Study of Natural Gas Processing in Bangladesh

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RECOMMENDATION OF THE BOARD OF EXAMINERS

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It is hereby declared that this project or any part of it has not been submitted elsewhere for the award of any degree or diploma.

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ABSTRACT

Natural gas has been an important indigenous hydrocarbon resource in Bangladesh It is predominant fuel for industries and commercial establishments. The natural gas produced from the reservoir is usually a complex mixture of several hydrocarbons in their liquid and gaseous states, intimately mixed with water Often, solids and other contaminants are also present in the mixture. Therefore, some processing is required for the produced natural gas before it can be brought to the customer.

The gas processing plants constitute a very important segment of the gas industry in Bangladesh. Currently, there are six companies involved in producing gas from fifteen different gas fields in Bangladesh. These companies operate thirty-nine gas processing plants, using a variety of technologies. Different technologies are involved in removing different elements from natural gas Therefore, a gas processing plant must combine the appropriate technologies to address the needs of a specific gas field. The selection and design of a processing plant is extremely important for operating a gas field efficiently and economically. This study takes a closer look at all these plants in Bangladesh. A scrutiny of each plant is presented with a view to identify potential rooms for improvement.

Whereas the knowledge and expertise on one particular plant is available, it is extremely difficult to get a broader perspective of the industry because no comparative literature is available This study attempts to fill in the knowledge base by presenting a comparative study of all the plants currently in operation in Bangladesh. It will be beneficial to all parties interested in the gas processing industry in Bangladesh. It should provide some directives regarding the future of the industry in Bangladesh

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NOMENCLATURE

ADB	Asian Development Bank
BAPEX	Bangladesh Petroleum Exploration & Production
bbl	Barrel
Bcf	Billion Cubic Feet
BD	Bangladesh
BGFCL	Bangladesh Gas Field Company Limited
BGSL	Bakhrabad Gas Systems Limited
BOGMC	Bangladesh Oil Gas Minerals Corporation (Petrobangla)
BOC	Burma Oil Company
BPC	Bangladesh Petroleum Corporation
BTU	British Thermal Unit
CNG	Compressed Natural Gas
CNGV	Compressed Natural Gas Vehicle
DEG	Di Ethylene Glycol
EPZ	Export Processing Zone
ESD	Emergency Shut Down
ESDV	Emergency Shut Down Valve
GIIP	Gas Initially In-Place
GOB	Government of Bangladesh
GOR	Gas Oil Ratio
GTCL	Gas Transmission Company Limited
HCU	Hydrocarbon Unit
HP	High Pressure
HSD	High Speed Diesel
IOC	International Oil Company
IKM	Intercomp-Kanata Management Ltd
JGTDSL	Jalalabad Gas Transmission and Distribution Systems Limited
JVA	Joint Venture Agreement
KW	Kilo Watt
LP	Low Pressure
LPG	Liquefied Petroleum Gas

LNG	Liquefied Natural Gas
LTS	Low Temperature Separation
LTX	Low Temperature Extraction
Mcm	Million Cubic Meter
MEA	Mono Ethanol Amine
MMcfd	Million Cubic Feet per Day
MMscfd	Million Standard Cubic Feet per Day
MS	Motor Spirit
msl	Mean Sea Level
MT	Metric Ton
NG	Natural Gas
NGL	Natural Gas Liquid
NPD	Norwegian Petroleum Directorate
OGDC	Oil & Gas Development Corporation
PCV	Pressure Control Valve
PD	Proportional Differential
PGCL	Pachhimanchal Gas Company Limited
PLC	Programmable Logical Control
POL	Petroleum Oil Lubricants
ppm	Parts Per Million
PPL	Pakistan Petroleum Limited
PSC	Production Sharing Contract
PSOC	Pakistan Shell Oil Company
PSV	Pressure Safety Valve
RPGCL	Rupantarita Prakritik Gas Company Limited
SCADA	Supervisory Control and Data Acquisition
SFYP	Sixth Five Year Plan
SGFL	Sylhet Gas Fields Limited
ss	Sea Surface
Tcf	Trillion Cubic Feet
TD	Total depth
TEG	Tri Ethylene Glycol
TGTDCL	Titas Gas Transmission and Distribution Company Limited
TVD	Total Vertical Depth

CHAPTER I

INTRODUCTION

Bangladesh is considered a gas prone country because of reverine delta having porous and permeable hydrocarbon bearing sand structures and unique condition of traps. Natural gas is and will continue to remain the major indigenous energy source, fueling the national economy Production plans has been drawn up to meet the increasing demand for natural gas by augmenting supply from national gas companies, and increasing purchase from the International Oil Companies, supported by increasing stress on exploration. Since the first use of natural gas in 1960, the consumption of natural gas has been increasing. In the month of August, 2005 the average production was 1405 MMscfd

A typical well stream is a high velocity, turbulent, constantly expanding mixture of gases and hydrocarbon liquids, intimately mixed with water vapor, free water, solids, and other contaminants. The gases in Bangladesh contain sour gases especially H_2S in trace quantity; the processing technology employed need not include special separation system to remove sour gases. The presences of water and liquefiable higher hydrocarbons have to be processed in a suitable gas processing plant to deliver a sale gas of the sales line specification. Numerous processes have been developed for gas processing, based on a variety of chemical and physical principles. A gas processing plant must combine the appropriate technologies to address the needs of a specific gas field. The selection and design of a processing plant is extremely important for operating a gas field efficiently and economically. Today, the gas processing plants attach a great importance to liquid hydrocarbon recovery and it's processing into desired fraction for maximizing revenue

Currently there are six companies involved in producing gas from different gas fields in Bangladesh Out of those, three are owned and operated by the Bangladesh government. The rest are foreign companies, also known as International Oil Companies (IOC). The six companies operate 39 process plants, using different technologies. Each of these processes has merits and demerits considering technology, operation, maintenance, investment etc. Process parameters may need to be modified or sometimes the entire processing system may need to be changed, depending on a variety of reasons such as increasing production through adding more wells to the reservoir, producing for a different reservoir where hydrocarbon composition may change significantly, depletion and consequent relation of well head pressure, change in phase behavior due to depletion etc.

Environment friendly fuel, Liquefied Petroleum Gas (LPG), can be recovered by Natural Gas Liquid (NGL) fractionation The government encourages the private sector to set up new NGL fractionation plant In the field processing, most of the portion of light hydrocarbon flows through sales line, but it is possible to recover by introducing a enhanced hydrocarbon recovery process and supplied as NGL, LPG etc.

The use of natural gas as a raw material for manufacture of petrochemicals is to a certain extent constrained by its composition. Analysis of gas being produced indicates very high methane content with small quantities of higher hydrocarbons. The deficiency of higher hydrocarbons precludes the use of the gas as a raw material for olefin manufacture such as methanol, acetylene and polyethylene etc.

CHAPTER II

STATEMENT OF THE PROBLEM

The gas processing plants constitute a very important segment of the gas industry in Bangladesh They produce pipeline quality gas as well as recover valuable condensable higher hydrocarbons including Liquefied Petroleum Gas (LPG) components. Recovery of higher hydrocarbons improves the economics of operation by producing more valued products such as Natural Gas Liquids (NGL), for which there is an expanding market. The thirty-nine gas processing plants in operation were designed employing variety of processing technologies. A gas processing plant must combine the appropriate technologies to address the needs of a specific well or gas field Each of these processes has merits and demerits considering technology, operation, maintenance, investment etc. Whereas the knowledge and expertise on one particular plant is available, it is extremely difficult to get a broader perspective of the industry because no comparative literature is available. This study takes a closer look at these plants in Bangladesh and presents a comparative study.

1.1 Objectives

The main objectives of this study are as follows:

- To obtain an overview of the current state of the natural gas processing industry in Bangladesh.
- To describe the overall processing methods as practiced in different processing. plants.
- To examine the appropriateness of selection of the process plants.
- To study the performance of each process plant with respect to capacity, operational break down, recovery of liquid hydrocarbon etc.
- To conduct a comparative study of these plants

1.2 Methodology

This study adopted the following methodology in order to accomplish the stated objectives.

- Collect the process manual/Operational manual and other relevant documents from every gas field
- Collect data about major break-down/maintenance work, production history etc.
- Summarize information and justify the appropriateness of process plant selection
- Analyze and compare these processes and point out the major differences
- Analyze the production history and find out the quality control and performance of these process plants

CHAPTER III

OIL & GAS EXPLORATION AND PRODUCTION IN BANGLADESH

3.1 Exploration for Oil and Gas

Bangladesh constitutes one of the largest delta of the world has proved its hydrocarbon potentiality through discovery of 22 gas fields and one oil field during the course of drilling only 66 exploration wells over a period of 96 years of sporadic exploration. Because of reverine delta having porous and permeable hydrocarbon bearing sand structure and unique condition of trap, Bangladesh is always considered a gas prone country. Due to resource constraints, the exploration activities were kept to a bare minimum. In spite of a slow exploration pace, the success ratio is 2.75: 1 (Brochure, Petrobangla, 2000). Hydrocarbon exploration activity has been continuing in this territory since the later part of the 19th century. Various national and international companies carried out exploration in the potential areas of Bangladesh.

Exploration activities took place in three phases. These phases are divided on the basis of different administrative regimes such as British, Pakistan and Bangladesh. Exploration activities of three phases are shown in Table 3.1.

Table 3.1: Exploration Activities In Bangladesh.

Phase	Number of Well	Discovery	Exploration Basis
I (1908-1933) British Period	6	None; minor oil flowed at Patharia	Near seep
II (1947-1971) Pakistan Period	22	8 Gas fields	Seismic and other early geophysical methods
III (1971-2004) Bangladesh Period	34	14 Gas fields, 1 Oil field	Digital Seismic (2D & 3D)
Total	66	22 Gas fields, 1 Oil field	

3.1.1 Phase-I (British Period)

The search of oil and gas in the area constituting Bangladesh began in the later part of the 19th century through some isolated geological mapping. In the early days (1910-1933) of exploration, drilling was mainly concentrated near seeps in the fold belt. At this stage shallow wells ranging from 763 to about 1,047 meters were drilled. The first serious attempt to find oil and gas was undertaken in Sitakund in 1908 by the Indian Petroleum Prospecting Company (IPC). This Company drilled three exploratory shallow wells near Sitakund on the Sitakund structure between 1,908 and 1,914. The Burma Oil Company (B.O.C.) also drilled an exploratory shallow well in 1,914 in the same structure. During 1923-33 BOC drilled two shallow wells in Patharia. The wells were abandoned though there was a reported occurrence of oil. In this phase, total Six exploratory wells were drilled, the deepest being 1,047 meters. No commercial gas/oil field was discovered in that phase (Saleque, 2001). Phase-I exploration activities are shown in Table 3.2

Table 3.2: Phase-I Exploration Activities.

SI. No.	Well Name	Operator	TD (meter)	Formation at TD	Date of Completion	Status
01,	Sitakund -1	I.P.C	762	Bhuban	1914	Plugged & Abundant (P & A), oil show
02.	Sitakund -2	I.P.C.	-	Bhuban	1914	P&A
03.	Sitakund -3	I.P.C.	-	Bhuban	1914	P&A, oil show
04.	Sitakund -4	B.O.C.	1024	Bhuban	1914	P&A, oil show
05	Patharia –1	B.O.C.	875	Bhuban	1923	P&A
06	Patharia –2	B.O.C.	1047	Bhuban	1933	P&A

3.1.2 Phase II (Pakistan Period)

During the second phase early forms of modern geophysical methods were used for the first time. Gravity and surface magnetic reconnaissance survey were followed by single fold seismic studies supplemented by geological information from wells and outcrops in the surrounding areas (Saleque, 2001). The promulgation of Pakistan Petroleum Act in 1948 infused interest of international oil companies in oil and gas exploration. Phase-II exploration activities are shown in Table 3.3.

Table 3.3 : Phase-II Exploration Activities.

Sl. No	Well Name	Operator	TD (meter)	Formation at TD	Date of Completion	Status
01	Patharia-3	PPL	1649	Bhuban	10 12 51	Oil show
02	Patharia-4	PPL	830	Bhuban	23 02.53	P&A
03	Patiya-1	PPL	3102	Bhuban	14 09.53	P&A
04	Sylhet-1	PPL	2379	Bhuban	12 05.55	P&A
05	Sylhet-2	PPL	2819	Bhuban	07.10.56	Blow-out, P&A
06	Lalmai-1	PPL	2993	Bhuban	11.02.58	P&A
07	Chattak-1	PPL	2135	Bhuban	14.04.59	Gas well
08	Kuchma- 1	Stanvac	2875	Gondwana	21.06.59	P&A
09	Bogra-1	Stanvac	2187	Basement	08.02.60	P&A
10	Fenchugonj-1	PPL	2438	Bhuban	14.04.60	P&A
11	Rashidpur-1	Shell	3860	Bhuban	20.07.60	Gas well
12	Hazipur	Stanvac	3816	Barail	05 09.60	P&A
13	Lalmai-2	PPL	4117	Bhuban	27 10 60	P&A
14	Kailastila-1	Shell	4139	Bhuban	22 03 62	Gas well
15	Titas-1	Shell	3758	Barail	23.08.62	Gas well
16	Habigonj-1	Shell	3508	Bhuban	22.05.63	Gas well
17	Jaldi-1	OGDC	2300	Bhuban	10.03.65	P&A
18	Jaldi-2	OGDC	3360	Bhuban	27.11.66	P&A
19	Semutang-1	OGDC	4088	Bhuban	22.05.69	Gas disc.
20	Bakhrabad-1	Shell	2838	Bhuban	09.06.69	Gas disc.
21	Jaldi-3	OGDC	4500	Bhuban	25 05 70	P&A
22	Cox's Bazar	Shell	3698	Bhuban	16 03 69	P&A

The Standard Vacuum Oil Company (STANVAC) of USA, Pakistan Petroleum Ltd. (PPL) a Burmah Oil Company affiliate and Pakistan Shell Oil Company (PSOC) took up concessions during early fifties and carried out exploration till the end of sixties. STANVAC drilled 3 wells at Hazipur, Bogra and Kuchma in the northwestern part of the country without success. PPL drilled wells in Sylhet, Patharia, Chhatak, Fenchuganj, Patiya and Lalmai, and made the first gas discovery in Haripur in 1955 followed by Chhattak in 1959. PSOC was the most successful company and discovered the 5 gas fields of Titas, Habiganj, Rashidpur, Kailashtila, and Bakhrabad; they also drilled the first offshore well Cox'sbazar -1, which was dry. During this time Oil and Gas Development Corporation (OGDC) was established in the national sector in 1961 and the root of exploration for oil and gas were set up in the country. OGDC carried out geological and geophysical survey including gravity, magnetic and seismic, and drilled wells in Jaldi and Semutang, discovering gas in Semutang in 1970. The operators of the second phase drilled 22 exploratory wells, thereof one offshore, and discovered eight gas fields.

3.1.2 Phase III (Bangladesh period)

Bangladesh Oil, Gas and Mineral Corporation (Petrobangla) continued its exploration efforts while the Bangladesh Petroleum Act was enacted in 1974 to facilitate international participation under Production Sharing Contact (PSC). The offshore area of Bangladesh was divided into 6 blocks, which were, taken up by Ashland, Atlantic Richfield Company (ARCO), BODC (JAPEX), Union Oil, Canadian Superior Oil and Ina-naftaplin (Yougoslav state oil) under production sharing contract. These companies carried out gravity, magnetic and seismic surveys for about 32,000 km and drilled 7 wells. Only Union Oil Company discovered an offshore gas field in 1977 in Kutubdia. This phase of PSC ended with relinquishments by 1978 (Annual Report, Petrobangla, 2003).

In 1981 Shell Oil Company was awarded the Chittagong Hill Tracts for petroleum exploration under PSC. Shell conducted geological and seismic survey and drilled the Sitapahar well, subsequently Shell undertook exploration in the extreme north west of the country and drilled the first well in the area. The well Salbanhat was dry. In 1988 Scimitar Exploration was awarded what is now block 13 in Surma basin They failed to prove the extent of the oil discovery at Sylhet structure but discovered the Jalalabad gas field.

The 1980's saw accelerated exploration activities by Petrobangla, which drilled exploration wells in Muladi, Begumganj, Singra, Beanibazar, Atgram, Feni, Fenchuganj, Sitakund, Bogra, Kamta, Marichakandi (Meghna), and Belabo (Narshingdi) and discovered 7 gas fields in Begumganj, Beanibazar, Feni, Fenchuganj, Kamta, Marichakandi (Meghna), and Belabo (Narshingdi). Among these fields, Fenchuganj well remains the deepest drilled well in Bangladesh (4977m). Meanwhile a new milestone was achieved when Petrobangla discovered the first commercial oil pool in Sylhet on December 23, 1986. From 1989, BAPEX has continued exploration for Petrobangla, and drilled 3 exploratory wells discovering gas in Shahbazpur and Saldanadi

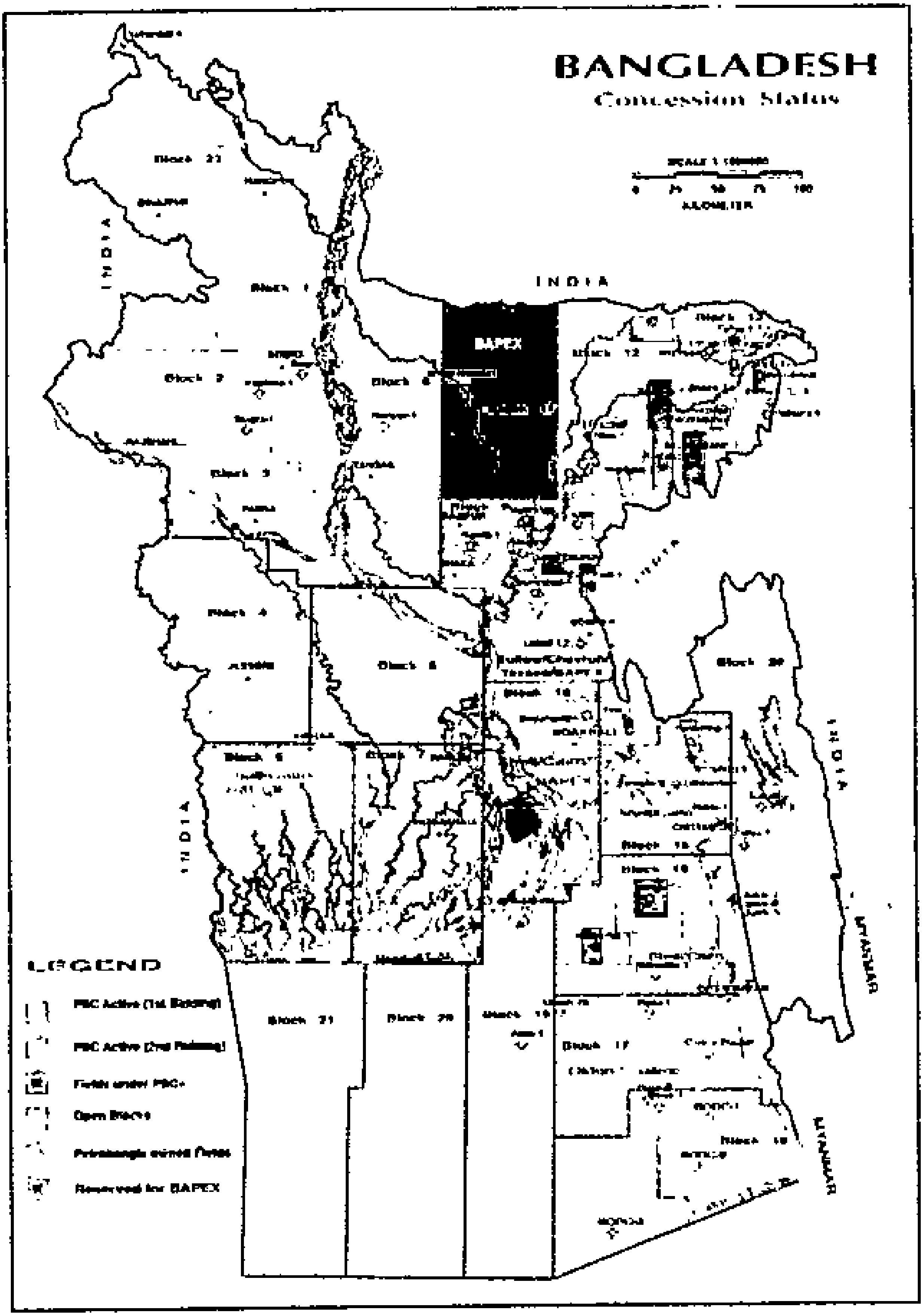


Figure 3.1: Block Map of Bangladesh.

A Model Production Sharing Contract (MPSC) was prepared in 1988, which was revised in 1993 under Petroleum Policy. The offshore and onshore areas of Bangladesh were divided into 23 blocks, which were shown in Figure 3.1. Under the 1993/94 awards, Block numbered 12, 13 and 14 were awarded to Occidental (now Unocal Bangladesh), Blocks 15 and 16 to Cairn Energy, blocks 17 and 18 to Rexwood/ Okland (now operated by Tullow oil) and block 22 to UMC (now operated by Ocean Energy). Under these PSCs the respective operators have conducted varying amount of exploration and development works In Blocks 12,13 and 14, a total of 5 exploratory wells were drilled and two discoveries were made (two by Unocal at Bibiyana and Moulvibazar). There was a massive blow in MB-1, resulting in major loss of hydrocarbon and other surface assets. The previously discovered Jalalabad field was developed and is in production since 1998. In Blocks 15 and 16, the operator drilled 6 exploratory wells including 4 offshore wells, resulting in discovery of offshore Sangu Gas Field. This field has been developed and is in production since 1997 In Blocks 17 and 18 a single offshore well was found dry. There was practically no exploration work in block 22. With the discovery of a gas structure in the Bay of Bengal by Anglo Dutch joint venture company Cairn- Shell in 1996, Bangladesh attained the world focus and was being thought to become a happy playground of the major oil companies. As a result, there was tremendous response in the second bidding round for selecting International Oil Companies (IOC) for exploration in the 15 (fifteen) blocks. It may be mentioned that 8 (eight) blocks were in first round and 4 (four) blocks are in second round bidding that have been leased out under PSC

Significant parts or whole of these blocks are now relinquished as per contract. Under the second bidding rounds, four blocks have been awarded. Unocal Bangladesh was awarded block 7, Shell/Cairn JV was awarded blocks 5 and 10 with a 10 % carried stake for BAPEX, and Tullow/Chevron/Texaco JV was awarded block 9 with a 10 % carried stake for BAPEX.

Between 1972 and till now, a total of 36 exploratory wells were drilled by the national and international companies, which resulted in the discovery of 13 gas fields. Since the first exploration well was drilled in 1908 a total of 128 wells have been drilled in Bangladesh till 2004, of which 66 are exploration wells. Phase-III exploration activities are shown in Table 3.4 and 3.5

Table 3.4 : Phase-III Exploration Activities (on shore)

Sl. No.	Well Name	Operator	TD (meter)	Formation at TD	Date of Completion	Status
01	Muladi-1	Petrobangla	4732	Bhuban	16.12.76	P&A
02	Begumgonj	Petrobangla	3655	Bhuban	27 01.77	Gas disc
03	Muladi-2	Petrobangla	4556	Bhuban	15.01.81	P&A
04	Singra-1	Petrobangla	4100	Gondwana	30.04.81	P&A
05	Feni	Petrobangla	3200	Bhuban	26.06.81	Gas disc.
06	Beanibazar	Petrobangla	4109	Bhuban	12 05 81	Gas disc
07	Kamta	Petrobangla	3614	Bhuban	16.03.82	Gas disc.
08	Atgram-1	Petrobangla	4961	Barail	10.06.82	P&A
09	Fechugonj-2	Petrobangla	4977	Bhuban	28.04.88	Gas disc.
10	Shalbabhat	Shell	2518	Basement	16.06 88	P&A
11	Sitakund-5	Petrobangla	4005	Bhuban	10.10.88	P&A
12	Sitapahar	Shell	1560	Bhuban	06.12.88	P&A
13	Bogra-2	Petrobangla	2100	Bhuban	05.12 89	P&A
14	Jalalabad	SCIMITAR	2626	Bhuban	13.11.89	Gas disc.
15	Meghna	Petrobangla	3069	Bhuban	07 07.90	Gas disc
16	Narshingdi	Petrobangla	3450	Bhuban	08.10 90	Gas disc.
17	Patharia-5	BAPEX	3438	Bhuban	20.07.92	P&A
18	Shahbazpur	BAPEX	3342	Bhuban	1995	Gas disc.
19	Saldanadi	BAPEX	2511	Bhuban	1996	Gas disc.
20	Sylhet-7	Petrobangla			1986	Oil disc.
21	Bibiyana-1	Occidental	4014	Bhuban	1998	Gas disc
22	Bibiyana-2	Oxy/Unocal	4276	Bhuban	1999	Gas disc.
23	MB-1	Occidental	840		1997	Blow-out
24	MB-2	Occidental	3510		1999	Gas disc.
25	Kapna-1	Occidental	3149		1999	P&A
26	Ratna-1	Occidental	3835		1999	P&A
27	Kasalong-1	UMC	3500		1999	P&A
28	Lalmai-3	Tullow		Bhuban	2003	
29	Vangura-1	UMC			2004	
30	Srikail-1	BAPEX			2004	

Table 3.5 : Phase-III Exploration Activities (off shore)

Sl No	Well Name	Operator	TD (meter)	Formation at TD	Date of Completion	Status
01	ARCO-1	ARCO	3903	Bokabil	29.05,76	P&A
02	Bina-1	INA	4095	Bokabil	30 03.76	P&A
03	Bina-2	INA	4294	Bokabil	01.03.77	P&A
04	BODC-1	BODC	4598	Bokabil	10.03.76	P&A
05	BODC-2	BODC	4436	Bokabil	17 06 76	P&A
06	BODC-3	BODC	4488	Bhuban	20 03 78	P&A
07	Kutubdia	Union oil	3508	Bhuban	16 01 77	Gas disc.
08	Sangu-1	Cairn	3500	Bhuban		Gas disc.
09	Halda-1	Cairn	4519		1998	P&A
10	Reju-1	Oakland	4450		1999	P&A
11	Swandip East	Cairn				

3.2 Production History

Utilization of natural gas started in Bangladesh since 1962 with the commencement of gas supply to Chatak Cement Factory from Chatak Gas Field Almost simultaneously gas was supplied from Haripur Gas Field to Fenchugonj Fertilizer Factory. Today, fifteen gas fields are producing gas from 63 wells and the average gas production from all fields are 1405 MMSCFD (August, 2005). In Table 3.6 and 3.7, yearly production of gas and condensate of all fields since inception, are shown.

Table 3.6: Yearly Gas Production History of Different Fields

Figures in MMcf

Year	BGFCL							BAPEX		SGFL					Unocal		Cairn	Total Bcf
	Titas	Habiganj	Bakhrabad	Kamta	Feni	Narshingdi	Meghna	Saldanadi	Fenchuganj	Sylhet	Chattak	Kailastila	Rashidpur	Beani Bazar	Jalalabad	Molavi Bazar	Sangu	
1960										22								0
1961										1476	728							2.2
1962										3433	770							4.2
1963										5642	921							6.5
1964										5205	721							5.9
1965										5761	489							6.3
1966										5536	544							6.1
1967										6970	923							7.9
1968										5934	697							6.6
1969	1154	3149								5635	710							10.6
1970	8684	3567								5571	642							20.5
1971	4122	1827								4197	282							10.4
1972	9904	3597								4900	491							18.6
1973	17427	3159								4313	380							25.3
1974	14682	2590								5797	905							23.9
1975	15313	2133								5128	1037							23.8
1976	22965	2206								5271	977							31.3
1977	21716	2797								5908	1477							31.9
1978	24543	5111								4595	1764							36
1979	29659	5280								6139	1777							42.9
1980	32250	5644								7091	2070							47.1
1981	37035	10220								7107	1979							56.5
1982	45033	14455								7024	1658							65.23
1983	52791	15504								5187	2064	1939						76.6
1984	50260	17657	2343	474						3828	1744	3781						90.1
1985	49032	25944	11343	5444						2962	180	5364						100.3
1986	48132	32498	19390	5144						3491		5040						114
1987	56904	34603	29880	3715						4068		5982						135.2
1988	64553	31908	40159	3153						4264		6579						150.6
1989	70065	32940	47055	1204						2895		7375						167.5
1990	81493	28251	49487	1241						1847		7845						170.5
1991	81527	26579	52779	763	2324					1802		8052						173.8
1992	99911	40723	51504		6972					1708		7309						208.2
1993	90222	59114	47749		6631					1272		9241	2075					224.3
1994	95102	51921	49885		5384					2133		9744	23483					233.7
1995	98541	57413	52771		9445					1948		12411	27708					260.2
1996	101590	57579	49405		6326	3807				2048		17411	26551					264.6
1997	105811	59393	32379		3025	6500	9561			1975		25042	29357					287
1998	108216	60284	28288		242	6996	8597	4526		1937		33256	28780				12288	290.3
1999	106011	69858	14071			6589	8619	5262		1951		30255	28114	3365	21857		37785	318.7
2000	115396	86721	12598			5965	6335	5470		1924		32693	29571	1320	31108		45447	354.2
2001	119233	80743	12542			5923	4077	5432		1923		29550	35879	2218	30442		50408	388.3
2002	130600	85274	12575			5381	3078	5592		1884		27382	36269	7676	32080		51795	404.8
2003	135699	101501	12867		Niko	8053	1783	5809		1934		26108	37781	8257	43900		51521	435.4
2004	114205	108382	12679		1152	7225	1362	5829	4817	1970		20797	34205	8825	67218	994	45274	467.8
2005	99159	87938	8454		7587	4587	778	3722	10670	3111		13180	20569	4803	44681	12844	33766	336.2
Total	2418809	1276040	644711	21139	49082	58142	34380	41638	15587	178820	25834	347205	361652	36186	271272	13827	330945	6124.5

Table 3.7 : Yearly Condensate Production History of Different Fields

Figures in bbls

Year	BGFCL							BAPEX		SGFL					Unocal		Cairn	Total
	Titas	Habiganj	Bakhrabad	Kamta	Feni	Narshingdi	Meghna	Saldanadi	Fenchuganj	Sylhet	Chattak	Kailashtila	Rashidpur	Beani Bazar	Jalalabad	Molavi Bazar	Sangu	000'bbl
1964										6559	14							6.6
1965										21049	38							21
1966										19434	37							19.4
1967										25294	49							25.3
1968										21220	41							21.2
1969	1752	269								21536	49							22.7
1970	14716	311								19815	43							34.9
1971	7517	67								12692	12							20.3
1972	16331	131								17064	37							33.5
1973	28247	93								14571	22							42.9
1974	24027	60								20098	74							44.2
1975	26758	67								18237	83							45.2
1976	38518	114								18547	79							57.2
1977	36541	191								20087	127							56.6
1978	39288	215								13147	139							52.7
1979	43300	210								7884	144							51.5
1980	45439	432								21709	167							68.1
1981	50742	798								21357	158							72.7
1982	63607									20031	116							84.6
1983	71605	804								12660	99	11756						97
1984	82502	916	1654	121						10533	37	43901						139.2
1985	88250	1268	7190	1027						7470	14	61797						146.9
1986	70136	1747	18773	903						8142		59678						159.3
1987	73812	1845	54935	806						11633		69493						218.5
1988	100675	1483	59379	532						6956		73012						242.1
1989	109547	1489	66459	252						8067		75624						261.5
1990	105470	1258	96509	263						7283		78110						289
1991	118747	1308	93844	147	6648					10185		80697						311.4
1992	136991	2018	94718		16694					12938		71618						334.9
1993	134407	2788	75328		16807					5320		90035	228					324.9
1994	130088	2578	70362		11383					7903		103842	34015					306.7
1995	129761	2982	82821		16083					7208		142978	42070					403
1996	128480	3076	60317		15497	8200				7604		242055	37450					503
1997	128154	3052	45845		4838	15018	8032			7603		343947	43877					600.9
1998	123394	3078	38425		309	15428	11077	3893		7525		415873	42878					658.9
1999	116375	3239	17513			14291	11159	4502		6704		378197	35768	49780	357 524			999.1
2000	149149	3446	12208			13687	9033	4149		6957		449446	42319	18280	400 722			1111
2001	170604	4766	90545			15804	6145	4289		7227		475304	54973	37682	488532			1143 2
2002	160207	5180	70800			12903	3357	5005		7098		437405	54138	140897	457184			1011
2003	165989	5848	83110			13944	2803	5557		7227		284277	53208	152629	458135			1984
2004	135620	6123	83868		2400	11500	1422	3831	1179	5340		199843	33793	169832	674494			2245
2005 (Aug)	120604	4022	9017		8089	10329	697	2997	3232	21169		110424	25071	62435	420424	13463		832
Total 000' bbl	3230	67	910	4	97	133	53	35	5	642	2	4280	513	815	2907	13		13475

CHAPTER IV

OVERVIEW OF GAS PROCESSING IN BANGLADESH

There are six companies including International Oil Companies (IOC) who produce and process gas from fifteen gas fields in Bangladesh. These companies operate a total of 63 wells, and 39 process plants The companies are

1. **Bangladesh Gas Fields Company Limited (BGFCL):** It owns seven gas fields, namely, Titas, Habigonj, Bakhrabad, Narshingdi, Meghna, Feni and Kamta. The production from the Kamta and Feni fields were suspended and now Niko, a Canadian company operates Feni field. BGFCL operates 24 gas processing plants and 3 fractionation plants at 8 sites.

2. **Sylhet Gas Fields Limited (SGFL):** It owns five gas fields, namely, Haripur (Sylhet), Kailashtila, Rashidpur, Beanibazar and Chhatak. The production from the Chhatak field was suspended and now the development work is being done by Niko. SGFL operates 8 gas processing plants at 5 sites. It also operates one fractionation plant

3. **Bangladesh Exploration & Production Co. Ltd. (BAPEX):** it owns five fields, namely Saldanadi, Fenchuganj, Shabajpur, Semutung and Begumganj It operates only Saldanadi and Fenchuganj using two plants at two sites.

4. **UNOCAL Bangladesh Ltd. (UNOCAL):** It owns three gas fields, namely, Jalalabad, Maulavibazar and Bibiyana It produces gas from the Jalalabad and Moulavi Bazar fields.

5 **Cairn Energy Plc:** It operates two gas processing plants in Sangu field. Processing operation is done on land.

6.**Niko Resources Ltd.:** It operates Feni field using two process plants

Cairn Energy and UNOCAL are international oil companies (IOCs) operating under Production Sharing Contract (PSC) and Niko operates under the Joint Venture Agreement (JVA) with BAPEX

The total processing capacity of the plants combined, excluding the Moulabibazar plant is about 2680 MMscfd. The total production capacity of all the wells, with respect to the target production in 2005-06, is about 1436 MMscfd As of August 2005, the total production from all fields is 1405 MMscfd, out of which 1389 MMscfd is sold to the distribution companies. The contribution to total production by each company is shown in Table 4.1.

Table 4.1 : Contribution to Natural Gas Production by Different Companies.

Fiscal Year	Total Production (Bcf)	Percentage of total production (%)					
		BGFCL	SGFL	BAPEX	UNOCAL	CAIRN	NIKO
1999-00	332.4	61	19	-	8	13	-
2000-01	373.7	61	18	-	8	13	-
2001-02	391.5	60	18	2	8	12	-
2002-03	421 2	59	18	2	9	12	-
2003-04	452.8	59	16	1	13	11	-
2004-05	486.8	57	13	4	15	10	1

Number of wells, production capacity and present production rate of different gas fields are shown in Table 4.2.

Table 4.2 : Field Wise Production Rate of Natural Gas.
(MIS Report. Petrobangla, August, 05)

Operator	Producing Gas Fields	No. of Wells	No of Producing Wells	Capacity of Plant (MMcfd)	Average Daily Producing Capacity (MMcfd)	Average Daily Production (MMcfd) August, 05
BAPEX	Fenchuganj	2	2	60	47	45.2
	Salda Nadi	2	1	20	14	15
BGFCL	Bakhrabad	8	4	240	35	34.7
	Habigonj	10	9	360	300	275.7
	Meghna	1	1	40	3 5	3.4
	Narshingdi	1	1	60	20	19.7
	Titas	14	14	660	415	404.9
SGFL	Beanibazar	2	2	60	30	21.9
	Kailashtilla	4	3	120	57	54.6
	Rashidpur	7	7	220	82	82.2
	Sylhet	7	2	30	20	19.2
UNICOL	Jalalabad	4	4	130	140	146.5
	Moulavi Bazar	4	4	-	70	102 7
Cairn	Sangu	7	6	520	172	148.7
NIKO	Feni	5	3	40	30	30 5
	Total	**78**	**63**	**2680**	**1436**	**1405**

The available processing capacity cannot be fully utilized for various reasons. The older processing plants cannot handle the name plate gas flow rates and the separation of liquefiable HC is not satisfactory leading to condensation of remaining liquefiable HC inside the transmission lines. Sometimes, the wells cannot deliver enough gas. On the other hand, the pressure and temperature of the wellhead gas are significantly different from those used in the design of the process plants. Moreover, with the depletion of reserve the gas composition has also changed.

4.1 Gas Fields in Bangladesh

The demand of fuel in Bangladesh is being met by produced gas and by imported POL by government. Since the first use of natural gas· 1960, over the year natural gas is predominant fuel for industries & commercial establishments Now, natural gas is produced from fifteen gas fields out of discovered 22 gas fields and one oil field. The locations of different fields are shown in Figure 4.1 A brief description of each field is presented in alphabetical order as follows.

4.1.1 Bakhrabad Gas Field

The Bakhrabad Gas Field is located approximately 41 miles east of Dhaka. In 1981 Bakhrabad Gas Systems Ltd (BGSL) was formed to develop, produce, transmit and distribute gas from this field. In 1989 Petrobangla reorganized its operational activities and as part of that Bakhrabad Gas Field was handed over to BGFCL.

Bakhrabad was discovered by Pakistan Petroleum Ltd.(PPL) using gravity survey in 1953. The Bakhrabad Field was the last gas discovery in the Bengal folded belt by the Shell in 1968 of drilling BK-1.The field have five major pay zones, 'B' (5905 – 5993 ft), 'D' Upper (6363- 6445 ft), 'D' Lower (6475-6545 ft), 'G' (6823–6965 ft) & 'T' (7001-7331 ft) constituting more than 95 percent of in-place reserves The reserves of the five remaining minor reservoirs, namely 'A', 'C', 'F', 'K' and 'L'. The reserves of the 'A', 'K' and 'L' Sands are classified as possible reserves.

The first stage of development drilling involved work over BK-1 and drilling four deviated wells BK-2, BK-3, BK-4 and BK-5 by JAPEX in 1981 - 1982 from the same pad as BK-1. The latest round of drilling was under the auspices of ADB in 1989 that drilled three deviated holes; BK-6, BK-7, and BK-8. BK-6 was drilled from a separate pad approximately 1590 feet northeast of BK-1and the J sand.

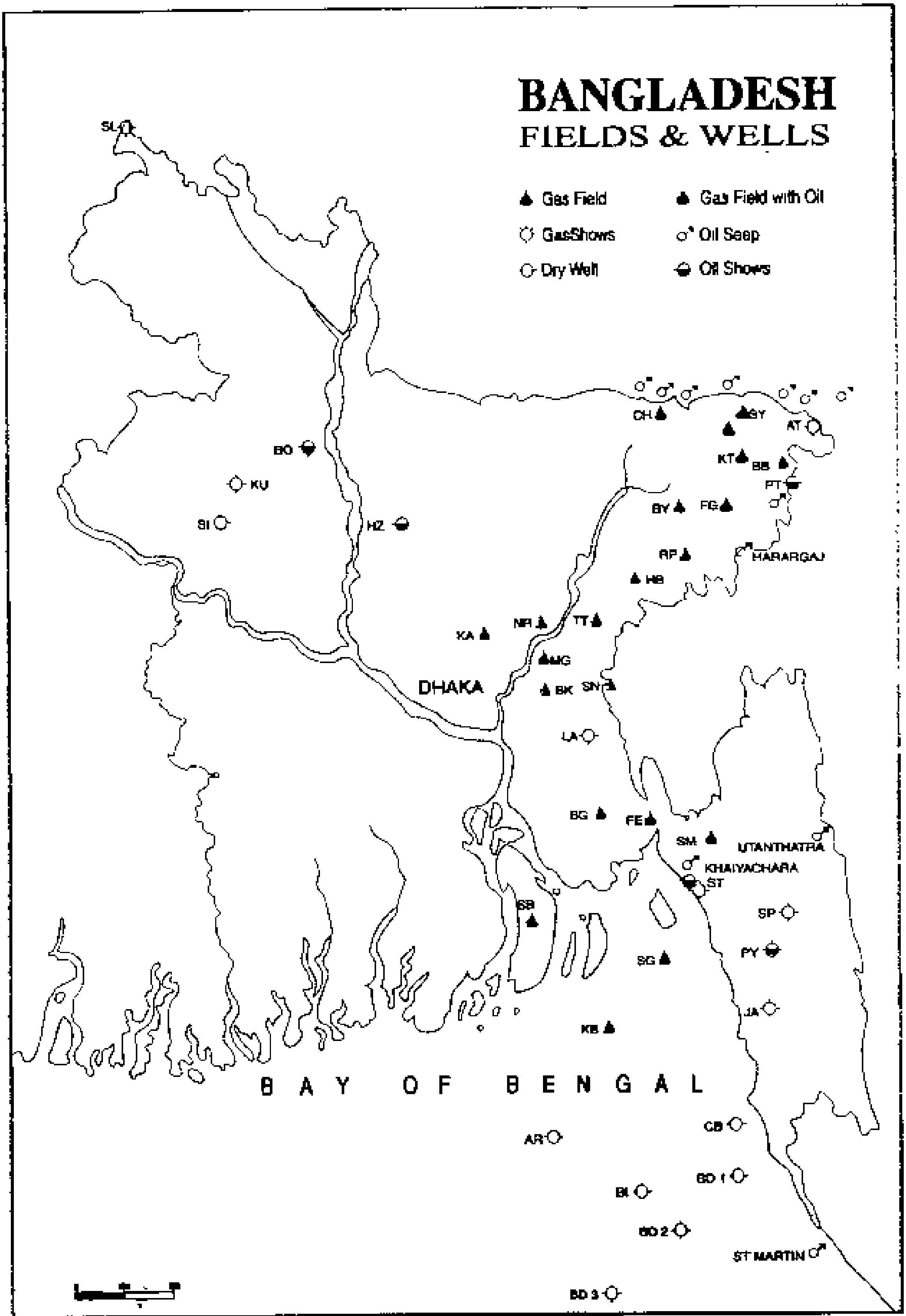


Figure 4.1: Location Map of Fields and Wells in Bangladesh.

The reservoir fluid of all produced Bakhrabad reservoirs is non-retrograde at reservoir temperature. The Bakhrabad Gas Sands contain a dry gas of relatively uniform composition The compositional data contains an even lower variation in composition between reservoirs with C_1 ranging from 93.6 to 94.0 percent and C_{5+} from 0.44 to 0.47 percent. The reservoirs contain a relatively uniform lean gas with a liquid-gas ratio of 2.0 bbl/MMscf (based on production history).

Production from Bakhrabad started in May 1984 when well 2 (D Lower sand) started flowing gas was shut down in June 1999 due to high water production In October 84 Well 5 (B sand) started producing and was suspended in July 1994 due to excessive water production. The well was re-completed in D Lower sand and production started in December 1994 and was suspended again in June 1997 due to excessive water production. Well 1 (J Sand) was placed under production in August 1985. Well 3 (G) and 4 (D upper) were opened for production in October 1986 In June 1992 the well 4 was shut in due to high water cut and was recompleted in G Sand but this well produced water at a higher rate than before. Production from this well again shut off after a short period. In October 1994 well 4 was recompleted again in G sand but the well started to produce water at a higher rate than before and ultimately was shut off in June 1998. Production from well 6,7 and 8 (J sand) were started since December 1989 and well 6 was suspended in August 1998 due to excessive water production Currently well 1,7 and 8 are producing from J sand and well 3 from G sand. The field has been supplying gas to Bangladesh consumers on a continual basis with total gas and condensate production of 644.711 Bcf and 918000 bbl to 31 August 2005, respectively.

In 1984 Glycol Dehydration Plant was installed for production of raw gas in this field. In October 1986 after installation of Silica gel plants, Glycol plant was relocated in Norshingdi Gas Field Now, the gas process facilities consist of four 60 MMcfd Silica gel Dehydration trains An absorption type process plant installed at Bakhrabad field shown in Figure B-1. Adsorption type process plant is used to remove hydrocarbon, water and contaminants from gas streams and to recover hydrocarbon As solid desiccant silica gel is used in this type of plant. The trains are identical although the fourth train, Train 'D', brought on stream in December 1989, employs a pre-cooler to cool the gas prior to processing.

Silica-gel plants of this field have a booster compressor for the regeneration gas for processing in "Closed Cycle". In a closed cycle regeneration gas from gas scrubber is compressed then combine with high pressure partial portion of gas stream of filter separator and then passing through gas-gas heat exchanger to oil bath heater to regeneration tower. In open cycle operation regeneration gas direct combine with adsorption tower Beside in this process regeneration gas cool by gas-air cooler then gas-water cooler but silica-gel process plant of Fenchuganj, Rashidpur, Beani-bazar regeneration gas cool only by gas-air cooler.

4.1.2 Beani Bazar Gas Field

The Beani Bazar field is located approximately 35 km east of Sylhet, in north-eastern part of Bangladesh Beani Bazar structure is one of the youngest structures of the entire frontal folded belt and only two wells Beani Bazar-1 (T.D. 13,082 ft) and Beani Bazar-2 (T.D 11,905 ft) have been drilled 1 5 km apart, on the crest Beani Bazar well 1 was completed as selective dual producer in 1982. In 1989, Well-2 was completed in the Upper Gas Sand. The Upper Gas Sand, which is the main pay, is found at a depth of approximately 10,500 feet ss, and contains a lean gas with a liquid-gas ratio of 13.2 bbl/MMscf at field separator conditions. The Lower Gas Sand is found at a depth of approximately 11,500 feet ss and contains a lean gas mixture with a liquid-gas ratio of 15 7 bbl/MMscf at separator condition.

Production commenced from Well 1 in May 1999 from the Lower Sand. Well-2 was brought into production in January 2002 from the Upper Sand Cumulative production August 2005 was 36.196 Bcf of gas and 6,15,000 bbl of condensate.

The produced gas in this field is process by a Silica-gel process plant. This process plant was installed in Feni Gas Field. After suspension of production from Feni Gas Field, it was relocated in Beani Bazar in1999. The capacity of this process plant is 60 MMscfd. The plant is operated by Programmable Logical Control (PLC) system. The PLC system of this plant includes a tower cyclical control system, ESD logic control and monitoring system

4.1.3 Fenchuganj Gas Field

Fenchuganj Gas Field is located approximately 40 km away from Moulavi Bazar district Fenchuganj-1 was drilled in 1960 and terminated as a dry hole. Well-2 was drilled in 1986 by Petrobangla to a total depth of 4,977 meters, which is the deepest well in Bangladesh. Testing has been conducted for over a year and gas, condensate and oil have been discovered. Sand A is the young folding and truncation at the top of the stratigraphic section. At B is a possible high angle reverse fault. C, D and E mark respectively the position at which gas, condensate and oil have been tested. There are three prospective zones- Upper, Middle and Lower sands. Well-3 was drilled up to 3,057 meter by BAPEX in 2004.

Production from Fenchuganj-2 started on May 22, 2004 from the Upper gas zone by the installation of interim production facilities. Well-3 stated on January 2005 by these interim production facilities From September 1, 2005, production from well 2 & 3 started by newly installed silica-gel process plant Process diagram is shown in Figure B-2. Cumulative gas and condensate production from this field was 15.587 Bcf and 35,000 bbl as of August 2005.

4.1.4 Feni Gas Field

The Feni Gas Field was discovered by Petrobangla in 1980 by drilling well-1 and tested gas from two horizons. A second, Well, Feni-2, was drilled in 1993. The Feni-2 was completed in Upper Gas Sand. The Feni-1 was brought into production from the Lower Sand on September 1991. Due to excessive water production from Feni-1, the production was suspended since February 10, 1998. The Feni- 2 was put on production since January 8, 1995 and watered out since February 17, 1997. Gas was produced from the field by the BGFCL till February 1998. The cumulative production for the period when BGFCL operated was 40.333 Bcf gas and 86,939 bbl condensate

BAPEX-NIKO Resources Ltd of Canada signed a joint venture Agreement on October 16, 2003 for redeveloping of this field. Niko drilled three well (3,4 & 5) in 2003-2004. Since November 2004, production from Feni (well-3 & 4) field is operated by Niko. Production stated from well-5 in February 2005 The total production of the field was 49.082 Bcf gas and 97,000 bbl condensate as of August 31, 2005 (including BGFCL period).

The LTX plant of Titas field was relocated at Feni Gas Field in 1991 and Feni-1 gas stream was processed by this plant. Feni-2 was initially processed by glycol plant of Kamta Gas Field, later a silica-gel process plant was installed for Feni-2 Now, gas stream (well- 3,4 & 5) of Feni Gas Field are processed by newly installed two Glycol Dehydration Plant shown in Figure B-3.

A widely used system of drying gas is the Propak Systems Ltd. Glycol Dehydration Unit. This method provides for absorption of water from the vapor phase into the dry glycol in a contactor tower, regeneration of the wet glycol followed by recirculation to the contactor.

4.1.5 Habiganj Gas Field

Habiganj is spatially adjacent to the Rashidpur Gas Field (12 Km), the first ever frontal folded belt discovery by Shell in 1960. Natural gas reserves were discovered in the Habiganj Gas Field by Pakistan Shell Oil Company (PSOC) with the drilling of the well, Habiganj No. 1 (HB-1) in 1963. The evaluation is essentially directed to two pay zones defined in the discovery well HB-1 of upper gas sand (4,500 - 4,875 ft ss) and lower gas sand (9,805 - 9,855 ft ss)

PSOC drilled a second well to appraise the Upper Gas Sand reserves in 1963. Both HB-1 and HB-2 were left as suspended wells until final completion operations were undertaken in 1967. Two development wells were drilled in 1984 under a programmed financed by the French government. HB- 3 & 4 was drilled into Upper Gas Sand approximately 3000 feet and southeast and 4300 ft east-southeast of the HB-I/HB-2 location respectively. HB-5 was drilled deviated to encounter the Upper Gas Sand at its crest and the Lower Gas Sand approximately 4900 feet south-southeast of the HB-3 location in 1989 under an ADB project. HB- 6 was drilled approximately 6500 feet south-southeast of the HB-5 surface location in 1989 under the Gas Field Appraisal Project. During 1998-2000 HB- 7 to 10 wells were drilled and all the wells are producing from Upper Sand.

All wells are currently completed in the Upper Gas Sand, which is very dry, containing no condensable hydrocarbons. The Lower Sand is also very dry, containing only trace amounts of condensable hydrocarbons From the point of view of gas processing, both sands can be considered as dry. Although the gas produced in the production test of the Lower Gas Sands is very lean, the condensate fraction is still higher than in the Upper Gas Sands, showing a trend in the increase in the condensate fraction with depth. The test production record indicates condensate production at liquid-gas ratios varying from 0.9 to 1 5 bbl/MMscf. The Habiganj Gas Sands contain a dry gas of relatively uniform composition. Composed of roughly 97 7 percent methane and in the complete absence of C3+, the reservoir fluid is classified as a dry gas and is suitable for sales after minimal (H_2O) dew point processing

Initial production from the Habiganj Gas Field occurred from HB-1 & 2 in February1969. HB-3 and HB-4 were placed on-production in 1984 (mid 1985) and are currently producing gas to the Habiganj Gas Plant located at the HB-l/HB-2 surface location. For wells HB-1 and HB-2, identical trains, each with design capacity of 60 MMscf/d, are linked together. In 1985, installed process trains for wells HB-3 and HB-4 each have a design capacity of 75 MMscfd In 1989 HB-5 was added and this well started production from Upper Sand. HB-6 started production in February 1995. During 2000 HB-7 to 10 wells are producing from Upper Sand.

In present situation, raw gas from HB-1 & 2 are processed by plant 1 &2 Raw gas from HB-3 & 4 are processed by plant 3 and that of HB-5 & 6 are processed by plant 4. HB-7 & 9 are processed by new installed one process plant and 8 & 10 are processed by another new plant. The cumulative production of gas and condensate were 1276.04 Bcf and 67000 bbl as on 31 August 2005, respectively.

Total six absorption (Glycol Dehydration) plants in this field. Capacity of pump in this field is low for low content of water in raw gas require low circulation rate of pump. Plant 1 & 2 share the same Condensate flash tank and Plant 3 & 4 share another condensate flash tank. The four process trains are tied-in to shared custody transfer, condensate tank and flare systems Gas processing of plants-1, 2, 3 & 4 are similar. But, in plant- 3 & 4, Glycol surge tank/accumulator and glycol-glycol heat exchanger are separate in this plant but in plant –1 & 2, are surge tank act as a glycol-glycol heat exchanger & accumulator where surge tank is a shell side and tube inside the surge tank of heat exchanger So, plant-3 &4, glycol stream of the reboiler is passing through the glycol-glycol heat exchanger to surge tank but in plant-1 & 2, glycol stream of the reboiler is direct go to surge tank cum heat exchanger. Besides two gas driven pump use, one pump for to pump rich glycol to regenerator and another for surge tank to contractor top tray spray in plant 3 & 4. But in plant 1 & 2 use only one pump for surge tank to contractor top tray spray. Some different have in between Plant 5 & 6 with others plant Process diagram of all of those plants are shown in Figure B-4 and B-5.

4.1.6 Jalalabad Gas Field

Jalalabad gas field was the first on-shore gas field to be developed by an IOC under the Production Sharing Contract Scimitar Oil discovered this field in 1989 and later Occidental Bangladesh developed this field The wells have been drilled to a depth of 10,000 ft. JB-1 and JB-2 have been completed in BB-70 sand and other two wells, JB-3 and JB-4 have been completed in BB-60 sand overlying BB-70 sand BB-70 is comparatively rich in liquid hydrocarbons than BB-60 sand. Average depth for the wells is around 8200 ft. Average initial reservoir pressure in BB-70 and BB-60 sands are 3516 psig and 3486 psig respectively and bottom hole temperatures are 146 ^{0}F respectively.

Well-1 started producing from BB 50 sand and other three wells from BB 60 sand. During September 2002, well- 1 & 2 were re-completed in BB70 sands. Now Unocal Bangladesh is operator of this gas field.

Production from Jalalabad field commenced in February 1999 and all four wells were opened up. The cumulative gas and condensate production was 271.272 Bcf and 29,97,000 bbl respectively as of August 2005.

4.1.7 Kailashtila Gas Field

The Kailashtila discovery well is located 13 km to the south of the Sylhet wells, and 74 km to the northeast of the Rashidpur discovery. There are three gas bearing horizons, are as follows:

Upper Gas Sand	7483 to 7662 ft KB	(7422 to 7601 ft ss)
Middle Gas Sand	9665 to 9734 ft KB	(9604 to 9673 ft ss)
Lower Gas Sand	9808 to 9990 ft KB	(9747 to 9929 ft ss)

The Kailashtila field discovery in 1961 was Shell's second in the Frontal Folded Belt. Natural gas reserves were established in the Kailashtila Field in 1962 by PSOC with the drilling of KTL-1 (T.D.13,577 feet KB) in the southern part of the Kailashtila anticline, with gross pay sand thickness of 414 feet (Upper Gas Sand, Middle Gas Sand and Lower Gas Sand). Operations on this well were suspended on March 22, 1962. The well was completed as a dual producer in the Upper and Lower Gas Sands during the latter part of 1982.

KTL-2 (T.D 10,702 feet KB) and KTL-3 (T.D. 10,853 feet KB) (directional) were drilled and completed in the Upper and Middle Sands, respectively, as part of the Gas Field Appraisal Project. KTL-2 & 3 are 1 5 km to the north-northeast of KTL-1, with gross sand thickness of 515 feet and 1 km north-northeast of KTL-2 at the bottom hole location, with a gross sand thickness of 527 feet respectively. KTL 4 was drilled in 1996 and completed in Lower Gas Sand

The reservoir fluid for Upper and Lower Gas sand is slightly retrograde at reservoir temperature. Volume percentage of C_3, C_4 and higher hydrocarbon are higher than other fields but lower than that of Beani Bazar field.

The KTL-1 started production on June 28, 1983 by 30 MMscfd Silica gel plant. Production from KTL-2 and 3 started in February 1995. After work over, the well 3 was re-completed in the Middle Gas Sand and production started on 26 February 1998. KL 4 started production in March 97. KTL-2, 3 & 4 are processed by 90 MMscfd Molecular Sieve Turbo Expander (MSTE) process plant Cumulative production of gas and condensate from Kailastila Gas Field was 347.205 Bcf and 42,60,000 bbl respectively as of August 2005.

4.1.8 Meghna Gas Field

The Megna (Marichakandi) Gas Field located approximately 35 miles east of Dhaka in east-central Bangladesh. The structure has no surface expression being covered by the extensive flood plain of the Meghna River It was spotted as a pronounced gravity anomaly in 1953. Shell acquired single-fold seismic data over the entire Bakhrabad Main-Marichakandi-Belabo area in mid-1960's Petrobangla discovered the Meghna Gas Field in 1990. A total of six gas-bearing zones have been identified viz. A, B, C, D, E and F. The major gas sands of Meghna Gas Field are A and C sands. New commercial discovery, encountered approximately 1600 feet lower and of different depositional facies than the sands of the main Bakhrabad Gas Field. The reservoirs of the Meghna Gas Field are named the A to F Sands and have no direct correlation to the similarly named sands in the Bakhrabad Gas Field.

In total, eight gas sands (six named, two unnamed) have been encountered in the Marichakandi area between the depths 7508 to 9917 ft subsea

'A' Sand (7533-7508 ft subsea) : Untested, net 17 ft, Gross 25 ft.

'B' Sand (7630-7611 ft subsea) : Untested, net 12 ft, Gross 19 ft.

'C' Sand (8727-8697 ft subsea) : Untested, net 30 ft, Gross 30 ft.

'D' Sand (9596-9578 ft subsea) : Untested, net 11 ft, Gross 18 ft.

'E' Sand (9721-9710 ft subsea) : Untested, net 06 ft, Gross 11 ft.

'F' Sand (9917-9881 ft subsea) Untested, net 29 ft, Gross 36 ft

The reservoir fluid of the Megna Gas Field is non-retrograde at reservoir temperature. Liquid is condensed from the well effluent for temperatures lower than 100 °F. This representative gas composition contains 98 mole% methane and ethane, with only a small amount of recoverable C_{5+} liquids (less than 3 bbl/MMscf).

Well no. 1 was brought into production from `C' sand on 24 June 1997. Cumulative production of gas and condensate from this field were 34.39 Bcf and 53000 bbl until 31 August 2005.

Two Low-temperature extraction (LTX) plants were originally installed at Titas field in 1969 and subsequently relocated to Feni in 1991 and Meghna in July 1996

4.1.9 Narshingdi Gas Field

The Narshingdi Gas Field is located approximately 46 km east of Dhaka. The well-1 (BK-10), was drilled as part of the Gas Field Appraisal Project to evaluate the hydrocarbon potential of the northern culmination of the Bakhrabad structures identified by the Pakistan Shell Oil Company in the early 1960's The single well penetrating the two commercial Narshingdi gas reservoirs was drilled as a development/exploration well investigating the northerly extension of the Bakhrabad structure. The gas reserves identified through DST evaluation and production testing represent a new type of gas reservoir in Bangladesh, namely a stratigraphic gas reservoir.

The gas sands encountered in BK-10 with a total depth of 11,253 ft subsea are two commercial accumulations of gas. Lower Gas Sand (10,333-10,378 ft ss) and J Sand (9,506-9,537 ft ss.). The 'A2' culmination of Shell has been redesignated as the 'C culmination by Petrobangla

The reservoir fluid of the Narshingdi Gas Field is non-retrograde at reservoir temperature. Fluid properties for the Upper and Lower Gas Sands of Narshingdi Gas Field are consistent with the mole fraction compositions. Gas composition contains over 97 mole % methane and ethane, with a significant amount of recoverable C_{5+} liquids (almost 9 bbl/MMscf) The Narshingdi reservoir fluid contains a larger percentage of C_{7+} which is consistent with testing results in which the condensate-gas ratio was found to be 2.5 bbl/MMscf (at separator condition).

Production from this field commenced on July 25, 1996 from the Lower Gas Sand. The cumulative production from Lower Gas Sand was 59.142 Bcf gas and 1,33,000 bbl condensate as of August 2005.

The Glycol Dehydration plant involved in raw gas processing which was originally installed at Bakhrabad Gas Field in 1984 and relocated to this field in 1994.

4.1.10 Rashidpur Gas Field

The Rashidpur Gas Field is located approximately five miles west of Srimangal in the east-central part of Bangladesh. Natural gas reserves were discovered in the Rashidpur Field in 1960 by Pakistan Shell Oil Company with the drilling of the first well RP-1 and got two pay zones i.e. Upper Gas Sand (4,530-4,825 ft KB) and Lower Gas Sand (8,880 - 9,145 ft KB)

RP-1 was completed in Upper Gas sand A second well, RP-2 was also drilled along side RP-1 in 1960-61 up to a depth of 15,071 feet. In 1989, RP-2 was re-completed the Lower Gas Sand. Two new wells RP-3 and RP-4 were drilled and completed in the Lower Gas Sand in 1989 as part of the Gas Field Appraisal Project. During 1999, RP-5, 6 and 7 were drilled. RP 5 was drilled in Lower Gas Sand (Bhuban Thin Alteration). RP-6 was completed in Bhuban Sand and RP-7 was completed in Lower Gas Sand

The reservoir fluid of the Upper and Lower Gas Sands is non-retrograde at reservoir temperature. The Upper Gas Sand contains a very dry gas mainly composed of methane with no gas liquid potential. Composed of roughly 99.4 percent methane, the reservoir gas is classified as dry gas, and is suitable for sales after minimal (H_2O) dew point processing. Theoretical liquid recoveries based on field separator conditions were predicted at 2.21 bbl/MMscf to all lower zone production.

Production commenced from RP-1 in September 1993 and followed by RP-2,3 and 4 during February to April 1994. RP-5, 6 and 7 were brought into production during January 2000. The cumulative production from Rashidpur Gas Field was 361 652 Bcf gas and 5,13,000 bbl condensate as of August 31, 2005

A Glycol Dehydration process plant of 60 MMscfd capacity is used for processing the raw gas from RP-1. Raw gas stream of RP-2, 3 & 4 are processed by Silica-gel process plant of 70 MMscf/d capacity. Raw gas stream of RP-5, 6 & 7 are processed by two new Silica-gel process plant (2X45 MMscfd). Glycol is similar to newly installed plant of Habiganj Gas Field (Plant 5 &6). Here, entrainment separator was installed to separate liquid portion of the gas stream coming from the glycol tower. It is installed for finally remove the dust, liquid hydrocarbon, water or other undesirable foreign particle (if any) of sales gas Lower part of the glycol tower is equipped with scrubber section It is remove liquid and solid impurities that may carry over from upstream vessels. As a result, the life of the glycol is increased and is increased the bubble plate efficiency. Process diagram of those plants are shown in Figure B-6, B-7 and B-8

4.1.11 Saldanadi Gas Field

Saldanadi Gas Field is located in the eastern part Bangladesh in Brahmanbaria District It is a part of Rukhia anticline Saldanadi-1 was drilled in 1996 by BAPEX There are three gas bearing horizons: Upper Gas Sand (7352-7057 ft), Middle Gas Sand (7235-7039 ft) and Lower Gas Sand (7913-7832 ft) Well-1 was completed as a dual producer of Upper and Lower Gas Sand. Saldanadi-2 was drilled directionally in 1999 by BAPEX, which was completed as a single producer from the Middle Sand.

From well-1 and 2 production started from 28 March 1998 and 3 May 2001, respectively by the BGFCL. BGFCL handed over the field to BAPEX at July1, 2001. Cumulative production of the field was 41.838 Bcf gas and 35,000 bbl condensate as of August 2005.

The Glycol Dehydration Plant of this field originally was installed at Kamta Gas Field in 1984. Due to shut in of Kamta well, the plant earlier relocated to Feni Gas Field in 1992 For the same reason subsequently the plant relocated in this field in 1997 by the BGFCL. Block diagram and process flow diagram of the plant are shown in Figure B-9 and B-10.

4.1.12 Sangu Gas Field

Sangu is an offshore gas field, located at distance of some 40 kilometers south west of Chittagong, in Block 16. The PSC of Block 16 between Petrobangla, Cairn Energy Plc and Holland Sea Search Bangladesh B.V was signed in May 1994. The exploration well Sangu-1 was drilled in February 1996 and discovered gas Four potential gas-bearing sands and number of minor sands were identified. So far six wells have been drilled, out of which four wells are in production. Shell Bangladesh Exploration and Development B V. (SBED) explores for gas in the southeast of Bangladesh (Block 15 and 16) through a 50/50 partnership with Cairn Energy Plc. In addition, with HBR Energy Inc, the Joint Venture operates the Sangu Gas Field. In July 1999 Shell took over the operatorship of the Joint Venture in Blocks 15 and 16 from Cairn.

The Sangu gas from the production platform flows via a pipeline to the onshore gas processing plant at Chillimpur and is then being transported into the national grid. Both the offshore production platform and the gas plant are designed to deal with exceptional weather conditions, such as cyclones and floods.

The Sangu offshore production platform is unmanned, operated by a telecommunication system at the onshore gas processing plant at Chillimpur. An operations crew visits the platform twice a week to conduct production, maintenance and inspection activities.

Gas production commenced from Sangu on June 12, 1998 from the wells Sangu-3Z and Sangu-4. Sangu-5 was brought into production from July 16 and Sangu-1 to 4 were brought into production from October in the same year. Sangu-8 & 9 brought into production in March 2005 and Sangu-7 were brought into production in June 2005. The cumulative production from Sangu Gas Field was 330 945 Bcf as of August 2005.

4.1.13 Sylhet Gas Field

The Sylhet Gas Field was discovered by the Pakistan Petroleum Limited (PPL) in 1955. Sylhet-1 was spudded with a target to drill down to 3,800m. But after cementing of casing at 2,377m, the well blew out Sylhet-2 was drilled in 1956 but, due to abnormal pressure encountered at 2,818m the wellbore was plugged and abandoned Sylhet-3 was drilled successfully in 1957 and was put on production in 1960 as commingled producer from the Upper and Second Boka Bil Sands In 1962, Sylhet-4 was abandoned due to presence of abnormal pressure at shallower depth In 1963, Well-5 was drilled as an observation well to monitor pressure behavior of shallow sands. Sylhet-6 was successfully drilled in 1964 and was completed as selective dual producer well in the Upper and Second Boka Bil Sand. Sylhet 6 started production in August 1964 Gas production from 2nd Boka Bil was suspended during March 1988 due to excessive water and sand production Gas production from Sylhet-6 (Upper Sand) continued at about 5.5 MMscfd Sylhet 7 started producing on April 2005, after an work over operation by BAPEX The cumulative production from Sylhet Gas Field was 176 829 Bcf gas and 5,42,000 bbl condensate as on 31 August 2005

A Silica gel process plant of 30 MMscfd capacity is used for processing the raw gas from this field

4.1.14 Titas Gas Field

The Titas anticline is along the strike trend with the western most surface structure of Tripura, the Rokhia anticline, approximately 20 km to the south of Titas. The gravity survey of PPL in the early 1950s provided the initial indication of the Titas subsurface closure. A natural gas reserve was discovered in the Titas Gas Field by Pakistan Shell Oil Company (PSOC) with the drilling of Titas Well No. 1 (TT-1) in 1962 The Titas field is the largest and most promising discovery in Bangladesh. The gas sands are classified into two categories: major sands and minor sands Major sands include A2, A3, A4, B3 and C3 while minor sands include A1, B0, B1, B2, C1, C2 etc. The individual sands of the B and C Sand Groups are more consolidated than the A Sands. The hydrocarbon accumulations of Titas Gas Field are contained in 13 distinct reservoir sands, which have been grouped by depth into the A Sand Group, B Sand Group and C Sand Group.

PSOC drilled TT-2 in 1962 and deviated well TT-3 & 4 from TT-1 were drilled in 1969. Petrobangla completed the development of the A Sand Group between 1981 and 1985 through the drilling of the wells TT-5 to TT-7 The TT-5 and TT-7 wells were directionally drilled from the surface location 1. TT-6 was drilled as a vertical well in a step-out location (Location No. 3) to the north. TT-8, 9 & 10 were directionally drilled in B and C Sand Groups in 1985,1987 & 1988 from the surface location of TT-6 respectively. Titas Well No. 11 was drilled as part of the Gas Field Appraisal Project in the Northern most in 1990. TT- 12 to 14 (TT-13 & 14 deviated well) were drilled in A Sand Group under the Titas Natural Gas (TNG) project of BGFCL in between 1999 to

2000. Eight wells are currently completed in the A Sand Group: TT-1 through TT-7 and TT-II. The B and C Sand Groups are currently being depleted on a commingled basis through wells TT-8, TT-9 and TT-10. Now, the drilling programmed of TT-15 & 16 are continued by BAPEX for make up national gas demand.

Commercial production from Titas Gas Field was commenced on February 1969 with start-up of wells TT-1 and TT-2. Two more wells, TT-3 and TT-4 were produced on 1970 June 1981, TT-5 was brought on-stream. TT-6 and TT-7 were added in February-1984 and August-1985, respectively. Production from the B and C Sand Groups commenced in February 1986 when TT-8 began operation. Wells TT-9 and TT-10 were added in March-1989 and September-1990, respectively. Cumulative production of the field was 2418 808 Bcf of gas and 32,20,000 bbl of condensate on August 31, 2005

At Location 1, the gas processing facilities for each of four wells (TT-1, TT-3, TT-4 and TT-5) are based on the glycol dehydration process (Plant 1, 3, 4 & 5). The gas stream from the TT-7 goes through a Low Temperature Separation With Glycol Injection (LTS) process (Plant 7) train, which includes a well stream cooler on the inlet and glycol injection for hydrate prevention. Design capacity of the gas processing trains for wells TT-1, TT-3, TT-4, TT-5 and TT-7 are each 60 MMscfd and process diagrams are shown in Figure B-11 and B-12. Also situated at Location 1 are common facilities for sales gas measurement and transmission and condensate product storage & transport, flare and utility gas systems. Design capacity for these common facilities, which handle custody transfer for all wells in Titas Gas Field, are 250 MMcf/d of dry gas and 200 bbl/d of liquid condensate Schematic diagram of Titas Location –1 is shown in Figure 4 2.

Location 2 is comprised of the surface location of well TT-2 and, prior to 1991, a 40 MMscfd Low Temperature Separation train based on the LTX process, which makes use of hydrate formation in the recovery of liquid hydrocarbons. As shown in, the outlet dry gas and condensate streams from Location 2 were piped to the common facilities at Location 1. In 1991, the LTX process train was removed from Location 2 and relocated to the Feni Gas Field. Currently, the gas stream from well TT-2 is process partially by Heater & K.O. Separator in Location 2 then flow line is connected to Location 1 for further processing, where it shares the glycol dehydration process trains of wells TT-1, TT-3, TT-4 and TT-5.

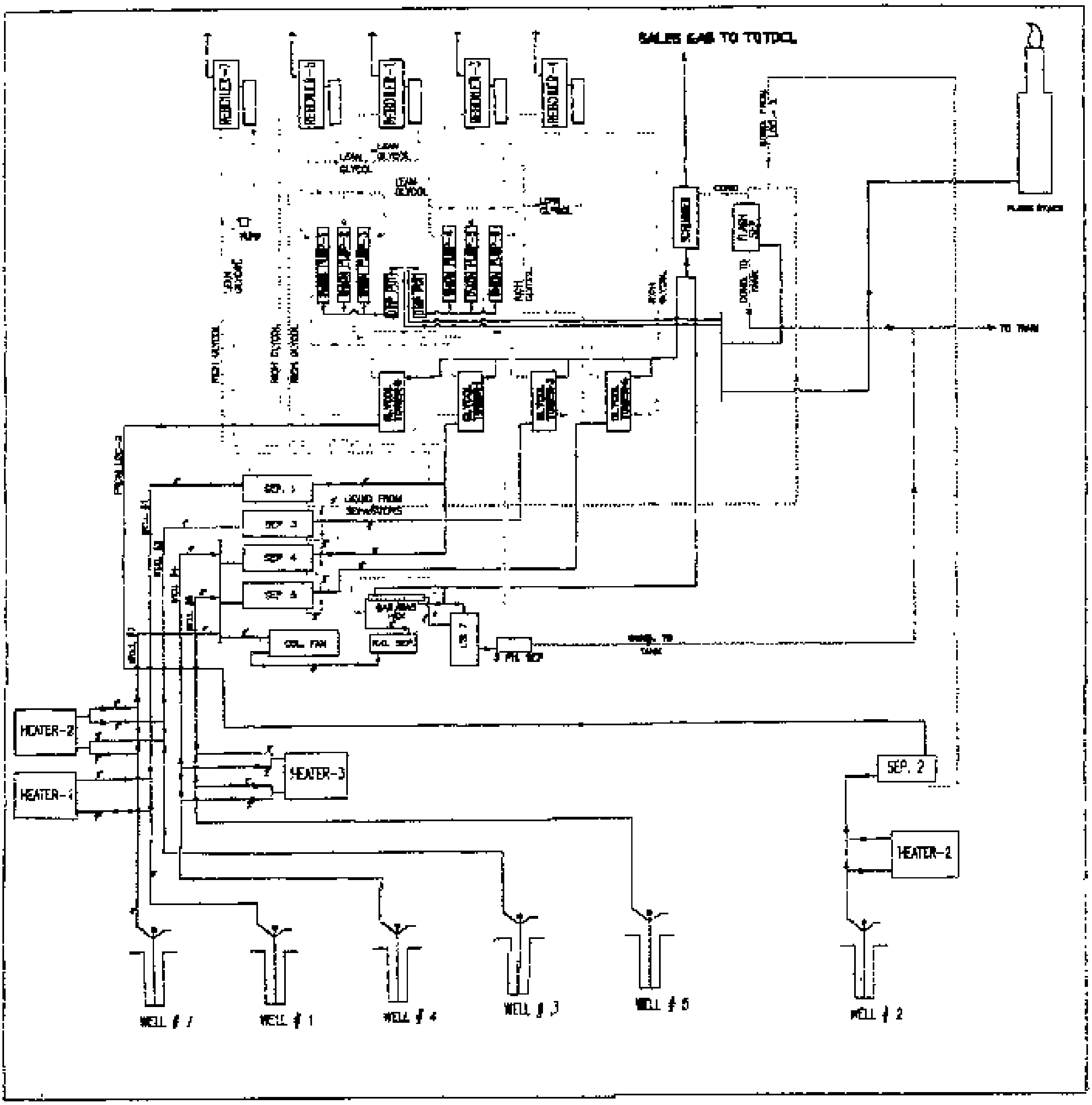


Figure 4.2: Schematic Diagram of Titas Location-1

At Location 3, the gas processing facilities for well TT-6 are based on the glycol dehydration process (Plant 6), while the gas streams from wells TT-8, go through Low Temperature Separation With Glycol Injection (LTS) process trains (Plant 8) and TT-9 & 10 go through Low Temperature Separation With Out Glycol Injection (LTS) process trains (Plant 9 & 10) which include well stream coolers on the inlet. The facilities for well TT-8 also incorporate glycol injection for hydrate prevention. The Production Facilities TT-11, located Location 4, is tied-in by flowline to Locations 3 and shares the gas processing facilities associated with well TT-6. Design capacity of the gas processing trains for wells TT-6, TT-8, TT-9 and TT-10 are each 60 MMcf/d Schematic for wells TT-6, TT-8 and TT-11 are presented in Figure B-13.

At Location 5, Gas stream of TT-12 not flow through gas processing facilities due to excessive water production. Gas stream only pass through K.O Separator then common sales Scrubber to R-A transmission line & condensate separate in Skim pit. TT –13 & 14 each go through two newly installed Low Temperature Separation Without Glycol Injection (LTS) process trains (Plant 11 & 12) which include well stream coolers on the inlet. Design capacity of the gas processing trains for wells TT-13 and TT-14 are each 60 MMcf/d. The outlet dry gas of TT 12,13 & 14 are common facilities for sales gas measurement and transmission and condensate streams are piped to the common facilities at Location 1 storage, transport or further processing.

4.2 Process Plants in Bangladesh

Numerous technologies have been developed for gas processing based on a variety of chemical and physical principles The selection of the technology and the design of the overall plant depend on many factors. The following key data / factors are required to select surface facility / Process Plant:

Reservoir and Fluid data:

- Gas reserve/ gas in place
- Gas recovery
- Reservoir deliverability
  - The deliverability of a well can be estimated by applying LIT (Laminar-inertial-turbulent) analysis.
  - The Absolute Open Flow Potential (AOFP) of well is estimated from deliverability equation
  - Deliverability or producing capacity of a well or field with respect to time must be known for economic evaluation and planning equipment purchase
- Reservoir gas composition / fluid analysis:
  - -Gas is dry or wet (containing appreciable heavier hydrocarbon)
  - -Presence of heavier hydrocarbon fraction
  - -Amount of condensable hydrocarbons at separator condition
  - -Presence of water fraction
  - -Presence of contaminants or undesirable components, such as hydrogen sulfide and other corrosive sulfide compounds and carbon dioxide etc.
  - -Presence of water
  - -Retrograde or non-retrograde at reservoir.
- Physical and thermodynamic properties of the reservoir fluid:
  - -Initial average reservoir static pressure
  - -Reservoir average temperature
  - -Shut-in wellhead pressure
  - -Specific gravity, specific heat, viscosity, compressibility factor, critical pressure and temperature etc.
  - -Corrosive or non-corrosive

The following properties of gases are essential to design flowlines, flanges, heat exchangers, separators, vessels and other surface facilities.

- Production forecast /gas recovery period/ Life of the field:
  - -Total amount of economically recoverable gas
  - -Constant production period
  - -Rate of return and profitability analysis.
- Condensate gas ratio:
  - -Amount of free condensate in the gas stream
  - -Estimate recovery by a different process plants
  - -Over all rate of return/economic feasibility
- Water gas ratio
  - -Qualify reservoir
  - -Calculate pumping rate / desiccant volume
  - -Reboiler / Heater duty

The gas compositions of different fields in Bangladesh are shown in Table A-2. From this table, we observe that the presence of sulfur compound is nil/trace amount, and heavier hydrocarbon is present in small amount in most of the fields Due to this composition of the natural gas in Bangladesh, the need for sweetening etc is minimal / not required. Therefore, gas processing mostly involves dehydration The following types of gas processing plants are used in Bangladesh:

1. Absorption Process Glycol dehydration plant.
2. Adsorption Process: Silica gel dehydration plant
3. Low Temperature Extraction (LTX).
4. Low Temperature Separation (LTS) with Glycol Injection.
5. Low Temperature Separation (LTS) without Glycol Injection.
6. IFPEXOL Process (Refrigeration process absorption by methanol and propane as a refrigerant.).
7. Adsorption Process with Turbo Expander: Molecular sieve cum turbo expander plant and
8. Absorption Process with Turbo Expander. Glycol dehydration cum turbo expander plant.

Each of these processes has merits and demerits considering technology, operation, maintenance, investment etc. Table 4.3 shows the company names, along with the plant capacities, manufacturer and year of installation etc. A discussion on each type of plant is presented in the next sections.

Table 4.3 : Current Status of Gas Processing Plants in Bangladesh.

Field	Type of plant	Nos.	Technology Source (Manufacturer / Supplier)		Year of installation	Name plate Capacity (MMscfd)	Present Processing Capacity (MMscfd)	Expected Replacement Time
Titas	Glycol Dehydration	5	Plants -1 & 3	CE NATCO USA, LTD	March, 1969 & September, 1969	60	45	2006-2007
			Plants - 4 & 5.	CE NATCO UK. LTD.	June, 1981	60	45	2009-2010
			Plants -6	MALONEY STEEL LTD . CANADA	February. 1984	60	45	-
	LTS with glycol injection	2	ESCHER B.V., HOLLAND Plants - 7 & 8		February, 1987 & July, 1987	60	50	-
	LTS without glycol injection	4	Plants -9 &10.	ESCHER B.V . HOLLAND	September, 1990	60	50	-
			Plants-11 & 12	HYUNDAI ENGG. & CORP	2001	60	60	-
	Condensate Fractionation Plants	2	No 1		1980	500 bbl / day	350 bbl/day	2007-2008
			No. 1		1992	500 bbl/day	450 bbl/day	-
	Scrubber	2	No 1		1980	250	230	2012-2014
			No.1		- 1984	1 50	140	2012-2014
Habiganj	Glycol Dehydration	6	Plants - 1 & 2.	P T. AVLAU INDONESIA FABRICATORS. INDONESIA.	May, 1981	60	45	2010-2011
			Plants - 3 & 4.	BLACK, SIVALLS A BRYSON. FRANCE	June. 1985	75	65	-
			Plants -5 & 6	ESCHER HOLLAND B.V., THE NETHERLANDS	2001	75	75	-
Bakhrabad	Silicagel Dehydration	4	Train A,B, & C	SEAMORE OIL AND GAS PROCESS. NEDERLAND	October, 1986	60	50	-
			Train D	ESCHER B,V , HOLLAND	December, 1989	60	60	
	Fractionation plant	1	-		1986	750 bbl/day	600 bbl/day	-

Table 4.3 (Cont'd) : Current Status of Gas Processing Plants in Bangladesh.

Field	Type of plant	Nos.	Technology Source (Manufacturer / Supplier)	Year of installation	Name plate Capacity (MMscfd)	Present Processing Capacity (MMSCFD)	Expected Replacement Time
Narsingdi	Glycol absorption	1	ABAX, CANADA	First installed at Bakhrabad field in 1984, relocated to Narsingdi field in 1994.	60	40	-
Meghna	LTX	2	CE NATCO UK LTD.	First installed at Titas in1969, relocated to Feni field in 1994, relocated to Meghna field in 1997	20	15	2006
Sylhet (Haripur)	Silica gel	1		1962	30	30	-
Rasidpur	Glycol dehydration	1	SEAMORE OIL AND GAS PROCESS, NEDERLAND	1993	60	60	-
	Silica gel	2	CHINA HUANQIU CHEMICAL ENGG. CORP.	2000	45	45	-
	Silica gel		ESCHER B.V., HOLLAND	1994	70	70	-
Kailashtila	Silica gel	1	-	1983	30	30	-
	Molecular Sieve - Turbo expander	1	ABB RANDELL CORPORATION, TEXAS	1995	90	90	-
Beanibazor	Silica gel	1	-	First installed at Feni field in 1984, relocated to Beanibazar field in 1999.	60	60	-
Saldanadi	Glycol dehydration	1	ESCHER B,V., HOLLAND	First installed at Kamta in 1984, relocated to Feni field in 1994, relocated to Saldanadi field in 1998.	20	20	-
Fenchuganj	Silica gel Dehydration	1	CHINA HUANQIU CHEMICAL ENGG. CORP.	2005	60	60	-
Feni	Glycol dehydration	2	PROPAK SYSTEM LTD. CANADA	2005	20		-
Moulobibazar			-	2005	-	-	-
Jalalabad	IFPEXOL	1	IFPEXOL, FRANCE	1999	130	130	-

4.2.1 Absorption Process: Glycol Dehydration Plant

In an absorption process, the extent of dew point depression is determined by inlet gas temperature and pressure, type of liquid absorbent used, concentration of absorbent, circulation rate and the quantity of contaminants in the absorbent. Where maximum dew point depression is desired, maximum glycol concentration is required. This requires maximum safe regeneration temperatures, in either conventional or gas stripped unit.

A dehydration process, which lowers the water content of natural gas, will prevent the formation of hydrates. A secondary benefit, which results from the removal of the free water, is retarding corrosion to the pipeline. The formation of gas hydrates, which are crystalline structures, will result in the reduction or blockage of flow in natural gas gathering systems or transmission lines. Conditions that promote hydrate formation are the presence of free water, low temperature and high pressure.

Triethylene is the most predominantly used glycol for dehydration and has largely replaced diethylene for this purpose Triethytene glycol has a higher decomposition temperature than diethylene, and can be reconcentrated to a higher degree, with a resultant increase in dew point depression.

There are sixteen glycol process plants located at different fields as shown in Table 4.4 In most of the glycol plants, processing procedure are similar, but glycol regeneration systems are different.

Table 4.4 : Glycol Dehydration Process Plants in Different Fields.

Name of The Gas Field	No. of Process Plant	Capacity of Plant (MMscfd)
Feni	2	2 X 20
Habiganj	6	2 X 60 + 4 X 75
Narshingdi	1	60
Rashidpur	1	60
Saldanadi	1	20
Titas	5	5 X 60
Total	16	750

In addition to the ones mentioned in Table 4 4, four glycol related plants are installed in Titas and Sangu fields. In Titas, two LTS with glycol injection plants are installed. Where glycol regeneration systems are quite similar to a typical glycol dehydration plant. Two glycol with turbo expander plants are installed in Sangu field. In those plants the glycol dehydration and regeneration systems are also quite similar to a typical glycol dehydration plant.

General description of equipment and process of a glycol dehydration plant are presented in the following sections.

4.2.1.1 Equipment Description

Generally a glycol plant consists of the following major components/systems:

i. Pressure Reduction Unit

There are two pressure reduction valves (in parallel complete with necessary isolating valves), one operating and the other standby to reduce line pressure to plant operating pressure by a pressure controller receiving signal from downstream of the pressure reduction valves.

ii. Inlet Water Bath Heater

An inlet water bath heater is required for each plant to prevent formation of hydrates in the pressure reducing choke valve when incoming gas is cooled. If the possibility of hydrate formation in the gas gathering pipelines, this raise the temperature above the hydrate formation.

iii. High Pressure Inlet Knock-out Separator

Removal of free water, free liquid hydrocarbon is done in the inlet knock-out separators. Separator operates basically upon the principle of pressure reduction to achieve separation of gas and liquid from inlet stream. In the separator different technologies applied for mechanical separation process, such as centrifugal action, gravity settling and impingement technique based upon thermodynamic vapor-liquid equilibrium principles It is fitted with a de-mister pad, liquid level controller etc. Liquids extracted at this vessel are dumped to flash separator after level control of liquid.

iv. Glycol Contactor Tower

Tri-ethylene glycol contactor tower dehydrate the wet gas coming from inlet separator The dry gas passes over through the top of the tower and water-rich glycol is to be collected at the bottom and discharged to the regeneration unit. It is equipped with bubble try, mist extractor, level controller & safety valve etc.

v. Gas-Glycol Heat Exchanger

Gas-Glycol heat exchanger cools the glycol coming from regeneration unit and heats the processed gas from the glycol contactor tower. It is either fin tube or shell tube exchanger.

vi. Sales line Scrubber / Filter Separator

Sales line scrubber or filter separator is finally removed the dust, liquid hydrocarbon, water or other undesirable foreign particle for supply of clean gas. Most of the scrubber is horizontal single or double tube vessel

vii. Metering Station

Dry gas from glycol absorber tower (via. scrubber) is supplied to sales/transmission line. Orifice meter are adopted for the natural gas flow calculation by the flow computer on the outlet line of the plant. Three pen type (Mechanical recorder) is installed also for record flow rate (different pressure), pressure, and temperature. A flow control valve is control the flow of sales line.

viii. Glycol Regeneration Unit

Glycol regeneration unit comprising of glycol flash separator, glycol-glycol heat exchanger, glycol reboiler, glycol pumps, still column, glycol accumulator etc. This unit regenerates the water rich glycol from contactor tower The wet glycol flows through low pressure three-phase separator where the entrained gas and any liquid hydrocarbons present are removed. Glycol-glycol heat exchanger exchange heat between lean glycol from the reboiler and rich glycol from the glycol tower. Air-glycol heat exchanger is used to maintain the glycol temperature with respect to pump tolerable limit. Two types of glycol filter are used to remove solids by a sock filter and to absorb small amounts of hydrocarbon by a charcoal filter that may build up in the circulating glycol. Four energy exchange type or gas driven plunger type glycol pumps are installed for injection of glycol to tower. Water vapour from still column shall be accumulated to a vapour drum through a cooler for disposal of water to skim pit and vapour to a vent stack provided by the Contractor *ix. Condensate Flash Separator*

Water and condensate from high pressure inlet separator and glycol contractor shall be dumped to this flash separator. Condensate and water after separation in this flash separator will be automatically transferred or pumped to production/condensate tanks and waste water system respectively and flash gas to the flare/fuel gas header. Each liquid and vapour outlets in this vessel is provision of mechanical/pneumatic flowmeter for measuring flow per day

x *Fuel & Instrument gas system*

The flashed gas from the glycol & condensate flash separator is used within the plant as fuel & instruments gas for processes. The shortfall is made-up by the letting down sales gas by the regulator The fuel & instrument gas enters the scrubber for the removal of the entrained liquid before distributed to the utility fuel & instrument gas users.

xi. Controls & Instrumentation

The plant has a simple control system. Pneumatic or Electro-pneumatic controls are used All instruments shall use instrument gas and flow and pressure control systems shall be pneumatic. Temperature, pressure, differential pressure & flow controls, recorders, gauges, switches, alarms and indicators are provided to allow proper and satisfactory operation, control and monitoring of the plant. An annunciator panel to be located inside the operator room for annunciation of critical parameters such as high pressure and temperature, pilot & burner outage of heaters and reboilers, liquid level of vessels, shutdown annunciation for ESDVs etc.

Each plant inlet & outlet is provided with pneumatic emergency shutdown valve (ESDV), which shall be activated, by high plant inlet pressure and other parameters, which the Contractor considers critical and essential for smooth operation of the plants The ESDV shall also be activated by manual push buttons to be located in the plant area as well as in the remote annunciator panel

xii. Waste Water System

Oily water separator, Skim pit and soak pit are used for to remove water, condensate and suspended solids from waste water from the tanks, separators etc. The waste water maintain of suitable quality for disposal in the soak away pit with oil content less than 20 ppm and oil particle not greater than 10 micron *xiii. Natural Draft Air Cooler, Vapor*

The natural draft air cooler, a vapor drum and a vent stack are used for optimum recovery of condensate/water vapor from glycol regenerator/still column of the plants.

xiv. Flare System

The connections from this process plant to the flare system to burn unwanted gas from the flash separators, safety valves etc. and to depressurize the plant whenever is required. The depressurize line from the plant are connected through a manifold with a flare off-take. Necessary non-return valves are to be provided in each depressurizes line to prevent flash back. All pressure relief and safety valves shall be vented to the flare.

xv. Condensate Storage Tank

Two cylindrical welded cone roof or rectangular condensate storage tank is installed with plant. One tank use as production tank and another use as delivery tank. The tank will be provided with filling, transfer and discharge systems by condensate pump.

xvi. Fire and Safety System

The plant fire water system equipment consists of fire extinguisher, foam fire fighting system, Smoke detector and Heat detector, fire fighting pump and jockey pump with fire water spray ring and spray nozzles and fire hydrants etc.

The major equipments/components described in above are not installed in every glycol dehydration process plant. Moreover, same equipment of different types is installed in different plants. Pressure reduction unit, glycol contractor tower, condensate flash separator, reboiler, still column, recording system, fuel & instrument gas system, flare & burn pit, waste water system etc. are similar type installed in every glycol dehydration plant in Bangladesh.

4.2.1.2 Process Description:

The following basic operations are performed in the glycol dehydration plant:

i. *Pressure reduction, flow recording & heating*

Well head pressure is in the region of 185 - 210 barg. In the Pressure let down, the gas from each well is throttled to a plant by choke manifold operating at approximately 65-72 barg for delivery of the raw natural gas to plant. The gas stream after flashing across the inlet pressure controller may cool down to a level lower than the acceptable hydrate limits, especially during the winter months due to low feed gas temperature. When flowing well stream temperature is not high enough to maintain the temperature of knockout separator at above hydrate formation temperature after expansion of gas at control valve preceding the separator, a coil tube water-bath line heater is used to raise the temperature of the gas stream The coil tube water bath heater always keeps the water temperature above 50~90°C, the gas stream across the inlet water bath could be above the hydrate limit all time. To prevent the formation of hydrate, inlet water bath heater is provided in the down stream of the plant inlet header. If production from two or more gas wells in the gas field then more than one flow recorder (three pen type mechanical recorder / flow computer) are used for record flow rate (different pressure), pressure, and temperature of each well.

ii. *High pressure liquid knock-out*

Raw gas from well carries some free liquid is separated from gas stream by a knockout separator. A pressure control valve is installed at inlet of knockout separator to step sown the flowing gas pressure and to maintain the pressure of the separator at desired range. Drop in pressure of flowing gas stream after control valve causes expansion cooling of the gas stream into the separator, form droplets of liquid in gas stream, and separates the liquid from gas stream at coalescing plate into the separator. Raw gas from well also carries also some solid debris, which is separated from gas stream by a knockout separator Block diagram of glycol dehydration process is shown in Figure 4 3.

iii. *Absorption of water vapor from gas stream (dehydration)*

Outlet gas from separator containing some condensable hydrocarbon and saturated water enters a vertical contractor tower. Tower containing bubble-trays is used as absorber. The purpose of the bubble cap is to break the gas into many fine streams to provide intimate contact of the gas and glycol, permitting the absorption of the water vapour into the glycol.

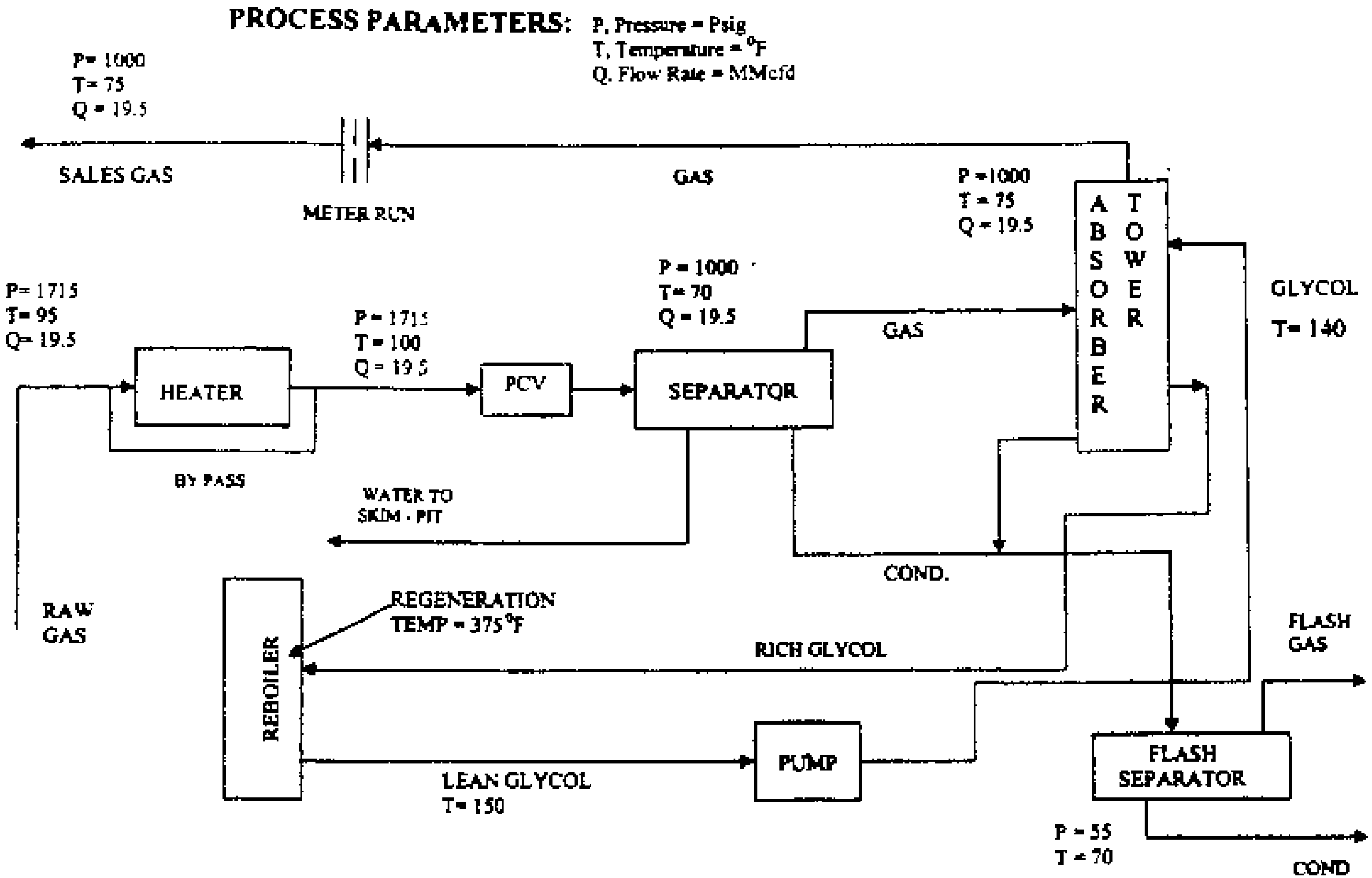


Figure 4.3 : Block Diagram of Glycol Dehydration Plant.

Wet gas after scrubbing of free liquids, enters contractor tower below the bottom tray. Reconcentrated glycol is pumped to the top tray by glycol pump and then downward to each succeeding tray until it is accumulates in the base of the contactor. So, the wet gas passes upward through the bubble caps, counter currently contacting the lean glycol as the glycol passes downward From here the wet glycol passes through either a diaphragm control valve actuated by a liquid level control or through the drive side of a glycol-powered pump. The liquid level control is required when either gas driven pumps are used. A level controller is not required with the glycol-powered pump. The glycol will absorb heavy hydrocarbon liquids present in the gas stream Accumulated heavy condensate over the level of water-rich glycol is sent to condensate flash separator after maintaining the level by the level control valve. After the gas stream leaves the contactor, it flows through a gas/glycol exchanger containing the warm the glycol feed to the contactor. This provides cooling of the glycol before direct contact with the gas stream on the top tray.

iv. *Reconcentration of water rich glycol (evaporation)*

The wet glycol flows through a glycol pump of pilot side to drive the pump & then flows to a optional low pressure separator operating at 35 to 50 psig where the entrained gas and any liquid hydrocarbons present are removed. This horizontal glycol separator is a standard three-phase vessel designed for at least 15-30 minutes retention time. The gas from the glycol separator can be used for fuel gas/instrument gas

The glycol then flows through the glycol/glycol heat exchanger of tube side for preheated where the rich glycol (shell side) is heated by the hot lean glycol to approximately 130°F to 150°F. The preheated glycol then flows through a glycol filter to remove solids. Filters are normally designed for the removal of 5-micron solids. The filters help minimize foaming and sludge build-up in the reconcentrator. The preheated glycol then flows through the reflux condensing coil in the still column mounted on the reconcentrator, which operates at atmospheric pressure As the glycol falls through the packing in the still column, it is heated by the vapors being boiled off the liquids in the reboiler. The falling liquid gets hotter and hotter. The gas flashing from this liquid is mostly water vapor with a small amount of glycol Thus, as the liquid falls through the packing it becomes leaner and leaner in water Before the vapors leave the top of the still they encounter the reflux condenser, where the cold rich glycol from the contractor cools them, condensing the glycol vapors and approximately 25 to 50% of the rising water vapor. This develops a reflux liquid stream, which reduces the glycol losses to atmosphere to almost zero. The water vapor exiting the top of the still contains a small amount of volatile hydrocarbons and is normally vented to atmosphere at a safe location. The water vapor can be condensed in an aerial cooler and routed to the produced water treating system to eliminate any potential atmospheric hydrocarbon emission The glycol liquid in the reboiler is heated to 340°F to 400°F to provide the heat necessary for the still column to operate The wide difference in the boiling points of water and glycol provides an easy, effective separation of the two components.

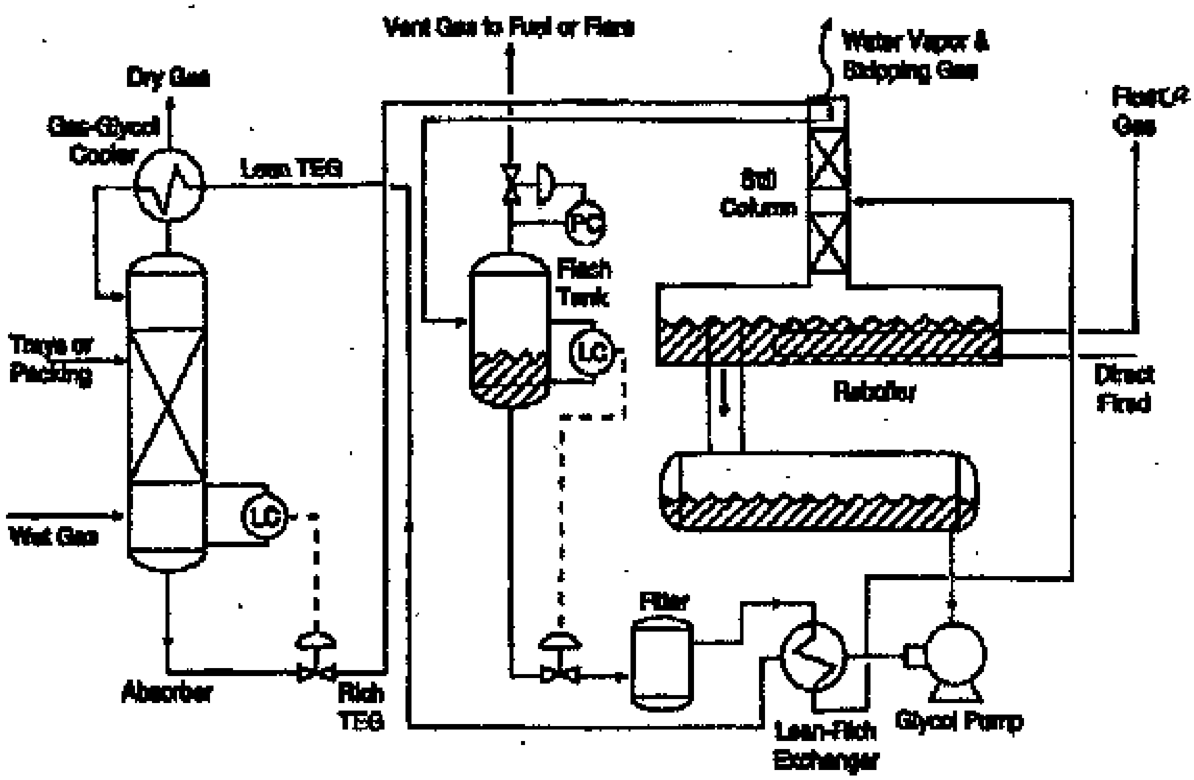
The lean (hot reconcentrated) glycol flows from the reboiler through a downcomer pipe into a surge tank, which could be constructed, as an integral part of the reboiler The surge tank must be large enough to allow for thermal expansion of the glycol and to allow for reasonable time between additions of glycol. Some plants the surge tank acts as a reservoir as well as normally containing the glycol-to-glycol heat exchanger. In order to obtain higher glycol concentration a stripping gas stream of 1-3 scf/gal. of TEG is introduced into the regenerator surge section to flow countercurrent through the packed section between the regenerator and the surge section The glycol pump takes suction from the surge tank and discharges back to the contactor to complete the cycle Simplified process flow diagram of glycol dehydration plant is shown in Figure 4.4.

v. *Sales gas handling*

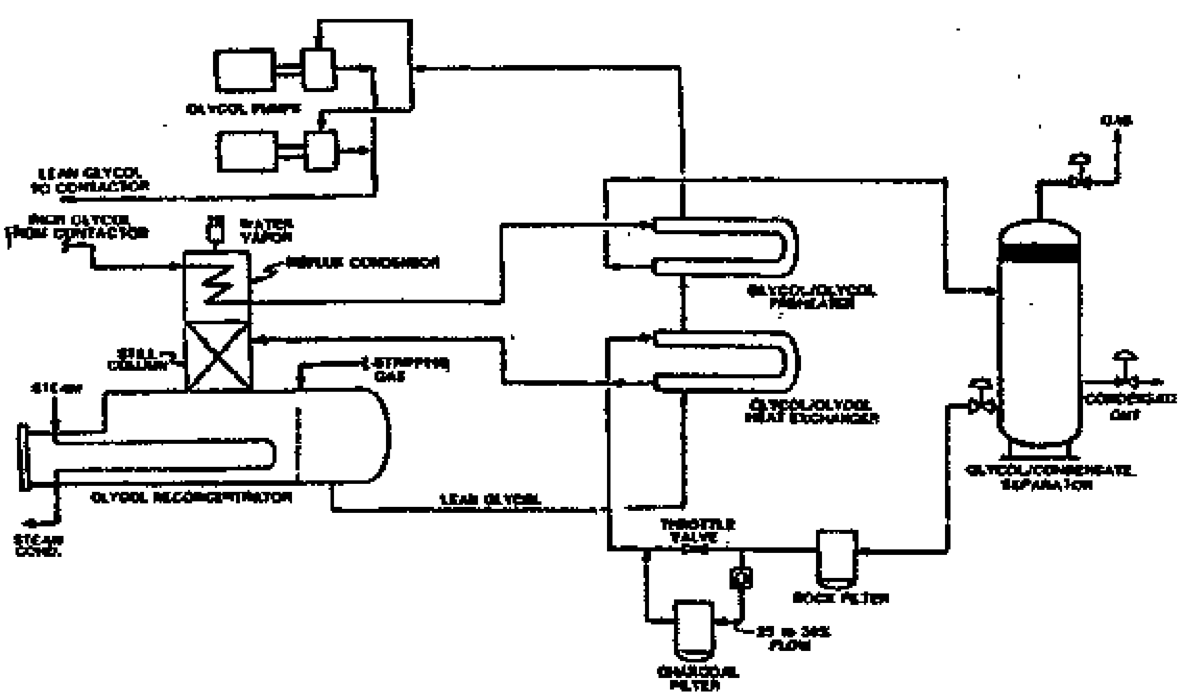
Gas from glycol absorber tower is supplied to sales/transmission line. Orifice meter are adopted for the natural gas flow calculation by the three pen type mechanical recorder for record flow rate(different pressure), pressure, and temperature on the outlet line of the plant. Flow computer also use for record of flow as well as others sales parameters.

vi. *Condensate stabilization (flashing and separating), storage and handling*

Liquid from knockout separator is flashed at 35-50 psi into a three phase condensate flash separator The vessel is divided into two compartments by an overflow baffle. The first compartment provides the required residence time for the hydrocarbon/water condensate. Two level controllers are provided for the vessel. An interface controller, which senses the interface and controls the condensate/water interface by controlling water flow through control valve & another controller, controls the condensate level by controlling oil flow through control valve. The gas line from the separator is connected to route fuel gas to the fuel gas system The operating pressure of the separator is controlled by back pressure regulator. The water from the separator is routed to the skim-pit. Condensate from flash



a. Basic Glycol Dehydration Plant.



b. Glycol Reconcentration System.

Figure 4.4: Flow Diagram of Glycol Dehydration Plant.

separator is released to atmospheric pressure at production condensate tank where hydrocarbon condensate and water stabilize and separate into phases. Hydrocarbon condensate accumulated in the production tank is transferred into storage tank for sale.

vii. *Fuel & Instrument gas system*

The flashed gas from the glycol & condensate flash separator is used within the plant as fuel & instruments gas for processes (e.g line heater, reboiler, gas generator, flare pilot and domestic uses etc). During normal plant operation, the fuel gas demand is expected to be higher than the flashed gas flow three phase separator The fuel & instrument demand in excess of flashed gas is met by tapping the dried gas from sales line.

viii. *Flare system and burn-pit*

Gas from pressure relief devices within the plant is vented into a flare header. Flashed gases in excess are also vented through flare header.

ix *Waste water treatment*

Water production from three phase condensate flash separator is accumulate in skim-pit Water accumulated in production tank is also drained into skim-pit where water is allowed to hold for extended period of time for further separation of suspended oil particles into water. Finally water is drained from skim-pit to soak-pit

x. *Fire and safety system*

The plant fire water system equipment consists of the following:

- The fire extinguisher can be used to extinguish minor fire in the initial period.
- Mobile foam unit can be used to extinguish the ground-level spill fire of liquid of flammable liquid in the area of tank yards where flammable liquid is stored. Foam fire fighting system consists of foam tank, foam proportioner, air foam chambers, foam distribution piping and manifold.
- Smoke detector and Heat detector are monitored by a central fire alarm panel installed in the control room
- The fire fighting pump will be started up automatically when the fire fighting equipment opened.
- The electrical jockey pump to maintain the hydraulic pressure of the fire fighting system.
- Fixed water cooling system consists of valves, fire water spray ring and spray nozzles etc.
- The fire hydrants to cool the tank, put out fire and supply fire water to fire engine.

4.2.2 Adsorption Process: Silica-Gel Dehydration Plant

As an adsorption process, the extent of dew point depression is determined by inlet gas temperature and pressure, type of adsorbent used. This dehydration process, which lowers the water content of natural gas, will prevent the formation of hydrates. A secondary benefit, which results from the removal of the free water and recover of free liquid hydrocarbon ("associated condensate") are done in the inlet knock-out separators. Removal of water vapour and recover of vaporized heavy hydrocarbons ("recovered condensate") are done in the Adsorption towers using Sorbeads as adsorbate in most of the field.

There are eleven silica gel process plants located at different fields as shown in table 4.5.

Table 4.5 : Silica Gel Dehydration Process Plants in Different Fields.

Name of the gas field	No. of Process Plant	Capacity of Plant (MMscfd)
Bakhrabad	4	4 X 60
Beanibazar	1	60
Fenchuganj	1	60
Kailashtila	1	30
Rashidpur	3	60 + 2 X 45
Sylhet	1	30
Total	11	570

General description of equipment and process of a Silica Gel plant are presented in the following sections.

4.2.2.1 Process Equipment

Generally a silica gel plant consists of the following major components/systems:

i. *Flow line and shut-in valve*

The flowlines run of different wells from different location to the Silica Gel Unit. Shut in valves are ball valves with spring loaded-actuators which close incase of ESD in flowlines. The ESD Valves are located on site on the inlet manifold skid The pressure control valves are conventional control valves with pneumatic actuator and valve positioner. The controllers are located in the control room panel.

ii. *Inlet water bath heater / Well stream heater*

Well stream heater is a horizontal indirect gas fired water bath heater. The gas is heated in the internal coils. The top of bath vessel is mounted with an expansion tank. The heating medium used is hot water. The bath vessel is insulated with a insulator such as glass wool. A removable firebox consisting of burner assemblies complete with a solenoid valve, safety solenoid valve and a flame arrester is connected to one end of the vessel Generally, heat is supplied to the bath by means of one fire tubes and two flue tubes connected to the burners at one end and to a flue gas stack at the other end. The natural gas from inlet header will be heated in heating gas coils, consisting of group of coils and welded onto the vessel and immersed in the hot water The temperature of gas is controlled by bypassing, a part of the gas across the heater via the temperature controller. The heater is equipped with a safety shut down panel local to the heater.

The fuel supply to the heater is routed to the heater from the fuel gas scrubber. The fuel gas is filtered in the fuel gas scrubber, before passing through the burner control assembly to the box. Other instrumentation provided for the heater includes level, pressure and temperature gauges at various locations, and pressure/vacuum relief valve on the fuel gas line.

iii. *Inlet knock- out separator*

The Inlet Knock-out Separator is a horizontal/vertical separator Skid mounted with all automatic level controls and liquid and gas outlet piping. The heated gas from the inlet water bath flows into the inlet separator. This vessel contains a vane type demister at the top, which removes any entrained liquid Condensate collected in this vessel is drained through level control valve, and sent to the heavy condensate three phase separator, and the water to the condensate/water separator.

iv. *First stage scrubber*

The first stage scrubber is a vertical gas/liquid separator to remove liquid portion from wet gas stream

v *Inlet filter separator*

The entrainment separator is a horizontal filter separator with removable internal filter elements to remove any vapour which might carry over from first stage scrubber. The type of two section filter separators has a high efficiency since it uses filter elements (tubular cartridges) in the first section and a vane mist extractor pack or in alternative a wire mist eliminator in the second section The gas stream enters the inlet nozzle and passes through the filter section where solid particles are filtered and liquid particles are coalesced into large droplets. The major quantity of these droplets is collected in the first stage of the sump. The remaining droplets pass through the tubes and are entrained in the second section of the separator, where a fine mist extraction element removes these still entrained coalesced droplets from the gas stream. These droplets are then collected in the second stage of the sump The different levels of condensate in the sump are controlled by control valve in the separator's liquid outlet line. The liquid outlet connects with the condensate line from inlet separator into the heavy condensate three phase separator.

The filter separator is designed to remove liquid particles down to 5-micron size A high pressure drops of about 0.2 barg or more would indicate the elements are clogged and need replacement. Separator drain lines are provided from the first and second stage sump connected to the oil/water separator.

vi *Desiccant towers*

The desiccant towers are vertical vessels containing desiccant material, supported on ceramic balls, supported in turn by a grid plate bolted onto supported beams. An inlet gas distributor is provided at the tower top to introduce the gas radially at a lower velocity. A layer of ceramic balls is provided at the top of the desiccant bed. The desiccant tower has internal insulation with centrifugal glass wool contained in a stainless steel shell. Manways are provided for filing and cleaning out purpose. Generally, the desiccant shall be lain two layers, the super stratum is "Sorbead WS" silica-gel, which is mostly, adsorb water, substrate be "Sorbead H". The layer is detached by a separated screen Depending on the operating mode, a tower will receive either the feed gas, regeneration gas or cooling gas. Operating cycle time is controlled by PLC The plant is designed for water removal as well as hydrocarbon recovery. When wet inlet gas flows downward through the desiccant bed, all adsorb able components are adsorbed at different rates. Water is always adsorbed rapidly by the top layer of the bed and the remaining natural gas components are adsorbed in lower layers in different zones The zones travel downwards and the break through of each component occurs at a different time. The adsorption cycle time is decided based on the optimum hydrocarbon cut that is desired to be achieved. For the Silica gel Type gas process plant the cycle time considered in the design is 30 minutes (For the design flow rate), but can be adjusted.

The process plant is designed to achieve an outlet hydrocarbon dew point of -15°C with the normal operating conditions The water content in the outlet gas is designed to be less than 7 Ibs/MMSCF at normal conditions.

A pressure drop of about 1 5 bar will take place across the desiccant bed during the normal desiccant life. As the desiccant ages, the pressure drop will increase due to the gradual breakage of the desiccant. Abnormal increases in the pressure drop would indicate a high degree of breakage.

vii. *Switching valve skid assembly*

This skid holds all piping manifolds and switching valves needed to direct the different types of gas through the dry desiccant towers.

viii *Sales gas filter*

The dry gas from the desiccant tower in the drying mode flows to the sales gas filter The filter is designed to remove solid particles of sizes down to 5 micron size, the high pressure drop across the filtering elements indicates a build up of impurities and the elements would need to be replaced.

ix *Metering station*

Orifice plate together with differential pressure transmitter is generally used for the natural gas flow rate measure. Generally, Daniel type orifice meter are adopted for the natural gas totalizer on the inlet line and the flow computer on the outlet line of the plant. The sales gas production from the plant, is metered through 2 X 100 % (duty and standby) custody transfer orifice meter runs, and recorded by flow recorder with pressure and temperature compensation. Each gas meter run is provided with a orifice fitting capable of orifice-plate change-over while in service The Flow Control Valve is a butterfly valve, controlling the silica gel units through put

Electronic flow meter is adopted for the local display and totalizing of the fuel gas and instrument gas. Three pen type (Mechanical recorder) use also for record flow rate (different pressure), pressure, and temperature. Mechanical type oval gear flow meter-a kind of PD meter, are used for the local totalizing of the condensate from tank to loading area

x. *Regeneration gas heater*

The regeneration gas heater is a horizontal oil bath type heater, indirect gas fired The top of bath vessel is mounted with an expansion tank. The Heat transfer medium is thermal oil, a proprietary heat transfer fluid The gas flows through removable U-tube bundles, which are submerged in the hot oil. The local panel provides burner management and safety The bath vessel is insulated with a glass fiber layer A removable fire box burner consisting of two burner assemblies complete with a two stage solenoid valve, safety solenoid valve and a flame arrestor is connected to one end of the vessel. Heat is supplied to the bath by means of two fire tubes connected to the burners at one end and to a flue gas stack at the other end. The regeneration gas heating is carried out in a heating gas bundle, consisting of coil, welded onto the bath vessel and immersed in the hot oil. The temperature of gas is controlled by bypassing, a part of the gas across the heater via the temperature controller.

The fuel supply to the heater is routed to the heater from the fuel gas drum The fuel gas is filtered in the fuel gas scrubber, before passing through the burner control assembly to the firebox.

The heater start up, shut down and controls are by means of a burner management system. Before ignition of the burners, the upstream line must be kept in straightway The heater control panel is located at the edge of the heater. Other instrumentation provided for the heater includes level, pressure and temperature gauges at various locations, and pressure/vacuum relief valve on the fuel gas line and the expansion vessel.

xi *Gas-gas exchanger*

The gas/gas exchanger is a shell and tube heat exchanger with "U" type removable bundle. The regeneration gas/cooling gas exchanger preheats the feed gas to the regeneration gas heater with either the hot cooling gas (during the initial stages of each operating cycle) or with the hot regeneration gas (during the final stages of operating cycle). The cool feed gas flows in the tube side of the exchanger, while the hot regeneration gas / cooling gas flows in the shell side The switching of the shell side fluid from the cooling gas to the regeneration gas is by means of the PLC, with the switching point being determined by temperature detection of the warm cooling gas from desiccant tower.

xii. *Regeneration gas cooler*

The Regeneration gas coolers are forced draft coolers with electric motor driven fan and finned tubes One unit is stand by. This cooler further cools the wet gas from the regeneration gas/cooling gas exchanger on regenerating cycle line. From the cooler gas, some gas condensed is routed to the regeneration gas separator. The air cooler consists of a single tube bundle Each fan is located below or top the tune bundle, to provide the cooling air flow required for the exchanger. The air coolers are protected from vibration cutout switches.

xiii. *Cooling gas cooler*

The Cooling Gas Coolers are forced draft coolers with electric motor driven fans and finned tube bundles. One unit is standby This cooler further cools the warm cooling gas from the regeneration gas/cooling gas exchanger on cooling cycle line From the cooler gas is routed to the sales gas filter. The air cooler consists of a single tube bundle Each fan are located below or top the tune bundle, to provide the cooling air flow required for the exchanger. The air coolers are protected from vibration cutout switches

xiv *Regeneration gas separator / scrubber*

The regeneration gas scrubber is a 2 phase separator The cooled regeneration gas from the regeneration gas cooler flows to the regeneration gas separator, a vertical vessel provided with an angle vane type demister to remove entrained liquids. The condensate collected in the vessel is removed through level control valve, and sent to the light condensate three phase separator

xv. *Heavy condensate three phase separator*

The separator is a horizontal, 3 phase low pressure separator. The vessel is divided into two compartments by an overflow baffle. The first compartment provides the required residence time for the hydrocarbon/water condensate Two level controllers are provided for the condensate/water interface level and the condensate level An interface controller, which senses and controls the condensate/water interface by controlling water flow through control valve The gas line from the separator is connected downstream of pressure control valve to route fuel gas to the fuel gas system. The condensate from the separator is routed to the condensate storage tank and the water to the oil/water separator .

xvi. *Light condensate three phase separator*

The separator is a horizontal, 3 phase low pressure separator. The vessel is divided into two compartments by an overflow baffle. The first compartment provides the required residence time for the hydrocarbon/water condensate. Two level controllers are provided for the vessel An interface controller, which senses the interface and controls the condensate/water interface by controlling water flow through control valve & another controller, controls the condensate level by controlling oil flow through control valve The gas line from the separator is connected downstream of pressure control valve to route fuel gas to the fuel gas system. The operating pressure of the separator is controlled by these PCV. The condensate from the separator is routed to the condensate storage tank and the water to the oil/water separator.

xvii. *Condensate storage tank*

The associated condensate storage tank is a cone roof tank. The tank is provided with flame arrester, utility connection, and a foam chamber for fire fighting. Instrumentation for the tank consists of a level gauge and sample connections.

xviii. *Condensate transfer pump*

Condensate is transferred from the condensate storage tanks to platform by means of condensate transfer pump The pumps are provided with suction strainers, on/off indication and handle switch

ixx. *Process / utility fuel gas drum*

The fuel gas knock-out pot is a vertical vessel with a design pressure of 8-10 barg at 70 deg.C. Nominal operating pressure is 6 barg at an expected temperature of 9.8 deg.C. Gas from the heavy and light condensate three phase separators flows into the pots During normal plant operation, the fuel gas demand is expected to be higher than the gas flow from heavy & light three phase separator. The shortfall is made-up by the letting down sales gas into the fuel gas drum by the pressure control valve and regulator From the knock-out pot, the fuel gas is routed to the various user points, e.g the heater and power generator.

xx. *Flare knock out drum*

The flare k o drum is a horizontal/vertical vessel with a design pressure of 10-12 barg at 70 deg.C. Nominal operating pressure is 0 5 barg at an expected temperature of 40 deg.C. Gas from fuel gas drum & heavy & light three phase separator flows into the L P flare header. Gas from desiccant towers, inlet separator & inlet header flows into the H.P.flare header. The two flare headers mix and then flow into this drum.

xxi. *Oil /water separator*

The oily water from the flash separation of process streams is separated in the oil/water separator to bring down the oil content in water to less 20 ppm before the water is discharged out of the unit. The oil/water separator is a proprietary design unit containing oil-contaminated wastewater pond, energy elimination pond, etc. in package oil-contaminated wastewater treatment and recovery oil tank. The oil water from the process plant first goes from wastewater pond to energy elimination pond by two oily water pumps and then flow to oil-contaminated wastewater treatment by gravity. The integral oil compartment is flow to the recovery oil tank by recovery pump. The treated water from the separator flows to underground. The wasted oil in the recovery oil tank can be collected into barrel by hand

xxii. *Power generation system*

The power requirements of the facility will be met by three gas generators (one in operation, one on stand-by and the other one assumed to be under maintenance) Power Factor Improvement Capacitors are provided to maintain a power factor of 0.85

xxiii. *Instrument air system equipment*

Compressed air for instrumentation is supplied by an air compressor package consisting of two air compressors Each compressor is equipped with an air cooled after cooler. The normal mode of operation for the compressors is to have one selected to operate in running and the other on stand by mode. Operation is controlled by pressure switches located on the air receiver through a local control panel. The air compressor control system includes such flowing Pressure switches functions. Air is discharged from the compressors via the air drying system to the air receiver. The air drying system consists of pre-filters, heatless type desiccant drying towers and after-filters.

xxiv. *Control system*

The whole plant control system, which located in control room consists of four instrument panels with mimic board and panel mounted instrument, PLC system together with accessories mounted in cabinets and HMI station, for sequence control, interlock logic, ESD and tank volume compensation.

xxv *Field instrument*

Field instrument are installed in the field for measuring process data. All electronic instrument and wiring are suitable for use in the relevant hazardous area classification, generally designed as intrinsically safety type and explosion proof type, if it is not available.

xxvi. *Safety equipment & gas detection system*

Other safety equipment located in the control room is:

- CO_2 extinguisher
- Manually raise the alarm from control room or from field by breaking Manual Call Point (BGU)
- Smoke detector and Heat detector

Manual push buttons strategically installed around the areas within the plant B.L. Totally nine sensors are strategically located all over the plant in order to guarantee a prompt detection of any possible leakage of natural gas from the process. The detectors are monitored by a central fire alarm panel installed in the control room. The panel is set up on a zonal basis to clearly show the status and location of the alarm.

Monitoring system is conventional panel in control room with alarming signal to alert operating personnel of any dangerous situation reached in identified area.

xxvii. *Fire fighting system equipment*

The plant fire water system equipment consists of the following:

- The fire fighting pump located in the pump shed near the fire water reservoir. If a fire does occur on the plant, the pump will be started up automatically when the fire fighting equipment opened.
- The electrical jockey pump located in parallel with the fire fighting pump. It worked to maintain the hydraulic pressure of the fire fighting system daily.

- Fixed water cooling system consists of valves, fire water spray ring and spray nozzles etc.
- Foam fire fighting system, which is fixed type, consists of foam tank, foam proportioner, air foam chambers, foam distribution piping and manifold.
- The fire hydrants which are connected to the fire water main can be used to cool the tank, put out fire and supply fire water to fire engine.
- Mobile foam unit can be used to extinguish the ground-level spill fire of liquid of flammable liquid in the area of tank yards where flammable liquid is stored
- The fire extinguisher can be used to extinguish minor fire in the initial period.

xxviii. *Plant shutdown systems*

The entire plant has two levels shutdown system (being WSD-well shutdown and BSD-emergency shutdown) that block in the produced fluid feed entering the plants Push button for initiating an ESD are provided in the control room Emergency shutdown valves to block-in the unit are also provided along with a depressuring valve with restriction orifice to limit the depressuring rate to 100 psi/min. to avoid damage to the Sorbeads.

ixxx *Relief valves*

Safety valves for protection of the vessels from over pressure, fire etc are directed to flare. Relief valves are provided in the plant at various locations to safety relieve high pressures. A full capacity relief valve to cater to the blocked outlet condition is provided for the line and inlet separator The set pressure of PSV valves of inlet separator is 1 barg lower than that of other middle pressure system PSV valve. External fire under blocked in conditions is considered in the design of all the separators and towers and the fuel gas drum scrubber relief valves. The outlet of inlet filter separator & sales gas filter PSV valves are focused into the flare header.

The major equipments/components described in above are not installed in every silica gel dehydration process plant Moreover, same equipment of different types is installed in different plants Pressure reduction unit, inlet filter separator, desiccant tower, Regeneration gas heater/cooler/scrubber, cooling gas cooler, condensate three phase separator, sales line scrubber, recording system, fuel gas & instrument air system, flare & burn pit, waste water system etc are similar type installed in every plant in Bangladesh.

4.2.2.2 Process description

Silica gel type gas process plant adopts solid desiccants, three towers process to dehydrate and recover all economical possible condensate from natural gas. The plant and associated facilities processes the natural gas from wells

The following is a brief description of the Hydrocarbon Desiccant & recovery plant. Block Diagram Figure 4 5 provides supplementary information to these descriptions. The process plant may be visualized, for convenience and consists of the following sections.

i *Flow lines first stage pressure reduction*

The inlet gas is drawn from wells are passing along the flow-lines, the gas flows via ESD valves. Flow rate, pressure and temperature of each well are monitored and controlled in the control room. The silica gel type gas process manifold is designed to operate at an inlet pressure of about 85 barg at the plant limit. If the pressure exceeds this value, the gas stream after flashing across the inlet pressure controller may cool down to a level lower than the acceptable hydrate limits, especially during the winter months due to low feed gas temperature.

ii. *Well stream heating*

The inlet water bath heater always keeps the water temperature above 50~90°C, the gas stream across the inlet water bath could be above the hydrate limit all time. To prevent the formation of hydrate, inlet water bath heater is provided in the down stream of the plant inlet header. The hydrate temperature at the nominal manifold operating pressure of 85 barg is approximately 17° C and allowing a suitable margin needs to be maintained at a minimum of 25°C. After being heated to the required temperature, the gas flows back to the manifold. The gas pressure is then reduced to 85 barg through the pressure reduction valves Because the pressure of the gas in the three Inlet KO Separators is higher than that in the production manifold, the gas must be throttled This is achieved in the flow control valves for three KO separators

iii. *Well stream separation*

Inlet separator is located downstream of pressure reduction valves to remove liquids from the incoming gas stream. The temperature of the inlet gas on arrival at the plant site is between 25 and 45°C, but could, possibly be as low as 4°C in mid winter.

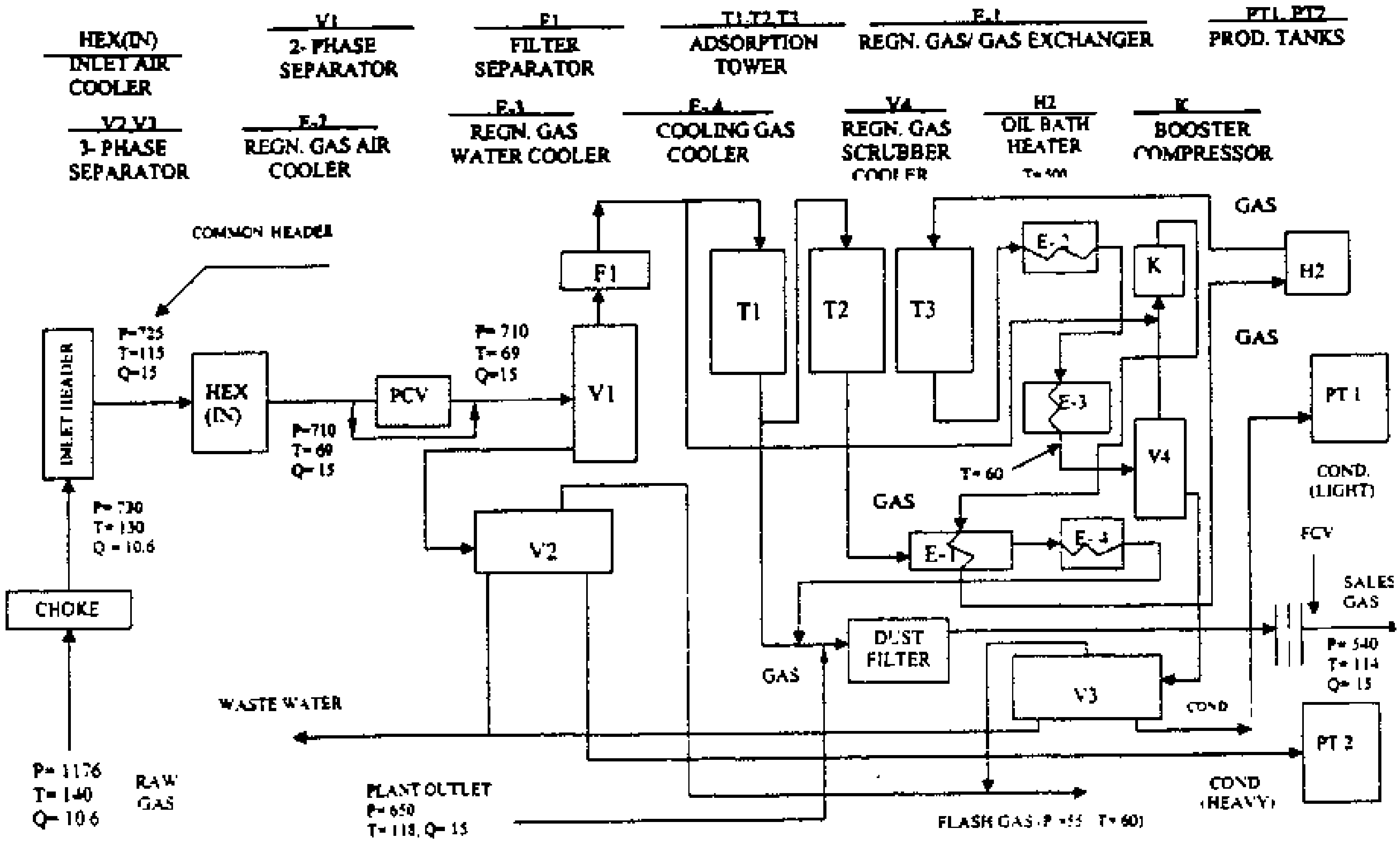


Figure 4.5 : Block Diagram of Silica Gel Dehydration Plant.

The gas from the inlet separator then flows to the inlet filter separator. Filter Separator to remove any solids and entrained liquids particularly water which can affect the silica gel desiccant performance.

The liquid from the Inlet Separator and the Inlet Filter Separator then passes to the plant associate / heavy condensate separator .

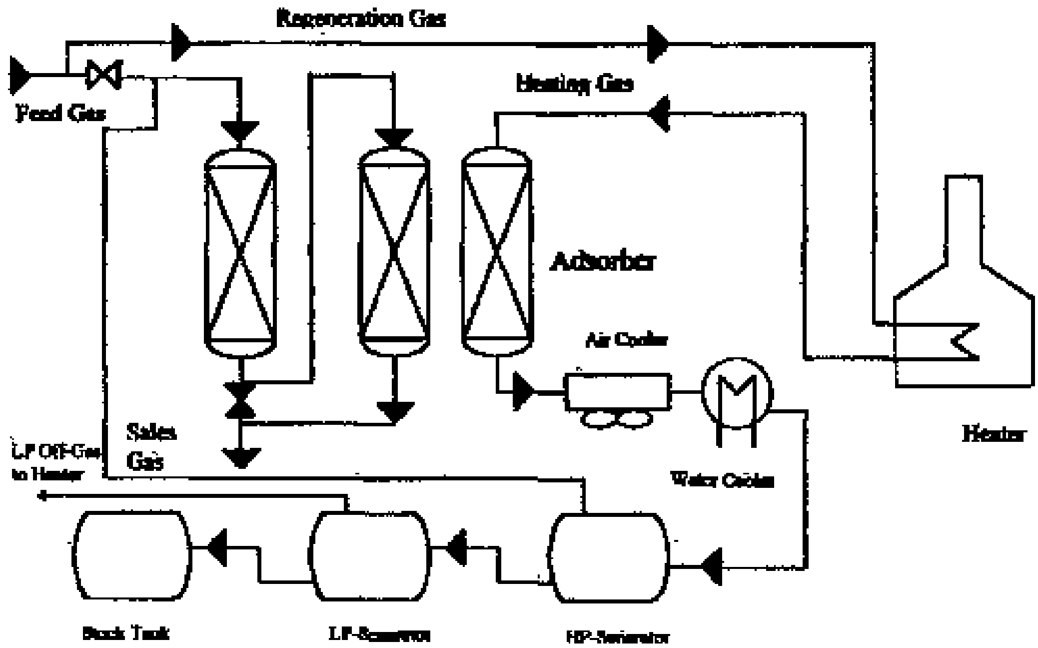
iv. *Gas dehydration*

The three desiccant towers operate in different modes at any given time Thus, while first tower is in the drying mode, the second is in the regeneration mode and the third is in the cooling mode. The operating mode for the towers changes with an approximate 1/2 hour interval cycle.

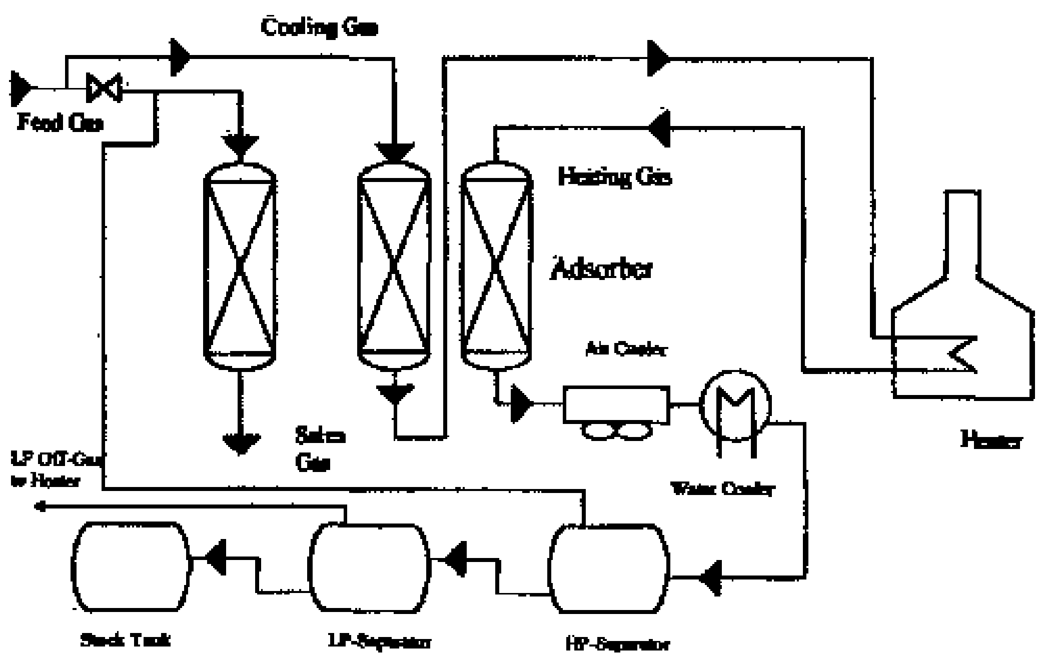
The optimum switch time of desiccant towers shall theoretically selected to ensure fully regeneration of regen tower and cooling down of cooling tower. The outlet temperature of regen. tower is recommended by vender around 250°C~260°C and that of cooling tower be around 30°C

At the beginning of each cycle the tower in live drying mode in the previous cycle changes to regeneration mode, the tower in the regeneration mode to cooling mode and the tower in the cooling mode to drying mode. The operating mode switch-over of the towers is controlled by a timer-activated automatic sequential control system programmed in a PLC, and set nominally at 30-minutes.

The filtered gas is routed to the desiccant towers and enters the tower in the drying mode from the top The towers contain a bed of silica gel based desiccant and, while passing through the bed, the water and C5 - plus the heavier hydrocarbon components present in the gas stream get adsorbed onto the desiccant. The contact with the desiccant bed renders the gas stream sufficiently dry to meet the dew point specifications (both water and hydrocarbon) required for the pipe line quality. The dried gas flows out from the bottom of the tower and is routed to the dust gas filter Basic flow sequence diagram of desiccant tower is shown in Figure 4.6.



a. Cooling Flow Sequence (Adsorption)



b. Cooling Heating Flow Sequence (Adsorption)

Figure 4.6 : Basic Flow Sequence in Adsorption Process.

v *Regeneration gas treatment*

The tower in the regeneration mode undergoes heating of the desiccant bed with hot regeneration gas This gas is a side stream of approx 30% of the feed gas to the desiccant towers and heated in the regeneration gas heater to about 250°C The hot gas, while passing over the desiccant bed, vaporizes the adsorbed water and hydrocarbons from the bed From the tower, the regeneration gas flows through the following exchangers in series to cool it down to about 45°C·

- Firstly, it passes through the shell side of the gas-gas exchanger where heat is exchanged with the cold regeneration gas en route to the regeneration gas heater
- During the initial stages of the cycle, when the regeneration gas exiting the tower is at a low temperature, the stream bypasses this exchanger Then, it flows through the regeneration gas cooler

At a temperature of approximately 45°C, most of the water and hydrocarbon (evaporated from the desiccant bed in the regeneration part of the cycle) condense out and are separated from the gas stream in the Regeneration Gas Separators and then blended back with the main raw process gas from the Filter Separator.

vi. *Cooling gas treatment*

At the end of the regeneration cycle, the desiccant bed regains its original capacity to adsorb water and hydrocarbons. However, before it is ready for this., it has to be cooled down approximately to the feed gas temperature This is achieved during the cooling cycle using the standard tail gas cooling configuration described below-

From the outlet of the desiccant tower in the drying mode, a side stream (approx. 30%) is withdrawn and passed over the desiccant in the cooling mode. After leaving the tower in the desiccant mode, the hot cooling gas flows through the following exchangers in series cool it down to about 50°C.

Firstly, it flows through the shell ,side of the gas-gas exchanger, where heat is exchanged with the cold regeneration gas to the regeneration gas heater

During the later stages of the cooling cycle - when temperature of the cooling gas exiting the tower is low, stream by passes this exchanger

After cooling, the gas stream is blended with the main stream exiting the desiccant tower in drying mode and passes on to the dust filter.

vii. *Sales gas metering and export*

The dried gas from the outlet of the desiccant tower in the drying mode is filtered in the dust filter/filter separator for removal of desiccant dust and fiscally metered before flowing out of the plant into the existing sales gas pipeline.

viii. *Condensate stabilization, storage and handling*

The hydrocarbon condensate is recovered in the plant from the following two sources:

-Upstream of the desiccant towers at the inlet knock out separators

-Inlet separator and

-Filter separators

-Regeneration gas separators.

The Condensate from the first sources contains comparatively heavier components and is therefore termed the 'Heavy Condensate' to distinguish it from the 'Light Condensate' from the second source. The two sources are processed and handled separately as described below-

The heavy condensate from the inlet knock out separators, inlet separators and filter separators is sent to the Associate Condensate Separator, designed for three-phase separation and operating at a pressure of 6 barg. Due to the lower pressure, some of the lighter components flash off and pass to the fuel gas system. Of the residual liquids, the condensate passes to the Associated Condensate Production tank and the water is routed to the Oil/Water Separator. From the Associated Condensate Production Tank, the heavy condensate passes to the Associated Condensate Storage tank for loading onto tankers

The light condensate from Regeneration Gas Separator is treated in a similar manner in another three-phase separator, the Recovered Condensate Separator then flows to the Recovered Condensate Production tank and the wastewater to the oil water separator. From the recovered condensate production tank, the light condensate passes to the Recovered Condensate Storage Tank. The condensate is exported by the condensate transfer pumps and two sets of loading facilities to road tanker. It is possible for each pump to transfer condensate from both separate tanks to both loading arms

The process wastewater generated in the plant is routed to Oil/Water Separator. This separator is used to remove any entrained condensate from the associated water streams draining from the plant. It is designed to meet the required effluent discharge specification. The wastewater separated from the separator is then discharged directly to the underground.

The condensate rising to surface of water is removed in the skimmed oil sumps and then transferred by means of the skimmed oil pumps back to Condense Storage Tank.

ix. *Flare system*

Gases from pressure relief device within the plant are collected into a flare header and then routed to the flare system comprising the flare k.o. drum and other required facilities.

x. *Waste water system*

The process wastewater generated in the plant is routed to Oil/Water Separator. This is used to remove any entrained condensate from the associated water streams draining from the plant. It is designed to meet the required effluent discharge specification. The wastewater separated from the separator is then discharged directly to the underground.

The condensate rising to surface of water is removed in the skimmed oil sumps and then transferred by means of the skimmed oil pumps back to Associated Condense Production Tank

xi. *Fuel gas system*

The gases flashed off from the heavy and light three phase separators are used as fuel gas within the plant (Power Generators, heaters etc.). Any shortfall in the fuel gas requirement is made up with dry product gas downstream of Dust Fillers The utility fuel gas enters the utility fuel drum / knock-out pots for the removal of the entrained liquid before distributed to the various utility fuel gas users.

xii *Instrument air system*

The instrument air requirements of the plant are provided by two instrument air compressor packages each consisting of a compressor, a filter and dryer with one in operation and the other on stand-by.

xiii. *Power generation*

The power requirements of the facility will be met by three gas generators (one in operation, one on stand-by and the other one assumed to be under maintenance)

xiv *Control panel*

The Control Panel in the control room displays virtually all vital operating parameters either on indicators or on recorders. Status of alarms (annunciation) is also shown In principle the operator can control the plant from the control panel. It is however important that the operator makes physical checks on the equipment in the plant to ensure its safe and proper operation.

The Control Panel is a free standing steel structure which contains all electronic control circuitry and interlocking systems of the plant, both for the glycol dehydration unit and for the silica gel unit.

- Controls: An overall mimic diagram depicts the flow scheme of the silica gel unit from the wells The two major process parameters are gas pressure and gas flow rate These are controlled from the panel by means of electronic controllers

  Pressure is controlled by controller and corresponding flow controllers, each controlling the individual well productions in a fixed preset (by operator) flow-ratio.

  The pipeline pressure controller overrides the flow controller in case of high pipeline pressure.

- Records: The Gas moisture content, density, the gas flow, pressure and temperature are recorded, parallel to the flow computer The recorder is duplicated for the two meter runs. The recorded flow shows compensated flow (P and T) and a signal is available for future transmission to SCADA These recorders are in the control panel.

  The adsorber tower outlet temperatures are recorded. The pattern of the temperature gives a good indication of the cyclic operation of each of the three towers

The blow down valve may be opened by pushing the button on the control panel to blow down the plant.

- Annunciator Panel: The annunciator panel provides, alarm indication for the Silica Gel Unit and its ancillaries. In case of an alarm the respective window will light, flashing. The operator shall acknowledge by pushing the "acknowledge" button, the window light" will then be permanent. The "mute" button stops the horn. When the problem is solved, pressing "reset" switches off the window light.

  Pressure & Temperature indicators are electronic indicators giving process parameters for the operator's information.

  The quantity of condensate stored in each of the tanks is displayed on the panel as percentage of the total tank capacity.

- Flow Computers: Two flow computers are connected to the two meter runs Each computer calculates the flows compensated for pressure, temperature and density and indicates following :

  -The rate of uncompensated flow. (MMscfd)
  -The integrated running total (Mscfd)
  -The total for the last 24 hours period, the last 7 day period, the last 28 day period and the last 3/6 and 12 months. (MMscf)

xv. *Fire and gas detection panel*

This panel consists of the following items:-

- Analyzers Panel.
- ESD Panel: The position of shutdown valves is shown in mimic panel. The ESD functions are displayed on the annunciator panel. ESD is reset at the annunciator panel.
- Printer
- Maintenance Overridden Switches: The panel includes hand switches to operate automatic valves Also a set of hand and key-switches is included to override shutdown functions in case of start up.

4.2.3 Low-Temperature Extraction Type Plant (LTX)

A low-temperature extraction (LTX) type process plant installed at Meghna field. Two similar train of LTX unit was installed each capacity 20 MMscfd The LTX system efficiently handles high-pressure gas at the wellhead, separating condensable liquid hydrocarbons from it at a temperature below its hydrate point. This process recovers more valuable liquids than conventional separation methods.

Separation of hydrocarbon liquids and water from gas stream is done by allowing expansion cooling of the gas stream through a choke, to a temperature well below a hydrate condition (sub-hydrate operating condition) Expansion of the gas stream results in the sudden drop in pressure and that results in drooping down the temperature of the gas stream according to Joule-Thomson expansion cooling effect of gas.

Description of process of LTX plant is presented in the following sections.

4.2.3.1 Process Description

Two Low Temperature Extraction Plant involve in for processing of gas on Meghna Gas Field shown in Figure 4.7. The capacity of each plant 40 MMscfd. The low-temperature extraction type process plant includes the following operations/equipments:

i *Inlet water bath heater*

The gas stream of wellhead pressure reduces by PCV and gas stream may cool down to a level lower than the acceptable hydrate limits, especially during the winter months. The inlet water bath heater always keeps the water temperature above 50~90°C, the gas stream across the inlet water bath could be above the hydrate limit all time. To prevent the formation of hydrate, inlet water bath heater is provided in the down stream of the plant inlet header After being heated to the required temperature, the gas flows back to the manifold. The gas pressure is then reduced through the pressure reduction valves In practically, water bath heater is not required in operation due to high wellhead temperature after choke manifold of wellhead

PROCESS PARAMETERS: P, Pressure = Psig
T, Temperature = $^\circ$F
Q, Flow Rate = MMcfd

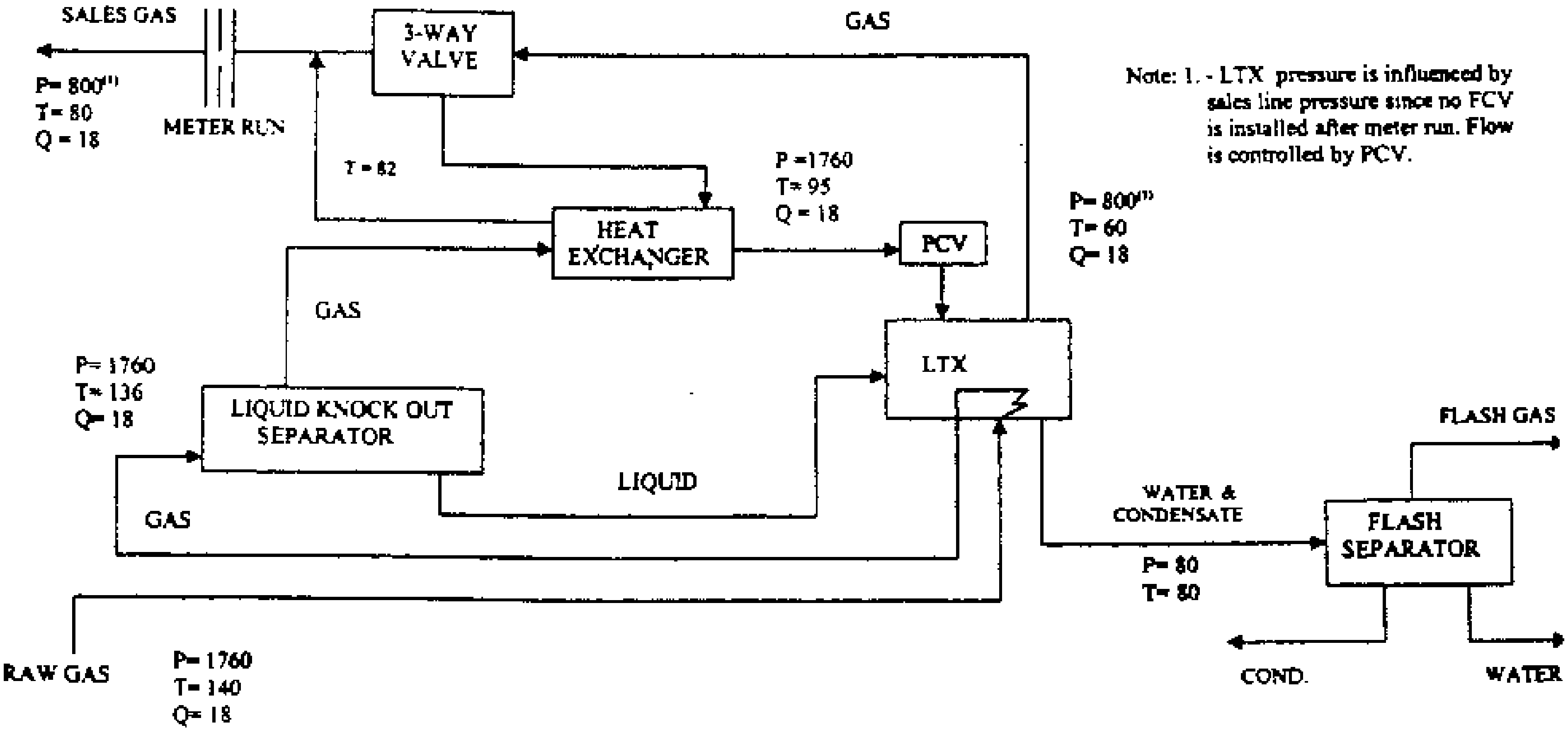


Figure 4.7 : Block Diagram of LTX Unit at Maghna Gas Field.

ii. *Low temperature extraction unit*

The hot gas stream enters a coil in the bottom of the low-temperature separator at a temperature of 120° or greater. The inlet gas is cooled to just above the hydrate formation temperature with the outlet coming off the low temperature separator to assure the lowest possible temperature when it enters the vessel after the choke. This choke is mounted in the vessel itself. Refrigeration is achieved at the expansion choke by pressure reduction. The inlet temperature is held as close/below to the hydrate formation temperature as possible by the temperature controller to ensure maximum separation by maximum temperature reduction. Hydrate formation temperature of typical natural gas is 60 ^{0}F at pressure 1000 psi. Hydrates form, but they fall into the bottom of the separator and are melted by the heating coil Liquid (hydrocarbon & water) in the gas stream is condensed at low temperature into LTX separator. The gas, condensate, and free water are then discharged from the vessel through backpressure and liquid dump valves. The gas leaving the separator is saturated with water vapor at the temperature and pressure of the low temperature separator. If this temperature is low enough, the gas may be sufficiently dehydrated to meet sales specifications. If the flowing temperature of the raw gas stream remains high enough to maintain the temperature of warm flow section of LTS separator then line heater is not required. The long travel of the liquid hydrocarbons in the LTX separator, plus the warming effect by virtue of the distillate sump being immersed in the warm water bath, allow the distillate to reach a considerable degree of stabilization before going to the low pressure separator (flash separator). The heavier components, which are driven out of the liquid as a result of this temperature increase, are returned to the liquid as a result of this temperature increase, are returned to the liquid stream having been condensed by the cold gas stream. Process flow diagram of LTX process is shown in Figure 4.8.

iii. *HP liquid knock-out separator*

The high pressure liquid knockout separator separates all liquid (hydrocarbon & water) from well stream. A liquid level controller operates a dump-valve that releases the fluid into the warm flow section of the low-temperature separator. The free water otherwise would freeze in the choke of the low-temperature separator as the expanding gas drops the temperature below the hydrate point Liquid hydrocarbons passing the choke do not contribute to the adiabatic expansion and only give up heat, thus decreasing the net refrigeration effect of the expanding gas

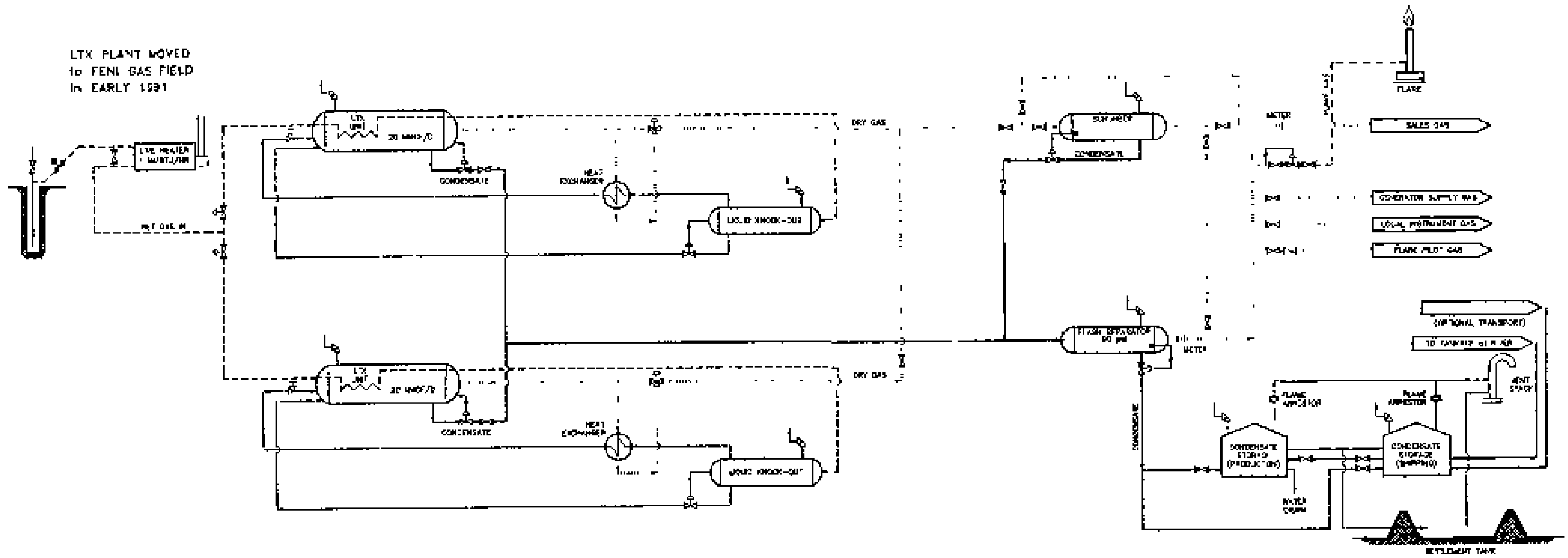


Figure 4.8 : Process Flow Diagram of LTX Unit at Maghna Gas Field.

iv. *Gas-gas heat exchanging*

The gas-gas heat exchanger cools warm high-pressure rich gas down stream of the knockout separator utilizing the effluent cold lean gas from the low-temperature separator as the coolant. A three-way heat exchanger by-pass valve located in the cold gas outlet piping accomplishes the proper degree of cooling A temperature controller with its sensing element upstream of the expansion choke actuates the valve.

v *Sales gas handling*

Cold gas leaves the LTX separator and flows either into, or through, a by-pass around the gas-gas heat exchanger The volume of gas passed through the heat exchanger is determined by the three-way proportioning valve, which in turn is controlled by the temperature controller. The surplus cold gas not required for cooling the high pressure mainstream, is diverted through the by-pass and combined at the three-way valve with the gas used for cooling and finally transmitted to sales line.

vi. *Condensate flash separator*

Liquid from LTX separator is flashed at 30-50 psi into a flash separator. The low-temperature separator acts as a cold feed condensate stabilizer. A natural cold reflux action exits between the rising warmed gases liberated from the liquid phase and cold condensed liquid falling from the stream inlet. The lighter hydrocarbons rejoin the departing gas stream and the heavier components recondense and are drawn from the vessel as a stable stock tank product The colder the temperature of the gas entering the separator downstream of the choke, the more intermediate hydrocarbons will be recovered as liquid

vii. *Condensate storage and handling*

Liquid from flash separator is released to atmospheric pressure at condensate production tank where hydrocarbon condensate and water stabilize and separate into phases Hydrocarbon condensate accumulate in the production tank is transferred into storage tank for sale or further treatment.

viii. *Fuel gas system*

The flashed gas from the flash separator is used within the plant as fuel for processes (e.g. line heater, reboiler, electric generator, flare pilot, instrument gas etc.) and domestic uses. The fuel gas demand in excess of flashed gas is met by tapping the dried gas.

ix *Flare system and burn-pit*

Venting of gas from pressure relief devices within the plant is done into a flare header. Flashed gas in excess is also vented through the flare header.

x *Waste water treatment*

Water accumulated in production tank is drained into skim-pit where water is allowed to hold for extended period of time for further separation of suspended oil particles into water. Finally water is drained from skim-pit to soak-pit

4.2.4 Low-Temperature Separation (without Glycol Injection) Plant

Only four Low-Temperature Separation (LTS) without glycol injection type process plant installed in Bangladesh. In Titas field at location 3, TT-9 & 10 go through LTS process trains (Plant 9 & 10) and at location 5, TT –13 & 14 each go through two newly installed LTS process trains (Plant 11 & 12) Design capacity of each gas processing train/plant is 60 MMscfd. The outlet dry gas of plant 9, 10, 11 & 12 are common facilities for sales gas measurement and transmission and condensate streams are piped to the common facilities at Location 1 storage, transport or further processing

The principle of LTS plant is same as LTX process shown in Figure 4.9. For no use of hydrate inhibitor allows a high pressure well stream to be cooled above the hydrate temperature ahead of the choke so that low temperature can be obtained General description of the process of those LTS plant is given in below:

4.2.4.1 Process description

The low-temperature separation without glycol injection type process plant includes the following operations/ equipment:

i. *Inlet gas cooler*

Gas stream from the TT- 9, 10, 13 & 14 well is passed through a well stream cooler. After cooling some liquid (hydrocarbon & water) is formed into the main stream After cooler a by-pass the hot gas stream enters a coil in the bottom of the low-temperature separator at a temperature of 120° or greater. The inlet gas is cooled to just above the hydrate formation temperature with the outlet coming off the low temperature separator to assure the lowest possible temperature when it enters the vessel after the choke

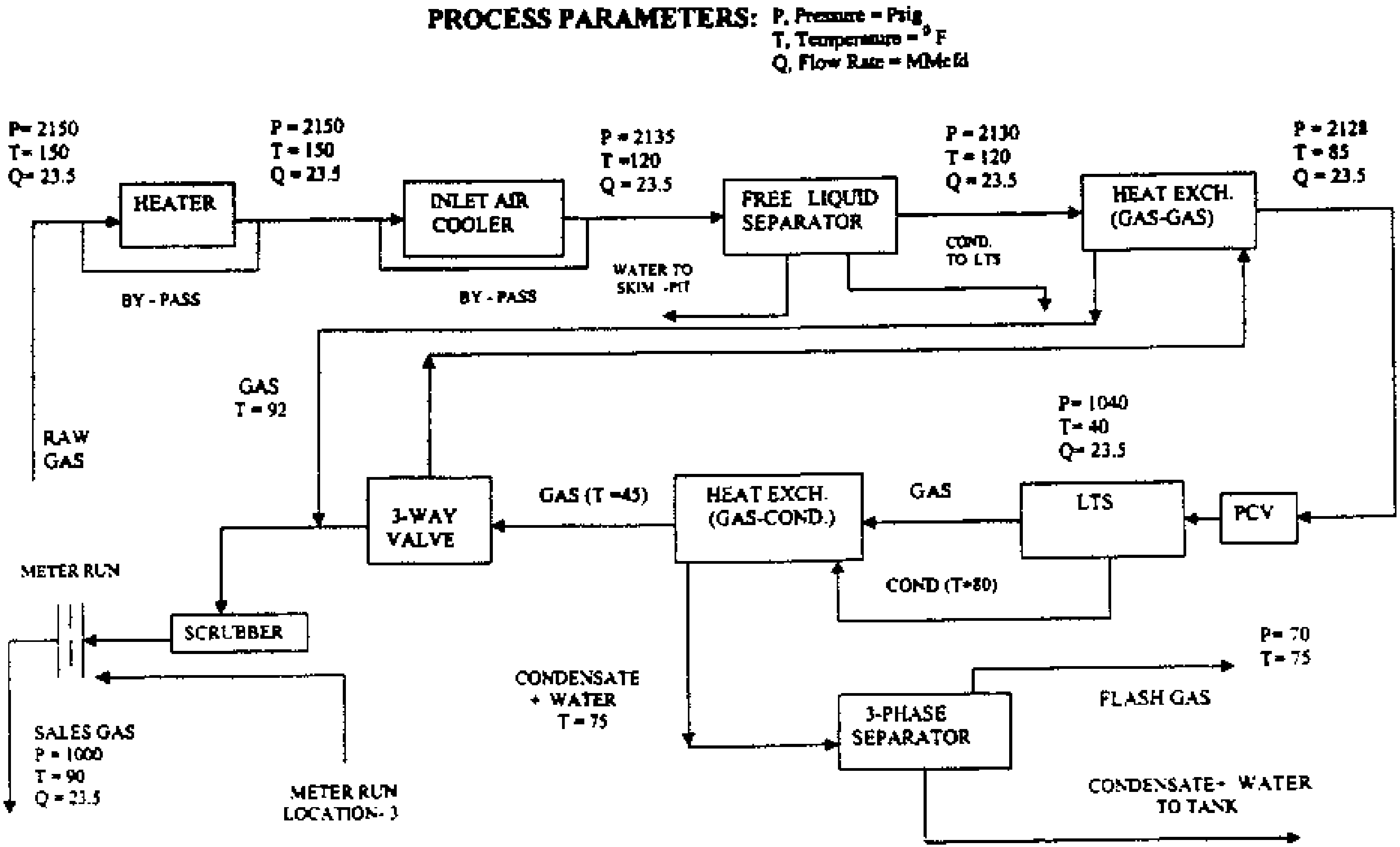


Figure 4.9 : Block Diagram of LTS without Glycol Injection Plant at Titas Gas Field.

ii. *Liquid knockout separator*

Liquid formed into the well stream after cooler is separated in the inlet knock-out separator. In the knock-out separator condensate and water is separated in separate chambers. A liquid level controller operates a dump-valve that releases the condensate from the separator into the liquid phase in the LTS separator. Water from the separator is controlled by a level control arrangement and is sent to skim-pit.

iii *Low temperature separator*

The low-temperature separator acts as a cold feed condensate stabilizer. A natural cold reflux action exits between the rising warmed gases liberated from the liquid phase and cold condensed liquid falling from the stream inlet. The lighter hydrocarbons rejoin the departing gas stream and the heavier components recondense and are drawn from the vessel as a stable stock tank product The gas, condensate, and free water are then discharged from the vessel through backpressure and liquid dump valves. The gas leaving the separator is saturated with water vapor at the temperature and pressure of the low temperature separator. If this temperature is low enough, the gas may be sufficiently dehydrated to meet sales specifications.

iv *Gas-gas heat exchanger*

For further cooling the gas stream from Liquid Knock-Out Separator is passed through the Gas-Gas Heat Exchanger, which cools warm high-pressure rich gas down stream of the knockout separator utilizing the effluent cold lean gas from the LTS as the coolant A three-way heat exchanger by-pass valve located in the cold gas outlet piping accomplishes the proper degree of cooling. By sensing the temperature of upstream of expansion choke the temperature controller actuate this valve

v. *Gas-condensate heat exchanger*

The gas stream from Gas-Gas Heat Exchanger is further passed through a Gas-Condensate Heat Exchanger to raise the temperature of gas before sales metering. In the Gas-Condensate Heat Exchanger condensate (Temp 80° F) comes from LTS unit and raises the temperature of gas stream (Temp 40° F) Process flow diagram is shown in Figure 4.10.

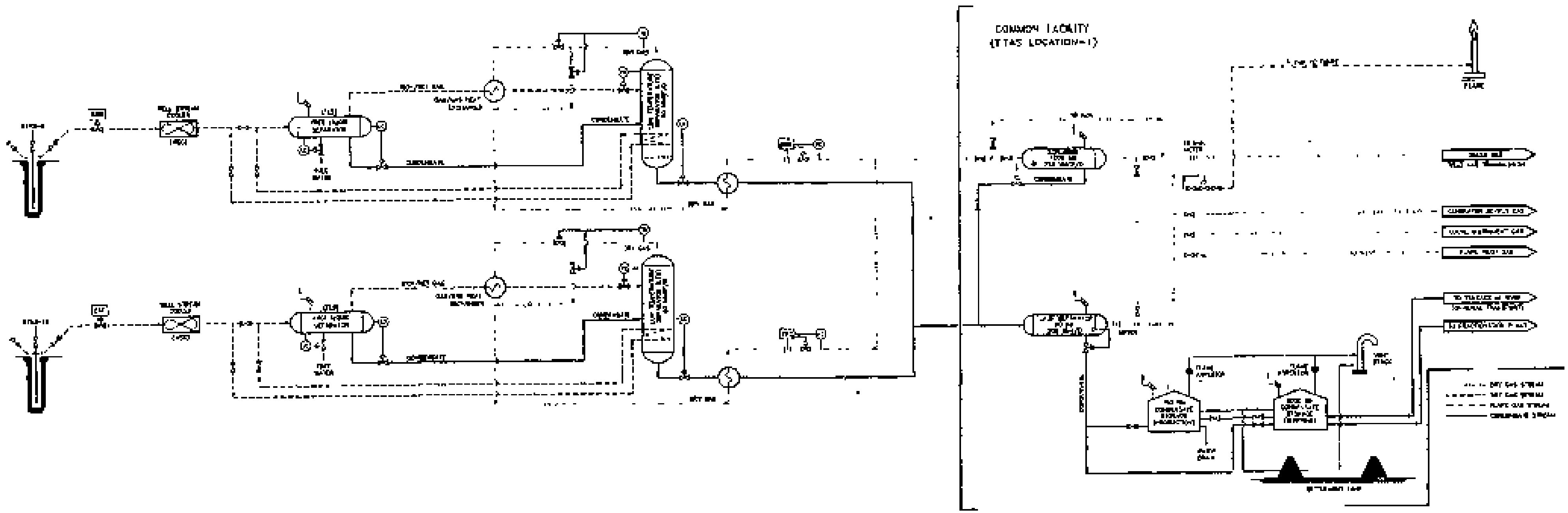


Figure 4.10 : Process Flow Diagram of LTS without Glycol Injection (Plants 9 & 10) at Titas Gas.

vi *Expansion choking*

The choke is mounted in the LTS vessel. After glycol injection the gas is then passed through the pressure control valve, where the pressure is reduced and automatic refrigeration is achieved below 40° F due to expansion cooling (Joule- Thomson effect) after pressure reduction. Due to this extreme low temperature of gas stream liquid (hydrocarbon + water) is formed and separated in the LTS separator. The gas from LTS separator continues to flow through the gas-gas and gas-condensate heat exchanger and is heated to attain under saturated condition and thereby, restricting formation of liquid in the transmission line.

Scrubber, Sales gas handling, Three phase flash separator, Instrument/Fuel gas system, Flare system and burn-pit, and Waste water treatment are similar / common facilities for all plants in Titas field.

4.2.5 Low-Temperature Separation (with Glycol Injection) Type Plant

Only two Low-Temperature Separation (LTS) type process plant installed in Bangladesh. In Titas field at Location 1, the gas processing facilities for the gas stream from the TT-7 goes through a LTS Process train (Plant 7) shown in Figure A-2-12. In Location 3, the gas processing facilities for the gas streams from wells TT-8, go through LTS Process trains (Plant 8). The Production Facilities Schematic for wells TT-8 is presented in Figure A-2-13 Design capacity of the gas processing trains for Plants 7 & 8 are each 60 MMscfd. Common facilities for sales gas measurement and transmission and condensate product storage & transport, flare and utility gas systems are situated at Location 1.

The principle of LTS plant is same as LTX process but glycol is injected as a hydrate inhibitor in those LTS process. The use of hydrate inhibitor allows a high pressure well stream to be cooled below the hydrate temperature ahead of the choke so that low temperature can be obtained.

General description of process of those LTS plant is given in below.

4.2.5.1 Process description

The low-temperature separation with glycol injection type process plant includes the following operations/equipments.

i. *Inlet gas cooler*

Gas stream from the TT- 7/ TT- 8 well is passed through a well stream cooler After cooling some liquid (mixture of hydrocarbon & water) is formed into the mainstream and temperature decreased from 145 to 120°F After cooler a by-pass stream is passed through a coil tube immersed into liquid phase in LTS separator to maintain the temperature of liquid phase in the LTS separator at above hydrate formation temperature.

ii *Liquid Knockout Separator*

Liquid formed into the cooler is separated in the inlet knock-out separator. In the knock-out separator condensate and water is separated in separate chambers. A liquid level controller operates a dump-valve that releases the condensate from the separator into the liquid phase in the LTS separator Water from the separator is controlled by a level control arrangement and is sent to skim-pit.

iii *Low temperature separator*

The low-temperature separator acts as a cold feed condensate stabilizer. A natural cold reflux action exits between the rising warmed gases liberated from the liquid phase and cold condensed liquid falling from the stream inlet. The lighter hydrocarbons rejoin the departing gas stream and the heavier components recondense and are drawn from the vessel as a stable stock tank product The gas, condensate, and free water are then discharged from the vessel through backpressure and liquid dump valves The gas leaving the separator is saturated with water vapor at the temperature and pressure of the low temperature separator If this temperature is low enough, the gas may be sufficiently dehydrated to meet sales specifications.

iv. *Gas-gas heat exchanger*

For further cooling the gas stream from Liquid Knock-Out Separator is passed through the Gas-Gas Heat Exchanger, which cools warm high-pressure rich gas down stream of the knockout separator utilizing the effluent cold lean gas from the LTS as the coolant. A three-way heat exchanger by-pass valve located in the cold gas outlet piping accomplishes the proper degree of cooling. By sensing the temperature of upstream of expansion choke the temperature controller actuate this valve.

v. *Gas-condensate heat exchanger*

The gas stream from Gas-Gas Heat Exchanger is further passed through a Gas-Condensate Heat Exchanger to raise the temperature of gas before sales metering. In the Gas-Condensate Heat Exchanger condensate comes from 3-Phase Separator and raises the temperature of gas stream. By the electric motor driven reciprocating pump glycol is injected into the gas stream after passing of this heat exchanger.

vi *Expansion Choking & Glycol Injection*

After glycol injection the gas is then passed through the pressure control valve, where the pressure is reduced and automatic refrigeration is achieved below 40° F due to expansion cooling (Joule- Thomson effect) after pressure reduction. Due to this extreme low temperature of gas stream liquid (hydrocarbon and water) is formed and separated in the LTS separator. The gas from LTS separator continues to flow through the gas-gas and gas-condensate heat exchanger and is heated to attain under saturated condition and thereby, restricting formation of liquid in the transmission line Process block diagram is shown in Figure 4.11

vii. *Scrubber*

Cold gas leaves the LTS separator and flows either into, or through, a by-pass around the gas-gas and gas-condensate heat exchanger. The volume of gas passed through the heat exchangers is determined by the three-way proportioning valve, which in turn is controlled by the temperature controller. The surplus cold gas not required for cooling the high pressure mainstream, is diverted through the by-pass and combined at the three-way valve with the gas used for cooling and finally transmitted to common Scrubber where rest of the condensate in dry gas stream separated and sent to Three Phase Separator.

viii. *Sales gas handling*

Gas stream from common Scrubber go through the common sales gas measurement and transmission system

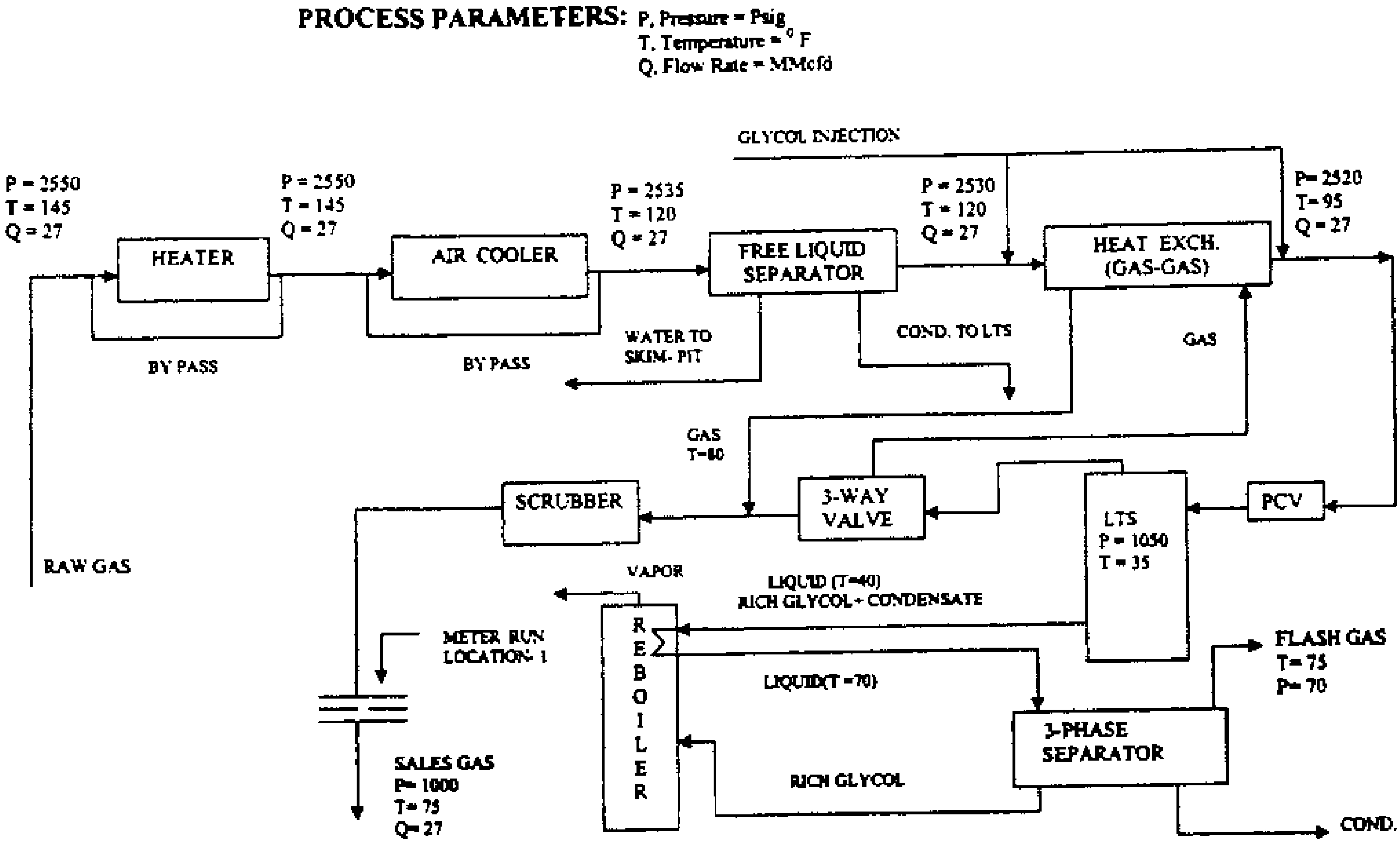


Figure 4.11 : Block Diagram of LTS with Glycol Injection Plant at Titas Gas Field.

ix *Three phase flash separator*

Liquid (rich glycol & condensate) from LTS separator is heated passing through glycol regeneration unit coil (or by pass) before entering 3-phase (water rich glycol, condensate and gas) common flash separator. Pressure of the 3-phase flash separator is controlled at 70-90 psi In the 3-phase separator a new equilibrium is established due to the lower pressure and the high temperature. Many of the light components evaporate (flash off) leaving condensate in the flash separator. Condensate and water rich glycol is trapped in different chambers in the flash separator. Condensate from the flash separator is passed through gas-condensate heat exchanger and is released to atmospheric pressure at condensate production tank where hydrocarbon condensate and water stabilize and separate into phases. Hydrocarbon condensate accumulated in the production tank is transferred into storage tank for sale or further treatment.

x. *Glycol reboiler*

Water rich glycol from the Three Phase Flash Separator is sent to Glycol Reboiler still column In the reboiler water is stripped off from glycol by evaporation Regenerated lean glycol is settled and stored in surge drum for cooling A electric motor driven reciprocating pump is used to inject lean glycol from surge drum to high pressure gas stream in between liquid knockout separator and PCV to complete the cycle

xi. *Instrument/Fuel gas system*

The flashed gas from the common 3-phase separator is used within the plant as fuel & instrument for processes (e.g. line heater, reboiler, electric generator, flare pilot etc) and domestic uses. The fuel gas demand in excess of flashed gas is met by tapping the dried gas from sales gas by pressure regulator.

xii. *Flare system and burn-pit*

Gas from pressure relief devices within the plant is vented into a flare header. Flashed gases in excess are also vented through flare header.

xiii *Waste water treatment*

Water accumulated in common production tank is drained into common skim-pit where water is allowed to hold for extended period of time for further separation of suspended oil particles into water. Finally water is drained from skim-pit to soak-pit.

4.2.6 Molecular Sieve Turbo Expander process plant

KTL-2, 3 & 4 are processed by 90 MMscfd Molecular Sieve Turbo Expander (MSTE) process plant. The Kailashtila was the only gas field in Bangladesh consideration would be given to constructing a more elaborate processing facility, which would split the liquid hydrocarbon stream into various components

The description of different systems and equipments of an MSTE plant is given below:

4.2.6.1 Process Description

i. *Inlet gas well heater*

There are three gas well heater for each well Each gas wells has two 3 inch lines each with block valve, emergency shutdown valve and 1 inch valve for future sand detector. The lines join upstream of the PIG launcher At regular intervals a pipeline pig is inserted to push the liquid out of the line. The shutdown valve action is controlled by the plant shutdown logic system. After shutdown valves a 3 inch connection with two full flow pressure safety valves is provided. Both PSV's are set at 234 Bar pressure and go to the flare system

The gas now flows through the Inlet Heater. The inlet heater is a double pipe type counter current heat exchanger with the inlet gas on the tube side and hot oil on the shell side. The purpose of the exchanger is to heat the gas to 26 deg. C or higher to prevent hydrate formation when the inlet gas pressure is reduced from 186 to 103.4 Bar. A flow of 307°F hot oil is used on the shell side of the heater to warm the inlet gas The reverse acting temperature controller flow of hot oil increases The inlet gas from the heater flows through a pressure control valve station and enters the top of the Inlet Separator.

ii. *Inlet separator*

There are three Inlet Separator for each well The inlet gas flows to the inlet separator where free water is separated from the hydrocarbon condensate liquid and the gas is separated from the liquids. The water is heavier so it separates and migrates to a "Boot" mounted on the bottom of the vessel. Water - hydrocarbon interface level is maintained in the "boot" by a level controller and control valve in the "boot" bottom outlet line to the closed drain. The hydrocarbon liquid floats on top of the water and must accumulate to a level 610 mm above the bottom of the vessel before it can enter the hydrocarbon section of the vessel. The 610 mm level is set by an internal weir or overflow baffle that separates the water hydrocarbon and hydrocarbon sections The position of the weir insures sufficient time for the water to separate and fall into the "boot". The hydrocarbon level is maintained behind the weir by a level controller and control valve in the line to the stabilizer. The normal hydrocarbon level is designed for 450 mm above the bottom of the vessel It passes through a vane type mist extractor before leaving the vessel to help separator any entrained liquid droplets. The separator inlet line and gas outlet line pressure are sensed to a differential pressure

A high differential pressure indicates some problem with the internal vane mist extractor-Inlet separator is protected from overpressure by two full flow pressure safety valves & each is set at 113.7 bar and go to flare, one PSV is spare and its inlet and outlet block valves are car sealed closed The gas stream joins the inlet gas streams from three inlet separators and flows to the inlet filter separator ahead of the gas dehydrators in the cryogenic section. It is horizontal vessel designed to the followings specifications:

Size : 1524 mm I.D x 3048 mm seam to seam (S/S)

Maximum Working Pressure (MWP). 113.8 bar at 66°C.

Stabilizer system

The stabilizer system provides a means of removing light hydrocarbons, mostly Methane and Ethane and most Propane and some H_2O, N_2 and CO_2 entrained in recovered condensate from the three inlet gas separators.

The liquid is pressured on level control from the separators to the Stabilizer where heat is applied by the stabilizer reboiler to vaporize light hydrocarbons from the condensate. The vapours exiting the Stabilizer overhead are pressure controlled to the plant fuel gas system.

A water draw-off tray below tray # 8 is provided in the upper section of the tower to coalesce and separate water so water can be manually drained from the system. The Stabilizer bottom liquid is air cooled and is pumped into the NGL surge drums.

iii. *Stabilizer*

The Stabilizer is a fractionation tower used to make a rough cut of the hydrocarbon condensate from the inlet separators At design condition, tower pressure of 12.1 Bar and a reboiler outlet temperature of 220°C, 97% of the ethane and lighter hydrocarbon components and 38% of the propane exit the top of the tower and 62% of the propane plus heavier components exit the bottom as a stabilized NGL product .In addition to stabilizing the NGL product, the stabilizer removes all of the N2 and CO2 from the feed stream. The tower overhead is pressure controlled to the plant fuel gas system. The NGL product recovered in the tower bottom is pumped to the NGL surge drums This vessel is designed to the followings specifications:

Size : 610 mm ID x 17,069 mm S/S

Number of trays : 16

MAWP. 15.5 Bar @ 183°C

iv. *Stabilizer water separator*

The tower has one feed source, 18 1° C condensate from the three inlet gas separators which enters onto the top tray #1. The feed also provides reflux liquid for product separation The pressure is decreased from 103.4 bar to 12.1 bar as it enters the stabilizer resulting in the 18.1°C feed temperature The total liquid feed from the 3 inlet separators is 5,01 M^3/Hr, however, some flashing occurs across the level control valves in the 3 feed lines The tower feed is saturated with water, therefore a Water Separator is required to remove the water. The separator is fed from a draw-off, tray below tray #8 and returns hydrocarbon condensate feed beneath the draw-off tray. Condensate feed to the coalescer section must flow through a mesh pad where mater molecules are coalesced to form larger droplets of water. In the separator section water is separated from the hydrocarbon condensate and accumulated in the Separator boot. A level gage glass is provided for visual inspection of the liquid accumulated in the boot. A water/hydrocarbon condensate interface should be maintained at all times to insure proper operation. Water accumulated in the separator boot must be drained manually at regular intervals If water is not drained from the Separator/ Stabilizer flooding will occur, reducing the efficiency of the Stabilizer. This will result in off-spec NGL product in the bottom of the tower. The Separator is designed with me following specifications

Size 508 mm ID X 3048 mm S/Flg.

MAWP· 15.5 bar @ 83°C.

v *Stabilizer reboiler*

Heat is added to the bottom of the tower by the stabilizer reboiter. The reboiler is a kettle type with hot oil circulated Through the tube bundle. The hot oil flow is temperature controlled to maintain a constant tower bottom temperature The reboiler shell is equipped with a spill-over weir which insures that the tube bundle is completely submerged in liquids, at all times. The weir forms a reservoir on the down stream side where the NGL product is collected. The excess NGL product is level controlled from the reservoir section through the stabilizer product cooler.

vi *Stabilizer product coolers*

There are two stabilizer product cooler. The 220°C NGL product from the stabilizer is cooled to 47°C by two identical forced draft air cooled exchangers One cooler is a spare and appropriate isolating valves are provided. Each air cooler has three fans driven by 1 6 KW electric motors. When a fan unit is tripped off from its high vibration, the other fans continue to run The vibration switches must be reset to restart the fan.

vii. *Stabilizer Pumps*

Two stabilizer pumps are positive displacement plunger type driven by 5.5 KW electric motors. One is a spare. These pumps take suction from the product cooler and send the stabilized product to the NGL surge drums at 4m3/hr flow with 17 4 Bar differential pressure

viii *Inlet filter separators*

Two inlet filter separators are the final clean up of the total inlet feed gas flow from the inlet separators and protect the expansive molecular sieve in the dehydrators Two 100% units are provided and one is a spare. The unit has an inlet filter area with replaceable filter elements in the first stage and a vane type mist extractor in the second stage to knockout entrained liquid droplets. A small bottle is placed below each stage filter ,all liquid that accumulates falls into the divided bottle Each end of the bottle has its own level control loop for pressuring the liquid into the closed drain. A differential pressure switch is placed across the filter elements to warn that they are dirty. Each filer separator is horizontal vessel designed to the followings specifications:

Size : 700 mm x 1200 mm x 2500 mm

MWP. 113 7 Bar @ 65.5°C.

Inlet gas dehydration system

The sole purpose of two dehydrators is the total removal of all the moisture in the process gas stream The gas stream entering the cryogenic plant must be dehydrated to as low a dew point as possibly due to the extremely cold temperature to which it will ultimately be subjected Block diagram of the process is shown in Figure 4.12.

ix. *Molecular sieve dehydration system*

After final clean up in the inlet filter separator, the inlet gas processing conditions of about 108,320 M3/hr, 103.1 bar pressure and 19°C temperature, the inlet feed gas is down flow dehydrated of moisture in the Molecular Sieve system on 8 hour cycles These two dehydrators are filled with molecular sieve desiccant. This porous bead looking material has tiny cavities that are big enough to trap water molecules, but small enough to allow hydrocarbon gas molecules to flow by. There are no "process controls'" as such on molecular sieve beds, but the vessel switching valves are time cycle controlled. There is a high moisture content alarm downstream of the bed to alert of a malfunction, in the sieve, and there are shutdown functions to protect the cryogenic plant equipment if there is a major malfunction in the mol sieve system. Mol sieve regeneration is that part of the process where water vapour is driven from the sieve cavities by flowing very hot, dry gas over the sieve at reduced system pressures. The plant's regeneration scheme uses hot oil to heat dry, residue gas to about 232°C at 38 Bar. This combination of temperature and low pressure "ultra dries" the mol sieve so dew points for cryogenic processing is obtainable. Typical regeneration gas process conditions for the plant require 3830 M^3/Hr of residue gas, 38 bar pressure and 30.9°C temperature to the regeneration gas heater. At least 5730 Kg/Hr of 307°C hot oil is necessary to transfer the required heat for regeneration gas temperatures of 232°C. The regeneration gas temperature from, the heater is controlled manually/automatically by reverse acting flow controller.

Each dehydrator has two (2) pressure safety valves, set at 113.7 Bar that exhausts to flare. One PSV is a spare and its block valves are car sealed closed. The block valves on the PSV in service are car sealed open. The dehydrators are internally Insulated vertical vessels with the following specifications:

Size: 1676 mm X 4267 mm S/S

MWAP: 113.7. Bar @ 260°C

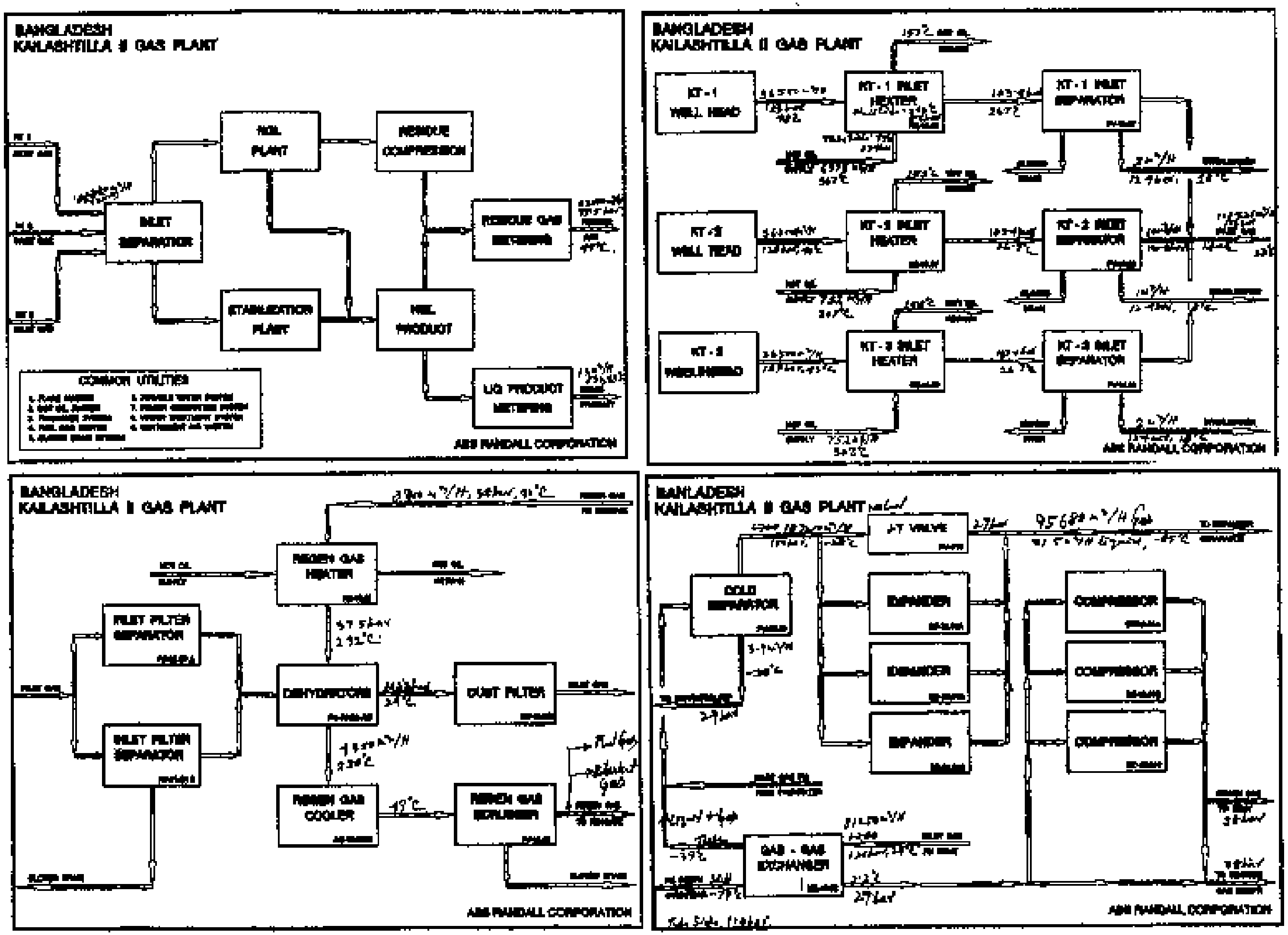


Figure 4.12 : Block Diagram of MSTE Plant at Kailashtila Gas Field.

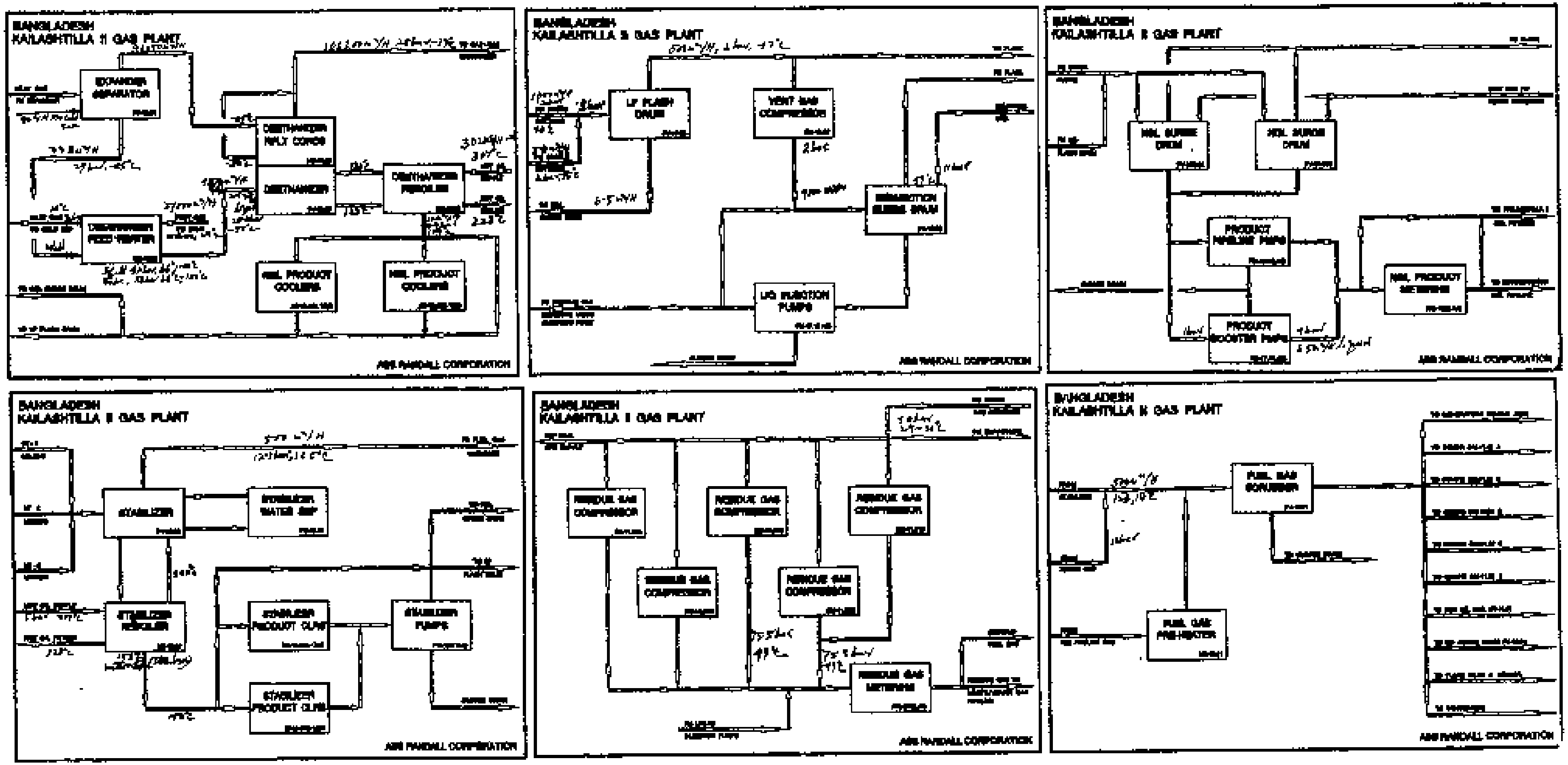


Figure 4.12 (Cont'd) : Block Diagram of MSTE Plant at Kailashtila Gas Field.

Typical dehydration regeneration cycle: The mol. sieve inlet gas drying cycle is 8 hours long, all regeneration activities (heating, cooling, bed pressurization/depressurization, valve switching sequence, etc) is concluded by the same cycle period. Heating the vessel, sieve and driving the water vapour out typically consumes about 4 hours of the available time with cooling the system below 39°C consumes about 3 hours and the vessel pressurization taking the balance. During the heat cycle, the entire vessel ultimately approaches the temperature of 204°C During the cool cycle, the gas is cooled so water vapour condenses and drops out of the gas stream in the regeneration gas scrubber

At the beginning of dehydration regeneration time cycle the inlet gas pressure equalizing valve opens to pressure the regenerated dehydrator from regeneration pressure to inlet gas pressure.

At the end of the pressure equalizing period the inlet gas valves are opened and the valve of the regenerated dehydrator closes

At the end of the valve switching cycle the inlet gas valves on the dehydrator to be regenerated are now closed.

The pressure release valve opens to equalize dehydrator regeneration system

At the end of the pressure equalizing period the regeneration gas valves on the dehydrator to be regenerated are now opened. At the same time the regenerated gas heater inlet valve is opened, the cool valve closes, the regenerated bypass valve closes and the pressure equalizing valve closes. This is the start of the heat cycle

At the end of the heating period the heater is bypass, the cool valve opens and the heat valve closes This is the start of the cooling cycle.

At the end of the cooling cycle the outlet of the dehydrator should be 54 4°C (maximum). All at the same time the regeneration gas flow bypass valve opens and the regeneration gas valves on the dehydrator being regenerated are closed. The cool valve remains open.

The inlet gas pressure equalizing valve opens to pressure the regenerated bed from regeneration pressure to inlet gas pressure.

The regenerated dehydrator inlet gas block valves are opened. The pressure equalizing valve closes and both dehydrators are again in dehydration service. The regeneration cycle is repeated for the next dehydrator.

x. *Moisture analyzer*

A moisture analyzer and recorder are provided to assist operating personnel in maintaining optimum conditions in the dehydrators. Any increase in moisture analysis is considered a problem, and steps taken to reverse the trend should be taken immediately. The sample stream is in the line between dust filter and the exchangers of the NGL plant When high moisture occurs on the dehydrator outlet stream the first step to take is to shorten the cycle time by resetting the heat and cool timers in the dehydration control cabinet. The regeneration gas flow should be increased, especially should the dehydrator outlet, temperature at me end of the heat cycle fail to reach a minimum of 204°C.

Dehydrator program: All operations required for switching the dehydrator block valves are initiated from and controlled by a timed dehydration control system. The control system consists of the following components

a. An Automatic Timing and Control Company (ATC) step programmer. This master controller consists of a camshaft with twenty (20) sliding segments that represent the twenty (20) steps that are available in the program The white segments are held in the slots in the camshaft hubs but are independently movable to the right or left Next to the white segment is a black area. When you see a white segment in a black area (or hub) , the switch will be activated at this point in the program. If no white segment is in the black area, the switch will not activate. The white segments in black areas actuate load switches, at preset times in the program, and in turn energizes and/or de-energize 3 -way solenoid Valves that actuate the switching valves in the dehydration system The camshaft is driven by an AC pulse motor. The motor is attached to the camshaft drive gear. Next to the drive gear an indicator strip shows step number as it lines up with the step position arrow on the motor. Next to the step number indicator strip is the segment indicator strip, which identifies cam segments.

b. The dehydrator controls also include four (4) ATC series 305 motor-driven reset timers with pilot lights Two timers have ranges of zero to fifteen (15) hours and are connected to the heat and cool sections of the programmer. These two timers are provided with a manual reset button on the control board. The heat and cool cycles can be reset (returned to the original time set period) by pushing this reset button A pilot light in each timer is illuminated whenever that timer is running The third timer has a range of zero to sixty (60) seconds and is provided for a step time delay when switching dehydrators. When the dehydrators are switched to regeneration and back to dehydrating inlet gas, this timer allows time for the larger dehydrator switching valves to open and/or close before the programmer automatically goes to the next step. This assures proper positioning of these valves. The fourth timer has a range of zero to sixty (60) minutes and is connected to the programmer to allow a period of time for pressuring up depressuring the dehydrator tower before switching into a drying cycle or a heating cycle.

c. The local control cabinet also contains 3-way solenoid valves. These solenoid valves are installed in the control instrument air line (1.406 kg/cm2 pressure) that eventually actuates all switching valves through the 4-way Versa valves. The main dehydrator switching valves are Orbit valves, which require air pressure (3.5 Bar maximum) on both sides of the diaphragm actuator to open and close. It takes two 3-way solenoid valves, therefore, to actuate these valves. One solenoid valve in the opening side and one solenoid valve in the closing side. The 3-way solenoid valves are in the control air line to each side of the 4-way Versa valve. One 4-way Versa valve is provided for each set of dehydrator switching valves; one, for the inlet gas into and out of each dehydrator, and one for the regeneration gas into and out of each dehydrator In other words, the cycle programmer sends a signal to the opened or closed solenoid valve and in turn shifts porting in a single 4- way Versa valve to open or close two switching valves simultaneously. The 3.5 Bar power air is vented out of the 4-way Versa valve exhaust port as air is applied to the opposite side of the Orbit valve Altogether the main dehydrator switching valves require eight (8) 3-way solenoid valves.

An on-off switch has been installed in the dehydration control panel This switch is not in the cycle programmer and must be actuated manually. In the off (de-energized) position the switch turns the power off a 3-way solenoid valve in the 20 psi control air line to all of the switching valves 3-way. Solenoids preventing the switching valves from changing positions The on-off switch is provided to allow the programmer camshaft to be rotated without changing switching valve position The camshaft can be rotated by another manual stepping push button on the dehydration control panel cover. Each time the manual stepping button is pushed the camshaft is rotated into the next or following function When the camshaft program is in the desired position, then the on-off switch is placed in the on position and the switching valves will automatically reposition to correspond to the new programmer setting. It is not anticipated that the manual stepping switch will be used; however, it is provided in case of trouble in the programmer or restarting a complete cycle after prolonged down time.

xi *Dust filter*

Some breakage of the mol. sieve material occurs during the initial loading and also during the operations of the timed cycles. This dust is removed by the Dust Filter, which is located directly downstream of the dehydration units. This filter's function is to prevent any dust or materials from passing downstream and possible plugging or fouling any of the heat exchangers. The dust filter has a pressure differential high alarm, which is set at 1.4 bar. Any time the pressure differential on the dust filter increases, the filter must be shutdown and elements replaced.

xii. *Regeneration gas system regeneration gas heater*

The regeneration gas heater is a shell and tube heat exchanger The 307°C hot oil from the hot oil heater flows through the tube side and heats the regeneration gas volume for the dehydrators to 232°C, flowing through the shell side. Design hot oil flow through the tube side is 5730 Kg/Hr. The hot oil from the shell side is designed for 200°C temperature. The only function of the heater is to heat the regeneration gas to 232°c during, the regeneration heat cycle it is bypassed during the cool and switch cycle.

Regeneration gas is supplied from the plant residue gas header after the expander compressors at a temperature of 30 9°C. The hot oil flow through the heater flows at all times and the gas flow is directed to or around the exchanger. The regeneration gas is up flow through the mol. sieve beds while inlet gas drying is down flow The regeneration gas flows from the top of the dehydrators through regeneration switching valves. From the dehydrators, the regeneration gas flows through the regeneration gas cooler. The regeneration gas heater is sized for 1774 MKJ/Hr, and specifications are

Tubes 8 6 Bar MWP at 343°C

Shell: 41.37 Bar MWP at 343°C

xiii. *Regeneration gas cooler*

The regeneration gas cooler is an air cooled heat exchanger designed to condense water and hydrocarbon vapour produced during the regeneration heat cycle. The cooler outlet maximum design temperature is 49°C and the minimum is limited to about 16°C to prevent hydrate problems The cooler the gas, the more vapour is condensed. Two 4 KW motors drive two fans for control the outlet temperature. The regeneration gas cooler is designed to the following specifications

Capacity. 1774 KJ/Hr

Tubes: 41.36 Bar at 260°C

xiv. *Regeneration gas scrubber*

The regeneration gas scrubber is designed to separate gas and liquid and send any accumulated liquid into the closed drain header automatically. The gas leaving the top of the vessel must pass through a wire mesh extractor to help remove entrained liquid. The is a vertical pressure vessel designed to the following specifications·

Size : 457 mm O D X 2438 mm S/S

Design Metallurgy : 41 37 Bar MWP @ 260°C

Cryogenic process system

xv. *Inlet gas cooling*

The dehydrated inlet feed gas from the dust filter at the design process conditions of 108,320 m3/Hr rate of flow, 29°C temperature, 102.1 bar pressure and 17 45 MW splits for flow through two (2) exchangers to recover refrigeration.

One inlet gas flow, 75% of the total inlet gas flow or 81,240 m3/Hr flows through the tube side of the gas-gas exchanger. One inlet gas flow, 25% of the total inlet gas flow or 27/080 m3/Hr, flows through the tube side of the deethanizer feed heater.

The main 10" inlet gas line and-the 6" line to deethanizer feed heater have orifice meters that are used to automatically maintain the required flow split to obtain lowest possible inlet gas temperature. The 10" line to gas-gas exchanger has a manual operated block valve & two full flow pressure safety valves and thermocouple that goes to the Control panel. The PSV's provide overpressure protection for the high pressure side of the cryogenic plant. From the gas-gas exchanger the inlet gas is cooled to -39°C and the residue gas on the shell side is warmed from -78.9°C to 2.2°c, and flows to the Cold Separator. The 6" inlet gas line to deethanizer feed heater has an orifice meter and control valve It flows through the tube side of the deetfianizer feed heater and, then ties into the 10" inlet gas line from gas-gas exchanger for flow into the cold separator. The inlet gas is cooled to 9.91 °C while warming the deethanizer feed liquid from -84.9°C to -76 8°C. The inlet gas line from deethanizer feed heater has a thermocouple that goes to the control panel. Process flow diagram is shown in Figure 4.13.

The Gas-Gas exchanger is actually two (2) shell and tube exchangers stacked and piped for series flow and is designed to the following specifications:

Duty: 16,75 MKJ/Hr

Shell: 411.4 Bar MWP at 66°C/-110°C

Tube: 113.7 Bar MWP at 6i6°C/-100°C

The deethanizer feed heater is designed to the following specifications:

Duty : 365 MKJ/HR

Shell 41.4 MWP at 66°C/-115°C

Tube : 113.8 MWP at 66°C/-100°C

xvi. *Cold separator*

The cold separator is designed to separate the liquid, formed" (condensed) by lowering the' temperature of the inlet gas from 28.5°C to-28.2°C in gas-gas exchanger & deethanizer feed heater from, the non-condensed inlet gas stream The separator has an internal mist extractor pad and is the final clean up before the expanders. The inlet gas stream from the cold separator, 107,160 M3/HR, 100 bar shutdown valves and 17.21 MW, flows through the three expanders or their JT bypass valve into the expander separator The liquid from the cold separator, 2.77 m3/HR at 0.578 SPGR, also goes to expander separator.The cold separator is designed to the following specifications :

Size: 1219 mm I.D X 2438 mm S/S

MWAP: 113.8 bar at 66°C /-45.5°C

Low inlet gas temperature can be compensated for by increasing hot oil flow through the three (3) inlet-gas heaters and only if pressure levels are at design. Inlet gas composition change may require new heat and material balance numbers however; some change can be

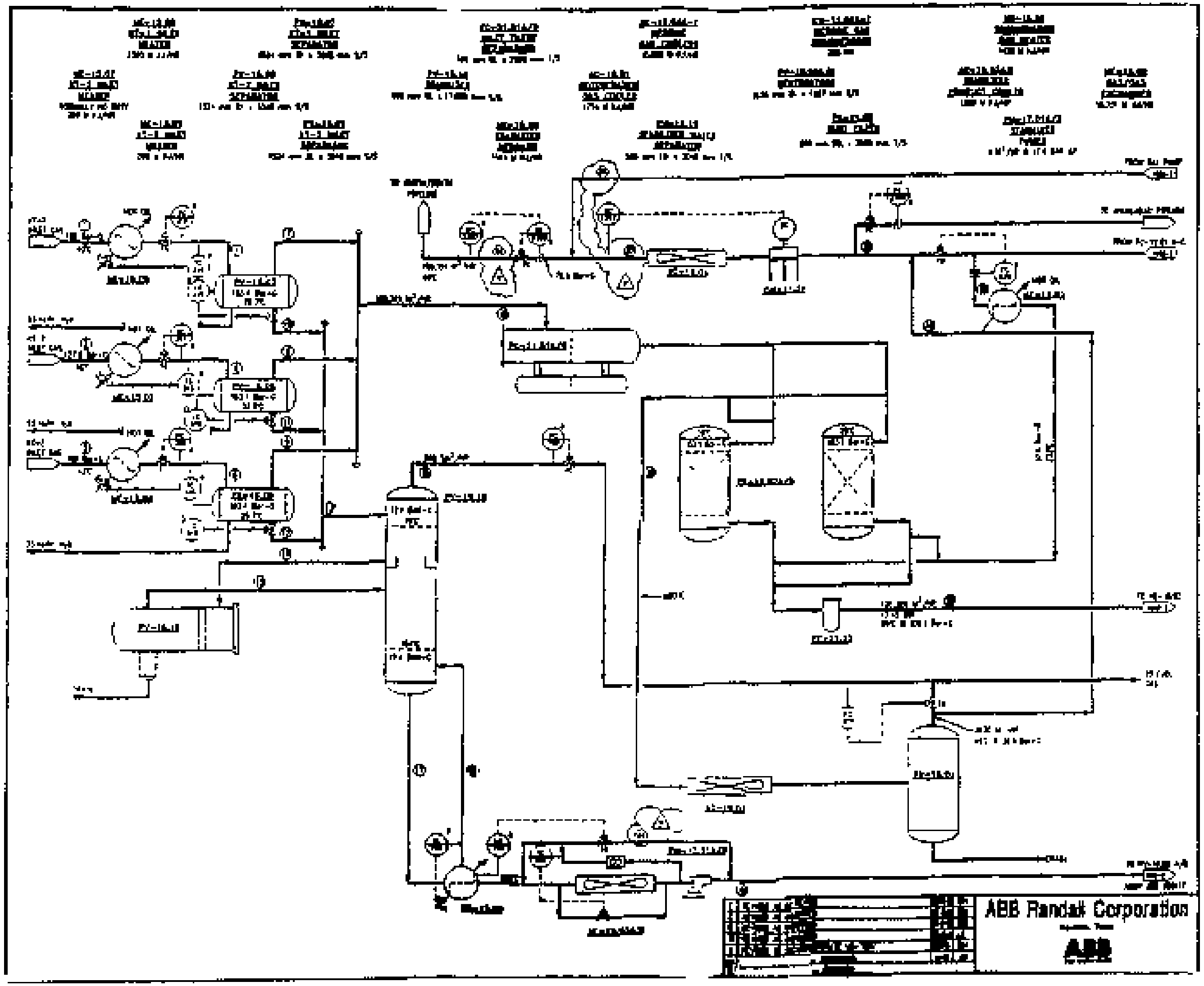


Figure 4.13 : Process Flow Diagram of MSTE Plant at Kailashtila Gas Field.

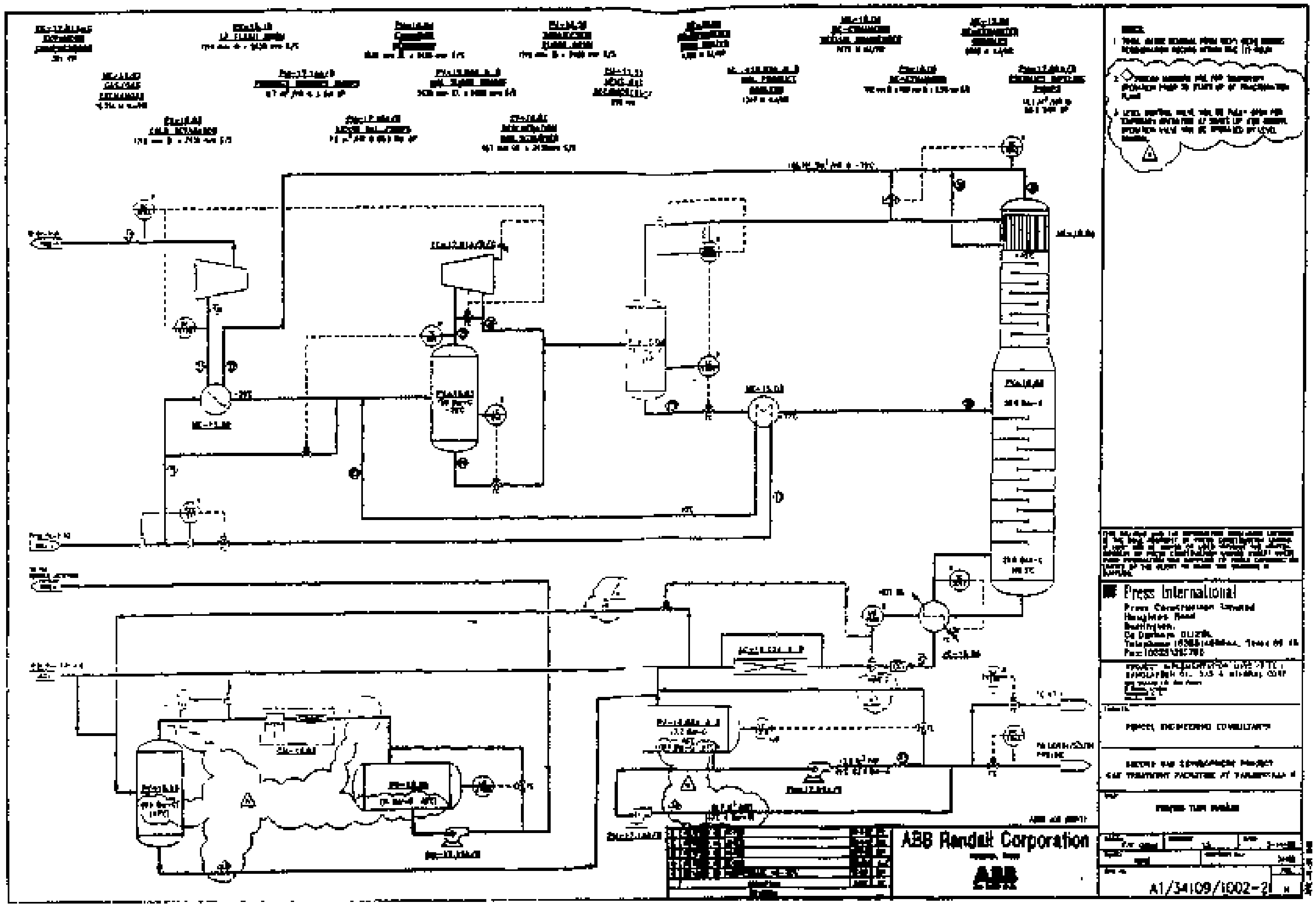


Figure 4.13 (Cont,d) : Process Flow Diagram of MSTE Plant at Kailashtila Gas Field.

compensated for by adjusting pressure levels. Decreasing plant temperature indicates the inlet gas contains less heavier components and the inlet gas pressure must be reduced or expander -outlet pressure increased to warm the plant. The plant temperature will decrease when the pressure differential across the expanders increase. Deethanizer flooding is usually associated with colder plant temperature causing more methane liquid to be fed to the column that it can handle. The liquid stacks up on the trays and goes overhead to the gas-gas exchanger chilling the inlet gas due to a gas-liquid exchange This- lowers the cold separator temperature and lowers the expander outlet temperature creating a snowball effect. To remedy, the expanders are shutdown and if that does not work the inlet gas flow is reduced.

xvii. *Expander-compressors*

From the cold separator the inlet gas, at design conditions of 107,106M^3/Hr, 100 Bar, -28.2°C and 17.21 MW, flows through the three (3) identical expanders and into the expander separator. Each expander generates 381 KW horsepower through the mechanical expansion of the inlet gas stream The expansion of the gas across the expander wheel releases energy and provides work. The work, or energy, provided is utilized by the expander compressor wheel, to compress the plant residue gas. The release of energy from the inlet gas results in a -85 4°C temperature at the expander, outlet causing additional liquid condensation. The expanders are simply highly efficient turbines operating on the same principle as the more familiar steam turbine, but with the prime objective of reducing temperature than obtaining power.

The design speed (about 59,200 RPM) of the unit takes into account the speed required to maximize expander efficiency together with matching the expander to the compressor. Thrust loads, high vibrations and resonance are considered in selecting the operating speed. Sensing the expander compressor discharge pressure (residue gas compressor inlet pressure) controls the expander loading, and therefore speed, by positioning a variable inlet nozzle assembly, which in rum determines the deethanizer pressure. The variable pitch blades are controlled externally by a pneumatic diaphragm operator. Upstream of the expander, a line with pneumatic motor valve, has been placed to bypass all the expanders and continue to operate the plant at reduced recovery. Both the bypass motor valve and the expander variable inlet vanes operator are provided with positioners to set up a split range control scheme Pressure controller first opens the expander inlet vanes from 3 psi to 9 psi

(0.2 to 0.6 Bar) and if the expander design is exceeded by the plant flow, the expander bypass valve (J-T valve) will start opening at 9 psi and will be wide open at 15 psi (0.6 to 1 0 Bar) air signal. In the signal line to the inlet vanes operator, a hand indicating controller is placed to manually adjust the inlet vanes. When the expander is put on line and the output signal from the pressure controller matches the manually set output, the hand controller is then switched to automatic and the vanes are than controlled from pressure controller.

The expander inlet valve is specially designed to close quickly (less than two seconds) to limit the driving force of the expander as quickly as possible, and prevent possible damage to the expander. The expander outlet valve is used to block in the expander, and is a back-up to stop the unit in case leaks through or does not close. The expander compressor outlet valve is provided to insure stoppage of flow and possible slow rolling the unit When the expander is shut down, all shutdown valves are automatically closed. The expander wheel must be loaded (braked by flow through the compressor wheel) at all times or it will over speed and damage itself. The expander inlet line has a 80 mesh screen with 150% opening. This screen has a pressure differential indicator and a differential pressure shutdown switch The shutdown switch is set for 0.3 bar differential and will shut down the expander when tripped When pressure differential indicator indicates increasing AP, the screen should be cleaned. This switch- prevents excessive pressure differential, which could collapse the screen. The expander compressor inlet has a 30 mesh screen, however, no pressure differential indicator is provided The residue gas to the expander compressor is normally a very clean gas stream. Once debris left from construction has been flushed out of the equipment, this screen should not get dirty.

The expander compressor process gas pressures are sealed at the shaft by labyrinth seals. To protect against possible cold process gas flowing into the lube oil tank and entry of oil into the. process, an outward leakage of gas is permitted out each labyrinth seal To prevent entry of oil into the process from the expander end, there is a provision at the middle of the expander end labyrinth seal to inject a stream of gas at a rate slightly higher than that leaking out through the seals.

The compressor lube oil system consists of the following: The lube oil and seal gas from the unit enters the surge tank. The combined stream enters onto a tray which helps separate the oil from the gas. The oil runs down into the tank through tray drain lines that terminate below the oil level The lube oil tank has an electric heater set 27°C The seal gas vapours pass through a mesh pad and enter the expander compressor inlet line, therefore, the oil surge tank pressure is always maintained at the expander compressor inlet pressure. From the surge tank the oil is picked up by one of two lube oil pumps, and then is cooled and filtered before entering the unit to complete the oil circuit The lube oil pumps should be shut down in five (5) minutes after the expander is shut down. It is suggested that the seal gas flow be stopped in ten (10) minutes after the lube oil pump stops if the expanders are to be down for a period of time. There is an automatic thrust balance valve in a line from the back of the compressor impeller to the compressor inlet. Opening this valve unloads the compressor thrust bearing and loads the expander bearing to maintain a balanced thrust. This valve is set in the factory and should not need field adjustment unless one of the seals washes out or ice deposits or the like collect in the wheel vent passages.

A discharge to suction bypass line with automatic valve is provided around the expander Compressor. This bypass can be used when low gas flow causes a surging of this unit. It is possible to surge the unit when flows of about 70% of design or lower are experienced. The recycle stream puts additional load on the compressor wheel and acts like a brake to slow the unit down. When the recycle valve opens, the boost in pressure across the compressor will decrease When anyone of the three (3) expander compressor anti-surge valves open, the compressor discharge check valve will probably close until the expander separator and deethanizer pressure increases to the point where it re-opens. The expander compressor outlet pressure is set at 36.7 bar by pressure controller, the inlet pressure is designed at 27 bar (9.7 bar differential pressure). Less than design inlet gas rate of flow or anytime the expander efficiency decreases, the compressor differential pressure decreases and the only way to flow the residue gas is to increase the compressor inlet pressure

xviii *Expander separator*

The expander separator is designed to separate the NGL liquids from the now completely processed inlet gas The gas from expander separator is the majority (88%) of the plant residue gas. It is passed through a mist extractor pad as it leaves the top of the vessel to help recover all possible NGL The separator has two (2) inlet lines, both two phase (gas/liquid). One from the, bottom of the cold separator and one from the expander outlet. The NGL liquid from expander separator is the total feed to the deethanizer, 21-1 M^3/Hr at

0 394 SPGR. The expander separator makes the deethanizer fractionator more efficient since it does not have to handle the large volume of residue gas. The expander separator liquid is pressured into the deethanizer although the residues gas from the separator and from the deethanizer join for flow through the gas-gas exchanger. An automatically controlled restriction (back pressure) is provided in the residue gas line from the separator to force the liquid flow. When the residue gas line pressure is higher than 40 bar the BSD system is tripped causing a shutdown of the cryogenic plant. Overpressure protection of the expander separator is by two (2) 100% capacity pressure safety valves, set 41.4 bar and exhaust into the residue gas header to the gas-gas exchanger One PSV is a spare and its inlet and outlet block valves are car sealed closed The expander separator is designed to the following specifications·

Size: 1538 mm I.D. X 2438 mm S/S
MWP. 41.37 bar at 63°C / -129°C

Residue gas handling system

To recover the refrigeration produced in the cryogenic plant and utilize the horsepower (KW) generated by the expanders. The residue gas stream from the top of the expander separator vessel is used to condense vapour for reflux in the top of the deethanizer, chill the inlet gas stream in the gas/gas exchanger and is then compressed by the expander compressors into the inlet to the residue gas recompressors where the pressure is increased to residue gas pipeline pressure

From the expander separator the residue gas at a rate of 96,350 M^3/Hr, -84.9°C and 16.33 MW is passed through the deethanizer reflux condenser. This is a shell and tube exchanger installed inside the top of the tower. The residue gas flows through the shell side of the condenser and the deethanizer overhead vapours flow through the condenser tubes. A portion of deethanizer overhead vapour condense in the tubes and fall back into the top of the tower. The non-condensed overhead vapours continue to flow through the tubes and leave the deethanizer overhead. The expander separator residue gas after the deethanizer condenser joins the deethariizer overhead stream and goes to the gas/gas exchanger at a rate of 106,230M^3/Hr, -79°C and 16.52 MW. The residue gas is exchanged with inlet gas to recover refrigeration. The temperature of the residue gas is increased from minus 79°C to 2.2°C by this exchange. From the gas/gas exchanger the residue gas is compressed from 27.6 bar to 38 05 bar by the expander driven compressors. It is then used as regeneration gas in the dehydration section, compressed to 75.5 Bar by the residue gas compressors and for future use a 6" line from the residue gas compression suction header to JGTDC pipeline has been provided

ixx *Deethanizer*

The purpose of the deethanizer is to separate by fractionation the methane and ethane components contained in the feed stream from the propane and heavier components, the desired products. A small amount of the ethane component is left in the bottom product, since stripping all ethane overhead would reduce the propane component recovery Along with the column top temperature, the amount of ethane left in the bottom product is the deethanizer bottom temperature control point.

It has an internal mist extractor in the top which all overhead vapour must pass; it is the contacting of the liquid feed with vapours rising in the tower from the reboiler which creates the stripping vapour action necessary to deethanize the product. There are 26 trays in the deethanizer tower which provide the contact surfaces necessary to assure proper stripping action. Tray #9 is the feed tray and as the liquid product falls down the tower it flows across the lower trays the vapours flow up through the trays. The liquid flowing down the tower collects in the bottom and flows into the bottom reboiler and vapour returned to the tower below the bottom tray. The reboiler is a horizontal shell and tube thermosyphon kettle type using hot oil flowing through the tube side as the heat medium. The deethanizer feed from expander separator is level controlled through the shell side of the deethaniaer feed heater where inlet gas heats the liquid from -84.9°C to -76.8°C and then enters the deethanizer on tray #9. The deethanizer is designed to the following specifications:-

Size; 1372 mm I.D X 1067 mm I.D. X 21,945 mm S/S

MWP : 41.37 bar at 149°C / -129°C.

xx *Deethanizer, reboiler*

The deethanizer reboiler supplies the heat input to the bottom liquid to generate sufficient vapour to strip the lighter components from the NGL product in the column trays The kettle type reboiler has hot oil flowing on temperature control through the tube bundle. The reboiler shell has a spill-over internal weir which insures that the tube bundle is completely submerged in liquid at all times. The weir forms a reservoir on the down stream side where the NGL is collected. The excess NGL liquid is pressured on level control through the NGL product air coolers into the NGL surge drums. The exchanger is designed to the following specifications:

Duty: 6903 MKJ/Hr

Shell. 41 37 bar MWP at 180°C

Tubes. 8.6 bar MWP at 343°C

xxi *Deethanizer reflux condenser*

The Condenser is an internal shell and tube exchanger installed in the top of the deethanizer. The cold -84.9°C residue gas from expander separator flows through the shell side on temperature control. The deethanizer vapour from the top tray at -45°C flows through the tubes and is cooled to -58.11°C before leaving the column. A portion of the overhead gas is condensed and this liquid falls back onto the top tray to provide reflux liquid for the trays above the feed tray Without reflux liquid the top trays will not separate components Essentially all deethanizer controls are on or, around the reboiler. The deethanizer reboiler outlet return line temperature is controlled (129.7°C design) by the reverse acting controller operates in the hot oil line to the reboiler tubes. The exchanger is designed to the following specifications:

Duty: 1179 MKJ/Hr

Shell. 41.37 MWP at 66°C/-130°C

Tubes: 41.37 MWP at 66°C/-130°C

xxii. *NGL product coolers*

The NGL product coolers lower the NGL product temperature from 129 7°C to 48.7°C. The maximum design NGL pipeline temperature is 50°C. A manual bypass around the product coolers is provided to maintain a minimum outlet temperature in the LP Flash Drum. This bypass is normally fully opened. There are two (2) 100% air cooled exchangers provided each with three (3) fans driven by 1.6 KW electric motors. Double block and in between vent valves are provided on each unit for isolation Each fan unit (6 total) has its own high high vibration shutdown switch. The vibration switch must be reset manually to restart the fan. The deethanizer NGL product joins the stabilizer bottom product and flows into the two (2) NGL surge drums. The NGL product coolers are designed to the following specifications:

Duty: 1347 MKJ/Hr

MWP: 41.37 bar at 160°C

xxiii. *NGL flash System*

The equipment used in the NGL Flash System is designed for the temporary operation required at startup to produce, an atmospheric NGL product for shipment through the NGL pipeline to a remote location At startup the remote facility fractionation equipment will not be in operation therefore requiring an NGL product with an atmospheric vapour pressure. After the remote facility fractionation system is in operation the NGL Flash System will no longer be required and the plant can produce the normal NGL product as designed

xxiv. *Flash drum*

The L.P. Flash Drum allows the NGL product recovered in the stabilizer and deethanizer to flash the light hydrocarbon due to the reduced operating pressure. The L.P. Flash Drum design operating pressure is .2 barg at 47 ° C. Because of the low operating pressure an atmospheric NGL product is produced. This atmospheric NGL product can then be transferred by the NGL pipeline to another facility. NGL liquids not flashed at the reduced pressure are accumulated in the bottom of the L P. Flash Drum and are pressured to the NGL Surge Drums on level control. The NGL flash vapours exit the top of the flash drum through a coalescing mesh pad to feed the suction of the Vent Gas Recompressor. Excess vapours not compressed by the recompressor are pressure control to the flare system. The flash drum is protected from over pressure by set at 10 barg.The L.P. Flash Drum is design to the following specification:

Size: 1219 mm I.D. X 2438 mm S/S

Design: 10 barg at 100°C

xxv. *Vent gas recompressor*

The Vent Gas Recompressor is used to boost the pressure of the gas flashed for injection into, the plant residue header. The discharge of the Vent Gas Recompressor is cooled and the flashed gas is recondensed before feeding the Reinjection Surge Drum The Vent Gas Recompressor suction pressure is 2 barg with a discharge pressure of 14 4 barg at 155°C. The increase in pressure is required to reinject condensed liquids via the Liquid Injection Pumps into the plant residue. The Vent Gas Recompressor is designed to the following specifications:

Capacity: 1570 M^3/Hr

Type : 3 stage reciprocating

xxvi. *Reinjection surge drum*

The Reinjection Surge Drum provides surge capacity for the condensed flash gas liquids after recompression Liquids condensed by the 'vent: gas recompressor Discharge Cooler are accumulated in, the Reinjection Surge Drum while any uncondensed vapours are pressured controlled to the flare header. The accumulated liquids are pumped from the Reinjection Surge Drum by the Liquid Injection Pumps into the plane residue header. The Reinjection Surge Drum design operating pressure is 11 barg at 49°C The reinjection surge drum off gas is pressured control to the flare header by a direct acting local pressure indicator controller set at 15 barg. Pressure is controlled by pressure regulator from the regeneration gas system. The vessel is protected form over pressure by set at 18.25 barg. The Reinjection Surge Drum is design to the following specifications:

Size .1219 mm I.D. X 24,38 mm S/S

Design: 18 25 barg at 60°C

xxvii. *Product booster pumps*

Two Product Booster Pumps are use to transfer NGL product from the NGL Surge Drum to the NGL pipelines. Because of the reduced NGL product due to producing an atmospheric NGL product, the booster pumps are required. The Product Booster Pumps are designed to the following specification.

Capacity 6.7 M^3/Hr at 3 bar ΔP

Type: Centrifugal pump

xxviii. *Liquid injection pumps*

Two Liquid Injection Pumps transfer the NGL flash vapours that were recondensed by the Vent Gas Recompressor Discharge Cooler from the Reinjection Surge Drum to the plant residue header. The liquid injection pumps are equipped with seal failure pressure switches & linked to the shutdown logic system. The Liquid Injection Pumps are designed to the following specification:

Capacity: 7.5 M^3/Hr at 72.4 bara

Type : Positive displacement pumps

ixxx. *Liquid injection spray nozzle*

The Liquid Injection Spray Nozzle is design to aerosol the injected liquid to help vaporize the liquid in the residue gas stream Two injection nozzles are provided so that maintenance of a single, nozzle can be performed if required. "Y" type strainers with 40 mesh screens are located upstream of the nozzles to prevent debris from plugging the nozzle orifices This type of strainer can be blown clean with out disassembly.

NGL product handling

xxx. *NGL surge drums*

Two NGL surge drums operate as one and provide some surge (storage) capacity to continue to run the plant in case of product pipeline or pipeline pump problems. They also provide positive suction for the pumps. The NGL product from the deethanizer and the stabilizer bottom product join and flow into both NGL surge drums. The NGL surge drums are designed to the following specifications.

Size : 2438 mm I D X 6400 mm S/S

MWP.31 bar at 66°C

xxxi. *Product pipeline pumps*

The two (2) 100% capacity pipeline pumps are designed to pump the NGL liquids into the North/South NGL pipeline and/or the Kailashtilla NGL pipeline The pumps are positive displacement plunger type pumps driven by 45 KW electric motors. They are designed for 14.1 M^3/Hr with 56.5 bar differential pressure. Each pump has double block and bleed valves on suction and discharge lines. A pulsation dampener has on both suction and discharge lines. Overpressure: protection for the two surge drums is provided by three (3) full flow pressure safety valves, set at 31 Bar and exhausted to flare.

xxxii *Residue gas compressors*

The residue gas compressors take suction from the expander compressor common discharge header in the cryogenic section, at a pressure of 38 05 bar, 30°c and 106,250M^3/HR at 16.52 MW. A common 12" suction header is provided for, the five (5) compressors The five compressors operate in parallel and increase the residue gas pressure to 75.5 bar and flows into the 24" North/South gas pipeline.

The five (5) residue gas, compressor are identical and separate self-contained package units. They are Atlas Copco Industries single stage dual cylinder gas engine driven compressors driven by Caterpillar gas engines. Each unit has its own lube oil and cooling water systems and air cooled oil, water and process gas exchangers Each compressor is rated at 810 horsepower at 1200 RPM engine speed. Each compressor is designed for 21,238M^3/Hr (20%) of plant capacity. They run in parallel and can be run on governor speed control, in the 800 to 1200 RPM range, or they can be run by manual set of speed.

xxxiii. *Residue gas system and metering*

The discharge from the compressors are collected in a common 12" header with the fallowing connections:

- A 6" line with a pressure control valve that is used to recycle gas from compression discharge to suction to maintain pressure.
- A 1" line that is used as a sample point to the dehydration outlet moisture analyzer. When the cryogenic plant is being dried-out, prior to lowering the temperature, this line is used to determine when to stop the dry-out.
- A 1 1/2" line that is the expander's seal gas supply source during start up operation.
- A 3" line that connects to the inlet, gas line to the cryogenic plant and upstream of the inlet filter separators This line is used as the cryogenic plant initial dry-out recycle line and normally for warming the plant to de-rime when necessary .
- A 12" emergency shutdown valve: The residue gas compression discharge valve closes when the cryogenic plant is shutdown via the BSD system
- A sample point, that goes to a gas chromatograph to analyze the contents of the residue gas.
- The residue gas header now splits for flow through two (2) identical custody transfer flow computerized meters on the main panel. One flow meter is a spare Flow relay goes to the printer, flow recorders & to the SCADA
- Another residue, gas plant outlet emergency shutdown valve is placed in the 12" line before connecting to the 24" pipeline.

4.2.7 IFPEXOL Process Plant

IFPEXOL is IFP's trademark for their patented Integrated Functions Processing Expertise, a process technology which offers a complete treatment of wet, sour, condensable hydrocarbon gases in a single process unit. It is based on freeze-point depression qualities of methanol-based solvent. Only one IFPXOL process plant is installed in Bangladesh at Jalalabad gas field.

The brief description of IFPEXOL plant is given below:

4.2.7.1 Process Description

The process serves for Hydrate Prevention, Dew Point Control, Dehydration, Acid Gas Removal. Plant consists of the following major components shown in the Figure 4.14 These are-

- HP separator
- Test separator
- Inlet gas filter
- MP production separator
- Gas boot
- IFPEXOL contactor
- LTS IFPEXOL pumps
- Gas-gas exchanger
- LT separator
- Gas chiller
- Propane compressor(s)
- Compressor inlet scrubber
- Refrigerant economizer
- Propane scrubber(s)
- Propane condenser & accumulator
- Methanol storage.

Besides, Instrument Air System, Flare System, Condensate Tank and Pumps, Fuel Gas System, Waste Water System and Fire Fighting System.

Flowing from each well arrive at the battery limit via 8 inch pipelines. The line is split and tie-in goes to a production header and a test header. The fluids collected in the production wells header are sent to a HP separator HP Separator is a three phase separator. The vessel is designed for a pressure of 1415 Psig and 120 ^{0}F and flow of 125 MMscfd of gas, 3820 BPD of hydrocarbon liquid and 1250 BPD of free water. Fluids from the test well header are sent to the Test Separator. It is designed to handle 50% of the designed flow rates of the Production Separator.

Gas from the HP Separator and Test Separator flow to the Inlet Gas Filter. The filter coalesces any liquid droplets entrained in the gas. The dry gas from the filter goes on to the IFPEXOL Contactor. Gas passes up through the contactor and it comes in contact with the water/methanol flowing down the column. As the gas passes up through the contactor it strips the methanol out of water. The gas exits at the top of the contactor and pure methanol is injected into this stream This is done in order to prevent any hydrate formation further downstream where the temperature will be lowered in order to achieve the dew point specification. Water collects at the bottom of the column and is drained out.

The methanol rich gas stream at 1276 psig and 119^{0}F enters the tube side of the Gas/Gas exchanger where it is cooled to 22°F by the counter flow of cold gas on the shell side of the exchanger. Gas then goes to tube side of the Chiller where the temperature is reduced to 0^{0}F. At this temperature liquids condense out of the gas stream. The cooling of the gas in the chiller is accomplished by the evaporating propane refrigerant on the shell side of the chiller.

The three-phase liquid from the chiller goes to the Low Temperature Separator. In LTS the gas is separated from the liquids and sent to the gas/gas exchanger, which pre-cools the incoming gas. Gas from LTS gets warmed in G/G exchanger and exits at 102^{0}F as the sales gas

The liquids collected in the LTS are separated by gravity. Hydrocarbon liquid collects in the shell of the vessel and water/methanol is collected in the boot. Water/methanol solution is pumped through filters to the IFPEXOL contactor.

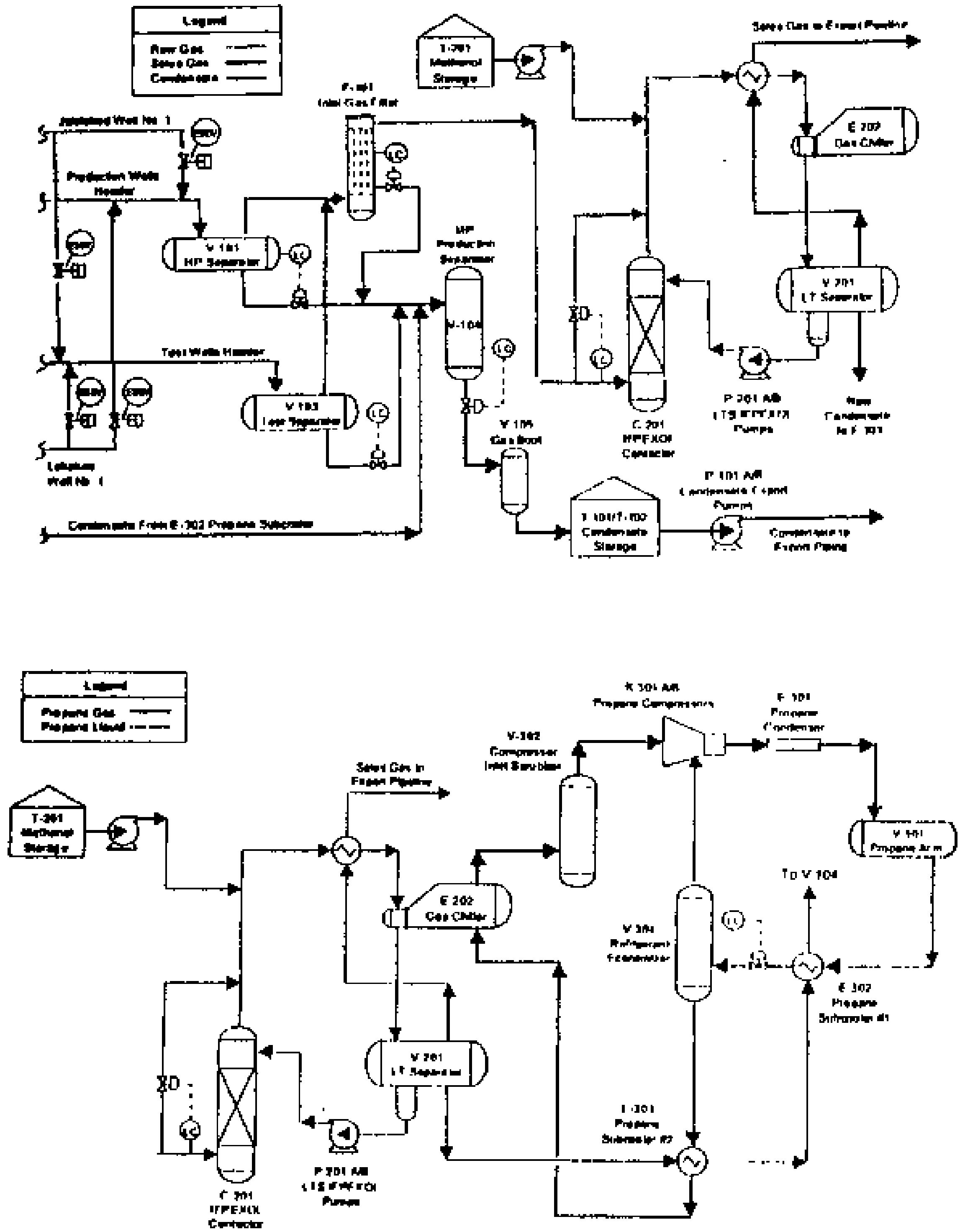


Figure 4.14 : Process Flow Diagram of IFPEXOL Plant at Jalalabad Gas Field.

Propane, which is used as a refrigerant to cool the gas is limited to a closed system Hence propane loss is negligible other than leaks through the safety relief systems. Propane refrigerant vapor from the Propane Compressors enters the Propane Condenser, an air cooler, at around 280 psig and 170°F. Propane is cooled and condensed here. Liquid propane flows to the Propane Accumulator Propane from the accumulator enters the shell side of the Propane Sub Cooler 1 and its temperature is lowered to 100°F in the heat exchange with the cold hydrocarbon liquid flowing in the tube side. Propane from here is flashed to 55 psig and 33°F. The two-phase liquid enters the Propane Economizer. The liquid is piped to the Propane Sub Cooler 2 and the vapor is then piped to the inter stage of the propane compressor. Liquid propane from the economizer enters the shell side of sub cooler 2 and cooled to 23° F and piped to the Chiller. The gas on the tube side of the chiller is cooled by the evaporating propane refrigerant on the shell side. The vaporized propane is piped to the propane compressor inlet.

The hydrocarbon liquid from LTS goes to the Propane Sub Cooler 2. The liquid exits through the tube side at 23°F After flashing through a valve it goes to the tube side of the Propane Sub Cooler 1 where it is warmed to 100°F. From here this liquid along with hydrocarbon liquids from the separators are piped to the MP Separator. The gas from MP separator is used as the main fuel gas The liquid from the MP separator is piped to the storage tanks.

The gas plant has been processing gas between the range 60/130 MMSCFD during its last one year of operation at Jalalabad gas field Plant operating pressure varied between 1100 and 1200 psig. Low Temperature Separator has been functioning between 0 and-10^0F Water dew point of the sales gas is maintained between 0 and -10^0F with water content ranging between 10^0F and 17^0F. A comparison of LTS temp, water and hydrocarbon dew point is shown in below-

The sales gas specific gravity varies between 0.579 and 0.604 with the BTU value ranging between 1045 for the lowest and 1080 btu/scf for the max sp. Gravity value.

<u>**IFPEXOL** Performance Range</u>:

Water & Hydrocarbon Dew Point:	down to-100^0C 1 ppm water vapor
CO2 content in treated gas:	down to 1000 ppm
H2S content in treated gas	¼ grain per 100 scf or 3.3 ppm vol
Methanol content in water out:	less than 50 ppm

4.2.8 Glycol Dehydration with Turbo Expander Plant

This process is combination of gas dehydration with liquid hydrocarbon enhance process. The gas dehydration process is similar to glycol dehydration process. Turbo Expander is installed for liquid hydrocarbon enhance process. Processing by turbo expander is similar with Kailashtila gas field Block diagrams are shown in Figure 4 15.

The brief equipments list of this plant, which is installed at Sangu gas fields, is given below:

4.2.8.1 Process Equipment

The Chillimpur Gas Plant was constructed by Brown & Root, an affiliate of HBR Energy Inc. The gas that comes onshore from the Sangu platform is of high quality and dry but still contains some water and condensate - hydrocarbon liquid that drops out of gas The water and condensate is removed from the gas stream at Chillimpur and the condensate is sold to Bangladesh Petroleum Corporation for refining. The dry gas is being transported into the Bakhrabad gas line of BGSL (Bakhrabad Gas System Limited). The grid in Chittagong is connected to the national grid in the north.

Offshore Platform Facilities at Sangu are :

- Wellheads with hydraulic power for actuation of well valves, choke valves and platform ESDV valves. (Control valves have separate dedicate hydraulic supplies).
- Test/Production Separation with metering of gas, condensate and water streams prior to recombination
- Permanently installed export pig launcher.
- Storage and injection of corrosion inhibitor for inhibition in export pipeline.
- HP vent for emergency and manual depressurisation of platform inventory
- Electrical power generation (diesel engines), distribution and UPS
- Control and monitoring system (CMS)
- ESD and fire and gas system
- Telecommunications
- Platform crane
- MEG injection facilities for start-up
- Local equipment room (LER).

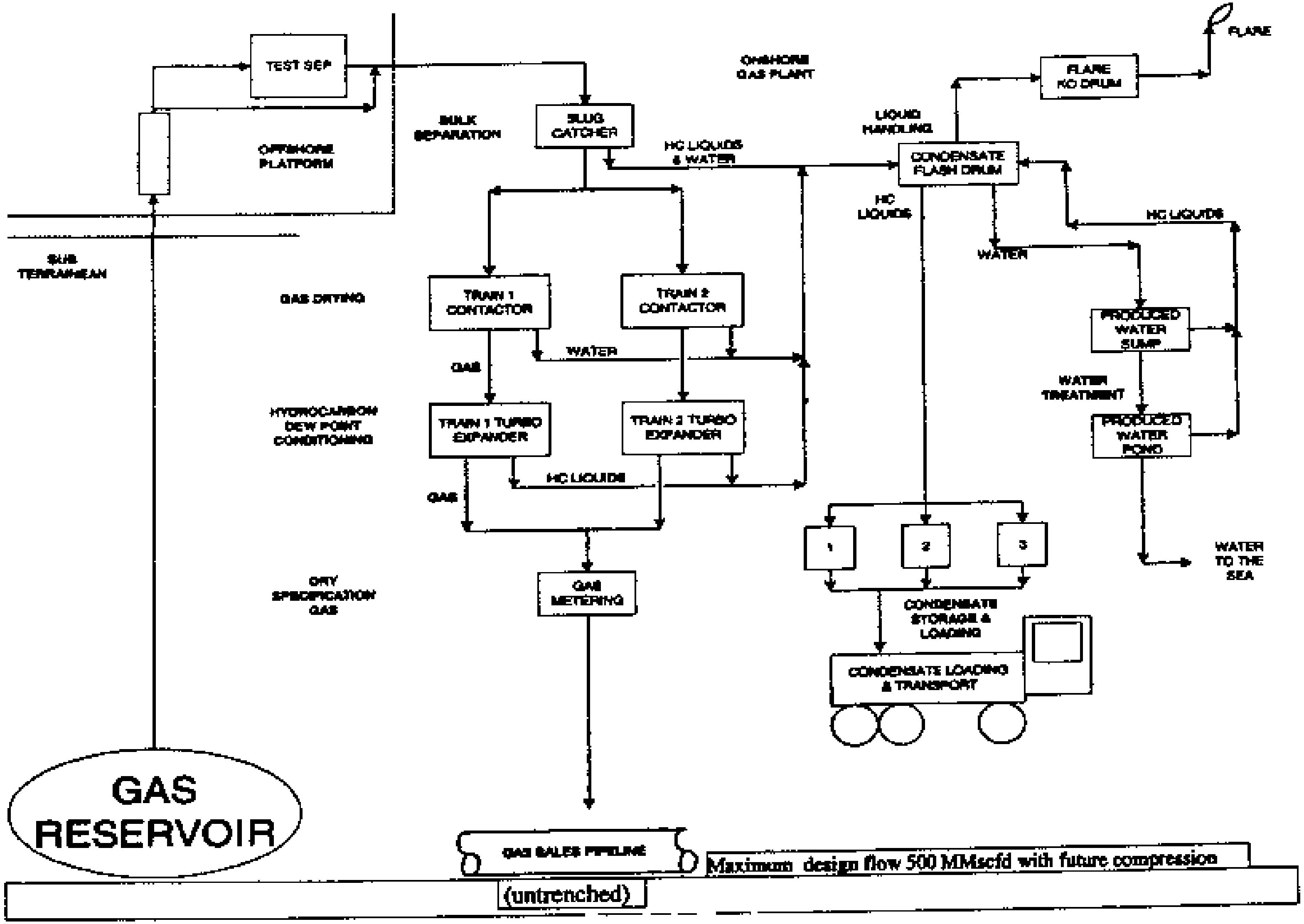


Figure 4.15 : Block Diagram of Glycol Dehydration with Turbo Expander Plant at Sangu Gas Field.

Onshore Facilities consist of a Pig Receiver to handle spheres and intelligent pigs Slug Catcher removes wet gas and liquid slugs from pigging operations and flow rate ramping. Gas is processed by glycol dehydration with turbo expander plant. There are two process train to the plant. Each train has a capacity of 260 MMscfd. The major components of the plant are shown in Figure 4.16. Each process train consists the following system and components:-

- Dehydration knock-out drum
- Glycol contactor with gas/glycol heat exchanger
- Glycol regeneration
- Gas/ gas exchangers
- Expander suction k-o drum
- Turbo-expander with parallel j-t valve
- Low temperature separator

Common facilities

- Gas fiscal metering and export
- Fresh TEG storage drum, chemical injection (pH and antifoam) and TEG closed drains system.
- Fuel gas system including start-up heater
- HP flare system
- LP flare and combined closed drains
- Instrument/plant air system
- Condensate stabilization, storage and export system
    - Condensate flash drum incorporating integral condensate heater
    - Condensate rundown cooler
    - Condensate transfer pumps
    - Condensate storage tanks
    - Condensate export pumps
    - Tanker loading package
- Produced water treatment system
    - Produced water sump
    - Recovered oil pump
    - Produced water transfer pumps

- Produced water treatment package (quality < 20ppm of entrained hydrocarbons)
- Produced water disposal pond and disposal pumps

- Warehouse / laboratory / maintenance facilities
- Main and auxiliary power generation and distribution and ups
- Fire protection systems including firewater and foam
- Control and monitoring system (CMS)
- ESD and fire and gas system
- Telecommunications
- Control room/local equipment room

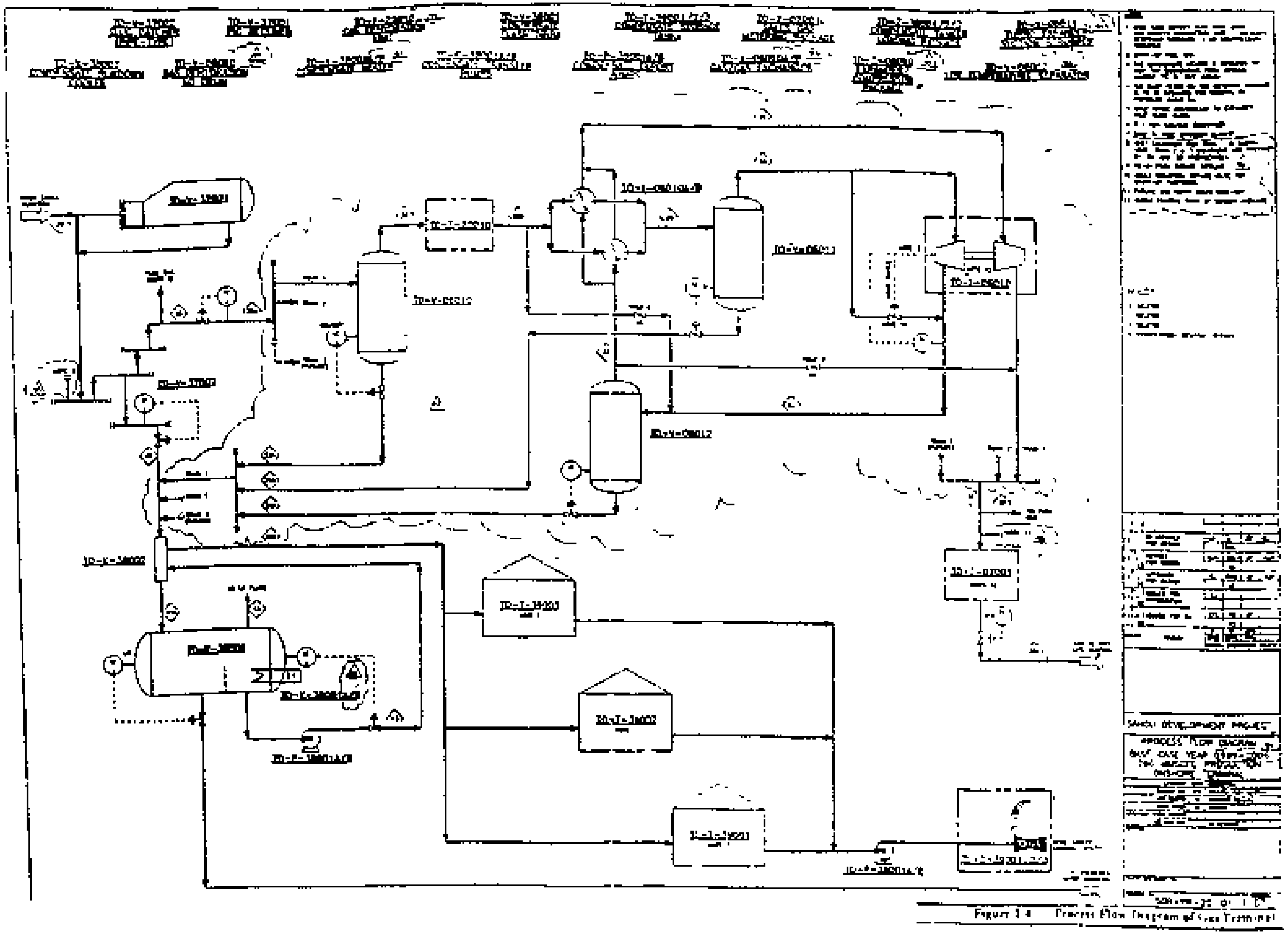


Figure 4.16 : Process Flow Diagram of Glycol Dehydration with Turbo Expander Plant at Sangu Gas Field.

CHAPTER V

COMPARATIVE STUDY OF THE GAS PROCESSING PLANTS IN BANGLADESH

The earlier chapters discussed the number and types of gas processing plants currently in operation in Bangladesh. Each type of plant was presented in detail regarding the technologies, major components and facilities, and the physical/chemical processes involved.

This chapter is dedicated for a comparative study among the different types of plants. The basis of comparison can be a variety of parameters such as, technology, equipment, process, performance, etc. In this project the following comparative studies are conducted:

- For a given type of technology, all the plants are compared on the basis of their major components and facilities.
- For a given type of technology, the major repairs and replacements for all plants are compared.
- Performance of the process plant at each field is examined, and field wise comparison is made.

Detail discussions and summary tables are presented in the next sections.

5.1 Comparisons by Major Facilities and Components

In this section, it is attempted to group the various process plants on the basis of their types for meaningful comparisons. Comparisons of similar type of plants at various locations are presented as follows:

5.1.1 Glycol Dehydration Process Plants

There are sixteen glycol process plants currently in operation in Bangladesh. The location, capacity, process and equipment description of these plants are presented in section 4.2.1. A comparative study of all these plants regarding their major components and facilities is presented as follows

- *Glycol circulation pumps.* Plants-1, 3, and 4 in Titas field use gas driven plunger type "union" pump for glycol circulation. Plants-5, 6 in Titas, plants in Narshingdi, Saldanadi, Feni and plants-5, 6 in Habiganj field use high pressure glycol driven four energy exchange type "Kimray" pumps In Titas, plant 7 and 8 (LTS with glycol injection), electric motor driven pumps are installed. The performance of glycol driven four energy exchange type pump is better than other types of pumps with respect to maintenance and service.

- *Glycol filters.* Two type of glycol filters, namely carbon and soak filter, are used in Titas plants-4 and 5, Rashidpur and Feni process plants. The other glycol dehydration and LTS with glycol injection plants in the country use only one type of filter, either carbon or soak. The sock filter removes solids and a carbon filter absorbs small amounts of hydrocarbons that may build up in the circulating glycol. Using both type of filters is more effective and preferable.

- *Glycol separator.* Three phase flash separators are installed in most of the glycol plants in the country However, such separators are not installed at Norshigdi, and Habiganj plants 5,6. All of the glycol three phase flash separators are horizontal type except for Feni field, where it is of vertical type.

- *Knock-out separator:* Horizontal knock-out separators are installed in the plants at Titas and Habiganj. But in the plants at Saldanadi and Norshinghdi, vertical knock-out separators are installed.

  In Feni field, Knock out separator is an integral part of the contractor tower. There is no individual knock out separator. The lower portion of the glycol contractor acts as a separator.

- *Surge tank and Heat exchanger:* Glycol surge tank/accumulator and glycol-glycol heat exchanger are separate vessels in Habiganj plants 3,4,5 & 6, Norshingdi plant and Titas plants. But at Saldanadi and Habiganj plants 1,2 and at Feni field, the surge tanks act as Shell Tube Heat Exchangers. The surge tank acts as the shell side, while the accumulator and tubes inside the surge tank act as the tube side of the heat exchanger.

Gas-glycol heat exchangers are installed in Feni, Rashidpur and Habiganj plants 5 and 6. Dry gas from the top of the glycol contactor flows through this heat exchanger This cools the incoming dry glycol to increase its absorption capacity, and decrease its tendency to flash in the contactor and be lost to the dry gas.

- *Cooler*: Only air-glycol cooler was installed at Feni. The high temperature of glycol may damage the different seals of glycol circulation pump.

  The natural draft air cooler with a vapour drum is installed in Norshigdi, Habiganj plants 5 and 6. Other plants do not have this facility, which achieve the optimum recovery of condensate/water vapor from glycol regenerator/still column of the plants. Feni field only has a cooler but no a vapour drum.

Table 5.1 shows the comparison of the major facilities and equipment of glycol process plants in Bangladesh.

5.1.2 Silica Gel Process Plant

There are eleven silica gel process plants currently in operation in Bangladesh. The location, capacity, process and equipment description of these plants are presented in section 4.2.2. A comparative study of all these plants regarding their major components and facilities is presented as follows:

- *Cooler*: Regeneration gas-water coolers are installed in the silica-gel plants of Bakhrabad and Sylhet Gas Fields. But in other silica-gel plants, regeneration air-gas coolers are installed. Operation of gas-water cooler requires other accessories / facilities. Operation of air-gas cooler is simple, not depending on other accessories except supply of electricity

  In the regeneration air-gas coolers at Bakhrabad, tube-fins are installed below the fan. In other fields, tube-fins are installed above the fan.

- *Valves*: In Bakhrabad Gas Field, butterfly valves are used in the tower manifold. But in the other fields, orbit valves are used in similar plants.

Table 5.1: Comparison of Equipment among Glycol Plants in Bangladesh

Legend :				
	Installed = √	Horizontal = H	Combind with accumulator = C	Four energy exchange
	Not installed = X	Vertical = V	Separate from accumulator = S	glycol driven = F

Equipment \ Field & Plant		Feni Plants 1 & 2	Habiganj Plants 1 to 6		Narshigdi Plant 1	Rashidpur Plant 1	Saldanadi Plant 1	Titas Plants 1,3,4,5 & 6
Water bath heater	Status	X	√		√	√	√	√
	Type	-	H		H	H	H	H
Knock out separator	Status	X	√		√	√	√	√
	Type	-	H		V	H	V	H
	Remarks	Lower portion of the glycol tower acts as a separator in plants 1 & 2 of Feni						
Gas-glycol exchanger	Status	√	X (1 to 4)	√ (5 & 6)	X	√	X	X
	Type	Shell & tube	-	Fin tube	-	-	-	-
	Remarks	Gas glycol heat exchanger is installed only in plants 5 & 6 in Habiganj field.						
Sales line scrubber/Filter separator	Status	X	√		X	√	X	√
	Type	-	H		-	Double tube-H	-	H
	Remarks	Common scrubber for all plants in Titas and Habiganj						
Glycol flash separator	Status	√	√(1 to 4)	X(5 & 6)	√	√	√	√
	Type	V	H	-	H	H	H	H
Glycol/Glycol heat exchanger	Status	√	√(1,2,5& 5)	√(3 & 4)	√	√	√	√
	Type	C	C	S	S	C	C	S
	Remarks	Surge tank act as the shell side of exchanger in Saldanadi, Rashidpur, Norshingdi, Feni and Habiganj (Plants 1, 2, 5 & 6).						
Surge tank / Accumulator	Status	√	√ (1,2,5& 5)	√ (3 & 4)	√	√	√	√
	Type	C	C	S	S	C	C	S
	Remarks	Accumulator act also shell side of glycol / glycol exchanger in combine case.						

Table 5.1 (Continued) : Comparison of Equipment among Glycol Plants in Bangladesh

Field & Plant / Equipment		Feni Plants 1 & 2	Habiganj Plants 1 to 6		Narshigdi Plant 1	Rashidpur Plant 1	Saldanadi Plant 1	Titas Plants 1,3,4,5 & 6	
Glycol filter	Status	√	√		√	√	√	√	
	Type	Soak & carbon	Soak		Soak & carbon	Soak	Soak (1,3 & 6)	Soak	Soak & carbon(4 & 5)
Glycol pump	Status	√	√	√	√	√	√	√	
	Type	F	F (1,2,5 & 6)	Dual pump (3 & 4)	F	F	F	Plunger pump (1,3 & 5)	F (5 & 6)
	Remarks	In Habiganj Plants 3 &4, two gas driven pump are used. One to pump rich glycol to regenerator, and another for surge tank to contractor							
Air/Glycol heat exchanger	Status	√	X		X	X	X	X	
	Type	Fin tube	-		-	-	-	-	
Vapour drum, Natural draft air cooler	Status	X	X (1 to 4)	√ (5 & 6)	√	X	X	X	
	Remarks	Arial cooler is installed instead of Vapour drum and Natural draft air cooler in plants of Saldanadi and Narshingdi							
Fuel gas scrubber	Status	√	√		√	X	X	√	
	Type	V	V		Drip pot	-	-	Drip pot (1,3 & 4)	V (5 & 6)
	Remarks	Common in plants for 1 to 4 of Habiganj field.							

- *Operation cycle*: The plant of Bakhrabad is the only one which has provision for processing in both "Closed Cycle" or "Open Cycle" operation. Plants in others fields have provision for only "Open Cycle" operation. Under "Closed Cycle" operation, a nominal improvement in the hydrocarbon liquid recovery is possible.

- *Separator*: Horizontal knock-out separators are installed in the silica-gel plant of Rashidpur Field, but the rest of the silica-gel plants have vertical type knock-out separators.

  In Fenchuganj and Beani-bazar, only one knock-out separator is installed for multiple wells. Other silica-gel process plants have individual knock-out separator for each well.

- *Well controller*: In Rashidpur, the plant has a well controller which automatically controls individual well flow with respect to total flow. Other plants do not have this provision.

Table 5.2 shows the comparison of the major facilities and equipment of silica-gel process plants.

5.1.3 General Comparisons

Following comparisons can be made among different types of plants:

- *Separator*. Only LTS and LTX type plants have the Knock out separators insulated, whereas in the other types of plants, they are not insulated. Temperature of knock out separators in the LTX and LTS plant is lower than ambient temperature The vessels are insulated to reduce heat loss.

  Knock out separator of LTS plant 9,10,11 & 12 in Titas are horizontal but in LTS plant 7 and 8 in Titas, they are vertical.

- *Instrumentation*: In the LTS, LTX and Glycol plants, dry natural gas is used for operating the process instruments. In the other plants, dry air is used instead. Using dry air enhances the life of instruments and cause less trouble.

Table 5.2: Comparison of Equipment among Silica Gel Plants in Bangladesh:

Legend : Installed = √ | Not installed = **X** | Horizontal = H | Vertical = V | Forced draft fin tube = F

<table>
<tr><th colspan="2">Field & Plant / Equipment</th><th colspan="2">Bakhrabad Plants 1 to 4</th><th>Beanibazar Plant 1</th><th>Fenchuganj Plant 1</th><th>Kailashtila Plant 1</th><th>Rashidpur Plants 2. 3 & 4</th><th>Sylhet Plant 1</th></tr>
<tr><td rowspan="3">Inlet air cooler</td><td>Status</td><td>X (1 to3)</td><td>√ (4)</td><td>X</td><td>X</td><td>X</td><td>X</td><td>X</td></tr>
<tr><td>Type</td><td>-</td><td>F</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Remarks</td><td colspan="7">Recently inlet air cooler was installed in plants 1 to 3 of Bakhrabad field.</td></tr>
<tr><td rowspan="3">Water bath heater</td><td>Status</td><td colspan="2">√</td><td>√</td><td>√</td><td>√</td><td>√</td><td>√</td></tr>
<tr><td>Type</td><td colspan="2">-</td><td>H</td><td>H</td><td>H</td><td>H</td><td>H</td></tr>
<tr><td>Remarks</td><td colspan="7">Common water bath heater for plants 3 & 4 of Rashidpur field</td></tr>
<tr><td rowspan="3">Knock out separator</td><td>Status</td><td colspan="2">√</td><td>√</td><td>√</td><td>√</td><td>√</td><td>√</td></tr>
<tr><td>Type</td><td colspan="2">V</td><td>V</td><td>V</td><td>V</td><td>H</td><td>V</td></tr>
<tr><td>Remarks</td><td colspan="7">Lower portion of the glycol tower act as a separator in plants 1 & 2 of Feni</td></tr>
<tr><td rowspan="2">First stage scrubber / separator</td><td>Status</td><td colspan="2">X</td><td>X</td><td>X</td><td>X</td><td>√</td><td>X</td></tr>
<tr><td>Type</td><td colspan="2">-</td><td>-</td><td>-</td><td>-</td><td>V</td><td>-</td></tr>
<tr><td rowspan="2">Regeneration gas water cooler</td><td>Status</td><td colspan="2">√</td><td>X</td><td>X</td><td>X</td><td>X</td><td>√</td></tr>
<tr><td>Type</td><td colspan="2">-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>H</td></tr>
<tr><td rowspan="3">Booster compressor</td><td>Status</td><td colspan="2">√</td><td>X</td><td>X</td><td>X</td><td>X</td><td>X</td></tr>
<tr><td>Type</td><td colspan="2">-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>Remarks</td><td colspan="7">Due to this compressor plants 1 to 4 of Bakhrabad field can be operated by closed cycle mode.</td></tr>
</table>

- *Filter/Scrubber*: All the silica gel plants use filter separator/scrubber before sales line In the MSTE plant, the stabilizer acts as the sales line scrubber. All the plants of Titas and Habiganj have common scrubber, but other plants in different fields have no a scrubber.

5.2 Major Replacements and Repairs

There are some regular maintenance and replacements common to all plants. These are-

- Seat-plug, ball, gate and diaphragm of different types control valve, globe valve, gear valve, ball valve, butterfly valve etc. are required to be replaced after 2/3 years. Valves are replaced every 10/12 years.
- Nozzles, bellows, relays, bourdon-tubes, diaphragms etc. of the controller/ positioner/ regulator/ transmitter are required to be changed every 4/5 years. Whole assembly should be replaced after 8/10 years.
- Pressure gauges & temperature gauges are replaced every 2/3 years

Major replacements and repairs at different types of process plants are listed below. The field names for each type of plant appear in alphabetical order.

5.2.1 Glycol Dehydration Plant

Habiganj Gas Field

- Revamping works of plants 1 & 2 were carried out in 1985 including the following:

  -Installation of a 3-phase horizontal flash separator in place of a vertical separator.

  -Addition of a charcoal filter.
- Degraded glycols were replaced in plants 1 & 2 in 1988, 1990 & 1993 During Glycol replacement, each plant was shut down for 5 days.
- Glycol flash separator and glycol-glycol heat exchanger of plants 1 to 4 are required to clean after every two/three years
- Glycol pump of the glycol plants 1 to 4 are required to repair after every 3/4 years

Norshigdi Gas Field

- High pressure gas gathering lines well head to knock out separator of well was replaced in 2003 due to internally eroded.
- Pressure control valves (PCV) of plants was replaced.
- Degraded glycol was replaced in 2004.

Saldanadi Gas Field

- Horizontal knock-out separator of glycol plant was replaced by vertical one in 2000.
- Gathering line of well 2 was installed with well 1 in 2001.
- Degraded glycol was replaced in 2002 & 2005.
- Glycol filter cartridges were replaced in 2002.
- New glycol pump was installed in 2003.
- Pipe line was prepared for gas generator in 2003
- The glycol flash separator and re-boiler were cleaned in 2004.
- The downcomer of reboiler was repaired in 2003.

Titas Gas Field

- Bubble trays of glycol tower Plants 1 & 3 were repaired in 1977-78.
- Glycol-glycol heat exchanger of plants 1,3,4 & 5 are required to clean after every two years
- Re-boiler fire tube of glycol plants 1 & 3 were repaired in 1978-79.
- Plunger type glycol pump of the glycol plants 1 & 3 are required to repair after every 2/3 months
- Well head to inlet heater pipe lines of glycol plants 1 & 3 were replaced two times.
- Pipe line to common header to well-5 was repaired in 1985.
- Tube of glycol-glycol heat exchanger of plant 7 was replaced in 2003.
- High pressure gas gathering lines (well head to common header) of well-1, 2, 3 & 6 were replaced in 1999 due to internally eroded
- Inlet control valves (PCV) of plants 3 & 5 were replaced.
- Well head to knock-out separator pipe lines of glycol plants 4,5 & 6 were replaced two times.

5.2.2 Silica Gel Dehydration Plant

Bakhrabad Gas Field

- Tube of regeneration gas-gas heat exchanger of silica gel plants was replaced in 1998.
- Regeneration gas-water cooler was repaired in 1992 and replaced in 2001
- Sand collector separator was installed in well 8 in 1999.
- Two inlet cooling fan were installed in trains A/B/C in silica-gel plants from LTS plant 10 of Titas Gas Field
- Silica-gel of trains A, B, C & D was replaced in March 91, January 94, August 91 & May 97 respectively
- Due to the decline of well head pressures, Pressure control valves (PCV) of well-1, 2, 3, 5 & 7 were removed during the period May-November, 1997
- Three water bath heater of Bakrabad gas field out of four were relocated to Beani Bazar, Habiganj & Meghna gas fields at different times
- Tubes of Heat Exchanger of train D were replaced in August 98.
- A free liquid knockout separator was installed on the flow line of well- 8.
- Gas-water Heat Exchangers of trains A & C were repaired in July 91 and September 92 respectively. The same of train B was repaired in June 91 and March 95.
- Cracked fire tubes of oil bath heater of train A were repaired in November 93 & November 94 and that of train B was repaired in August 94 Also the cracked fire tubes of train C were repaired in December 94 and March 93.
- Regeneration Air Cooler Heat Exchanger of train A was repaired in June 94 and February 95.

Rashidpur Gas Field

- The silica gel of old plant (70 MMscfd) was changed of Rashidpur Gas Field in 2001
- Tube of regeneration gas-gas heat excahanger of silica gel plants was replaced in 1998.
- Pressure control valves (PCV) of well-1,2 & 3 were replaced two times.
- Tubes of Heat Exchanger of old silica gel plant were replaced in 98.

Sylhet Gas Field

- Regeneration gas-water cooler was repaired two times.
- Silica-gel of dehydrator was replaced three times.
- Inlet choke valve of the well was repair several times and replaced two times.
- Gas-water Heat Exchangers of the plant was repaired in March 89 and October 98 respectively.
- Regeneration gas heater, air cooler & cooling gas cooler were repaired few times.

5.2.3 Low Temperature Separation (with/without Glycol Injection) Plant

Titas Gas Field

- Temperature controllers of three way pressure control valve of different LTS plants was replaced several times.
- Tube of glycol-glycol heat exchanger of plant 7 & 9 was replaced in 2003
- Pressure control valve of LTS unit was replaced in 1999
- Tube of inlet air cooler of the LTS plant 7 was repaired in 2001, 2003 and the cooler itself was replaced in 2004.
- Inlet air cooler of LTS plants 9 & 10 were replaced 1991, 1998 & 2004
- Inlet control choke valves (PCV) of plant -9 & 10 were replaced.
- Cracks developed in the fire tube of reboilers at plants 7 & 8 were repaired
- Leaking tubes of inlet air coolers of plants-7 & 8 were repaired several times.
- High pressure gas gathering lines from well head to plant inlet of well 7 & 8 were replaced in 1999.
- HP gas gathering lines from common header to plant inlet of well 9 & 10 were replaced in 1999.
- Viewing frequent recurrence of leakage in inlet air coolers were subsequently replaced. Leaking tubes of inlet air coolers of plants 9 &10 were repaired several times.

5.2.4 Low Temperature Extraction Plant

Meghna Field

- Heat Exchanger of unit 1 of LTX plant was replaced in 1981 and that of unit 2 was replaced in 1983 & 1984.
- Heat Exchangers of both units (unit1&2) of LTX plant were repaired at Titas workshop
- Pressure control valves (PCV) of both plants were replaced few times.

5.2.5 Other Types of Plants

- The molecular sieve of Kailastila plant was changed in 2001 .
- The bubble trays of de-ethanizer of Kailastila were replaced in 2001
- Separate oily water separator was installed for well 4 of Kailastila Gas Field in 1999.
- The knock out separator of Jalalabad plant was replaced in 2005
- Boiler tube of old fractionation plant in Titas was repaired in 1998, and was replaced in 1999.
- Boiler tube of new fractionation plant in Titas was replaced in 2004.

5.3 Performance of Process Plants in Different Fields

All of the installed plants in Bangladesh achieve a very good specification depress below the dew point even in the case of most old plant The older processing plants cannot handle the name plate gas flow rates and the separation of liquefiable HC is not satisfactory, leading to condensation of remaining liquefiable HC inside the transmission lines On the other hand, the pressure and temperature of the wellhead gas are significantly different from those used in the design of the process plants. With the depletion of reserve the gas composition has also changed, which affects the plant performance due to phase behavior.

The common problem in most of the plant in different gas fields is the lack of vapour recovery systems on condensate production. The liquids are not stabilized before being sent to the stock tank. Stabilization involves heating the liquid to a temperature above that which they will be stored before cooling in order to minimize vapour loss from the storage tank The process scheme high pressure (1000 psi) liquid streams are combined at the inlet of the 40-90 psi flash separator. After this flash, they are then combined with the low pressure liquid streams and sent to the atmospheric storage tank where the liquids are flashed again. This final flash strips the lightest components, which, in turn, "drags" some of the heavier components as well, thus contributing to liquid loss. Further loss occurs as the tank "breathes" as liquid levels are varied with shipping to and from the tank.

No vapour recovery systems are installed on the condensate stock tanks, causing weathering and loss of product to the atmosphere. Installation of pressurized storage tank may increase the liquid hydrocarbon recovery but in this case the condensate can not be carried in conventional tankers. Pressurized tanker will be required, which is not feasible currently. Introducing a vapour recovery system in a low capacity tank may not be feasible, but all large storage tanks for condensate product should be upgraded to incorporate vapour recovery systems Besides, installation of natural draft air coolers and vapor drums etc. may be able to enhance recovery of condensate/water vapor from glycol regenerator/still column of the plants.

In most of the plants, sales line scrubber are not installed, which is needed to finally remove the dust, liquid hydrocarbon, water or other undesirable foreign particle for supply of clean gas

In several fields, water handling and disposal facilities are not sufficient. Handling, processing and disposal of produced water will require installation of appropriate facilities including tanks, filtration systems and transfer pumps.

Though all of the fields meet efficiently the sales line specification but in the respect of liquid hydrocarbon recovery all the process plant are not appropriate for processing of raw gas from well.

The process performance at each field is presented next. Following discussions mainly focus on the ability to depress the dew point, i.e., the ability to remove entrained water and the effectiveness of the hydrocarbon recovery system. The problem of produced water handling is also addressed. In addition, ideas about enhancing hydrocarbon recovery and overall process improvement are suggested where applicable. The field names appear in alphabetical order.

5.3.1 Bakhrabad Gas Field

The gas process facilities consist of four 60 MMscfd Silica-Gel Dehydration trains. The average gas composition from the Bakhrabad Sands contains approximately 97.5 percent methane and ethane with only a small amount of recoverable $C5^{-}$ liquids. With the silica gel towers operated on a short cycle, (approximately 30 minutes) the process can recover some hydrocarbon liquids. Historically the Silica gel process achieves a very good specification on dew point but plant has never recovered much more than approximately 2 bbl/MMcf liquid hydrocarbon. When the field was processed by Glycol plant up to 1986, the average condensate recovery rate was 0.834 bbl/MMcf, in the case of silica gel it was 1.45 bbl/MMcf (average). So, silica gel process seems to perform better than a glycol plant with respect to hydrocarbon recovery. The plant design predicted liquid recovery exceeding 6 bbl/MMcf. Since the average flow rate for each train is less than the design rate, cross-sectional considerations and velocity through the silica gel adsorption tower should not cause the loss in efficiency. At least four possibilities exist which could explain the loss in plant liquid recovery efficiency. These are:

i) Inlet temperature: Inlet feed temperature to the process significantly higher than the temperature presumed in the design, (123°F versus 150°F). The higher inlet temperature acts to reduce the volume of liquids adsorbed on the silica gel, thereby reducing the volume of liquid, which can be recovered. This issue was addressed during design of the fourth train installed in 1989, where a fin-fan cooler was installed upstream of the process to pre-cool the inlet gas stream. Inlet cooling of the produced gas prior to processing is an effective means of improving liquid recovery. Recently, two old fin-fan cooler from installed in two trains from Titas Gas Field.

ii) Stock tank design. No vapour recovery of stock tank vapours causing weathering and loss of product to atmosphere.

iii) Operation cycle: Under "closed cycle" operation a nominal improvement is possible in the hydrocarbon liquid recovery. The compressor for the regeneration gas was often not in operation during this time consequently the process could not be run on a "closed cycle".

iv) Gas composition: The gas composition used in the design differs from "averaged" compositions from all gas sands produced to the plant.

Theoretical volume of liquid which could be recovered and stored in an atmospheric storage tank (C_{5+}) is 4.8 bbl/MMcf. It is estimated that the process recovery efficiency coupled with the inlet temperature of the gas and the lack of a vapour recovery system will limit recovery to approximately 3 barrels/MMcfd (almost entirely C_{5+}). Fluid composition of well C_1 ranging from 93.6 to 94.0 percent and C_2 to C_4 percent is higher than C_{5+}. But, The silica gel system to effectively recover more than the C_{5+} components and some small quantity of the C_{3+} and C_{4+} components for. If the cycle time set very short light hydrocarbon can be recover but it effect the dehydration of gas. So for recover of light hydrocarbon this process is not appropriate. For maximum potential recovery if the turbo expander process applied would be 13.3 bbl/MMcf, which is mixture of C_{3+} and higher hydrocarbon.

The turbo expansion process could make use of the existing dehydration facilities if they were used for water removal by silica gel process train would operate on a longer cycle. The inlet pressure to the turbo-expansion process is typically operated in the range of 600-900 psi. Now the pressures of the various gas sands are decline to plant design inlet pressure. At that point in time, booster compression can be added to raise the pressure to the desired inlet pressure. This booster compression may be powered off the turbo-expander itself.

In a Bakhrabad Gas Field, there are sufficient wells and process capacity to deplete the reserves in Bakhrabad consequently no conceptual facility plan is required for this field. The feasibility of reducing the inlet pressure to the plant and installing inlet booster compression should be re-evaluated.

5.3.2 Beani Bazar Gas Field

The Silica gel process has been able to depress the dew points lower than the sales line specification and average condensate recovery 16.99 bbl/MMSCF. For higher GOR some times the plant can not properly handle liquid hydrocarbon recovery, over flooding of hydrocarbon in the silica gel bed liquid hydrocarbon mixed with outlet gas of dehydrator. The Upper and Lower Gas Sand contain a lean gas with a liquid-gas ratio of 13.2 and 15.7 bbl/MMscf at field separator conditions. By introducing process facilities the recovery of condensate is slightly enhance with respect to field separator conditions.

The gas compositions for Kailashtila and Beani Bazar are very similar. In fact Beani Bazar has a sightly higher mole fraction of heavier components than does Kailashtila, therefore, the installing liquid recovery must be equal or better than for Kailashtila. Due to higher GOR the silica gel plant not handle below C_{5+} at all and small portion of C_{5+}. So for enhance recover of hydrocarbon turbo expander process would be applied like Kailashtila. Already, development project is being financed through floatation of a bond by SGFL to install a new MSTE process plant in this field under progress.

Vapour recovery of production tank/stock tank was not installed in the plant, which affect the vapour loss from the tank. More over flashing of condensate affect the loss of light hydrocarbon.

5.3.2 Fenchuganj Gas Field

Silica gel plant was installed in June 2005 and operation started on September 2005. The plant is now under warrantee period, some troubleshooting, changing of process parameters/operating condition affects the performance of this plant. It will need about a year of operational data before any conclusion be made on its performance. But for now, the plant appears to meet the sales line conditions Production from Fenchuganj well 2 started on 22 May 2004 from Upper gas zone by the installation of interim production facilities In a testing report GOR in Upper zone was near about 0 6 bbl/MMscf and but in the interim facilities it was 0.3 bbl/MMscf. In this plant the GOR slightly increased and became 0.4 bbl/MMscf.

5.3.4 Feni Gas Field

Feni-1 was processed by LTX unit, up to 1995 GOR was 2.5 bbl/MMscf (separate condensate data available up to this period). After production of Feni-1 & 2 by both LTX and silica gel plant GOR was 2.16 in the BGFCL period. In the case of new glycol plant, GOR is 1.47 bbl/MMscf. In view point of liquid hydrocarbon recovery, performance of LTX is preferable.

5.3.5 Habiganj Gas Field

There are six glycol dehydration plants in this field. Based on compatibility with installed plant facilities and phased development in which process demand is added in stages over time, the Tri-Ethylene Glycol (TEG) absorption process is the most attractive processing scheme Water dew point control is the only processing requirement to meet sales gas specifications for production from Habiganj Gas Field. Plants-1 & 2; 3 & 4 processing capabilities have been considerably decreased to each 45 MMscfd and 65 MMscfd due to continuous operation for 23 years and 19 years respectively.

Two new Glycol plant 5 & 6 are equipped with natural draft air cooler, vapor drum and a vent stack are used for optimum recovery of condensate/water vapor from glycol regenerator/still column of the plants which reduce the some hydrocarbon vapour loss.

Up to August average GOR is very low 0.053 bbl/MMscf. Fluid composition of this field above C_3 is nearly zero, and below C_3 are not recovered by the glycol plant and atmospheric storage tank. So, there are insufficient hydrocarbon liquids in the production from Habiganj Gas Field. Installation of a high efficiency liquid recovery scheme such as refrigeration or turbo-expansion plant with pressurized storage tank may increase the liquid hydrocarbon recovery.

The existing facilities have no provision for handling significant volumes of free water production. If water break through from the reservoir, the facility cannot handle this water.

5.3.6 Jalalabad Gas Field

Apparently IFPEXOL process is tailor made for a wet and sour gas. This process generally has 2 parts: IFPEX-1 for condensable hydrocarbons and water removal and IFPEX-2 for acid gas removal and recovery. Both of these criteria are missing at Jalalabad. Water content in the gas is very negligible. Average water content is about 0.2-0.3 bbl per MMSCF of gas. The gas does not have any significant amount of CO_2 and H_2S is completely absent.

The process has been able to depress the dew points much lower than the required values Condensate recovery ranges between 9 to 16 bbl/MMSCF. But water exiting the Contactor often contains much more methanol in it than what the IFP assures. The water contains about 7-9% of methanol in it Average methanol loss per day is more than 10 bbl. By compare the price of methanol and condensate, the recovery figure is not attractive. So, should be reducing methanol loss. The process may be economic when both wet and sour gases are processed coupled together.

Propane, which is used as a refrigerant to cool the gas, is limited to a closed system Hence propane loss is negligible other than leaks through the safety relief systems.

5.3.7 Kailastila Gas Field

The process has higher recovery levels than any other recovery process in Bangladesh Typically it recovers up to 85% of the ethane, 100% of the propane and 100% of the butane and heavier hydrocarbons.

Reducing the temperature at which separation occurs still lower using the turbo-expansion Joule-Thomson (J-T) valve expansion process will condense still greater amounts of liquids and still lighter hydrocarbon components from the inlet stream. The temperature of separation has been set to approximately -100°F effectively reducing the sales gas contains a two component methane ethane stream In the sales gas methane and ethane mole fraction is 99.48% and only a trace of propane. The sales gas gross heating value is 1020 Btu/scf excluding inert, which is higher than the 950 Btu/scf frequently specified as a minimum in a typical sales gas contract.

When the field alone processed by silica gel plant average GOR 10.5 bbl/MMscf but in the MSTE plant can recover more than double condensate (heavy condensate and NGL) (GOR > 20 bbl/MMscf). Even significant quantities of light hydrocarbons in the C_3~C_5 range are lost during the flash at 125 psig and weathering in atmospheric storage.

A simple flash calculation was run using HYSIM™, a proprietary process simulation package by Hyprotech Ltd., to determine the incremental achieved by dehydrating the gas so the gas stream could be expanded and chilled to its maximum. The simulation result shows a recovery of approximately 19 bbl/MMCF (IKM Report). Compared to the existing process recovery rate is similar.

The plant cannot recover more NGL Ethane content in NGL are flaring due high content of ethane in NGL can effect the processing of LPG, and fractionation of NGL. For reduce the content of ethane turbo expander are always not involve in operation, most of the time use J-T valve which reduce the recovery of liquid hydrocarbon.

Take appropriate policy to stop the flaring of ethane and proper utilize of turbo expander for enhance of liquid hydrocarbon recovery in Kailastila field Installation of another MSTE plant in Kailastila is under procurement process for two new development drilling (KTL-5 & 6).

5.3.8 Meghna Gas Field

The plant was originally installed at Titas field in 1969 and subsequently relocated to Feni in 1991 and Meghna in1996. The plant was originally installed at Titas field in 1969 and due to continuous operation since installation the efficiency of the plant has been decreased. Presently processing capacity of each plant is limited to 15 MMCFD (design capacity 20 MMcfd)

The gas composition contains 98 mole% methane and ethane, with only a small amount of recoverable C_{5+} liquids (less than 3 bbl/MMscf). Raw gas of Meghna field was processed by LTX unit. Upto August 2005, average GOR is 1.54 bbl/MMscf where in a feni field it was 2.5 bbl/MMscf in the same plant. Compare with respect to composition of two field, performance of the plants are satisfactory.

5.3.9 Narshingdi Gas Field

Historically the Glycol process plant has recovered much more than approximately 2.25 bbl/MMcf liquid hydrocarbon. Gas composition contains over 97 mole% methane and ethane, with a significant amount of recoverable C_{5+} liquids (almost 9 bbl/MMscf). The reservoir fluid contains a larger percentage of C_{7+} which is consistent with testing results in which the condensate-gas ratio was found to be 2.5 bbl/MMscf. Due to continuous operation since installation the capacity of the plant has been decreased from 60 to 40 MMscfd

With respect to the recovery of liquid hydrocarbon the plant is not efficient. The fluid compositions of this field nearly similar to Kailashtila gas field For enhance recovery installation of a high efficiency liquid recovery scheme such as refrigeration or turbo-expansion plant with pressurized storage tank may increase the liquid hydrocarbon recovery.

5.3.10 Rashidpur Gas Field

An advantage of the dry bed (silica gel) desiccant system is that it can dehydrate the gas of water and recover hydrocarbon liquids simultaneously Cycle time must be kept short, in the range of 30 minutes to keep the hydrocarbons in the bed otherwise only primary dehydration will occur. Hydrocarbon recovery is limited, (at best) to a small amount of the butanes and 75 to 90 percent of the $C5^+$. Theoretically, 2 3 and 2.8 bbl/MMcfd condensate could be recovered from by the present facilities but practically average GOR of the all plant is 1 42 bbl/MMscf where for glycol plant GOR is 0.316 bbl/MMscf. With respect to glycol plant, silica gel is better recovery. A more precise estimate of the hydrate formation temperature was obtained using the HYSIM computer process simulation package the mole fraction of the C_{5+} to 0.0070, which translates to maximum theoretical total liquid potential of 5.9 bbl/MMcf.

5.3.11 Saldanadi Gas Field

The water vapor can be condensed in an aerial cooler and routed to the produced water treating system to eliminate any potential atmospheric hydrocarbon emission. But the water vapor exiting the top of the still contains a small amount of volatile hydrocarbons and is normally vented to atmosphere. If natural draft air cooler, vapor drum are used, can help to reduce the some hydrocarbon vapour loss for optimum recovery of condensate/water vapor from glycol regenerator/still column of the plants.

High inlet temperatures pose efficiency problems for both the TEG absorption process. In the case of glycol dehydration, elevated inlet temperatures mean increased water vapour in the gas stream. This higher loading on the glycol system results in reduced liquid recovery efficiencies. The installation of fin-fan coolers upstream of the process to pre-cool the inlet gas streams The efficiency of the plant has been decreased to18 MMcfd (design capacity 20 MMcfd)

To maintain temperature of glycol maintain is difficult sometimes, in a Surge Tank cum heat exchanger due to the absent of air-glycol cooler which was installed in Feni glycol plant installed by Niko. The high temperature of this glycol may damage the glycol circulation pump

5.3.12 Sangu Gas Field

For the mechanical problem of turbo expander, most of the use J-T valve which reduce the recovery of liquid hydrocarbon. The process has been able to depress the dew points, and delivery gas maximum water content maximum 1.5 lbs/MMscf much lower than the required values, but the content of liquid hydrocarbon nearly the specification value 1.8 US gal/MMscf. So, recover of hydrocarbon enhance by operate the turbo expander by proper maintenance

5.3.13 Sylhet Gas Field

Raw gas is processed this oldest silica gel process plant. Still now the plant can achieve a good specification of the dew point and recovery of liquid hydrocarbon last year is 3.62 bbl/MMscf where historically it is 3.1 bbl/MM scf (average up to August 2005). It's indicating the consistency of the plant after long period of operation. Due to continuous operation since installation the efficiency of the plant has been decreased

5.3.14 Titas Gas Field

Three different gas processing schemes have been implemented among the eleven gas production streams at Titas Gas Field. Tri-Ethylene Glycol (TEG) Absorption, Low Temperature Separation without hydrate formation (LTS) and Low Temperature Separation with hydrate formation (LTX), under the appropriate operating conditions, are effective processes for hydrocarbon and water dew point control, with some potential for recovery of condensable hydrocarbons. There ability to provide sales gas, which meets both hydrocarbon, and water dew point specifications. Processing capabilities have been decreased to 45-50 MMscfd due to continuous operation of 15 to 35 years of plants-1, 3,4,5,6,7,8,9 and 10.

Production of condensate varies depending on the process facility. The glycol dehydration process (TEG) on wells TT-1, TT-3, TT-4, TT-5 and TT-6 has performed consistently near the average of 1 30 bbl/MMscf The LTX process installed at TT-2 has a higher recovery efficiency producing approximately 1 9 bbl/MMscf. The low temperature separation process (LTS) on wells TT-7, TT-8, TT-9 and TT-10 has proven only slightly more efficient, averaging 1.39 bbl/MMscf Clearly, at 2 10 bbl/MMscf, the low temperature separation process &-(LTX) on well TT-2 has demonstrated significantly higher performance

Based on the liquid hydrocarbon potential of the representative gas composition for Titas Gas Field shown in Table 5.4, theoretical liquid recovery in the 2.0 to 2.5 bbl/MMscf range might be expected for these gas processing facilities installed at Titas. Historically, the overall field average is 1.45 bbl/MMscf, with individual well liquid recoveries reported in the range of 1.25 to 2 10 bbl/MMscf.

The possible reasons for less recovery liquid recovery are as fellows.

i) Stock tank design: No vapour recovery systems are installed on the condensate stock tanks, causing weathering and loss of product to the atmosphere. Further loss occurs as the tank "breathes" as liquid levels are varied with shipping to and from the tank.

ii) Inlet temperature: A significant difference exists between the actual gas stream inlet temperatures to the processing plants and the temperature used for design. High inlet temperatures pose efficiency problems for both the TEG absorption process and low temperature separation. In the case of glycol dehydration, elevated inlet temperatures mean increased water vapour in the gas stream. This higher loading on the glycol system results in reduced liquid recovery efficiencies. The LTS and LTX processes are based on the temperature reduction of the gas stream associated with the significant pressure drop taken through the plant and the installation of fin-fan coolers upstream of the process to pre-cool the inlet gas streams for wells TT-7, TT-8, TT-9 and TT-10 should afford a better opportunity to recover liquids. Therefore, liquid recovery efficiencies are directly dependent on the inlet temperatures the lower, the better

iii) Gas composition: The composition used in the design may differ from the individual gas streams being produced from the various sand groups.

The existing glycol circulation pumps on process trains TT-1, TT-3 and TT-4 are plunger type reciprocating pumps, which were leaking significant amounts of glycol. Both for safety reasons and operational efficiency of the glycol dehydration systems, these should be replaced by more reliable reciprocating pumps or by centrifugal pumps, similar to those used on process trains TT-5 through TT-8 Consideration should also be given to the installation of stand by glycol pumps at Locations 1 and 3 to facilitate routine maintenance of this equipment.

Titas Gas Field has a combined design capacity of 660 MMcfd (Location 1 - 300 MMcfd, Location 3-240 MMcfd, Location 5 - 120 MMcfd) but due to continuous operation for a long time, capacity has decreased to 500 MMcfd. The design capacity is almost 1.5 times greater than present production rate. To make effective use of this excess processing capacity, it is necessary to drill development wells.

This field has no provision in the existing facilities for handling significant volumes of free water production from TT-12. Handling, processing and disposal of produced water will require installation of appropriate facilities include tankage, filtration system and transfer pumps will be required as part of future development.

Table 5.3 summarize the performance of the gas processing plants in Bangladesh It should be noted here that, all the plants achieve sales line quality satisfactory. However, for most plants the liquid hydrocarbon recovery is not satisfactory.

5.4 A Brief Discussion on Liquid Recovery

In our country, designing of a process plant the primarily concerns meeting the sales line specification. Not enough emphasis is given on the issue of liquid hydrocarbon recovery. The gas processing plants were initially set up for removing water and higher hydrocarbons Today, the gas processing plants attach a great importance to HC recovery, which has a high market value.

With the growth of the worldwide market for natural gas liquids (NGL), additional processes for higher recovery of the ethane, propane and butane fractions, which make up NGL, have been developed. These fractions are valuable for the petrochemical industry Usually the ethane and heavier fractions are used as gasoline blending.

In the world market the price of the liquid fuel is increasing. Bangladesh mostly depends on imported fuel (liquid fuel). If the recovery of liquid hydrocarbon can be increased, it will save significant amount of foreign currency. So special attention should be given to extract liquid hydrocarbons Table 5.4 shows the comparisons of recoverable and recovered liquid hydrocarbon in different fields.

TEG, LTS and silica gel process plants cannot recover hydrocarbon below C_4, and the maximum recovery of C_4 is 45%. So, installation of a high efficiency liquid recovery scheme such as refrigeration or turbo-expansion is necessary to recover C_3 and C_4 more effectively. The turbo-expander is the most effective process to recover hydrocarbon liquids from the gas stream. Theoretically, the turbo-expander is capable of recovering 90% of the C_2 and nearly 100% of the propane and butane from the raw gas stream. This results in a sale gas, which contains mostly C_1, C_2 (combined mole fraction 99.28%) and trace amount of C_3 The heating value of this mixture is 1020 Btu/scf, which is higher than

Table 5.3: Summary of Performance of Different Gas Processing Plants in Bangladesh:
Legend. Satisfactory=S, Not satisfactory= NS

Type of Process Plant	Name of The Field	Performance respect to				Overall Performance	Remarks
		Capacity	Repair and maintenances	Sales line specification	Hydrocarbon recovery		
Glycol Absorption Plant	Feni 1 & 2	S	S	S	NS	S	Older plants of Habiganj 1 to 4 and Titas 1 to 6 cannot handle design capacity. Glycol pant dehydrates the gas but can not recover HC without addition of HC unit
	Habiganj 1 to 4	NS	S	S	NS	S	
	Habiganj 5 & 6	S	S	S	NS	S	
	Norshigdi	NS	S	S	NS	S	
	Rashidpur	S	S	S	NS	S	
	Saldanadi	NS	S	S	NS	S	
	Titas plants 1 to 6	NS	S	S	NS	S	
Silica gel Adsorption Plant	Beanibazar	S	S	S	NS	S	Older plants of Bakhrabad 1 to 3 and Sylhet cannot handle design capacity. This pant is basically dehydrated the gas and recover small portion of C_{5+} but can not recover light HC.
	Bakhrabad 1 to 3	NS	S	S	NS	S	
	Bakhrabad 4	S	S	S	NS	S	
	Fenchuganj	Under warrantee period		S	NS		
	Kailashtila	S	S	S	NS	S	
	Rashidpur	S	S	S	NS	S	
	Sylhet	NS	S	S	NS	S	
LTS (With / with out glycol injection) Plant	Titas 7 to 10	NS	S	S	NS	S	Older plants (7 to 10) cannot handle design capacity
	Titas 11 & 12	S	S	S	NS	S	HC recover slightly higher than glycol plant
LTX Plant	Meghna 1 &2	N	S	S	S	S	Older plants cannot handle design capacity
MSTE Plant	Kailashtila	S	S	S	S	S	These three process equip with enhance HC recovery unit. In IFPEXOL plant methanol loss is higher than design value
IFPEXOL Plant	Jalalabad	S	S	S	S	S	
Glycol with Turbo Expander	Sangu	Cannot operate full capacity due to existing well cannot deliver enough gas.	S	S	Condensate production data is not available	S	

the typical sales specification, where minimum heat content is usually 950 Btu/scf. Therefore, by removing C_3 and above, the heating value of the sales gas is still maintained. The extra hydrocarbon can be used for producing Liquefied Petroleum Gas (LPG), Motor Spirit (MS) and High Speed Diesel (HSD) However, using a turbo-expander may not be feasible in small fields

Average percentage of ethane (C_{2+}) is more than 2.7 % in the sales line. So, from daily production of 1405 MMscf NG, 30 MMscf of C_{2+} will be recovered (considering 80% recoverable C_{2+}) which is important raw material of petrochemical industries

Ethane and higher hydrocarbon can be extracted from the national grid by tapping into and installing turbo-expander at suitable locations. The extracted hydrocarbon can then be used for various industrial products such as LPG, Polyethylene etc. This should ensure the maximum utilization of our natural gas, as well as save foreign currency. However, a proper economics analysis is necessary to see whether such measures would be viable.

Table 5.4: Comparison of Recoverable and Recovered Liquid Hydrocarbon in Differents Fields.

Elements	Mole fraction	Recoverable liquid hydrocabon (bbl/mmscf)	Average recovered liquid hydrocarbon (bbl/mmscf)	Mole fraction	Recoverable liquid hydrocabon (bbl/mmscf)	Average recovered liquid hydrocarbon (bbl/mmscf)	Mole fraction	Recoverable liquid hydrocabon (bbl/mmscf)	Average recovered liquid hydrocarbon (bbl/mmscf)
Field	**Bakhrabad**			**Beanibazar**			**Fenchuganj**		
C_{3+} Equivalent	0.0180	13.9826	Glycol plant : 0.316 (Upto 1986) Silica gel plant:1.45	0.0279	20.52	16.99	0.0084	5.27	0.40
C_{4+} Equivalent	0.0086	7.8293		0.0169	13.33		0.0021	1.15	
C_{5+} Equivalent	0.0046	4.7551		0.0017	1.86		0.0006	0.66	
Field	**Feni**			**Habiganj**			**Jalalabad**		
C_{3+} Equivalent	0.0087	6.00	LTX : 2.3 (Upto 1995), LTX & Silica gel : 2.16 (1995-1998) & Glycol plant 1.47	0.0045	3.2518	0.053	0.0233	21.43	11.05
C_{4+} Equivalent	0.0022	1.75		0.0018	1.4884		0.0177	17.77	
C_{5+} Equivalent	0.0020	0.22		0.0008	0.5652		0.0128	14.00	
Field	**Kailashtila**			**Meghna**			**Norshigdi**		
C_{3+} Equivalent	0.0149	10.81	Silica gel: 10.5, MSTE: 20.45, MSTE & Silica gel: 12.27	0.0112	8.6026	1.54	0.0178	15.3366	2.25
C_{4+} Equivalent	0.0055	4.66		0.0052	4.6794		0.0118	11.4134	
C_{5+} Equivalent	0.0014	1.53		0.0027	2.7621		0.0083	8.7358	
Field	**Rashidpur**			**Saldanadi**			**Sangu**		
C_{3+} Equivalent	0.0072	5.79	Glycol plant: 0.316 Glycol & Silica gel plant : 1.42	0.0069	4.94	0.84	0.0128	11.82	Condensate production data not available
C_{4+} Equivalent	0.0048	4.22		0.0024	0.24		0.0067	7.83	
C_{5+} Equivalent	0.0017	1.86		0.0017	0.55		0.0041	4.49	
Field	**Sylhet**			**Titas**			**Moulovibazar**		
C_{3+} Equivalent	0.0037	13.35	3.10	0.0086	7.0146	1.45	Data not available		
C_{4+} Equivalent	0.0032	13.02		0.0051	4.7261				
C_{5+} Equivalent	0.0017	1.86		0.0033	3.3498				

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

In this study, the processing methods of the different gas processing plants currently in operation in Bangladesh are examined. The performance of those process plants with respect to capacity, recovery of liquid hydrocarbon and sales line specification are scrutinized. In addition, comparative studies among these process plants as well as the appropriateness of selection of these process plants are investigated The following conclusions are made from this study:

- Due to the composition of natural gas found in Bangladesh, the role of the process plants is mostly removing water and heavy hydrocarbon The need for treating for CO_2, H_2S etc are minimal.
- All the plants are designed mainly to meet sales line specification. Liquid hydrocarbon recovery does not seem to be a priority in the design of these plants.
- All of the installed plants have been able to depress the dew points lower than the sales line specification, which indicates satisfactory levels of water removal.
- The older processing plants (installed before 1986) cannot handle the name plate gas flow rates.
- The separation of liquefiable hydrocarbon in the older plants is not satisfactory.
- Available processing capacity is not being fully utilized in most of the gas field.
- Several fields have no provision in the existing facilities for handling significant volumes of free water production
- The common problem in most of the plants in different gas fields is the lack of vapour recovery systems on condensate production and stock tanks.
- Around twenty-five process plants are not equipped with inlet gas scrubber/ filter separator
- Around twenty fields are not equipped with sales line scrubber/ filter separator.
- Gas composition used in the design differs from "averaged" compositions from all gas sands produced to the plant. The depletion of reserve changed the gas composition, which affects the plant performance.

- In some of the plants, a significant difference exists between the actual gas stream inlet temperatures to the plants and the temperature used for design, which poses efficiency problems for the plant.
- The existing glycol circulation pumps on process trains of well 1, 3 and 4 of Titas field are plunger type reciprocating pumps which were leaking significant amounts of glycol
- Beani Bazar has a slightly higher mole fraction of heavier components than does Kailashtila. The existing facilities of Beani Bazar cannot recover sufficient hydrocarbon with respect to Kailastila
- The loss of Methanol problem in IFPEXOL process is found at the Jalalabad field
- Around thirty five process plants (except turbo expander and IFPEXOL plants) can not recover hydrocarbon below C_4 Theoretically, TEG, LTS and silica gel process plants cannot recover below C_4 (recovery of C_4 max. 45%). In the field processing, most of the light portions of liquid hydrocarbon flows through sales line. Other portion may be flared or emitted.

Each of the processes studied in this project has merits and demerits considering technology, operation, maintenance, investment etc. Plants may be justified simply for the recovery of certain hydrocarbon components, even if those components are only a very small part of the gas stream. Today, the gas processing plants attach a great importance to HC recovery and its processing into desired fractions for maximizing revenue. These fractions are valuable for the petrochemical industry raw stocks. Usually ethane and heavier fractions are removed and used as gasoline blending. Following recommendations are made based on this study:

- Large storage tanks for condensate product should be upgraded to incorporate vapour recovery systems However, introducing a vapour recovery system in a low capacity tank may not be feasible.
- Special attention should be given to extract light hydrocarbons when setting up new process plants.
- Inlet and sales scrubbers should be installed in the fields where these were not installed
- Plunger-type glycol circulation pumps should be replaced by more reliable reciprocating or centrifugal pumps.

- Where wellhead temperature is high, fin-fan coolers should be installed at the upstream of the process inlet. This would pre-cool the inlet gas streams and improve liquid recovery.
- In several fields where produced water needs to be handled, appropriate facilities should be installed. These include tanks, filtration systems and pumps etc. Installation of these facilities should be incorporated in all future plans.
- Proper steps need to be taken to utilize the flaring ethane and to reduce the loss of methanol at Kailashtila and Jalalabad fields respectively.
- The gas volume throughput of transmission line is usually large, so the actual gallons of liquid propane or ethane recovered can be substantial. Ethane and higher hydrocarbon can be extracted from the national grid by tapping into and installing turbo-expander at suitable locations. The extracted hydrocarbon can then be used for various industrial products such as LPG, Polyethylene etc. This should ensure the maximum utilization of our natural gas, as well as save foreign currency. However, a proper economics analysis is necessary to see whether such measures would be viable.

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APPENDIX-A

Table A-1: Sales Gas Specification.

Serial No.	Parameters	Allowable limit
1	Flowing Gas Pressure	900-1 000 psig
2	Flowing Gas Temperature	<120 °F
3	Odor	No odor is allowed
4	Solid	No solid allowed
5	Water	< 7 lb/MMscf
6	Liquefiable Hydrocarbon	< 2 US gallons/MMscf
7	Total sulfur	<200 grains/ 100 scf
8	H_2S	< 1 grain/ 100 scf
9	Carbon dioxide	< 2% v/v
10	Oxygen	<1%v/v
11	Nitrogen	< 3% v/v
12	Heating value (Net)	>900Btu/scf

Table A-2 : Chemical Composition of Gas from Different Gas Fields.

SI No.	Nameof field	Methane (%)	Ethane (%)	Propane (%)	Iso Butane (%)	n Butene (%)	Higher HC Composition (%)	Nitrogen (%)	Carbon Dioxide (%)	Calorific value gross BTU/CFT	Sp Gravity
1	Bakhrabad	94.2	3.65	0.72	0.2	0.1	0.24	0.42	0.47	1057.73	0.597
2	Begumganj	95.46	3.19	0.64	0.17	0.04	-	-	0.3	1045.61	0.5833
3	Balabo	94.79	2.49	0.6	0.2	0.15	0.13	0.34	0.6	-	0.607
4	Feni2	95.71	3.29	0.65	0.15	0.05	-	-	0.15	1049.84	0.5782
5	Habiganj	97.63	1.31	0.27	0.08	0.04	0.06	0.38	0.07	1023.91	0.57
6	Kamta	95.36	3.57	0.47	0.09	-	-	-	0.51	1043.13	0.5743
7	Meghna	95.15	2.83	0.6	0.16	0.09	0.07	0.37	0.53	-	0.0591
8	Titas	97.33	1.72	0.35	0.08	0.05	0.06	0.3	0.11	1031.55	0.572
9	Shahbazpur	93.68	3.94	0.71	0.2	0.07	0.04	0.46	0.9	1046.21	0.58
10	Saldanadi	96.32	2.16	0.45	0.12	0.07	0.05	0.27	0.56	1032.6	0.57
11	Beanibazar	93.68	3.43	1.1	0.29	1.23	0.17	0.99	0.12	1061.95	1.6
12	Chattak	97.9	1.8	0.2	-	-	-	-	-	1005.71	0.548
13	Fenchuganj	95.66	2.5	0.63	0.11	0.04	-	-	0.06	1043.33	0.574
14	Sylhet 4	96.63	2	0.05	0.14	0.01	0.17	0.66	0.34	1050.68	0.546
15	Kailastila 3	95.57	2.7	0.94	0.21	0.2	0.14	0.24	-	1056	0.586
16	Rashidpur	98	1.21	0.24	-	-	0.17	0.02	0.05	1012	0.569
17	Jalalabad	95.03	2.45	0.56	0.35	0.14	-	0.12	0.07	-	0.648
18	Kutubdia	95.72	2.87	0.67		0.31		0.36	0.07	1041.68	0.586
19	Sangu	94.51	3.17	0.61	0.19	0.07	0.41	0.44	0.6	1058	0.59
20	Semutang	96.94	1.7	0.14	-	0.01	-	0.86	0.35	-	-

Table A-3 : Molecular and Isotopic Composition of Natural Gases.

Well Name/Test	Depth (m)	Molecular Composition							Isotopic Composition		
		C_1	C_2	C_3	iC_4	nC_4	CO_2	N_2	$^{13}C_1$	$^{13}C_2$	$^{13}C_3$
Atgram DST-4	4084	97.87	2.11	0.01		0.01			-40.3	-29.4	-30.6
Atgram DST-5	3999	95.86	2.79	0.87	0.81	0.2			-39.9	-29.1	-27.5
Atgram PT-6	3824	96.37	2.6	0.68	0.13	0.12			-40	-29.2	-27.6
Bakhrabad-I	2167	94.27	3.54	0.75	0.21	0.11	0.46	0.39	- 43.0	-28.6	-26
Beani Bazar DST-2A	3451	94.72	3.47	1.19	0.29	0.23			-40.9	-28.8	-26.6
Beani Bazar DST-3	3266	90.59	6.42	1.84	0.42	0.51			-41.9	-29.2	-26.7
Beani Bazar-1 XDST-4A	3230	92.49	4.59	1.42	0.38	0.38	0.11	0.28	-41.8	-29.3	-26.6
Begumganj-1	2296	94.98	3.6	0.74	0.18	0.06	0.1	0.29	-54.3	-30.7	-29.8
Begumganj-2	3428	95.18	3.71	0.75	0.22	0.09			-54.3	-31.1	-28.1
Bibiyana-1	2856	95.55	2.35	0.73	0.22	0.18	0.08	0.43	-40.5	-29.2	-26.6
Bibiyana-I	2960	95.54	2.43	0.74	0.21	0.17	0.12	0.31	-40.4	-29.1	-26.7
Bibiyana-1	3038	95.5	2.44	0.76	0.22	0.18	0.13	0.32	-40.4	-29.1	-26.7
Bibiyana-1	3065	95.46	2.42	0.75	0.22	0.18	0.13	0.35	-40.4	-29	-26.7
Bibiyana-I	3262	95.46	2.46	0.76	0.22	0.18	0.18	0.31	-40.4	-29.1	-26.4
Bibiyana-I	3318	95.43	2.46	0.77	0.22	0.18	0.2	0.33	-40.4	-29.1	-26.5
Bibiyana-I	3411	95.24	2.43	0.74	0.21	0.17	0.23	0.58	- 40.3	-29.1	-26.5
Borguna	0	91.68	1.51				2	2			
Chhatak-1	1082	97.72	0.24				0.04	2	-45.2	-41.7	
Fenchuganj-?	2578	96.67	2.33	0.58	0.15	0.11	0.05	0.11			
Fenchuganj-2	3259	97.84	1.77	0.32	0.06	0.01					
Feni-1	1757	96.43	2.8	0.55	0.13	0.03			-43.7		
Feni-1	2792	95.7	329	0.68	0.15	OJB	0.15		-43.7		
Coumadi	0	95.14					4.85				
Habiganj-1	1450	97.84	1.45	0.01			0.01	0.69	-44.5	-38.1	
Habiganj-1	3017	97.6	1.31	0.27	0.06	0.04	0.07	0.57	-43.7		
Habiganj-4	1361	98.51	1.49								
Inani	0	98.02					1.98				
Jaldi	0	96.5					3.5				
Jhinaidah	0	95.09					4.91				
Kailas Tila	2325	95.99	2.54	0.81	0.18	0.17	0.21				
Kailas Tila	3024	95.97	2.7	0.94	0.21	0.2	0.24				
Kaliganj (Jessore)	0	95.72					2:48				
Kamta	2290	94.66	3.57	0.47	0.07		0.42	0.81	-45.4		
Kamta	3525	98.38	1.42	0.16	0.04						
Kutubdia	2660	95.72	2.87	0.67			0.07	0.37			
Lakhsam	0	88.1					11.9				
Manikganj	0	99.13					0.87				
Muladi	4450	90.62	4.89	1.2	0.1		2.99				
Nilakhali	0	99.21	0.07				0.72				
Noakhali Chara	0	97.23	2.41	2.41	0.03		0.33				
Pabna	0	92.4					7.6				
Patharia	0	90.6	2.35	1.06	0.44	0.32	5.23				
Patharia-1	875	94.39	3.28	1.33	0.53	0.42	0.05		-42.4	-37.2	-34.7
Patiya	0	99.76	0.05				0.19				
Pirozpur	0	97.99					2.01				
Rankiongkhal seep	0	100							-59.1		

Table A-4 : Summary of Bangladesh Gas Reserves Estimation - 2003

Figures in Bcf

Sl no.	Field	Operator	Estimated by	Year	GIIP Proved + Probable	Recoverable (1000 psi)	Recovery Factor %	Cumulative Production upto June 2003	Remaining Reserves As of June 2003	Additional Recovery Using Compressor (500 psi)	Possible Rec.
Producing											
1	Bakhrabad	BGFCL	HCU	2003	1498	1048	70	638	410		
2	Beani Bazar	SGFL	IKM	1989	243	170	70	18	152		
3	Habiganj	BGFCL	HCU	2001	5139	3852	75	1027	2825		
4	Jalalabad	UNOCAL	Oxy	2000	1195	837	70	134	704		
5	KailasTila	SGFL	HCU	2001	2720	1904	70	304	1600	245	908
6	Meghna	BGFCL	HCU	2003	170	119	70	32	87		
7	Narshingdi	BGFCL	HCU	2003	335	235	70	44	191		
8	Rashidpur	SGFL	HCU	2001	2002	1401	70	285	1117	200	700
9	Saldanadi	BAPEX	Bapex	2002	166	116	70	30	86		
10	Sangu	SHELL	Shell	1997	1031	848	82	221	627		
11	Sylhet	SGFL	PPL	1971	684	479	70	171	308	60	
12	Feni	BGFCL	Bapex - Niko	2000	236	165	70	40	125		72
13	Titas	BGFCL	HCU	2003	7300	5110	70	2108	3002	730	1680
Production Suspended											
14	Chattak (West)	SGFL	Bapex - Niko	2000	677	474	70	27	447	68	254
15	Kamta	BGFCL	HCU	2000	72	50	70	21	29		
Non-producing											
16	Bagumganj	BAPEX	Petrobagla	1984	46	32	70				76
17	Bibiyana	UNOCAL	Oxy / Unocal	2000	3145	2377	76				3080
18	Fenchuganj	SGFL	Petrobagla	1988	404	283	70			40	
19	Kutubdia	SHELL	Shell	2001	65	46	70				
20	Moulavi Baza	UNOCAL	Unocal	2003	449	360	80				
21	Semutang	SHELL	Shell	2001	227	150	66				
22	Shahbazpur	BAPEX	Bapex-Unocal	1996	664	465	70			66	670
Total in Bcf					28466	20520		5098	15422	1409	7440
Total in Tcf					28.5	20.5		5.1	15.4	1.4	7.4

Table A-5: Sector wise annual gas sales.

GAS VOLUME IN BILLION CUBIC FEET (Bcf)

Year	Power	Fertilizer	Industry	Domestic	Commercial	Others	Total Sales	Total Production
1980-81	13 30	17 90	8 10	3 40	1.30	0.00	44.00	49.95
1981-82	18 00	26 60	9.10	4 20	1.70	0.00	59 60	64.85
1982-83	22.00	25.80	9.80	5 20	1.90	0 00	64.70	72.16
1983-84	22.90	29.40	10 40	5.80	2 10	0.00	70.60	83.29
1984-85	38.30	27.20	12.60	6.30	2 20	0 00	86.60	94.59
1985-86	39.80	33.70	16 40	6.80	2.70	0 00	99 40	106 66
1986-87	51 80	34.90	18.70	6.80	3 40	0.00	115.60	125.32
1987-88	62 10	51 00	16.70	7.60	3 60	0.00	141.00	147.50
1988-89	65 50	53.40	15 00	9.30	3.20	0.00	146 40	155.93
1989-90	75 60	55 90	14 30	10.20	3.10	0.00	159.10	167 83
1990-91	82 60	54 20	13 20	10 50	2.90	0.70	164.10	172 84
1991-92	88.10	61 60	13.40	11 60	2 90	0.90	178.50	188.48
1992-93	93.30	69.20	15 20	13.50	2.40	0 90	194.50	210 98
1993-94	97.30	74.50	20 26	15.40	2.87	1 80	212 13	223 76
1994-95	107.40	80.50	24.24	18.86	2 88	1 70	235 58	247.38
1995-96	110 90	90.98	27.31	20.71	3.00	1 71	254 61	265.51
1996-97	110 82	77.83	28.62	22.84	4.49	1 19	245 79	260.99
1997-98	123.55	80.07	32-32	24 89	4.61	1 13	266 57	282.02
1998-99	140.82	82 71	35.79	27 02	4 71	0.96	292 11	307.48
1999-00	147.62	83 31	41.52	29 56	3 85	0.99	306.86	332.35
2000-01	175.27	88 43	47.99	31 85	4.06	1.09	348.75	372.16
2001-02	190.03	78 78	53.56	36 74	4.25	1.16	364.62	391.53
2002-03	190.54	95 89	63.75	44 80	4.56	1.26	400.81	421 16
2003-04	231 33	92.80	46 37	49.26	4.79	2 87	451.42	452 50
2004-05	248 89	93 99	51 68	52.49	4 85	5 42	484 31	486.76
2005-06 (upto August)	19.29	12 51	9.44	9.14	0 92	0 97	85.97	86 97

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APPENDIX-B

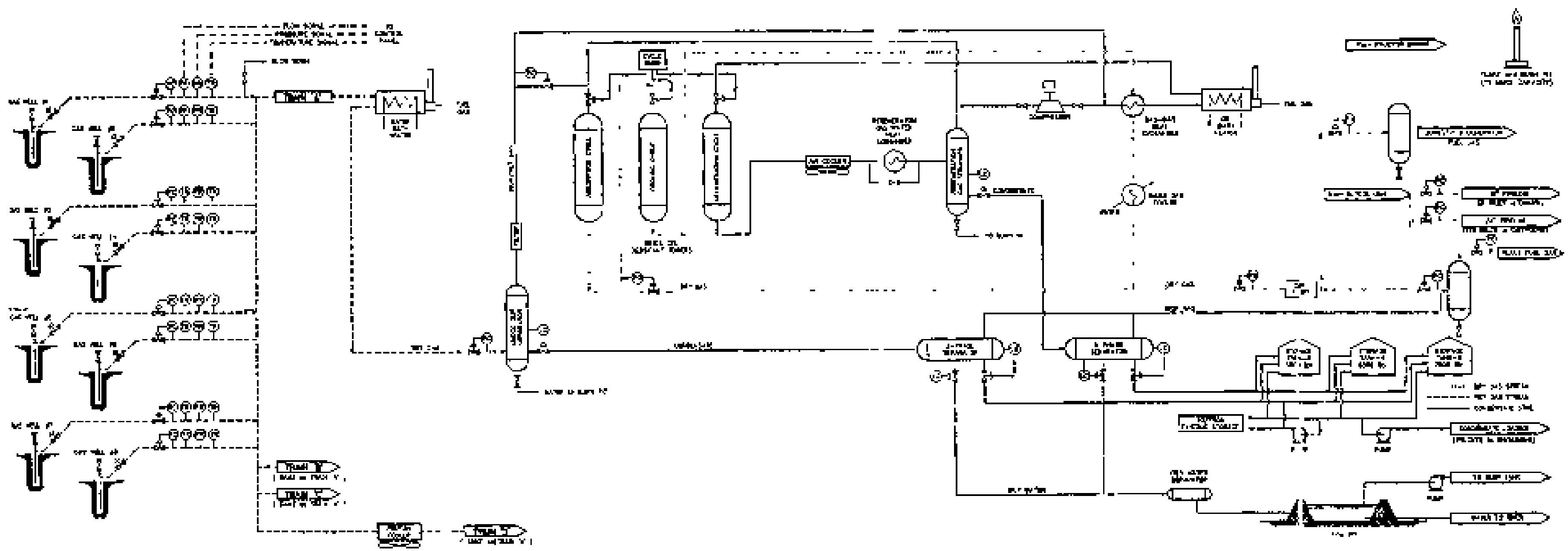

Figure B-1 : Process Flow Diagram of Silica Gel Plants at Bakhrabad Gas Field.

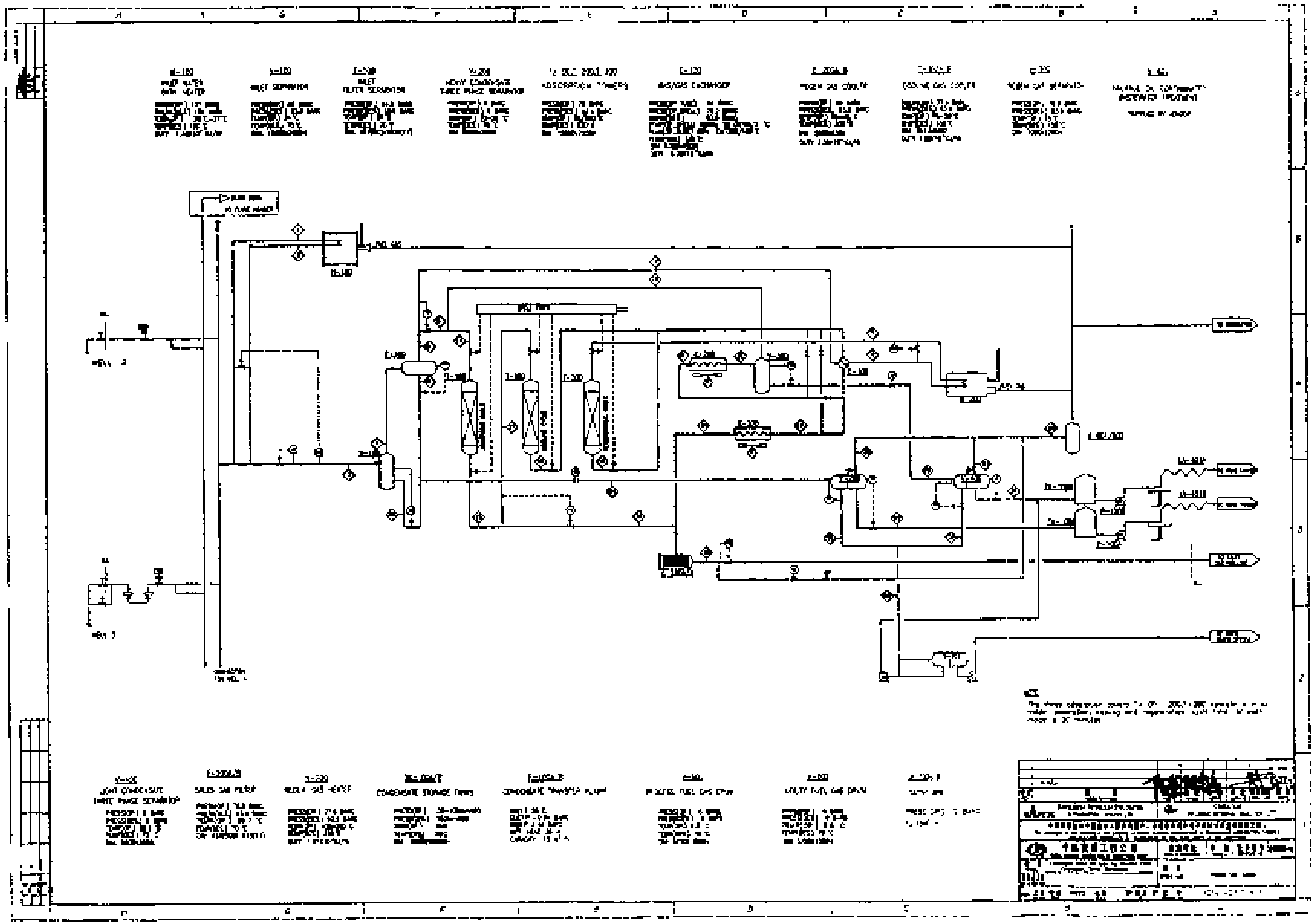

Figure B-2 : Process Flow Diagram of Silica Gel Plant at Fenchuganj Gas Field.

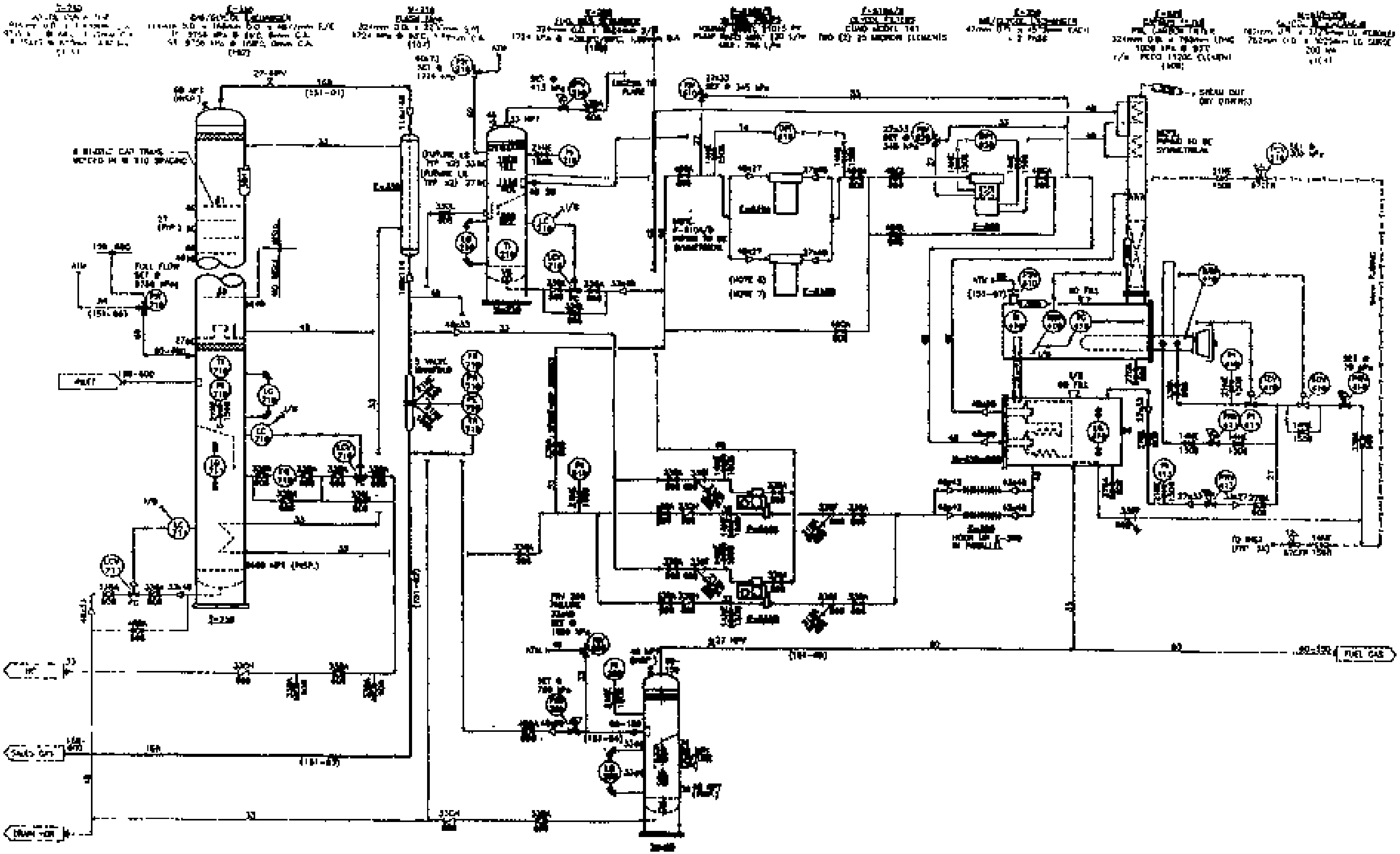

Figure B-3 : Process Flow Diagram of Glycol Dehydration Plant at Feni Gas Field.

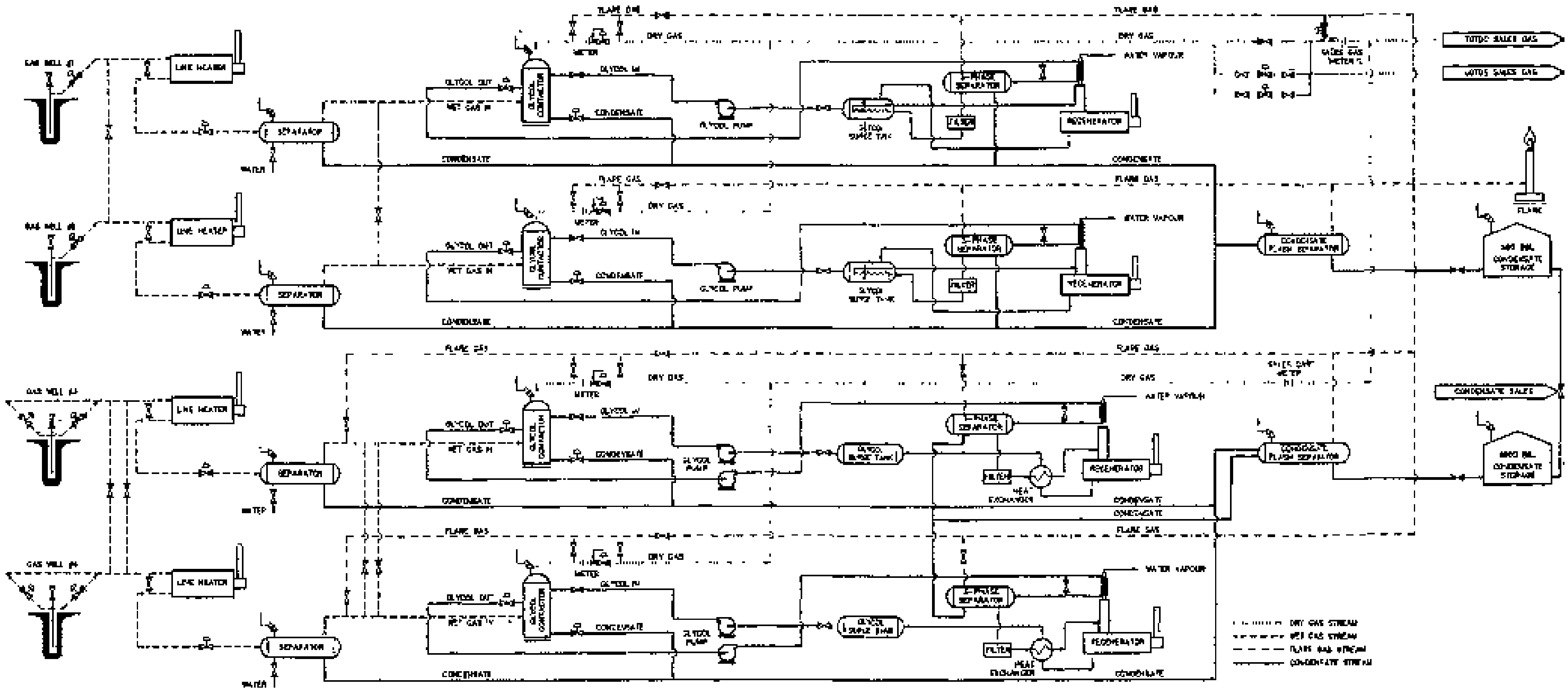

Figure B-4 : Process Flow Diagram of Glycol Dehydration Plants at Habiganj Gas Field.

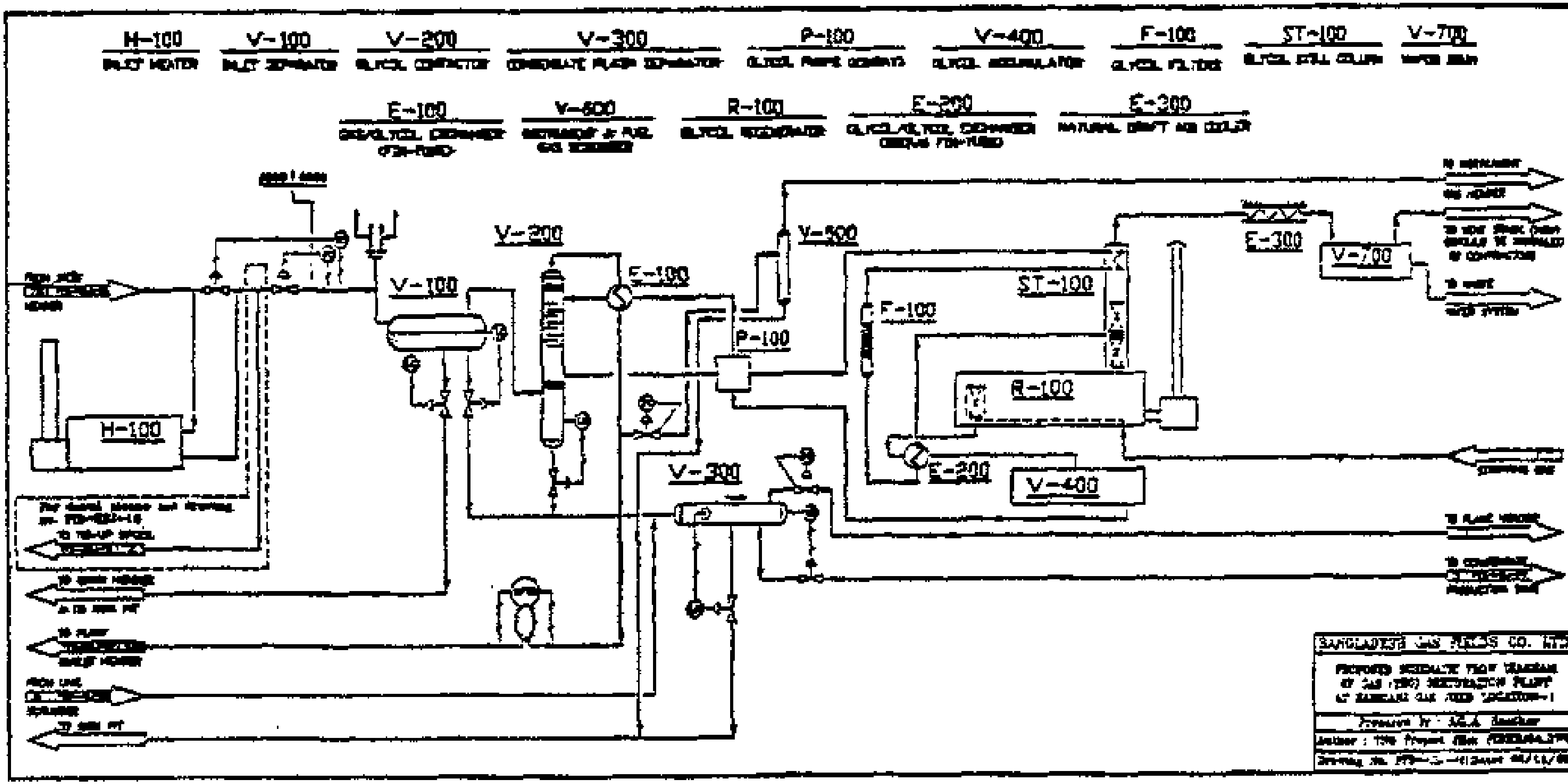

Figure B-5 : Process Flow Diagram of Glycol Dehydration Plants (Plant 5) at Habiganj Gas Field.

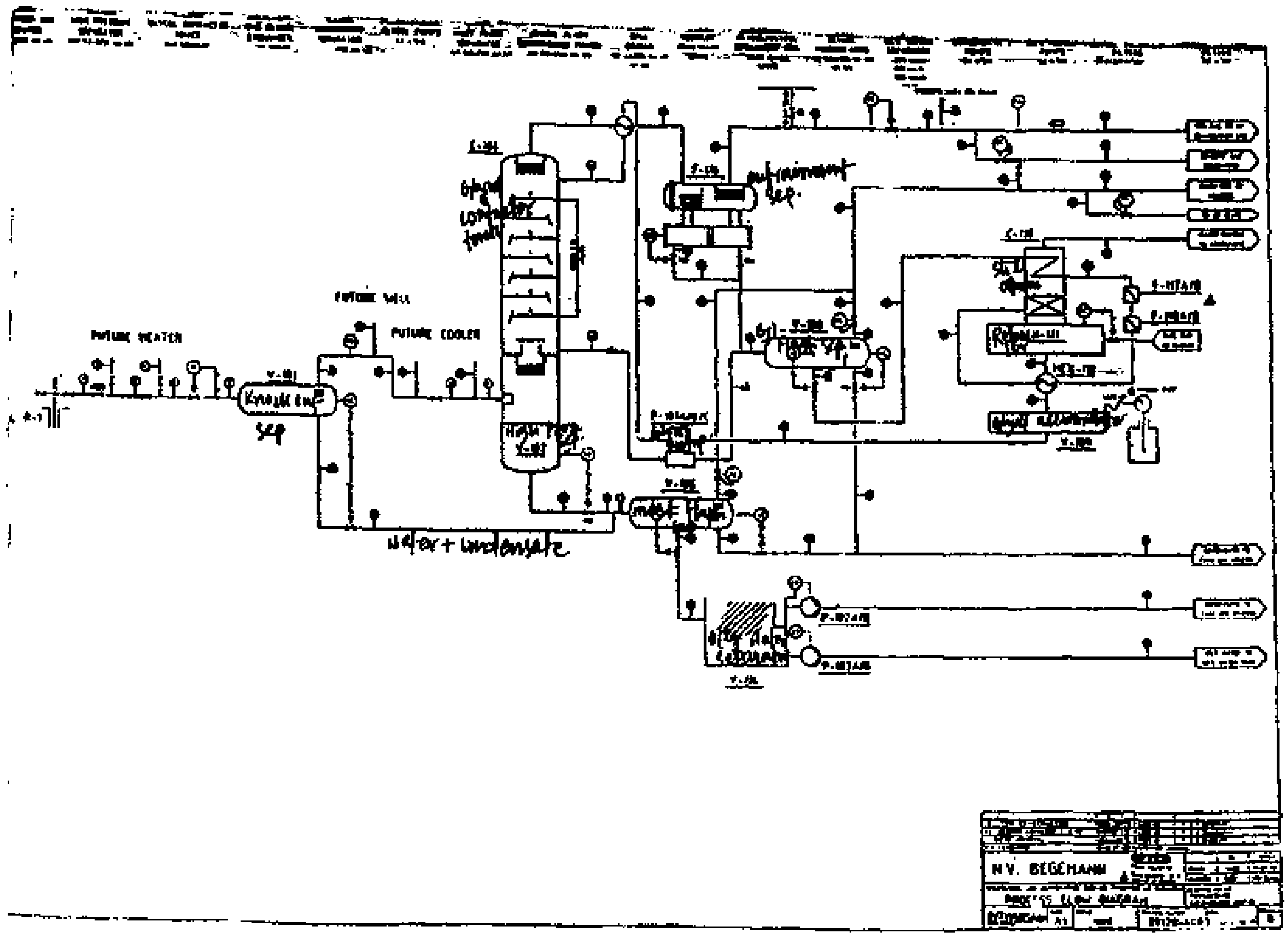

Figure B-6 : Process Flow Diagram of Glycol Dehydration Plant at Rashidpur Gas Field.

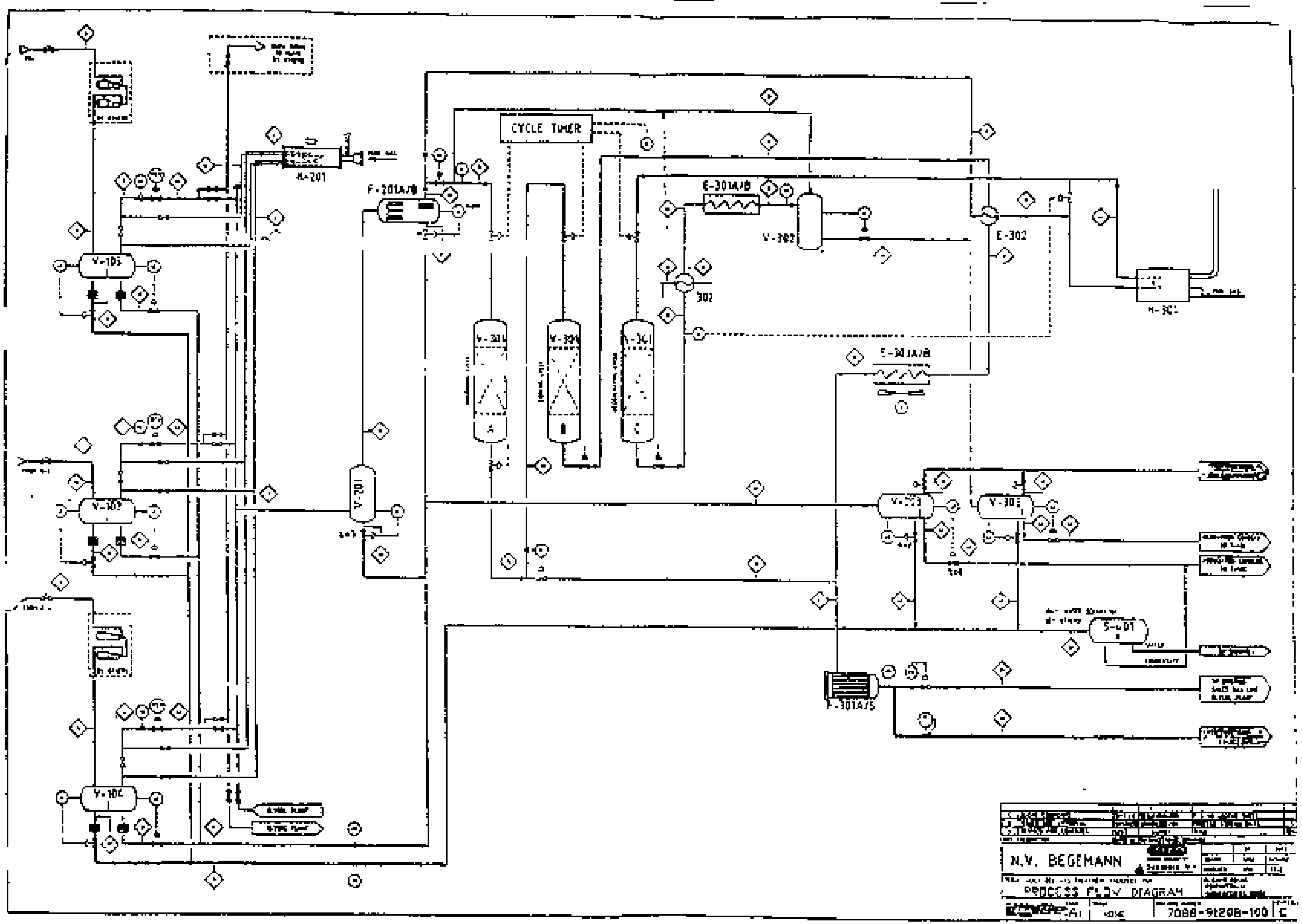

Figure B-7 : Process Flow Diagram of Silica Gel Dehydration Plant (70 MMscfd Capacity) at Rashidpur Gas Field.

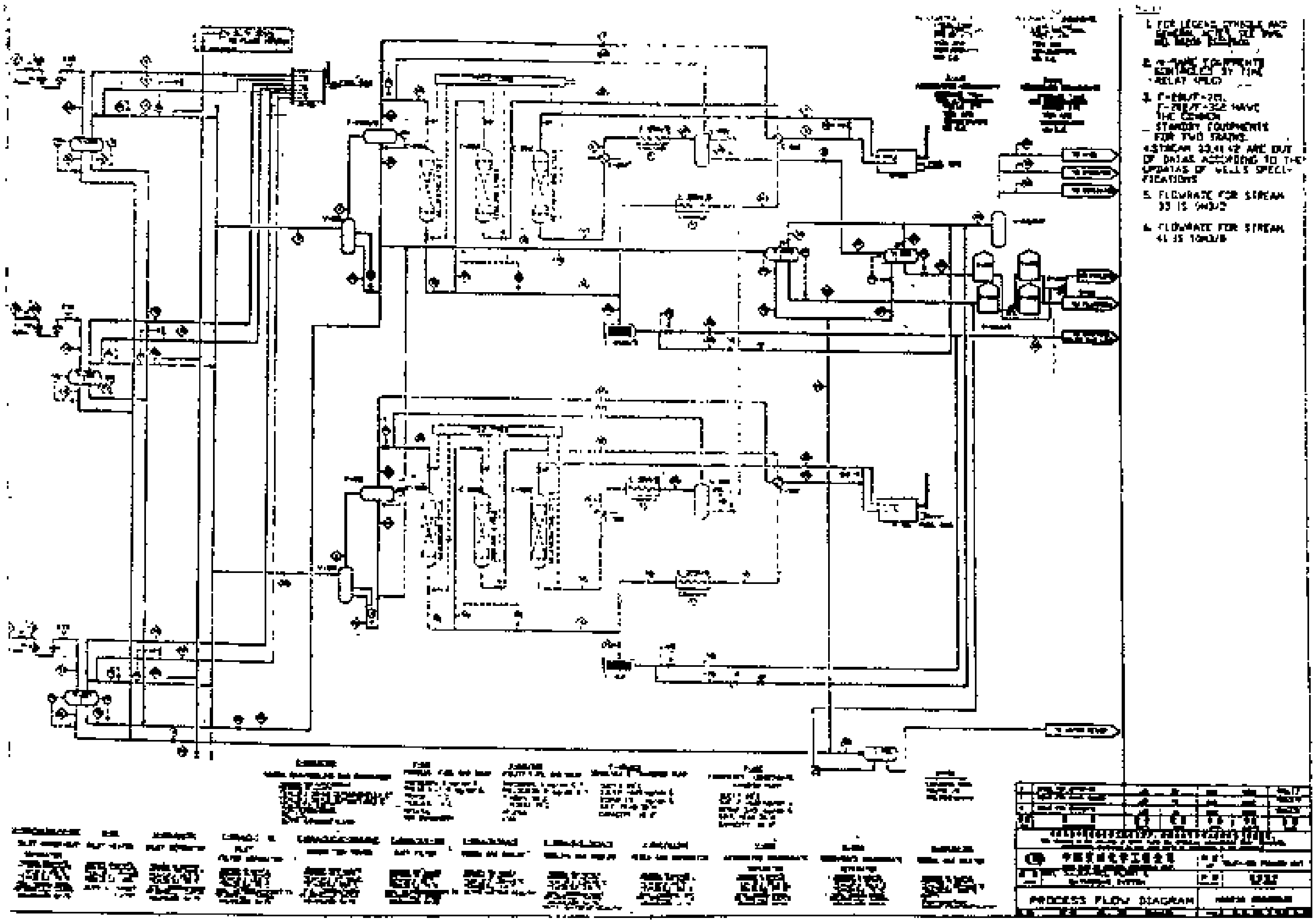

Figure B-8 : Process Flow Diagram of Silica Gel Dehydration Plants (45X2 MMscfd Capacity) at Rashidpur Gas Field.

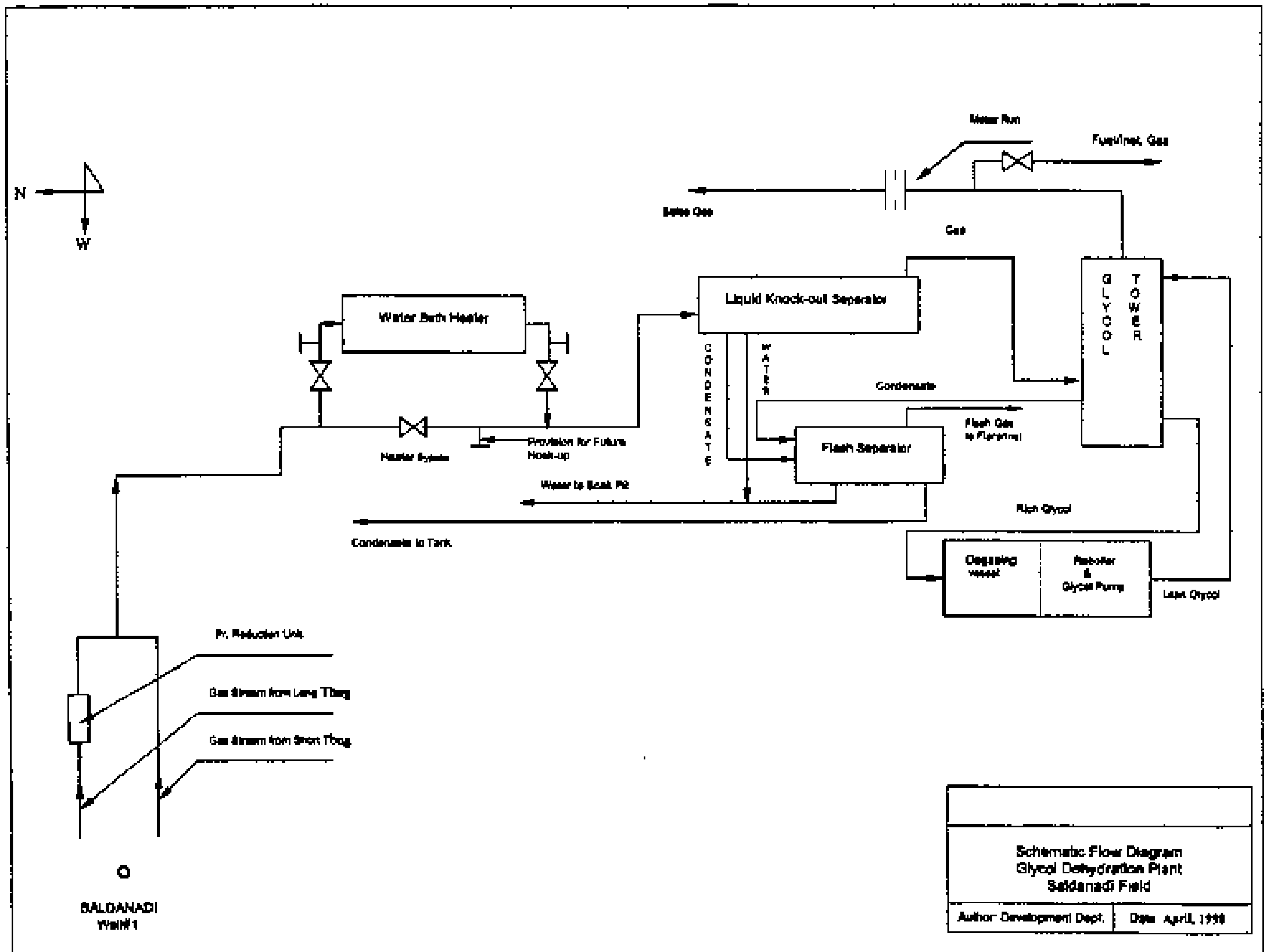

Figure B-9 : Block Diagram of Glycol Dehydration Plant at Saldanadi Gas Field.

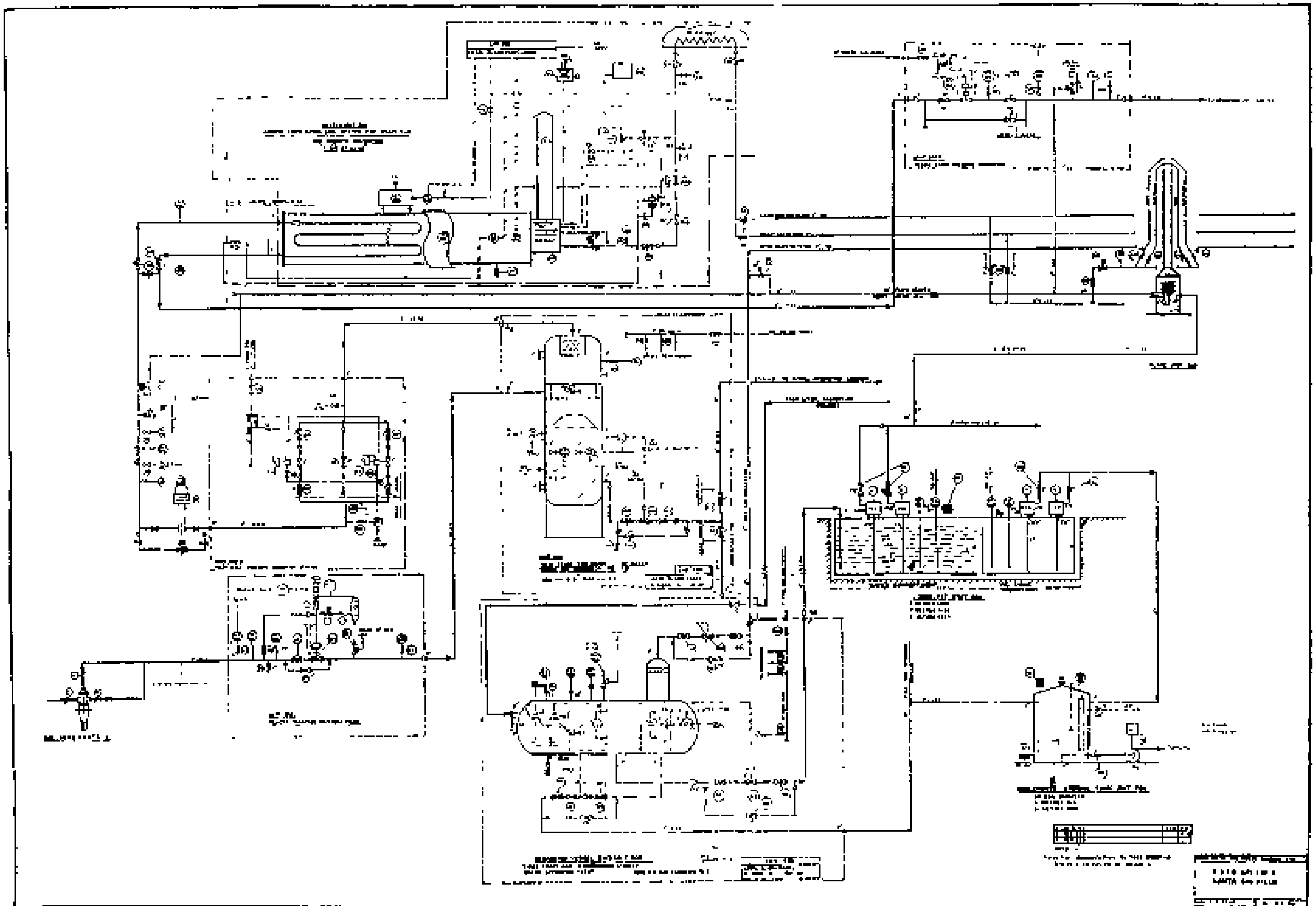

Figure B-10 : Process Flow Diagram of Glycol Dehydration Plant at Saldanadi Gas Field.

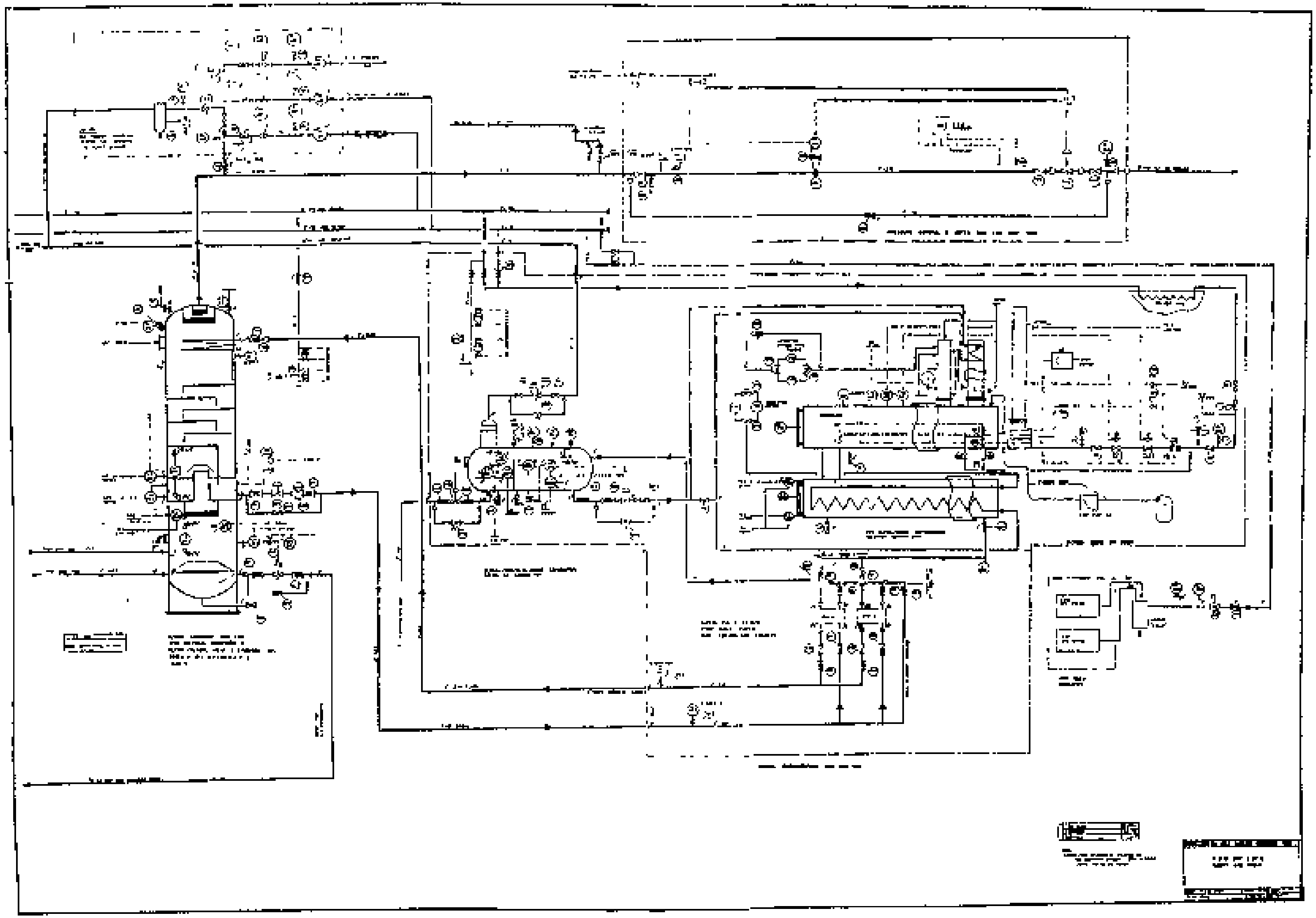

Figure B-10 (Cont'd) : Process Flow Diagram of Glycol Dehydration Plant at Saldanadi Gas Field.

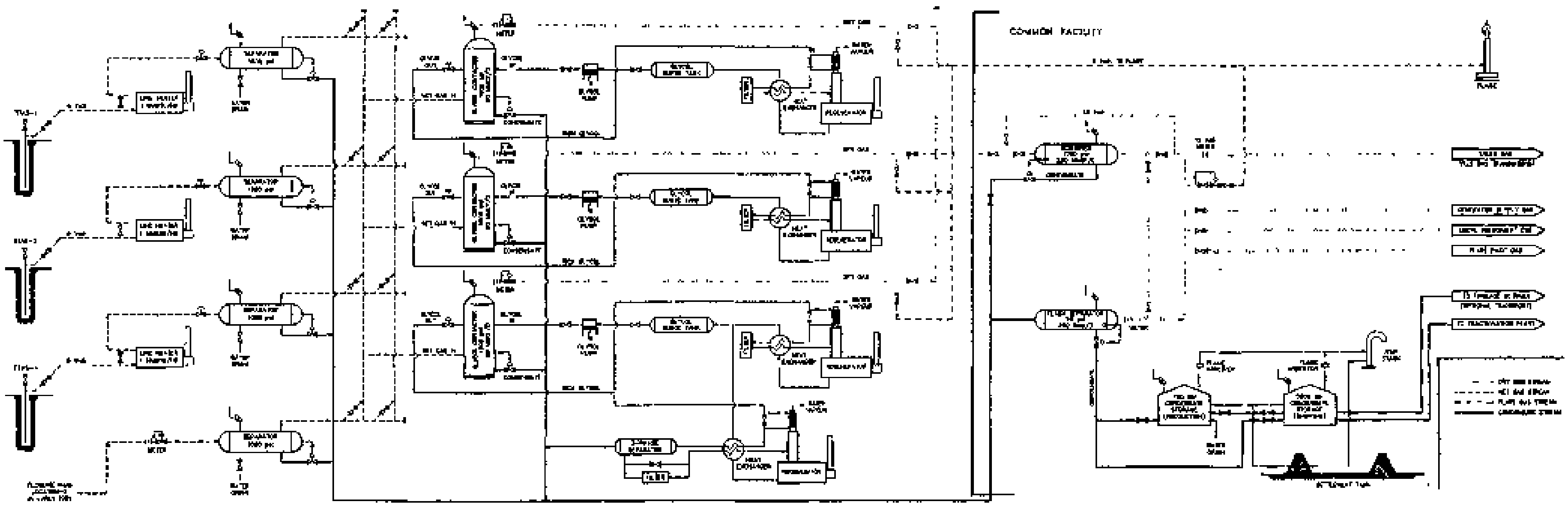

Figure B-11 : Process Flow Diagram of Glycol Dehydration Plants (1,3 & 4) at Titas Gas Field.

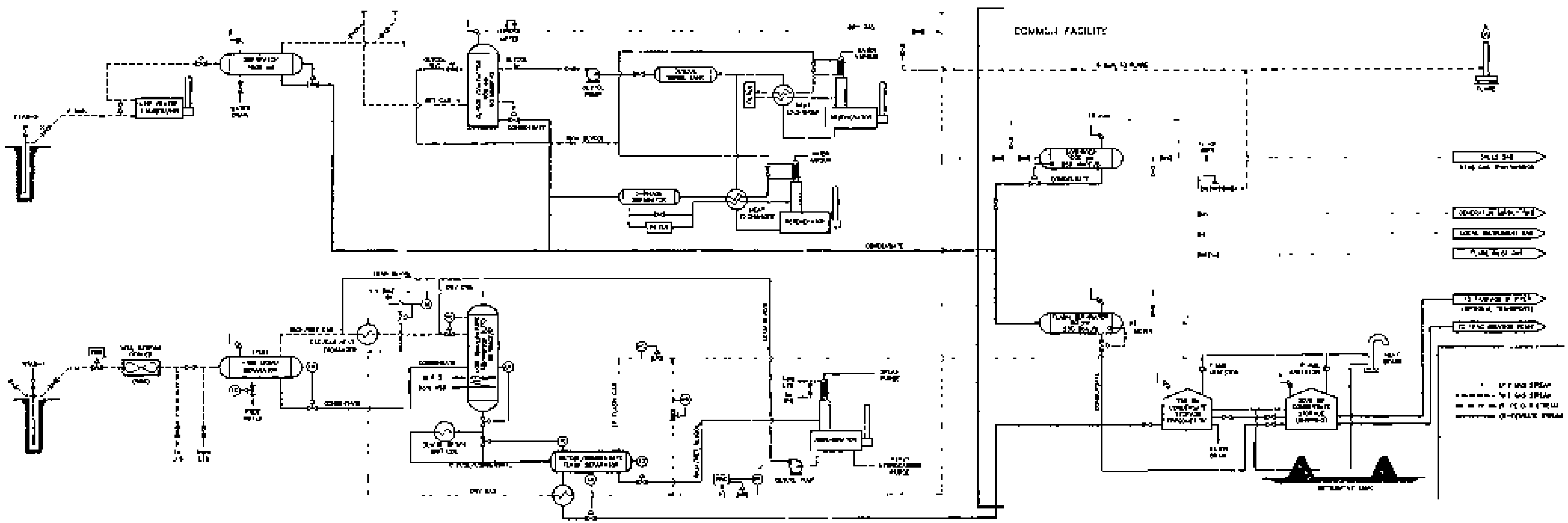

Figure B-12 : Process Flow Diagram of Glycol Dehydration & LTS with Glycol Injection Plants (5 & 7) at Titas Gas Field.

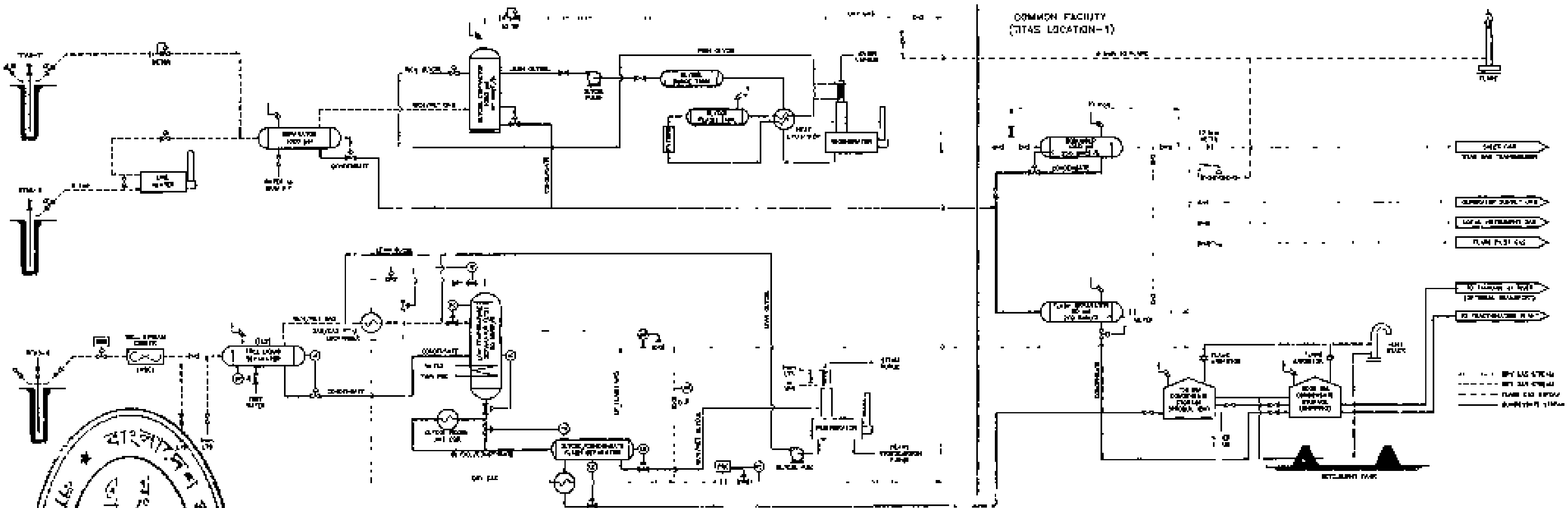

Figure B-13 : Process Flow Diagram of Glycol Dehydration & LTS with Glycol Injection Plants (6 & 8) at Titas Gas Field.