PIN | 4.892 | 5.958 | 2.920 | 21.23 | 24.15 |
| | 15 x TUBING JOINTS 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# KS BEAR PIN | 4.892 | 5.958 | 143.810 | 24.15 | 167.96 |
| | CROSS-OVER PUP JOINT 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# VAM TOP HC PIN | 4.874 | 5.958 | 2.793 | 167.96 | 170.76 |
| 2 | BAKER MODEL 'LP' NIPPLE c/w 4.562" 'AOF' PROFILE | 4.562 | 7.795 | | 170.76 | 170.76 |
| 3 | BAKER MODEL 5 1/2" 'TSME-5' SAFETY VALVE ASSEMBLY | 4.562 | 8.442 | 2.987 | 170.76 | 173.74 |
| | 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x 5 1/2" 17# VAM TOP HC PIN | | | | 173.74 | 173.74 |
| | PUP JOINT 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x 5 1/2" 17# KS BEAR PIN | 4.788 | 6.037 | 1.267 | 173.74 | 175.01 |
| | 2286 x TUBING JOINTS 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# KS BEAR PIN | 4.892 | 5.958 | 2739.340 | 175.01 | 2914.35 |
| | CROSS-OVER PUP JOINT 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# VAM TOP HC PIN | 4.824 | 5.976 | 2.801 | 2914.35 | 2917.15 |
| | COUPLING 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x BOX | 4.799 | 6.024 | 0.275 | 2917.15 | 2917.43 |
| 4 | BAKER SPLICE SUB 5 1/2" 13Cr. 80KSI 17# VAM TOP HC BOX x BOX | 4.824 | 8.231 | 0.756 | 2917.43 | 2918.18 |
| | COUPLING 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x BOX | 4.787 | 6.020 | 0.275 | 2918.18 | 2918.46 |
| 5 | BAKER PREMIER HYDRAULIC SET RETRIEVABLE PRODUCTION PACKER | 4.745 | 8.308 | 2.000 | 2918.46 | 2920.46 |
| | c/w MULTIPLE CONTROL LINE FEED THRU & 'HNBR' ELASTOMERS. SIZE 831-475 | | | | 2920.46 | 2920.46 |
| | 5 1/2" 13Cr. 80KSI 17# VAM TOP HC PIN x PIN | | | | 2920.46 | 2920.46 |
| | PUP JOINT 5 1/2" 13Cr. 80KSI 17# VAM TOP HC BOX x 5 1/2"17# VAM TOP HC PIN | 4.807 | 6.008 | 1.268 | 2920.46 | 2921.73 |
| | COUPLING 5 1/2" 13Cr. 80KSI 17# VAM TOP HC BOX x BOX | 4.790 | 6.011 | 0.275 | 2921.73 | 2922.00 |
| 6 | BAKER 'INFORCE' "HCM PLUS" SLIDING SLEEVE | 4.437 | 7.358 | 2.580 | 2922.00 | 2924.58 |
| | 5 1/2" x 4.437" BAKER 'AF' PROFILE | | | | 2924.58 | 2924.58 |
| | COUPLING 5 1/2" 13Cr. 80KSI 17# VAM TOP HC BOX x BOX | 4.793 | 6.007 | 0.275 | 2924.58 | 2924.86 |
| 7 | BAKER SPLICE SUB 5 1/2" 13Cr. 80KSI 17# VAM TOP HC PIN x PIN | 4.823 | 8.232 | 0.760 | 2924.86 | 2925.62 |
| | CROSS-OVER PUP JOINT 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x 5 1/2" 17# KS BEAR PIN | 4.821 | 5.998 | 1.266 | 2925.62 | 2926.88 |
| | 1 x TUBING JOINTS 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# KS BEAR PIN | 4.892 | 5.958 | 9.950 | 2926.88 | 2936.83 |
| | CROSS-OVER PUP JOINT 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# VAM TOP HC PIN | 4.828 | 5.971 | 2.786 | 2936.83 | 2939.62 |
| | BAKER CROSS-OVER 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x 4 1/2"12.6# VAM TOP HC PIN | 3.895 | 6.004 | 0.666 | 2939.62 | 2940.28 |
| | CROSS-OVER PUP JOINT 4 1/2" 13Cr. L80 12.6# VAM TOP HC BOX x 4 1/2" 12.6# KS BEAR PIN | 3.968 | 4.932 | 1.264 | 2940.28 | 2941.55 |
| | 15 x TUBING JOINTS 4 1/2" 13Cr. L80 12.6# KS BEAR BOX x 4 1/2" 17# KS BEAR PIN | 3.958 | 4.906 | 138.610 | 2941.55 | 3080.16 |
| | CROSS-OVER PUP JOINT 4 1/2" 13Cr. L80 12.6# KS BEAR BOX x 4 1/2" 12.6# VAM TOP HC PIN | 3.961 | 4.890 | 2.792 | 3080.16 | 3082.95 |
| | BAKER CROSS-OVER 4 1/2" 13Cr. L80 12.6# VAM TOP HC BOX x 3 1/2" 9.2# VAM TOP PIN BOT | 2.973 | 4.894 | 0.650 | 3082.95 | 3083.60 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.973 | 3.905 | 1.266 | 3083.60 | 3084.87 |
| | 1 x 3 1/2" TUBING JOINTS 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# KS BEAR PIN | 2.992 | 3.883 | 9.590 | 3084.87 | 3094.46 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.992 | 3.883 | 2.800 | 3094.46 | 3097.26 |
| 8 | 8 x BAKER SPECIAL PROTECTION BLAST JOINTS | 2.92 | 3.907 | 32.000 | 3097.26 | 3129.26 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.992 | 3.883 | 1.270 | 3129.26 | 3130.53 |
| | 4 x TUBING JOINTS 4 1/2" 13Cr. L80 12.6# KS BEAR BOX x 4 1/2" 17# KS BEAR PIN | 2.992 | 3.883 | 38.320 | 3130.53 | 3168.85 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.949 | 3.896 | 2.790 | 3168.85 | 3171.64 |
| | COUPLING 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x BOX | 2.960 | 3.909 | 0.180 | 3171.64 | 3171.82 |
| 9 | BAKER SPLICE SUB 3 1/2" 13Cr. 80KSI 9.2# VAM TOP PIN x PIN | 2.975 | 5.804 | 0.913 | 3171.82 | 3172.73 |
| | COUPLING 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x BOX | 2.957 | 3.911 | 0.180 | 3172.73 | 3172.91 |
| 10 | BAKER PREMIER HYDRAULIC SET RETRIEVABLE PRODUCTION PACKER | 2.973 | 5.882 | 2.064 | 3172.91 | 3174.97 |
| | c/w MULTIPLE CONTROL LINE FEED THRU & 'HNBR' ELASTOMERS. SIZE 591-294 | | | | 3174.97 | 3174.97 |
| | PUP JOINT 3 1/2" 13Cr. 80KSI 9.2# VAM TOP BOX x PIN | 2.979 | 3.908 | 1.264 | 3174.97 | 3176.24 |
| | COUPLING 3 1/2" 13Cr. 80KSI 9.2# VAM TOP HC BOX x BOX | 2.962 | 3.886 | 0.180 | 3176.24 | 3176.42 |
| 11 | BAKER 'INFORCE' "HCM PLUS" SLIDING SLEEVE | 2.961 | 5.215 | 2.617 | 3176.42 | 3179.03 |
| | 3 1/2" x 2.812" BAKER 'A1' PROFILE NIPPLE | | | | 3179.03 | 3179.03 |
| | COUPLING 3 1/2" 13Cr. 80KSI 9.2# VAM TOP HC BOX x BOX | 2.949 | 3.914 | 0.180 | 3179.03 | 3179.21 |
| | BAKER SPLICE SUB 3 1/2" 13Cr. 80KSI 9.2# VAM TOP PIN x PIN | 2.898 | 5.778 | 0.914 | 3179.21 | 3180.13 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.983 | 3.914 | 1.267 | 3180.13 | 3181.39 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.983 | 3.914 | 2.797 | 3181.39 | 3184.19 |
| 8 | 15 x BAKER SPECIAL PROTECTION BLAST JOINTS | 2.920 | 3.907 | 60.000 | 3184.19 | 3244.19 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.983 | 3.914 | 1.284 | 3244.19 | 3245.48 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.931 | 3.916 | 2.721 | 3245.48 | 3248.20 |
| | COUPLING 3 1/2" 13Cr. 80KSI 9.2# VAM TOP HC BOX x BOX | 2.939 | 3.922 | 0.180 | 3248.20 | 3248.38 |
| | BAKER SPLICE SUB 3 1/2" 13Cr. 80KSI 9.2# VAM TOP PIN x PIN | 2.974 | 5.811 | 0.915 | 3248.38 | 3249.29 |
| | COUPLING 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x BOX | 2.940 | 3.912 | 0.180 | 3249.29 | 3249.47 |
| 10 | BAKER PREMIER HYDRAULIC SET RETRIEVABLE PRODUCTION PACKER | 2.948 | 5.908 | 2.069 | 3249.47 | 3251.54 |
| | c/w MULTIPLE CONTROL LINE FEED THRU & 'HNBR' ELASTOMERS. SIZE 591-294 | | | | 3251.54 | 3251.54 |
| | PUP JOINT 3 1/2" 13Cr. 80KSI 9.2# VAM TOP BOX x PIN | 2.968 | 3.909 | 1.261 | 3251.54 | 3252.80 |
| | COUPLING 3 1/2" 13Cr. 80KSI 9.2# VAM TOP HC BOX x BOX | 2.951 | 3.907 | 0.180 | 3252.80 | 3252.98 |
| 11 | BAKER 'INFORCE' "HCM PLUS" SLIDING SLEEVE | 2.812 | 5.238 | 2.612 | 3252.98 | 3255.59 |
| | 3 1/2" x 2.812" BAKER 'A1' PROFILE NIPPLE | | | | 3255.59 | 3255.59 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.957 | 3.915 | 1.267 | 3255.59 | 3256.86 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.954 | 3.917 | 2.793 | 3256.86 | 3259.65 |
| 12 | BAKER MODEL 'AOR' BOTTOM NO-GO SEATING NIPPLE | 2.660 | 3.974 | 0.516 | 3259.65 | 3260.17 |
| | C/W BAKER MODEL 'AORH' BY PASS BLANKING PLUG. SIZE 3 1/2" x 2.750" | | | | 3260.17 | 3260.17 |
| | PUP JOINT 3 1/2" 13Cr. 80KSI 9.2# VAM TOP BOX x PIN | 2.951 | 3.934 | 1.264 | 3260.17 | 3261.43 |
| 13 | BAKER SELF ALIGNING MULE SHOE | 2.975 | 4.601 | 1.194 | 3261.43 | 3262.63 |
| | 3 1/2" 13Cr. 80KSI 9.2# VAM TOP BOX x HALF MULE SHOE | | | | | |

| PREPARED BY | OFFICE | TELEPHONE |
|---|---|---|
| Mike Ross | Edinburgh | 0131 475 3221 |

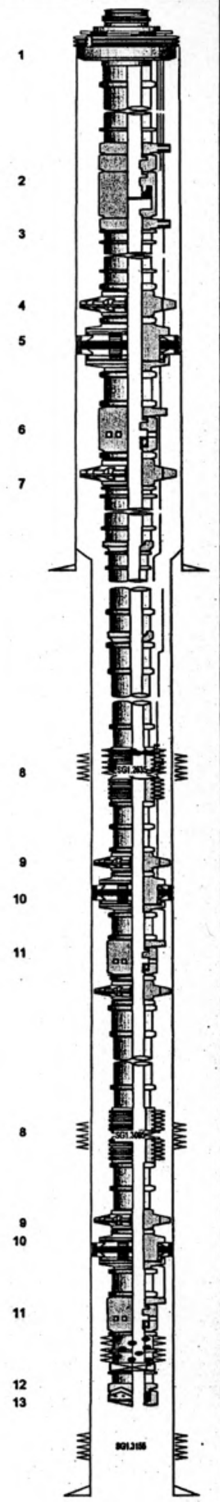
## Notes:

1. All lengths and depths are reported in meters.
2. Perf depths are reported as m MDBRT
3. Well drilled Jan 2005
4. Well completed March 2005
5. SG1.3255 not completed in this well as log data revealed a water contact
6. Water (formation) production observed from the SG1.2970 formation during clean up.

| Interval | Perforations | Perforations | Perforations | Perforations |
|---|---|---|---|---|
| *Date:* | Mar-05 | | | |
| MS2 Sand | interval not present | - | - | - |
| SG1.2585 | interval not present | - | - | - |
| SG3.2635 | interval not present | - | - | - |
| SG3z.2825 | interval not present | - | - | - |
| SG1.2970 | 3104 - 3121 (Isolated with SSD) | - | - | - |
| SG1.3085 | 3187 - 3238 (Isolated with SSD) | | | |
| SG1.3155 | 3268 - 3277.5<br>3279.5 - 3321.5 | | | |
| SG1.3255 | water contact observed | | | |

ATTACHMENT-1

# Sangu 9 Wellbore Schematic




| OPERATOR | CAIRN ENERGY | CASING | | LINER | | TUBING | | |
|---|---|---|---|---|---|---|---|---|
| WELL# | SANGU 9 (B Well) | SIZE | 9 5/8" | 7" | | 5 1/2" | 4 1/2" | 3 1/2" |
| FIELD | SANGU | WEIGHT | 47PPF | 29PPF | | 17PPF | 12.6 PPF | 9.2PPF |
| COUNTRY | BANGLADESH | GRADE | L80 | L80 | | L80 13Cr. | L80 13 Cr. | L80 13Cr. |
| Comp. DATE | 21st March 2005 | THREAD | FOX | Fox | | BEAR | BEAR | BEAR |
| Schem Update | Tuesday, April 22, 2008 | DEPTH(m) | 3100 | 3003 | 3975 | 2987.290 | 3121.61 | 3765.18 |
| Update by: | Babur Khan | MAX DEV | 39.7 | 34.3 | | | | |

| ITEM# | EQUIPMENT AND SERVICES | ID" | OD" | LENGTH | Top Depth | Bot. Depth |
|---|---|---|---|---|---|---|
| | Ocean Soverign Rig Floor elevation to platform hangoff point | | | 19.560 | 0.00 | |
| | | | | | 19.56 | |
| 1 | CAMERON TUBING HANGER | | 13.625 | 0.225 | 19.56 | 19.56 |
| | 13 5/8" x 6.375" HN/B 38685 CC-RS-04 151992-01-03 REV 01 110283887-2 | | | | 19.79 | |
| | PUP JOINT 5 1/2" 13Cr. L80 17# FOX PIN x 5 1/2" 17# KS BEAR PIN | 4.892 | 5.500 | 1.450 | 19.79 | 21.24 |
| | SPACER PUP JOINT 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# KS BEAR PI | 4.892 | 5.958 | 5.997 | 21.24 | 27.23 |
| | 3 x SPACER PUP JOINT 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# KS BEA | 4.892 | 5.958 | 1.463 | 27.23 | 28.70 |
| | 8 x TUBING JOINTS 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# KS BEAR PIN | 4.892 | 5.958 | 76.740 | 28.70 | 105.44 |
| | CROSS-OVER PUP JOINT 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# VAM TOP HC PIN | 4.817 | 6.000 | 2.788 | 105.44 | 108.22 |
| 2 | BAKER MODEL 'LP' NIPPLE c/w 4.562" 'AOF' PROFILE | 4.562 | 7.789 | | 108.22 | 108.22 |
| 3 | BAKER MODEL 5 1/2" 'TSME-5' SAFETY VALVE ASSEMBLY | 4.827 | 8.430 | 2.980 | 108.22 | 111.20 |
| | 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x 5 1/2" 17# VAM TOP HC PIN | | | | 111.20 | 111.20 |
| | PUP JOINT 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x 5 1/2" 17# KS BEAR PIN | 4.903 | 5.995 | 1.192 | 111.20 | 112.40 |
| | 295 x TUBING JOINTS 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# KS BEAR PIN | 4.892 | 5.958 | 2821.200 | 112.40 | 2933.60 |
| | CROSS-OVER PUP JOINT 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# VAM TOP HC PIN | 4.816 | 5.964 | 2.787 | 2933.60 | 2936.38 |
| | COUPLING 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x BOX | 4.791 | 6.014 | 0.275 | 2936.38 | 2936.66 |
| 4 | BAKER SPLICE SUB 5 1/2" 13Cr. 80KSI 17# VAM TOP HC BOX x BOX | 4.805 | 8.253 | 0.755 | 2936.66 | 2937.41 |
| | COUPLING 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x BOX | 4.801 | 6.015 | 0.275 | 2937.41 | 2937.69 |
| 5 | BAKER PREMIER HYDRAULIC SET RETRIEVABLE PRODUCTION PACKER | 4.747 | 8.308 | 2.008 | 2937.69 | 2939.70 |
| | c/w MULTIPLE CONTROL LINE FEED THRU & 'HNBR' ELASTOMERS. SIZE 831-47 | | | | 2939.70 | 2939.70 |
| | 5 1/2" 13Cr. 80KSI 17# VAM TOP HC PIN x PIN | | | | 2939.70 | 2939.70 |
| | PUP JOINT 5 1/2" 13Cr. 80KSI 17# VAM TOP HC BOX x 5 1/2" 17# VAM TOP HC PIN | 4.828 | 6.001 | 1.265 | 2939.70 | 2940.96 |
| | COUPLING 5 1/2" 13Cr. 80KSI 17# VAM TOP HC BOX x BOX | 4.789 | 6.016 | 0.275 | 2940.96 | 2941.24 |
| 6 | BAKER 'INFORCE' "HCM PLUS" SLIDING SLEEVE | 4.437 | 7.358 | 2.580 | 2941.24 | 2943.82 |
| | 5 1/2" x 4.437" BAKER 'AF' PROFILE | | | | 2943.82 | 2943.82 |
| | COUPLING 5 1/2" 13Cr. 80KSI 17# VAM TOP HC BOX x BOX | 4.806 | 6.021 | 0.275 | 2943.82 | 2944.09 |
| 7 | BAKER SPLICE SUB 5 1/2" 13Cr. 80KSI 17# VAM TOP HC PIN x PIN | 4.824 | 8.242 | 0.761 | 2944.09 | 2944.85 |
| | CROSS-OVER PUP JOINT 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x 5 1/2" 17# KS BEAR PIN | 4.899 | 5.999 | 1.263 | 2944.85 | 2946.11 |
| | 4 x TUBING JOINTS 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# KS BEAR PIN | 4.892 | 5.958 | 38.380 | 2946.11 | 2984.49 |
| | CROSS-OVER PUP JOINT 5 1/2" 13Cr. L80 17# KS BEAR BOX x 5 1/2" 17# VAM TOP HC PIN | 4.828 | 5.971 | 2.790 | 2984.49 | 2987.28 |
| | BAKER CROSS-OVER 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x 4 1/2" 12.6# VAM TOP HC PIN | 3.895 | 6.004 | 0.670 | 2987.28 | 2987.95 |
| | CROSS-OVER PUP JOINT 4 1/2" 13Cr. L80 12.6# VAM TOP HC BOX x 4 1/2" 12.6# KS BEAR PIN | 3.968 | 4.932 | 1.263 | 2987.95 | 2989.22 |
| | 11 x TUBING JOINTS 4 1/2" 13Cr. L80 12.6# KS BEAR BOX x 4 1/2" 17# KS BEAR PIN | 3.958 | 4.906 | 132.390 | 2989.22 | 3121.61 |
| | CROSS-OVER PUP JOINT 4 1/2" 13Cr. L80 12.6# KS BEAR BOX x 4 1/2" 12.6# VAM TOP HC PIN | 3.884 | 4.930 | 2.785 | 3121.61 | 3124.39 |
| | BAKER CROSS-OVER 4 1/2" 13Cr. L80 12.6# VAM TOP HC BOX x 3 1/2" 9.2# VAM TOP PIN BOT | 2.969 | 4.912 | 0.645 | 3124.39 | 3125.04 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.944 | 3.925 | 1.264 | 3125.04 | 3126.30 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.992 | 3.883 | 2.800 | 3126.30 | 3129.10 |
| 8 | 7 x BAKER SPECIAL PROTECTION BLAST JOINTS | 2.92 | 3.907 | 28.000 | 3129.10 | 3157.10 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.993 | 3.531 | 1.215 | 3157.10 | 3158.32 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.935 | 3.911 | 2.791 | 3158.32 | 3161.11 |
| | BAKER CROSS-OVER 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 4 1/2" 12.6# VAM TOP HC PIN | 2.946 | 4.527 | 0.606 | 3161.11 | 3161.71 |
| | CROSS-OVER PUP JOINT 4 1/2" 13Cr. L80 12.6# VAM TOP HC BOX x 4 1/2" 12.6# KS BEAR PIN | 3.850 | 4.936 | 1.267 | 3161.71 | 3162.98 |
| | 49 x TUBING JOINTS 4 1/2" 13Cr. L80 12.6# KS BEAR BOX x 4 1/2" 17# KS BEAR PIN | 3.958 | 4.906 | 468.630 | 3162.98 | 3631.61 |
| | CROSS-OVER PUP JOINT 4 1/2" 13Cr. L80 12.6# KS BEAR BOX x 4 1/2" 12.6# VAM TOP HC PIN | 3.952 | 4.599 | 2.785 | 3631.61 | 3634.40 |
| | BAKER CROSS-OVER 4 1/2" 13Cr. L80 12.6# VAM TOP HC BOX x 3 1/2" 9.2# VAM TOP PIN BOT | 2.969 | 4.903 | 0.650 | 3634.40 | 3635.05 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.957 | 3.904 | 1.269 | 3635.05 | 3636.31 |
| | 6 x TUBING JOINTS 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# KS BEAR PIN | 2.992 | 3.883 | 57.450 | 3636.31 | 3693.76 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.982 | 3.916 | 2.796 | 3693.76 | 3696.56 |
| | COUPLING 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x BOX | 2.944 | 3.914 | 0.180 | 3696.56 | 3696.74 |
| 9 | BAKER SPLICE SUB 3 1/2" 13Cr. 80KSI 9.2# VAM TOP PIN x PIN | 2.989 | 5.776 | 0.912 | 3696.74 | 3697.65 |
| | COUPLING 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x BOX | 2.949 | 3.914 | 0.180 | 3697.65 | 3697.83 |
| 10 | BAKER PREMIER HYDRAULIC SET RETRIEVABLE PRODUCTION PACKER | 2.961 | 5.893 | 2.068 | 3697.83 | 3699.90 |
| | c/w MULTIPLE CONTROL LINE FEED THRU & 'HNBR' ELASTOMERS. SIZE 591-29 | | | | 3699.90 | 3699.90 |
| | PUP JOINT 3 1/2" 13Cr. 80KSI 9.2# VAM TOP BOX x PIN | 2.944 | 3.941 | 1.264 | 3699.90 | 3701.16 |
| | COUPLING 3 1/2" 13Cr. 80KSI 9.2# VAM TOP HC BOX x BOX | 2.949 | 3.914 | 0.180 | 3701.16 | 3701.34 |
| 11 | BAKER 'INFORCE' "HCM PLUS" SLIDING SLEEVE | 2.812 | 5.094 | 2.618 | 3701.34 | 3703.96 |
| | 3 1/2" x 2.812" BAKER 'A1' PROFILE NIPPLE | | | | 3703.96 | 3703.96 |
| | COUPLING 3 1/2" 13Cr. 80KSI 9.2# VAM TOP HC BOX x BOX | 2.949 | 3.914 | 0.180 | 3703.96 | 3704.14 |
| | BAKER SPLICE SUB 3 1/2" 13Cr. 80KSI 9.2# VAM TOP PIN x PIN | 2.989 | 5.776 | 0.912 | 3704.14 | 3705.05 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.983 | 3.914 | 1.267 | 3705.05 | 3706.32 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.983 | 3.914 | 2.800 | 3706.32 | 3709.12 |
| 8 | 13 x BAKER SPECIAL PROTECTION BLAST JOINTS | 2.920 | 3.907 | 52.000 | 3709.12 | 3761.12 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.983 | 3.914 | 1.264 | 3761.12 | 3762.39 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.975 | 3.898 | 2.794 | 3762.39 | 3765.18 |
| | COUPLING 3 1/2" 13Cr. 80KSI 9.2# VAM TOP HC BOX x BOX | 2.953 | 3.920 | 0.180 | 3765.18 | 3765.36 |
| | BAKER SPLICE SUB 3 1/2" 13Cr. 80KSI 9.2# VAM TOP PIN x PIN | 2.972 | 5.821 | 0.913 | 3765.36 | 3766.27 |
| | COUPLING 5 1/2" 13Cr. L80 17# VAM TOP HC BOX x BOX | 2.942 | 3.920 | 0.180 | 3766.27 | 3766.45 |
| 10 | BAKER PREMIER HYDRAULIC SET RETRIEVABLE PRODUCTION PACKER | 2.941 | 5.910 | 2.067 | 3766.45 | 3768.52 |
| | c/w MULTIPLE CONTROL LINE FEED THRU & 'HNBR' ELASTOMERS. SIZE 591-29 | | | | 3768.52 | 3768.52 |
| | PUP JOINT 3 1/2" 13Cr. 80KSI 9.2# VAM TOP BOX x PIN | 2.946 | 3.922 | 1.254 | 3768.52 | 3769.77 |
| | COUPLING 3 1/2" 13Cr. 80KSI 9.2# VAM TOP HC BOX x BOX | 2.946 | 3.922 | 0.180 | 3769.77 | 3769.95 |
| 11 | BAKER 'INFORCE' "HCM PLUS" SLIDING SLEEVE | 2.812 | 5.218 | 2.618 | 3769.95 | 3772.57 |
| | 3 1/2" x 2.812" BAKER 'A1' PROFILE NIPPLE | | | | 3772.57 | 3772.57 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# VAM TOP BOX x 3 1/2" 9.2# KS BEAR PIN | 2.966 | 3.914 | 1.268 | 3772.57 | 3773.84 |
| | CROSS-OVER PUP JOINT 3 1/2" 13Cr. L80 9.2# KS BEAR BOX x 3 1/2" 9.2# VAM TOP PIN | 2.928 | 3.898 | 2.797 | 3773.84 | 3776.64 |
| 12 | BAKER MODEL 'AOR' BOTTOM NO-GO SEATING NIPPLE | 2.660 | 3.948 | 0.516 | 3776.64 | 3777.15 |
| | C/W BAKER MODEL 'AORH' BY PASS BLANKING PLUG. SIZE 3 1/2" x 2.750" | | | | 3777.15 | 3777.15 |
| | PUP JOINT 3 1/2" 13Cr. 80KSI 9.2# VAM TOP BOX x PIN | 2.946 | 3.945 | 1.264 | 3777.15 | 3778.42 |
| 13 | BAKER SELF ALIGNING MULE SHOE | 2.976 | 4.601 | 1.194 | 3778.42 | 3779.61 |
| | 3 1/2" 13Cr. 80KSI 9.2# VAM TOP BOX x HALF MULE SHOE | | | | | |

| PREPARED BY | OFFICE | TELEPHONE |
|---|---|---|
| Mike Ross | Edinburgh | 0131 475 3221 |

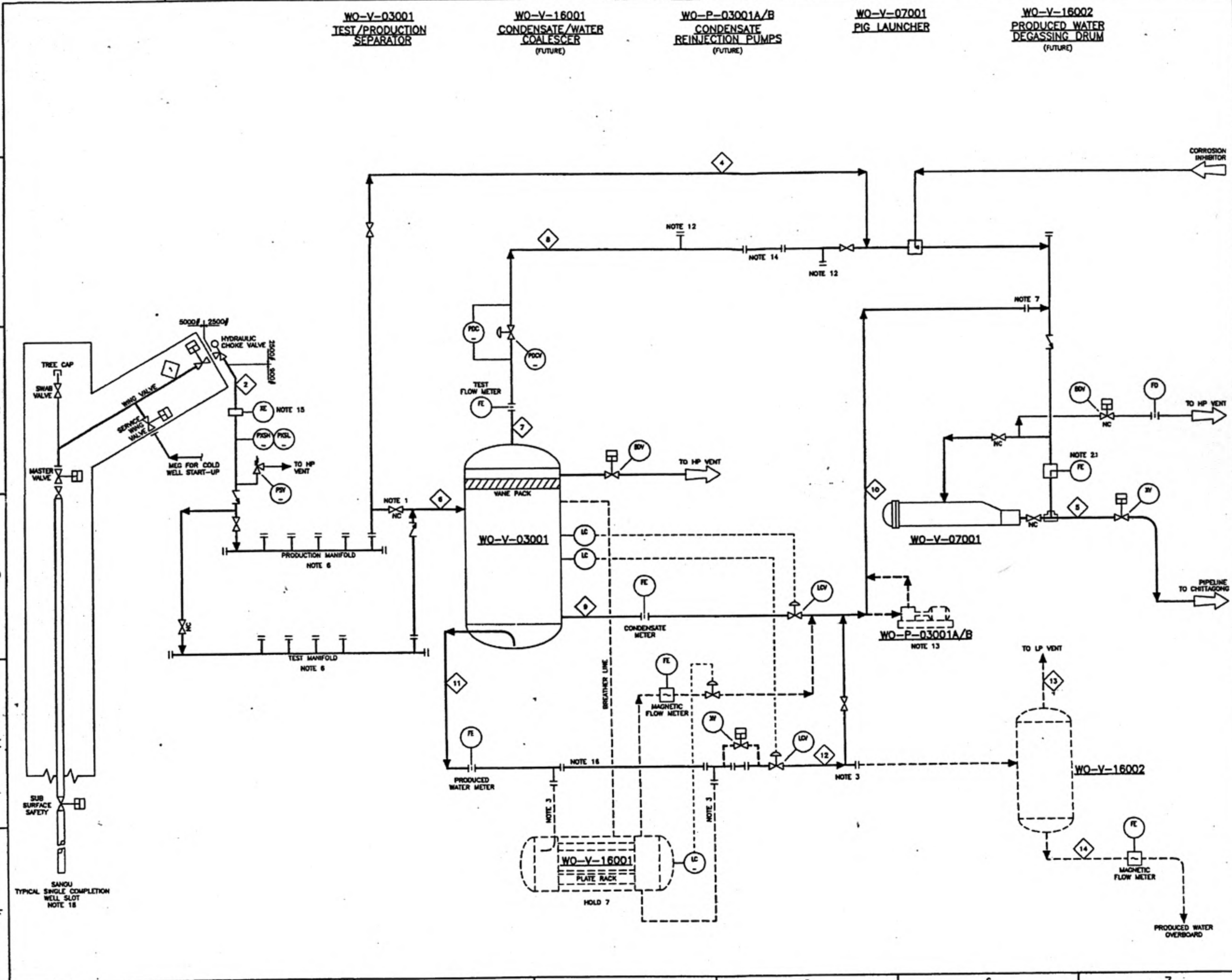
**Notes:**

1. All lengths and depths are reported in meters.
2. Perf depths are reported as m MDBRT
3. SG1.3255 not completed in this well as log data revealed a water contact
4. SG1.2635 flowed 20.53 MMscf/d on 1/2" choke during clean uo. 0% BS&W
5. Reperforated SG1.3155 during completion due to poor performance of 1st perf run.
6. Attempted to open the SG3.2635 SSD during 07 intervention but lost significant water resulting in the the zones inability to flow.
7. Perforated tailpipe (3773 - 3775m) during 07 intervention to access the SG1.3155 due to risk of pulling plug on the 'AOR' nipple
8. Perforated production tubing ( 3137 - 3146m) during Dec '08 intervention to access SG3.2635 due to SSD failure

| Interval | Perforations | Perforations | Perforations | Perforations |
|---|---|---|---|---|
| *Date:* | Mar-05 | Mar 05 (re-perf) | Feb-07 | Dec-08 |
| SG3.2635 | 3135 - 3151 (Isolated with SSD) | 3135 - 3151 (Isolated with SSD) | 3135 - 3151 (Isolated with SSD) | 3137 - 3146m ( re-perforated through production tubing) |
| SG1.3085 | 3713 - 3756 (Isolated with SSD) | 3713 - 3756 (Isolated with SSD) | 3713 - 3756 (Isolated with SSD) | |
| SG1.3155 | 3782 - 3855 | 3811.4 - 3848.6 | 3773 -3775 (tail pipe) | |
| SG1.3255 | | | | |
| HUD in 7" liner at 3937m | | | | |
| | | | | |

# ATTACHMENT-2: SANGU OFFSHORE FACILITIES PFD

N:\DMENTUM\export\SGB-PR-100.00.tif




NOTES.

1. NORMAL FLOW WILL BE THROUGH THE PRODUCTION MANIFOLD TO EXPORT. DURING WELL TESTING ONE WELL WILL BE DIRECTED THROUGH THE TEST MANIFOLD & SEPARATOR. THE SEPARATED FLUIDS WILL THEN BE RECOMBINED WITH PRODUCTION FLOW FOR EXPORT. IN THE FUTURE WHEN SIGNIFICANT FORMATION WATER IS PRODUCED THE SEPARATOR WILL BE USED AS A PRODUCTION SEPARATOR AND THE WATER TREATMENT FACILITIES WILL BE ADDED & PRODUCED WATER DISPOSED OF OFFSHORE.
3. CONNECTIONS TO/FROM FUTURE WATER TREATMENT.
4. DELETED.
5. DELETED.
6. SIX SLOT MANIFOLD WITH SPACE FOR FUTURE SIX SLOT MANIFOLD.
7. FROM CONDENSATE REINJECTION.
12. TIE-IN'S FOR GAS FROM FUTURE WELLHEAD PLATFORMS. FUTURE LP GAS TO TIE-IN UPSTREAM OF COMPRESSION TIE-IN AND FUTURE HP GAS TO TIE-IN DOWNSTREAM OF COMPRESSION.
13. CONDENSATE REINJECTION PUMP WO-P-03001 WILL ONLY BE REQUIRED WITH OFFSHORE COMPRESSION.
14. BREAK OUT SPOOL TO ALLOW TIE-IN OF FUTURE COMPRESSION.
15. SAND MONITORING. SAND FILTERS WILL BE INSTALLED ON A NEW SPOOL PIECE BETWEEN THE TREE AND CHOKE VALVE IF SIGNIFICANT SAND PRODUCTION IS MEASURED.
16. BREAK OUT SPOOL FOR TIE-IN OF COALESCER WHEN SIGNIFICANT WATER PRODUCED.
18. FIVE WELLHEADS INITIALLY. THESE WILL BE SINGLE COMPLETION WELLS. FUTURE WELLS WILL BE A MIXTURE OF SINGLE COMPLETION, COMMINGLED SINGLE SELECTIVE AND DUAL COMPLETION.
20. THE BASE CASE IS ONSHORE COMPRESSION. OFFSHORE COMPRESSION WILL BE REQUIRED WHEN ANOTHER PLATFORM TIES INTO THE EXPORT HEADER AND EXPORT IS INCREASED TO A NOMINAL 500 MMSCFD.
21. PIMMS METER.

HOLDS

7. WATER TREATMENT PROCESS (COALESCER OR HYDROCYCLONE).

REFERENCE DOCUMENT
SBG-PR-102.01/02/03/04/05/06/07/08/09/10/11/12/13/14 HEAT & MASS BALANCE TABLES.

| REV | DATE | REVISION | BY | CHKD | PROJ | CLIENT |
|---|---|---|---|---|---|---|
| C2 | | REVISED FOR CONSTRUCTION | | | | |
| C1 | 03 | AFC | AS | GM | AF | KH |
| D1 | 11 | APPROVED FOR DESIGN | AS | HS | ARF | |
| A1 | 09 | ISSUED FOR IDC | AS | HS | ARF | |

SANGU DEVELOPMENT PROJECT

PROCESS FLOW DIAGRAM

SANGU PLATFORM

| CATEGORY | CODE | DESCRIPTION |
|---|---|---|
| DOCUMENT TYPE | PFD | PROCESS FLOW DIAGRAM |
| AREA IDENTIFIER | WO | WELLHEAD PLATFORM |
| SYSTEM NUMBER | 00 | GENERAL |
| OPERATIONAL SYSTEM IDENTIFIER | | |
| LIFE CYCLE CODE | A | AS DESIGNED |

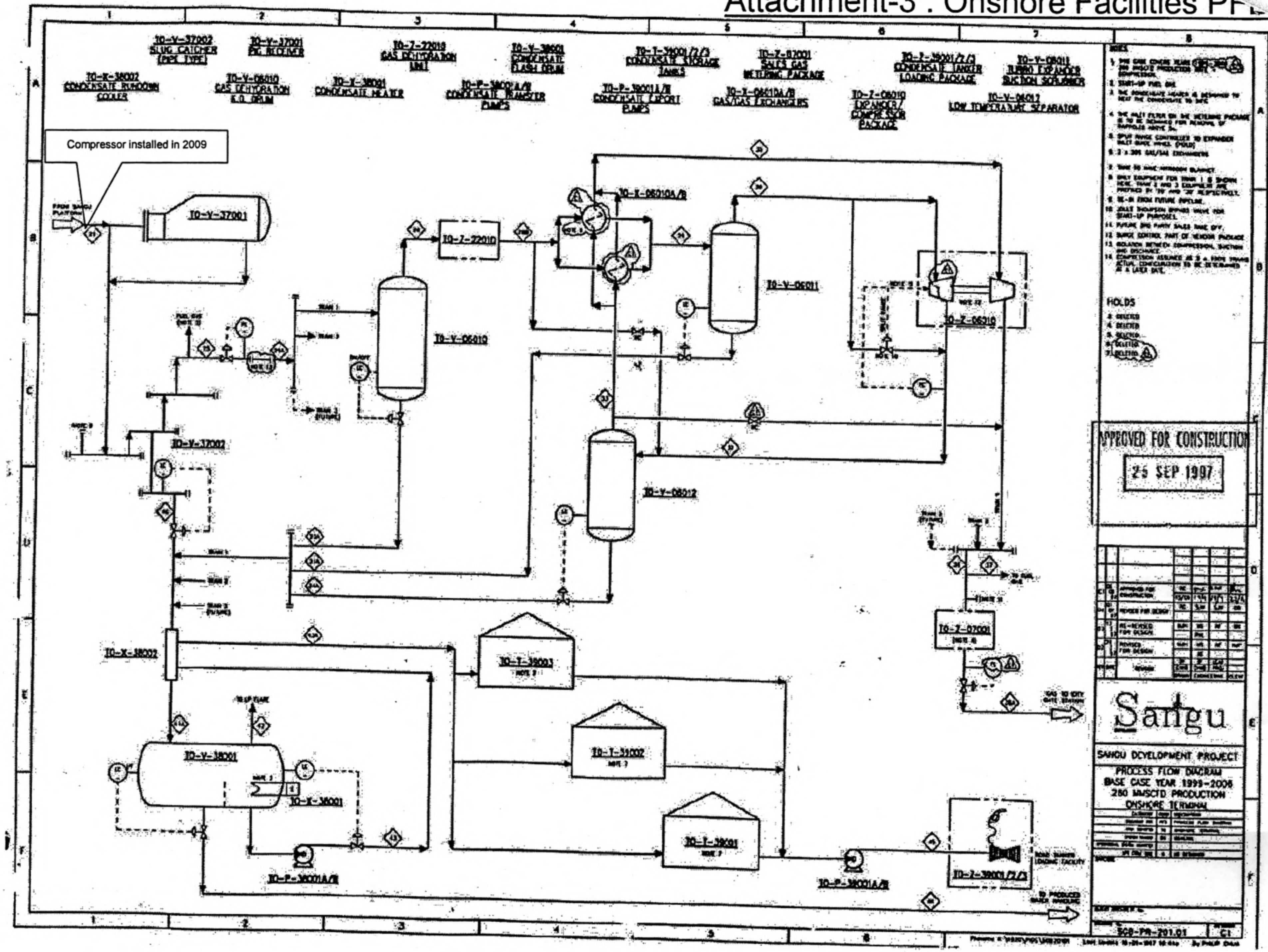
BARCODE

CLIENT DOCUMENT No.

DRAWING No. SGB-PR-100.00 REVISION C2

CAD REF: /USR2/ADB/FD/SANGU/PFD/SGB10000.DWG

## Attachment-3 : Onshore Facilities PF



# Field /Resource Volumetrics

| Volumetrics (GIIP) for Sangu and South Sangu Reservoirs (bcf) | | | | |
|---|---|---|---|---|
| Reservoirs | Up side Case | Mid Case | Low Side Case | Reserves/Resource Category |
| Sangu Main | | | | |
| SG1.2585 | 5.6 | 4.1 | 2.9 | Reserves |
| SG3.2635 | 50 | 30.3 | 26.9 | Reserves |
| SG1.2900 | | 3.97 | | Reserves |
| SG1.2970 | 12.68 | 9.99 | 1.215 | Reserves |
| SG1.3085 | 80.56 | 59.32 | 50.24 | Reserves |
| SG1.3155 | 586.44 | 551.63 | 542.86 | Reserves |
| SG1.3255 | 164.32 | 154.44 | 142.66 | Reserves |
| Sangu South | | | | |
| Seq 2.70 | 77 | 58 | 42 | Contingent Resources |
| SG1.3255 | 50 | 35 | 21 | Contingent Resources |
| New MS2 | 45 | 31 | 19 | Prospective Resources |

# Questionnaire for Field Operations

**Tullow Bangladesh Limited**
**Bangora – Lalmai Field**
**Block 9**

**Wellbore Equipment**

Please provide copies of wellbore diagrams for representative wells showing typical configurations for wellbore designs including current casing and tubing pipe sizes and wellhead equipment.

***Excel file included showing well schematics and completion diagrams. (Bangora_Well_Completion_Diagrams.xls)***

**Facilities Equipment Layout**

Please describe or provide diagrams that show surface facility layout that would include gathering, separation, dehydration, metering, natural gas liquids plant and transport. Please note that a high level of technical detail is not required but rather just a summary view to understand general nature of the production facility design.

***Bangora plot map attached showing location of wells and production facilities. (Bangora_Plot_Map.pdf)***

**Production Rate Practices**

Please describe current practices for producing gas from wells in the field. This would include determination of optimum flow rates (based on absolute open flow or other criteria), reservoir management practices, choke sizes. Please also describe current working pipeline pressures at delivery points in the sales line and if compression is being used.

***AOFP testing is carried out on a 6 monthly basis and used to establish optimum rates. Wells are also individually tested through the test separator on a weekly basis.***

***Export pressure is 945 psi.***

***Compression is not in use at present.***

Please describe if optimum flow rates are currently (past year) being realized or are constrained or exceeded due to market demand, equipment and facility design or other.

***Optimum plateau rate of 120 mmscfd (which is design capacity of facilities) is being maintained since the tie-in of Bangora-3 in October 2009.***

## Production Enhancement

Please describe any plans to implement or potential (but not yet planned) in the field for the following:

Production enhancement through facilities enhancement with consideration for compression to allow high reserve recovery through lower abandonment pressures.

***Current provisional planning is for the installation of compression in 2012/2013when wellhead flowing pressures reach 1,000 psi and the field would come off plateau. Compression will allow wells to produce at a wellhead pressure of 500 psi, and maintain a field plateau rate of 120mmscfd.***

Production enhancement through workovers and recompletions.

***Workovers are planned on Bangora-2 and Bangora-5 in Q1 2011. The primary objective is to replace corroded tubing, however Bangora-2 will also be perforated over the Upper D Sand. Investigations are underway with regard to the recompletion of Bangora-1 which would result in co-mingled production from the Upper D and Lower D Sands.***

***Perforation of the A, B, C, and E Sands will be carried in the existing wells later in field life.***

Reserve growth through use of3 D seismic and analysis of bottom hole pressure surveys.

***3D seismic was acquired over the Bangora – Lalmai area during the Appraisal Phase of operations in 2005. The 3D interpretation was incorporated into Petrel and Eclipse reservoir models. The models are regularly updated based on well performance and annual bottom hole pressure surveys. This has lead to reserves upgrades in instances where the reservoirs have outperformed initial expectations.***

Production and reserve enhancement through drilling to prove up probable and possible reserves.

***Studies (including seismic reprocessing) are underway at present to establish the merits of drilling additional wells in the Bangora South – Lalmai area.***

# Bangladesh

# Parameters for Volumetric Reserves / Resources Calculation

## Block 9

## Bangora – Lalmai

## Bangora: Most Likely Reserves Case for all reservoirs sands - Reservoir parameters from Petrel subsurface models

## Lalmai: Mid Case Estimate for Contingent Resources

| Parameter | Most Likely Reserves Bangora A Sand | Most Likely Reserves Bangora B Sand | Most Likely Reserves Bangora C Sand | Most Likely Reserves Bangora D Sand | Most Likely Reserves Bangora E Sand | Mid Case Resources Lalmai Sands |
|---|---|---|---|---|---|---|
| Gas Gravity, relative to air=1 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| %N2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| %CO2 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| %H2S | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Condensate Yield, m3/m3 | 1.78E-05 | 1.78E-05 | 1.78E-05 | 1.78E-05 | 1.78E-05 | 8.90E-06 |
| Reservoir Temperature, deg C | 95 | 96 | 100 | 111 | 116 | 38 |
| Initial Reservoir Pressure, kg/cm2 | 244 | 250 | 281 | 310 | 326 | 242 |
| psi | | | | | | |
| Depth,m | | | | | | |
| Temperature gradient, deg C/m | | | | | | |
| Pressure Gradient, kg/cm2/m | | | | | | |
| Abandonment pressure, kg/cm2 | 35 | 35 | 35 | 35 | 35 | 35 |
| Net Pay, m | 6 | 8 | 6 | 37 | 7 | 25 |
| Water saturation, % | 47 | 61 | 59 | 59 | 48 | 68 |
| Porosity, % | 21 | 24 | 17 | 11 | 14 | 13 |
| Productive Area, m2 | 4,093,339 | 3,467,878 | 8,625,522 | 43,717,377 | 4,889,626 | 10,313,429 |

Notes: Data can be entered several ways.

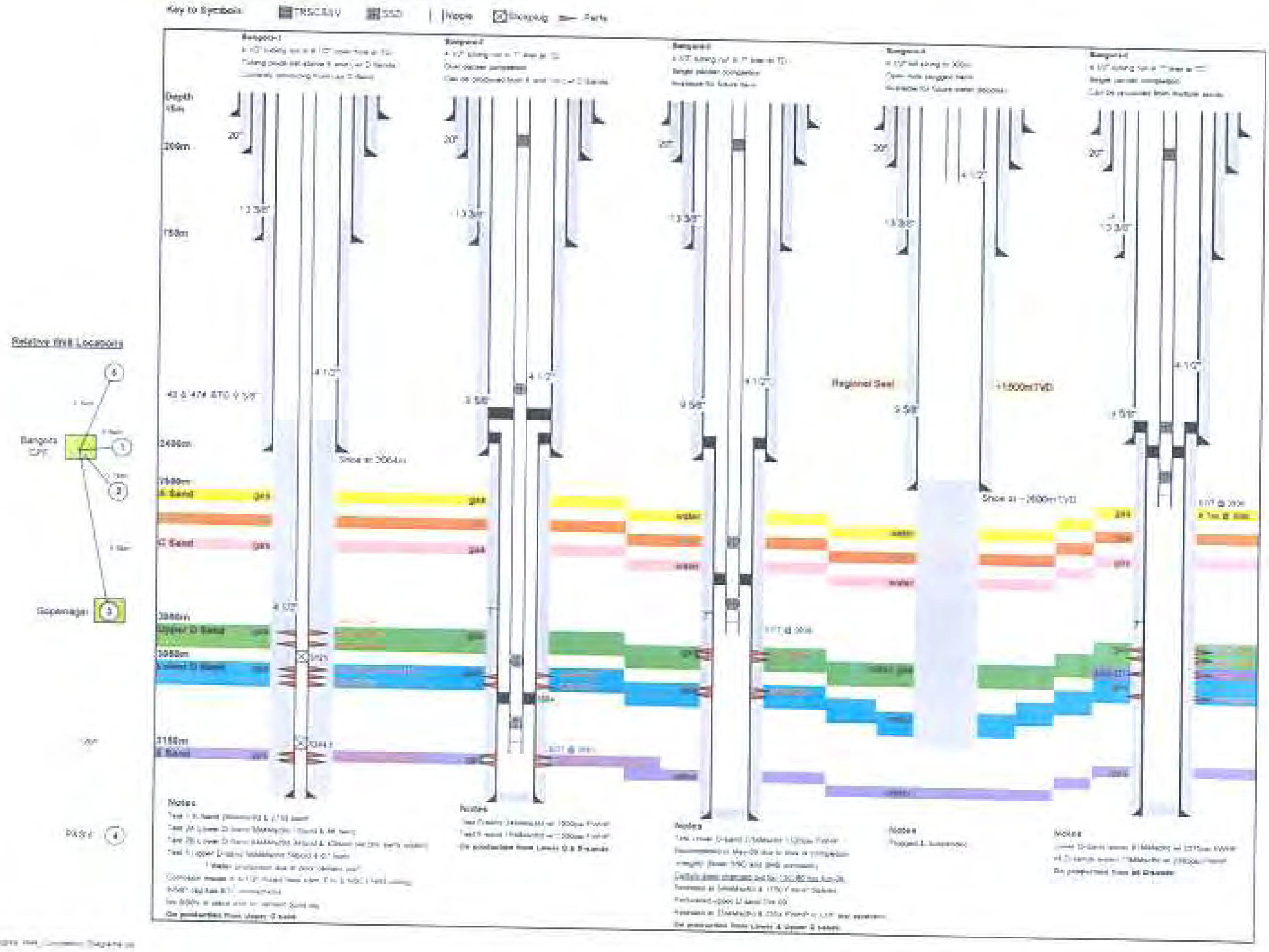
1) a single most likely value, if there is very little uncertainty or variation in the value. We will then take it as a constant.

2) a minimum and a maximum only, if the range of a parameter is known but there is no indication that one value is any more like likely than another. We will use a uniform distribution between the min and max.

3) Enter one low, one medium, and one high value. We will use a triangular distribution. In the terminology here, The minimum and maximum values are never sampled from the distribution. The P5 is the value where 95%of the time the actual value is higher, and 5% of the time the actual value is lower. P10, P90, and P95 behave in the same manner.

4) These parameters always represent the uncertainty in the average over the entire reservoir, not the range of a parameter within the reservoir. In other words, if the porosity at some depths in some wells is as low as 10%, do not enter that number here.
Rather, enter the low number that represents the lowest that the average porosity for the reservoir could be, considering data measured at the wells and possible variation between wells.

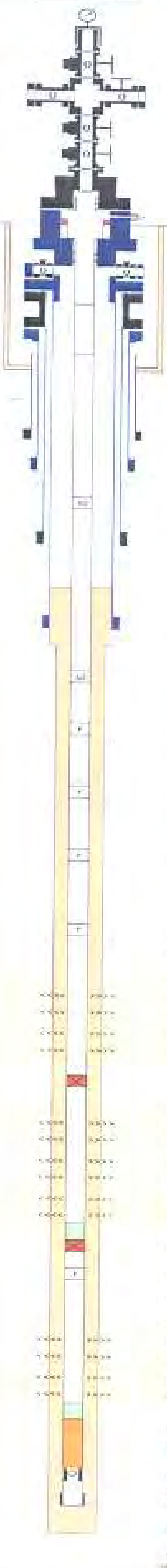
Bangora Well Completion Schematics (not to scale)



TULLOW

## TULLOW BANGLADESH LIMITED

## BANGORA-1 WELL - 4 1/2" MONOBORE COMPLETION DIAGRAM



| COMMENTS (mRBT) | COMPLETION ITEM (DETAILS) | DEPTH (mRBT) | DEPTH (mTVDRBT) | DEPTH (mRSV) | LENGTH (metres) | MIN ID (ins) | MAX OD (ins) |
|---|---|---|---|---|---|---|---|
| ROTARY TABLE | ROTARY ELEVATION (m above G.L.) | 0.00 | 0.00 | -5.42 | | | |
| SWAB CAP | [illegible] Quick Union Swab Cap | 4.72 | 4.72 | [illegible] | [illegible] | [illegible] | 4.000 |
| SWAB VALVE | [illegible] 5000 psi Swab Valve (Cameron) | 5.42 | 5.42 | [illegible] | [illegible] | [illegible] | |
| PRODUCTION WING | [illegible] 5000 psi Production Wing Valve | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | |
| UPPER MASTER | [illegible] 5000 psi Upper Master Valve (Cameron) | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | |
| LOWER MASTER | [illegible] 5000 psi Lower Master Valve (Cameron) | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | |
| | TUBING BONNET | [illegible] | [illegible] | [illegible] | [illegible] | | |
| | Tubing Hanger above Hang-Off | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] 11" 5M SPOOL | [illegible] | [illegible] | [illegible] | [illegible] | | |
| | GROUND LEVEL | [illegible] | [illegible] | [illegible] | | | |
| | (Tubing Hanger Hang-off) | [illegible] | [illegible] | | | | |
| | 4 1/2" 12.6 ppf Tubing Hanger below Hang-off | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 11" CASING HEAD SPOOL | [illegible] | [illegible] | [illegible] | [illegible] | | |
| | 4 1/2" 12.6 ppf Pup Joint | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 20 3/4" CASING HEAD SPOOL | [illegible] | [illegible] | [illegible] | [illegible] | | |
| | 4 1/2" 12.6 ppf Production Tubing | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | Base Cellar | [illegible] | [illegible] | [illegible] | | | |
| MEAN SEA LEVEL | MEAN SEA LEVEL | [illegible] | [illegible] | [illegible] | | | |
| [illegible] | 30" CONDUCTOR SHOE | [illegible] | [illegible] | [illegible] | | 12.415 | 14.375 |
| [illegible] | 20" K55 94 lb/ft Casing Shoe | 202.00 | 202.00 | 196.59 | | [illegible] | [illegible] |
| | 26" Hole TD | [illegible] | [illegible] | [illegible] | | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 4 1/2" 12.6 ppf Production Tubing | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | 13 3/8" J55 68 lb/ft Casing Shoe | 695.00 | [illegible] | [illegible] | | [illegible] | [illegible] |
| | 16" Hole TD | [illegible] | [illegible] | [illegible] | | | |
| [illegible] | 9 5/8" L80 43.5 lb/ft Casing Shoe | 2064.00 | [illegible] | [illegible] | | [illegible] | [illegible] |
| | 12 1/4" Hole TD | [illegible] | [illegible] | [illegible] | | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 4 1/2" 12.6 ppf Production Tubing | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | 4 1/2" 12.6 ppf Production Tubing Pup Joint | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 4 1/2" 12.6 ppf Production Tubing | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | 4 1/2" 12.6 ppf Production Tubing Pup Joint | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 4 1/2" 12.6 ppf Production Tubing | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | 4 1/2" 12.6 ppf Production Tubing Pup Joint | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 4 1/2" 12.6 ppf Production Tubing | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | 4 1/2" 12.6 ppf Production Tubing Pup Joint | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 4 1/2" 12.6 ppf Production Tubing | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | PRODUCTION TEST 3: RESERVOIR D | | | | | | |
| [illegible] | Through Tubing Perforations | | | | | | |
| [illegible] | 2 7/8" 6 spf Hollow Carrier Guns | [illegible] | [illegible] | [illegible] | [illegible] | | |
| [illegible] | Through Tubing Perforations | | | | | | |
| [illegible] | 2 7/8" 6 spf Hollow Carrier Guns | [illegible] | [illegible] | [illegible] | [illegible] | | |
| | Slickline Retrievable Nipple-less Plug | [illegible] | [illegible] | [illegible] | [illegible] | | 3.958 |
| | PRODUCTION TEST 2A/2B: RESERVOIR D | | | | | | |
| [illegible] | Through Tubing Perforations | | | | | | |
| [illegible] | 2 7/8" 6 spf [illegible] HMX Hollow Carrier Guns | [illegible] | [illegible] | [illegible] | [illegible] | | |
| [illegible] | Through Tubing Perforations | | | | | | |
| [illegible] | 2 7/8" 6 spf [illegible] HMX Hollow Carrier Guns | [illegible] | [illegible] | [illegible] | [illegible] | | |
| [illegible] | Through Tubing Perforations (Production Test 2a) | | | | | | |
| [illegible] | 2 7/8" 6 spf [illegible] HMX Hollow Carrier Guns | [illegible] | [illegible] | [illegible] | [illegible] | | |
| | Slickline Retrievable Nipple-less Plug | [illegible] | [illegible] | [illegible] | [illegible] | | [illegible] |
| [illegible] | 4 1/2" 12.6 ppf Production Tubing Pup Joint | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 4 1/2" 12.6 ppf Production Tubing | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | PRODUCTION TEST 1: RESERVOIR F | | | | | | |
| [illegible] | Through Tubing Perforations | | | | | | |
| [illegible] | 2 7/8" 6 spf Hollow Carrier Guns | [illegible] | [illegible] | [illegible] | [illegible] | | |
| [illegible] | Through Tubing Perforations | | | | | | |
| [illegible] | 2 7/8" 6 spf Hollow Carrier Guns | [illegible] | [illegible] | [illegible] | [illegible] | | |
| | Hold-up Depth (Tagged [illegible]) | [illegible] | [illegible] | [illegible] | | | |
| [illegible] | Float Collar | [illegible] | [illegible] | [illegible] | [illegible] | | |
| [illegible] | 4 1/2" 12.6 ppf Production Tubing Pup Joint | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 4 1/2" L80 12.6 lb/ft Production Tubing Shoe | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | 8 1/2" Drilled TD | [illegible] | [illegible] | [illegible] | | | |

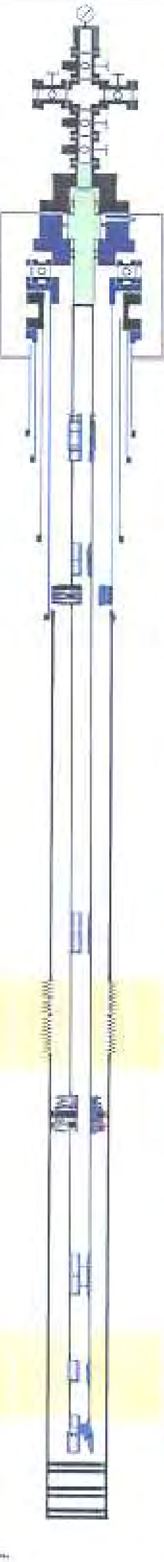
Depths to top of item

All depths in metres unless indicated otherwise

[illegible]

TULLOW BANGLADESH LIMITED

BANGORA-? WELL - 4 1/2" COMPLETION DIAGRAM



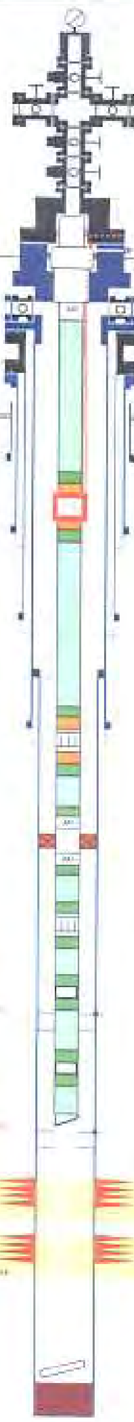
| COMMENTS (mBRT) | COMPLETION ITEM (DETAILS) | DEPTH (mBRT) | DEPTH (mTVDBRT) | DEPTH (mTVDSS) | LENGTH (metres) | MIN ID (ins) | MAX OD (ins) |
|---|---|---|---|---|---|---|---|
| ROTARY TABLE | ROTARY ELEVATION (m above GL) | 0.00 | 0.00 | -12.12 | | | |
| SWAB CAP | [illegible] Swab Cap | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| SWAB VALVE | 4 1/16" 5,000psi Swab Valve (Centre Line) | [illegible] | [illegible] | [illegible] | [illegible] | 4.000 | |
| PRODUCTION KILL | 4 1/16" 5,000psi Production/Kill Valve | [illegible] | [illegible] | [illegible] | [illegible] | 4.000 | |
| UPPER MASTER | 4 1/16" 5,000psi Upper Master Valve (Centre Line) | [illegible] | [illegible] | [illegible] | [illegible] | 4.000 | |
| LOWER MASTER | 4 1/16" 5,000psi Lower Master Valve (Centre Line) | 7.74 | 7.74 | [illegible] | [illegible] | 4.000 | |
| | TUBING BONNET | 6.44 | 6.44 | [illegible] | 0.25 | | |
| | Tubing Hanger above Hang-Off | 6.31 | 6.31 | [illegible] | 0.56 | | |
| | 13-5/8" 10K x 13-5/8" 5K Manifold | 6.7 | 6.7 | 5.42 | 0.52 | | |
| | GROUND LEVEL | 6.7 | 6.7 | -5.42 | | | |
| | (Tubing Hanger Hang-Off point) | 6.81 | 6.81 | -5.31 | | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | 1.23 | | |
| | 2 1/16" 10K valves | | | | | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | 3.833 | [illegible] |
| | 9-5/8" Casing Hang-off Point | 7.44 | 7.44 | -4.68 | | | |
| | 13 5/8" CASING HEAD SPOOL | 7.92 | 7.92 | -4.2 | [illegible] | | |
| | 13-3/8" Casing Hang-off Point | 8.14 | 8.14 | [illegible] | | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | 47.56 | [illegible] | [illegible] |
| | Base Cellar | 9.20 | 9.20 | -2.92 | | | |
| MEAN SEA LEVEL | MEAN SEA LEVEL ---- | 12.12 | 12.12 | 0 | | | |
| ([illegible] mBRT) | 30" CONDUCTOR SHOE | 14.00 | 14.00 | 1.88 | | | |
| ([illegible] mBRT) | [illegible] | [illegible] | [illegible] | [illegible] | 3.43 | 3.813 | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | 20" K55 - 94 lb/ft Casing Shoe | 202.00 | 202.00 | 189.88 | | 19.124 | 20.00 |
| | 26" Hole TD | 205.00 | 205.00 | 192.88 | | | |
| ([illegible] mBRT) | 13 3/8" 1-80 - 68 lb/ft Casing Shoe | 724.50 | 712.90 | 700.78 | | 12.415 | 13.375 |
| | 16" Hole TD | [illegible] | 715.12 | [illegible] | | | |
| | (Theoretical Top Of Cement behind 13 3/8" shoe) | 50.00 | 50.00 | 37.88 | | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | 2.91 | 3.813 | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | 9.46 | 3.833 | [illegible] |
| ([illegible] mBRT) | [illegible] | [illegible] | [illegible] | [illegible] | 3.54 | 3.833 | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | 879.31 | 3.833 | [illegible] |
| | Top of liner | 2601.61 | 2280.13 | 2267.99 | 1047.82 | [illegible] | [illegible] |
| | 9 5/8" L80 - 47 lb/ft Casing Shoe | 2755.00 | 2400.14 | 2388.02 | | 8.681 | 9.625 |
| | 12 1/4" Hole TD | [illegible] | 2404.13 | [illegible] | | | |
| | (Top of cement behind 9 5/8" csg at surface) | | | | | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | 3.98 | 3.833 | 6.078 |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | RA Casing Marker (Top of Pup Joint) | [illegible] | 3023.67 | [illegible] | [illegible] | [illegible] | [illegible] |
| | Perforations [illegible] | [illegible] | [illegible] | [illegible] | | | |
| | | [illegible] | [illegible] | [illegible] | 41.7 | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | | | |
| | [illegible] | | | | | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | 2.84 | 3.833 | 6.078 |
| | [illegible] | [illegible] | [illegible] | [illegible] | 1.44 | 3.833 | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | 0.69 | [illegible] | [illegible] |
| | RA Casing Marker (Top of Pup Joint) | [illegible] | 3114.41 | 3092.28 | | | |
| ([illegible] mBRT) | Hold-Up Depth | 3673.00 | 3187.00 | 3174.88 | | | |
| | Landing Collar | 3673.74 | 3187.73 | [illegible] | [illegible] | | |
| ([illegible] mBRT) | Float Collar | 3686.67 | 3199.56 | 3187.44 | [illegible] | | |
| ([illegible] mBRT) | 7" Liner casing Shoe | 3699.90 | 3212.45 | 3200.33 | | | |
| ([illegible] mBRT) | 8 1/2" Drilled TD | 3704.00 | 3216.77 | 3204.65 | | | |

All depths [illegible]

All depths [illegible]

TULLOW BANGLADESH LIMITED

BANGORA-3 WELL - 4 1/2" SINGLE PACKER COMPLETION DIAGRAM



| COMMENTS (mBRT) | COMPLETION ITEM (DETAILS) | DEPTH (mBRT) | DEPTH (mTVDBRT) | DEPTH (mBGL) | DEPTH [illegible] | LENGTH (meters) | MIN ID (ins) | MAX OD (ins) |
|---|---|---|---|---|---|---|---|---|
| ROTARY TABLE | ROTARY ELEVATION [illegible] | 0.00 | 0.00 | -6.70 | 7.29 | | | |
| SWAB CAP | [illegible] Swab Cap | [illegible] | [illegible] | [illegible] | -2.99 | | 5.000 | |
| SWAB VALVE | 4-1/16" 10,000psi Swab Valve [illegible] | [illegible] | [illegible] | [illegible] | -2.61 | | 4.000 | |
| PRODUCTION/KILL | 4-1/16" 10,000psi Production/Kill Valves | [illegible] | [illegible] | [illegible] | [illegible] | | 4.000 | |
| UPPER MASTER | 4-1/16" 10,000psi Upper Master Valve [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | 4.000 | |
| LOWER MASTER | 4-1/16" 10,000psi Lower Master Valve [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | 4.000 | |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | | |
| [illegible] | Tubing Hgr 13-5/8" x 4-1/2" [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | 1.145 | | |
| [illegible] | 4 x 4-1/2" 12.6ppf 13Cr80 RI New Vam Tubing | 8.80 | | 2.10 | [illegible] | 50.58 | [illegible] | |
| | Cellar Base | 9.21 | 9.21 | 2.30 | [illegible] | | | |
| 30" Conductor Shoe [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | | | |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 59.27 | | [illegible] | [illegible] | 1.87 | | |
| | 4-1/2" 13Cr80 New Vam Flow Coupling | 62.45 | | [illegible] | [illegible] | 1.729 | | |
| 20" K55 [illegible] Casing Shoe [illegible] | TRSCSSV [illegible] 3.812" [illegible] Profile | 64.18 | | 57.48 | [illegible] | 2.09 | [illegible] | 7.325 |
| | 4-1/2" 13Cr80 New Vam Flow Coupling | 66.27 | | [illegible] | [illegible] | 1.72 | | |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 68.00 | | [illegible] | [illegible] | [illegible] | | |
| 13 3/8" K55 [illegible] Casing Shoe [illegible] | 217 x 4-1/2" 12.6ppf 13Cr80 RI New Vam Tubing | 65.85 | | [illegible] | [illegible] | [illegible] | | |
| [illegible] Liner & Hanger [illegible] | | | | | | | | |
| 9 5/8" [illegible] Casing Shoe [illegible] | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2850.99 | | [illegible] | [illegible] | 1.87 | | |
| | 4-1/2" 13Cr80 New Vam Flow Coupling | 2852.06 | | [illegible] | [illegible] | 1.71 | | |
| | 3.75" Baker "LMD" w/ F Nipple | 2852.79 | | [illegible] | [illegible] | 1.28 | [illegible] | 5.300 |
| | 4-1/2" 13Cr80 New Vam Flow Coupling | 2855.00 | | [illegible] | [illegible] | 1.71 | | |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2856.81 | | [illegible] | [illegible] | [illegible] | | |
| | 1 x 4-1/2" 12.6ppf 13Cr80 RI New Vam Tubing | 2857.87 | | [illegible] | [illegible] | 12.78 | | |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2870.65 | | [illegible] | [illegible] | [illegible] | | |
| | 4-1/2" 12.6ppf 13Cr80 New Vam [illegible] | 2871.71 | | [illegible] | [illegible] | [illegible] | | |
| | Baker Premier Packer [illegible] | 2872.88 | [illegible] | [illegible] | [illegible] | 2.19 | [illegible] | [illegible] |
| | 4-1/2" 12.6ppf 13Cr80 Vam Top [illegible] New Vam [illegible] | 2874.[illegible] | | [illegible] | [illegible] | [illegible] | | |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2874.82 | | [illegible] | [illegible] | [illegible] | | |
| | 1 x 4-1/2" 12.6ppf 13Cr80 RI New Vam Tubing | 2875.88 | | [illegible] | [illegible] | 12.78 | | |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2888.67 | | [illegible] | [illegible] | [illegible] | | |
| | 3.75" Baker "CMD" w/ F Nipple | 2889.73 | | [illegible] | [illegible] | 1.30 | [illegible] | 5.500 |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2891.03 | | [illegible] | [illegible] | [illegible] | | |
| | 1 x 4-1/2" 12.6ppf 13Cr80 RI New Vam Tubing | 2892.09 | | [illegible] | [illegible] | 12.68 | | |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2904.77 | | [illegible] | [illegible] | 1.87 | | |
| | Baker F Nipple [illegible] | 2905.83 | | [illegible] | [illegible] | 0.52 | [illegible] | [illegible] |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2906.35 | | [illegible] | [illegible] | [illegible] | | |
| | 1 x 4-1/2" 12.6ppf 13Cr80 RI New Vam Tubing | 2907.41 | | [illegible] | [illegible] | 12.78 | | |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2920.19 | | [illegible] | [illegible] | [illegible] | | |
| | Baker R Nipple [illegible] | 2921.34 | | [illegible] | [illegible] | [illegible] | [illegible] | 4.000 |
| | 4-1/2" 12.6ppf 13Cr80 New Vam Pup Joint | 2921.87 | | [illegible] | [illegible] | [illegible] | | |
| | 1 x 4-1/2" 12.6ppf 13Cr80 RI New Vam Tubing | 2922.93 | | [illegible] | [illegible] | 12.78 | | |
| | 4-1/2" WEG [illegible] | 2935.71 | [illegible] | [illegible] | [illegible] | 0.27 | [illegible] | 4.000 |
| | End of Completion | 2935.98 | | [illegible] | [illegible] | | | |
| Upper D Perforations [illegible]<br>Through Tubing Perforations<br>[illegible] mBRT<br>2 1/8" [illegible] | [illegible]<br>Top of Upper D Sand | 2981.00 | [illegible] | [illegible] | [illegible] | | | |
| | Bottom of Upper D Sand | [illegible] | [illegible] | [illegible] | [illegible] | | | |
| Lower-D Perforations [illegible]<br>Through Tubing Perforations<br>[illegible] mBRT<br>2-7/8" [illegible] | Top of Lower D Sand | [illegible] | [illegible] | [illegible] | [illegible] | | | |
| | Bottom of Lower D Sand | [illegible] | [illegible] | [illegible] | [illegible] | | | |
| [illegible] | [illegible] | | | | | | | |
| Float Collar [illegible]<br>Float Shoe [illegible] | Top of Cement | 3113.00 | 3113.10 | 3106.20 | | | | |

Depths in [illegible]

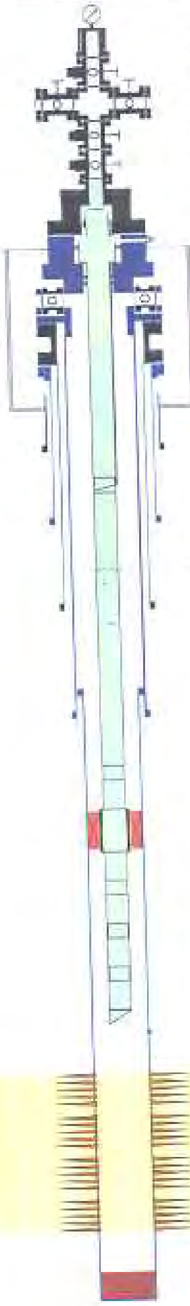
All depths in meters [illegible]

Revised: [illegible]

TULLOW BANGLADESH LIMITED

BANGORA-5 WELL - 4 1/2" SINGLE PACKER COMPLETION DIAGRAM

Engineering Department Rev. [illegible]



| COMMENTS (mBRT) | COMPLETION ITEM (DETAILS) | DEPTH (mBRT) | DEPTH (mTVDBRT) | DEPTH (mBGL) | LENGTH (meters) | MIN ID (ins) | MAX OD (ins) |
|---|---|---|---|---|---|---|---|
| ROTARY TABLE | ROTARY ELEVATION 6.6m above GL | 0.00 | 0.00 | -6.60 | | | |
| SWAB CAP | 4 1/2" Otis Quick Union Swab Cap | N.A | N.A | N.A | | [illegible] | |
| SWAB VALVE | 4 1/16" 10,000psi Swab Valve (Cameron Gate) | N.A | N.A | N.A | | 4.000 | |
| PRODUCTION KILL | 4 1/16" 10,000psi Production Kill Valves | N.A | N.A | N.A | | 4.000 | |
| UPPER MASTER | 4 1/16" 10,000psi Upper Master Valve (Cameron Gate) | 5.87 | 5.87 | [illegible] | | 4.000 | |
| LOWER MASTER | 4 1/16" 10,000psi Lower Master Valve (Cameron Gate) | 6.54 | 6.54 | [illegible] | | [illegible] | |
| | [illegible] | [illegible] | [illegible] | [illegible] | | | |
| | [illegible] Tubing Head Spool | [illegible] | [illegible] | [illegible] | | | |
| [illegible] mBRT | GROUND LEVEL | [illegible] | [illegible] | [illegible] | | | |
| | Tubing Hanger [illegible] | [illegible] | [illegible] | [illegible] | | | |
| | 4 1/2" 12.6 ppf Tubing Hanger below flange | 8.93 | 8.93 | [illegible] | | [illegible] | 7.000 |
| | [illegible] | | | | | | |
| | [illegible] CASING HEAD SPOOL | | | | | | |
| | 20" [illegible] CASING HEAD SPOOL | | | | | | |
| | Base Collar | [illegible] | [illegible] | [illegible] | | | |
| MEAN SEA LEVEL | MEAN SEA LEVEL | [illegible] | [illegible] | [illegible] | | | |
| ([illegible] mBRT) | 30" CONDUCTOR SHOE | [illegible] | [illegible] | [illegible] | | | |
| | 3.813" TR-5 Tubing Retrievable Safety Valve | 48.37 | 48.37 | [illegible] | 1.89 | 3.813 | 7.125 |
| (148 mBRT) | 20" K55 - 94 lb/ft Casing Shoe | 148.00 | 148.00 | 141.40 | | 19.12 | 20.000 |
| | 20" Hole TD | 148.00 | 148.00 | 141.40 | | | |
| (727 mBRT) | 13 3/8" K55 - 68 lb/ft Casing Shoe | 727.00 | 697.12 | 720.40 | | 12.415 | 13.375 |
| | 17" Hole TD | 727.00 | 697.12 | 720.40 | | | |
| | 7" Liner Hanger | [illegible] | [illegible] | [illegible] | | [illegible] | [illegible] |
| (2695 mBRT) | 9 5/8" L80 - 43.5 lb/ft Casing Shoe | 2695.00 | 2154.46 | 2688.40 | | | |
| | 12 1/4" Hole TD | [illegible] | [illegible] | [illegible] | | | |
| | 3.75" CMD Sliding Side Door | [illegible] | [illegible] | [illegible] | [illegible] | 3.750 | 5.000 |
| | Premium Hydraulic Set 7" Packer | 2887.52 | 2295.87 | 2880.92 | [illegible] | [illegible] | 5.000 |
| | 3.75" CMD Sliding Side Door | 2901.76 | 2306.24 | 2895.16 | [illegible] | 3.750 | 5.000 |
| | 3.75" F Nipple | 2914.71 | 2315.68 | 2908.11 | 0.46 | 3.750 | 5.000 |
| | 3.68" R Nipple | 2926.00 | [illegible] | 2919.40 | [illegible] | [illegible] | 5.000 |
| | Wireline Re-Entry Guide | 2935.83 | 2331.08 | 2929.23 | 0.28 | [illegible] | 5.000 |
| | [illegible] | [illegible] | [illegible] | [illegible] | | | |
| | RESERVOIR [illegible] | | | | | | |
| (3728.0 mBRT) ([illegible] mBRT) | Through Tubing Perforations 2 7/8" [illegible] Hollow Carrier Guns | 3728.00 | [illegible] | 3721.40 | | | |
| (3763.0 mBRT) ([illegible] mBRT) | Through Tubing Perforations 2 7/8" [illegible] Hollow Carrier Guns | 3763.00 | 2963.20 | [illegible] | | | |
| (3786.0 mBRT) ([illegible] mBRT) | Through Tubing Perforations 2 7/8" [illegible] Hollow Carrier Guns | 3786.00 | 2982.36 | 3779.40 | | | |
| (3818.0 mBRT) ([illegible] mBRT) | Through Tubing Perforations 2 7/8" [illegible] Hollow Carrier Guns | 3818.00 | [illegible] | 3811.40 | | | |
| | Top of Cement | 4012.00 | [illegible] | 4005.40 | | | |
| (4012.9 mBRT) | Float Collar | 4012.90 | [illegible] | [illegible] | | | |
| (4025.6 mBRT) | 7" L80 29ppf Liner | 4025.60 | [illegible] | [illegible] | | [illegible] | 7.000 |
| (4042.0 mBRT) | 8 1/2" Drilled TD | 4042.00 | [illegible] | 4035.40 | | | |

Depths at top of item

All depths in meters unless indicated otherwise

[illegible]

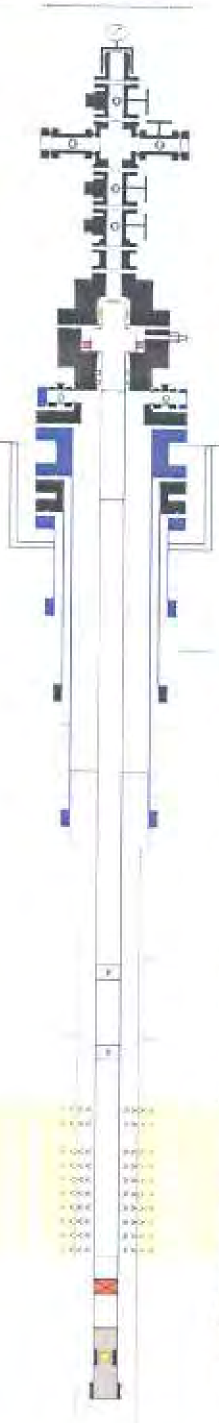
Engineering Department Rev. [illegible]

TULLOW

# TULLOW BANGLADESH LIMITED

## LALMAI-3 WELL - 4 1/2" COMPLETION DIAGRAM (PRODUCTION TESTING)

Engineering Department Rev [illegible]



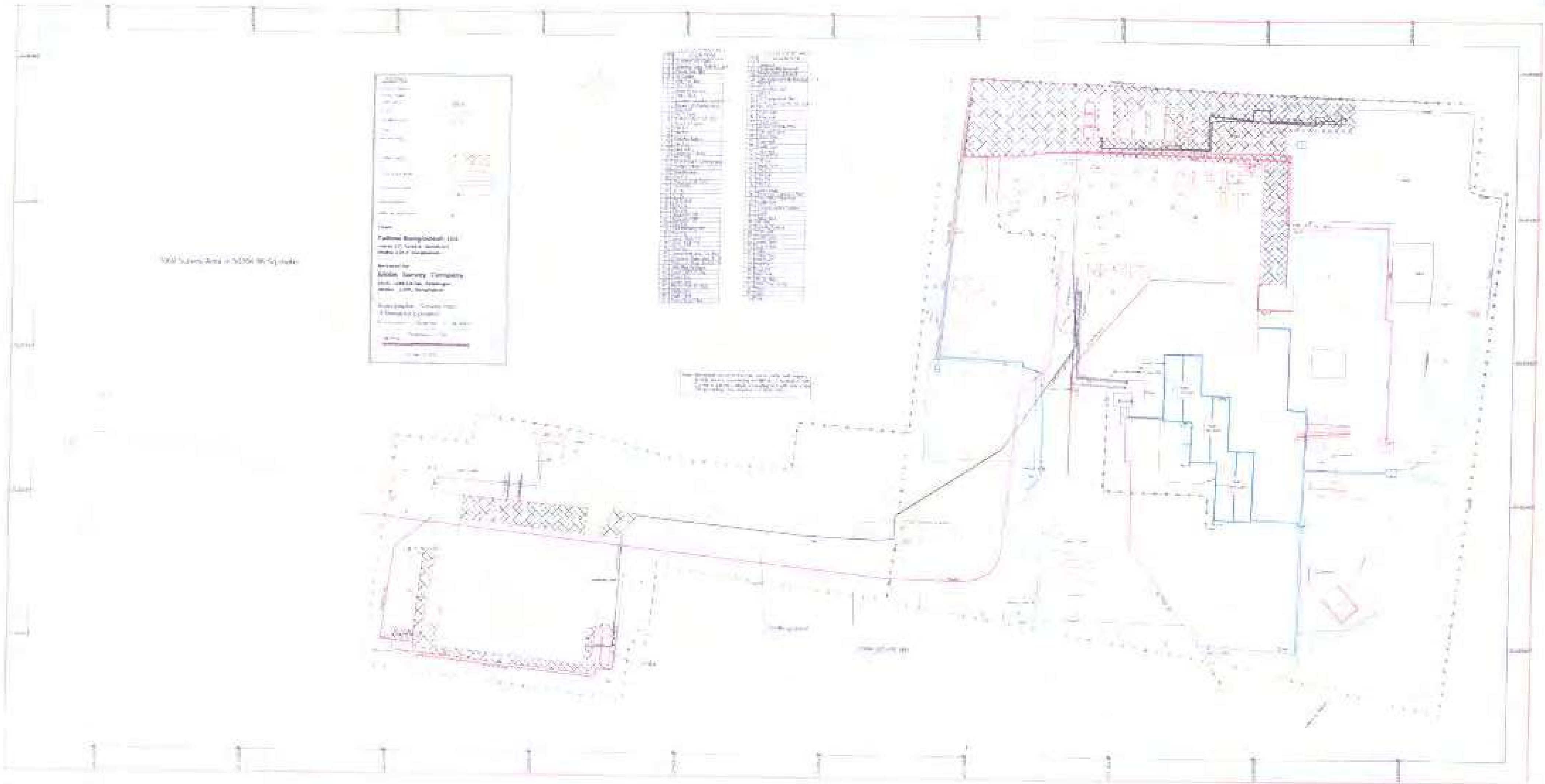
| COMMENTS | COMPLETION ITEM (DETAILS) | DEPTH (mTVDBRT) | DEPTH (mBSV) | LENGTH (metres) | MIN ID (ins) | MAX OD (ins) |
|---|---|---|---|---|---|---|
| ROTARY TABLE | ROTARY ELEVATION (7.83 m above GL) | 0.00 | -4.83 | | | |
| SWAB CAP | 4 1/4" Otis Quick Union Swab Cap | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| SWAB VALVE | 4 1/16" [illegible] psi Swab Valve (Centre Gate) | 4.83 | 0.00 | [illegible] | 4.100 | |
| PRODUCTION/KILL | 4 1/16" 10,000 psi Production/Kill Valves | [illegible] | [illegible] | [illegible] | 4.100 | |
| UPPER MASTER | 4 1/16" 10,000 psi Upper Master Valve (Centre Gate) | [illegible] | [illegible] | [illegible] | 4.100 | |
| LOWER MASTER | 4 1/16" 10,000 psi Lower Master Valve (Centre Gate) | [illegible] | [illegible] | [illegible] | [illegible] | |
| | ADAPTER SPOOL | [illegible] | ( 5.04 ) | [illegible] | | |
| | TUBING HEAD BONNET | ( 7.22 ) | ( 2.39 ) | [illegible] | | |
| | Tubing Hanger above Hang Off | [illegible] | 2.18 | [illegible] | [illegible] | [illegible] |
| | TUBING HEAD ADAPTER SPOOL | ( 7.59 ) | ( 2.76 ) | ( 0.34 ) | | |
| | Tubing Hanger Hang off | ( 7.45 ) | ( 2.61 ) | | | |
| | 4 1/2" 12.6 ppf Tubing Hanger below Hang off | 7.45 | 2.61 | [illegible] | [illegible] | [illegible] |
| | 9 5/8" x 4 1/2" ANNULUS c/w 2 1/16" 5000 psi Flange | | | | | |
| | 4 1/2" 12.6 ppf Pup Joint | [illegible] | 2.94 | [illegible] | [illegible] | [illegible] |
| | 9 5/8" CASING HEAD SPOOL | ( 7.83 ) | ( 3.89 ) | [illegible] | | |
| 7.8 mBRT | GROUND LEVEL | ( 7.83 ) | ( 3.05 ) | | | |
| | 13 3/8" CASING HEAD SPOOL | ( 8.57 ) | ( 3.74 ) | ( 0.82 ) | | |
| | 4 1/2" 12.6 ppf Production Tubing | 8.99 | 4.16 | 2190.58 | [illegible] | [illegible] |
| | 20" CONDUCTOR | ( 9.08 ) | ( 4.25 ) | | | |
| ( 14.0 mBRT ) | 20" K55 - 94 lb/ft Conductor Shoe | ( 14.00 ) | ( 9.17 ) | | 12.415 | 13.375 |
| SEA LEVEL | MEAN SEA LEVEL | ( 45.92 ) | ( 41.09 ) | | | |
| ( 282.0 mBRT ) | 13 3/8" J55 - 68 lb/ft Casing Shoe | 282.00 | 277.17 | | 12.415 | 13.375 |
| | 16" Hole TD | 285.00 | [illegible] | | | |
| ( 1039.0 mBRT ) | 9 5/8" L80 - 43.5 lb/ft Casing Shoe | 1039.00 | 1034.17 | | 8.681 | 9.625 |
| | 12 1/4" Hole TD | 1047.00 | 1042.17 | | | |
| ( 2199.[illegible] mBRT ) | [illegible] Marker [illegible] Pup Joint | [illegible] | [illegible] | | | |
| ( 2199.4 mBRT ) | 4 1/2" 12.6 ppf Production Tubing Pup Joint | 2199.[illegible] | [illegible] | [illegible] | 3.958 | [illegible] |
| | 4 1/2" 12.6 ppf Production Tubing | 2201.[illegible] | 2196.[illegible] | 193.90 | 3.958 | [illegible] |
| ( 2395.0 mBRT ) | [illegible] Marker [illegible] Pup Joint | [illegible] | [illegible] | | | |
| ( 2395.1 mBRT ) | 4 1/2" 12.6 ppf Production Tubing Pup Joint | 2395.08 | 2390.[illegible] | [illegible] | 3.958 | [illegible] |
| | 4 1/2" 12.6 ppf Production Tubing | 2398.81 | 2393.78 | [illegible] | 3.958 | [illegible] |
| | **PRODUCTION TEST 2: 2400m SAND (2410.0 - 2460.0 mBRT)** | | | | | |
| ( 2415.0 mBRT ) ( 2420.0 mBRT ) | 2C RUN#10 (28-05-04): Through Tubing Perforations 2 7/8", 16 spm, 6 spf, 60 degree Hollow Carrier Guns | 2418.00 | 2413.17 | 6.20 | | |
| ( 2431.0 mBRT ) ( 2435.4 mBRT ) | 2A RUN#8B (24-05-04): Through Tubing Perforations 2 7/8", 16 spm, 6 spf, 60 degree Hollow Carrier Guns | 2431.00 | 2426.17 | 4.40 | | |
| ( 2435.4 mBRT ) ( 2443.8 mBRT ) | 2A RUN#7 (24-05-04): Through Tubing Perforations 2 7/8", 16 spm, 6 spf, 60 degree Hollow Carrier Guns | 2435.40 | 2430.57 | 8.30 | | |
| ( 2443.6 mBRT ) ( 2451.8 mBRT ) | 2A RUN#6B (23-05-04): Through Tubing Perforations 2 7/8", 16 spm, 6 spf, 60 degree Hollow Carrier Guns | 2443.60 | 2438.77 | 8.20 | | |
| ( 2451.8 mBRT ) ( 2460.0 mBRT ) | 2B RUN#6 (25-05-04): Through Tubing Perforations 2 7/8", 16 spm, 6 spf, 60 degree Hollow Carrier Guns | 2451.80 | 2446.97 | 8.20 | | |
| | PT2 Produced Water: Water Spacer | [illegible] | [illegible] | | | |
| ( [illegible] mBRT ) | Baker Shoulder Retrievable WG-RBP [illegible] | 2661.70 | 2656.87 | 2.00 | | 5.950 |
| | **PRODUCTION TEST 1: 2700m SAND (2683.0 - 2729.0 mBRT) [illegible]** | | | | | |
| | [illegible] | [illegible] | [illegible] | | | |
| ( [illegible] mBRT ) | Float Collar | 2764.[illegible] | [illegible] | [illegible] | | |
| ( [illegible] mBRT ) | 4 1/2" 12.6 ppf Production Tubing Pup Joint | 2765.[illegible] | 2760.[illegible] | [illegible] | [illegible] | [illegible] |
| | 4 1/2" L80 - 12.6 lb/ft Production Tubing Shoe | 2784.70 | 2779.[illegible] | [illegible] | [illegible] | [illegible] |
| ( [illegible] mBRT ) | [illegible] | [illegible] | [illegible] | | | |
| | [illegible] Drilled TD | [illegible] | [illegible] | | | |

Depths to top of item

All Depths in metres unless indicated otherwise

[illegible]

Engineering Department Rev [illegible]



# APPENDIX C

# INPUT PARAMETERS FOR VOLUMETRIC CALCULATIONS

| | | | | |
|---|---|---|---|---|
| Field: | Bakhrabad | | | |
| Reservoir: | B Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.449 | 0.472 | 0.496 |
| Depth | ft | 5,905 | 6,059 | 6,213 |
| Abandonment Pressure | psia | 591 | 848 | 1,243 |
| Porosity | % | 20 | 25 | 30 |
| Water Sat. | % | 30 | 35 | 40 |
| Drainage area | Acres | 5,978 | 5,978 | 5,978 |
| Net Pay | feet | 20 | 25 | 30 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.62 | 0.86 | 1.10 |

| | | | | |
|---|---|---|---|---|
| Field: | Bakhrabad | | | |
| Reservoir: | C Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.472 | 0.497 | 0.522 |
| Depth | ft | 6,248 | 6,353 | 6,457 |
| Abandonment Pressure | psia | 625 | 889 | 1,291 |
| Porosity | % | 5 | 20 | 30 |
| Water Sat. | % | 25 | 55 | 80 |
| Drainage area | Acres | 2,558 | 2,842 | 3,126 |
| Net Pay | feet | 10 | 19 | 27 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.59 | 1.93 | 3.28 |

| | | | | |
|---|---|---|---|---|
| Field: | Bakhrabad | | | |
| Reservoir: | D upper sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.434 | 0.457 | 0.480 |
| Depth | ft | 6,335 | 6,441 | 6,546 |
| Abandonment Pressure | psia | 634 | 902 | 1,309 |
| Porosity | % | 18 | 22 | 24 |
| Water Sat. | % | 25 | 30 | 35 |
| Drainage area | Acres | 4,395 | 5,170 | 5,687 |
| Net Pay | feet | 30 | 36 | 43 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.05 | 0.28 | 0.50 |

| | | | | |
|---|---|---|---|---|
| Field: | Bakhrabad | | | |
| Reservoir: | D lower sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.502 | 0.528 | 0.554 |
| Depth | ft | 6,445 | 6,564 | 6,683 |
| Abandonment Pressure | psia | 645 | 919 | 1,337 |
| Porosity | % | 17 | 19 | 21 |
| Water Sat. | % | 20 | 31 | 35 |
| Drainage area | Acres | 3,296 | 3,878 | 4,265 |
| Net Pay | feet | 33 | 39 | 46 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1.30 | 5.90 | 10.50 |

| | | | | |
|---|---|---|---|---|
| Field: | Bakhrabad | | | |
| Reservoir: | F sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.517 | 0.545 | 0.572 |
| Depth | ft | 6,618 | 6,729 | 6,839 |
| Abandonment Pressure | psia | 662 | 942 | 1,368 |
| Porosity | % | 17 | 19 | 22 |
| Water Sat. | % | 25 | 35 | 40 |
| Drainage area | Acres | 1,824 | 2,026 | 2,229 |
| Net Pay | feet | 13 | 20 | 26 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.59 | 1.93 | 3.28 |

| | | | | |
|---|---|---|---|---|
| Field: | Bakhrabad | | | |
| Reservoir: | G Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.449 | 0.472 | 0.496 |
| Depth | ft | 6,795 | 6,952 | 7,108 |
| Abandonment Pressure | psia | 680 | 973 | 1,422 |
| Porosity | % | 15 | 18 | 22 |
| Water Sat. | % | 25 | 30 | 40 |
| Drainage area | Acres | 4,513 | 5,310 | 5,841 |
| Net Pay | feet | 33 | 49 | 66 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.59 | 1.93 | 3.28 |

| | | | | |
|---|---|---|---|---|
| Field: | Bakhrabad | | | |
| Reservoir: | J Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.449 | 0.472 | 0.496 |
| Depth | ft | 6,963 | 7,231 | 7,499 |
| Abandonment Pressure | psia | 696 | 1,012 | 1,500 |
| Porosity | % | 15 | 20 | 25 |
| Water Sat. | % | 23 | 26 | 40 |
| Drainage area | Acres | 3,801 | 4,472 | 4,919 |
| Net Pay | feet | 98 | 115 | 131 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.40 | 0.70 | 1.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Bakhrabad | | | |
| Reservoir: | K Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.449 | 0.472 | 0.496 |
| Depth | ft | 7,470 | 7,739 | 8,008 |
| Abandonment Pressure | psia | 747 | 1,084 | 1,602 |
| Porosity | % | 18 | 22 | 25 |
| Water Sat. | % | 25 | 35 | 40 |
| Drainage area | Acres | 5,543 | 6,521 | 7,173 |
| Net Pay | feet | 16 | 23 | 30 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.59 | 1.93 | 3.28 |

| | | | | |
|---|---|---|---|---|
| Field: | Bakhrabad | | | |
| Reservoir: | L Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.463 | 0.488 | 0.512 |
| Depth | ft | 7,985 | 8,033 | 8,081 |
| Abandonment Pressure | psia | 799 | 1,125 | 1,616 |
| Porosity | % | 14 | 16 | 22 |
| Water Sat. | % | 25 | 35 | 40 |
| Drainage area | Acres | 2,422 | 6,055 | 6,661 |
| Net Pay | feet | 13 | 33 | 39 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.59 | 1.93 | 3.28 |

| | | | | |
|---|---|---|---|---|
| Field: | Bangora | | | |
| Reservoir: | A Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.588 | 0.596 | 0.608 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.29% | 0.30% | 0.32% |
| CO2 | % | 0.57% | 0.60% | 0.63% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.430 | 0.436 | 0.442 |
| Depth | ft | 7,874 | 7,976 | 7,989 |
| Abandonment Pressure | psia | 500 | 700 | 1,025 |
| Porosity | % | 19 | 21 | 23 |
| Water Sat. | % | 42 | 47 | 52 |
| Drainage area | Acres | 910 | 1,011 | 1,113 |
| Net Pay | feet | 24 | 26 | 29 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.75 | 0.78 | 0.80 |

| | | | | |
|---|---|---|---|---|
| Field: | Bangora | | | |
| Reservoir: | B Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.588 | 0.596 | 0.608 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.29% | 0.30% | 0.32% |
| CO2 | % | 0.57% | 0.60% | 0.63% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.430 | 0.436 | 0.442 |
| Depth | ft | 8,058 | 8,160 | 8,196 |
| Abandonment Pressure | psia | 401 | 646 | 980 |
| Porosity | % | 22 | 24 | 26 |
| Water Sat. | % | 55 | 61 | 63 |
| Drainage area | Acres | 776 | 862 | 948 |
| Net Pay | feet | 24 | 26 | 29 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.75 | 0.78 | 0.80 |

| Field: | Bangora | | | |
|---|---|---|---|---|
| Reservoir: | C Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.588 | 0.596 | 0.608 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.29% | 0.30% | 0.32% |
| CO2 | % | 0.57% | 0.60% | 0.63% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.430 | 0.433 | 0.442 |
| Depth | ft | 8,462 | 8,563 | 8,613 |
| Abandonment Pressure | psia | 600 | 800 | 1,100 |
| Porosity | % | 15 | 17 | 19 |
| Water Sat. | % | 53 | 59 | 61 |
| Drainage area | Acres | 1,918 | 2,131 | 2,344 |
| Net Pay | feet | 18 | 20 | 22 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.75 | 0.78 | 0.80 |

| Field: | Bangora | | | |
|---|---|---|---|---|
| Reservoir: | D Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.588 | 0.596 | 0.608 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.29% | 0.30% | 0.32% |
| CO2 | % | 0.57% | 0.60% | 0.63% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.451 | 0.457 | 0.460 |
| Depth | ft | 9,515 | 9,659 | 10,581 |
| Abandonment Pressure | psia | 320 | 614 | 976 |
| Porosity | % | 10 | 11 | 12 |
| Water Sat. | % | 53 | 59 | 61 |
| Drainage area | Acres | 9,723 | 10,803 | 11,883 |
| Net Pay | feet | 109 | 121 | 133 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.75 | 0.78 | 0.80 |

| | | | | |
|---|---|---|---|---|
| Field: | Bangora | | | |
| Reservoir: | E Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.612 | 0.613 | 0.614 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.29% | 0.30% | 0.32% |
| CO2 | % | 0.57% | 0.60% | 0.63% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.445 | 0.448 | 0.457 |
| Depth | ft | 10,171 | 10,384 | 10,453 |
| Abandonment Pressure | psia | 425 | 675 | 1,020 |
| Porosity | % | 12.6 | 14.0 | 15.4 |
| Water Sat. | % | 43.2 | 48.0 | 52.8 |
| Drainage area | Acres | 1,110 | 1,233 | 1,356 |
| Net Pay | feet | 21 | 23 | 25 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.75 | 0.78 | 0.80 |

| | | | | |
|---|---|---|---|---|
| Field: | Beani Bazar | | | |
| Reservoir: | Upper Gas sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.38% | 0.40% | 0.42% |
| CO2 | % | 0.10% | 0.10% | 0.11% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.013 | 0.013 |
| press gradient | psi/ft | 0.425 | 0.427 | 0.428 |
| Depth | ft | 10,791 | 10,799 | 10,808 |
| Abandonment Pressure | psia | 1,079 | 1,512 | 2,162 |
| Porosity | % | 17 | 18 | 18 |
| Water Sat. | % | 31 | 32 | 33 |
| Drainage area | Acres | 1,440 | 1,801 | 2,001 |
| Net Pay | feet | 66 | 79 | 92 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 9.00 | 10.00 | 11.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Beani Bazar | | | |
| Reservoir: | Lower Gas Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.38% | 0.40% | 0.42% |
| CO2 | % | 0.10% | 0.10% | 0.11% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.013 | 0.013 |
| press gradient | psi/ft | 0.425 | 0.427 | 0.428 |
| Depth | ft | 11,346 | 11,434 | 11,523 |
| Abandonment Pressure | psia | 1,135 | 1,601 | 2,305 |
| Porosity | % | 16 | 16 | 17 |
| Water Sat. | % | 40 | 41 | 43 |
| Drainage area | Acres | 1,739 | 1,932 | 2,033 |
| Net Pay | feet | 20 | 26 | 31 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 9.00 | 10.00 | 11.00 |

| Field: | Bibiyana | | | |
|---|---|---|---|---|
| Reservoir: | BB60ab | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.013 |
| press gradient | psi/ft | 0.430 | 0.445 | 0.482 |
| Depth | ft | 8,367 | 9,062 | 9,758 |
| Abandonment Pressure | psia | 310 | 606 | 748 |
| Porosity | % | 16 | 19 | 21 |
| Water Sat. | % | 19 | 24 | 27 |
| Drainage area | Acres | 6,766 | 7,988 | 8,413 |
| Net Pay | feet | 238 | 264 | 291 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 5.8 | 8 |
| Bulk Volume | | 1,787,481.7 | 2,110,181.9 | 2,222,600.7 |

| Field: | Bibiyana | | | |
|---|---|---|---|---|
| Reservoir: | BB65 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.430 | 0.436 | 0.475 |
| Depth | ft | 8,695 | 9,226 | 9,758 |
| Abandonment Pressure | psia | 320 | 610 | 758 |
| Porosity | % | 14 | 15 | 16 |
| Water Sat. | % | 34 | 37 | 39 |
| Drainage area | Acres | 4,293 | 5,865 | 6,810 |
| Net Pay | feet | 79 | 98 | 108 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 5.8 | 8 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BB70 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.430 | 0.433 | 0.463 |
| Depth | ft | 9,023 | 9,551 | 10,076 |
| Abandonment Pressure | psia | 345 | 635 | 782 |
| Porosity | % | 11 | 15 | 19 |
| Water Sat. | % | 22 | 29 | 43 |
| Drainage area | Acres | 4,892 | 5,477 | 6,025 |
| Net Pay | feet | 131 | 164 | 180 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 6.6 | 8 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH10 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.011 | 0.012 |
| press gradient | psi/ft | 0.433 | 0.439 | 0.472 |
| Depth | ft | 9,597 | 10,279 | 10,962 |
| Abandonment Pressure | psia | 535 | 755 | 972 |
| Porosity | % | 11 | 12 | 13 |
| Water Sat. | % | 46 | 47 | 47 |
| Drainage area | Acres | 5,744 | 5,913 | 6,504 |
| Net Pay | feet | 82 | 105 | 125 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 5.9 | 8 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH20ab | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.427 | 0.439 | 0.451 |
| Depth | ft | 10,089 | 10,552 | 11,014 |
| Abandonment Pressure | psia | 476 | 718 | 945 |
| Porosity | % | 10 | 14 | 15 |
| Water Sat. | % | 20 | 27 | 60 |
| Drainage area | Acres | 3,762 | 3,825 | 4,208 |
| Net Pay | feet | 105 | 131 | 157 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 5 | 8 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH20c | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.427 | 0.439 | 0.451 |
| Depth | ft | 10,279 | 10,821 | 11,362 |
| Abandonment Pressure | psia | 476 | 718 | 945 |
| Porosity | % | 10 | 13 | 15 |
| Water Sat. | % | 20 | 31 | 60 |
| Drainage area | Acres | 2,940 | 3,087 | 3,234 |
| Net Pay | feet | 77 | 98 | 118 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 5 | 8 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH20d | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.427 | 0.439 | 0.451 |
| Depth | ft | 10,496 | 10,929 | 11,362 |
| Abandonment Pressure | psia | 476 | 718 | 945 |
| Porosity | % | 10 | 11 | 16 |
| Water Sat. | % | 20 | 47 | 60 |
| Drainage area | Acres | 2,818 | 2,959 | 3,100 |
| Net Pay | feet | 33 | 50 | 66 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 5 | 8 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH25 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.427 | 0.439 | 0.451 |
| Depth | ft | 10,676 | 11,159 | 11,641 |
| Abandonment Pressure | psia | 500 | 740 | 965 |
| Porosity | % | 14 | 15 | 16 |
| Water Sat. | % | 34 | 37 | 39 |
| Drainage area | Acres | 640 | 1,008 | 1,377 |
| Net Pay | feet | 63 | 70 | 77 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 5 | 8 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH30ab | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.427 | 0.439 | 0.451 |
| Depth | ft | 10,995 | 11,267 | 11,536 |
| Abandonment Pressure | psia | 500 | 740 | 965 |
| Porosity | % | 10 | 11 | 13 |
| Water Sat. | % | 50 | 53 | 59 |
| Drainage area | Acres | 0 | 640 | 2,275 |
| Net Pay | feet | 53 | 58 | 64 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 4 | 8 |
| Bulk Volume | | 0.0 | 37,413.6 | 132,981.3 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH30c | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.427 | 0.439 | 0.451 |
| Depth | ft | 11,169 | 11,418 | 11,667 |
| Abandonment Pressure | psia | 505 | 745 | 970 |
| Porosity | % | 9 | 10 | 11 |
| Water Sat. | % | 46 | 48 | 49 |
| Drainage area | Acres | 1,961 | 2,118 | 2,157 |
| Net Pay | feet | 23 | 33 | 39 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 2 | 4 | 8 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH40a | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.427 | 0.439 | 0.451 |
| Depth | ft | 11,319 | 11,552 | 11,782 |
| Abandonment Pressure | psia | 510 | 750 | 975 |
| Porosity | % | 7 | 12 | 13 |
| Water Sat. | % | 39 | 44 | 48 |
| Drainage area | Acres | 1,355 | 1,464 | 1,491 |
| Net Pay | feet | 16 | 33 | 43 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1 | 2 | 4 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH40b | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.427 | 0.439 | 0.451 |
| Depth | ft | 11,428 | 11,680 | 11,933 |
| Abandonment Pressure | psia | 510 | 750 | 975 |
| Porosity | % | 8 | 10 | 12 |
| Water Sat. | % | 51 | 52 | 53 |
| Drainage area | Acres | 1,053 | 1,623 | 1,782 |
| Net Pay | feet | 26 | 33 | 43 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1 | 2 | 4 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH40c | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.427 | 0.439 | 0.451 |
| Depth | ft | 11,644 | 11,897 | 12,150 |
| Abandonment Pressure | psia | 510 | 750 | 975 |
| Porosity | % | 9 | 10 | 11 |
| Water Sat. | % | 49 | 52 | 55 |
| Drainage area | Acres | 974 | 1,487 | 1,631 |
| Net Pay | feet | 30 | 39 | 43 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1 | 2 | 4 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH50a | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.011 | 0.012 |
| press gradient | psi/ft | 0.451 | 0.460 | 0.469 |
| Depth | ft | 12,058 | 12,166 | 12,274 |
| Abandonment Pressure | psia | 520 | 770 | 995 |
| Porosity | % | 9 | 11 | 13 |
| Water Sat. | % | 47 | 50 | 56 |
| Drainage area | Acres | 966 | 1,479 | 1,833 |
| Net Pay | feet | 69 | 82 | 92 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1 | 2 | 4 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH50b | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.011 | 0.012 |
| press gradient | psi/ft | 0.451 | 0.460 | 0.469 |
| Depth | ft | 12,058 | 12,166 | 12,274 |
| Abandonment Pressure | psia | 520 | 770 | 995 |
| Porosity | % | 9 | 11 | 13 |
| Water Sat. | % | 47 | 50 | 56 |
| Drainage area | Acres | 1,733 | 1,833 | 2,016 |
| Net Pay | feet | 69 | 82 | 92 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1 | 2 | 4 |

| | | | | |
|---|---|---|---|---|
| Field: | Bibiyana | | | |
| Reservoir: | BH60 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.584 | 0.586 | 0.589 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.23% | 0.25% | 0.28% |
| CO2 | % | 0.00% | 0.02% | 0.07% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.011 | 0.012 |
| press gradient | psi/ft | 0.634 | 0.643 | 0.652 |
| Depth | ft | 12,222 | 12,307 | 12,356 |
| Abandonment Pressure | psia | 525 | 775 | 1,000 |
| Porosity | % | 16.1 | 18.7 | 18.8 |
| Water Sat. | % | 32.8 | 34.0 | 50 |
| Drainage area | Acres | 708 | 765 | 779 |
| Net Pay | feet | 23 | 33 | 39 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1 | 2 | 4 |

| | | | | |
|---|---|---|---|---|
| Field: | Fenchuganj | | | |
| Reservoir: | Upper sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.450 | 0.460 | 0.470 |
| Depth | ft | 7,802 | 7,812 | 7,822 |
| Abandonment Pressure | psia | 780 | 1,094 | 1,564 |
| Porosity | % | 20 | 23 | 25 |
| Water Sat. | % | 25 | 39 | 40 |
| Drainage area | Acres | 6,795 | 16,754 | 23,549 |
| Net Pay | feet | 12 | 14 | 16 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.50 | 1.00 | 3.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Fenchuganj | | | |
| Reservoir: | Middle Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.450 | 0.460 | 0.470 |
| Depth | ft | 8,458 | 8,468 | 8,478 |
| Abandonment Pressure | psia | 846 | 1,186 | 1,696 |
| Porosity | % | 16 | 18 | 25 |
| Water Sat. | % | 25 | 35 | 40 |
| Drainage area | Acres | 988 | 1,483 | 2,471 |
| Net Pay | feet | 29 | 38 | 46 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.50 | 1.00 | 3.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Fenchuganj | | | |
| Reservoir: | Lower Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.450 | 0.460 | 0.470 |
| Depth | ft | 9,082 | 9,103 | 9,124 |
| Abandonment Pressure | psia | 908 | 1,274 | 1,825 |
| Porosity | % | 15 | 18 | 25 |
| Water Sat. | % | 25 | 35 | 40 |
| Drainage area | Acres | 680 | 1,359 | 2,039 |
| Net Pay | feet | 36 | 41 | 46 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.50 | 1.00 | 3.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Feni | | | |
| Reservoir: | Upper Gas sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.38% | 0.40% | 0.42% |
| CO2 | % | 0.19% | 0.20% | 0.21% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.459 | 0.483 | 0.507 |
| Depth | ft | 5,811 | 5,830 | 5,850 |
| Abandonment Pressure | psia | 581 | 816 | 1,170 |
| Porosity | % | 18 | 19 | 21 |
| Water Sat. | % | 23 | 25 | 27 |
| Drainage area | Acres | 247 | 0 | 0 |
| Net Pay | feet | 39 | 47 | 54 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.00 | 0.00 | 0.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Feni | | | |
| Reservoir: | K sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.38% | 0.40% | 0.42% |
| CO2 | % | 0.19% | 0.20% | 0.21% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.459 | 0.483 | 0.507 |
| Depth | ft | 5,811 | 5,830 | 5,850 |
| Abandonment Pressure | psia | 581 | 816 | 1,170 |
| Porosity | % | 18 | 19 | 21 |
| Water Sat. | % | 23 | 25 | 27 |
| Drainage area | Acres | 0 | 0 | 0 |
| Net Pay | feet | 39 | 47 | 54 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.00 | 0.00 | 0.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Feni | | | |
| Reservoir: | M sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.38% | 0.40% | 0.42% |
| CO2 | % | 0.19% | 0.20% | 0.21% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.459 | 0.483 | 0.507 |
| Depth | ft | 5,811 | 5,830 | 5,850 |
| Abandonment Pressure | psia | 581 | 816 | 1,170 |
| Porosity | % | 18 | 19 | 21 |
| Water Sat. | % | 23 | 25 | 27 |
| Drainage area | Acres | 0 | 0 | 0 |
| Net Pay | feet | 39 | 47 | 54 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.00 | 0.00 | 0.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Feni | | | |
| Reservoir: | R sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.38% | 0.40% | 0.42% |
| CO2 | % | 0.19% | 0.20% | 0.21% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.459 | 0.483 | 0.507 |
| Depth | ft | 5,811 | 5,830 | 5,850 |
| Abandonment Pressure | psia | 581 | 816 | 1,170 |
| Porosity | % | 18 | 19 | 21 |
| Water Sat. | % | 23 | 25 | 27 |
| Drainage area | Acres | 0 | 0 | 0 |
| Net Pay | feet | 39 | 47 | 54 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.00 | 0.00 | 0.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Feni | | | |
| Reservoir: | Lower Gas Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| $N_2$ | % | 0.00% | 0.00% | 0.00% |
| $CO_2$ | % | 0.00% | 0.00% | 0.00% |
| $H_2S$ | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.459 | 0.483 | 0.507 |
| Depth | ft | 9,056 | 9,131 | 9,203 |
| Abandonment Pressure | psia | 906 | 1,278 | 1,841 |
| Porosity | % | 10 | 12 | 15 |
| Water Sat. | % | 40 | 49 | 55 |
| Drainage area | Acres | 0 | 0 | 0 |
| Net Pay | feet | 0 | 107 | 0 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.00 | 0.00 | 0.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Habiganj | | | |
| Reservoir: | Upper Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.5656 | 0.5656 | 0.5656 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.70% | 0.78% | 0.87% |
| CO2 | % | 0.00% | 0.01% | 0.01% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.013 | 0.013 |
| press gradient | psi/ft | 0.469 | 0.493 | 0.518 |
| Depth | ft | 4,121 | 4,358 | 4,708 |
| Abandonment Pressure | psia | | | |
| Porosity | % | 26 | 28 | 30 |
| Water Sat. | % | 20 | 22 | 25 |
| Drainage area | Acres | 7,244 | 8,049 | 8,853 |
| Net Pay | feet | 262 | 312 | 394 |
| % Recovery | | 65.0% | 72.0% | 73.0% |
| Condensate Content | Bbl/MMCF | 0.01 | 0.05 | 0.10 |

| | | | | |
|---|---|---|---|---|
| Field: | Habiganj | | | |
| Reservoir: | Lower Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.57 | 0.57 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.34% | 0.38% | 0.42% |
| CO2 | % | 0.24% | 0.27% | 0.30% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.013 | 0.013 |
| press gradient | psi/ft | 0.415 | 0.437 | 0.459 |
| Depth | ft | 9,641 | 9,805 | 9,855 |
| Abandonment Pressure | psia | | | |
| Porosity | % | 17.0 | 20.0 | 22.5 |
| Water Sat. | % | 35.0 | 40.0 | 45 |
| Drainage area | Acres | 4,011 | 5,158 | 5,965 |
| Net Pay | feet | 23 | 33 | 39 |
| % Recovery | | 65.0% | 72.0% | 73.0% |
| Condensate Content | Bbl/MMCF | 0.50 | 0.71 | 0.97 |

| | | | | |
|---|---|---|---|---|
| Field: | Jalalabad | | | |
| Reservoir: | BB20 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.62 | 0.65 | 0.68 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.20% | 0.21% | 0.22% |
| CO2 | % | 0.04% | 0.04% | 0.04% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.010 | 0.011 | 0.011 |
| press gradient | psi/ft | 0.411 | 0.440 | 0.451 |
| Depth | ft | 4,902 | 5,053 | 5,086 |
| Abandonment Pressure | psia | 350 | 592 | 915 |
| Porosity | % | 19 | 19 | 23 |
| Water Sat. | % | 41 | 44 | 47 |
| Drainage area | Acres | 640 | 1,173 | 1,408 |
| Net Pay | feet | 49 | 56 | 66 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 4.75 | 5.00 | 5.25 |

| | | | | |
|---|---|---|---|---|
| Field: | Jalalabad | | | |
| Reservoir: | BB50 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.62 | 0.65 | 0.68 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.20% | 0.21% | 0.22% |
| CO2 | % | 0.04% | 0.04% | 0.04% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.010 | 0.011 | 0.012 |
| press gradient | psi/ft | 0.411 | 0.445 | 0.451 |
| Depth | ft | 6,956 | 7,284 | 7,546 |
| Abandonment Pressure | psia | 315 | 595 | 940 |
| Porosity | % | 17 | 18 | 18 |
| Water Sat. | % | 33 | 36 | 43 |
| Drainage area | Acres | 2,044 | 3,167 | 4,290 |
| Net Pay | feet | 115 | 125 | 148 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 7.32 | 7.70 | 8.09 |

| | | | | |
|---|---|---|---|---|
| Field: | Jalalabad | | | |
| Reservoir: | BB60 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.62 | 0.65 | 0.68 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.20% | 0.21% | 0.22% |
| CO2 | % | 0.04% | 0.04% | 0.04% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.010 | 0.011 | 0.011 |
| press gradient | psi/ft | 0.411 | 0.448 | 0.451 |
| Depth | ft | 7,458 | 7,783 | 8,058 |
| Abandonment Pressure | psia | 306 | 592 | 946 |
| Porosity | % | 18 | 19 | 19 |
| Water Sat. | % | 27 | 30 | 37 |
| Drainage area | Acres | 2,901 | 3,191 | 3,481 |
| Net Pay | feet | 213 | 246 | 279 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 7.32 | 7.70 | 8.09 |

| | | | | |
|---|---|---|---|---|
| Field: | Jalalabad | | | |
| Reservoir: | BB70 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.62 | 0.65 | 0.68 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.20% | 0.21% | 0.22% |
| CO2 | % | 0.04% | 0.04% | 0.04% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.010 | 0.011 | 0.011 |
| press gradient | psi/ft | 0.411 | 0.436 | 0.451 |
| Depth | ft | 7,924 | 8,055 | 8,058 |
| Abandonment Pressure | psia | 357 | 625 | 967 |
| Porosity | % | 16.8 | 18.3 | 19.3 |
| Water Sat. | % | 32.7 | 40.7 | 47 |
| Drainage area | Acres | 871 | 991 | 1,110 |
| Net Pay | feet | 52 | 59 | 66 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 11.31 | 11.90 | 12.50 |

| | | | | |
|---|---|---|---|---|
| Field: | Kailash Tila | | | |
| Reservoir: | Upper Gas Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.63 | 0.652 | 0.7 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.36% | 0.38% | 0.40% |
| CO2 | % | 0.05% | 0.05% | 0.05% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.008 | 0.009 | 0.009 |
| press gradient | psi/ft | 0.442 | 0.449 | 0.451 |
| Depth | ft | 7,362 | 7,422 | 7,483 |
| Abandonment Pressure | psia | 308 | 591 | 943 |
| Porosity | % | 19 | 21 | 23 |
| Water Sat. | % | 26 | 34 | 37 |
| Drainage area | Acres | 5,678 | 6,246 | 7,495 |
| Net Pay | feet | 164 | 197 | 213 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 9.00 | 10.00 | 11.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Kailash Tila | | | |
| Reservoir: | A Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.63 | 0.652 | 0.7 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.36% | 0.38% | 0.40% |
| CO2 | % | 0.05% | 0.05% | 0.05% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.008 | 0.009 | 0.009 |
| press gradient | psi/ft | 0.442 | 0.449 | 0.451 |
| Depth | ft | 8,806 | 8,920 | 9,034 |
| Abandonment Pressure | psia | 308 | 591 | 943 |
| Porosity | % | 14 | 17 | 20 |
| Water Sat. | % | 45 | 50 | 55 |
| Drainage area | Acres | 640 | 2,615 | 2,906 |
| Net Pay | feet | 21 | 24 | 26 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 9.00 | 10.00 | 11.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Kailash Tila | | | |
| Reservoir: | HRZ Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.63 | 0.7 | 0.735 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.36% | 0.38% | 0.40% |
| CO2 | % | 0.05% | 0.05% | 0.05% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.011 | 0.012 | 0.012 |
| press gradient | psi/ft | 0.406 | 0.421 | 0.427 |
| Depth | ft | 9,028 | 9,052 | 9,075 |
| Abandonment Pressure | psia | 308 | 591 | 943 |
| Porosity | % | 18 | 20 | 24 |
| Water Sat. | % | 35 | 43 | 50 |
| Drainage area | Acres | 640 | 2,559 | 2,843 |
| Net Pay | feet | 33 | 43 | 47 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 35.00 | 36.94 | 39.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Kailash Tila | | | |
| Reservoir: | Middle Gas Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.63 | 0.655 | 0.7 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.08% | 0.23% | 0.38% |
| CO2 | % | 0.05% | 0.12% | 0.19% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.008 | 0.008 | 0.009 |
| press gradient | psi/ft | 0.411 | 0.444 | 0.451 |
| Depth | ft | 9,584 | 9,605 | 9,625 |
| Abandonment Pressure | psia | 345 | 630 | 992 |
| Porosity | % | 17 | 19 | 21 |
| Water Sat. | % | 16 | 17 | 19 |
| Drainage area | Acres | 3,644 | 4,008 | 4,810 |
| Net Pay | feet | 72 | 82 | 98 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 9.00 | 10.00 | 11.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Kailash Tila | | | |
| Reservoir: | Lower Gas Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.63 | 0.661 | 0.7 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.08% | 0.08% | 0.08% |
| CO2 | % | 0.18% | 0.19% | 0.20% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.008 | 0.008 | 0.009 |
| press gradient | psi/ft | 0.411 | 0.440 | 0.451 |
| Depth | ft | 9,808 | 9,918 | 10,028 |
| Abandonment Pressure | psia | 350 | 635 | 1,000 |
| Porosity | % | 17.0 | 20.0 | 21.0 |
| Water Sat. | % | 20.0 | 24.0 | 28 |
| Drainage area | Acres | 4,372 | 4,590 | 5,279 |
| Net Pay | feet | 82 | 98 | 115 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 9.00 | 10.00 | 11.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Moulavi Bazar | | | |
| Reservoir: | BB20 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.58 | 0.58 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.17% | 0.18% | 0.19% |
| CO2 | % | 0.09% | 0.10% | 0.11% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.012 | 0.013 |
| press gradient | psi/ft | 0.445 | 0.448 | 0.451 |
| Depth | ft | 2,543 | 2,871 | 3,199 |
| Abandonment Pressure | psia | 365 | 619 | 955 |
| Porosity | % | 25 | 28 | 31 |
| Water Sat. | % | 43 | 48 | 53 |
| Drainage area | Acres | 640 | 1,280 | 5,704 |
| Net Pay | feet | 37 | 46 | 55 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.65 | 0.67 | 0.70 |

| | | | | |
|---|---|---|---|---|
| Field: | Moulavi Bazar | | | |
| Reservoir: | BB50 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.58 | 0.58 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.17% | 0.18% | 0.19% |
| CO2 | % | 0.09% | 0.10% | 0.11% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.012 | 0.013 |
| press gradient | psi/ft | 0.445 | 0.448 | 0.451 |
| Depth | ft | 4,675 | 5,004 | 5,332 |
| Abandonment Pressure | psia | 365 | 619 | 955 |
| Porosity | % | 20 | 22 | 24 |
| Water Sat. | % | 30 | 33 | 36 |
| Drainage area | Acres | 0 | 1,000 | 2,564 |
| Net Pay | feet | 52 | 65 | 78 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.72 | 0.77 | 0.82 |

| | | | | |
|---|---|---|---|---|
| Field: | Moulavi Bazar | | | |
| Reservoir: | BB60 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.58 | 0.58 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.17% | 0.18% | 0.19% |
| CO2 | % | 0.09% | 0.10% | 0.11% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.012 | 0.013 |
| press gradient | psi/ft | 0.445 | 0.448 | 0.451 |
| Depth | ft | 5,660 | 5,988 | 6,316 |
| Abandonment Pressure | psia | 365 | 619 | 955 |
| Porosity | % | 17 | 19 | 21 |
| Water Sat. | % | 28 | 31 | 34 |
| Drainage area | Acres | 2,577 | 3,305 | 3,845 |
| Net Pay | feet | 44 | 56 | 67 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.75 | 0.79 | 0.85 |

| | | | | |
|---|---|---|---|---|
| Field: | Moulavi Bazar | | | |
| Reservoir: | BB70 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.58 | 0.58 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.17% | 0.18% | 0.19% |
| CO2 | % | 0.09% | 0.10% | 0.11% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.012 | 0.013 |
| press gradient | psi/ft | 0.445 | 0.448 | 0.451 |
| Depth | ft | 6,480 | 6,966 | 7,054 |
| Abandonment Pressure | psia | 365 | 619 | 955 |
| Porosity | % | 15.0 | 21.0 | 24.0 |
| Water Sat. | % | 25.0 | 34.0 | 55 |
| Drainage area | Acres | 2,372 | 3,812 | 5,940 |
| Net Pay | feet | 115 | 148 | 164 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.75 | 0.80 | 0.85 |

| | | | | |
|---|---|---|---|---|
| Field: | Moulavi Bazar | | | |
| Reservoir: | BB80 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.58 | 0.58 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.17% | 0.18% | 0.19% |
| CO2 | % | 0.09% | 0.10% | 0.11% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.012 | 0.013 |
| press gradient | psi/ft | 0.445 | 0.448 | 0.451 |
| Depth | ft | 6,808 | 7,294 | 7,382 |
| Abandonment Pressure | psia | 365 | 619 | 955 |
| Porosity | % | 20.7 | 23.0 | 25.3 |
| Water Sat. | % | 33.6 | 37.3 | 41 |
| Drainage area | Acres | 640 | 1,280 | 4,038 |
| Net Pay | feet | 44 | 56 | 67 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.75 | 0.80 | 0.85 |

| | | | | |
|---|---|---|---|---|
| Field: | Narsingdi | | | |
| Reservoir: | Upper Gas sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.29% | 0.30% | 0.32% |
| CO2 | % | 0.57% | 0.60% | 0.63% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.013 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.419 | 0.441 | 0.463 |
| Depth | ft | 9,600 | 9,610 | 9,620 |
| Abandonment Pressure | psia | 960 | 1,345 | 1,924 |
| Porosity | % | 20 | 21 | 22 |
| Water Sat. | % | 40 | 41 | 42 |
| Drainage area | Acres | 2,889 | 4,334 | 7,224 |
| Net Pay | feet | 10 | 16 | 20 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1.90 | 2.40 | 3.10 |

| | | | | |
|---|---|---|---|---|
| Field: | Narsingdi | | | |
| Reservoir: | Lower Gas Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.29% | 0.30% | 0.32% |
| CO2 | % | 0.57% | 0.60% | 0.63% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.013 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.419 | 0.441 | 0.463 |
| Depth | ft | 10,289 | 10,365 | 10,440 |
| Abandonment Pressure | psia | 1,029 | 1,451 | 2,088 |
| Porosity | % | 16 | 17 | 18 |
| Water Sat. | % | 40 | 41 | 43 |
| Drainage area | Acres | 5,159 | 7,739 | 12,898 |
| Net Pay | feet | 25 | 30 | 34 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1.90 | 2.40 | 3.10 |

| | | | | |
|---|---|---|---|---|
| Field: | Rashidpur | | | |
| Reservoir: | Upper Gas Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.52915 | 0.557 | 0.58485 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.31% | 0.44% | 0.50% |
| CO2 | % | 0.02% | 0.03% | 0.05% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.010 | 0.011 | 0.011 |
| press gradient | psi/ft | 0.415 | 0.415 | 0.418 |
| Depth | ft | 4,147 | 4,976 | 5,806 |
| Abandonment Pressure | psia | 276 | 550 | 880 |
| Porosity | % | 23 | 25 | 27 |
| Water Sat. | % | 26 | 30 | 34 |
| Drainage area | Acres | 1,507 | 3,014 | 5,024 |
| Net Pay | feet | 164 | 197 | 230 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1.00 | 1.15 | 1.30 |

| | | | | |
|---|---|---|---|---|
| Field: | Rashidpur | | | |
| Reservoir: | Middle Gas Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.52915 | 0.557 | 0.58485 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.31% | 0.44% | 0.50% |
| CO2 | % | 0.02% | 0.03% | 0.05% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.010 | 0.011 | 0.011 |
| press gradient | psi/ft | 0.415 | 0.415 | 0.418 |
| Depth | ft | 5,724 | 6,821 | 7,917 |
| Abandonment Pressure | psia | 276 | 550 | 880 |
| Porosity | % | 22 | 23 | 25 |
| Water Sat. | % | 33 | 40 | 48 |
| Drainage area | Acres | 10,771 | 17,952 | 22,440 |
| Net Pay | feet | 105 | 112 | 118 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1.00 | 1.15 | 1.30 |

| | | | | |
|---|---|---|---|---|
| Field: | Rashidpur | | | |
| Reservoir: | Lower Gas Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.574 | 0.578 | 0.6 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.21% | 0.28% | 0.39% |
| CO2 | % | 0.05% | 0.14% | 0.20% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.012 | 0.012 | 0.013 |
| press gradient | psi/ft | 0.433 | 0.436 | 0.439 |
| Depth | ft | 8,525 | 9,010 | 9,495 |
| Abandonment Pressure | psia | 337 | 615 | 968 |
| Porosity | % | 15 | 20 | 25 |
| Water Sat. | % | 27 | 40 | 57 |
| Drainage area | Acres | 5,336 | 6,670 | 8,004 |
| Net Pay | feet | 115 | 131 | 148 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.95 | 1.00 | 1.05 |

| | | | | |
|---|---|---|---|---|
| Field: | Salda Nadi | | | |
| Reservoir: | Upper sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.448 | 0.472 | 0.495 |
| Depth | ft | 7,120 | 7,194 | 7,267 |
| Abandonment Pressure | psia | 712 | 1,007 | 1,453 |
| Porosity | % | 14 | 16 | 20 |
| Water Sat. | % | 29 | 34 | 38 |
| Drainage area | Acres | 640 | 5,102 | 5,612 |
| Net Pay | feet | 59 | 69 | 115 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 1.00 | 1.05 | 1.10 |

| | | | | |
|---|---|---|---|---|
| Field: | Salda Nadi | | | |
| Reservoir: | Middle Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.448 | 0.472 | 0.495 |
| Depth | ft | 7,564 | 7,635 | 7,705 |
| Abandonment Pressure | psia | 756 | 1,069 | 1,541 |
| Porosity | % | 17 | 21 | 25 |
| Water Sat. | % | 48 | 53 | 58 |
| Drainage area | Acres | 1,099 | 1,374 | 1,717 |
| Net Pay | feet | 13 | 18 | 23 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.65 | 0.72 | 0.80 |

| | | | | |
|---|---|---|---|---|
| Field: | Salda Nadi | | | |
| Reservoir: | Lower Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.596 | 0.6 | 0.618 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.40% | 0.58% | 0.75% |
| CO2 | % | 0.26% | 0.33% | 0.38% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.448 | 0.472 | 0.495 |
| Depth | ft | 7,907 | 7,933 | 7,958 |
| Abandonment Pressure | psia | 791 | 1,111 | 1,592 |
| Porosity | % | 14 | 16 | 17 |
| Water Sat. | % | 25 | 29 | 33 |
| Drainage area | Acres | 667 | 1,334 | 3,820 |
| Net Pay | feet | 30 | 39 | 56 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.65 | 0.80 | 1.10 |

| | | | | |
|---|---|---|---|---|
| Field: | Sangu | | | |
| Reservoir: | SG 1.1860 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.60 | 0.63 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.46% | 0.48% | 0.50% |
| CO2 | % | 0.56% | 0.59% | 1.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.406 | 0.427 | 0.449 |
| Depth | ft | 6,103 | 6,302 | 6,502 |
| Abandonment Pressure | psia | 427 | 630 | 650 |
| Porosity | % | 20 | 24 | 27 |
| Water Sat. | % | 40 | 45 | 50 |
| Drainage area | Acres | 1,614 | 1,793 | 1,993 |
| Net Pay | feet | 27 | 71 | 93 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.20 | 0.35 | 0.45 |
| Bulk Volume | ac-ft | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sangu | | | |
| Reservoir: | SG 1.2585 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.56525 | 0.60 | 0.62 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.50% | 0.53% | 0.56% |
| CO2 | % | 0.46% | 0.48% | 1.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.427 | 0.449 | 0.472 |
| Depth | ft | 8,498 | 8,554 | 8,609 |
| Abandonment Pressure | psia | 595 | 855 | 861 |
| Porosity | % | 11 | 13 | 17 |
| Water Sat. | % | 40 | 46 | 52 |
| Drainage area | Acres | 779 | 865 | 962 |
| Net Pay | feet | 28 | 33 | 41 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.20 | 0.35 | 0.45 |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |

| | | | | |
|---|---|---|---|---|
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sangu | | | |
| Reservoir: | SG 3.2635 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.5662 | 0.60 | 0.63 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.47% | 0.49% | 0.51% |
| CO2 | % | 0.66% | 0.69% | 1.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.018 | 0.019 |
| press gradient | psi/ft | 0.424 | 0.446 | 0.468 |
| Depth | ft | 8,642 | 8,709 | 8,777 |
| Abandonment Pressure | psia | 605 | 871 | 878 |
| Porosity | % | 24 | 25 | 26 |
| Water Sat. | % | 30 | 35 | 40 |
| Drainage area | Acres | 526 | 584 | 649 |
| Net Pay | feet | 36 | 38 | 41 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.20 | 0.35 | 0.45 |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sangu | | | |
| Reservoir: | SG 1.2970 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.60 | 0.63 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.46% | 0.48% | 0.50% |
| CO2 | % | 0.56% | 0.59% | 1.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.428 | 0.450 | 0.473 |
| Depth | ft | 9,758 | 9,895 | 10,033 |
| Abandonment Pressure | psia | 683 | 990 | 1,003 |
| Porosity | % | 11 | 11 | 13 |
| Water Sat. | % | 40 | 47 | 52 |
| Drainage area | Acres | 922 | 1,024 | 1,138 |
| Net Pay | feet | 41 | 46 | 52 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.20 | 0.35 | 0.45 |
| | | | | |
| Gas Initially in Place | BCF | | | |

| | | | | |
|---|---|---|---|---|
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sangu | | | |
| Reservoir: | SG 1.3085 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.60 | 0.63 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.46% | 0.48% | 0.50% |
| CO2 | % | 0.56% | 0.59% | 1.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.425 | 0.447 | 0.469 |
| Depth | ft | 10,150 | 10,451 | 10,752 |
| Abandonment Pressure | psia | 710 | 1,045 | 1,075 |
| Porosity | % | 11 | 15 | 19 |
| Water Sat. | % | 30 | 35 | 40 |
| Drainage area | Acres | 1,626 | 1,807 | 2,007 |
| Net Pay | feet | 21 | 30 | 36 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.20 | 0.35 | 0.45 |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sangu | | | |
| Reservoir: | SG 1.3155ABC | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.5776 | 0.61 | 0.64 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.41% | 0.43% | 0.45% |
| CO2 | % | 0.56% | 0.59% | 1.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.016 | 0.017 |
| press gradient | psi/ft | 0.431 | 0.453 | 0.476 |
| Depth | ft | 10,354 | 10,661 | 10,968 |
| Abandonment Pressure | psia | 725 | 1,066 | 1,097 |
| Porosity | % | 12 | 15 | 18 |
| Water Sat. | % | 30 | 35 | 40 |
| Drainage area | Acres | 5,967 | 6,630 | 7,367 |
| Net Pay | feet | 60 | 64 | 75 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.20 | 0.35 | 0.45 |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sangu | | | |
| Reservoir: | SG 1.3255 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.60 | 0.63 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.46% | 0.48% | 0.50% |
| CO2 | % | 0.56% | 0.59% | 1.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.433 | 0.456 | 0.479 |
| Depth | ft | 10,658 | 10,918 | 11,178 |
| Abandonment Pressure | psia | 746 | 1,092 | 1,118 |
| Porosity | % | 14 | 16 | 18 |
| Water Sat. | % | 30 | 35 | 40 |
| Drainage area | Acres | 3,582 | 3,980 | 4,422 |
| Net Pay | feet | 26 | 29 | 34 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.20 | 0.35 | 0.45 |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sangu | | | |
| Reservoir: | SG 2.3480 | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.57 | 0.60 | 0.63 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.46% | 0.48% | 0.50% |
| CO2 | % | 0.56% | 0.59% | 1.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.451 | 0.475 | 0.499 |
| Depth | ft | 11,421 | 11,472 | 11,522 |
| Abandonment Pressure | psia | 799 | 1,147 | 1,152 |
| Porosity | % | 10 | 14 | 18 |
| Water Sat. | % | 39 | 49 | 59 |
| Drainage area | Acres | 2,312 | 2,569 | 2,855 |
| Net Pay | feet | 22 | 26 | 30 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.20 | 0.35 | 0.45 |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Shahbazpur | | | |
| Reservoir: | I Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.58 | 0.6 | 0.62 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.42% | 0.44% | 0.46% |
| CO2 | % | 0.80% | 0.87% | 0.94% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.015 | 0.016 | 0.017 |
| press gradient | psi/ft | 0.422 | 0.445 | 0.467 |
| Depth | ft | 8,458 | 8,493 | 8,527 |
| Abandonment Pressure | psia | 846 | 1,189 | 1,705 |
| Porosity | % | 16 | 18 | 20 |
| Water Sat. | % | 30 | 34 | 37 |
| Drainage area | Acres | 953 | 1,072 | 1,191 |
| Net Pay | feet | 10 | 16 | 21 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.01 | 0.02 | 0.03 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Shahbazpur | | | |
| Reservoir: | II Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.58 | 0.6 | 0.62 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.42% | 0.44% | 0.46% |
| CO2 | % | 0.80% | 0.87% | 0.94% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.448 | 0.472 | 0.495 |
| Depth | ft | 10,348 | 10,462 | 10,576 |
| Abandonment Pressure | psia | 1,035 | 1,465 | 2,115 |
| Porosity | % | 15 | 17 | 18 |
| Water Sat. | % | 35 | 39 | 42 |
| Drainage area | Acres | 1,236 | 1,390 | 1,544 |
| Net Pay | feet | 24 | 40 | 53 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.01 | 0.02 | 0.03 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Shahbazpur | | | |
| Reservoir: | III Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.58 | 0.6 | 0.62 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.42% | 0.44% | 0.46% |
| CO2 | % | 0.80% | 0.87% | 0.94% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.473 | 0.498 | 0.523 |
| Depth | ft | 10,555 | 10,703 | 10,850 |
| Abandonment Pressure | psia | 1,055 | 1,498 | 2,170 |
| Porosity | % | 15 | 17 | 19 |
| Water Sat. | % | 32 | 36 | 39 |
| Drainage area | Acres | 2,372 | 2,669 | 2,965 |
| Net Pay | feet | 48 | 80 | 104 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.01 | 0.02 | 0.03 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Shahbazpur | | | |
| Reservoir: | IV Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.58 | 0.6 | 0.62 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.42% | 0.44% | 0.46% |
| CO2 | % | 0.80% | 0.87% | 0.94% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.477 | 0.503 | 0.528 |
| Depth | ft | 10,932 | 11,006 | 11,080 |
| Abandonment Pressure | psia | 1,093 | 1,541 | 2,216 |
| Porosity | % | 14 | 16 | 18 |
| Water Sat. | % | 29 | 33 | 36 |
| Drainage area | Acres | 741 | 834 | 927 |
| Net Pay | feet | 26 | 43 | 56 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.01 | 0.02 | 0.03 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Shahbazpur | | | |
| Reservoir: | V Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.58 | 0.6 | 0.62 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.42% | 0.44% | 0.46% |
| CO2 | % | 0.80% | 0.87% | 0.94% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.477 | 0.502 | 0.527 |
| Depth | ft | 11,146 | 11,237 | 11,329 |
| Abandonment Pressure | psia | 1,115 | 1,573 | 2,266 |
| Porosity | % | 14 | 16 | 18 |
| Water Sat. | % | 32 | 35 | 39 |
| Drainage area | Acres | 988 | 1,112 | 1,236 |
| Net Pay | feet | 26 | 43 | 56 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.01 | 0.02 | 0.03 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sylhet | | | |
| Reservoir: | UBok | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.58 | 0.6 | 0.62 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.26% | 0.27% | 0.28% |
| CO2 | % | 0.14% | 0.15% | 0.16% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.016 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.437 | 0.460 | 0.470 |
| Depth | ft | 3,800 | 3,900 | 3,960 |
| Abandonment Pressure | psia | 380 | 546 | 792 |
| Porosity | % | 18 | 21 | 23 |
| Water Sat. | % | 30 | 36 | 45 |
| Drainage area | Acres | 4,747 | 5,933 | 7,120 |
| Net Pay | feet | 60 | 80 | 110 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 3.00 | 3.40 | 4.00 |

| | | | | |
|---|---|---|---|---|
| Field: | Sylhet | | | |
| Reservoir: | MidBok | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.59 | 0.60 | 0.61 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.26% | 0.27% | 0.28% |
| CO2 | % | 0.14% | 0.15% | 0.16% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.017 | 0.017 | 0.018 |
| press gradient | psi/ft | 0.434 | 0.457 | 0.480 |
| Depth | ft | 4,100 | 4,300 | 4,480 |
| Abandonment Pressure | psia | 410 | 602 | 896 |
| Porosity | % | 17 | 19 | 22 |
| Water Sat. | % | 32 | 38 | 45 |
| Drainage area | Acres | 852 | 1,066 | 1,172 |
| Net Pay | feet | 100 | 120 | 140 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 3.00 | 3.10 | 3.40 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sylhet | | | |
| Reservoir: | LowBok | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.59 | 0.60 | 0.61 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.26% | 0.27% | 0.28% |
| CO2 | % | 0.14% | 0.15% | 0.16% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.015 | 0.016 | 0.017 |
| press gradient | psi/ft | 0.442 | 0.465 | 0.489 |
| Depth | ft | 6,000 | 6,149 | 6,297 |
| Abandonment Pressure | psia | 600 | 861 | 1,259 |
| Porosity | % | 20 | 22 | 23 |
| Water Sat. | % | 33 | 38 | 42 |
| Drainage area | Acres | 844 | 1,714 | 2,056 |
| Net Pay | feet | 50 | 70 | 90 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 7.00 | 7.40 | 8.00 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Sylhet | | | |
| Reservoir: | UBhuban | | | |
| | | Minimum | Most Likely | Maximum |
| Oil Gravity | API | 27 | 29 | 32 |
| Gas-Oil Ratio | cuft/bbl | 400 | 414 | 450 |
| Gas Gravity | | 0.59 | 0.60 | 0.61 |
| TEMP-res | °F | | | |
| TEMP-sep. | °F | | | |
| Temp gradient | °F/ft | 0.015 | 0.016 | 0.017 |
| PRES-sep. | psia | | | |
| PRESS-res | psia | | | |
| press gradient | psi/ft | 0.43 | 0.45 | 0.48 |
| Depth | ft | 6,150 | 6,185 | 6,200 |
| Porosity | % | 18 | 20 | 22 |
| Water Sat. | % | 35 | 37 | 45 |
| Drainage area | Acres | 160 | 480 | 2091 |
| Net Pay | feet | 30.0 | 50.0 | 70.0 |
| % Recovery | | 5% | 15% | 16% |
| | | | | |
| | | | | |
| Oil in Place | MMBO | | | |
| Estimated Ultimate Recovery | MMBO | | | |
| Associated Gas in Place | BCF | | | |
| Associated Gas Recovery | BCF | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Titas | | | |
| Reservoir: | A1,2,2b,3 Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.56 | 0.584 | 0.6 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.28% | 0.34% | 0.39% |
| CO2 | % | 0.11% | 0.72% | 0.83% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.451 | 0.451 | 0.451 |
| Depth | ft | 8,445 | 8,836 | 9,226 |
| Abandonment Pressure | psia | 335 | 615 | 850 |
| Porosity | % | 13.0 | 19.0 | 21.0 |
| Water Sat. | % | 30.0 | 35.0 | 40.0 |
| Drainage area | Acres | 17,773 | 18,761 | 19,748 |
| Net Pay | feet | 115 | 131 | 148 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.61 | 1.58 | 2.28 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Titas | | | |
| Reservoir: | A4u,4l Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.56 | 0.584 | 0.6 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.28% | 0.34% | 0.39% |
| CO2 | % | 0.11% | 0.72% | 0.83% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.451 | 0.451 | 0.451 |
| Depth | ft | 8,777 | 8,982 | 9,187 |
| Abandonment Pressure | psia | 331 | 612 | 848 |
| Porosity | % | 16.0 | 19.0 | 21.0 |
| Water Sat. | % | 30.0 | 35.0 | 40.0 |
| Drainage area | Acres | 17,773 | 18,761 | 19,748 |
| Net Pay | feet | 89 | 98 | 108 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.61 | 1.58 | 2.28 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Titas | | | |
| Reservoir: | B1,2 Sands | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.56 | 0.584 | 0.6 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.00% | 0.00% | 0.00% |
| CO2 | % | 0.00% | 0.00% | 0.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.451 | 0.451 | 0.451 |
| Depth | ft | 9,252 | 9,384 | 9,515 |
| Abandonment Pressure | psia | 825 | 980 | 1,150 |
| Porosity | % | 14.0 | 16.0 | 18.0 |
| Water Sat. | % | 31.0 | 36.0 | 41.0 |
| Drainage area | Acres | 10,151 | 11,420 | 12,689 |
| Net Pay | feet | 1 | 2 | 2 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.95 | 1.33 | 2.15 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Titas | | | |
| Reservoir: | B3a,3b Sands | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.56 | 0.584 | 0.6 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.00% | 0.00% | 0.00% |
| CO2 | % | 0.00% | 0.00% | 0.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.451 | 0.451 | 0.451 |
| Depth | ft | 9,433 | 9,572 | 9,712 |
| Abandonment Pressure | psia | 825 | 980 | 1,150 |
| Porosity | % | 14.0 | 16.0 | 18.0 |
| Water Sat. | % | 31.0 | 36.0 | 41.0 |
| Drainage area | Acres | 10,151 | 11,420 | 12,689 |
| Net Pay | feet | 48 | 68 | 88 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.95 | 1.33 | 2.15 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Titas | | | |
| Reservoir: | C1 Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.56 | 0.584 | 0.6 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.00% | 0.00% | 0.00% |
| CO2 | % | 0.00% | 0.00% | 0.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.451 | 0.451 | 0.451 |
| Depth | ft | 9,672 | 9,856 | 10,040 |
| Abandonment Pressure | psia | 825 | 980 | 1,150 |
| Porosity | % | 14.0 | 16.0 | 18.0 |
| Water Sat. | % | 31.0 | 36.0 | 41.0 |
| Drainage area | Acres | 10,151 | 11,420 | 12,689 |
| Net Pay | feet | 8 | 12 | 15 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.95 | 1.33 | 2.15 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |

| | | | | |
|---|---|---|---|---|
| Field: | Titas | | | |
| Reservoir: | C2 Sand | | | |
| | | Minimum | Most Likely | Maximum |
| Gas Gravity | | 0.56 | 0.584 | 0.6 |
| Condensate? | 1=yes, 2=no | | | |
| N2 | % | 0.00% | 0.00% | 0.00% |
| CO2 | % | 0.00% | 0.00% | 0.00% |
| H2S | % | 0.00% | 0.00% | 0.00% |
| TEMP-res | °F | | | |
| PRESS-res | psia | | | |
| temp gradient | °F/ft | 0.014 | 0.014 | 0.015 |
| press gradient | psi/ft | 0.451 | 0.451 | 0.451 |
| Depth | ft | 9,827 | 10,038 | 10,250 |
| Abandonment Pressure | psia | 825 | 980 | 1,150 |
| Porosity | % | 14.0 | 16.0 | 18.0 |
| Water Sat. | % | 31.0 | 36.0 | 41.0 |
| Drainage area | Acres | 10,151 | 11,420 | 12,689 |
| Net Pay | feet | 1 | 2 | 3 |
| % Recovery | | | | |
| Condensate Content | Bbl/MMCF | 0.95 | 1.33 | 2.15 |
| Net/Gross Ratio | fraction | | | |
| Gross Sand | ft | | | |
| | | | | |
| Gas Initially in Place | BCF | | | |
| Gas EUR | BCF | | | |
| Condensate EUR | MMBO | | | |