FLUID CHARACTERISTIC EVALUATION OF KAILASHTILA GAS FIELD

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(in Petroleum)

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RECOMMENDATION OF THE BOARD OF EXAMINERS

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ABSTRACT

Production data for many gas condensate producing wells all over the world have shown that the productivity is severely curtailed when the flowing bottom-hole pressure is less than the saturation (dew point) pressure of the in-place fluid It is generally accepted that this reduction is due to accumulation of condensed liquid near the wellbore.

A reservoir simulation study by EXODUS (Implicit Compositional Simulator) is conducted to address this issue for the Kailashtila gas field. Fluid composition and phase behavior studies are also conducted using gas chromatograph, PVT apparatus and HYSIM simulator

The results have revealed that the productivity impairment due to condensate accumulation near the wellbore is not likely the case for the Kailashtila Gas Field during its entire depletion life at the current rate of production. Considering the nature of the reservoir and fluid of the other existing fields in Bangladesh, this conclusion can also be a benchmark for them

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INTRODUCTION

1.1 Background of the Study

Large reductions in well productivity can occur in gas condensate reservoirs during pressure depletion, when bottom hole flowing pressure drops below the dew point, due to buildup of a condensate saturation ring near the wellbore[1,2]. The productivity loss is due to reduced relative permeability to gas as the condensate saturation increases[3]. A productivity loss can occur much sooner than the time at which reservoir pressure falls below the dew point due to a pressure drawdown in the near wellbore region Deddy Afidick et al.[4] reported a 50% reduction in productivity of some wells in Arun retrograde-gas reservoir. They identified the near wellbore condensate accumulation as an extremely important factor to consider when predicting the future well performance.

Most of the gas fields in Bangladesh produce fair amount of condensate. There is a possibility of formation and accumulation of condensate near the wellbore as the reservoirs deplete. As a result, significant productivity impairment may happen. This study is intended to address this issue.

1.2 Objectives of the Study

The study is aimed at achieving the following objectives:

(i) To investigate the possibility of productivity impairment due to condensate accumulation near the wellbore.

(ii) To analyse the representative fluid samples to study the composition and phase behaviour of the reservoir fluid.

(iii) If significant productivity impairment happens due to near wellbore condensate blockage, to study the feasibility of drilling horizontal well in order to improve productivity.

1.3 Methodology

Methodology of the study is summarised below:

(i) Reservoir simulation of the selected gas field in Bangladesh that has the highest possibility of productivity impairment due to condensate accumulation near the wellbore EXODUS reservoir simulator (implicit compositional model).

(ii) Collection of representative fluid samples (gas and gas condensate) from the respective field.

(iii) Compositional analysis of the fluid samples by gas chromatograph.

(iv) Phase behaviour study of the reservoir fluids using PVT apparatus and HYSIM simulator

1.4 Selection of the Field for Study

The higher the condensate dropout in the reservoir, the higher is the tendency of condensate accumulation near the wellbore. A rich gas contains higher fraction of condensate and more chance for condensate dropout than a lean gas Therefore, retrograde-gas reservoirs have higher probability to form condensate ring around wellbore than wet-gas reservoirs The historical condensate production rates of several producing gas fields in Bangladesh is presented in Table1.4.1.

Table 1.4.1: Historical Condensate Production Rates of Several Producing Gas Fields in Bangladesh.

Field	Condensate Rate, Bbl/MMscf[4]	Phase Characteristic[6-12]
Kailashtila gas field	11.18	Slightly-retrograde
Bakhrabad gas field	1.52	Non-retrograde
Rashidpur gas field	1.35	Non-retrograde
Belabo gas field	2.00	Non-retrograde
Titas gas field	1.39	Non-retrograde
Habiganj gas field	0.05	Non-retrograde
Feni gas field	2.42	Non-retrograde
Sylhet gas field	3.49	Non-retrograde

Among the producing fields only Kailashtila reservoir show slightly retrograde behaviour. This field also has the highest condensate production rate among the producing fields. Beani Bazar gas field (non-producing) has a higher condensate-gas ratio (13.2 BBL/MMSCF), but the fluids show non-retrograde behaviour[13]. Therefore, Kailashtila gas field is the prime candidate for the proposed study.

Chapter 2

REVIEW OF KAILASHTILA GAS FIELD

2.1 Introduction

Kailashtila is one of the largest gas fields in Bangladesh This field is located in the north-eastern part of the country (14th gas block), the so-called gas province of Bangladesh Gas block 14 is leased to the Occidental Co Ltd under a production sharing contract (Fig 2.1 1). Although all these existing discovered fields including Kailashtila have seen fenced off.

The field was discovered in 1962 and went on production in July 1983. The cumulative sales gas and condensate production from the field up to September 1998 was 0.16 TCF and 1 87 MMBBL, respectively with a condensate-gas ratio of 11 69 BBL/MMSCF.

The phase behaviour of the reservoir fluids shows slightly retrograde nature and therefore, has been selected for the proposed study In this chapter, the reservoir description, the rock and fluid properties and the production and pressure history of the Kailashtila Gas Field are described in the following sections.

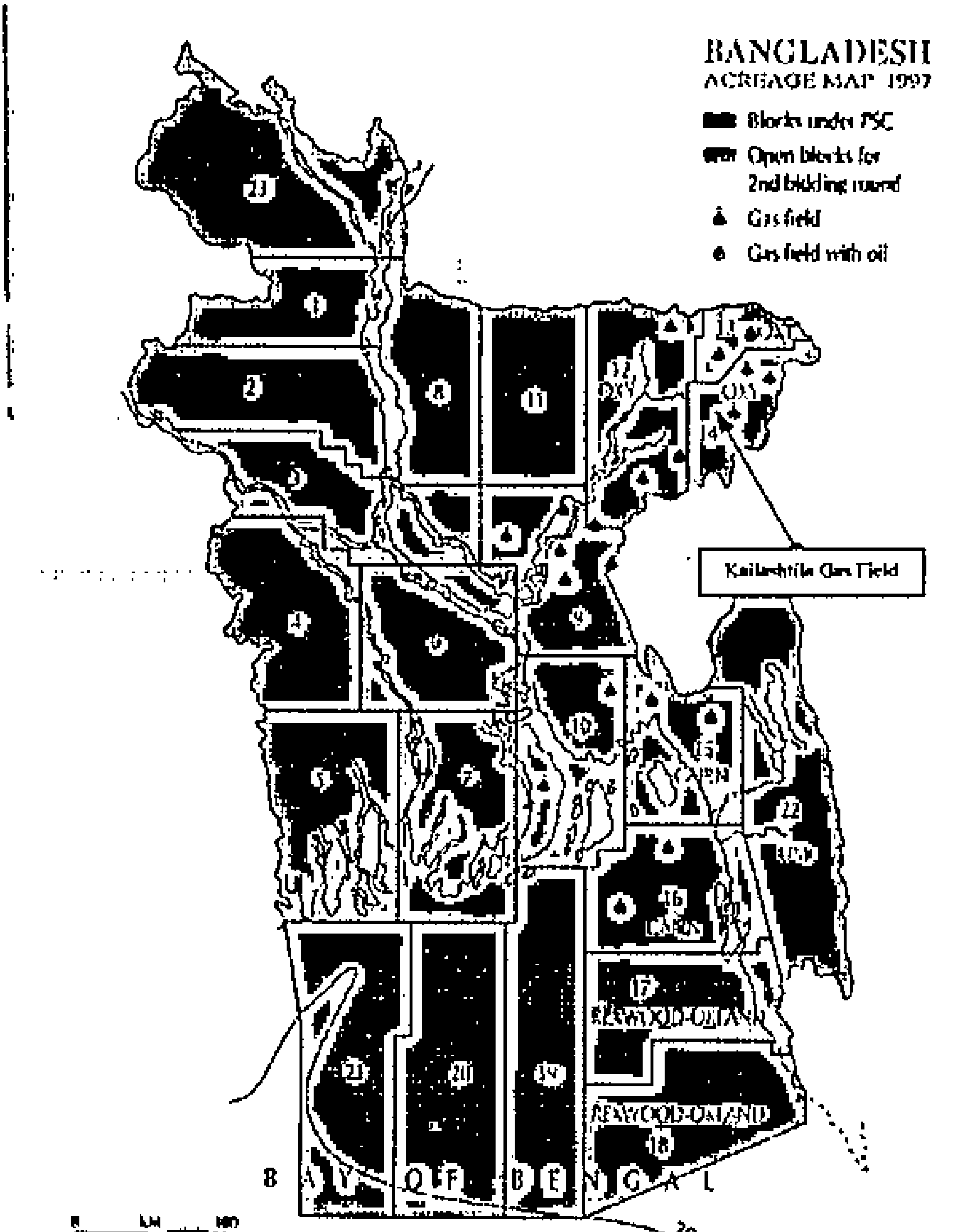


Figure 2.1.1: The Acreage Map of Bangladesh Showing the Location of Kailashtila Gas Field[4]

2.2 Reservoir Description

Three major isolated commercial accumulations of hydrocarbons are encountered by the first three wells (KTL1, KTL2 and KTL3) in the field These gas intervals are consistent with the seismic prognostications The upper gas sand (UGS) is found at a depth of approximately 7500 feet SS and contains a lean gas with a liquid-gas ratio of 11 2 BBL/MMSCF. The middle gas sand (MGS) and lower gas sand (LGS) are found at depths of 9600 feet SS and 9800 feet SS, respectively Both zones contain lean gas with a liquid-gas ratio of approximately 11.7 BBL/MMSCF (All LGR references based on field separator conditions)[6] The seismic based gross pay Isopachs of proved and probable reserves for each zone are shown in Figures 2.2.1, 2.2 2 and 2 2 3, respectively.

A total of seven minor hydrocarbon prospective horizons are also encountered by the first three wells consistent with the geological, geophysical and petrophysical evaluation of the field The most promising gas-bearing zone is identified as the new gas sand (NGS) at a depth of 8814 to 8990 feet SS (between upper and middle gas sands). The NGS is present in all the above wells but is found to diminish in the region of KTL3[14-15]. The reserve classifications of the UGS, MGS, LGS and NGS are presented in Table 2.2 1.

The six remaining minor horizons collectively referred to as the deep sands (DS), occur at depths exceeding the depth of the LGS (depth range 10120 to 10693 feet SS) Drill stem testing (DST) of the DS-1 in the KTL2 well has reported oil production in association with gas and water. The probable oil-in-place and gas-in-place of this sand is 3 98 MMBBL and 25.5 BSCF, respectively The remaining deep sand reservoirs contain a total volume of 49.7 BSCF of probable gas-in-place reserves. These zones represent minor, single well accumulation of little economic interest[14-15]. This study concerns KTL1 well only

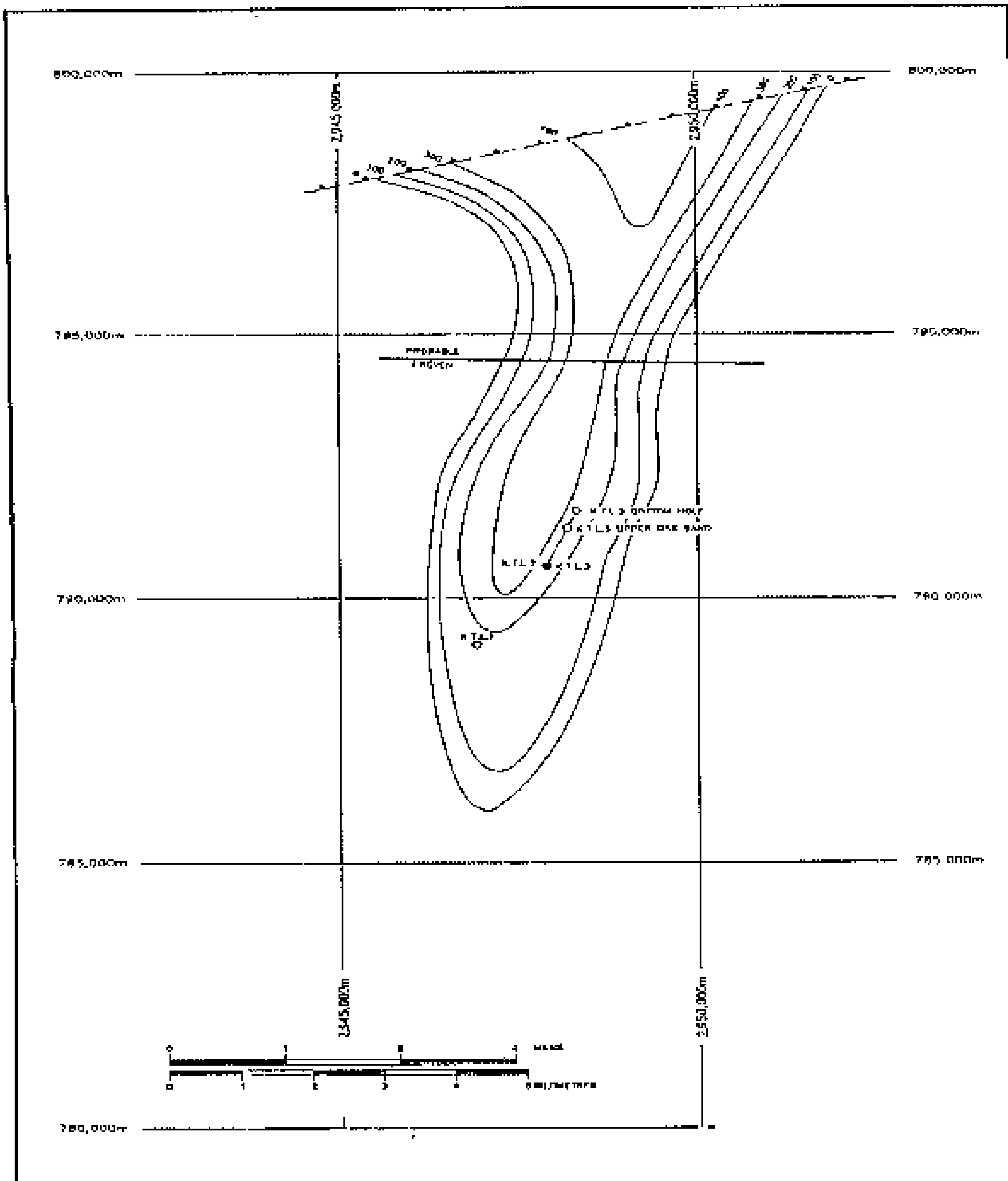


Figure 2.2.1: Gross Pay Isopachs of Upper Gas Sand[6]

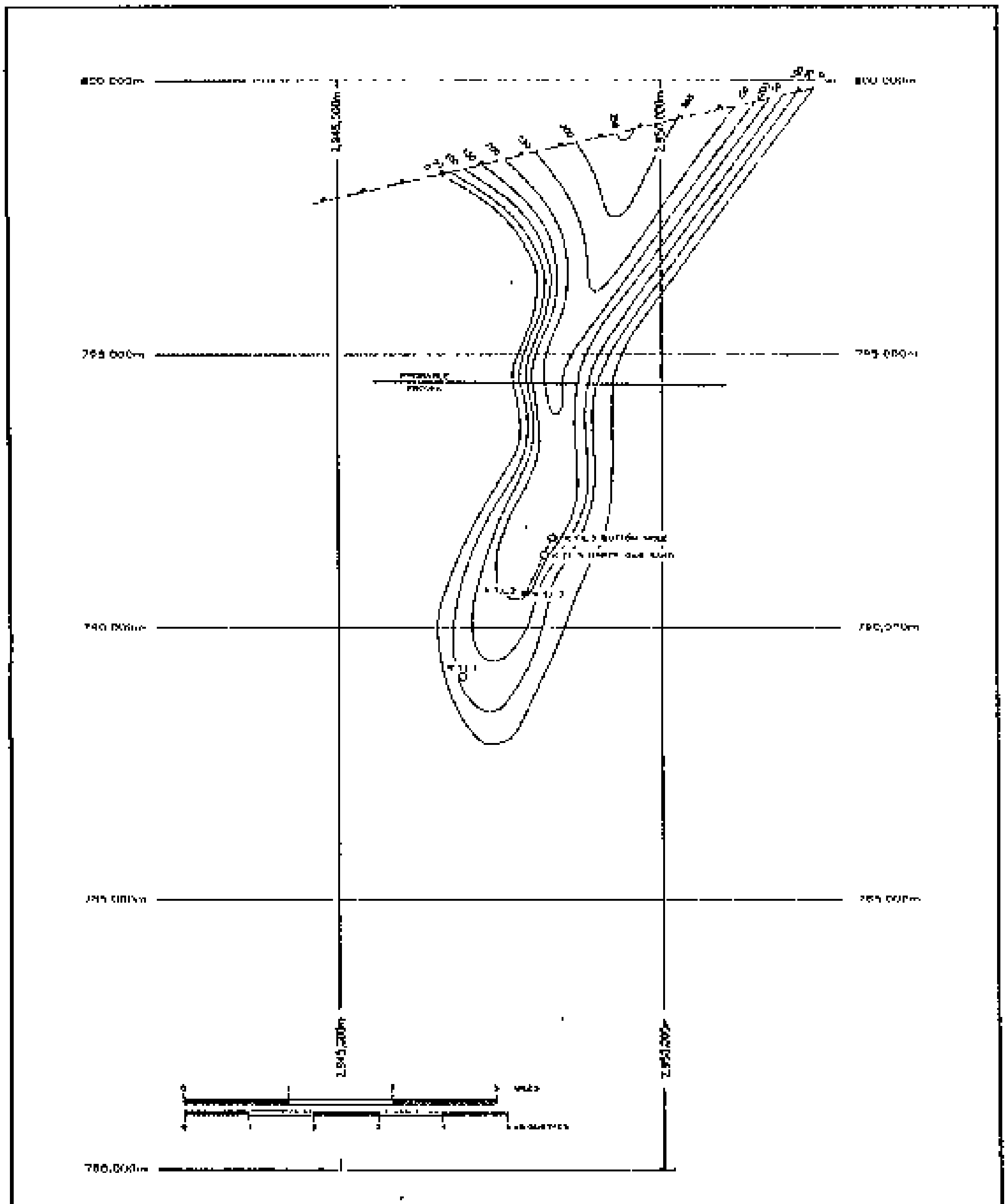


Figure 2.2.2: Gross Pay Isopachs of Middle Gas Sand[6]

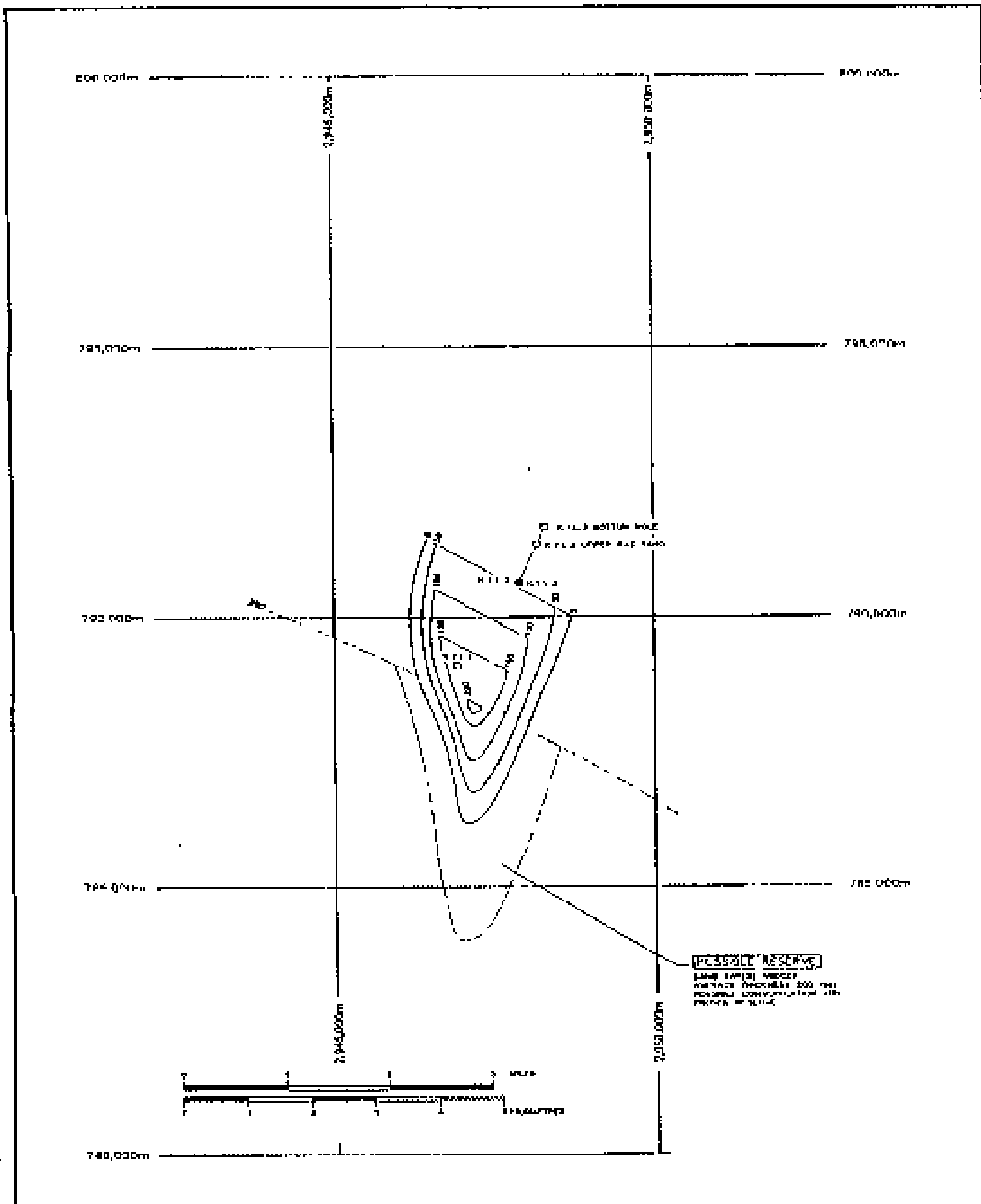


Figure 2.2.3: Gross Pay Isopachs of Lower Gas Sand[6]

Table 2.2.1: Reserve classifications of the UGS, MGS, LGS and NGS[6,15]

	Proved Reserves, BSCF				Probable Reserves, BSCF			
	UGS	MGS	LGS	NGS	UGS	MGS	LGS	NGS
Area [acre]	4611	2725	1752	-	3788	3192	-	1081
Av. h [ft]	177.4	84.2	89.0	-	261.0	190.1	-	69.5
h_n/h_g ratio	0.795	0.741	0.847	-	0.795	0.741	-	0.57
G [Bscf]	1076.6	282.7	247.8	-	1301.3	748.0	-	54.7

Note: No Possible Reserves are reported in the literature.

2.3 Rock and Fluid Properties

The important rock properties in reservoir engineering are porosity, permeability, relative permeability, capillary pressure, compressibility, wettability, etc. The important fluid properties are the compositions, saturations and the pressure-volume-temperature (PVT) properties like formation volume factor, viscosity, compressibility factor, etc. for the different phases present in the reservoir.

The reservoirs in Kailashtila gas field are assumed to be homogeneous ignoring the permeability variation in horizontal and vertical directions. The porosity, permeability, gas specific gravity, gas saturation, initial gas formation volume factor, gas compressibility factor, initial pressure, reservoir temperature, gas molecular weight, critical pressure, critical temperature and dew-point pressure of the main reservoirs are listed in Table 2.3.1.

The sandstone reservoirs in Bangladesh are water-wet meaning the water preferably adheres to the rock surface. The rock compressibility has not been reported in the literature and therefore, is assumed a value of 3.2×10^{-6} psi^{-1}. The two-phase relative permeability and capillary pressure functions are presented in Table 2.3.2, and Figures 2.3.1 to 2.3.3.The gas compositions of the main reservoirs of the field are shown in Table 2.3.3. The PVT properties of the reservoir fluids (gas and water) are shown in Table 2.3.4 and Figures 2.3.4 and 2.3.5.

Table 2.3.1: Some basic rock and fluid properties of UGS, MGS, LGS and NGS[6,15]

	UGS	MGS	LGS	NGS
Porosity [fraction]	0.20	0.18	0.20	0.185
Permeability [md]	386.6	126.0	287.1	226.0
Gas S.G [water=1]	0.628	0.630	0.630	0.628
$S_g=1-S_{wi}$ [fraction]	0.84	0.84	0.84	0.65
B_{gi} [R_{vol}/S_{vol}]	0.00442	0.00396	0.0039	0.0041
Z-factor	0.851	0.954	0.954	0.916
P_i [psia]	3332	4263	4366	3870
T_R [°F]	152	171	172	159
M_w [lb/lbmol]	18.2	18.3	18.3	18.2
P_c [psia]	663.7	663.2	663.2	663.7
T_c [°R]	361.9	362.1	362.1	361.9
$P_{dew-point}$ [psia]	2725	2814	2814	2725

Note: Given the proximity between the MGS and LGS, the lower sand properties are assumed valid for application to the middle zone. The UGS properties are also assumed to be valid for NGS

Table 2.3.2: The relative permeability and capillary pressure functions[16]

SW	KRW	KROW	PCW(psia)	KRG	KROG	PCG(psia)
0.160	0.0	1.0	53.3334	1.0	0.0	0.0
0.165	0.000001	0.928	38.3333	0.937	0.013	0.0
0.175	0.000002	0.904	24.9000	0.8871	0.013	0.0
0.200	0.000004	0.857	12.1737	0.687	0.027	0.0
0.225	0.000006	0.821	8.3000	0.557	0.043	0.0
0.250	0.000008	0.785	6.0000	0.443	0.053	0.0
0.275	0.00001	0.7495	4.0000	0.35	0.07	0.0
0.300	0.00002	0.714	2.8178	0.253	0.087	0.0
0.350	0.00009	0.643	1.3000	0.13	0.11	0.0
0.400	0.00026	0.571	0.6000	0.067	0.143	0.0
0.450	0.00079	0.5	0.0	0.03	0.175	0.0
0.500	0.00308	0.428	0.0	0.013	0.2	0.0
0.550	0.017	0.357	0.0	0.004	0.225	0.0
0.580	0.036	0.32	0.0	0.0	0.24	0.0
0.600	0.056	0.286	0.0	0.0	0.25	0.0
0.700	0.175	0.143	0.0	0.0	0.3	0.0
0.800	0.391	0.0	0.0	0.0	0.37	0.0
0.900	0.662	0.0	0.0	0.0	0.5	0.0
1.000	1.000	0.0	0.0	0.0	1.0	0.0

Table 2.3.3: The gas compositions of the main reservoirs[6,15]

Component	Mole Fraction			
	UGS	MGS	LGS	NGS
N_2	0 0038	0 0008	0 0008	0.0038
H_2S	0.0000	0 0000	0 0000	0 0038
CO_2	0 0005	0 0019	0 0019	0.0038
C_1	0.9403	0.9415	0.9415	0 9403
C_2	0.0273	0.0271	0 0271	0 0273
C_3	0.0102	0.0088	0.0088	0.0102
iC_4	0.0026	0.0022	0 0022	0 0026
nC_4	0.0029	0.0023	0.0023	0.0029
iC_5	0.0015	0.0013	0 0013	0 0015
nC_5	0 0009	0.0007	0.0007	0 0009
C_6	0.0014	0 0019	0.0019	0.0014
C_7	0 0026	0 0035	0 0035	0.0026
C_8	0 0028	0 0038	0.0038	0.0028
C_9	0.0013	0.0017	0.0017	0 0013
C_{10}	0.0006	0 0008	0.0008	0.0006
C_{11}	0 0003	0 0004	0.0004	0.0003
C_{12}	0.0002	0 0003	0.0003	0.0002
C_{13}	0.0002	0 0003	0.0003	0 0002
C_{14}	0.0002	0 0003	0.0003	0.0002
C_{15}	0 0004	0.0005	0.0005	0 0004

Note. Given the proximity between the MGS and LGS, the lower sand fluid compositions are assumed to be valid for the middle zone. The UGS compositions are also assumed to be valid for NGS.

Table 2.3.4: The PVT properties of the reservoir fluids[6,15]

Pressure [psia]	B_g [rcf/scf]	μ_g [cp]	B_w [rb/stb]	μ_w [cp]
100	0 173805	0.01305	1.0347	0.33
500	0.03332	0.01345	1 0335	0 33
1000	0 01593	0 0142	1.032	0 33
1500	0.01026	0 0154	1 031	0 33
2000	0 00754	0.01705	1.03	0 33
2500	0.00599	0 0191	1.0285	0 33
2725	0 0056	0.0202	1 0279	0.33
2813 5	0.00547	0 0206	1.0276	0 33
3000	0 0049	0.02155	1 027	0 33
3345	0.00455	0 0231	1.0263	0 33
3500	0.0045	0.02395	1 026	0 33
4000	0 00404	0 02645	1 025	0.33
4379	0.00377	0 0284	1.024242	0 33

Reservoir temp is 172°F

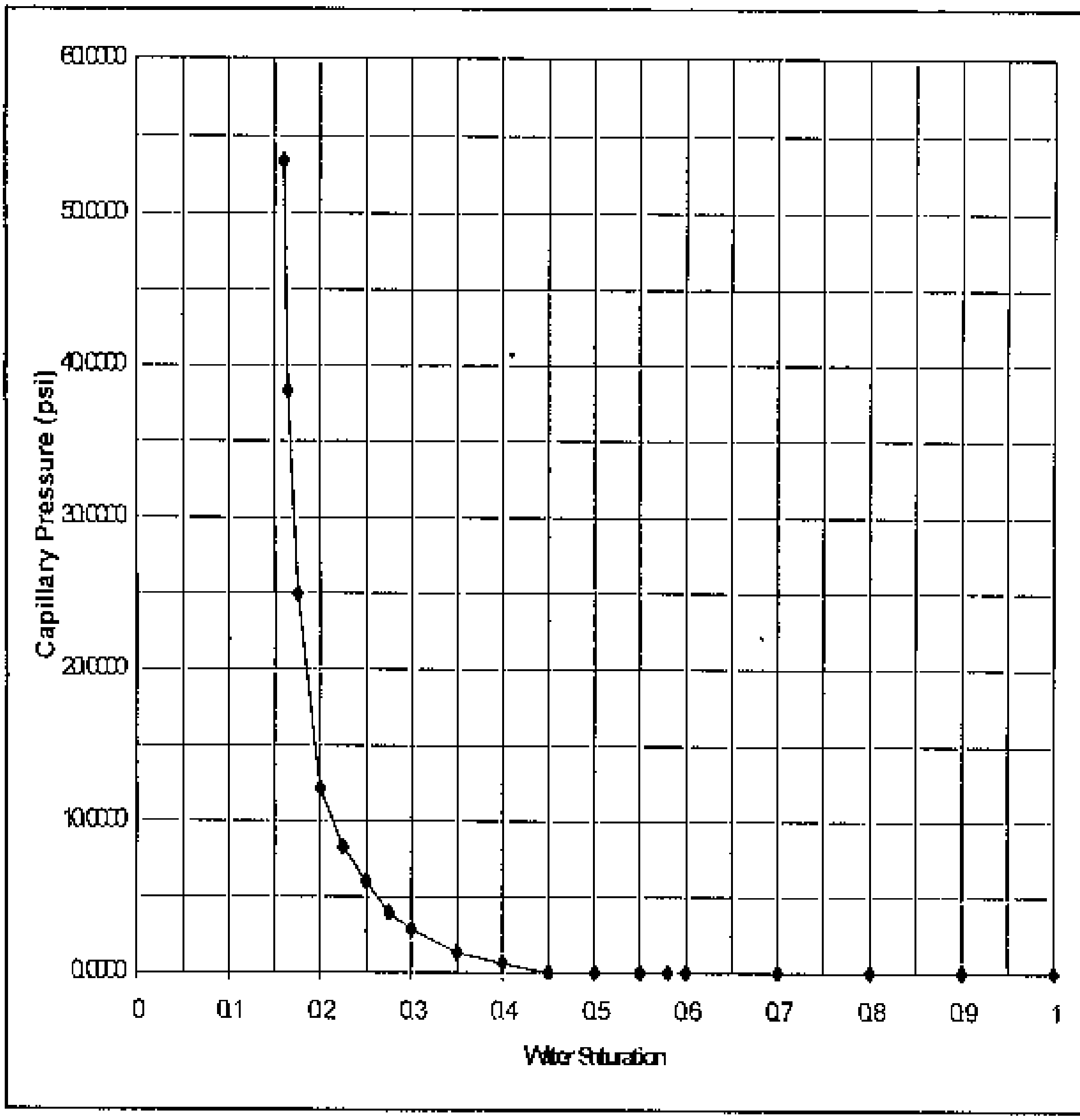


Figure 2.3.1: Gas-Water Capillary Pressure[17]

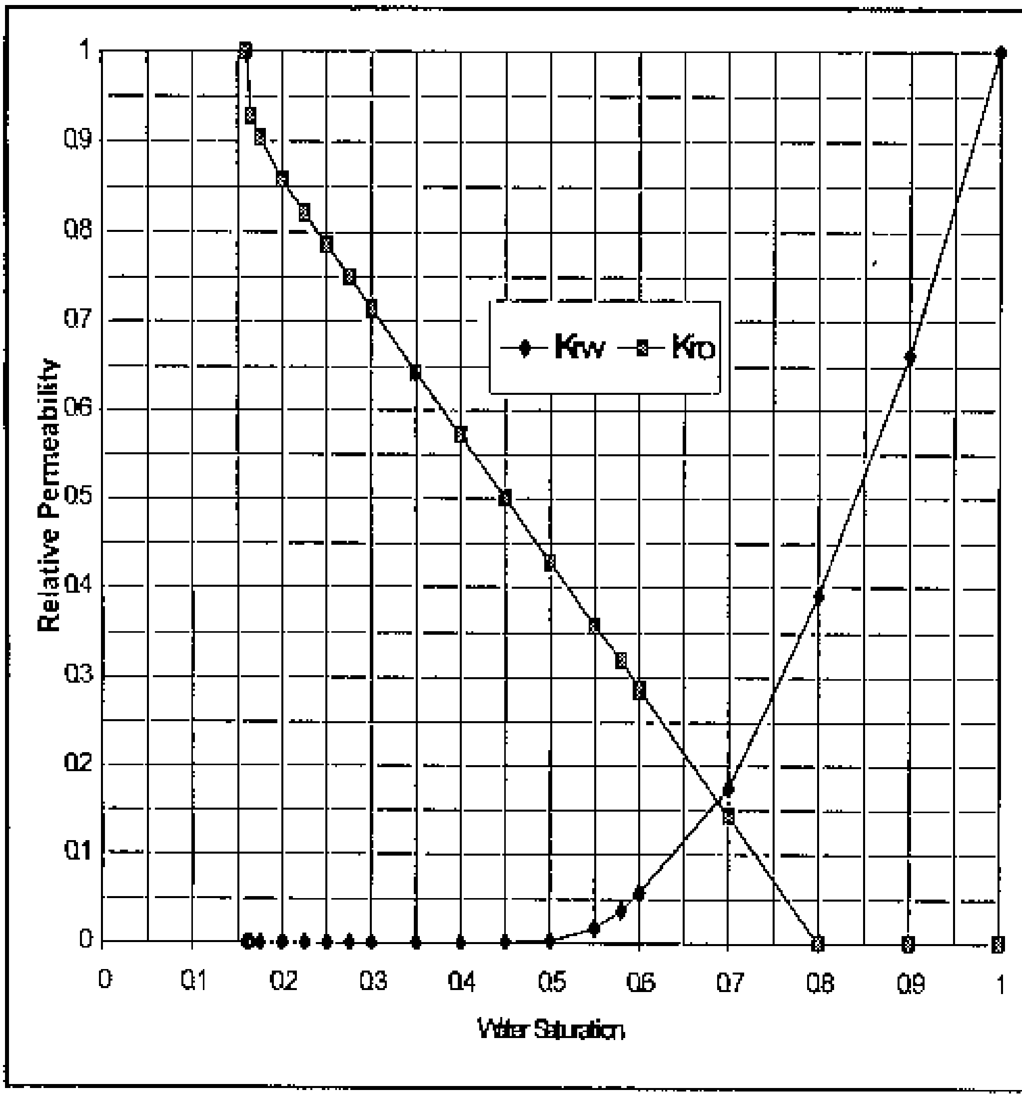


Figure 2.3.2: Oil-Water Relative Permeability[17]

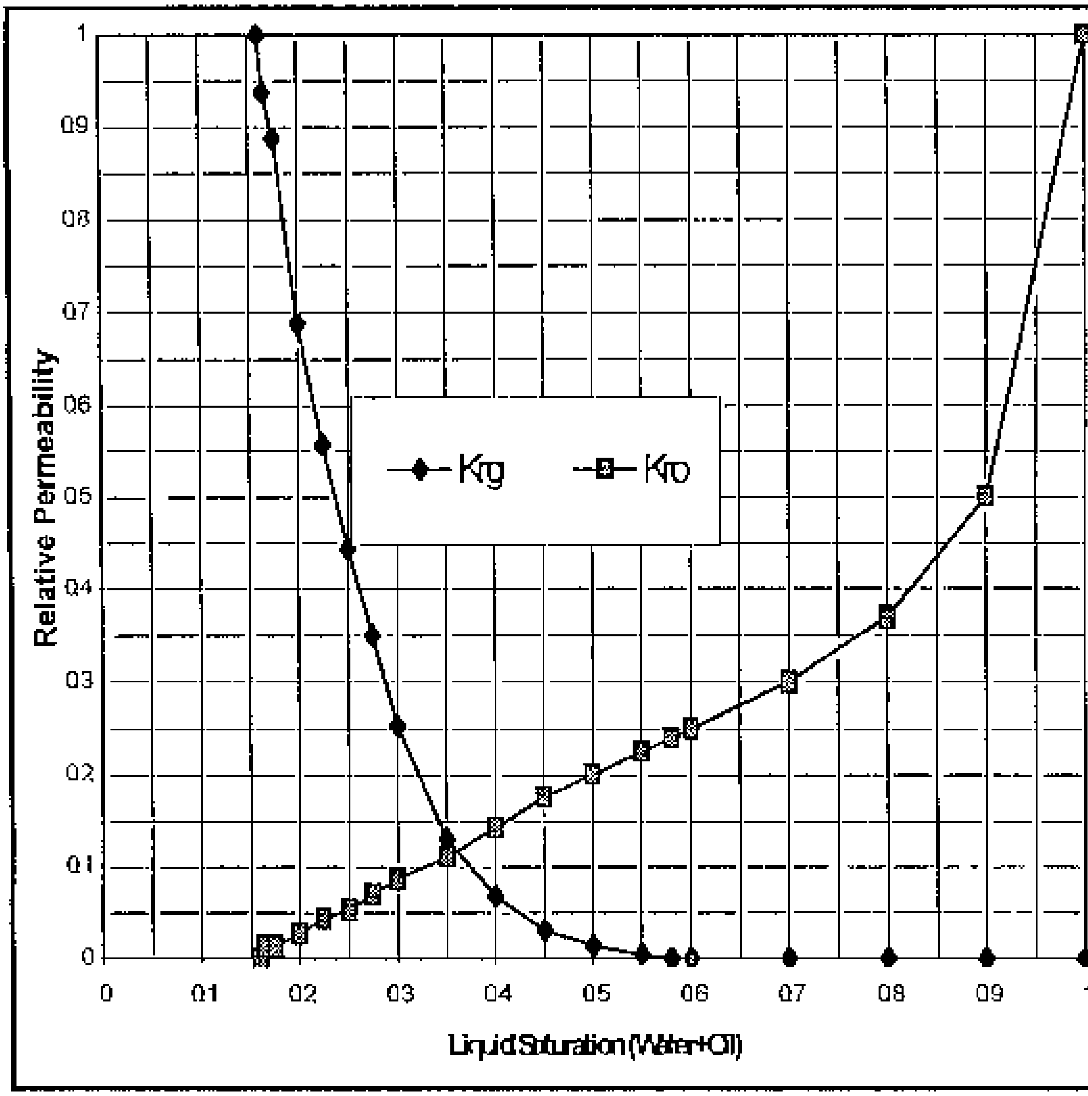


Figure 2.3.3: Gas-Oil Relative Permeability[17]

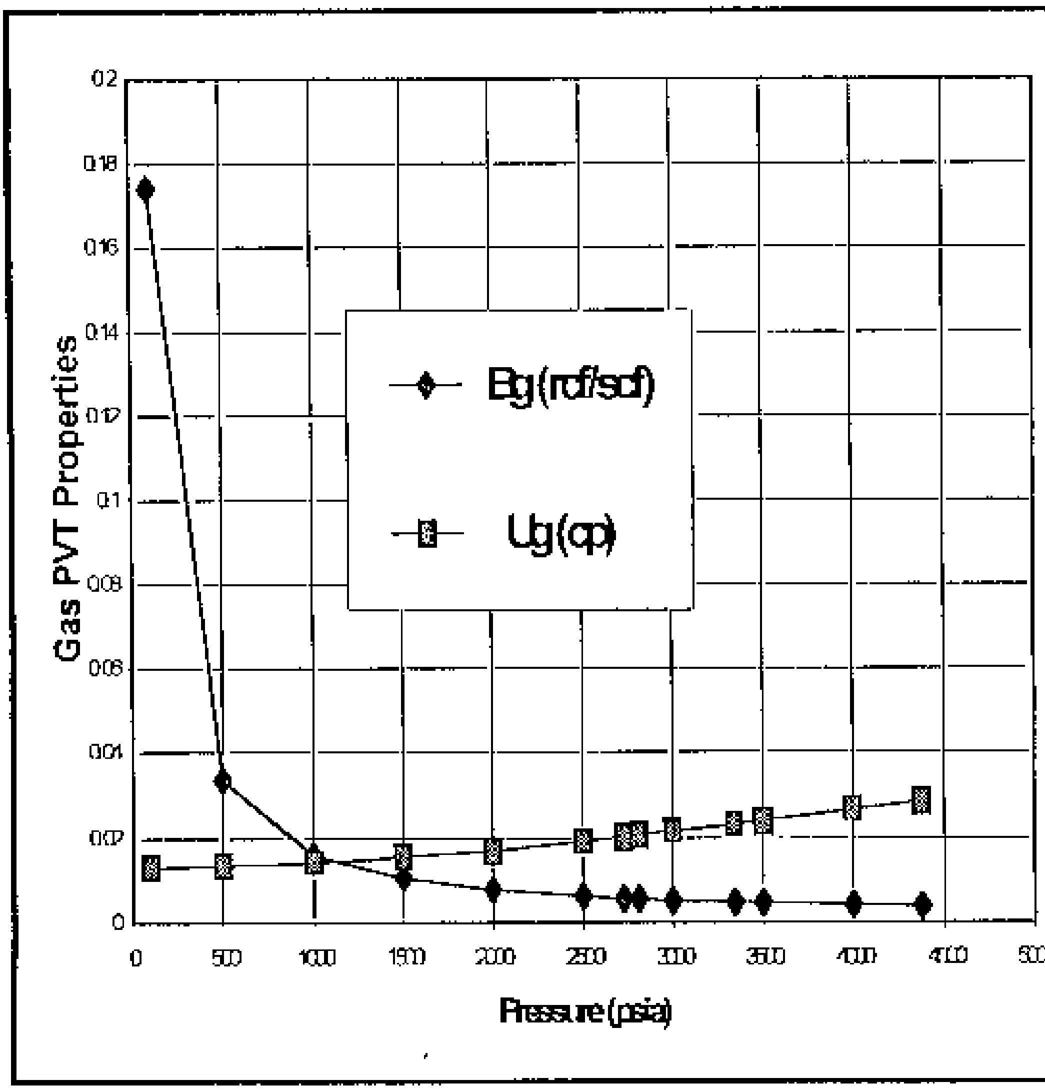


Figure 2.3.4: Gas Formation Volume Factor (Bg) and Gas Viscosity (Ug)[17]

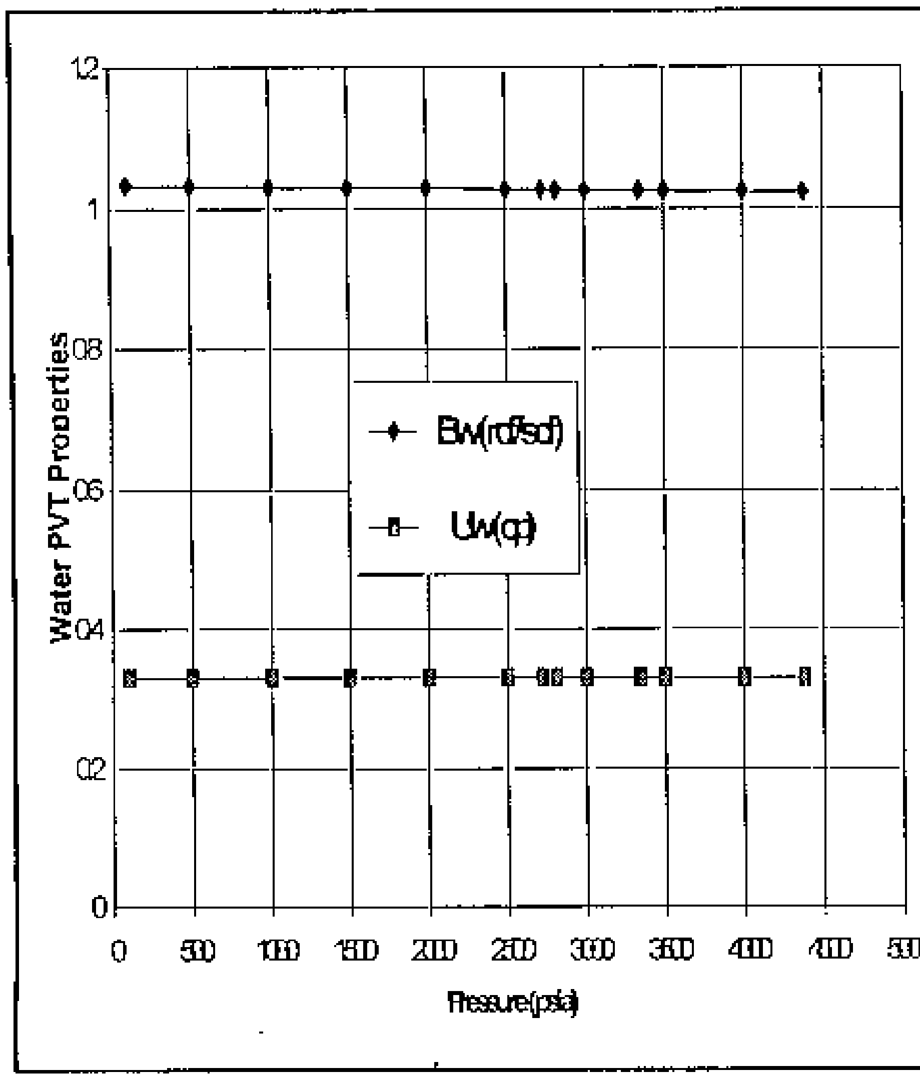


Figure 2.3.5: Water Formation Volume Factor (Bw) and Water Viscosity (Uw)[17]

2.4 Production and Pressure History

Production History

Gas production in Kailashtila field began from both upper and lower sands in July 1983 at KTL1. Due to an excessive water cut from lower sand, this sand was permanently sealed off in the first workover operation during May to August 1995. Some production is reported from upper sand in September 1995. Continuous production from this well (only from upper sand) resumed in May 1997. Production from this well again suspended from October 1997 due to an excessive water cut Therefore, the well is also sealed off in the upper sand in the second workover operation during October 1997 to February 1998 The total gas, condensate and water production from lower and upper sands by KTL1 is 82118.421 MMCF, 860025 STB and 166347 BBL respectively Approximately 55% of this gas production is attributable to the lower sand

KTL1 was reopened in the middle sand during second workover operation. The production from this sand started from February 1998. The total gas, condensate and water production from middle sand by KTL1 up to September 1998 is 4801 397 MMCF, 44922 STB and 1281 BBL respectively

The production from KTL2 began from upper sand alone in February 1995 but the well was out of production from April 1995 to August 1995. The total gas, condensate and water production from KTL2 up to September 1998 is 27151.332 MMCF, 368318 STB and 4678 BBL respectively.

The production from KTL3 began from middle sand alone in March 1995 but no production is reported in April 1995. The total gas, condensate and water production from KTL3 upto September 1998 is 32467.773 MMCF, 434120 STB and 6647 BBL, respectively.

The production from KTL4 began from lower sand alone in March 1997. The total gas, condensate and water production from KTL4 upto September 1998 is 13393.465 MMCF, 162440 STB and 2323 BBL, respectively.

The total production of gas, condensate and water in the field up to September 1998 is 159932.388 MMCF, 1869825 STB and 181276 BBL, respectively, with a historical condensate-gas ratio of 11.69 STB/MMCF and a historical water-gas ratio of 1.13 BBL/MMCF. The monthly production records of the wells in Kailashtila gas field are presented in Table 2.4.1.

Pressure History

Initial pressures for the upper and lower gas zones at KTL1 were determined in March 1962 by Shell upon well completion. Pressures were later estimated at this well in January 1985 as a result of the production/pressure test operations conducted by IPEC. Pressures for both upper and lower zones were estimated. No other reliable pressure estimate at KTL1 in upper gas zone is available. Two other pressure values are collected from field sources. One is the pressure estimate conducted in March 1993 and the other is the calculated pressure in April 1995. Two additional pressures were determined in the upper sand during testing of KTL2 in October 1988 and August 1992. The pressure history of Kailashtila Gas Field is shown in Table 2.4.2.

Table 2.4.1: Monthly production records of the wells in Kailashtila Gas Field

KTL-1:

Month	Gas Production, MCF			Oil Production, STB		Water Production, BBL	
	UGS	MGS	LGS	UGS&LGS	MGS	UGS&LGS	MGS
Jul-83	175100	0	214800	4302	0	198	0
Aug-83	0	0	0	0	0	0	0
Sep-83	0	0	0	0	0	0	0
Oct-83	0	0	0	0	0	0	0
Nov-83	267600	0	329400	6956	0	206	0
Dec-83	0	0	0	0	0	0	0
Jan-84	290700	0	355100	7723	0	168	0
Feb-84	0	0	0	0	0	0	0
Mar-84	304900	0	369900	7678	0	213	0
Apr-84	0	0	0	0	0	0	0
May-84	283900	0	344200	7079	0	198	0
Jun-84	0	0	0	0	0	0	0
Jul-84	228200	0	276000	5449	0	210	0
Aug-84	66100	0	80800	1641	0	216	0
Sep-84	0	0	0	0	0	0	0
Oct-84	267000	0	323600	6657	0	192	0
Nov-84	236700	0	289300	6145	0	195	0
Dec-84	47500	0	58000	1320	0	224	0
Jan-85	151700	0	182800	3981	0	243	0
Feb-85	66700	0	79300	1752	0	202	0
Mar-85	299300	0	363000	6372	0	231	0
Apr-85	357300	0	434000	8194	0	219	0
May-85	353600	0	429300	7787	0	231	0
Jun-85	192500	0	232600	4490	0	217	0
Jul-85	188200	0	249100	4648	0	217	0
Aug-85	154000	0	201200	4524	0	197	0
Sep-85	165100	0	216100	5419	0	180	0
Oct-85	172200	0	225400	5838	0	192	0
Nov-85	72800	0	93600	2090	0	205	0
Dec-85	218400	0	286600	6167	0	209	0
Jan-86	212400	0	278600	6128	0	223	0
Feb-86	171200	0	224300	4873	0	189	0
Mar-86	34500	0	42700	1062	0	226	0
Apr-86	47000	0	59500	1338	0	197	0
May-86	220200	0	289000	6336	0	200	0
Jun-86	216100	0	283700	5934	0	184	0
Jul-86	78800	0	101600	2081	0	171	0
Aug-86	229200	0	300800	6133	0	177	0
Sep-86	218200	0	286500	5911	0	173	0
Oct-86	230300	0	302400	5891	0	193	0
Nov-86	218200	0	286500	5851	0	210	0
Dec-86	323000	0	425300	8171	0	212	0
Jan-87	235900	0	311400	6411	0	197	0

Month	Gas Production, MCF			Oil Production, STB		Water Production, BBL	
	UGS	MGS	LGS	UGS&LGS	MGS	UGS&LGS	MGS
Feb-87	196000	0	257100	5312	0	198	0
Mar-87	220200	0	288900	6208	0	240	0
Apr-87	218300	0	286600	6084	0	246	0
May-87	214800	0	281800	5771	0	248	0
Jun-87	206500	0	270900	5578	0	236	0
Jul-87	252000	0	305300	6423	0	261	0
Aug-87	235500	0	285100	5797	0	770	0
Sep-87	213600	0	258300	5161	0	261	0
Oct-87	232300	0	281100	5678	0	287	0
Nov-87	209000	0	252800	5098	0	277	0
Dec-87	246000	0	297800	5978	0	289	0
Jan-88	256900	0	311200	6228	0	283	0
Feb-88	249900	0	302800	5914	0	256	0
Mar-88	245500	0	297200	5890	0	287	0
Apr-88	233500	0	282700	5486	0	250	0
May-88	218200	0	263900	5326	0	284	0
Jun-88	196300	0	237200	4902	0	275	0
Jul-88	224000	0	271000	5530	0	240	0
Aug-88	246400	0	298400	6106	0	232	0
Sep-88	266600	0	323200	6593	0	228	0
Oct-88	310700	0	378400	7432	0	272	0
Nov-88	265100	0	321400	6520	0	252	0
Dec-88	298700	0	363800	7165	0	239	0
Jan-89	260800	0	393040	7157	0	210	0
Feb-89	256590	0	384459	6729	0	220	0
Mar-89	294045	0	327322	6395	0	195	0
Apr-89	213680	0	324880	5233	0	175	0
May-89	195980	0	296078	4838	0	169	0
Jun-89	234440	0	333106	5698	0	177	0
Jul-89	372650	0	287523	6748	0	198	0
Aug-89	309500	0	313603	6441	0	194	0
Sep-89	277680	0	305094	5833	0	178	0
Oct-89	287310	0	377898	6694	0	197	0
Nov-89	338990	0	348631	7063	0	206	0
Dec-89	387920	0	270309	7001	0	201	0
Jan-90	351410	0	167324	5210	0	168	0
Feb-90	373730	0	263194	6243	0	180	0
Mar-90	373430	0	339757	7295	0	213	0
Apr-90	365930	0	339475	7191	0	199	0
May-90	325920	0	361869	6908	0	198	0
Jun-90	319790	0	327374	6512	0	199	0
Jul-90	358850	0	348805	7132	0	210	0
Aug-90	336460	0	345667	6826	0	216	0
Sep-90	282710	0	298213	5790	0	188	0
Oct-90	244810	0	348893	5806	0	192	0
Nov-90	242360	0	382242	6017	0	195	0
Dec-90	303980	0	435913	7251	0	224	0
Jan-91	375080	0	415112	7972	0	243	0
Feb-91	305920	0	328667	6392	0	202	0

Month	Gas Production, MCF			Oil Production, STB		Water Production, BBL	
	UGS	MGS	LGS	UGS&LGS	MGS	UGS&LGS	MGS
Mar-91	403750	0	393769	7684	0	231	0
Apr-91	341900	0	366512	6310	0	219	0
May-91	346650	0	392127	7593	0	231	0
Jun-91	282720	0	379883	6797	0	217	0
Jul-91	312430	0	369807	6728	0	217	0
Aug-91	255390	0	350642	6087	0	197	0
Sep-91	223580	0	335417	5661	0	180	0
Oct-91	223350	0	367350	6134	0	192	0
Nov-91	263940	0	367305	6702	0	205	0
Dec-91	269930	0	376509	6788	0	209	0
Jan-92	245140	0	389661	6755	0	223	0
Feb-92	214270	0	364760	6100	0	189	0
Mar-92	273850	0	401734	6914	0	226	0
Apr-92	234140	0	364428	6029	0	197	0
May-92	264450	0	319922	5978	0	200	0
Jun-92	196310	0	350814	5554	0	184	0
Jul-92	314684	0	216709	5048	0	171	0
Aug-92	319998	0	245956	5341	0	177	0
Sep-92	306914	0	245103	5058	0	173	0
Oct-92	258841	0	388505	5804	0	193	0
Nov-92	289370	0	396287	6406	0	210	0
Dec-92	313430	0	397783	6660	0	212	0
Jan-93	333594	0	307670	5727	0	197	0
Feb-93	302491	0	335324	6025	0	198	0
Mar-93	377414	0	360172	7468	0	240	0
Apr-93	409291	0	358224	7651	0	246	0
May-93	359441	0	399622	7563	0	248	0
Jun-93	314976	0	388916	6908	0	236	0
Jul-93	362223	0	418295	7720	0	261	0
Aug-93	402960	0	402669	7827	0	270	0
Sep-93	402652	0	378203	7209	0	261	0
Oct-93	527805	0	418803	8920	0	287	0
Nov-93	438990	0	387281	8247	0	277	0
Dec-93	464118	0	391147	8786	0	289	0
Jan-94	466538	0	377598	8693	0	283	0
Feb-94	447557	0	370887	8302	0	256	0
Mar-94	486599	0	354159	8612	0	287	0
Apr-94	406402	0	336591	7318	0	250	0
May-94	446995	0	419676	8774	0	284	0
Jun-94	472439	0	396611	8818	0	275	0
Jul-94	354454	0	344926	6939	0	304	0
Aug-94	490764	0	375032	8903	0	802	0
Sep-94	440750	0	285516	7688	0	1268	0
Oct-94	520568	0	379257	9492	0	2120	0
Nov-94	498211	0	326539	8657	0	2528	0
Dec-94	506356	0	261693	7898	0	3233	0
Jan-95	514810	0	339452	8601	0	3955	0
Feb-95	471969	0	297180	8218	0	4216	0
Mar-95	315176	0	55394	4350	0	1361	0

Month	Gas Production, MCF			Oil Production, STB		Water Production, BBL	
	UGS	MGS	LGS	UGS&LGS	MGS	UGS&LGS	MGS
Apr-95	426346	0	11227	3941	0	2102	0
May-95	168147	0	0	1486	0	529	0
Jun-95	0	0	0	0	0	0	0
Jul-95	0	0	0	0	0	0	0
Aug-95	0	0	0	0	0	0	0
Sep-95	38694	0	0	432	0	518	0
Oct-95	0	0	0	0	0	0	0
Nov-95	0	0	0	0	0	0	0
Dec-95	0	0	0	0	0	0	0
Jan-96	0	0	0	0	0	0	0
Feb-96	0	0	0	0	0	0	0
Mar-96	0	0	0	0	0	0	0
Apr-96	0	0	0	0	0	0	0
May-96	0	0	0	0	0	0	0
Jun-96	0	0	0	0	0	0	0
Jul-96	0	0	0	0	0	0	0
Aug-96	0	0	0	0	0	0	0
Sep-96	0	0	0	0	0	0	0
Oct-96	0	0	0	0	0	0	0
Nov-96	0	0	0	0	0	0	0
Dec-96	0	0	0	0	0	0	0
Jan-97	0	0	0	0	0	0	0
Feb-97	0	0	0	0	0	0	0
Mar-97	0	0	0	0	0	0	0
Apr-97	0	0	0	0	0	0	0
May-97	55292	0	0	476	0	5104	0
Jun-97	383904	0	0	3251	0	19800	0
Jul-97	543423	0	0	5386	0	24673	0
Aug-97	348743	0	0	3304	0	21278	0
Sep-97	322093	0	0	3379	0	25331	0
Oct-97	203599	0	0	2040	0	19952	0
Nov-97	0	0	0	0	0	0	0
Dec-97	0	0	0	0	0	0	0
Jan-98	0	0	0	0	0	0	0
Feb-98	0	51729	0	0	547	0	20
Mar-98	0	773494	0	0	7248	0	161
Apr-98	0	673338	0	0	6510	0	166
May-98	0	644571	0	0	6288	0	178
Jun-98	0	711428	0	0	6583	0	182
Jul-98	0	668997	0	0	6165	0	201
Aug-98	0	678744	0	0	6162	0	195
Sep-98	0	599095	0	0	5419	0	177

Note : Data supplied by SGFL

Table 2.4.2: Pressure history of Kailashtila gas Field

KTL1-UGS:

Year	Month	Day	Static Pressure (psia)	P/Z (psia)	Gp (MMSCF/D)
1962	3	15	3332	3870	175
1985	1	15	3305	3843	2319
1988	10	15	3291	3828	11887
1992	8	3	3285	3823	25427

KTL1-LGS:

Year	Month	Day	Static Pressure (psia)	P/Z (psia)	Gp (MMSCF/D)
1962	3	15	4366	4700	0
1985	1	15	4309	4580	2823.90
1993	3	15	3809	4280	32991.91
1995	4	15	3658 (Calculated)	4110	41466.81

Note : Data supplied by SGFL

2.5 MATERIAL BALANCE

A material balance was done for the reservoir to find out the actual cause of this high-pressure maintenance. Here, it has been assumed to be a volumetric depletion type reservoir, which means that when the pressure declines due to production, there is an insignificant amount of water influx into the reservoir from adjoining aquifer. Thus the reservoir volume occupied by hydrocarbons will not decrease during depletion So, the expression for the hydrocarbon pore volume (HCPV) is as following –

The Material balance for a given volume of production, G_p and consequent pressure drop in the average reservoir pressure, $\Delta p = P_i - P$ is then

Production = GIIP - unproduced gas
(in sc) (in sc) (in sc)

$$G_p = G - \frac{HCPV}{B_g}$$

$$G_p = G - \frac{G * B_{gi}}{B_g}$$

Which can be expressed as

$$\frac{G_p}{G} = 1 - \frac{B_{gi}}{B_g}, \quad \text{using expression, } B_g = \frac{P_{std}TZ}{T_{std}P}$$

It comes to

$$\frac{P}{Z} = \frac{P_i}{Z_i}(1 - \frac{G_p}{G}) \quad \text{---} \quad (2.5.1)$$

Now, $\frac{P}{Z}$. vs. G_p (cumulative gas production) will give a straight line. This line when extended up to $\frac{P}{Z}=0$ will give total gas in place. This is a more shortcut method of finding the GIIP of a reservoir. But, estimations obtained in this method are very sensitive to the accuracy and availability of prolongs production data. If estimates are made on only the initial production data, there is a great chance of getting erroneous results[18].

In case of Kailashtila gas field the number of available data for $\frac{P}{Z}$ and G_p is only four. Apart from the initial reservoir pressure of the Kailashtila gas field, only three shut-in pressures are available which are given in the Table 2 4.2.

Using the given data in Equation 2.5.1 a plot of $\frac{P}{Z}$ vs. G_p is produced, which has been presented in Fig. 2.5.1. In this figure the GIIP shown is 361 BSCF, whereas IKM reported 47.8 BSCF for KTL1 lower sand and for upper sand the GIIP shown is 2600 BSCF/D whereas IKM reported 1130 090 BSCF.

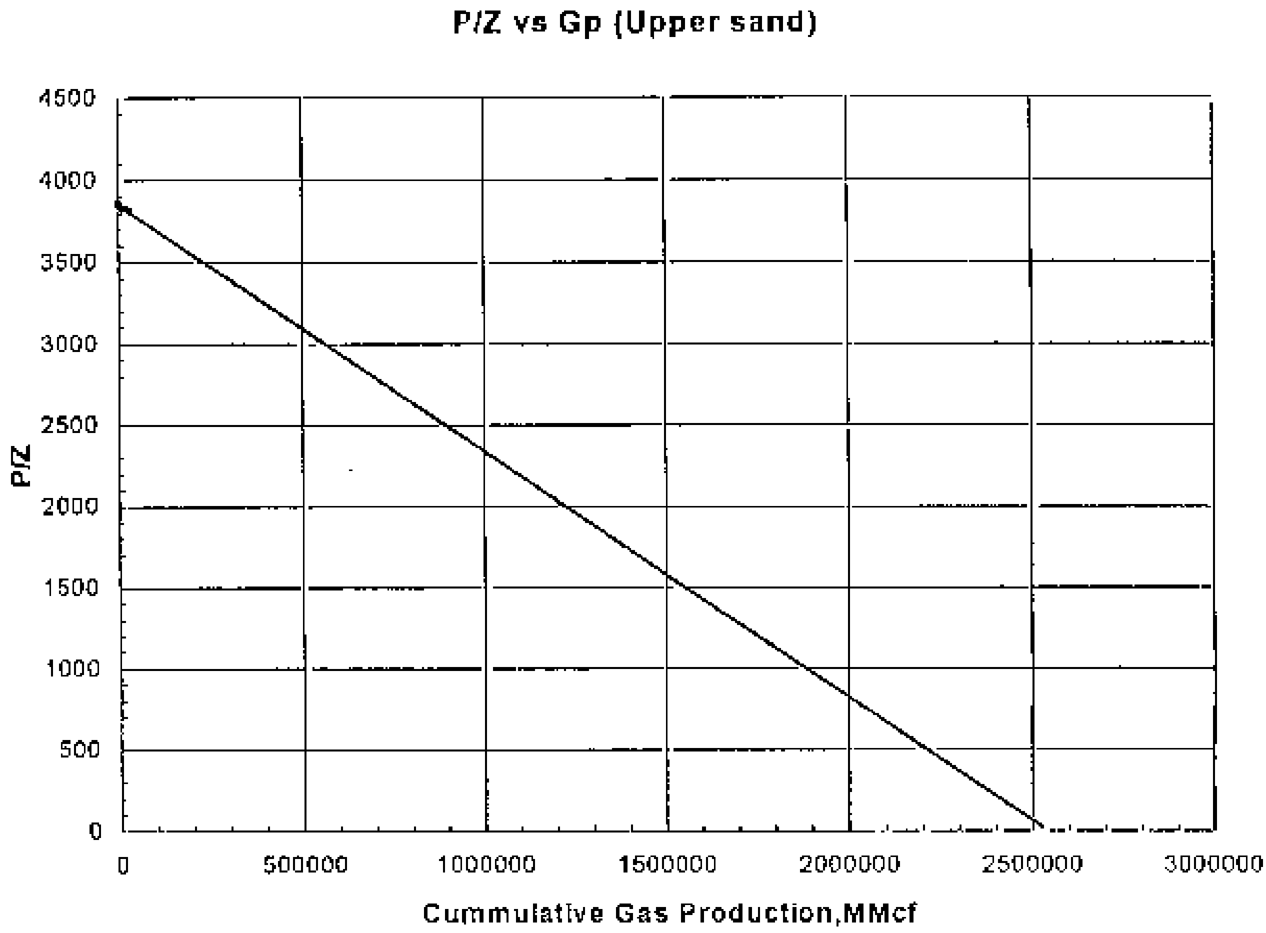


Figure 2.5.1: Static bottom Pressure vs. cumulative gas production (Upper sand)

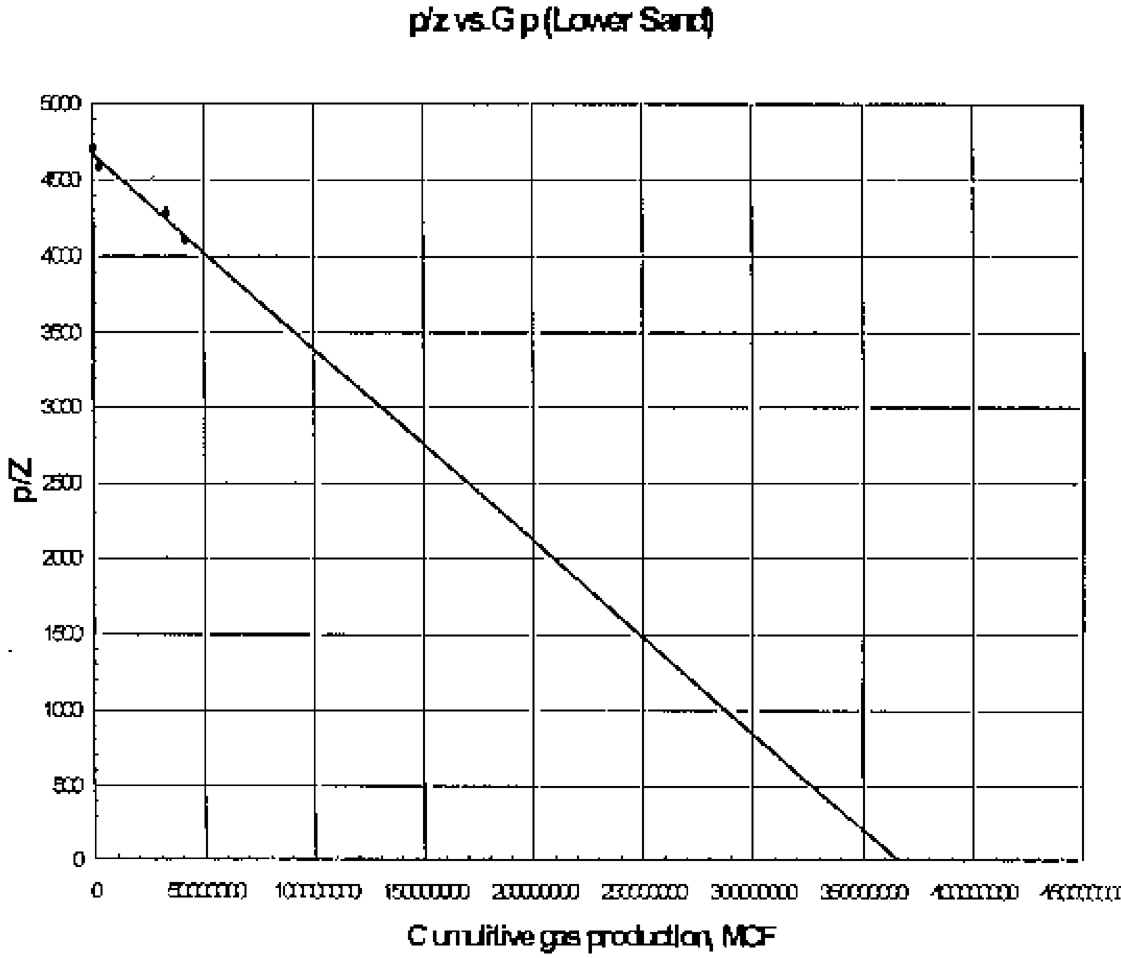


Figure 2.5.1: Static bottom Pressure vs. cumulative gas production (Lower sand)

Chapter 3
RESERVOIR SIMULATION

3.1 Introduction

The EXODUS reservoir simulation software has been used to investigate the problem of productivity impairment due to condensate accumulation near the wellbore of vertical wells in Kailashtila gas field. The two major gas sands namely UGS and LGS have been considered in the study. The sands contain 72% of the total gas-in-place of the field[6,15]

In this chapter, the main features of EXODUS reservoir simulator, the simulation grid system and the essential input parameters are described The different prediction cases are also described.

3.2 EXODUS Reservoir Simulator

The T & T Associates Inc. of Canada developed the EXODUS reservoir simulator. The recommended configuration for a PC running EXODUS is a 486DX with at least 8 Mbytes of memory, 200+ Mbytes of hard disk capacity. Microsoft Windows 3.1 or higher and Microsoft Excel 4.0 or higher are also necessary.

EXODUS is a general-purpose compositional model for simulating black oil, gas or gas condensate, volatile oil reservoirs. The compositional formulation of the model accurately represents phase behaviour for treatment of variable bubble points, mixing of different PVT regions, tracer tracking and differentiation of injected and in-place fluids. The transfer of any component between the oil, gas and water phases is calculated using equilibrium ratios. Black oil data are internally converted to compositional equivalents.

The program can simulate problems in one, two or three dimensions using either rectangular (x-y-z) or cylindrical (r-θ-z) co-ordinates, with any combination of oil, gas or water phases, and characterising the reservoir fluid into one or more components. Interblock mass transfer is represented by Darcy's law with relative permeabilities, capillary pressure and gravity effects. The reservoir description capability includes naturally fractured reservoirs, and communicating faulted reservoirs. Dual porosity/dual permeability reservoirs can also be simulated. The model also allows special connection of non-neighbouring grid cells for unconventional problems. Wells can be deviated or horizontal. Multiphase correlation is fully coupled to provide pressure losses in the tubing.

EXODUS has non-linear regression parameter built into it whereby the program user may find the best values of porosity, permeability, relative permeability that will match observed field history. This is commonly known as automatic history matching. This feature is of great value in reducing the time required to obtain a history match[19].

3.3 Mathematical basis for implicit compositional model

The simulation model is a fully implicit, three dimensional, multi-component model for simulating isothermal processes. The finite difference formulation is a block centred approximation to the partial differential equations. In addition to five and nine point finite difference approximations, the model allows the linking of any pair of grid cells for mass transfer.

In finite difference formulation a partial differential equation is converted to a finite difference equation using the Taylor series expansion. The reservoir is discretized to a number of blocks and each block is represented by a finite difference equation. The boundary conditions are also converted to a corresponding finite differential equation. These result in a set of algebraic equations, which is then solved using a suitable scheme.

Mathematical formulation used in the model is briefly discussed below:

Any component can exist in any phase and we assume there are 'N' phases and Nc components

Component balance, I = 1,2,3 ---------------Nc

$$\sum_{n=1}^{N} \nabla\left[T\frac{K_r}{}\frac{\rho_n}{\mu_n}\frac{X_{in}}{}\left(\Delta P+\Delta P_{cn}-\gamma_n \Delta Z\right)\right]=\frac{V}{\Delta t}\partial\left(\phi\sum_{n=1}^{N}\rho_n S_n X_{in}\right)+q_i \quad \text{------------} \quad (3.3.1)$$

where, the terms are

T = Transmissibility ; Kr = Relative permeability, Δp = Pressure drop ; ΔPc = Capillary pressure drop ; γ = Specific gravity ; V = Volume; Δt = Length of time step; ρ = Density; q_i = Production rate

The interface mass transfer is handled by means of K values Thus for each pair of phases, e.g. oil and gas $y_i = K_{go} X_i$ -- (3 3.2)

where y_i is the mole fraction of component, i, in the gas phase, Kgo is the interface mass transfer co-efficient for the component, i, X_i is the mole fraction of component, i, in the oil phase. Phase constraint equation's, one for each phase, ensure that the mole fractions sum to 1.

$$\sum_{i=1}^{N_c} X_{in} = 1.0 \quad \text{--} \quad (3.3.3)$$

A saturation constraint equation:

$$\sum_{n=1}^{N_c} S_n = 1.0 \quad \text{--} \quad (3.3.4)$$

completes the equation set[19].

3.4 Simulation Grid Description

As mentioned in Section 3.1, the three main gas sands of Kailashtila gas field are selected for simulation The gross pay isopach of these sands are shown on Figures 2.2.1, 2.2.2 and 2.2.3.

A three-dimensional 23x5x3-grid model of the upper sand and lower gas sand, as configured by IKM[6], is used for prediction. The individual sands are modelled as isolated gas accumulation as present in the reservoir. Each of the sands is further divided into suitable number of layers The zero edges of the sands and the model grid system used in the simulation are shown in Figure 3.3.1[6]. The spatial orientation of the sands along with the model grid system is shown in Figure 3.3 2[6]

The upper gas sand is divided into four layers having a gross thickness of 100 feet each The lower gas sand is divided into three layers but having a gross thickness of 50 feet each. The grids those contain the perforated section of the well are further refined, using EXODUS, to specify the accurate perforation interval This also helps to achieve better resolution in determining the change of phase saturation near the wellbore

The volumetric area of the sand present in each grid is manually calculated and approximated into rectangular grid cells. The proved and probable reserves of the sands are included in the model. The dimensions of the grid blocks are chosen in such a way so that the shape and the volume of the reservoirs are duplicated. The calculated gas in place of the simulation model is more than that reported in the IKM report[6].

The individual reservoirs are assumed to be homogeneous and isotropic. The necessary input parameters to the EXODUS simulator are discussed in the following section The completion data of the wells are shown in the Table 3.4 1.

Table 3.4.1: Completion data of the wells[6,20,21]

	Perforation interval (ft ss)				
Well	UGS	MGS	LGS	r(ft)	Skin
KTL1	7426-7186	9591-9661	9749-9809	0.188	135.4(UGS),277(LGS)
KTL2	7329-7369	-	-	0.146	183.60
KTL3	-	9568-9698	-	0.146	15.05
KTL4	-	-	9820-9870	0.146	135.4

Horizon: UGS 7210-7610ft ss, MGS 9370-9670ft ss, LGS 9780-9930 ft ss.

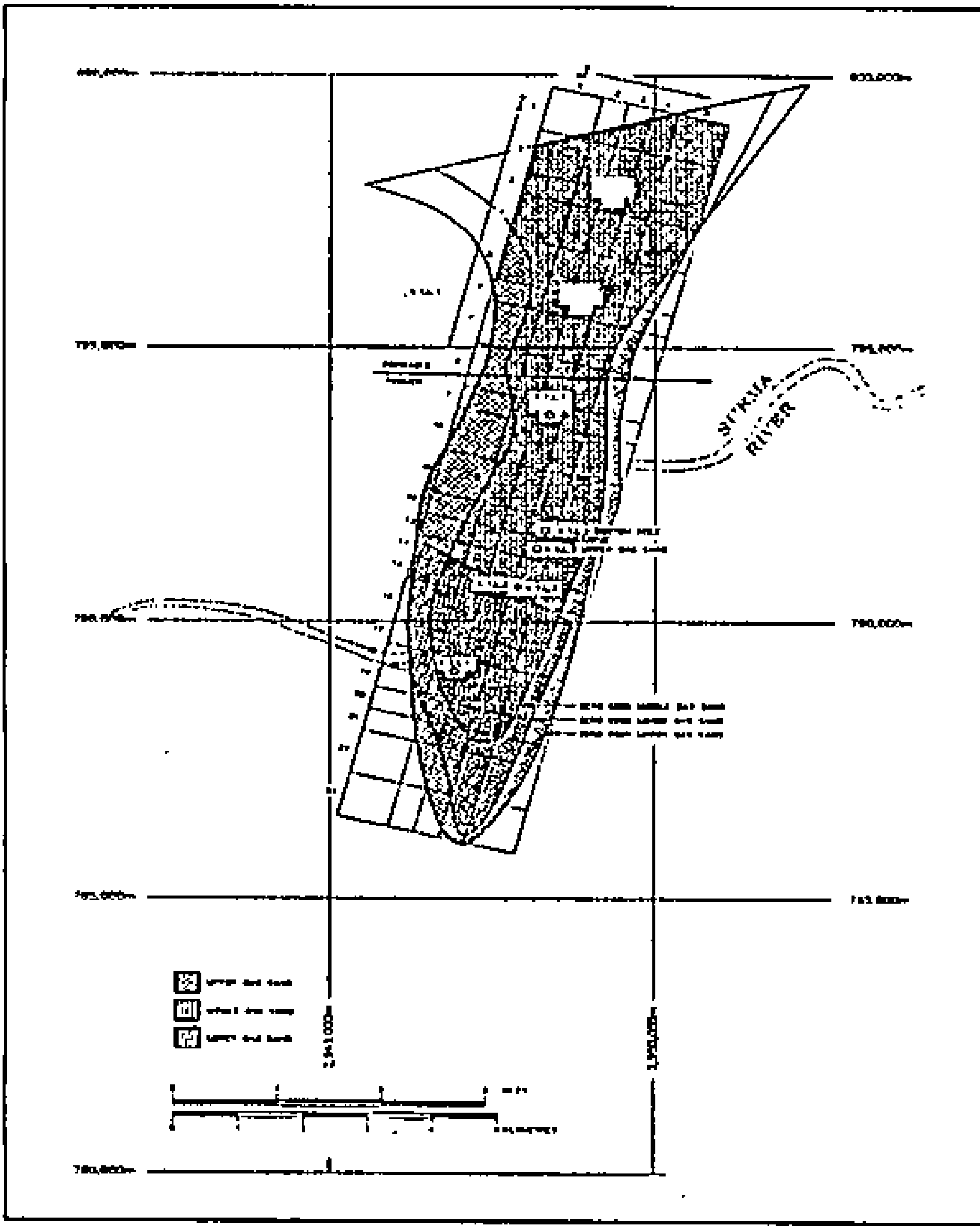


Figure 3.3.1: Zero Edges of the Sands and Model Grid System Used In the Simulation[6]

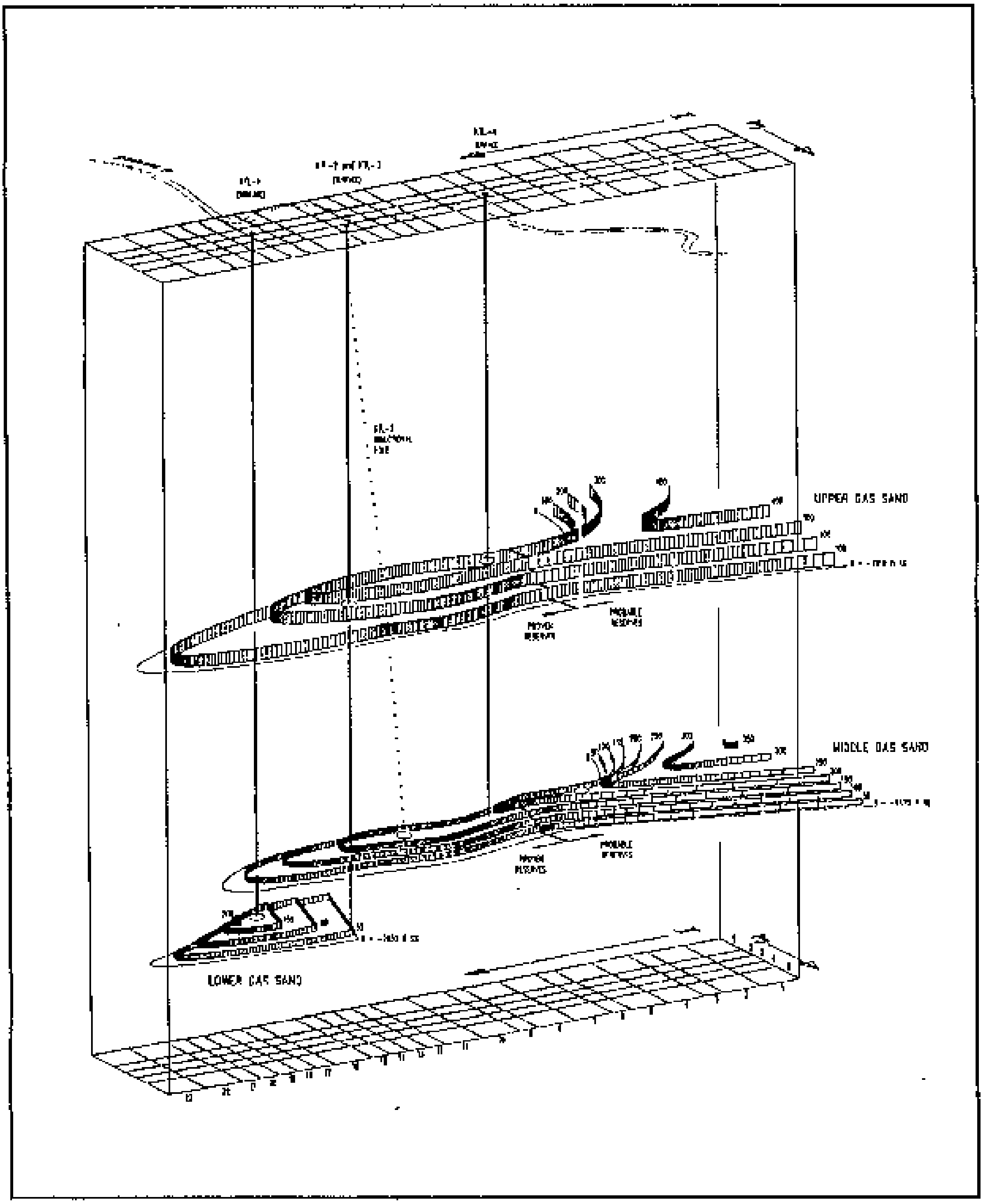


Figure 3.3.2: Spatial Orientation of the Sands and Grid System Used in the Simulation[6]

3.5 Input Parameters

For perfect reservoir simulation the accurate reservoir and fluid description are indispensable. Therefore, the better we know about the reservoir, the more reliable is the simulated predictions. Unfortunately, the least information is known during the early life of the reservoir and the maximum information is known when the reservoir is empty. At least some accurate input parameters are essential for any kind of reservoir simulators for reasonable prediction.

As mentioned earlier, the EXODUS reservoir simulator is a restricted compositional model. To perform a simulation study, the following information are needed:

1. PVT properties of the reservoir fluid, i.e. B_o, B_w, B_g, R_s, μ_o, μ_w, μ_g as functions of pressure. EXODUS can also generate PVT properties from **Standing's correlations**. For gas-water reservoirs, the only effective parameters are B_w, B_g, μ_w and μ_g (Table 2.3.4), but realistic oil properties have to be entered as the model goes through the conversion to equivalent compositional properties.

2. Relative permeabilities, viz. K_{ro} and K_{rw} as a function of S_w, and K_{ro} and K_{rg} as a function of S_l (=1-S_g). Again EXODUS can generate these values from **Honarpour's correlations**. For gas-water reservoirs (S_l=S_w), water phase relative permeabilities and water-oil capillary pressures are obtained from the K_{rw} vs. S_w and P_{cw} vs. S_w curves respectively. Similarly, gas phase relative permeabilities and gas-oil capillary pressures are obtained from the K_{rg} vs. S_l and P_{cg} vs. S_l curves respectively (Table 2.3.2). The oil phase relative permeabilities should be entered as K_{ro} is calculated using Stone's model 2.

3. For a field study, maps of structure on top of porosity, gross pay thickness, net pay thickness, porosity etc. Constant values may be entered for various properties or may be interpolated from well values using EXODUS. However, the more information that is available from the geologist, the better. Maps should be provided for each layer of the model, however, the formula capability of EXODUS may be used to subdivide and compute layer properties from other layers.

For a theoretical model study, where no maps are used, grid cell values may be entered directly into EXODUS. The contour maps and the necessary rock and fluid properties used in this study are shown in Figures 2 2 1, 2.2 2 and 2.2 3 and Tables 2.2.1 and 2.3.1.

4 Well location and completion data of the wells are indicated in the grid systems of the individual sands (Figures 3 3.1, 3 3.2 and 3.3.3). The completion data of the wells are presented in Table 3.4.1.

5. The historical production and pressure data of the Kailashtila wells are listed in Tables 2.4.1 and 2.4.2 respectively.

3.6 Prediction Cases

The prediction for the productivity losses due to condensate accumulation near the wellbore was made at the current well production rates The current gas production rate of KTL1 is approximately 25 MMCF/D. The current condensate production rates of the well are approximately 9 BBL/MMCF Similarly, water production rate is approximately 0.3 BBL/MMCF The historical gas, condensate and water production rates of the well are given as input in the simulator for an accurate prediction. The current gas rates of the well are the standard for Kailashtila gas field, as well as for the other gas fields in Bangladesh The reservoir model can also be simulated for other higher or lower rates with minor changes in the well flow parameters. At higher rates, a higher drop of pressure is expected near the wellbore resulting in a higher dropout of condensate At the same time, the high velocity gas has the energy to carry away a higher amount of condensate At lower rates, the results can be expected to be opposite to the high rate cases.

3.7 History Matching

It is one of the common uses of reservoir simulation for field problems. History matching is very useful and powerful reservoir description technique

The primary objectives of history matching are to test and to improve the reservoir model. History matching will contribute to an understanding of the current status of the reservoir, including fluid distribution and fluid movement and perhaps to verification on identification of the current depletion mechanism. It will allow to infer a reservoir description, including oil and gas in-place, in parts of the reservoir where there are no data and will supply details to justify plans to establish objectives for obtaining data[22]

However, the most useful and usually the only available way to test the model is to simulate the past performance of the reservoir and to compare the simulation with actual historical performance The gas rate and reservoir pressure depletion along with the model output for the well-1 of the upper sand and lower sand of Kailashtila gas field are displayed graphically in Fig. 3 7.1 and 3.7 2 using EXODUS.

3.7.1 Pressure History Matching

The purpose of history matching is to find a set of reservoir parameters that will match the observed data. It dose by repeatedly running EXODUS, varying parameters until it finds the set that results in a minimum value of the error function[19].

The field performance data may be in error, of course. Sometimes this becomes a major problem in obtaining an acceptable history match For this discussion, however, we assume that the field performance data are accurate

Trail and error do most history matching For this, the first consideration to match the reservoir size or original gas in-place This often is determined with a simulator using the principles of material balance From lower sand p/z vs Gp curve, the GIIP is 361 BSCF and after simulation run this GIIP is 255 646 BSCF. This new volume of gas can be used to verify the simulation pressure drop calculations Keeping the reservoir structure at it was, it can be increased to the new volume by multiplying the reservoirs x and y directional block size by the following multiplying factor

$$MF = \sqrt{(\text{New reservoir volume})/(\text{Old reservoir volume})}$$
$$= \sqrt{(361)/(255.646)} = 1.18$$

The simulation of the reservoir is done again with the new block size This produced a new set of pressure vs. time data, which has been presented in Fig 3.7.1. The modified simulation result is showing significant improvement in matching with the actual reservoir data So, it can be stated that, the reservoir volume is larger than what was anticipated by IKM, which was 247 8 BSCF So, the final GIIP is 309.3316 BSCF.

For the upper sand, from material balance the GIIP is 2600 BSCF. And from simulation the GIIP we get is 2614.27 BSCF So, same as before the multification factor is

$$MF = \sqrt{(\text{New reservoir volume})/(\text{Old reservoir volume})}$$
$$= \sqrt{(2600)/(2614.27)} = 0.99$$

Now, the x and y grid of upper sand multiplied 0.99 value and the final GIIP get is 2989 316 BSCF. As a result the pressure matching is slightly improve than before, which is shown in Fig. 3 7.1. Whereas the GIIP from IKM was 1130.090 BSCF by material balance. But before pressure history matching for both upper and lower sand are shown in Fig. 3.7

There is a possibility that the pressure maintenance is due to a water encroachment into the reservoir It can not be proved with accuracy that water is not coming into the reservoir, but in that case water content of the produced gas would have increased.

Since no such scenario has been observed, it confirms the increased reservoir volume assumption. As a result, the simulation data is well matched with actual field data.

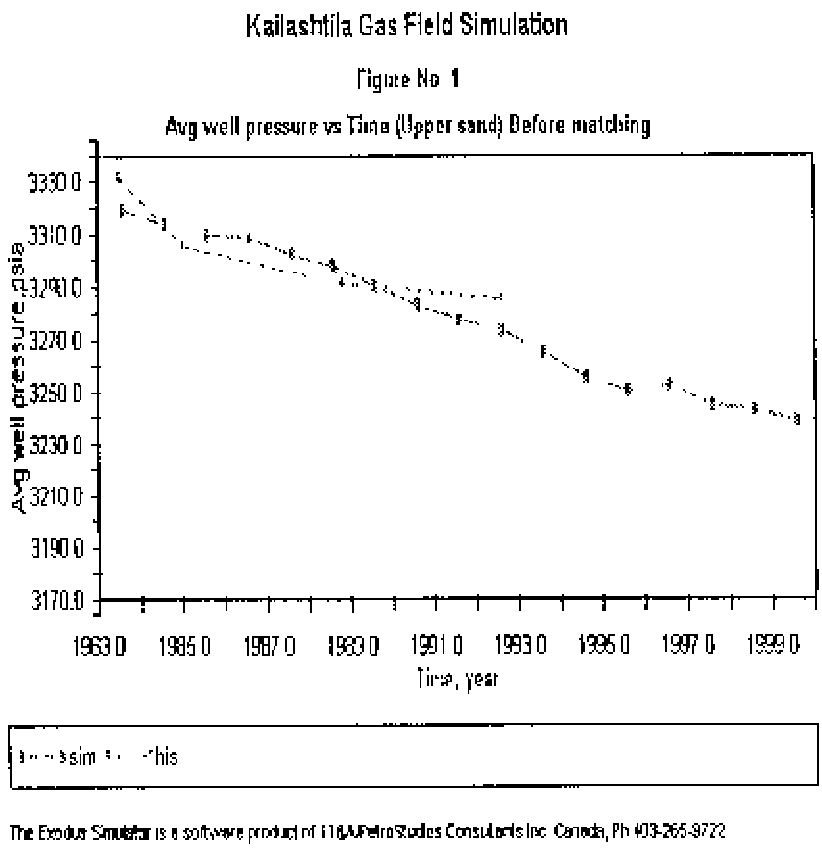


Figure 3.7.1 : Pressure history before matching for upper sand

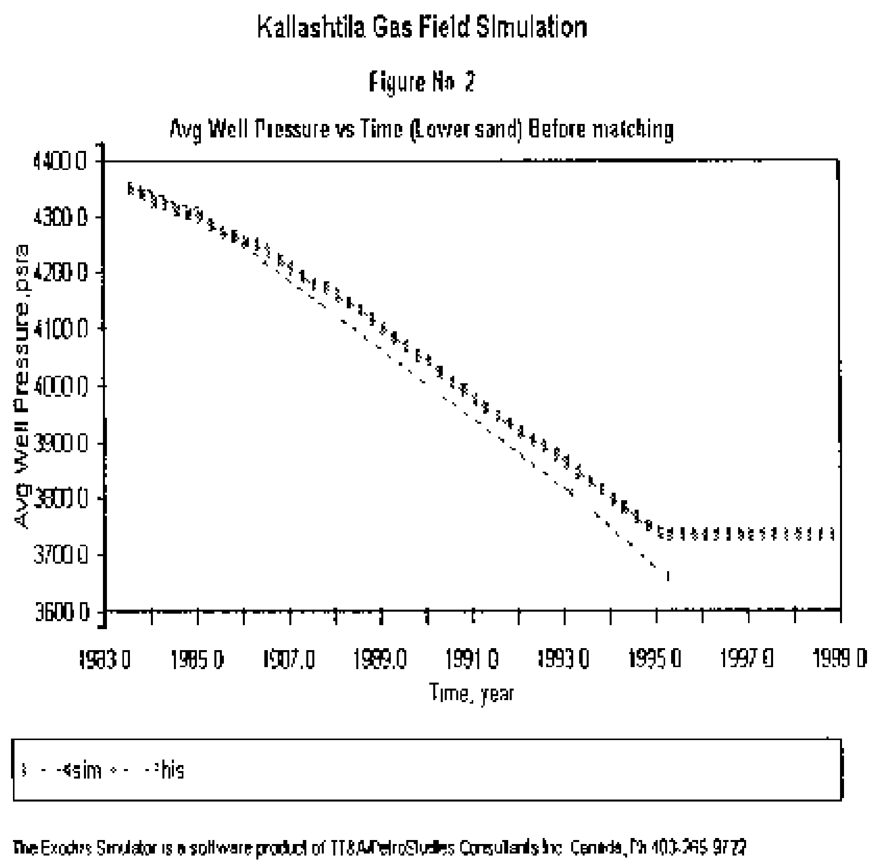


Figure 3.7.2 : Pressure history before matching for lower sand

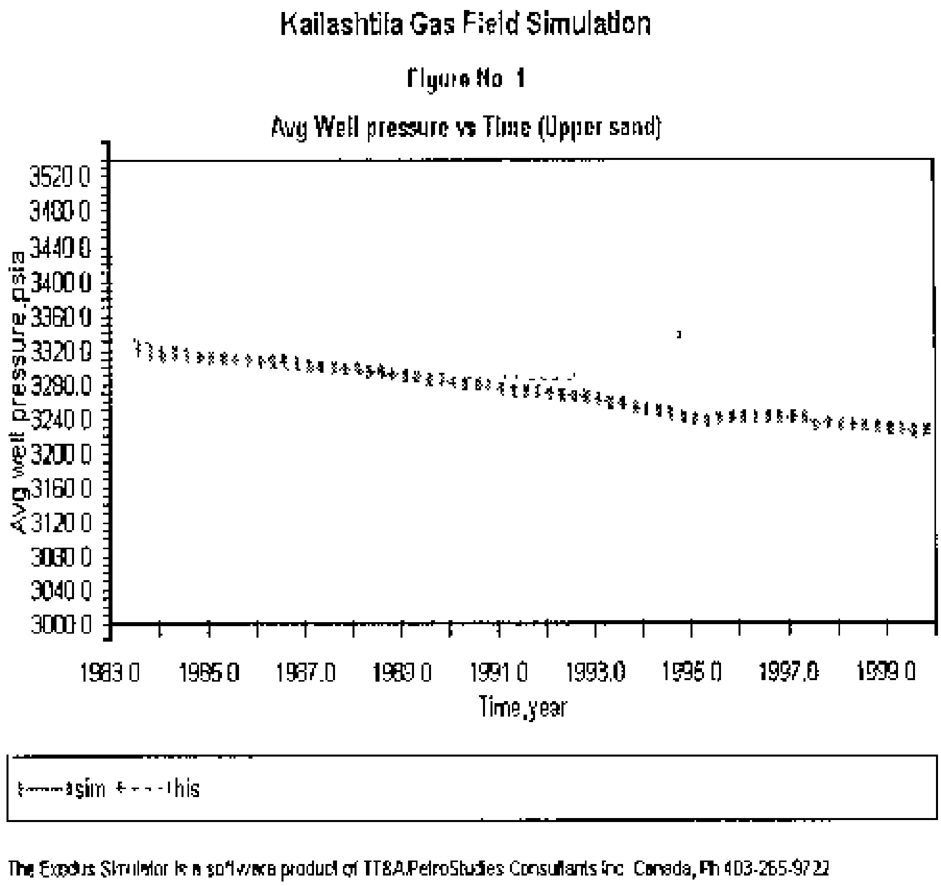


Figure 3.7.3: Pressure history matching for upper sand

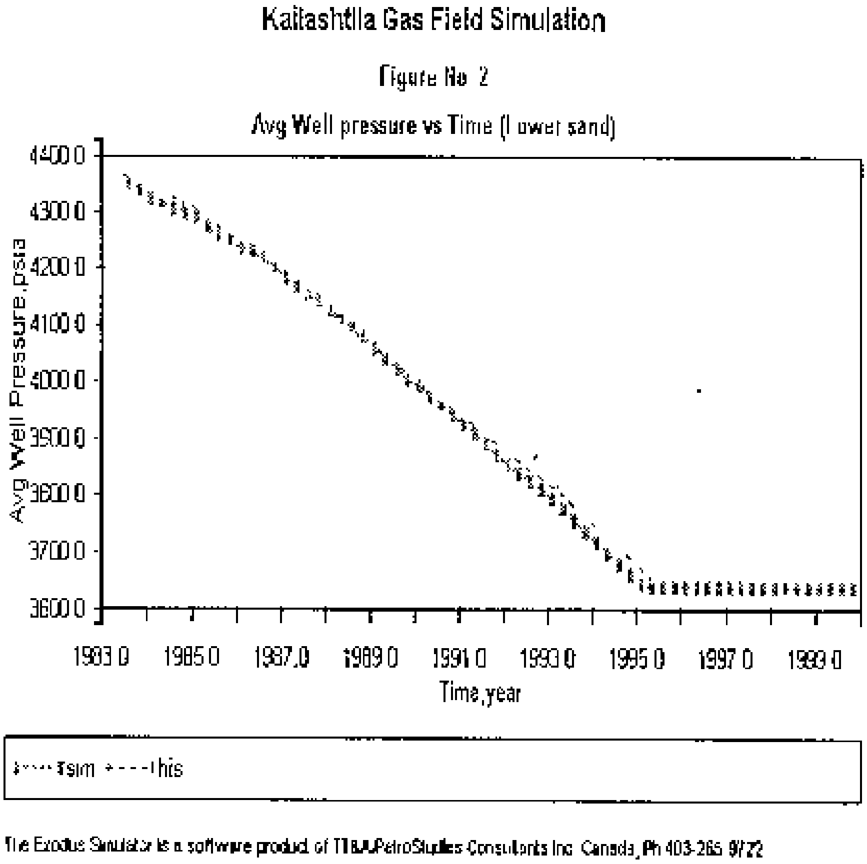


Figure 3.7.4: Pressure history matching for lower sand

3.7.2 Production History Matching

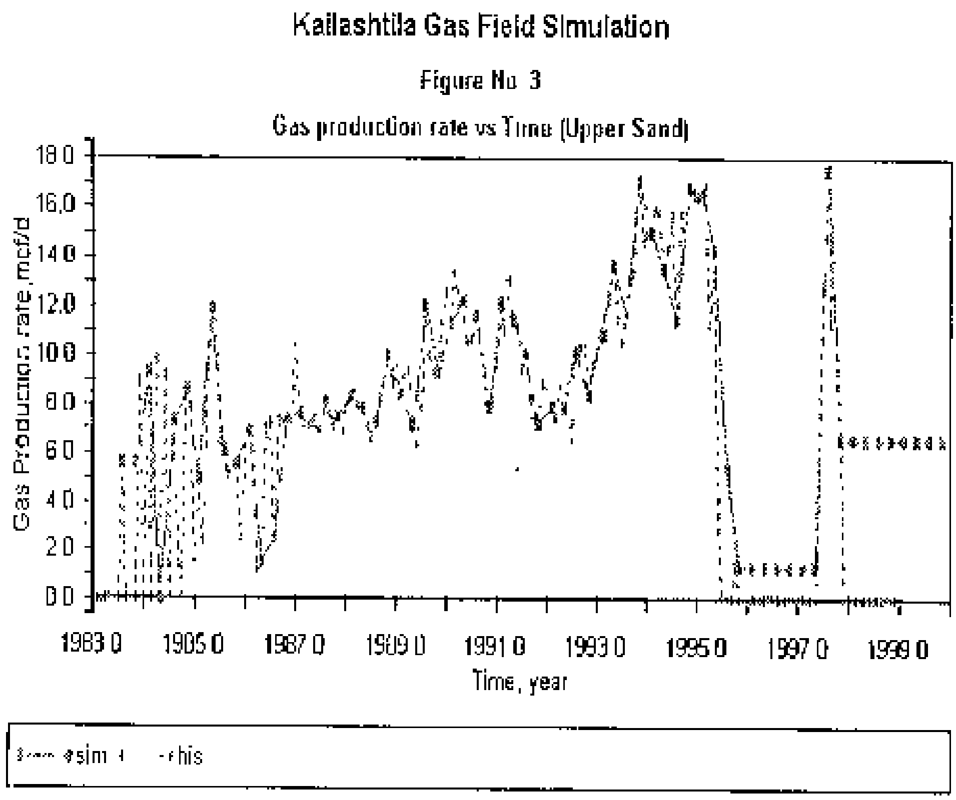
Most reservoir produce some hydrocarbon liquid, commonly called condensate, in the range of a few to a hundred or more barrels per million standard cubic feet.

The production history matching is done similarly as pressure history matching. Due to the increased volume the matching is better than previous one. So, from the production history matching we can also say that the reserve of the lowersand (309 3316 BSCF) is more than estimated by IKM (247.8 BSCF).

For the upper sand, the simulated production data is well matched with the actual field data. From simulation we get the primary GIIP is 2304.9384 BSCF. Since the data does not match with the actual field data, so for matching increase the reservoir volume, using multification factor, the GIIP for upper sand is 2679.9844 BSCF. So the total GIIP of KTL1 is 2989 316 BSCF from simulation and from IKM it was 2625.70 BSCF which is lower than simulation result. A comparative study of GIIP estimated by IKM and this study is shown below in Table 3.7 1.

Table 3.7.1: Comparison of GIIP estimates of KTL1 conducted by IKM and Present study

SAND	Material Balance IKM BSCF	Material Balance Present study BSCF	Simulation studies IKM BSCF	Simulation studies Present study BSCF
Upper sand	1130 090	2600.00	2377 90	2679 9844
Lower sand	304.843	361.00	247 80	309.3316
Total GIIP	1434.933	2961.00	2625.70	2989.316



The Exodus Simulator is a software product of TT&A/PetroStudies Consultants Inc. Canada, Ph 403-265-9722

Figure 3.7.5: Production History Matching for upper sand

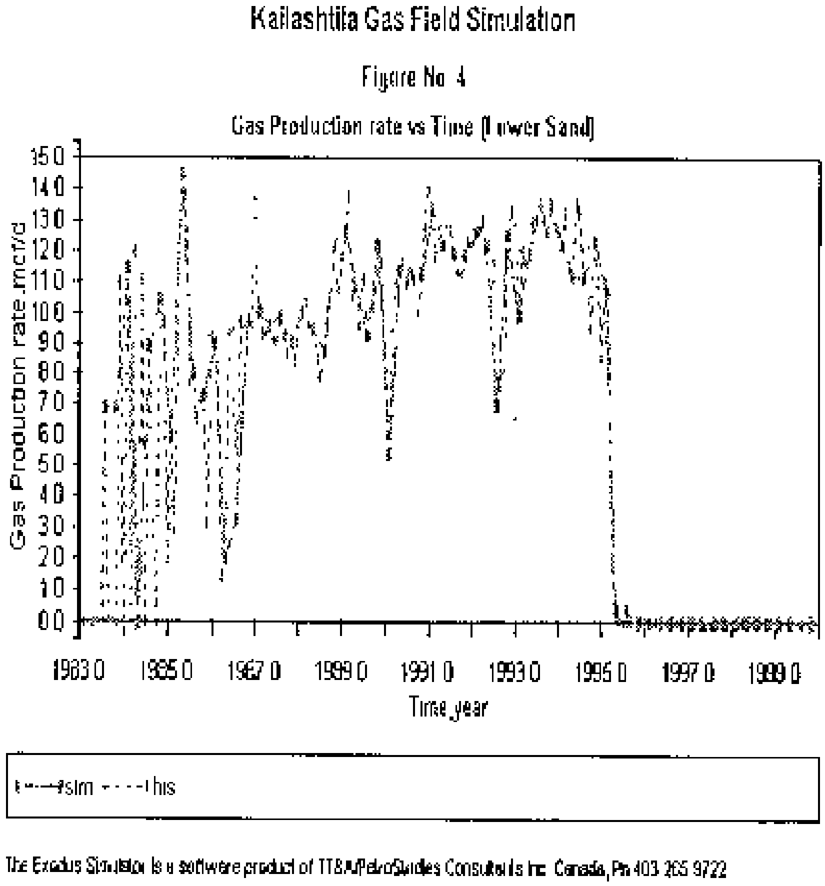


Figure 3.7.6: **Production History Matching for lower sand**

Chapter 4

SAMPLE COLLECTION AND ANALYSIS

4.1 Introduction

As part of the project, several samples of gas and condensate were collected from strategic points for compositional and phase behaviour analysis. The compositions of the fluid samples were analysed by gas chromatograph. The phase behaviour studies were performed both by the PVT apparatus and the HYSIM simulator. The sample collection and analysis procedure and results are discussed in the following sections

4.2 Sample Collection

Gas and condensate samples were collected from the existing well of Kailashtila gas field. Fluid samples were collected from the field separators at separator pressures and temperatures. The standard procedures were followed to collect them. The surface sampling data are presented in Tables 4 2 1 and 4 2 2.

Table 4.2.1: Surface sampling data of KTL1 condensate

Test Number	Rate Number	Area	Date (D/M/Y)	Page Number	Total Pages
1		Golapganj, Sylhet	21-10-1998	1	2

Customer	Well Name or Number	Field	Formation
Department of PMRE, BUET	KTL1	Kailashtila Gas Field	Lower Gas Sand

Elevation (feet)	Standard Conditions		Time Well Flowing or Shut in Before Sampling	Interval Tested (feet)
	Psia: 14 7	°F: 60		9749-9809

SAMPLE NUMBER: 01

Time Taken	Container Number	Container Volume (cc) or (gal)	Sample Type	Sample Taken at	Sampling Pressure (psig)	Sampling Temp (°F)	Atmospheric Pressure (psia)	Atmospheric Temperature (°F)	Time to Take Sample (min.)
15:18 hrs	KTL1-Condensate	500 cc	Cond.	LP 3-phase separator	135	89	14.7	86	10

FIELD READINGS

WELL HEAD		CHOKE	SEPERATOR		BOTTOM HOLE		OIL		GAS		WATER
Press. (psig)	Temp (°F)	Size (64^{th} in)	Press. (psig)	Temp. (°F)	Press.(psig) @ ft	Temp.(°F) @ ft	Rate (B/MMCF)	Grav. (°API)	Rate (MMCF/D)	Grav (Air=1)	Rate (B/MMCF)
3100	115	40	135	89			9	0.81	25	0.62	0.2

Supervised by: Dr. Edmond Gomes

Sampled by: Dr. Edmond Gomes and Md. Saifullah Talukdar

Table 4.2.2: Surface sampling data of KTL1 gas

Test Number	Rate Number	Area	Date (D/M/Y)	Page Number	Total Pages
2		Golapganj, Sylhet	21-10-1998	2	2

Customer	Well Name or Number	Field	Formation
Department of PMRE, BUET	KTL1	Kailashtila Gas Field	Lower Gas Sand

Elevation (feet)	Standard Conditions		Time Well Flowing or Shut in Before Sampling	Interval Tested (feet)
	Psia 14.7	°F 60		9749-9809

SAMPLE NUMBER: 02

Time Taken	Container Number	Container Volume (cc) or (gal)	Sample Type	Sample Taken at	Sampling Pressure (psig)	Sampling Temp. (°F)	Atmospheric Pressure (psia)	Atmospheric Temperature (°F)	Time to Take Sample (min.)
15:35 hrs	KTL1-Gas	500 cc	Gas	2nd stage 2-phase separator	690	68	14.7	86	10

FIELD READINGS

WELL HEAD		CHOKE	SEPERATOR		BOTTOM HOLE		OIL		GAS		WATER
Press. (psig)	Temp. (°F)	Size (64^{th} in)	Press. (psig)	Temp. (°F)	Press.(psig) @ ft	Temp.(°F) @ ft	Rate (B/MMCF)	Grav (°API)	Rate (MMCF/D)	Grav (Air=1)	Rate (B/MMCF)
3100	115	40	690	68			9	0.81	25	0.62	0.2

Supervised by: Dr. Edmond Gomes

Sampled by: Dr. Edmond Gomes and Md. Saifullah Talukdar

4.3 Analysis

Compositional analyses of the gas and condensate samples were conducted to determine the hydrocarbon and non-hydrocarbon components present in them. The behaviour of a fluid entirely depends on its compositions The phase behaviour study is intended to determine the liquid recovery of the combined fluid stream at controlled temperature and pressure.

4.3.1 Compositional Analysis

Using gas chromatograph the compositions of heavier hydrocarbon liquids are shown in Table 4.3.1 and 4 3.2

Table 4.3.1: Compositional analysis of KT1 Gas by Gas Chromatograph

Component	Chromatographic area	RF	Corrected area	Weight %	Volume	Volume %
C_1	371492 855	0 95	352918.212	84.84	0.053	93.49
C_2	16082.8520	1.29	20746.879	4.98	$1.66*10^{-3}$	2 928
C_3	10349	0 959	9924 691	2.38	$5.41*10^{-4}$	0.954
i-C_4	3346	0.97	3245 62	0.78	$1.34*10^{-4}$	0 236
n-C_4	3502	1.0	3502	0.841	$1.45*10^{-4}$	0.2557
i-C_5	2062	1.08	2226 96	0 535	$7.43*10^{-5}$	0.131
n-C_5	1224	1 20	1468 8	0 353	$4\ 9*10^{-5}$	0.0864
i-C_6	1290	2.22	2863.8	0.688	$8*10^{-5}$	0.141
n-C_6	528	2 22	1172.16	0 281	$3.267*10^{-5}$	0.0576
C_6 (cyclo)	2386	2.22	5296.92	1.273	$1.48*10^{-4}$	0.261
i-C_7	880	1 00	880	0 211	$2\ 11*10^{-4}$	0.3722
n-C_7	262	1.00	262	0 062	$6.2*10^{-6}$	0.0109
C_7 (cyclo)	1380	1 00	1380	0.331	$3\ 31*10^{-5}$	0.0583
i-C_8	1723	1.036	1785.028	0.429	$3\ 76*10^{-5}$	0.0663
n-C_8	206	1 036	213.416	0 0513	$4.5*10^{-6}$	0.007938
C_8 (cyclo)	871	1 036	902.356	0.2169	$1.902*10^{-5}$	0.0335
N_2	4507.97	0 856	3858.82	0.927	$3.31*10^{-4}$	0 5838
Co_2	1185.86	2 8	3320 419	0.798	$1\ 813*10^{-4}$	0.3198

Table 4.3.2: Compositional analysis of KT1 Gas-Condensate by Gas Chromatograph

Component	Chromatographic area	RF	Corrected area	Weight %	Volume	Volume %
$C_1 + C_2$	9152	0.82	7504.64	0 2795	0.00006076	0 590
C_3	25522	2 053	52396.66	1.95149	0.0004435	4.309
i-C_4	20223	1 876	37938.348	1 4129	0 0002436	2.366
n-C_4	32669	2 24	73178.56	2.725	0 0004698	4.5648
i-C_5	40756	0 639 4	26059.38	0 97057	0 0001348	1.309
n-C_5	433649	0 872	378141 92	14 083	0 001955	18 99
i-C_6	71403	0.905	64619 715	2 4067	0 0002798	2 718
n-C_6	33161	0.905	30010.705	1.1177	0 0001299	1.262
C_6 (cyclo)	60247	0.905	54523 53	2.0307	0 0002361	2 294
Benzen	79424	2.749	218336.57	8.1318	0.0010425	10 129
i-C_7	168305	1 020	171671 1	6.3938	0 0006393	6 211
n-C_7	34324	1.020	35010.48	1.30395	0.00013039	1.2669
C_7 (cyclo)	200292	1 020	204297.84	7.6089	0 0007608	7 392
Toluene	5016	1.134	5688 144	0 2118	0.00002302	0.2236
i-C_8	348719	1 18	411488.42	15.325	0.001344	13.059
n-C_8	41506	1 18	48977.08	1.824	0 00016	1 55
C_8 (cyclo)	7553	1.18	8912.54	0.33194	0.00002911	0.2828
m-x	31236	0 79	24676 44	0.91906	0.00008670	0.8424
o-x	25983	0.736	19123.488	0 7122	0 00006718	0.6527
n-C_9	205213	0.912	187154.256	6 97048	0 00054456	5 291
C_9 (cyclo)	96363	0 912	87883.056	3 273	0 0002557	2.484
i-C_{10}	45300	0.946	42853.8	1 59607	0.0001123	1.0911
n-C_{10}	12766	0 946	12076 636	0.44978	0 00003167	0 3077
p-cyemen	35410	0.75	26557 5	0.9891	0 00007436	0 7225
i-C_{11}	133784	1.015	135790.76	5.0574	0.00032419	3.15
n-C_{11}	8985	1.015	9119 775	0.33966	0 0000217	0 2108
C_{11} (cyclo)	39115	1.015	39701 725	1.4786	0.00009478	0.9209
i-C_{12}	21303	1.116	23774 148	0 8854	0.00005208	0.5060
n-C_{12}	29657	1.116	33097.212	1 2326	0.0000725	0.7044
n-C_{12} '	192104	1.116	214388.064	7.984	0.0004696	4 5629

4.3.2 Phase Behaviour Study Using PVT Apparatus

The JEFRI PVT apparatus is a very expensive piece of equipment available in the PMRE department, BUET. This is the only one of this kind in Bangladesh. This is the versatile equipment used for the purpose of measuring fluid properties and studying fluid phase behaviour at controlled temperature and pressure. Measurements of interest encompass various vapour and liquid physical properties such as density, vapour/liquid ratios, critical parameters, and saturation pressures and phase compositions.

4.3.3 Phase Behaviour Study Using HYSIM Simulator

The HYSIM developed by Hyprotech Ltd. is a powerful desktop process simulator designed for the gas processing, oil refining, petrochemical, chemicals, and synthetic fuels industries. It has built in modules that cover the entire chemical processing industry, including separators, heat exchangers, compressors, pumps, valves, mixers, multiple reactor models, rigorous columns plus a range of helpful utilities. There are no pre-programmed limits on the number of components, streams, unit operations or trays. HYSIM offers a wide selection of property methods, including equation of state, semi empirical correlation, and activity Models.
For installation and proper use, HYSIM requires operating system DOS 3.0 or greater, a minimum conventional memory of 200 KB, a minimum extended memory of 3.5 MB for the 386 version, a minimum of 9 MB of disk space to store the executable and data files. HYSIM also requires a math co-processor[23].

The HYSIM process simulator was used in this study to predict the condensate recovery of the Kailashtila reservoir fluids. The compositions of the gas and condensate obtained from gas chromatograph were fed in the HYSIM at the historical condensate gas ratio and the recovery of condensate is estimated at different pressures of the depletion process.

Combining the gas and condensate, using another software RECOMBINATION we get new composition. Using this new composition the phase diagram drawn shown in Fig 4.3.3. From this phase diagram we have seen that the reservoir is non-retrogate reservoir. Because the reservoir Temperature and pressure are 152°F and 3332 psia for upper sand and 172°F and 4366 psia for lower sand. Both reservoir conditions are out of range of this phase diagram So from this conditions we can also say that the reservoir is non-retrogate

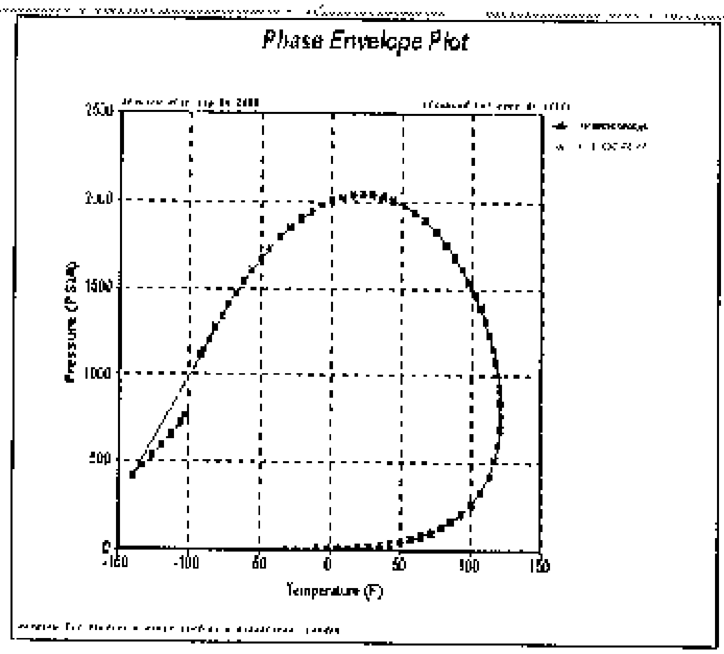


Figure 4.3.3: Phase diagram of KTL1

Chapter 5
RESULTS

5.1 Introduction

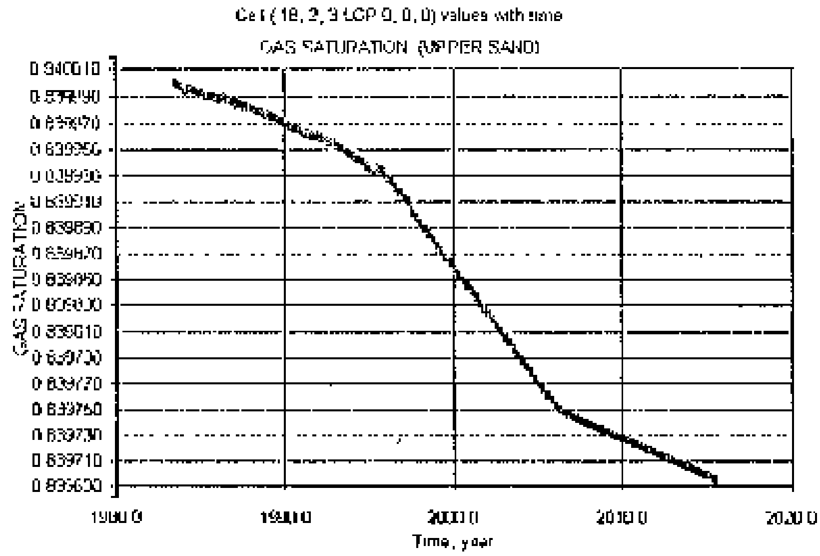
In a reservoir engineering study reservoir simulation and fluid sample analysis are very important to know different reservoir information and predict future production performance. This study uses simulation software EXODUS and fluid analysis by chromatograph and HYSIM simulator to find out reservoir characteristics and pressure and production scenarios of Kailashtila gas field. The scope of the reservoir engineering study included a detailed integrated approach using all available core PVT, production and pressure test data to develop a description of the reservoir rock and fluid properties and predict the future performance assuming alternative development and operating scenarios.

5.2 Reservoir Simulation Results

For reservoir simulation, all data except relative permeability values (saturation table) are taken from IKM reports and Kailashtila field personnel Capillary pressure data are taken from a report in the BPI library. Gas-water relative permeability data are taken from IKM's Beani-Bazar report The output simulation results are shown in Table no 5.2.1. From simulation results gas and water saturation at the perforated grid block and besides grid block are also shown in Fig no 5.2.1 and 5.2 2 for both sands From these figures it have been seen that gas saturation is decreasing and water saturation is increasing with time during production period and when production is extended up to time 2020, these curves shown the same nature

Table 5.2.1: KTL1 simulation output results

KAILASHTILA SIMULATION RESULTS								
Calendar Date	Avg. Pressure Psia	Gas in Place MCF	Water Rate BBLS/D	Gas Rate MCD/D	Cum Water Prod BBLS	Cum Gas Prod MCF/D	Water Recovery %	Gas Recovery %
(1983 JUL 1)	3412.189	2.99E+09	0	0	0	0	0	0
(1983 AUG 1)	3411.608	2.99E+09	4.53E-07	12577.41	1.12E-05	389899.8	2.52E-12	1.30E-02
(1984 AUG 1)	3404.415	2.98E+09	4.64E-06	16264.51	8.90E-04	5213822	2.01E-10	0.1744152
(1985 AUG 1)	3396.957	2.98E+09	7.81E-06	14106.46	3.02E-03	1.02E+07	6.81E-10	0.3399515
(1986 AUG 1)	3390.775	2.98E+09	4.37E-06	5819.341	5.73E-03	1.42E+07	1.29E-09	0.4759358
(1987 AUG 1)	3.38E+03	2.97E+09	1.95E-05	17977.4	1.18E-02	2.06E+07	2.66E-09	0.6888976
(1988 AUG 1)	3371.876	2.96E+09	2.19E-05	15967.74	1.89E-02	2.64E+07	4.25E-09	0.8843772
(1989 AUG 1)	3360.411	2.96E+09	3.11E-05	21295.89	3.05E-02	3.37E+07	6.87E-09	1.126817
(1990 AUG 1)	3348.728	2.95E+09	4.38E-05	22827.58	4.42E-02	4.15E+07	9.96E-09	1.388877
(1991 AUG 1)	3.34E+03	2.94E+09	5.34E-05	22007.65	6.29E-02	4.98E+07	1.42E-08	1.664378
(1992 AUG 1)	3326.596	2.93E+09	3.72E-05	17141.72	8.28E-02	5.69E+07	1.87E-08	1.90471
(1993 AUG 1)	3314.491	2.92E+09	7.75E-05	25177.99	0.1060031	6.51E+07	2.39E-08	2.178682
(1994 AUG 1)	3299.563	2.91E+09	7.30E-05	22560.64	0.1348652	7.50E+07	3.04E-08	2.50973
(1995 AUG 1)	3.29E+03	2.91E+09	5.65E-06	5798.323	0.1523466	8.21E+07	3.43E-08	2.746572
(1996 AUG 1)	3287.71	2.91E+09	7.52E-07	1289.817	0.1529102	8.27E+07	3.44E-08	2.767766
(1997 AUG 1)	3285.637	2.91E+09	1.14E-05	17529.78	0.1537387	8.41E+07	3.46E-08	2.812417
(1998 AUG 1)	3281.487	2.90E+09	4.32E-06	6567.717	0.1554664	8.67E+07	3.50E-08	2.901649
(1999 AUG 1)	3.28E+03	2.90E+09	4.51E-06	6567.709	0.1570805	8.91E+07	3.54E-08	2.981642
(2000 AUG 1)	3273.998	2.90E+09	4.71E-06	6567.714	0.1587709	9.15E+07	3.58E-08	3.062254
(2001 AUG 1)	3270.246	2.90E+09	4.90E-06	6567.708	0.1605277	9.39E+07	3.62E-08	3.142447
(2002 AUG 1)	3266.487	2.89E+09	5.09E-06	6567.7	0.1623547	9.63E+07	3.66E-08	3.22264
(2003 AUG 1)	3.26E+03	2.89E+09	5.28E-06	6567.712	0.1642514	9.87E+07	3.70E-08	3.302833
(2004 AUG 1)	3258.944	2.89E+09	5.47E-06	6567.713	0.166223	1.01E+08	3.74E-08	3.383246
(2005 AUG 1)	3255.166	2.89E+09	5.66E-06	6567.711	0.1682581	1.04E+08	3.79E-08	3.463439
(2006 AUG 1)	3251.382	2.88E+09	5.85E-06	6567.69	0.1703612	1.06E+08	3.84E-08	3.543632
(2007 AUG 1)	3.25E+03	2.88E+09	6.03E-06	6567.715	0.1725316	1.08E+08	3.89E-08	3.623825
(2008 AUG 1)	3243.783	2.88E+09	6.21E-06	6567.707	0.1747751	1.11E+08	3.94E-08	3.704237
(2009 AUG 1)	3239.977	2.88E+09	6.39E-06	6567.7	0.1770787	1.13E+08	3.99E-08	3.784431
(2010 AUG 1)	3236.167	2.87E+09	6.57E-06	6567.713	0.1794478	1.16E+08	4.04E-08	3.864624
(2011 AUG 1)	3.23E+03	2.87E+09	6.75E-06	6567.699	0.1818817	1.18E+08	4.10E-08	3.944817
(2012 AUG 1)	3228.513	2.87E+09	6.93E-06	6567.707	0.1843869	1.20E+08	4.15E-08	4.025229
(2013 AUG 1)	3224.68	2.87E+09	7.10E-06	6567.7	0.1869494	1.23E+08	4.21E-08	4.105422
(2014 AUG 1)	3220.841	2.86E+09	7.27E-06	6567.714	0.1895751	1.25E+08	4.27E-08	4.185616
(2015 JUN30)	3.22E+03	2.86E+09	7.43E-06	6567.718	0.1920256	1.27E+08	4.33E-08	4.258778



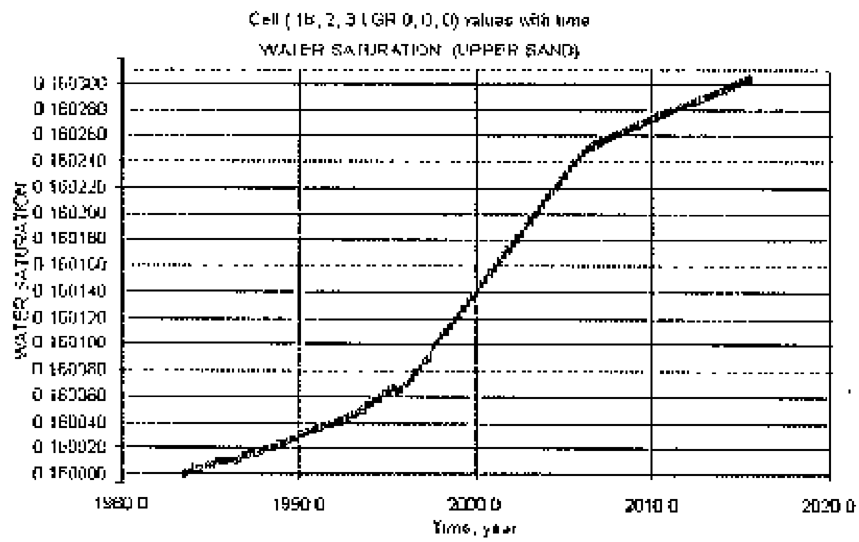


Figure 5.2.1: Upper sand Gas and Water saturation at block no (18,2,3)[17]

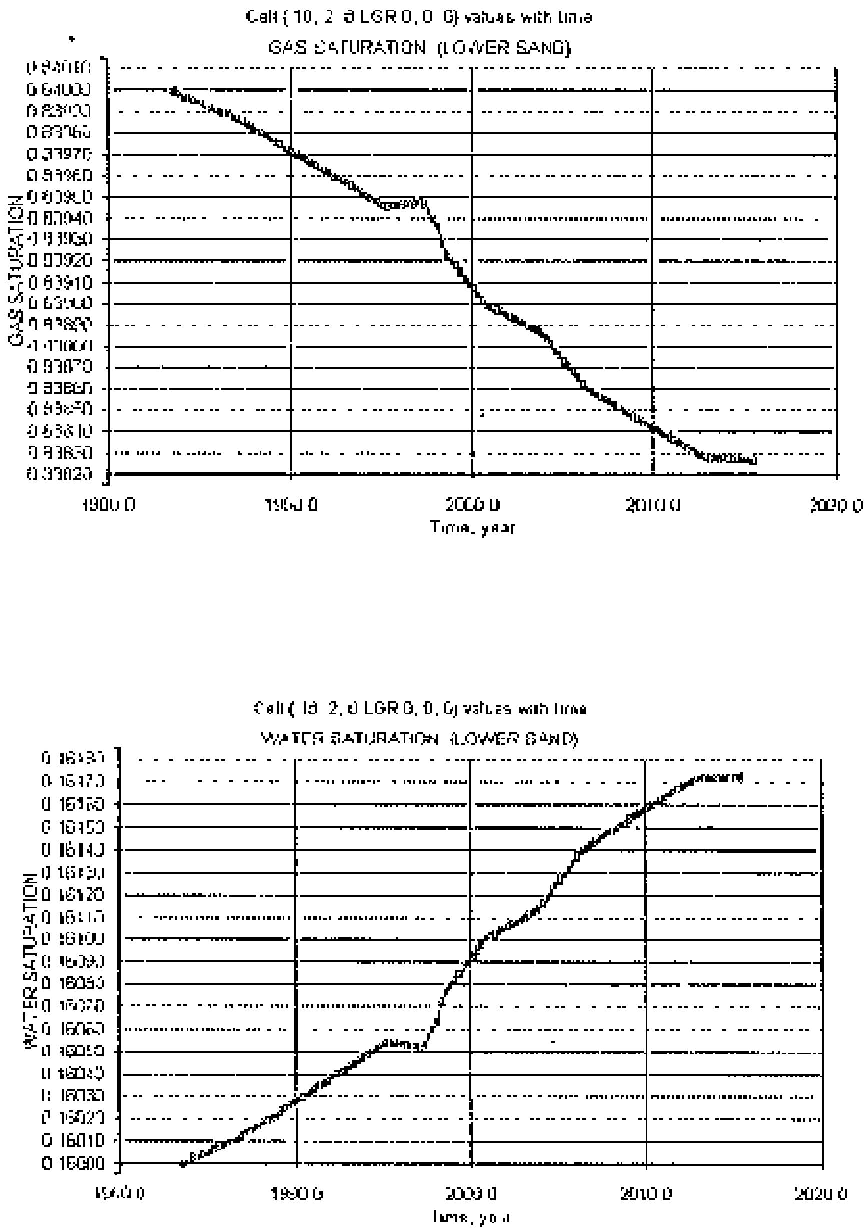
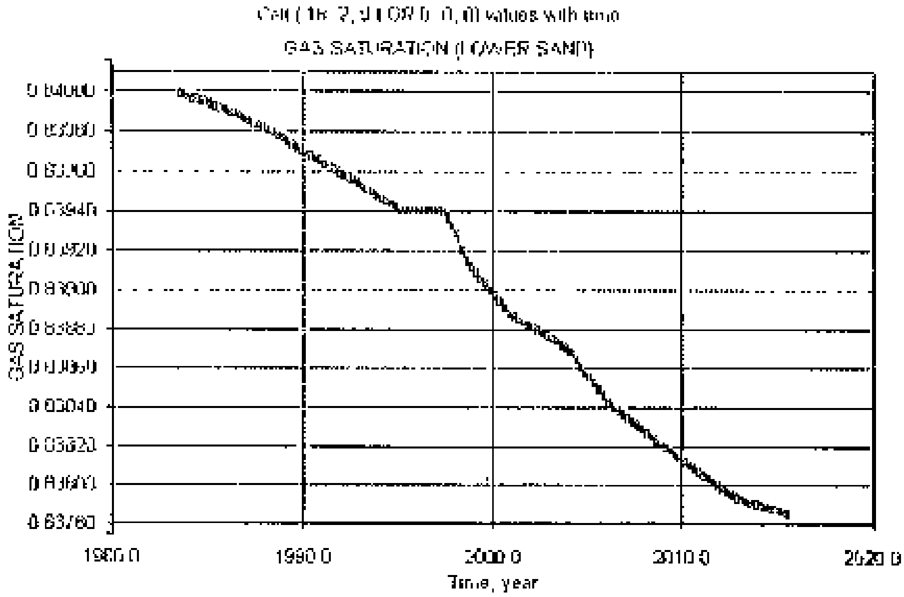


Figure 5.2.2: Lower sand Gas and water saturation at block no (18,2,8)[17]



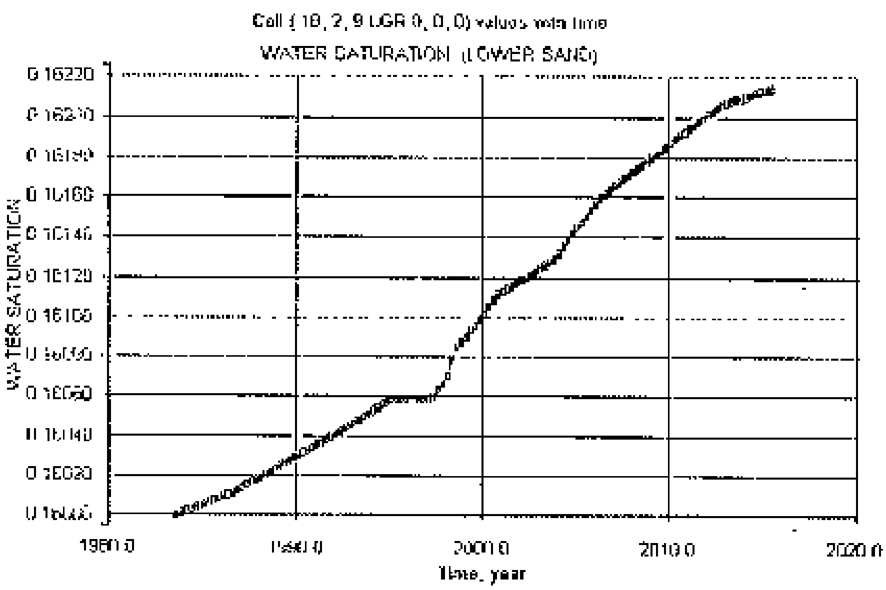


Figure 5.2.3: Lower sand Gas and water saturation at block no (18,2,9)[17]

5.3 Fluid Analysis Results

Fluid analysis is done through Gas Chromatograph and HYSIM simulator Gas chromatograph analysis results are shown on Table 4.3.1 and 4.3.2. Both gas and condensate analysis is done. From the analysis, it has been seen that the reservoir is composed of mainly gas and some condensate of negligible percentage. From HYSIM simulator it has also been seen that the reservoir is gas reservoir. Using the fluid analysis results in RECOMBINATION, which is another software used to combine gas and condensate mole percentage and given a recombined composition This RECOMBINATION is shown on Table 5 3 1.In this table the critical pressure is 661 81 psia and critical temperature is 355 2 R

Table 5.3.1: RENOMBINATION results

Chapter 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

- Using the same grid blocks that were used by IKM the simulation results does not match the actual field data.

- Accommodating the additional volume, denoted by material balance study, in simulation grid blocks, the proved gas-in-place for the upper and lower sands were found to be 2679.9844 Bscf and 309.3316 Bscf respectively. So, the total gas-in-place in KTL1 is 2989.316 Bscf, which are approximately 12 2% more than IKM.

- The most likely mechanism of recovery would be volumetric depletion as no evidence of aquifer support exists at the present time.

- From simulation study and phase diagram, it is found that there is no support for condensate accumulation

- Since no condensate is accumulated near the wellbore, drilling of horizontal well is not a viable option.

6.2 Recommendations

- Additional well effluent sampling and analysis are recommended for the zone as early in the production period as possible to create a statistically valid data base to determine reservoir fluid composition.

- The implementation of a pressure survey program is recommended prior to production from additional wells in the field.

- The implementation of accurate wellstream measurement practices at the Kailashtila facility should be given the highest priority

- In the future, the combination of material balance and reservoir simulation study will help to exploit the reservoir in the most economic way.

NOMENCLATURE

Symbol		Description
BBL	=	Barrel
MMSCF	=	Million Standard Cubic Feet
MMSCFD	=	Million Standard Cubic Feet per Day
STB	=	Stock tank barrel
EOS	=	Equation-of state
Bs	=	Gas formation volume factor, rb free gas/scf gas
B_{gi}	=	Gas formation volume factor at initial reservoir pressure
B_o	=	Oil formation volume factor, rb(oil+dissolved gas)/stb oil
B_{oi}	=	Oil formation volume factor at initial reservoir pressure
c_w	=	Water isothermal compressibility, psi^{-1}
c_f	=	Formation isothermal compressibility, psi^{-1}
f	=	Moody friction factor
G	=	Initial reservoir gas volume
G_p	=	Gas production
M	=	Ratio, initial hydrocarbon volume of the gascap/ initial hydrocarbon volume of the oil
N	=	Initial reservoir oil, stb
N_p	=	Cumulative produced oil, stb
P_{std}	=	Pressure at standard condition
P	=	Reservoir pressure
P_i	=	Initial Reservoir pressure
q_{sc}	=	Gas flow rate at standard condition
R_p	=	Cumulative produced gas-oil ratio

R_s = Solution gas oil ratio, scf gas/stb oil

R_{si} = Solution gas oil ratio at Initial Reservoir pressure

S_{wc} = Connate or irreducible water saturation

T = Temperature

T_{av} = Average Temperature

T_{sc} = Temperature at standard condition

V_f = Total pore volume

Z = Gas compressibility factor

Z_i = Gas compressibility factor at Initial Reservoir pressure

K_r = Relative permeability

Δp = Pressure drop

Δp_c = Capillary pressure drop

γ = Specific gravity

Δt = Length of time step

ρ = Density

q_i = Production rate

ϕ = Porosity

μ = Viscosity

X_{ur} = Mole fraction of the component

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