SIMULATION OF DEPLETED GAS RESERVOIR FOR UNDERGROUND GAS STORAGE

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ABSTRACT

SIMULATION OF DEPLETED GAS RESERVOIR FOR UNDERGROUND GAS STORAGE

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For a natural gas importing country, “take or pay” approach creates problems since the demand for natural gas varies during the year and the excess amount of natural gas should be stored.

In this study, an underground gas storage project is evaluated in a depleted gas Field M. After gathering all necessary reservoir, fluid, production and pressure data, the data were adapted to computer language, which was used in a commercial simulator software (IMEX) that is the CMG’s (Computer Modelling Group) new generation adoptive simulator, to reach the history matching.

The history matching which consists of the 4 year of production of the gas reservoir is the first step of this study. The simulation program was able to accomplish a good history match with the given parameters of the reservoir.

Using the history match as a base, five different scenarios were created and forecast the injection and withdrawal performance of the

reservoir. These scenarios includes 5 newly drilled horizontal wells which were used in combinations with the existing wells.

With a predetermined injection rate of 13 MMcf/D was set for all the wells and among the 5 scenarios, 5 horizontal – 6 vertical injectors & 5 horizontal - 6 vertical producers is the most successful in handling the gas inventory and the time it takes for a gas injection and production period. After the determination of the well configuration, the optimum injection rate for the entire field was obtained and found to be 130 MMcf/D by running different injection rates for all wells and then for only horizontal wells different injection rates were applied with a constant injection rate of 130 MMcf/d for vertical wells.

Then it has been found that it is better to apply the 5th scenario which includes 5 horizontal – 6 vertical injectors & 5 horizontal - 6 vertical producers having an injection rate of 130 MMcf/d for horizontal and vertical wells. Since within the 5th scenario, changing the injection rate to 1.3 Bcf/d and 13 Bcf/d, did not effect and change the average reservoir pressure significantly, it is best to carry out the project with the optimum injection rate which is 130 MMcf/d.

The total gas produced untill 2012 is 394 BCF and the gas injected is 340 BCF where the maximum average reservoir pressure was recovered and set into a new value of 1881 psi by injection and cushion gas pressure as 1371 psi by withdrawal. If 5th scenario is compared with the others, there is an increase in injection and production performance about 90%.

Keywords: Underground Gas Storage, Depleted Gas Reservoir, History Matching and Simulator.

ÖZ

DOĞAL GAZIN TÜKENMİŞ GAZ REZERVUARINDA DEPOLANMASININ MODELLENMESİ

ÖZTÜRK, Bülent

Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği Bölümü

Tez Yöneticisi: Prof. Dr. Suat Bağcı

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Doğal gaza olan talep yıl içinde değiştiği için, doğal gaz ihraç eden bir ülke için "al ya da öde" yaklaşımı problemler yaratmaktadır ve fazla miktarı depolanmalıdır.

Bu çalışmada tükenmiş gaz rezervuarı olan M sahası yer altı gaz depolaması projesinde değerlendirilmiştir. Saha ile ilgili bütün gerekli rezervuar, akışkan, üretim ve basınç değerleri toplandıktan sonra, bu bilgiler CMG (Computer Modelling Group)'nin yeni nesil Simülatöründe (IMEX) kullanılmak üzere sahanın tarihsel eşleştirmesinin gerçekleştirilmesi için bilgisayar diline uyarlanmıştır.

Gaz rezervuarının 4 senelik üretiminin tarihsel eşleştirilmesi işlemi, bu çalışmanın ilk ayağı idi. Kullanılan parametrelerle, simülasyon programı iyi bir tarihsel eşleştirme yapmayı başarmıştır.

Tarihsel eşleştirmeyi temel alarak, beş farklı senaryo yaratılmış ve rezervuarın enjeksiyon ve üretim performansları öngörülmüştür. Bu

senaryolar mevcut kuyularla birlikte kullanılan 5 yeni yatay kuyuyu içermektedir.

Bütün senaryolar ve kuyularda kullanılan ve de önceden 13 MMcf/gün olarak kararlaştırılmış olan enjeksiyon debisinde, 5 yatay – 6 dikey enjeksiyon kuyuları ve 5 yatay – 6 dikey üretim kuyuları senaryosu bütün senaryolar arasında gaz envanterini en iyi değerlendirme ve gazın enjeksiyonu ve üretiminin aldığı zaman açısından en iyisi olarak görülmüştür. Kuyu konfigürasyonun kararlaştırılmasından sonra, bütün kuyularda değişik enjeksiyon debiler kullanılarak saha için en uygun enjeksiyon debisi 130 MMcf/gün olarak elde edilmiş ve ardından sadece yatay kuyular için, dikey kuyuların enjeksiyon debisi 130 MMcf/gün' de sabit tutularak, değişik debiler tekrar denenmiştir.

Bu denemelerin ardından, 5 yatay – 6 dikey enjeksiyon kuyuları ve 5 yatay – 6 dikey üretim kuyuları konfigürasyonunu içeren 5 nci senaryo, yatay ve dikey kuyularda 130 MMcf/gün enjeksiyon debisi kullanılmak şartı ile en iyi senaryo olarak görülmüştür. 5nci senaryo dahilindeki denemelerde, enjeksiyon debisinin 1.3 Bcf/gün ve 13 Bcf/gün olarak değiştirilmesi maksimum ortalama rezervuar basıncında kaydadeğer bir değişikliğe neden olmamasından dolayı, bu projenin 130 MMcf/gün enjeksiyon debisi kullanılarak uygulamaya geçirilmesi daha uygundur.

Maksimum ortalama rezervuar basıncının enjeksiyon sayesinde 1881 psi değerine kadar toparlandığı ve de sabitlendiği 5 nci senaryoda, 2012 yılına kadar, üretilen gaz 394 Bcf ve enjekte edilen gaz 340 Bcf olarak görülmüştür. 5 nci senaryo diğer senaryolarla karşılaştırıldığında, enjeksiyon ve üretim performansının %90 arttığı görülmektedir.

Anahtar Kelimeler: Yeraltı Gaz Depolama, Tükenmiş Gaz Rezervuarı, Tarihsel Eşleştirme ve Simülatör.

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TABLE OF CONTENTS

LIST OF TABLES

TABLES

LIST OF FIGURES

FIGURES

ABBREVIATIONS

UGS	: Underground Gas Storage
LPG	: Liquefied Petroleum Gas
CMG	: Computer Modelling Group
μ_g	: Gas Viscosity, cp
B_g	: Gas Formation Volume Factor, RB/scf
P	: Pressure, psi
S_w	: Water Saturation, %
K_{rw}	: Relative Permeability to Water, %
S_g	: Gas Saturation, %
K_{rg}	: Relative Permeability to Gas, %
P_{wf}	: Flowing Bottomhole Pressure, psi
P_{wh}	: Flowing Tubing Pressure, psi
γ_g	: Gas Specific Gravity
H	: True Vertical Depth, ft
q_{inj}	: Injection Rate, MMcf/d
d	: Tubing Inside Diameter, inch
N_{Re}	: Reynolds Number
ε	: Pipe Roughness, inch
$\bar{Z}$	: Average Compressibility Factor
$\bar{T}$	: Average Wellhead Temperature, °R

CHAPTER 1

1. INTRODUCTION

Underground gas storage (UGS) may be defined as the storage in reservoirs of porous rock, salt formations and aquifers, at various depth beneath the surface of the earth of large quantities of natural gas not native to these reservoirs in order to support the natural gas demand in domestic, commercial, industrial, or space heating which is the most critical case and reason for storage especially in cold winter months.

The strong trend towards increasing the number of UGS facilities, which is currently seen in countries with sharp weather differences in winter and summer, is related to the fact that this operating tool is the most adequate, economical, safe and environment-friendly technological means that the industry has to store large volumes of gas ready to be marketed. [1]

With the rapid growth of the natural gas industry, UGS has grown to become a large and essential part of the natural gas delivery system. Long-term demand variations of natural gas caused by the increased fuel need for space heating during the cold weather require large amounts to be stored. These seasonal demand variations can be satisfied effectively by UGS, if such facilities exist close to the area where demand variations take place. [1] Natural gas importing countries, such as Germany, France and Italy have had to develop UGS in places near the main industrial and urban centers for strategic reasons that emerged in the past and also because of the need to have a realiable supply and obtain good prices in the mid-and long-term gas purchase agreements. [1] UGS is a very well known practice to gas utilities, gas producers and large ultimate gas consumers for mainly economical reasons. [2] An analysis of what is currently happening in the world clearly shows that UGS is essential in order to meet gas demand increases at the exact moment in which the need arises, preventing interruptions in the supply to large users such as thermoelectric power plants and industries by means of uninterrupted service.

In this thesis, the Field M was selected to be evaluated as an UGS reservoir since it is a gas reservoir and near to major cities. The exploitation period was simulated using the gathered original data and matched with real data which lead to a good match. Using the matched data set, 5 different scenarios having 5 newly drilled horizontal wells were built and the results of them were compared. At the end, the scenario with 5 horizontal – 6 vertical injectors & 5 horizontal - 6 vertical producers was found to be the best with an injection rate 130 MMcf/d showing 90 % improvement in performance with respect to other scenarios.

CHAPTER 2

2. NATURAL GAS STORAGE

Natural gas occurs in subsurface rock formations in association with oil (associated gas) or on its own (non-associated gas). Roughly 60 percent of the natural gas reserves is non-associated. [3]

The main constituent of natural gas is methane. The remainder may contain various amounts of the higher hydrocarbon gases (ethane, propane, butane, etc.) and non-hydrocarbon gases such as carbon dioxide, nitrogen, hydrogen sulfide, helium, and argon. [3]

Although natural gas occurs under pressure in porous rock beneath the earth's surface, often it is in solution with crude oil or condensate. Then it may be described as the volatile portion of petroleum. [3]

Natural gas is primarily used as fuel for industrial and residential applications. An increasing share of the natural gas production, however, is being used as feedstock for the chemical industry. [3]

2.1 History of Natural Gas

Chinese are the first community used natural gas to their adventages for production. They transported the gas, which had been seeped from rocks, by bamboo pipelines and used to boil the sea water to extract the salt from it. [4]

Britain was the first country to commercialize the use of natural gas. Around 1785, natural gas produced from coal was used to light the houses, as well as the streetlights. [4]

Manufactured natural gas of this type was first brought to the United States in 1816, when it was used to light the streets of Baltimore, Maryland. However, this manufactured gas was much less efficient, and less environmentally friendly, than modern natural gas that comes from underground. [4]

Naturally occurring natural gas was discovered and identified in America as early as 1626, when French explorers discovered natives igniting gases that were seeping into and around Lake Erie. [4]

In 1821, the first well specifically intended to obtain natural gas was dug in Fredonia, New York, by William Hart. After noticing gas bubbles rising to the surface of a creek, Hart dug a 27 foot well to try and obtain a larger flow of gas to the surface. Lake Erie. The American natural gas industry got its beginnings in this area. In 1859, Colonel Edwin Drake dug the first well. Drake hit oil and natural gas at 69 feet below the surface of the earth. [4]

During most of the 19th century, natural gas was used almost exclusively as a source of light. Without a pipeline infrastructure, it was difficult to transport the gas very far, or into homes to be used for heating or cooking. [4]

One of the first lengthy pipelines was constructed in 1891. This pipeline was 120 miles long, and carried natural gas from wells in central Indiana to the city of Chicago. However, this early pipeline was very rudimentary, and was not very efficient at transporting natural gas. It wasn't until the 1920's that any significant effort was put into building a pipeline infrastructure. However, it wasn't until after the World War II that welding techniques, pipe rolling, and metallurgical advances allowed for the construction of reliable pipelines. [4]

2.2 Natural Gas in Turkey

In Turkey, natural gas transmission is the responsibility of a state-owned company, BOTAS (Petroleum Pipeline Corporation). BOTAS handles oil and gas pipelines, and also has the monopoly for import, distribution, pricing, and sale of natural gas in Turkey. [5]

The 20 billion cubic feet (bcf) of natural gas that was produced in Turkey in 2000 met only 3.8% of domestic consumption. The rest was imported either by pipelines or as liquified natural gas (LNG). Turkey's natural gas consumption is expected to grow rapidly, quadrupling within the next 20 years, with 1,400 bcf consumption projected for the year 2020. Getting this capacity by domestic production would require $4.5 billion in foreign investment over about the next 20 years. [5]

Presently, the largest share of Turkey's imported natural gas comes from Russia, much of it via the newly-completed Blue Stream Pipeline, which will provide Turkey with 14.1 trillion cubic feet (Tcf) of gas over the life of a 25-year agreement that began in 2002. However, Turkey is trying to diversify its sources, and is considering Turkmenistan, Kazakhstan, Uzbekistan, Egypt, Nigeria, Iraq, and Iran as possible sources. Under a 25-year deal signed in 1996, Turkey plans to buy 3 billion cubic meters (bcm) of natural gas per year from Iran through 2007, after which the amount will increase to 10 bcm annually. In December 2001, gas deliveries from Iran finally began, after repeated delays. Gas purchases from Iran could total $23 billion over the life of the arrangement. [5]

An historical summary of natural gas production and consumption in Turkey is shown in Figure 2.1.

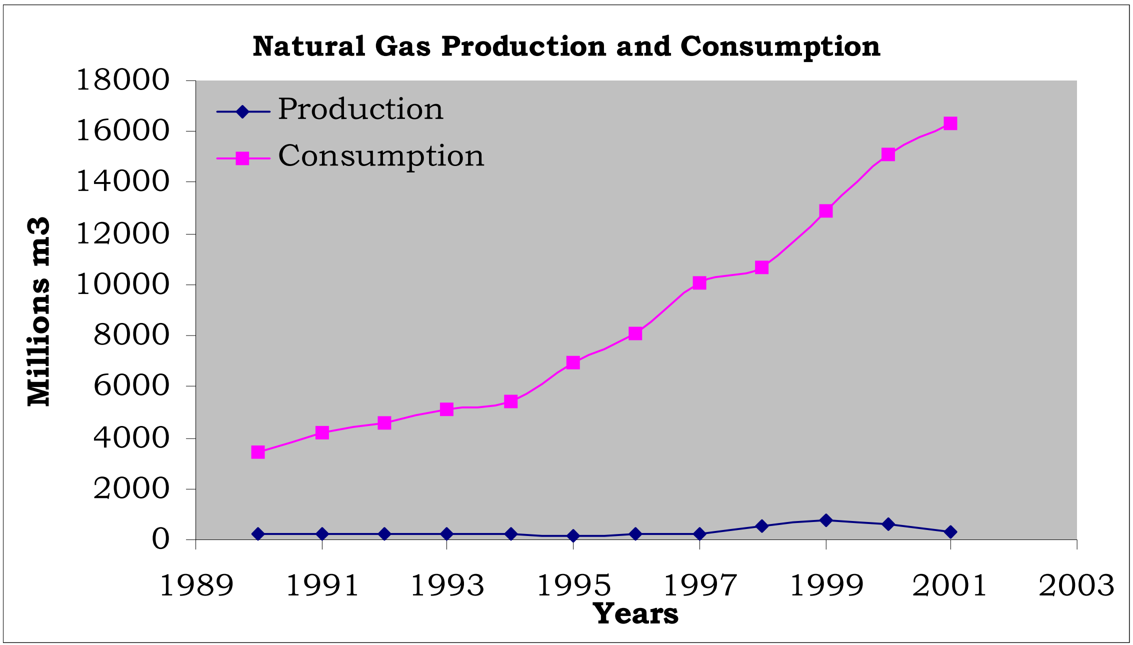

Figure 2.1. Natural Gas Production and Consumption in Turkey, 1990-2001

Source: Turkish Ministry of Energy and Natural Sources

http://www.enerji.gov.tr/December 2004

2.2.1 Gas Pipelines, Terminals, and Storage

There are several existing gas pipelines in Turkey. The Eastern Anatolia Gas Pipeline brings gas into Turkey from Iran and is the main natural gas pipeline in eastern Turkey; the pipeline presently extends as far west as Ankara. The 842-kilometer Russia-Turkey Natural Gas Pipeline runs from Russia through Ukraine, Romania, and Bulgaria into Turkey. An extension of this pipeline brings gas to Ankara and to Hamitabat, where it supplies a combined cycle power plant. In 1996, another 209-kilometer extension of this pipeline to the western Black Sea region called the Izmit-Karadeniz Ereğlisi Natural Gas Transmission Line was finished, and following that, a 208-kilometer extension, the Bursa-Çan Natural Gas Transmission Line, was added to take the pipeline to the city of Çan. In

2000, a 107-kilometer extension to the port city of Çanakkale called the Çan-Çanakkale Natural Gas Pipeline was completed. [5]

The $3.3 billion Blue Stream Pipeline, which will transport 565 bcf per year of natural gas 1,200 kilometers from Russia to Turkey, was completed in October 2002. The pipeline starts at Izobilnoye near Krasnodar in southern Russia and runs overland on the Black Sea coast 370 kilometers to Dzhubga. Construction of the deep-sea portion of the Blue Stream Pipeline began in June 2002. The undersea portion consists of twin pipelines running 375 kilometers under the Black Sea from Dzhubga, Russia, to the Turkish port of Samsun; this undersea portion reaches a depth of 2,150 meters, making it the world's deepest pipeline. From Samsun, the pipeline then runs overland to provide gas to Ankara. The Blue Stream Pipeline was jointly built by Russia's Gazprom and Italy's ENI, with each having a 50% share; the project was undertaken because of Turkey's 1997 agreement with Russia to buy 565 bcf per year of natural gas. The schedule for the pipeline calls for 70.6 bcf of natural gas deliveries to Turkey in 2002, while from 2003 to 2009, Russia will increase deliveries through the pipeline by 70.6 bcf per year until final capacity of 565 bcf per year is reached in 2009. [5]

In March 2002, Turkey signed a $300 million deal with Greece to extend an Iranian natural gas pipeline to Greece. The pipeline will go 125 miles inside Turkey and cross the Dardanelles Straits into Greece. This will extend the pipeline from Karacabey in western Turkey to the city of Komotini in northeastern Greece. The pipeline is expected to carry 17.5 bcf of gas per year, and could be completed by 2005. [5]

Turkey is also planning extensions to the Eastern Anatolia Natural Gas Pipeline within the country. The 565-kilometer Southern Natural Gas Transmission Line Project would extend the Eastern Anatolia Pipeline in three stages: from Sivas to Malatya (168 kilometers), Malatya to Gaziantep

(182 kilometers), and Gaziantep to Mersin (215 kilometers). The proposed 618-kilometers Konya-Izmir Natural Gas Transmission Line Project would extend the Eastern Anatolia Gas Main from Konya to Izmir, also supplying the cities of Burdur, Isparta, Denizli, and Nazilli. This project would also consist of three stages: Konya to Isparta (217 kilometers), Isparta to Nazilli (203 kilometers), and Nazilli to Izmir (198 kilometers). BOTAS has planned for completion of both of these projects in 2003. [5]

Georgia, Azerbaijan, Kazakhstan and Turkmenistan have backed a plan to transport natural gas from Turkmenistan and Kazakhstan with a pipeline running under the Caspian Sea to Baku. This proposed $2.7 billion Trans-Caspian Gas Pipeline would be 1,700 kilometers long and carry 16 billion cubic meters of natural gas per year. The projected route of the pipeline is from Turkmenbashy, Turkmenistan, via Baku, Azerbaijan, and Tbilisi, Georgia, to Erzurum in Turkey, where it would link up to the Turkish natural gas pipeline system. There was an intergovernmental declaration in support of the project in November 1999 by Turkey, Turkmenistan, Azerbaijan, and Georgia; the next step would be a definitive agreement by the four governments. Credit Suisse and First Boston have been appointed financial advisors for the project. There are obstacles to overcome before this pipeline can become a reality, however, not the least of which being the economic effects of the new Blue Stream Pipeline from Russia. Turkmenistan and Azerbaijan have also had difficulty reaching agreement on pipeline volumes. It is not yet clear if the Trans-Caspian Pipeline will proceed. [5]

Also, in February 2000, Turkey and Egypt signed a protocol concerning oil and gas issues that among other things declared their intention for constructing a gas pipeline under the Mediterranean Sea that would transport about 140 bcf per year of natural gas from Egypt to Turkey. [5]

Besides pipelines, Turkey also receives imported natural gas in the form of LNG. There is a terminal at Marmara Ereglisi on the Sea of Marmara. This terminal has the capacity to provide 105 bcf per year of LNG from Algeria and Nigeria. Turkey is also considering LNG imports from Australia, Egypt, Qatar, and Yemen. Also, there were engineering studies concerning possible construction of natural gas storage facilities at several sites in Turkey. One of these was for the Northern Marmara and Degirmenkoy gas fields, which had been upgraded for gas storage after their depletion. [5]

Turkey's recent natural gas pipelines and LNG importing routes are shown in the following Figure 2.2.

Figure 2.2 Natural Gas Pipeline System in Turkey

Source: BOTAŞ Turkish Petroleum Pipeline Corporation

http://www.botas.gov.tr/December 2004

Table 2.1 Natural Gas Supply Contracts of BOTAŞ

		Max Capacity (BCM/Year)	Term (Year)	Start	Finish
In Operation	Russian Fed. (West)	6	25	1987	2011
	Algeria (LNG)	4	20	1994	2014
	Russian Fed. (Turusgaz)	8	23	1998	2020
	Nigeria (LNG)	1.2	22	1999	2021
	Iran	10	25	Dec 2001	2026
	Russian Fed. (Blue Stream)	16	25	Feb 2003	2027
	Turkmenistan	16	30	2006	2035
	Azerbaijan	6.6	15	2006	2020
	Total	**67.8**			

Domestic Gas Transmission and Distribution System of Turkey:

Existing System	4700 kms
Under Construction	2400 kms
Planned	1000 kms

Source: BOTAŞ Turkish Petroleum Pipeline Corporation
http://www.botas.gov.tr/December 2004

There are several scenarios about natural gas supply and demand in Turkey. The following Table 2.2. shows the govenmental approach for the future prediction of natural gas upstream and downstream scenarios.

Table 2.2 Supply and demand prediction scenarios for Turkey

(Million m^3)

	YEARS	2004	2005	2006	2007	2008	2009	2010	2015	2020
Sm^3	TOTAL DEMAND (*)	21965	24299	29839	33365	35948	38378	40712	44656	42977
	YEARS SUPPLIES									
	CONTRACTED VOLUMES									
	YEARS	2004	2005	2006	2007	2008	2009	2010	2015	2020
Cm^3	RUSSIAN FEDERATION	6000	6000	6000	6000	6000	6000	6000	0	0
Cm^3	1. LNG (M. EREĞLİSİ) ALGERIA	4444	4444	4444	4444	4444	4444	4444	0	0
Cm^3	1. LNG (M. EREĞLİSİ) NIGERIA	1338	1338	1338	1338	1338	1338	1338	1338	1338
Cm^3	IRAN	5733	6689	8600	9556	9556	9556	9556	9556	9556
Cm^3	RUSSIAN FED. (ADDITION)(WEST)	8000	8000	8000	8000	8000	8000	8000	8000	8000
Cm^3	RUSSIAN FED. (BLACKSEA)	4000	6000	8000	10000	12000	14000	16000	16000	16000
Cm^3	TURKMENISTAN (**)	0	0	0	0	0	0	0	0	0
Cm^3	AZERBAIJAN (***)	0	0	0	2000	3000	5000	6600	6600	6600
Sm^3	TOTAL SUPPLIES	29016	31921	35766	40638	43587	47519	51058	40791	40791

(*) : The "CONTRACTED VOLUMES" are written in contract m^3 unit. However the "TOTAL DEMAND" and "TOTAL SUPPLIES " are the conversion values of the total contract m^3 into standard m^3.

(**) : There is an uncertainty of purchasing natural gas.

(***) : Annual contracted amounts may change upon changes in the initial date for gas deliveries.

Source: BOTAŞ Turkish Petroleum Pipeline Corporation

http://www.botas.gov.tr/December 2004

2.2.2 Sector Profile of Natural Gas

The amount of investments for natural gas in 2002 is 334 million USD. The total amount that has been purchased in the last 15 years is 100 billion m^3. And the need for natural gas in 2005 will be 44 billion m^3, while contracted amount is 40.5 billion m^3. It is estimated that the increase in the usage of natural gas will continue and the demand in 2010 will be 55 billion m^3, and in 2020 82 billion m^3. The estimation table for demand of the sectorial natural gas is shown in Table 2.3. (million m^3). [6]

Table 2.3 The demand estimation with respect to sectors, million m³

	1999	2000	2005	2010	2015	2020
Residence	2.355	2.724	7.371	11.091	12.446	13.088
Industry	1.801	1.895	14.226	18.294	19.957	21.146
Fertilizer	141	110	304	304	304	304
Electricity	7.743	9.420	21.698	25.413	34.638	48.246
Total Demand	14.148	14.148	43.598	55.102	67.344	82.785

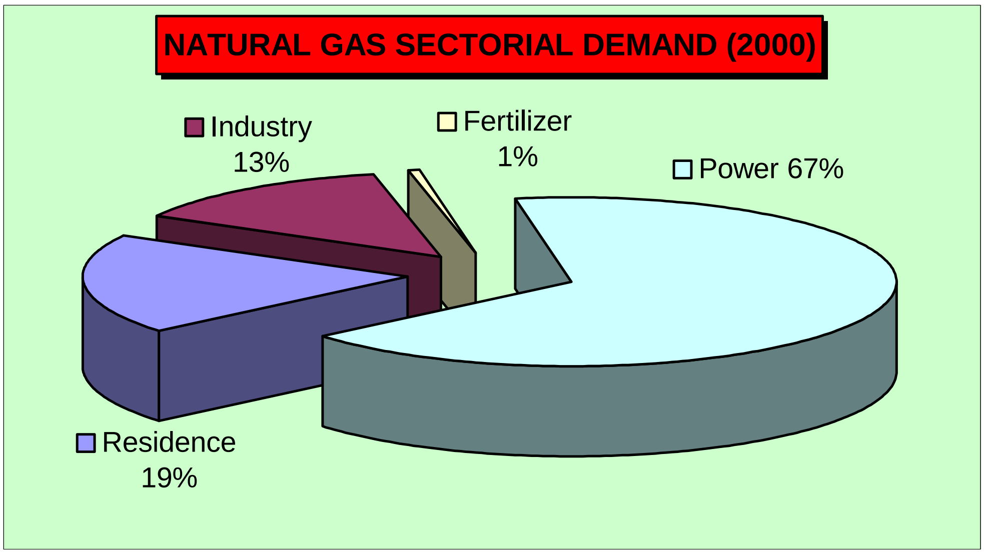

Figure 2.3. Natural gas demand by sectors

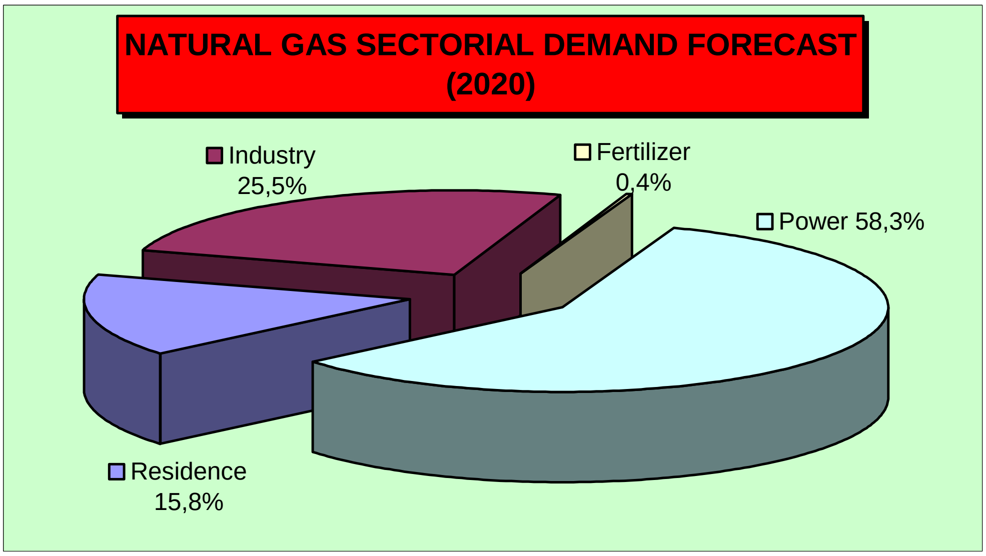

Figure 2.4. Natural gas demand forecast by sectors

2.3 What is Natural Gas Storage

It is a fact that with storage facilities, fewer production and transport plants will in general be used and peak prices will be lower than otherwise, and considerable welfare benefits can be obtained. In this sense, even though natural gas requires huge amounts of capital investment and operating costs to be supplied to customers, the price that customers actually pay may be said to be much lower than if it was not storable. [7]

Natural gas storage is a kind of buffer in a gas supply system. Without a buffer, an energy supply system can easily break down by an internal an external shock, which translates into a vast economic cost. Because electricity is not storable, an electricity supply system should maintain a ceratin amount of generation reserve margins. However, since natural gas is stotable in storage facilities as well as pipelines, a natural gas supply system is relatively flexible to internal and external shocks. Although, a direct comparison of the benefits and costs of flexibility between electrcity and natural gas is impossible, it may be argued that the gains from system security obtained from storability are enormous. [7]

As the generic service which natural gas storage facilities provide is flexibility, which is valuable in an expensive gas supply network, more profitable business opportunities are being developed in the natural gas storage business, as the market becomes liberalised and gas supply functions are unbundled. [7]

2.3.1 Purpose of Natural Gas Storage

Storage over the past years has served a number of purposes and the developing industry is still finding new roles for it. The recent reasons why UGS is preferred can be summarized as;

1. Providing an economical way to supply gas for space heating consumption.

2. To use transmission lines at full capacity during the entire year by delivering gas to the consumer or to the UGS reservoir.

3. Usage of low-pressure wells in the storage field enabling storage wells to have much greater deliverability during the peak season.

4. Acting as a safeguard for countries having long distance transmission lines in case of possible failures thus becomes a strategic reserve.

5. Reducing the risks of fire and explosion by means of storing the gas in oxygen-free environment.

2.3.2 Types of Natural Gas Storage

It can be seen from Table 2.5 [8] that most existing gas storage is held in depleted natural gas/oil fields located close to consumption centers. Conversion of a field from production to storage duty takes advantage of existing wells, gathering systems, and pipeline connections. The geology and producing characteristics of a depleted field are also well known.

However, choices of storage field location and performance are limited by the inventory of depleted fields in any region.

In some areas natural aquifers have been converted to gas storage reservoirs. An aquifer is suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. While the geology of aquifers is similar to depleted production fields, their use in gas storage usually requires base (cushion) gas and greater monitoring of withdrawal and injection performance. Deliverability rates may be enhanced by the presence of an active water drive.

Salt caverns, the third main type of storage, provide very high withdrawal and injection rates compared with their working gas capacity. Base gas requirements are relatively low. The large majority of salt cavern storage facilities have been developed in salt dome formations. Salt caverns leached from bedded salt formations are also being developed to take advantage of the high volume and flexible operations possible with a cavern facility. Cavern construction is more costly than depleted field conversions when measured on the basis of dollars per thousand cubic feet of working gas, but the ability to perform several withdrawal and injection cycles each year reduces the per-unit cost of each thousand cubic feet of gas injected and withdrawn.

Storage facilities may be classified as seasonal supply reservoirs (depleted gas fields and aquifers for the most part) and high-deliverability sites (mostly salt cavern reservoirs); High deliverability can be achieved in a depleted oil or gas reservoir if the reservoir rock has high porosity and permeability (allowing a rapid flow of gas), and the reservoir has sufficient base gas pressure and a sufficient number of wells to maximize withdrawal. Additionally, it would be desirable to be able to refill a reservoir in a reasonably short time. Salt cavern storage is ideal for high deliverability, as the entire cavern is one large "pore." On average, salt storage facilities can withdraw their gas in 12 days, versus 71 days for aquifers and 64 days for all depleted oil or gas reservoirs.

2.3.2.1 Depleted Gas Fields

Underground storage in depleted gas fields is used when gas can be injected into reservoirs with suitable pore space, permeability, and retention characteristics. All gas reservoirs share similar characteristics in that they are composed of rock with enough porosity so that hydrocarbons can accumulate in the pores in the rock, and they have a less permeable layer of rock above the hydrocarbon-bearing stratum. Depleted gas reservoirs are the most commonly used underground storage sites because of their wide availability. They use the pressure of the stored gas and, in some cases, water infiltration pressure to drive withdrawal operations. Cycling (number of times a year the total working gas volume may be injected/withdrawn per year) is relatively low, and daily deliverability rates are dependent on the degree of rock porosity and permeability, although the facilities are usually designed for one injection and withdrawal cycle per year.

Daily deliverability rates from depleted fields vary widely because of differences in the surface facilities (such as compressors), base gas levels, and the fluid flow characteristics of each reservoir. Retention capability, which is the degree to which stored gas is held within the reservoir area, however, is highest of the three principal types of underground storage. Depleted field storage is also the least expensive to develop, operate, and maintain. In order to use an abandoned gas reservoir for storage, one or more of the wells used for extraction are typically used to inject gas. As with extraction, the more porous the rock, the rate of injection can be. As pressure builds up in the reservoir, the rate of injection slows down (pushing the gas in against higher pressure requires more force). Similarly, when the reservoir is at peak pressure, the rate of extraction is greater than at minimum pressure. The factors that determine whether a gas reservoir will make a good storage reservoir are both geographic and geologic. The greater the porosity of the rock, the faster the rates of injection and withdrawal. In some cases, where the reservoir rock is "tight" or of low porosity, then some form of stimulation of the reservoir may also be performed. This would include various methods to introduce cracks into the reservoir rock, thus increasing the opportunities for the hydrocarbon to flow towards the well hole.

The size of the reservoir (the thickness of the gas-bearing rock stratum and the extent to which the stratum is covered by cap rock) is another factor. Location is also a factor. If the reservoir is not close to existing trunk pipelines or market areas and distribution lines, then greater expense will be incurred to establish connecting pipelines.

The prime factor in the design of a depleted reservoir to a storage pool is the safeguards against migration, therefore during the design phase the reservoir should carefully be studied and made sound that the gas will not migrate away from the designated area. In this manner careful studies of seismic and well data are carried out. Old production wells and wells classified as dry are reopened to obtain more relevant data about the reservoir, as well as the wells themselves. Ensuring that the gas will not migrate from the reservoir, however, is not enough. Well studies should also be carried out to make sure that there will not be any loss through the wells or that the wells penetrating the storage zone have not damaged the caprock to a point where the caprock will not be able to withstand the top gas pressure. Therefore, in many cases, all the original production wells in a field are reworked and are made mechanically sound before starting with the storage operations. [2]

Another important parameter in underground storage operations is the assurance of deliverability. The reservoir must be able to deliver the peak load requirements of the country during the coldest days of the winter season. It should be remembered that storage reservoirs must be able to deliver as much as 50% or more of its original content within 3 or 4 months. Therefore, storage operations normally require many more wells than the number of wells drilled for original production. [2]

The important thing to remember about the storage wells is that they must be properly designed to stand the stress of being continually cycled from a minimum to a maximum pressure at least once every year and that they must have a relatively higher deliverability compared to old production wells where the maximum pressure is experienced only once during the entire lifetime. [2]

The storage field should be operated carefully in order to meet the needed gas during the heating days. A detailed study of the reservoir and model construction will enable correct forecasts thus the successful operation of the underground storage facility. In the event that the demand exceeds the field's top production capacity, optimisation has to be made in order to maximize the gas production. Forecasting in this case will help determine the amount of make-up gas needed to fulfil the remaining demand and leave time to take the steps for obtaining it in some way. [8]

A major advantage of storing gas in a depleted gas reservoir is that the performance, where in many cases is reflected by a plot of gas production versus reservoir pressure, is known. In this manner it is very easy to predict storage properties beforehand. The top pressure of a storage reservoir corresponds to the pressure where the reservoir contains the maximum amount of gas it can store. The use of the field at the highest pressure level will normally give the maximum storage capacity and the highest flow capacity of the wells, and this is usually the goal of the design. [2]

With the rapid increase of space heating consumption of natural gas in Turkey underground storage of natural gas has become a necessity for reasons of safety, security and environmental quality. Turkey imports most of the natural gas it consumes from the Russian Federation with a transmission line extending from the natural gas fields in Siberia, to the Malkoclar region located at the border between Bulgaria and Turkey where it enters the country. The primary objective of underground storage in Turkey is to balance the supply and demand of natural gas due to the gas coming with a constant annual rate. However underground storage will also be acting as a safeguard against possible failures on the main transmission line. [2]

The Northern Marmara natural gas field located in the Thrace region is planned to convert to a storage pool. This field was chosen due to the relatively high permeability of the field when compared with the other gas reservoirs in the area, and to the location, where the field is located close to industrial plants, major gas consuming cities and the main transmission line extending from the Malkoclar region. [2]

2.3.2.2 Aquifers

An aquifer storage site is a water-only reservoir conditioned to hold natural gas. Such sites are usually used as storage reservoirs only when depleted gas or oil reservoirs are not available. Aquifers have been developed exclusively in market areas. In general, aquifer storage is more expensive to develop and maintain than depleted gas or oil reservoir storage.

There are several reasons why an aquifer is the least desirable site for natural gas storage. First, it takes much longer to condition the site. Unlike a depleted site, the geology of an aquifer site is unknown beforehand. As a result, seismic testing must be performed to determine its geologic profile. Important also are such characteristics as the confinement area of the reservoir, the location and type of the "cap" rock ceiling barrier, existing reservoir pressure, and the porosity and permeability of the reservoir rock. The potential capacity of the reservoir is also unknown and can only be determined as the site is further developed.

Second, all new facilities must be installed, including wells, pipelines, dehydration facilities, and compressor operations. Aquifer storage sites may also require additional facilities such as greater compression for injection purposes (to push back the water), more extensive dehydration facilities (which are not always needed at gas reservoir sites), and "collector" wells drilled into formations above the cap rock, which recover gas that may penetrate out of the storage zone. An important consideration is that the design of the facilities specifically meets the peak-period needs of the customers expected to use the service. Because of the additional support of an aquifer's water (pressure) drive, in most instances, higher sustained deliverability rates than gas or oil reservoirs can be designed and incorporated at the site.

Third, no native gas is present in an aquifer formation. Thus, once initial testing has been completed and site development approval has been granted, base or cushion gas must be introduced into the reservoir to build and maintain deliverability pressure. While base gas in gas/oil storage reservoirs usually is about 50 percent of total capacity, base gas in aquifer storage may constitute as much as 80 to 90 percent by the time the site is fully developed for gas storage. Needless to say, the need to acquire such large volumes of base gas to maintain operational integrity is a crucial component in assessing the economic viability of the overall project. Most, if not all, of this base gas is not recoverable (even when the site is abandoned). Many of the sites in operation today were developed when the market price for natural gas was very low. In today's market, developing aquifer storage can be a very expensive undertaking. Aquifer storage deliverability during the heating season is designed around specific customer requirements. These requirements may be for deliveries over a set period of time, for instance, 20, 60, or 120 days. The overall facility design reflects these combined requirements. These requirements also delimit the degree of cycling, that is, the number of times total working levels may be depleted and replenished during a heating season, that may occur at an aquifer site. The sustained delivery rate cannot exceed design limits. Otherwise, unlike depleted oil and gas reservoir storage where cushion gas can be tapped when needed, tapping cushion gas in an aquifer storage site can have an adverse effect upon reservoir performance.

Lastly, and perhaps the most important constraint on the future use of aquifer formations for natural gas storage, is the environmental qualifier.

2.3.2.3 Salt Formations

Salt formations have several properties that make them ideal for storing natural gas. A salt cavern is virtually impermeable to gas and once formed, a salt reservoir's walls have the structural strength of steel. Thus, gas cannot easily escape the large hollowed-out shape that forms a salt storage cavern.

There are two basic types of salt formations used to store natural domes and beds. Salt domes are very thick salt formations. A salt dome formation might be a mile in diameter, 10,000 m in height, and begin about 500 m below the surface. The depth of the caverns that are hollowed out within the formation is critical for reasons of pressure and structural integrity. The pressure at which the gas can be stored is a function of the depth of the cavern. However, at extreme depths, as temperature and pressure increases, salt behaves as a plastic and will creep or flow, which can become a major consideration in cavern construction possibly leading to cavern closure. Thus, salt storage is generally limited to depths shallower than 2,000 m.

A salt bed storage site, on the other hand, is generally developed from a much thinner salt formation (300 m or less) located at shallower depths. As a result, the height-to-width ratio of the leached cavern is much less than with dome reservoirs, which are relatively high and narrow. Salt bed storage formations also contain much higher amounts of insoluble particles (shale and anhydrite rock) than salt dome formations. These materials remain in the reservoir after the leaching process and affect the flow velocity and capacity of the reservoir itself. In addition, because the height/width aspect is thin, the flatter reservoir ceiling is subject to greater stress and potential wall deterioration. As a result of these as well as other factors, salt bed storage development and operation can be more expensive than that of salt dome storage.

Salt bed or dome storage is prepared by injecting water (leaching) into a salt formation and shaping a cavern. It is the most costly of the three types of facilities to develop, often two to three times more expensive. Because they are susceptible to cavern wall deterioration over time and to salt water incursion, these facilities may incur high workover costs, as well as additional expenses for special equipment on site. However, deliverability rates are high because a salt formation reservoir is essentially a high-pressure storage vessel (that is, an underground tank).

Base gas requirements are low (about 25 percent) and can usually be withdrawn fully in an emergency. On average, salt formation storage is capable of multiple cycling of inventory per year, in comparison to the typical one cycle or less for depleted gas field and aquifer storage. As such, salt formation storage is well suited for meeting large swings in demand.

A salt cavern site occupies a much smaller area than a gas reservoir. On average, the amount of acreage taken up by a depleted gas field reservoir is more than a hundred times the amount of acreage taken up by a salt dome. Consequently, a salt cavern storage operation is generally easier to monitor than a gas field reservoir operation made up of many wells. Development time is also much less for salt formation storage than for gas field reservoirs. Thus, a new saltformation storage site will begin to pay off sooner than a gas field reservoir.

For the same working gas capacity, new salt formation storage reservoirs are also capable of yielding much greater revenues for a heating season than conventional gas field reservoirs. This is because the working gas capacity of a salt formation storage facility can be turned over three, four, or more times during a heating season while generally a gas field operation can be turned over only once.

In summary, although they are the most expensive type of storage to develop and maintain, salt formation storage facilities permit withdrawals at high rates and can be drawn down quickly in emergency situations. As such, salt formation sites are well suited for peaking operations to meet dramatic swings in gas demand.

Using the temperature and consumption data relationship, the demand scenarios could be forecast. The required number of caverns could be estimated according to this forecast.[9]

2.3.3 Underground Gas Storage in the World

Based on the country-based data, a working gas volume of some $340 x 10^9$ m^3 is operated in about 634 existing storage facilities. A withdrawal capacity of some $200.000 x 10^3$ m^3/h is provided by some 23.000 storage wells. A summary of installed capacities and planned capacities in existing and in greenfield storages is given by regions in Table 2.5 [8]. The working gas volume, at reference year 2001, installed in some 634 UGS facilities in the world is presented in the following chart by regions. The greater part of the working gas volume is installed in East Europe/Central Asia and in America. [10]

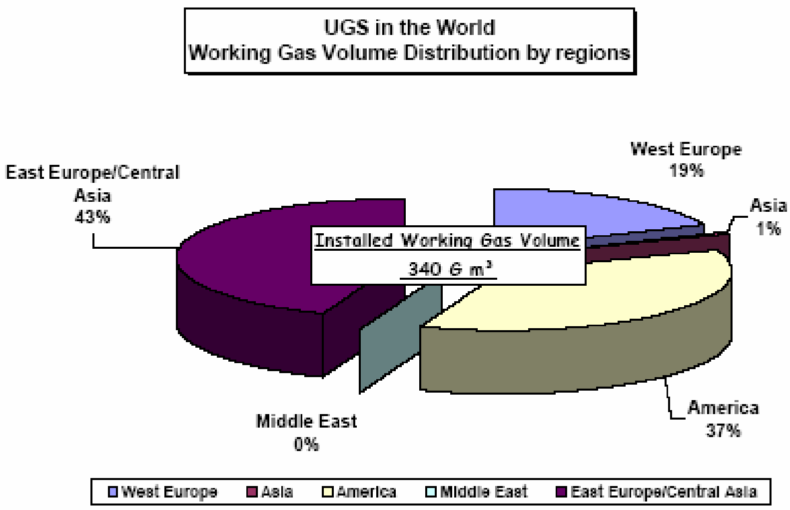

Figure 2.5. Working gas distribution by regions

It is evident from the following chart that the greater part of the working gas volume is installed in UGS facilities in former gas fields (83 %), followed by storage facilities in aquifer structures and caverns. Abandoned mines (0,05 %) and rock caverns (0,02 %) are of no great relevance on a world scale. [10]

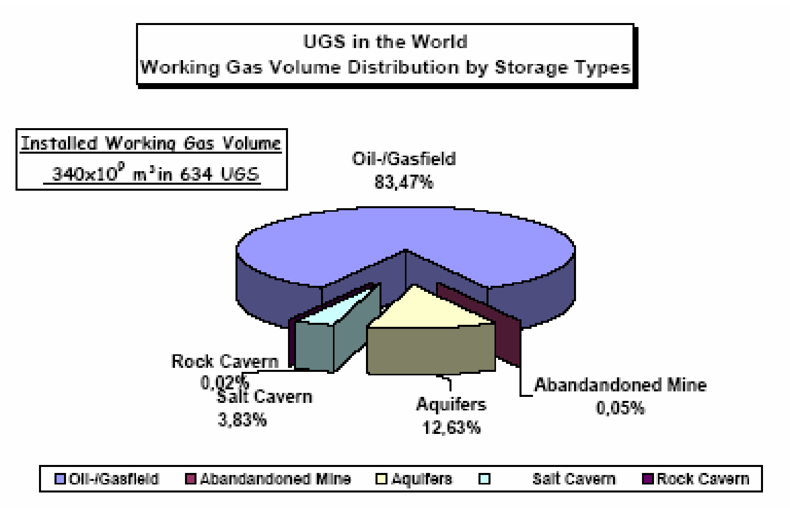

Figure 2.6. Working gas distribution by storage types

The working gas volume capacities of the countries with known underground gas storage facilities in operation, derived from International Gas Union Working Committee 9 (IGU WOC 9) and national information, are listed in Table 2.4. [10]

Table 2.4 Working gas capacities vs. UGS facilities

Nation	Installed Working Gas Volume (10^6 m³)	No. of UGS Facilities
USA	110.485	417
Russia *	90.045	23
Ukraine	34.065	13
Germany	19.772	41
Italy	17.300	10
Canada	14.070	42
France	11.633	15
Netherlands	4.750	3
Uzbekistan	4.600	3
Kazakhstan	4.203	3
Hungary	3.610	5
United Kingdom	3.267	4
Czech Republic	2.801	8
Austria	2.647	4
Slovakia	2.341	4
Latvia	2.105	1
Spain	1.990	2
Poland	1.572	6
Romania	1.470	5
Japan	1.143	6
Azerbaijan	1.080	2
Australia	934	4
Denmark	815	2
Belarus	750	2
Belgium	650	2
China	600	1
Bulgaria	500	1
Croatia	500	1
Armenia	150	1
Ireland	100	1
Argentina	80	1
Kyrgyzstan	60	1
Total	340.087	634

* including long-term reserves

Table 2.5 UGS in the world [10]

Region	UGS Nations	Storage Type	UGS in operation									New Greenfield UGS Projects		Total	
			Installed Cpacities					Planned Projects in existing UGS		Undeveloped Capacities in existing UGS					
			No. of UGS	Cushion Volume	Working Gas Volume	Peak Withdrawal Capacity	İnjection Capacity	Working Gas Volume	Peak Withdrawal Capacity	Working Gas Volume	Peak Withdrawal Capacity	Working Gas Volume	Peak Withdrawal Capacity	Working Gas Volume	Peak Withdrawal Capacity
America		Oil/gas field	383	105.834	108.981	72.449	0	0	0	17.144	0	0	0	126.125	72.449
		Aquifers	40	26.080	11.102	10.200	0	0	0	27.105	0	1.700	0	39.907	10.200
		Salt Cavern	35	1.759	4.490	14.734	0	0	0	1.744	0	0	0	6.234	14.734
		Rock Cavern	0	0	0	0	0	0	0	0	0	0	0	0	0
		Abondened Mine	2	23	63	247	0	0	0	92	0	0	0	155	247
	3	Total	460	133.696	124.636	97.630	0	0	0	46.085	0	1.700	0	172.421	97.630
Asia		Oil/gas field	11	1.155	2.677	1.135	539	0	0	0	0	1.501	0	4.178	1.135
		Aquifers	0	0	0	0	0	0	0	0	0	0	0	0	0
		Salt Cavern	0	0	0	0	0	0	0	0	0	0	0	0	0
		Rock Cavern	0	0	0	0	0	0	0	0	0	0	0	0	0
		Abondened Mine	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	Total	11	1.155	2.677	1.135	539	0	0	0	0	1.501	0	4.178	1.135
East Europe/Central Asia*		Oil/gas field	63	115.562	130.964	39.277	28.464	420	188	24.090	15.722	5.155	2.292	161.629	57.479
		Aquifers	13	21.037	18.328	6.910	4.415	0	0	3.000	2.592	13.200	6.070	34.528	15.572
		Salt Cavern	2	210	500	606	0	0	0	0	0	5.934	7.894	6.434	8.500
		Rock Cavern	1	13	60	250	250	0	0	0	0	0	0	60	250
		Abondened Mine	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	Total	79	136.822	149.852	47.043	33.129	420	188	27.090	18.314	24.289	16.256	202.651	81.801
Middle East		Oil/gas field	0	0	0	0	0	0	0	0	0	3030	646	3030	646
		Aquifers	0	0	0	0	0	0	0	0	0	550	0	550	0
		Salt Cavern	0	0	0	0	0	0	0	0	0	1275	0	1275	0
	0	Total	0	0	0	0	0	0	0	0	0	4855	646	4855	646
West Europe		Oil/gas field	37	76.046	41.262	28.980	14.866	1.759	296	5.776	4.620	5.585	1.451	54.382	35.347
		Aquifers	21	15.956	13.537	8.940	5.320	200	190	680	650	2.410	880	16.827	10.660
		Salt Cavern	24	3.063	8.021	14.004	4.596	2.416	2.395	660	1.000	1.401	900	12.498	18.299
		Rock Cavern	0	0	0	0	0	0	0	0	0	8	0	8	0
		Abondened Mine	2	112	104	92	105	0	0	0	0	0	0	104	92
	10	Total	84	95.177	62.924	52.016	24.887	4.375	2.881	7.116	6.270	9.404	3.231	83.819	64.398
World		O Oil/gas field	494	298.597	283.884	141.841	43.869	2.179	484	47.010	20.342	15.271	4.389	349.344	167.056
		Aquifers	74	63.073	42.967	26.050	9.735	200	190	30.785	3.242	17.860	6.950	91.812	36.432
		Salt Cavern	61	5.032	13.011	29.344	4.596	2.416	2.395	2.404	1.000	8.610	8.794	26.441	41.533
		Rock Cavern	1	13	60	250	250	0	0	0	0	8	0	68	250
		Abondened Mine	4	135	167	339	105	0	0	92	0	0	0	259	339
	32	Total	634	366.850	340.089	197.824	58.555	4.795	3.069	80.291	24.584	41.749	20.133	467.924	245.610

27

2.3.4 Storage Measures

There are several volumetric measures used to quantify the fundamental characteristics of an underground storage facility and the gas contained within it. For some of these measures, it is important to distinguish between the characteristic of a facility such as its capacity, and the characteristic of the gas within the facility such as the actual inventory level. These measures are as follows: [11]

Total gas storage capacity is the maximum volume of gas that can be stored in an underground storage facility by design and is determined by the physical characteristics of the reservoir and installed equipment. [11]

Total gas in storage is the volume of storage in the underground facility at a particular time.

Base gas (or **cushion gas**) is the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. [11] It can constitute up to half of the total amount of gas stored and make up the largest part of the investment of a storage project. Mixing of inert such as nitrogen cushing gas with natıral gas is a way to reduce this investment cost. [12]

Working gas capacity refers to total gas storage capacity minus base gas.

Working gas is the volume of gas in the reservoir above the level of base gas. Working gas is available to the marketplace. [11]

Deliverability is most often expressed as a measure of the amount of gas that can be delivered (withdrawn) from a storage facility on a daily basis. Also referred to as the deliverability rate, withdrawal rate, or withdrawal capacity, deliverability is usually expressed in terms of millions of cubic feet per day (MMcf/day). Occasionally, deliverability is expressed in terms of equivalent heat content of the gas withdrawn from the facility, most often in dekatherms per day (a therm is roughly equivalent to 100 cubic feet of natural gas; a dekatherm is the equivalent of about one thousand cubic feet, or 1 Mcf). The deliverability of a given storage facility is variable, and depends on factors such as the amount of gas in the reservoir at any particular time, the pressure within the reservoir, compression capability available to the reservoir, the configuration and capabilities of surface facilities associated with the reservoir, and other factors. In general, a facility's deliverability rate varies directly with the total amount of gas in the reservoir: it is at its highest when the reservoir is most full and declines as working gas is withdrawn. [11]

Injection capacity (or rate) is the complement of the deliverability or withdrawal rate–it is the amount of gas that can be injected into a storage facility on a daily basis. As with deliverability, injection capacity is usually expressed in MMcf/day, although dekatherms/day is also used. The injection capacity of a storage facility is also variable, and is dependent on factors comparable to those that determine deliverability. By contrast, the injection rate varies inversely with the total amount of gas in storage: it is at its lowest when the reservoir is most full and increases as working gas is withdrawn. [11]

These measures for any given storage facility are not necessarily absolute and are subject to change or interpretation. For example, in practice, a storage facility may be able to exceed certificated total capacity in some circumstances by exceeding certain operational parameters.

Additionally, the distinction between base gas and working gas is to some extent arbitrary; so gaswithin a facility is sometimes reclassified from one category to the other. Further, storage facilities can withdraw base gas for supply to market during times of particularly heavy demand, although by definition, this gas is not intended for that use. [11]

2.3.5 Functions of Natural Gas Storage

UGS has traditionally played three roles in the gas supply system: seasonal and peak supply-demand matching; optimising transport network capacity; and providing security. These traditional system operation functions of gas storage are sometimes reffered to as utility functions. However, in markets having no production or insufficient production, the role of inventory feedstock, which can be compared to production reservoirs, has also been important in those markets. [7]

Gas storage can be used to ensure a match between available supply and demand on cold days. Storage to meet additional demand during cold weather generally takes two forms. One is seasonal storage, which enables delivery of a large volume of gas over an extended period of time to ensure supply-demand matching throughout the winter the other is peak-shaving storage, which makes it possible to deliver gas over a short period of time to cover needle peaks. [7]

Gas storage can be used as an alternative to investment in transport capacity. In economies where there are only a small number of very cold winter days a year and gas has penetrated the space heating market, a large volume of pipeline capacity is needed to meet demand. However, an alternative to this high volume of pipeline capacity is locating peak-shaving storage facilities at the extremities of the pipeline system, reducing the required pipeline capacity. Gas may be injected into storage facilities when demand is low and there is spare capacity of pipelines. And gas can be withdrawn from storage when available gas or pipeline capacity cannot meet demand. This kind of storage capacity also allows the pipeline system to operate at a higher load factor. [7]

Gas supply can be adversely affected by a number of factors, including offshore supply failures, onshore supply failures such as pipeline fractures and compression failures, and demand forecast errors. In this regard, underground gas storage facilities provide strategic supply security in the event of extended supply failures. [7]

There are very important functions of UGS for gas importing markets such as Turkey. Since, the above mentioned interruptions have the chance to be occured in Turkey especially in heavy weathered winter days, it is essential to have a strategical reserves for the days of hard times. These functions can be summarized berifly as follows;

2.3.5.1 Gas balancing

As competitive gas supply markets generally require a certain form of periodical balancing. The imbalance penalties make gas storage a valuable option for gas shippers as it can provide a degree of protection against balancing costs. Typical storage services for this purpose include parking and loaning. [7]

2.3.5.2 Gas trading

Gas storage has become a gas-trading tool as gas commodity markets are developed. Shippers can buy spot gas in summer when it is cheap and can be injected into storage reservoirs and sell it in winter. [7]

2.3.5.3 Mitigating "take-or-pay" constraint

This concept is the worst problem for Turkish natural gas market since in summer the demand is very low and the pipe capacity of the pipelines are limited when compared to the total contracted natural gas amount imported through pipelines. For this reason Turkey had to pay the gas even it is not been used. This excess amount can be injected to pools in summer so that it can be re-produced and used for heating and power purposes in winter.

For this reason, Turkey's needs in underground gas storage facilities are increasing since most of the gas used in Turkey is being imported and the demand for gas also increasing. Today, having UGS facilities have never meant this much importance to Turkey than before.

CHAPTER 3

3. STATEMENT OF THE PROBLEM

In this thesis, a depleted gas reservoir having the potential for being an underground gas storage will be studied. The reservoir data, fluid properties and production data are the first step to be examined. Then, a history match case will be created depending on the data in a code, which will also be used in a commercial reservoir simulator. Production data one of which is original and the other is calculated by the simulator will be compared and until the match will be achieved the code will be revised. After matching finishes, for four conditions, the code will be changed for future predictions and totally 5 scenarios will be made using the simulator. Best configuration for new wells and production and injection cycles will be determined.

CHAPTER 4

4. RESERVOIR DESCRIPTION

The field was discovered in 1988, located about 3 km off the shore. The wildcat was situated 43 m below the sea level. The field initially planned to be developed with 3 wells, but 3 additional wells were added during the development of the field to increase the exploitation of the reservoir. The structure has a regular elongated shape, with the major axis striking from NW to SE, and is bounded by two normal faults at the east and west. The reservoir is a reefal and bioclastic limestone. The top of the reservoir is located 1150 m (3773 ft) deep. The porosity and average water saturation of the reservoir rock are 15 and 10% respectively with an average permeability of 45 md and a thickness of 65 m (213 ft). There is no indication of aquifer support or a gas water contact hence making the field more desirable for conversion to storage. Original pressure of the reservoir was recorded as 2075 psia and the temperature is around 68 °C (155 °F). The caprock is composed of mostly marl and tuff and has a thickness varying from 10 to 60 m (32.8 to 196.8 ft).[13] The fluid properties are given in Table 4.1. Commercial gas production started in 1997. The composition of the produced gas is shown in Table 4.2. The reservoir properties used in this study is summarized in Table 4.3. Figure 4.1 shows the reservoir boundaries with grids used in this study.

Table 4.1 Fluid properties of the reservoir

Fluid Properties	
Specific Gravity	0.6030
Density of Gas	0.1109 lb/ft^3
Density of Water	62.46 lb/ft^3
Viscosity of Gas	0.016 cp
Compressibility of Gas	5.02E-04 1/psi
Compressibility of Water	3.52E-06 1/psi

Table 4.2. Composition of produced gas

Composition of the Field M Gas	
Component	Molecular Fraction, %
C_1	91.45
C_2	3.21
C_3	1.21
i-C_4	0.24
n-C_4	0.30
i-C_5	0.09
n-C_5	0.07
N_2	2.28
CO_2	1.15

Table 4.3. Reservoir Properties

Reservoir Properties Used in Simulator	
Initial Reservoir Pressure	2075 psia
Fracturing Pressure Gradient	0.65 psi/ft
Original Gas in Place	3.10^9 sm^3
Reservoir Temperature	155 ^oF
Wellhead Temperature	85 ^oF
Area of the Reservoir	3.46 km^2
Pay Thickness	213 ft
Wellhead Pressure	1015 psia
Wellbore Radius	0.1875 ft
Porosity	15 %
Permeability In x Direction	45 md
Permeability In y Direction	45 md
Permeability In z Direction	31.5 md
Original Water Saturation	10 %
Rock Compressibility	4.0E-6 1/psi

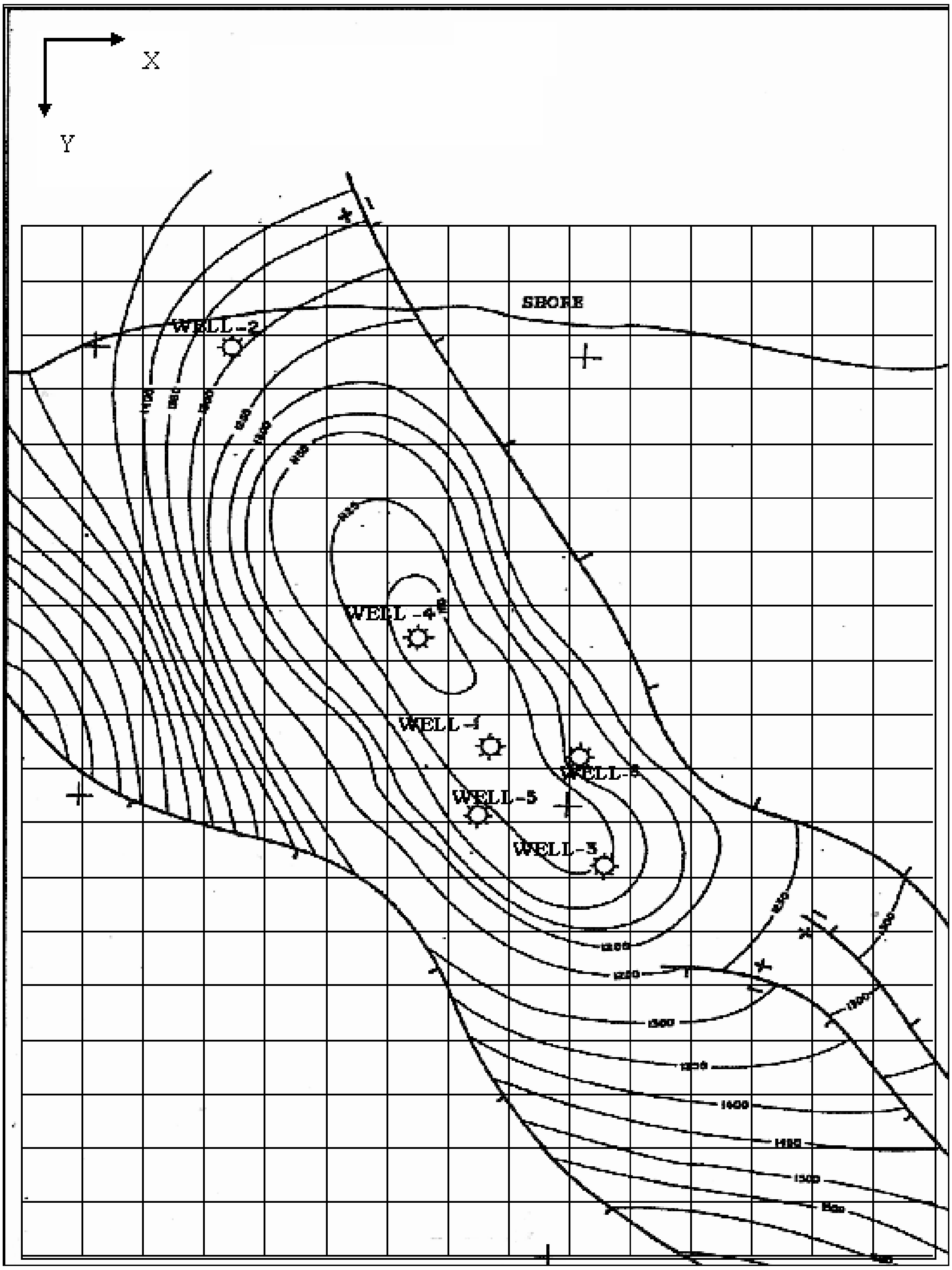

Figure 4.1 Reservoir grid map

CHAPTER 5

5. USE OF COMMERCIAL SOFTWARE

In this study, IMEX Simulator that is the CMG's (Computer Modelling Group) new generation adaptive implicit-explicit black-oil simulator was used to investigate the production and injection performance of depleted gas reservoir. [14]

5.1 Description of Commercial Software

IMEX is a three-phase black-oil simulator with gravity and capillary terms. Grid systems may be cartesian, cylindrical or variable depth/variable thickness. Two-dimensional and three-dimensional configurations are possible with any of these grid systems. IMEX was developed to simulate primary depletion, coning, water, gas, solvent and polymer injection in single and double porosity reservoirs.

IMEX uses the data set that you create initially and then creates three or four other files. Each IMEX run creates an output-file (OUT), an index-results-file (IRF) and a main-results-file (MRF). In addition a rewindable-results-file (RRF) may or may not be created depending on the options selected by the user.

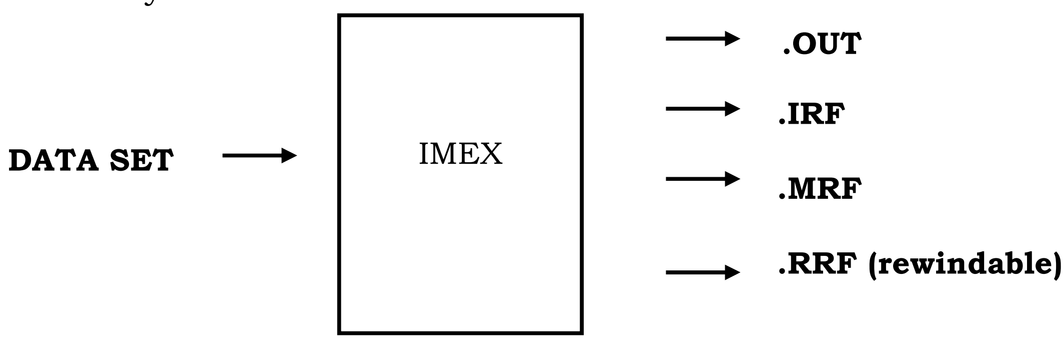

Figure. 5.1. Execution of IMEX

If a restart run is desired, then several existing files are needed and another three are generated. This is illustrated in the diagram:

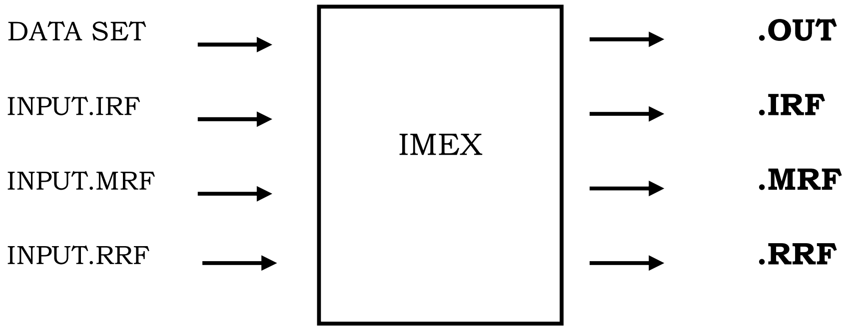

Figure. 5.2. Execution of IMEX (restart)

5.2. Data Groups in the Keyword Input System

There are several points to remember when a data set is built using keyword input system:

a) There are several diffirent data groups in the keyword input system

b) The groups must follow a certain input order:

- I/O Control
- Reservoir Description
- Component Properties
- Rock-fluid Data
- Initial Conditions
- Numerical Methods Control
- Well Data and Recurrent Data

c) The keywords belonging to each group cannot appear in pther groups, unless it is specifically written. Usually, this happens with recurrent data from other sections, which may be changed in the Well Data section.

d) Also, the order of some keywords, within a group, is important.

5.3 Model Description & Model Data Preparation

5.3.1. Input & Output Control Section

*TITLE1 is used for Project identification. This keyword must appear in the I/O Control keyword group, at the start of the input data file. *TITLE2 and *TITLE3 is used for Project identification, to provide second and third line for Project identification.

***TITLE1 'UNDERGROUND GAS STORAGE PERFORMANCE'**

***TITLE2 'GAS-WATER,2-PHASE'**

***TITLE3 'GAS CYCLING'**

*INUNIT specifies the input data units.

*FIELD specifies FIELD units for input data

***INUNIT *FIELD**

*WRST controls the frequency of writing restart records to the index-results-file and to either the main-results-file or the rewindable-results-file.

*WPRN controls the frequency of writing data to the output file.

*WELL *TIME writes well results to the output-file at every time specified by subsequent recurrent *TIME or *DATE keywords in the input-data-file.

*GRID *TIME writes grid results to the output file at every time specified by subsequent recurrent *TIME or *DATE keywords in the input data file.

*OUTPRN identifies what information is written to the output-file

*WELL specifies that well results will be written to the output-file.

*LAYER writes a summary of layer variables at surface conditions to the output-file.

*GRID specifies that grid results will be written to the output-file.

*IMEXMAP, Implıcıt/Explicit Block Map.

*SG, Gas saturation

*SW, Water saturation

*PRES, Pressure

*WSRF controls the writing of well and/or grid information to the index-results-file and the main-results-file (the SR2 file system).

*WELL *TIME writes well results to the SR2 file system at every time specified by subsequent recurrent *TIME or *DATE keywords in the input-data-file.

*GRID *TIME writes grid results to the SR2 file system at every time specified by subsequent recurrent *TIME or *DATE keywords in the input-data-file.

*OUTSRF identifies what information is written to the index-results-file and the main-results-file (the SR2 file system).

*GRID specifies that grid results will be written to the SR2 file system.

*OUTDIARY controls some of the information written to the output-diary-file.

*PRESAQ specifies that the total pore volume average pressure, including the aquifer blocks, will be written to the output-diary-file.

*HEADER writes the table header to the output-diary-file every freq time steps.

***INUNIT *FIELD**

***WRST *TIME**

***WPRN *WELL *TIME**

***WPRN *GRID *TIME**

***OUTPRN *WELL *LAYER**

***OUTPRN *GRID *IMEXMAP *SG *SW *PRES**

***WSRF *WELL *TIME**

***WSRF   *GRID *TIME**

***OUTSRF   *GRID *IMEXMAP *SG   *SW *PRES**

***OUTDIARY   *PRESAQ *HEADER 20**

5.3.2. Reservoir Description Section

A grid block is taken like a rectangular prism having the dimensions of 450x450x66 foot and 450x450x116 foot as shown in Figure 5.3.

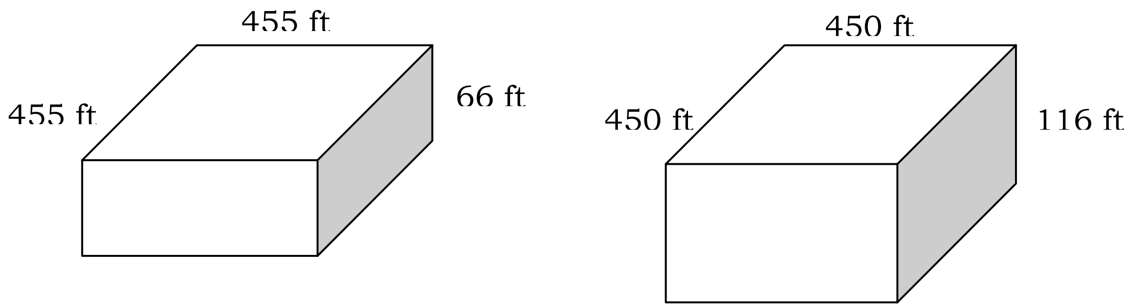

Figure 5.3. Schematic view of grid blocks

The keyword *GRID indicates the grid type and the number of grid blocks within the fundamental grid system. This keyword should be the first keyword in reservoir description keyword group.

The *GRID keyword defines a grid consisting of ni, nj, nk blocks. The blocks are rectangular in shape for cartesian system;

I, J, and K indices are used to identify the blocks, where I runs in the range of 1 to ni, j runs in the range of 1 to nj and k runs in the range of 1 to nk. The rotation (i, j, k) are sometimes be used to denote a block. Blocks are ordered with I increasing fastest, J next fast and K slowest.

For variable depth/variable thickness grids, I corresponds to the 2x2 direction, J to the 'y' direction and K to the 'z' direction, where 'x', 'y', 'z' refer to a standard coordinate system in the reservoir.

***GRID *VARI 15 19 3**

The keywords *DI, *DJ, *DK are required keywords.

*DI signals input of an array of grid block lengths for the I directions. The values are block widths measured in the I direction.

This keyword must be in the reservoir description keywrod group. If all the grid increments for a cartesian grid is same, then subkeyword *CON is used.

***DI *CON 450**

*DJ signals input an array of grid block lengths for the J direction. The values are block widths measured in the J direction.

This keyword must be in the reservoir description keywrod group. If all the grid increments for a cartesian grid is same, then subkeyword *CON is used.

***DJ *CON 450**

*DK signals input an array of grid block lengths for the K direction. The values are block widths measured in the K direction.

This keyword must be in the reservoir description keywrod group. If all the grid increments for a cartesian grid is same, then subkeyword

*CON is used. Oherwise *KVAR is used to indicate values that vary in the K direction, but which are constant in the other two directions.

***DK *KVAR 66 66 116**

*DTOP indicates input of a number of depths that provide the depth to the center of the top face of each grid block in the top layer of the grid. A total ni x nj depth must be entered. The values are to be measured downwards from a horizontal reference surface to the centre of the tops of the grid blocks in the upper-most layer. The values are to be entered roe by row with the I index changing fastest and the J index slowest.

*DTOP 4593.2 4593.2 4839.2 4511.2 4429.1

*NULL indicates the input of an array of null block indicators which can be used to mark individual porosities as non-participating in dual porosity models, or entire blocks as non-participating.

***NULL *IJK**
1:2 1:1 1:3 0

*POR indicates input of porosities, where zero values can be used to mark individual porosities as null (non-participating) in dual porosity models, or entire blocks as null.

Here the prosities of the grid blocks are given layer by layer showing homogenity within grids but heterogenity through the field. All the porosity values are written in array scheme.

***POR**
0.12005 0.12005 0.16015 0.16015 0.16015

*PERMI indicates input of an array of I direction permebilities.

*PERMJ indicates input of an array of J direction permebilities.

*PERMK indicates input of an array of K direction permebilities.

*EQUALSI indicates that values in the J and K directions are the same as those in the I direction, or that the values given for the I direction may be modified by division.

***PERMI 14 14 14 14**
***PERMJ *EQUALSI**
***PERMK *EQUALSI *0.7**

*CPOR signals the input of a rock compressibility value that will be used throughout the entire model.

***CPOR** $\mathbf{4x10^{-6}}$

*PRPOR signals the input of a reference pressure for the rock compressibility. This pressure is the fluid (pore) pressure at which the values input using *POR are to hold.

***PRPOR 2100**

5.3.3. Component Property Section

*MODEL signals the input of the fluid component model to use for the simulation.

*GASWATER is a two-phase gas and water model, with no oil phase modeling only two are solved for simultaneously. Gas PVT properties are entered using *PVTG keyword.

*BG indicates that the gas formation volume factor will be used instead of the gas expansion factor.

After the above mentiones keywords, gas formation (B_g, RB/Scf) and gas viscosity (Vis_g, cp) data is entered in Table 5.1.

The calculation of P vs B_g and μ_g is in Appendix A.

***MODEL *GASWATER**

***PVTG *BG 1**

Table 5.1. Pressure vs B_g and μ_g data

P	B_g	μ_g
psi	RB/Scf	cp
14.7	0.19844	0.01204
50.0	0.05812	0.01206
100.0	0.02891	0.01211
200.0	0.01430	0.01221
400.0	0.00700	0.01246
700.0	0.00388	0.01295
1000.0	0.00264	0.01356
1300.0	0.00198	0.01428
1600.0	0.00158	0.01512
1827.0	0.00137	0.01582
2000.0	0.00124	0.01640
2250.0	0.00110	0.01727

Then, densities will be read in the same order that the PVT tables were specified.

Density of the gas is taken as 0.1109 lbm/ft^3

Density of the water is taken as 62.46 lbm/ft^3

*BWI indicates the input of the water formation volume factor which is taken as 0.5 RB/STB.

*CW indivates the input of the water compressibility which is taken as 3.5 E-6 1/psi.

*REFPW indicates the input of the reference pressure which is taken as 2075 psi.

*VWI signals the input of the water viscosity. Viscosity of water phase at the reference pressure is 1.0 cp.

*CVW keyword indicates the input of pressure dependence water viscosity which is 0.0 cp by default.

```
*DENSITY *GAS     0.1109
*DENSITY *WATER  62.46
*BWI              0.5
*CW             3.58E-6
*REFPW           2075.0
*VWI              1.0
*CVW              0.0
```

5.3.4. Rock Fluid Property Section

*ROCKFLUID indicates the start of the rock fluid data.

This keyword must be the first keyword in the Rock Fluid Data keyword group.

*RPT indicates that a set of relative permeability curves will be defined by table entries.

*RPT set_number

*SWT indicates the start of the water saturation and relative permeability to water table. The data is given in Table 5.2.

Table 5.2. Water saturation vs relative permeability to water data

S_{w}, %	K_{rw}, %
0.1	0.0
0.2	0.001371742
0.3	0.010973937
0.4	0.037037037
0.5	0.087791495
0.6	0.171467764
0.7	0.296296296
0.8	0.470507545
0.9	0.702331962
1.0	1.0

*SGT indicates the start of gas saturation and relative permeability to gas table. The data is given in Table 5.3.

Table 5.3. Gas saturation vs relative permebility to gas data

S_{g}, %	K_{rg}, %
0.0	0.0
0.1	0.039458497
0.2	0.110825515
0.3	0.20206671
0.4	0.308559693
0.5	0.427363331
0.6	0.55620369
0.7	0.6930621
0.8	0.835995131
0.9	0.96

5.3.5. Initial Conditions Section

*INITIAL indicates the beginning of initial condition values.

This keyword must be the first keywrod in the initial conditions. To initialise the reservoir.

*VERTICAL *DEPTH_AVE *WATER_GAS is used.

Gravity initialisation for a reservoir in which all of the hydrocarbon fluid is initially in the gas phase with saturation averaged over the depth interval covered by a grid block. In this approach, if a grid block has its block center slightly below the water gas contact depth, the water saturation assigned to the block is the average over the block volume of the local water and not simply the water saturation value in the water zone.

For this option, the water gas contact depth, together with a reference pressure and a reference depth must be specified.

*VERTICAL indicates that pressure are determined from the hydrostatic equation and saturations from the capillary pressure tables.

*DEPTH_AVE is the Sub-option of *VERTICAL. It assigns block saturations as averages over the depth interval spanned by the grid block.

*WATER_GAS perform gravity capillary equilibrium initialisation for reservoirs with only water and gas pheses initially present.

Under VERTICAL DEPTH_AVE WATER_GAS, the water-gas contact depth (*DWGC) together with a reference pressure (*REFPRES) of a reference depth (*REFDEPTH) must be specified.

*REFDEPTH is measured from correlation of contour lines of the top of reservoir contour map .

*REFPRES is the hyrdostatic pressure of reference depth.

***INITIAL**

***VERTICAL *DEPTH_AVE *WATER_GAS**

***REFDEPTH 5565.5**

***REFPRES 2075.0**

***DWGC 5700.0**

5.3.6. Numerical Control Section

*NUMERICAL identifies the beginning of all numerical methods control keywords. The numerical control methods control keyword group follows the initial conditions keyword group in the data file.

*DTMAX identifies the maximum time step size.

*NCUTS controls the number of time-step size cuts allowed in a single timestep.

***NUMERICAL**

***DTMAX 30.0**

***NCUTS 4**

5.3.7. Well and Recurrent Data Section

Input data of program is in Appendix C.

*RUN identifies the beginning of all well and recurrent data keywords.

The well and Recurrent Data keyword group follows the Numerical keyword group in the data file. It is the last keyword group in the input data file.

*DATE keyword indicates a new well change time. Any well keyword that appears between two *DATE cards will be applied between the times indicated. The first well change must be *DATE keyword indicating the starting date of the simulation. Well names are entered via the keyword *WELL. Wellbore geometries can be entered using *GEOMETRY keyword and *PERF indicates the grid blocks where the well is perforated.

The type of well is described by the keywords *PRODUCER or *INJECTOR.

In this data program, wellbore model is used for both producers and injectors and indicated by *PWELLBORE keyword. Also, *MODEL indicates the wellbore hydraulic pressure loss for single phase gas producers will be calculated by using the friction factor correlation and the equation of state. In the subkeyword group, welldepth, well length, relative well roughness, wellhead temperature, bottomhole temperature, well radius and the composition of the produced or injected gas are given respectively.

*OPERATE defines the well operating constraints, and the remedial action to be taken when a constraint is violated. *MAX and *MIN subkeywords specifies the specified values are maximum or minimum.

*STG identifies a surface gas rate constraint. *BHP identifies a bottom hole pressure constraint.

*GEOMETRY specifies the well geometric characterisitcs to be used by the simulator to calculate the well index internally. To specify the wellbore axis, *K is used as a subkeyword. Well radius, geometric factor for the well element, fraction of a circle that the well models and skin factor data can be given after *K subkeyword in tabular form respectively.

*PERF specifies the location of the well completion grid blocks.

*GEO indicates that well indices of layers are to be calculated from the geometric information on the last *GEOMETRY keyword and from the dimensions and permeability of the grid block in which the completion occurs.

*ALTER allows modification of only the primary operating constraint value the well(s) whose names or numbers are listed. The primary operating constraint is the first constraint entered for the well using *OPERATE keyword. To apply the alteration of the primary operating constraint, any number of well names given in quotes must be entered.

*TARGET allows modification of any previously specified well constraint value or the specification of a new constraint type and value for well(s) listed by well numbers.

*STOP causes simulation to terminate. This keyword must be located in the Well and Recurrent Data keyword group.

CHAPTER 6

6. HISTORY MATCHING

The main idea behind the history matching in this project is to compare the production and pressure results obtained from the simulator and the real field production and pressure characteristics of the reservoir using the gathered data input to the simulator file between the years of 1998 and 2002.

The field was started production in 1997 with 3 wells and then was developed and 3 wells were drilled additionally. Totally, 5 wells had been used in production until the year 2002, January with a satisfactory amount of gas left as a cushion. The aim of history matching is to adapt the original field data to the commercial simulator and have the runs as far as the calculated results obtained from the program matches or approaches the real field data. For this purpose the real data had been entered into program input data and ran until satisfactory match achieved. The actual production data is given in Appendix B. Depending on the real data several runs had been made and necessary changes had been made to reservoir characteristics. Originally reservoir porosity has taken as 15% but as long as the data run trials had started, there seemed to be a necessity of having grid based porosity distribution and finally the following distribution of porosity, which is shown in Table 6.1, have been had for all layers of the reservoir.

Table 6.1 Final porosity distribution for each layer

Grid No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	0.12	0.12	0.16	0.16	0.16	0.16	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
2	0.12	0.12	0.20	0.20	0.20	0.16	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
3	0.13	0.16	0.20	0.20	0.20	0.16	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
4	0.14	0.16	0.20	0.20	0.20	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
5	0.14	0.14	0.20	0.20	0.20	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
6	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
7	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.16
8	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.16
9	0.17	0.17	0.17	0.17	0.17	0.20	0.20	0.20	0.20	0.20	0.17	0.17	0.17	0.17	0.17
10	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
11	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
12	0.17	0.17	0.17	0.17	0.17	0.17	0.20	0.20	0.20	0.20	0.20	0.17	0.17	0.17	0.17
13	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16
14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
17	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
18	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
19	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12

The latter procedure was applied to the horizontal and vertical permeability data, which are originally 45 md and 31.5 md respectively, of the reservoir and finally the following permeability distribution, which is shown in Table 6.2, is obtained for horizontal and vertical permeability values. Vertical permeability distribution is assumed to be 70% of the horizontal permeability values.

Table 6.2 Final permeability distribution for each layer

Grid No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
2	14	20	20	20	20	20	20	20	14	14	14	14	14	14	14
3	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
4	35	35	35	35	35	35	42	42	42	42	42	42	42	39.2	35
5	39.2	42	42	42	42	42	42	42	42	42	42	42	42	40.6	35
6	39.2	42	35	35	35	42	42	42	42	42	42	42	42	39.2	35
7	39.2	42	35	26.6	35	42	42	42	42	42	42	42	42	37.8	35
8	39.2	42	35	35	35	42	39.2	39.2	42	42	42	42	42	36.4	35
9	35	42	42	35	35	35	35	35	42	42	42	42	42	39.2	35
10	28	28	28	28	22.4	26.6	25.2	26.6	28	28	28	28	28	28	28
11	14	14	14	14	20	18	16	20	20	20	20	14	14	14	14
12	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
13	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
15	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
16	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
17	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
18	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
19	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14

After the re-definition of the reservoir properties, gas saturation and pressure distribution, average reservoir pressure, wellhead pressure and cumulative production data obtained from the best run is compared with the original data in well and field base. The gas saturation and pressure distribution of the reservoir at the beginning and end of the production history are given in Figures 6.1, 6.2, 6.3 and 6.4. Actual gas production and average reservoir pressure data are plotted in the following Figures 6.5 and 6.6 respectively. Since there is no active aquifer, water production can not be mentioned.

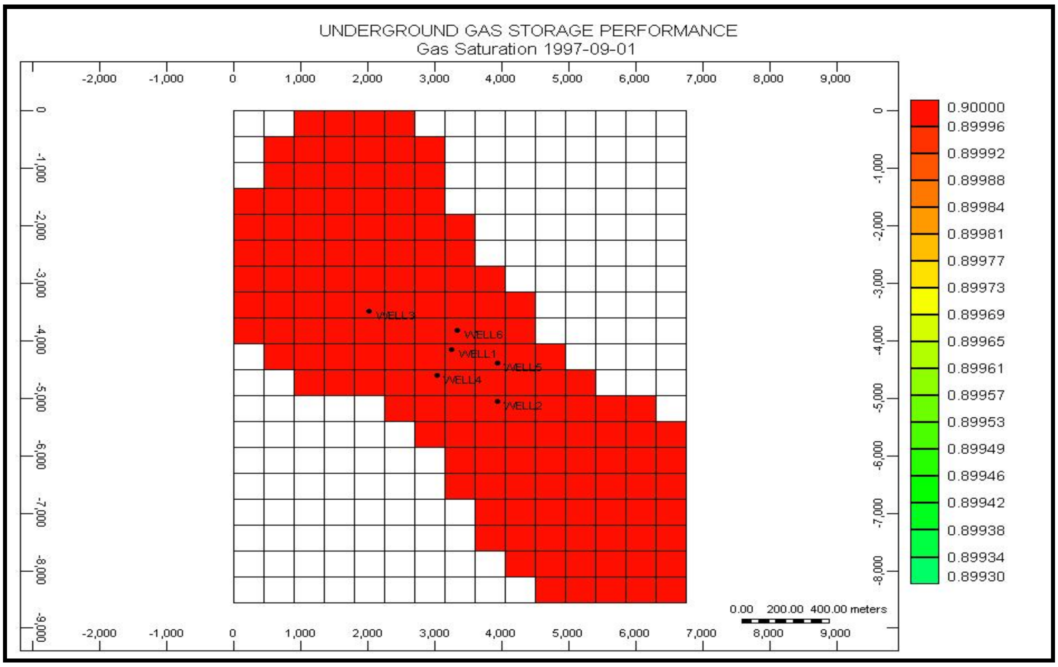

Figure 6.1 Gas saturation distribution in 1997

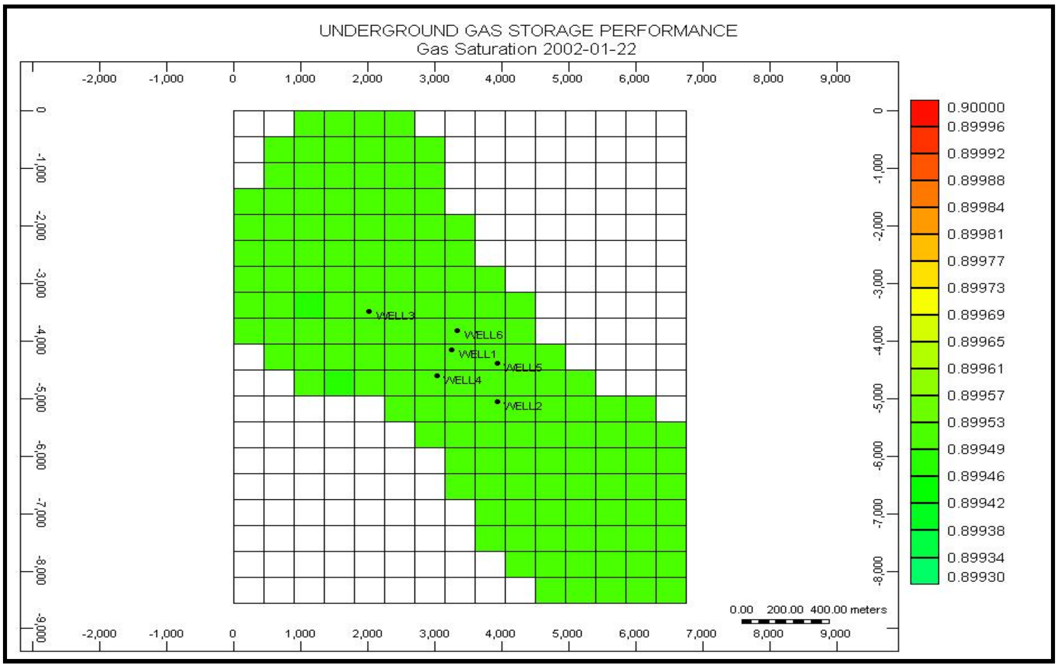

Figure 6.2 Gas saturation distribution after depletion in 2002

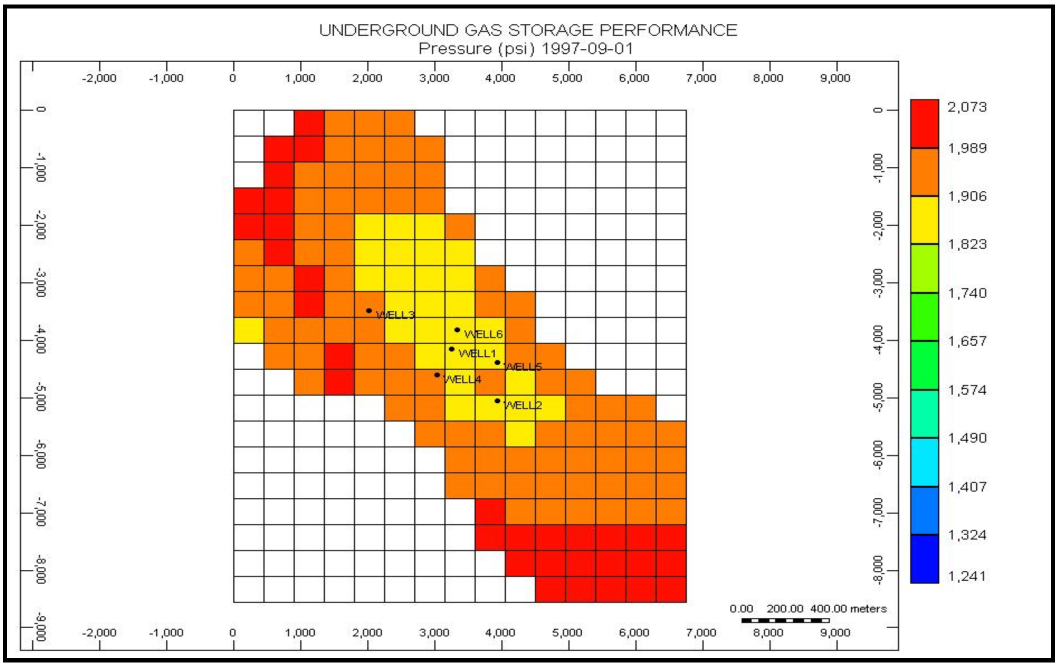

Figure 6.3 Pressure distribution in 1997

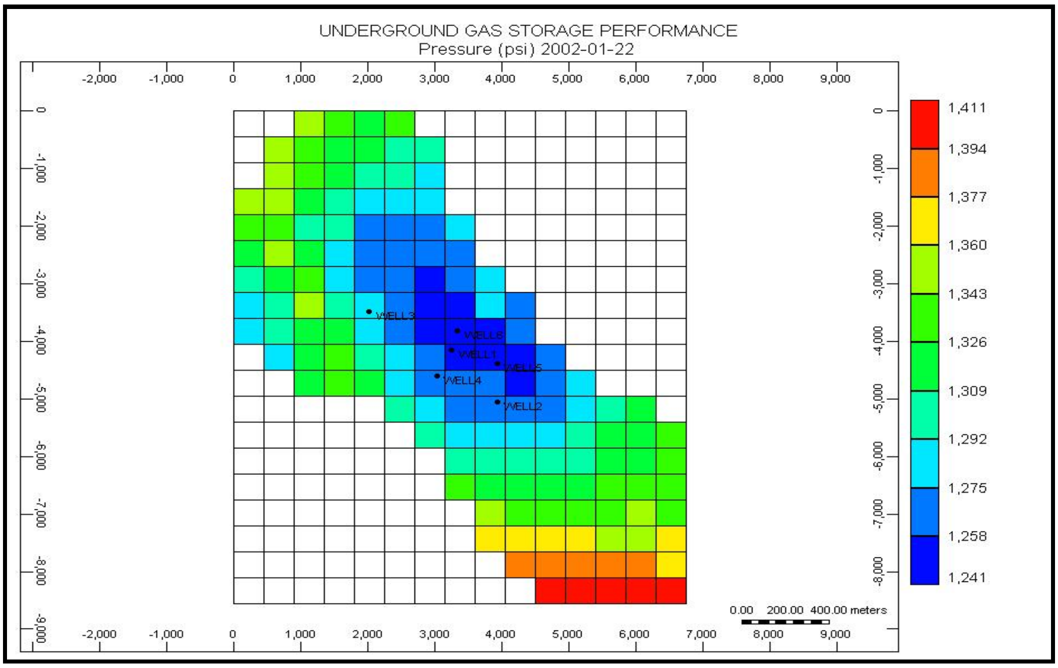

Figure 6.4 Pressure distribution after depletion in 2002

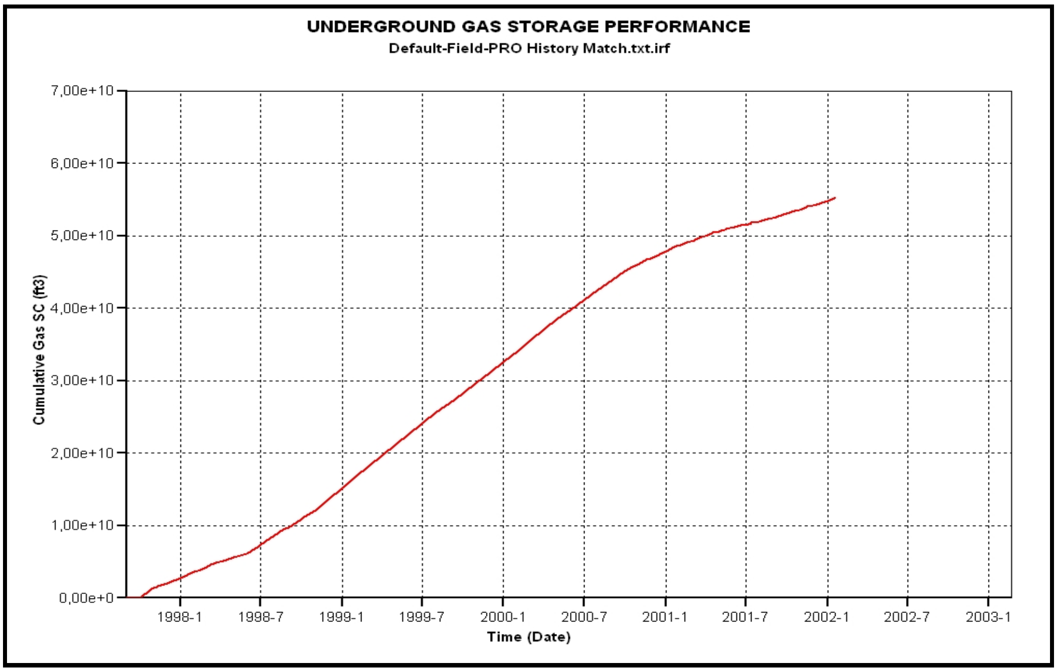

Figure 6.5 Cumulative gas production between 1997-2002

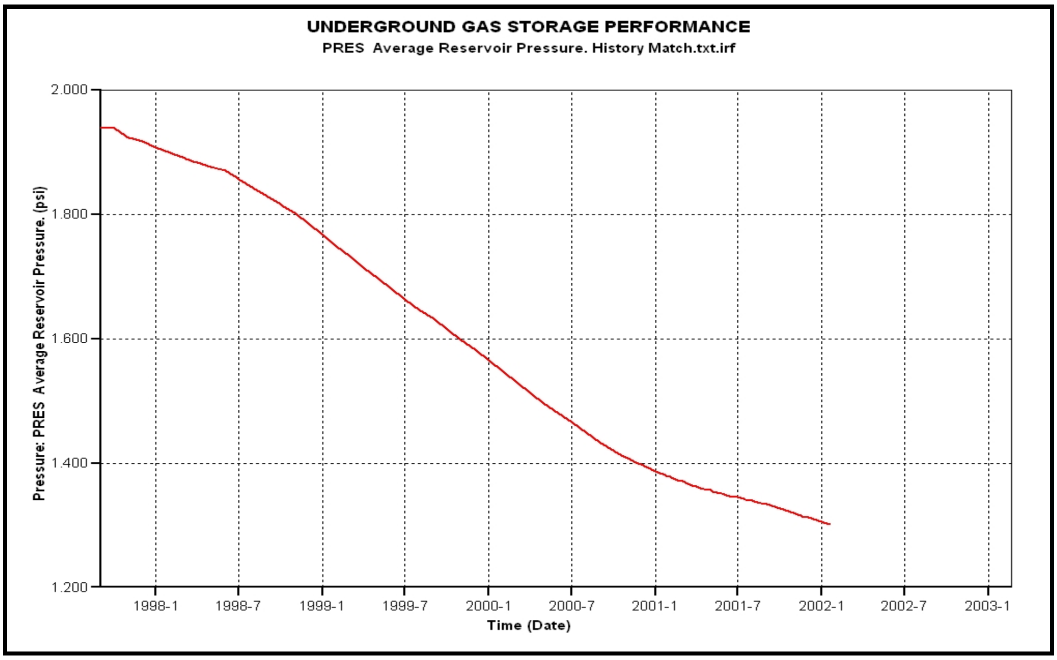

Figure 6.6 Average reservoir pressure between 1997-2002

After having calculated the average reservoir pressure, the measured values of average reservoir pressure data is compared and from the Figure 6.7 below shows the efficiency of the software to simulate the field during exploitation of the reservoir. It can be understood from the trend of the two lines that there is a good similarity between the measured and calculated values of average reservoir pressure of the Field M, thus the history matching procedure could be paused for comparison of other properties of the field..

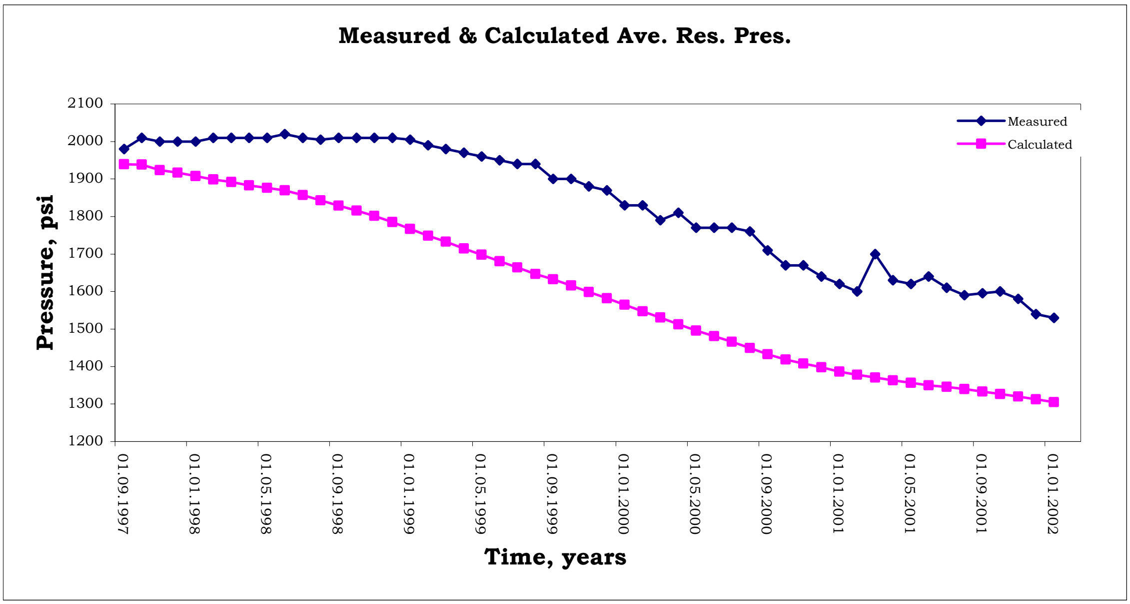

Figure 6.7 Comparison of calculated and measured Average Reservoir pressure of the field

For future prediction, first history of the reservoir production should be simulated and the calculated values of production and pressure data should be matched with measured data. The gathered data of the reservoir and production was adapted to the data input file of IMEX Simulator. Since the reservoir is heterogeneous and the commercial simulator software depends and constructed on the mathematical modelling, and assuming homogenity at least within the grid blocks, the input of real data could not end with perfect match of reservoir history. Thus, to match with the measured values, some data inputs like porosity and permeability of the grid blocks was changed slightly and simultaneously the data file was run.

After several runs, the calculated values of production and pressure data approached and matched with the actual production history data. The results of history matching are shown in the following figures well by well and for the field.

If the calculated wellhead pressure data is compared with the measured data, one can see distinct similarity of the values throughout the depletion period.The following Figures 6.8, 6.9, 6.10, 6.11 and 6.12 summarizes the latter situation for all wells.

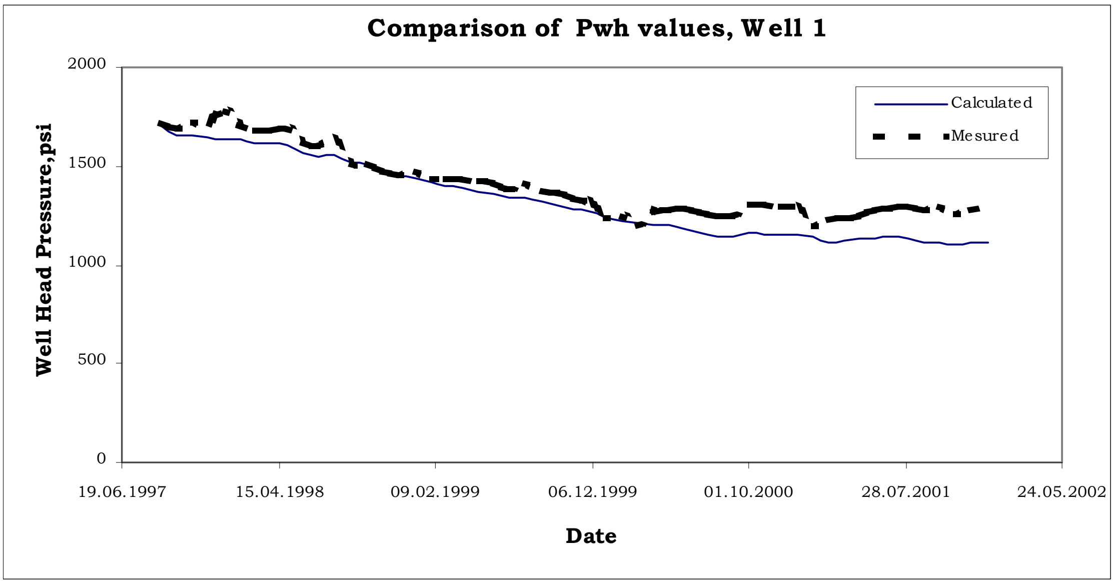

Figure 6.8 The comparison of calculated and measured wellhead pressure values for Well 1

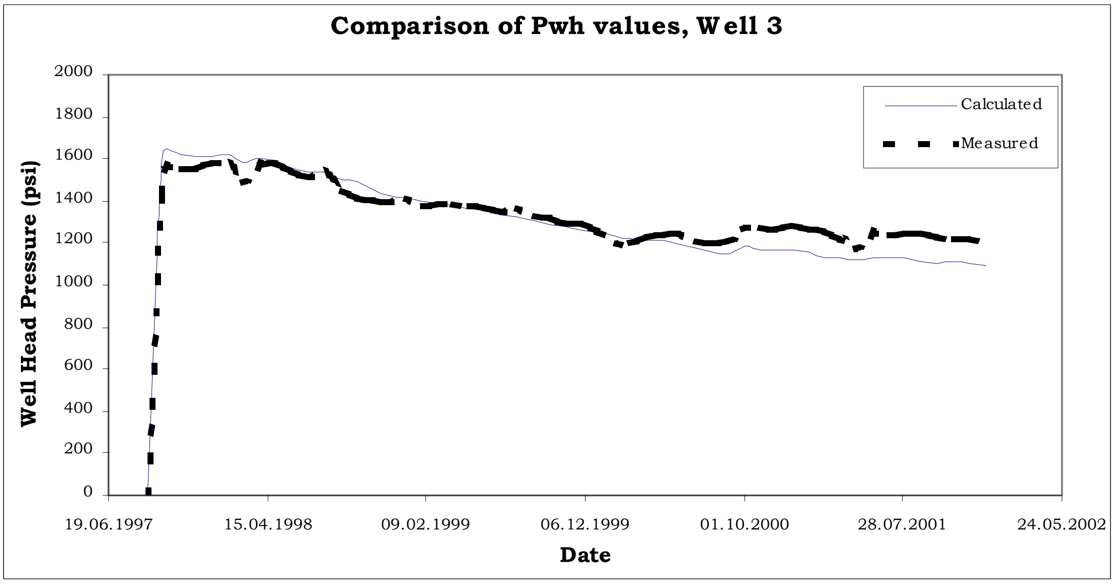

Figure 6.9 The comparison of calculated and measured wellhead pressure values for Well 3

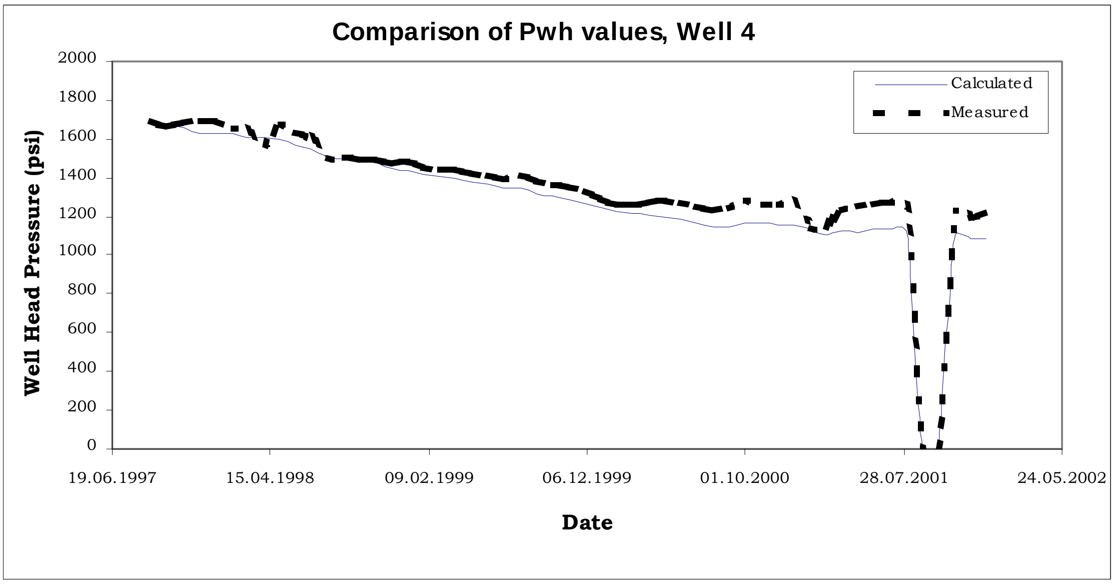

Figure 6.10 The comparison of calculated and measured wellhead pressure values for Well 4

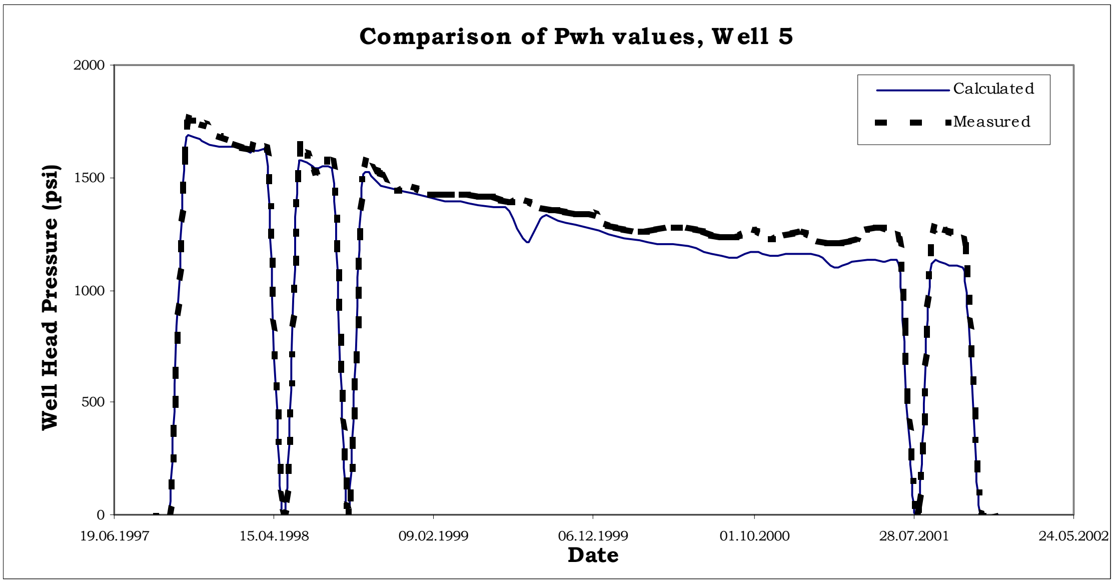

Figure 6.11 The comparison of calculated and measured wellhead pressure values for Well 5

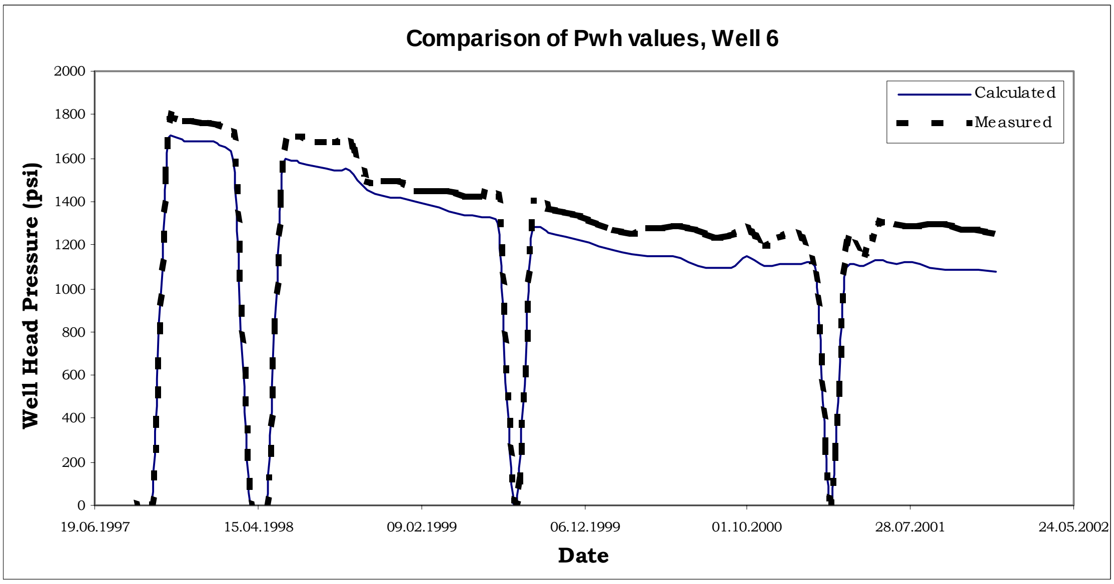

Figure 6.12 The comparison of calculated and measured wellhead pressure values for Well 6

The criteria used for the matching of the calculated and measured wellhead pressure values is selected as RMSE [15] (Root Mean Square Error) which is given in Appendix D with data of calculated and measured wellhead pressures. Final matches are selected through the runs having least RMSE which is shown in Table 6.3.

Table 6.3 P_{wh} matching

Wells	**RMSE, psi**
Well 1	84
Well 3	56
Well 4	67
Well 5	61
Well 6	108
Average	75

There is a good similarity between the measured and calculated values of cumulative gas production and average reservoir pressure which can be seen from the comparison shown in Figures 6.13, 6.14, 6.15, 6.16, 6.17 and 6.18.

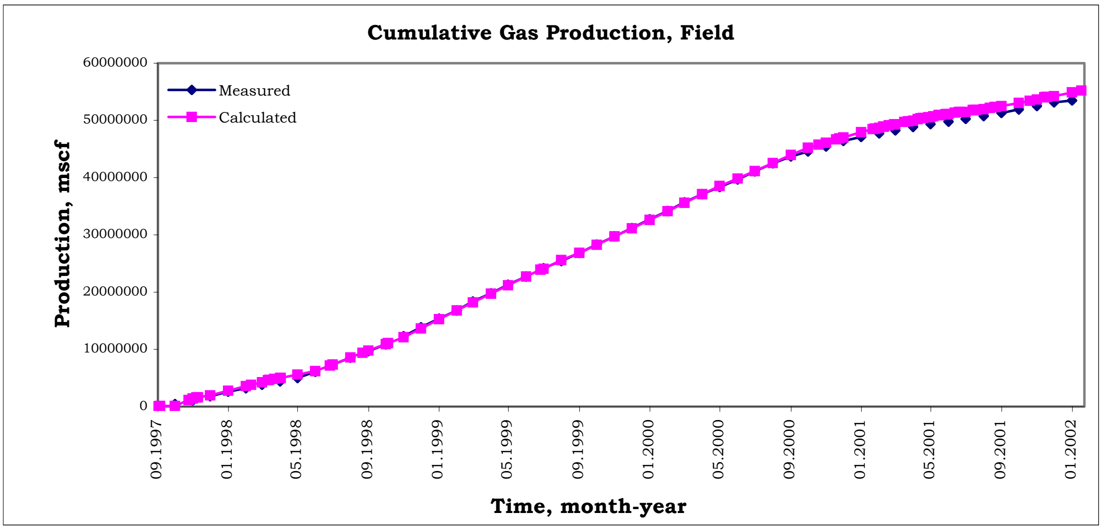

Figure 6.13 Comparison of cumulative gas production of the Field

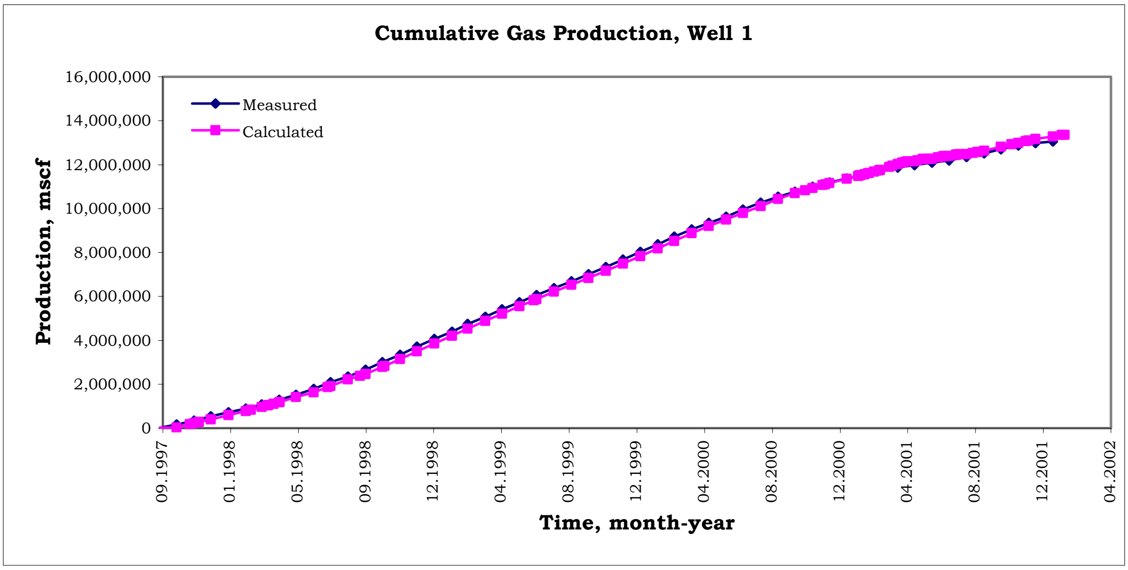

Figure 6.14 Comparison of cumulative gas production of Well 1

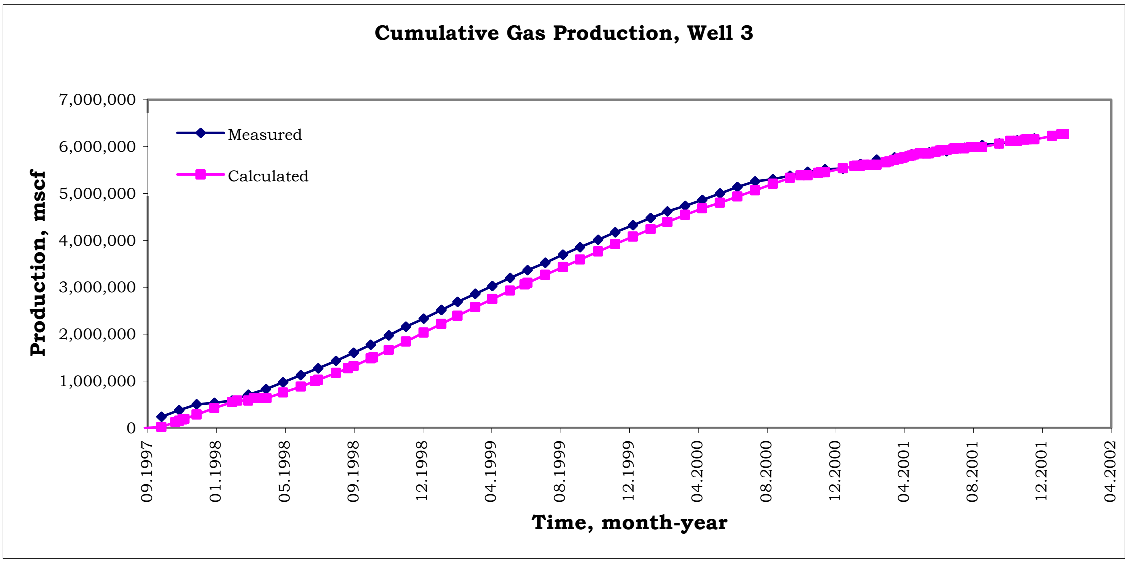

Figure 6.15 Comparison of cumulative gas production of Well 3

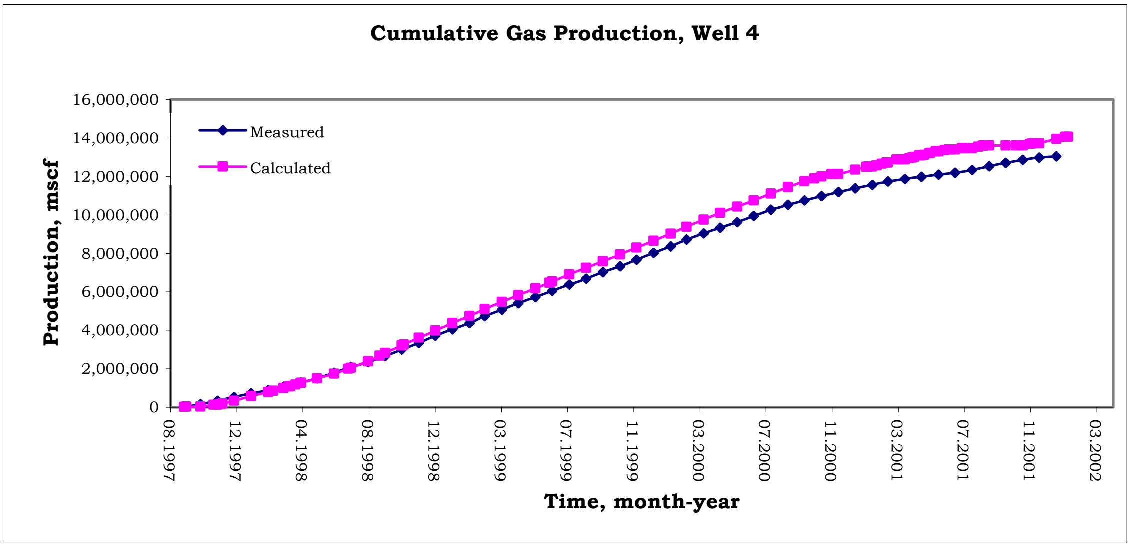

Figure 6.16 Comparison of cumulative gas production of Well 4

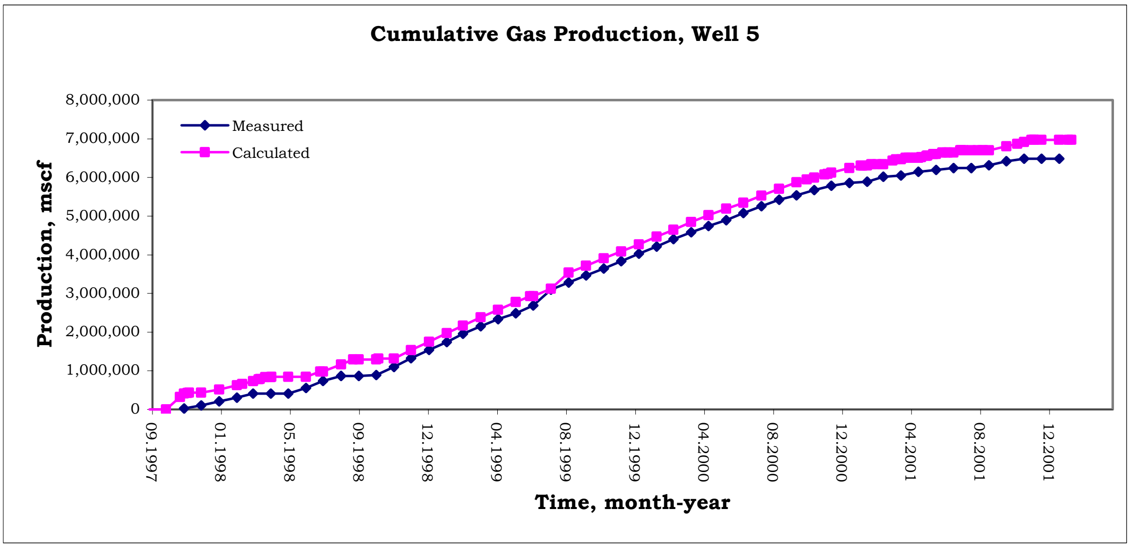

Figure 6.17 Comparison of cumulative gas production of Well 5

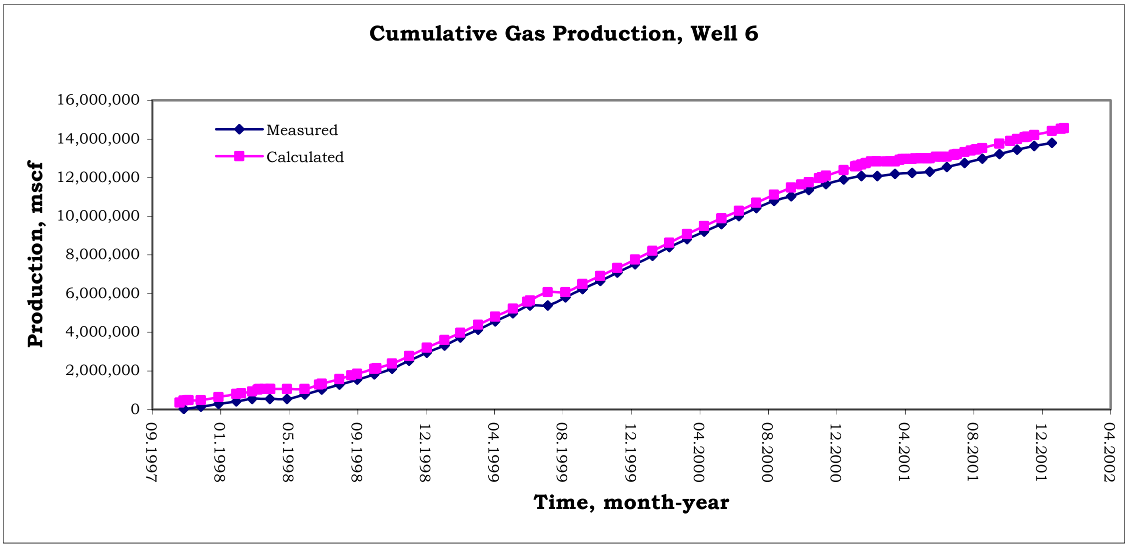

Figure 6.18 Comparison of cumulative gas production of Well 6

Although there is no active aquifer, water production was seen in the measured data of the field. The original value of cumulative water production is 21,712 bbl. From the simulator since no active aquifer was defined, water production did not occured. Using Katz's Chart [16] showing the water content of natural gas in equilibrium with liquid water, in which reservoir temperature and pressure values are entered to find the water content in lb/MMcf. The Figure 6.19 is showing the comparison of measured and calculated values of cumulative water production. Makete Chart and the table including the obtained values of produced water from natural gas is given in Appendix E.

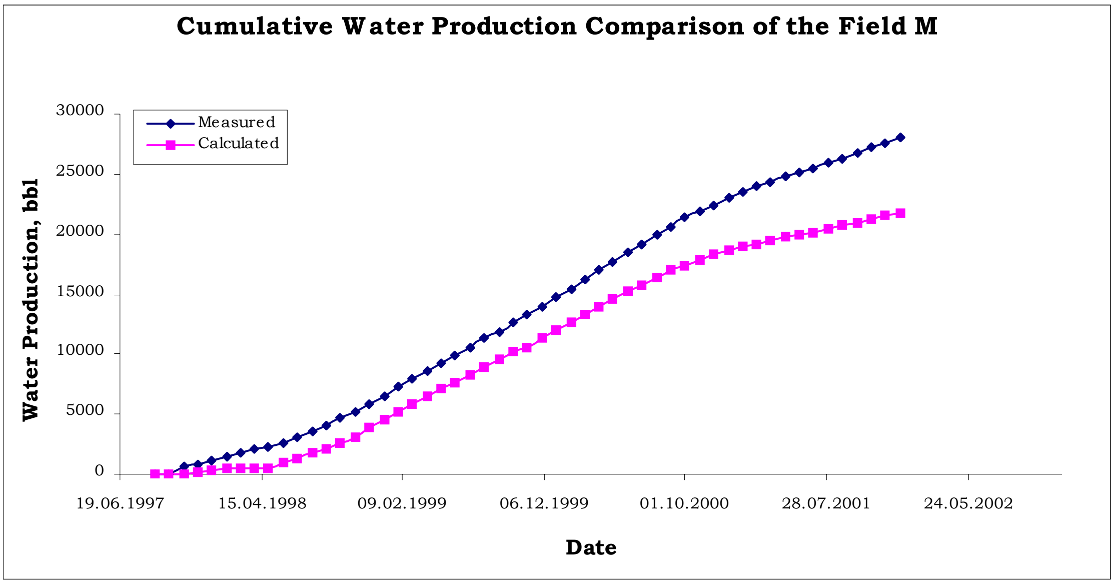

Figure 6.19 Comparison of cumulative water production of Field M

The comparison of the results obtained from the history matching with the original field data is briefly summarised in the following Table 6.4 with respect to well based cumulative gas production and average well head pressure data.

Table 6.4 General comparison of the measured and calculated cumulative gas production and average Pwh data

Well No.	Cum. Gas Prod., BCF		Average P_{wh}, psi	
	Measured	**Calculated**	**Measured**	**Calculated**
Well 1	13,30	13,10	1412	1329
Well 3	6,27	6,17	1346	1323
Well 4	14,10	13,90	1350	1285
Well 5	6,97	6,48	1401	1192
Well 6	14,60	13,80	1419	1190

CHAPTER 7

7. UNDERGROUND GAS STORAGE PERFORMANCE

The history match data file was used as a fundamental step to the prediction of the behaviour of the reservoir during the UGS operations and decision of the location, amount and type of the injection and production wells. The results of history match run such as gas saturation, porosity distribution, permeability characteristics and average reservoir pressure distribution are the main source of decision instruments for the future scenarios.

The existing wells are also evaluated either as production or injection wells. New wells were drilled depending on the criteria mentioned above in different locations and the new wells were drilled as horizontal wells. These new horizontal wells and existing vertical wells were used in 5 different combinations where vertical and horizontal wells were used as production or injection wells.

7.1 Scenario 1- 6 vertical producers & 6 vertical injectors

In this scenario, the existing 6 vertical wells were evaluated as producers and injectors for UGS project with 13 MMcf/d injection rate. For the producton rate, the bottom hole pressure is selected as a constraint and decision agent. The performance for this approach is summarized below.

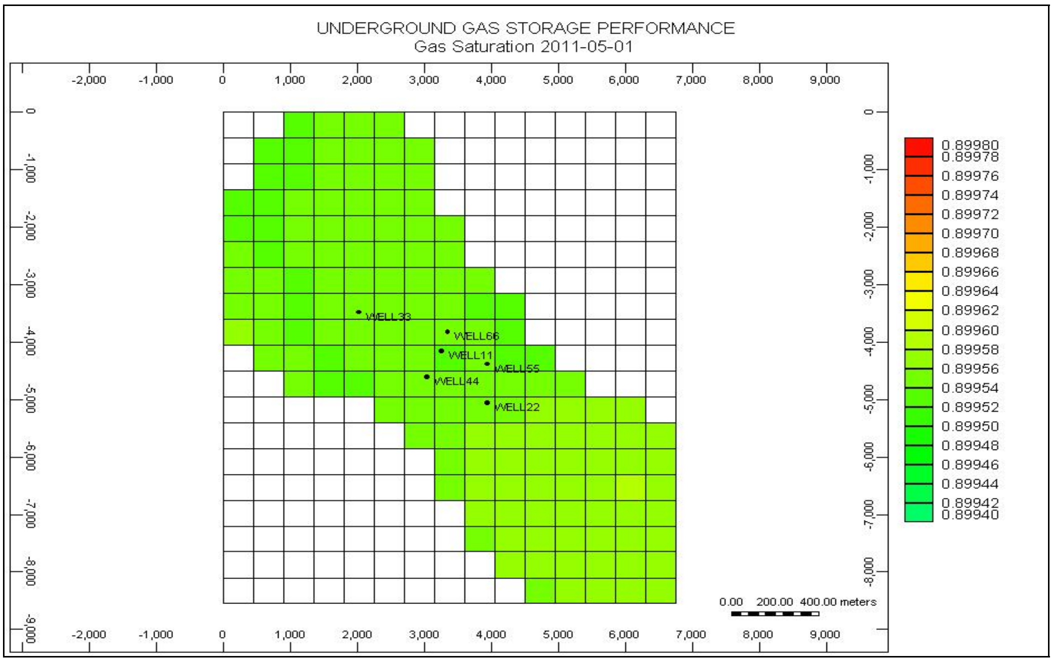

Figure 7.1.1 Gas saturation distribution at the end of gas withdrawal for the Scenario 1 in 2011

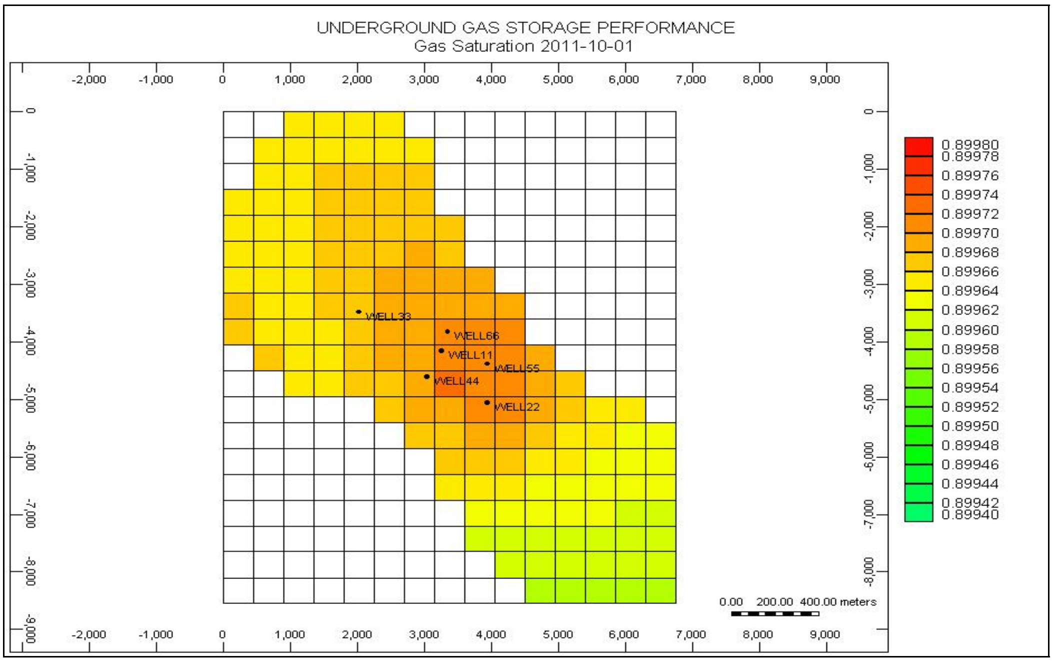

Figure 7.1.2 Gas saturation distribution at the end of gas injection for the Scenario 1 in 2011

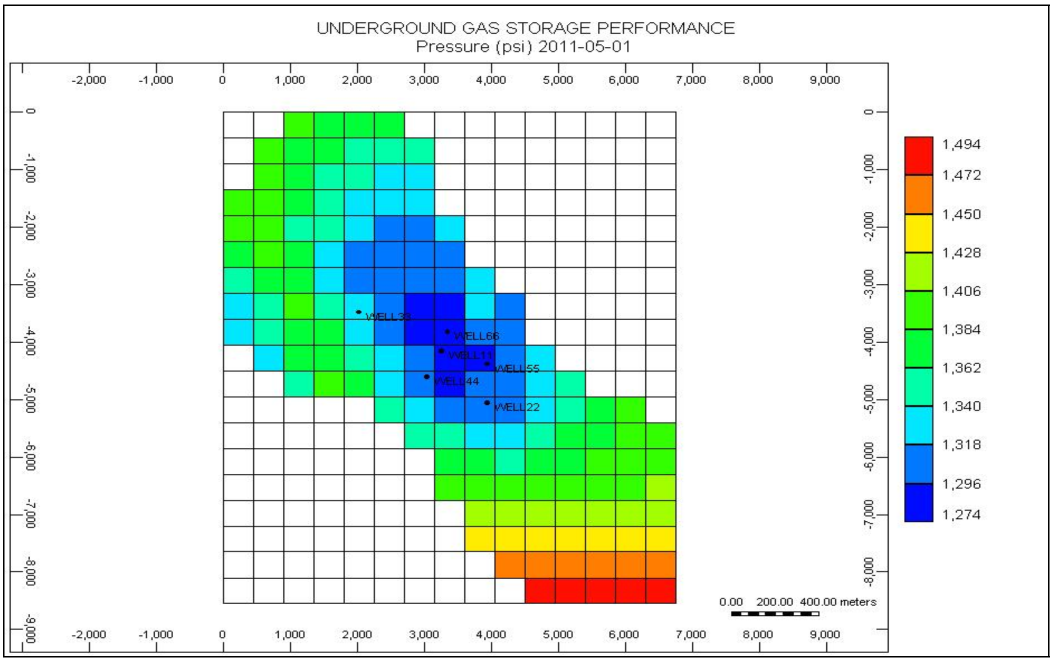

Figure 7.1.3 Pressure saturation distribution at the end of gas withdrawal for the Scenario 1 in 2011

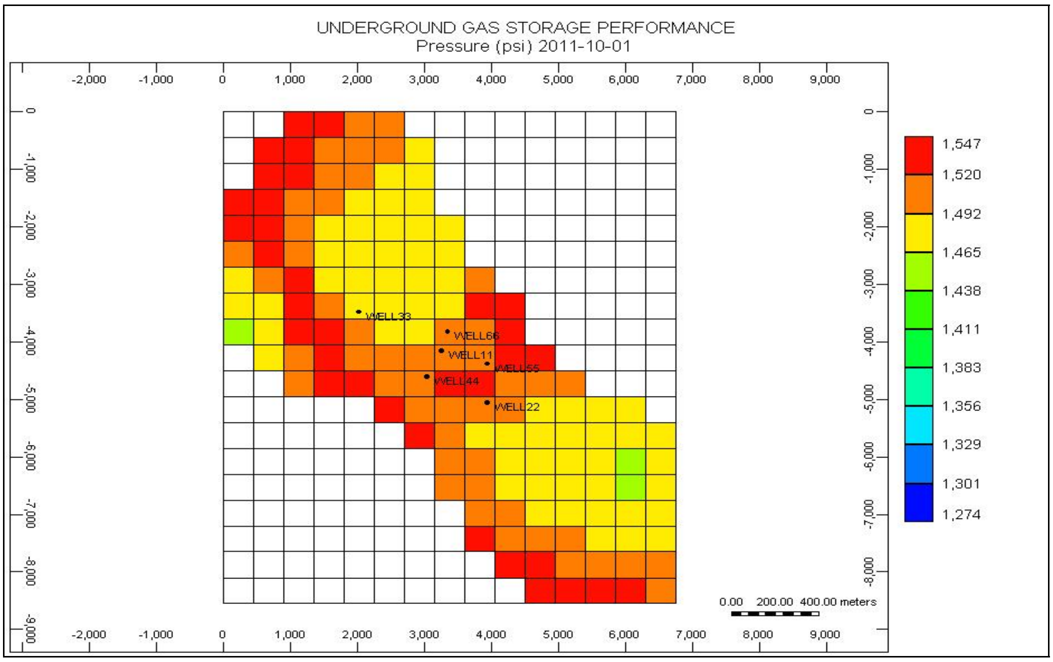

Figure 7.1.4 Pressure saturation distribution at the end of gas injection for the Scenario 1 in 2011

7.2 Scenario 2- 5 horizontal producers & 5 horizontal injectors

In this scenario, 5 horizontal wells were drilled and completed as injectors and also producers for UGS project with an injection rate of 13 MMcf/d. The existing 6 vertical wells were not used and assumed to be shut in during the project.

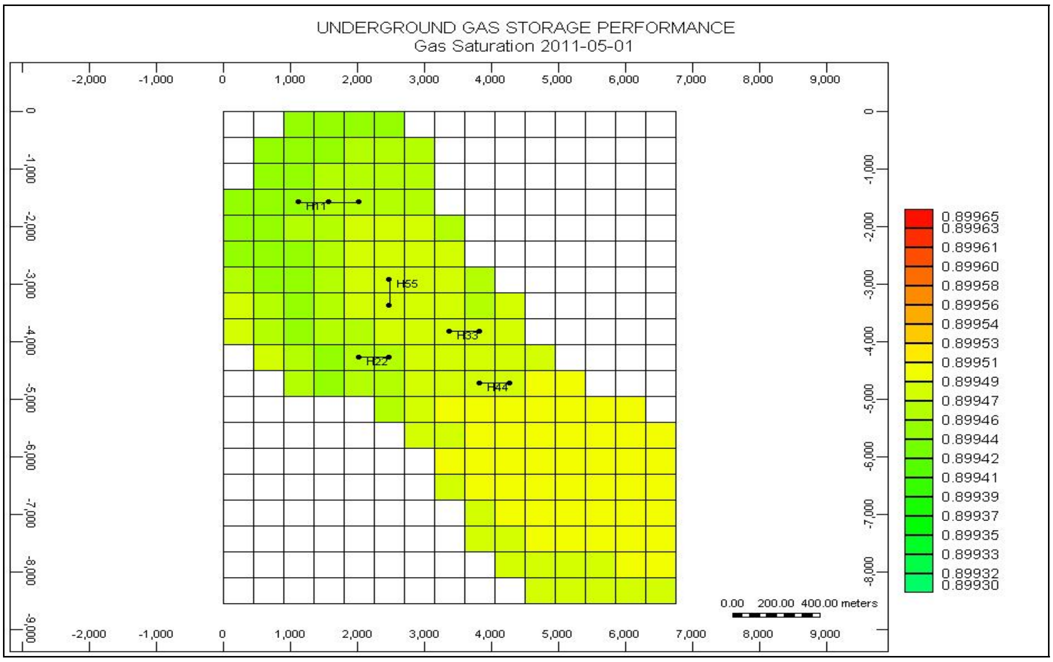

Figure 7.2.1 Gas saturation distribution at the end of gas withdrawal for the Scenario 2 in 2011

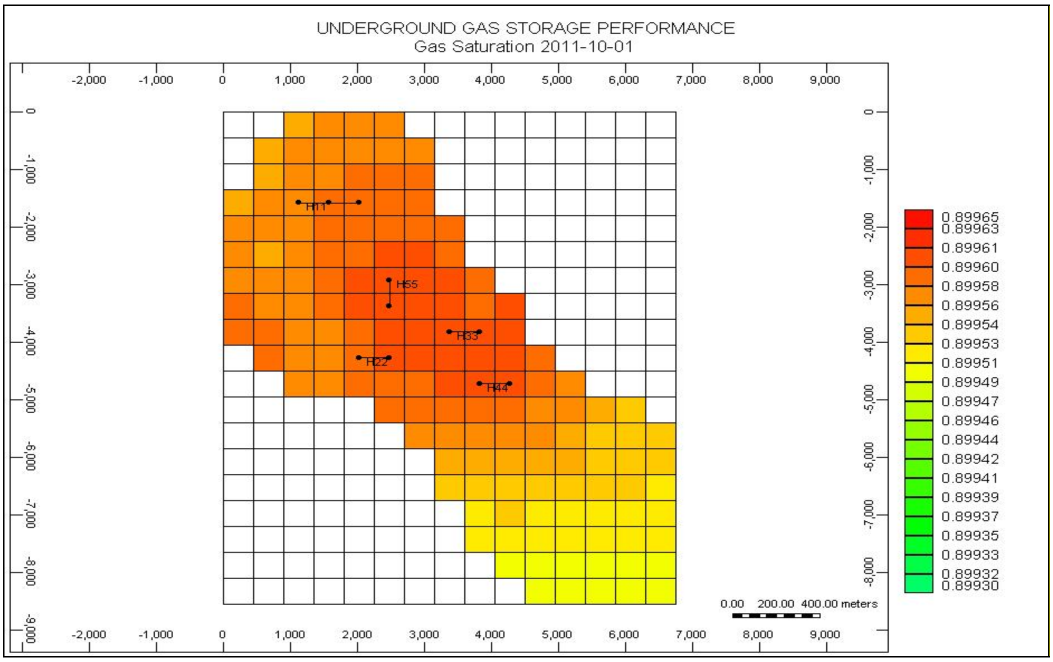

Figure 7.2.2 Gas saturation distribution at the end of gas injection for the Scenario 2 in 2011

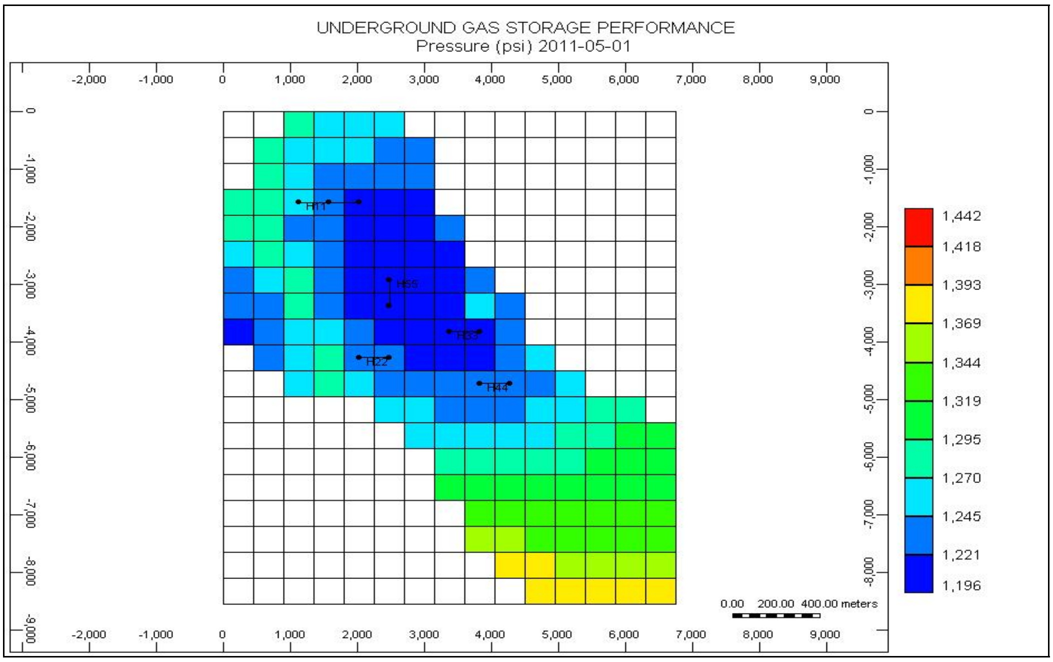

Figure 7.2.3 Pressure distribution at the end of gas withdrawal for the Scenario 2 in 2011

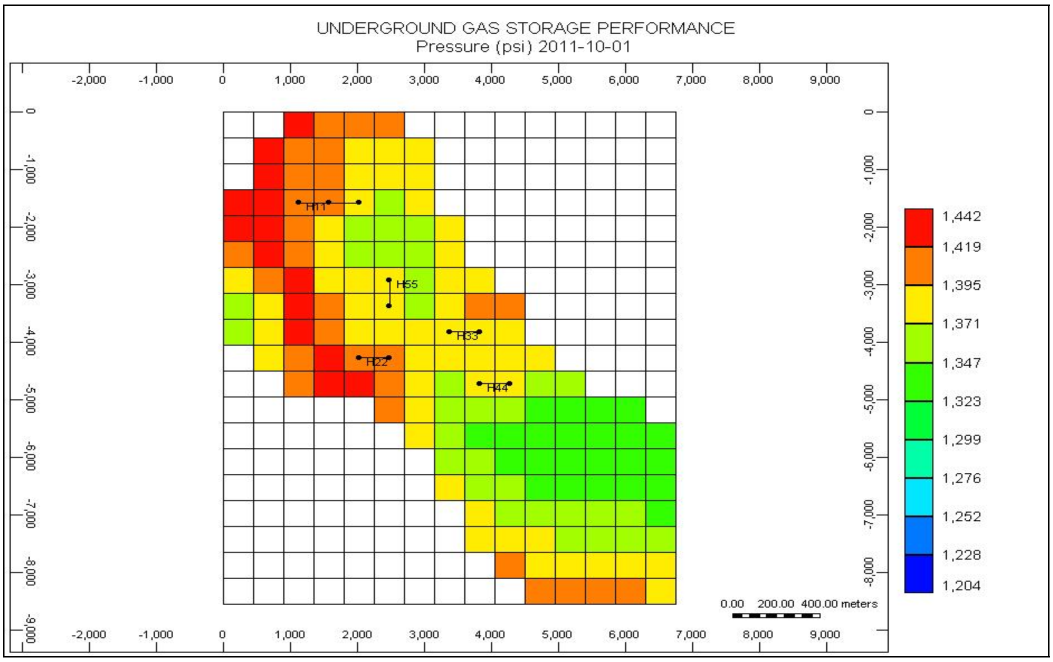

Figure 7.2.4 Pressure distribution at the end of gas injection for the Scenario 2 in 2011

7.3 Scenario 3- 5 horizontal producers & 6 vertical injectors

In this scenario existing 5 vertical and newly drilled 6 horizontal wells were evaluated as producers and injectors respectively. The injection rate of the wells was selected as 13 MMcf/d.

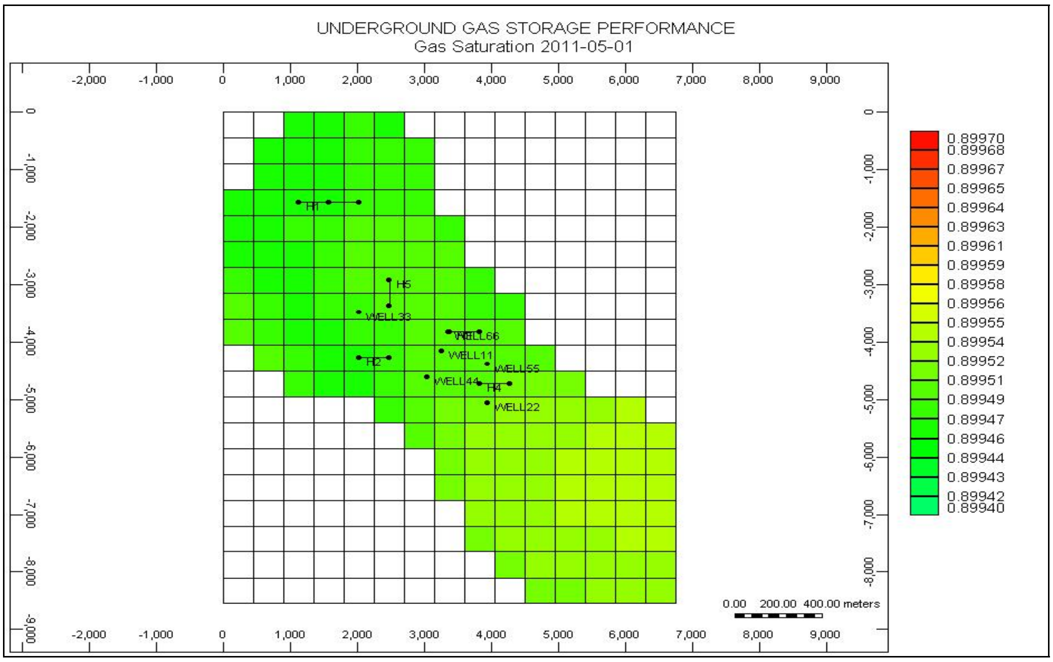

Figure 7.3.1 Gas saturation distribution at the end of gas withdrawal for the Scenario 3 in 2011

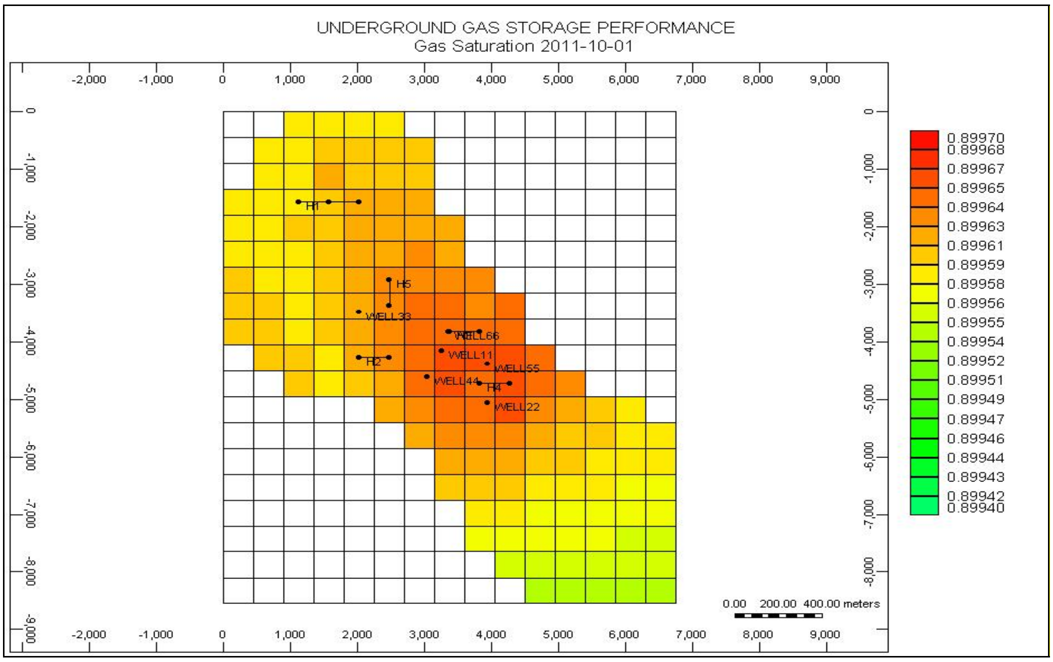

Figure 7.3.2 Gas saturation distribution at the end of gas injection for the Scenario 3 in 2011

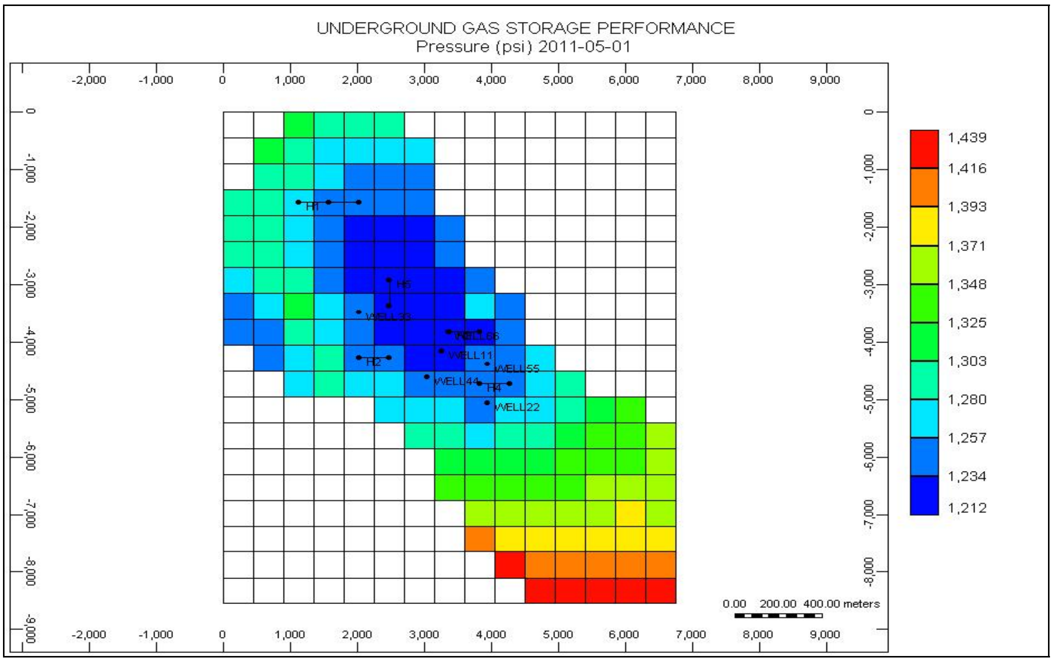

Figure 7.3.3 Pressure distribution at the end of gas withdrawal for the Scenario 3 in 2011

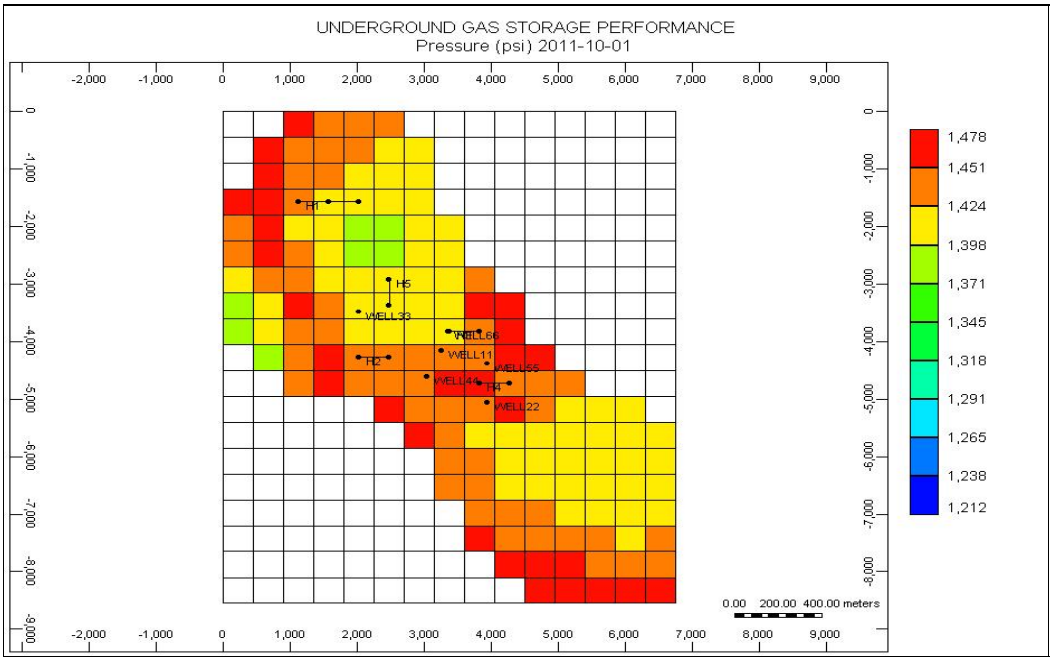

Figure 7.3.4 Pressure distribution at the end of gas injection for the Scenario 3 in 2011

7.4 Scenario 4- 5 horizontal injectors & 6 vertical producers

In this approach the horizontal wells were completed as injectors and the vertical wells were utilized as producers with a production and injection rates of 13 MMcf/d.

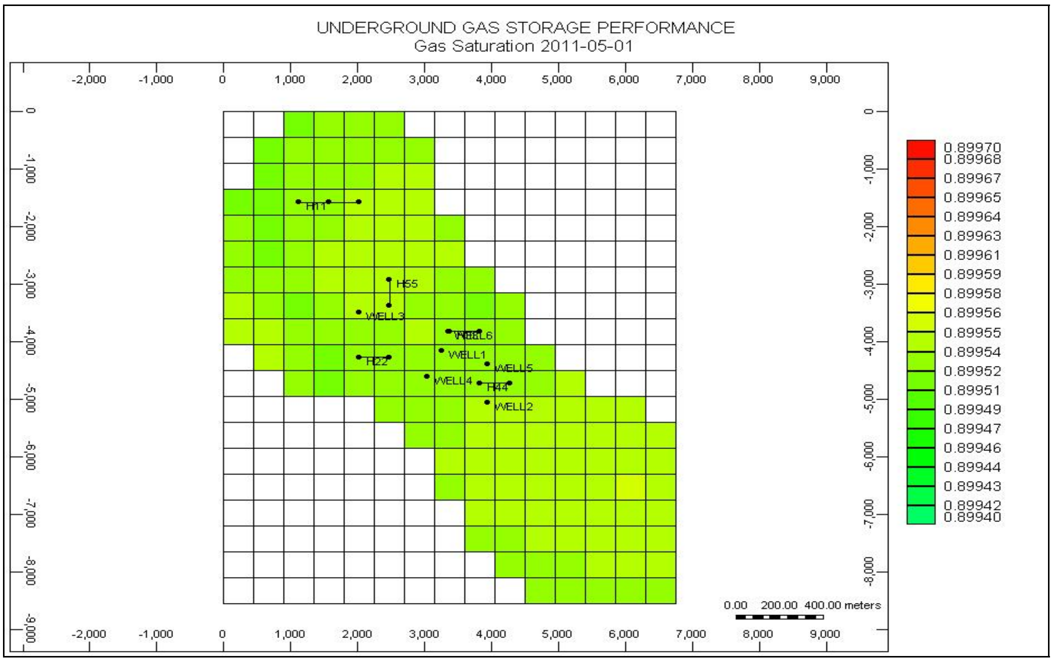

Figure 7.4.1 Gas saturation distribution at the end of gas withdrawal for the Scenario 4 in 2011

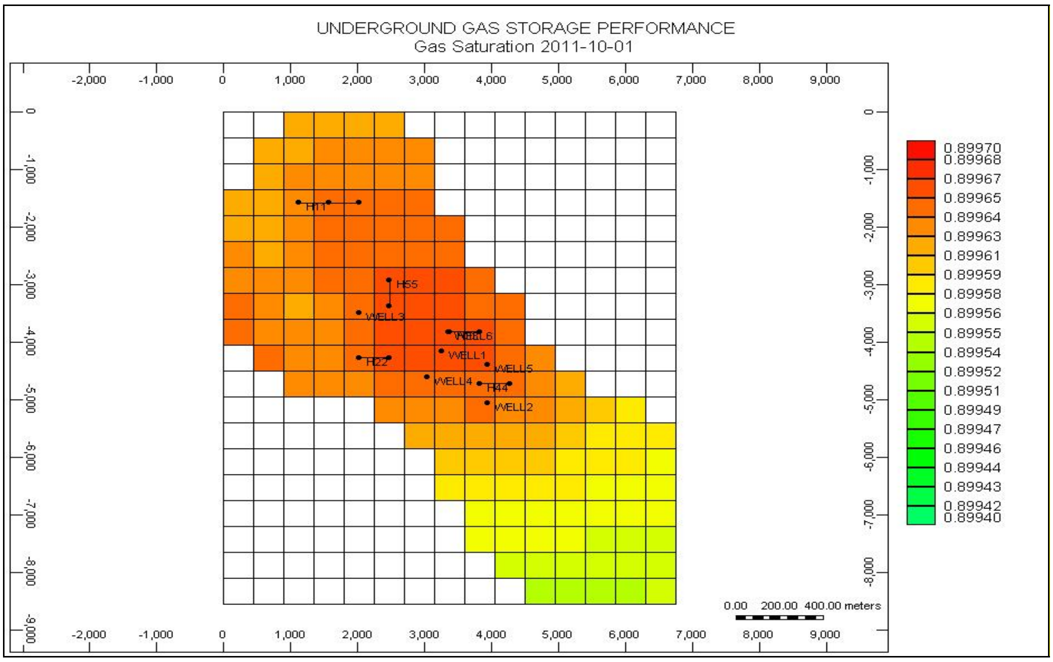

Figure 7.4.2 Gas saturation distribution at the end of gas injection for the Scenario 4 in 2011

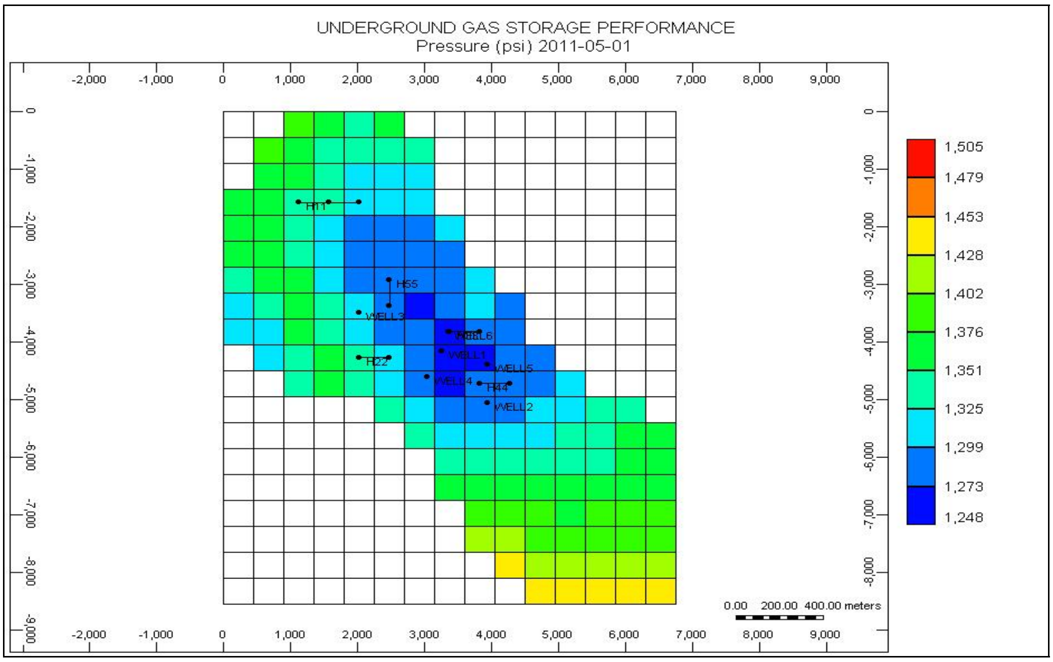

Figure 7.4.3 Pressure distribution at the end of gas withdrawal for the Scenario 4 in 2011

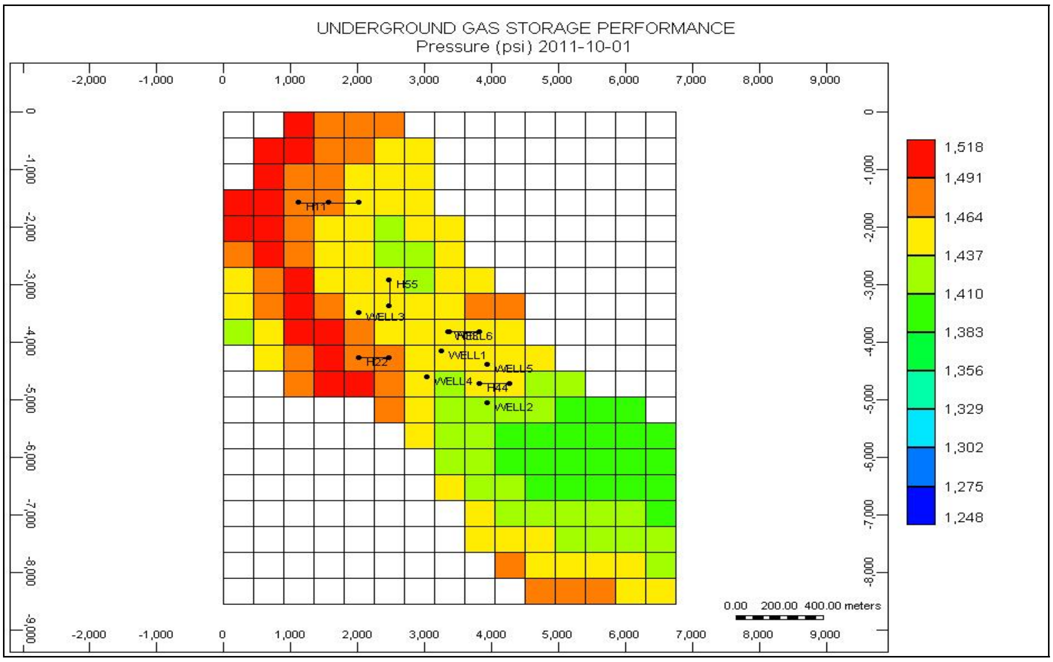

Figure 7.4.4 Pressure distribution at the end of gas injection for the Scenario 4 in 2011

7.5 Scenario 5- 5 horizontal – 6 vertical injectors & 5 horizontal - 6 vertical producers

For this scenario the whole vertical and horizontal wells were used as producers and injectors. The production and injection rates of the wells are selected as 13 MMcf/d.

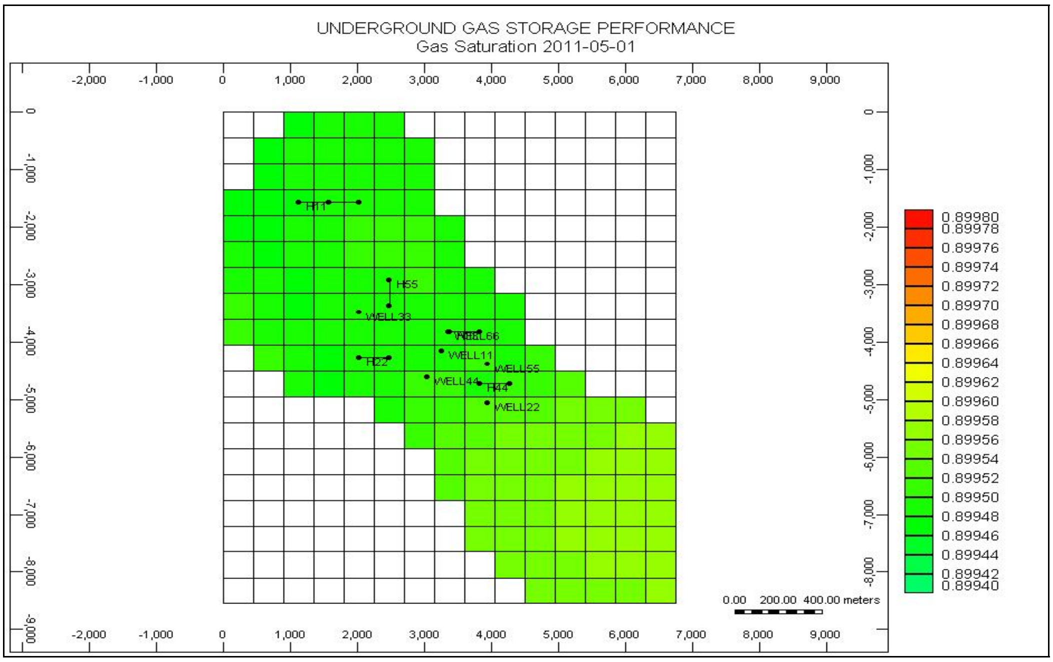

Figure 7.5.1 Gas saturation distribution at the end of gas withdrawal for the Scenario 5 in 2011

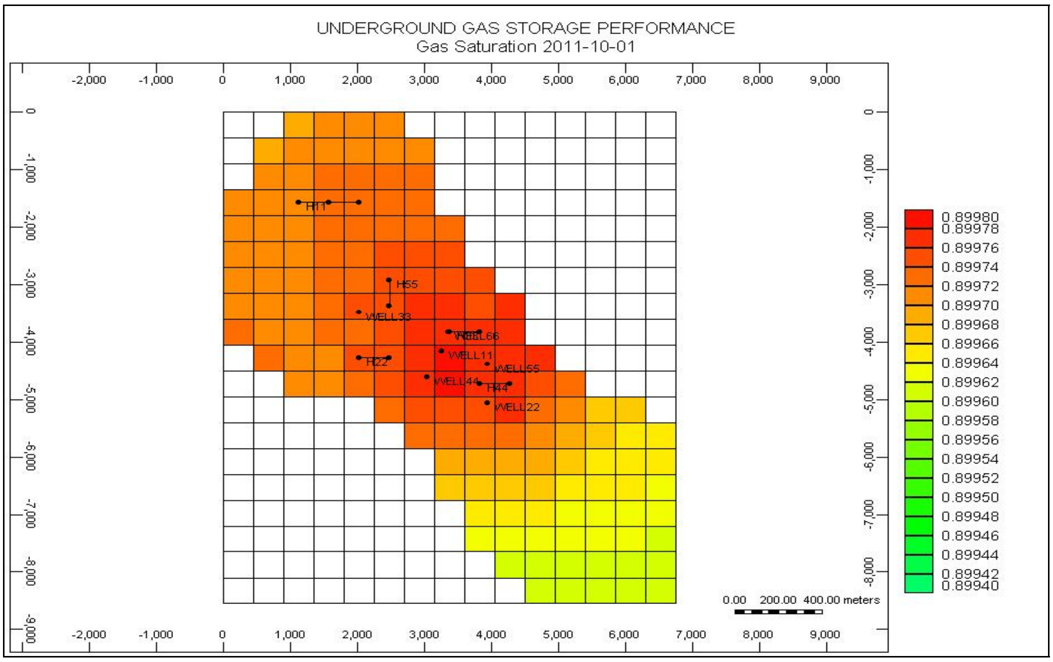

Figure 7.5.2 Gas saturation distribution at the end of gas injection for the Scenario 5 in 2011

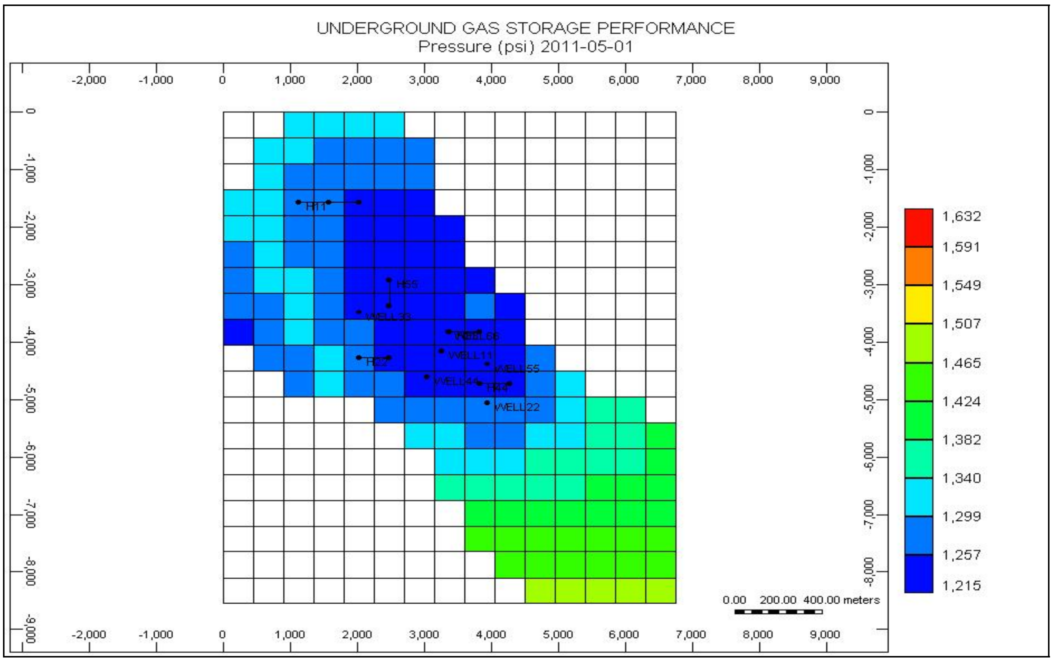

Figure 7.5.3 Pressure distribution at the end of gas withdrawal for the Scenario 5 in 2011

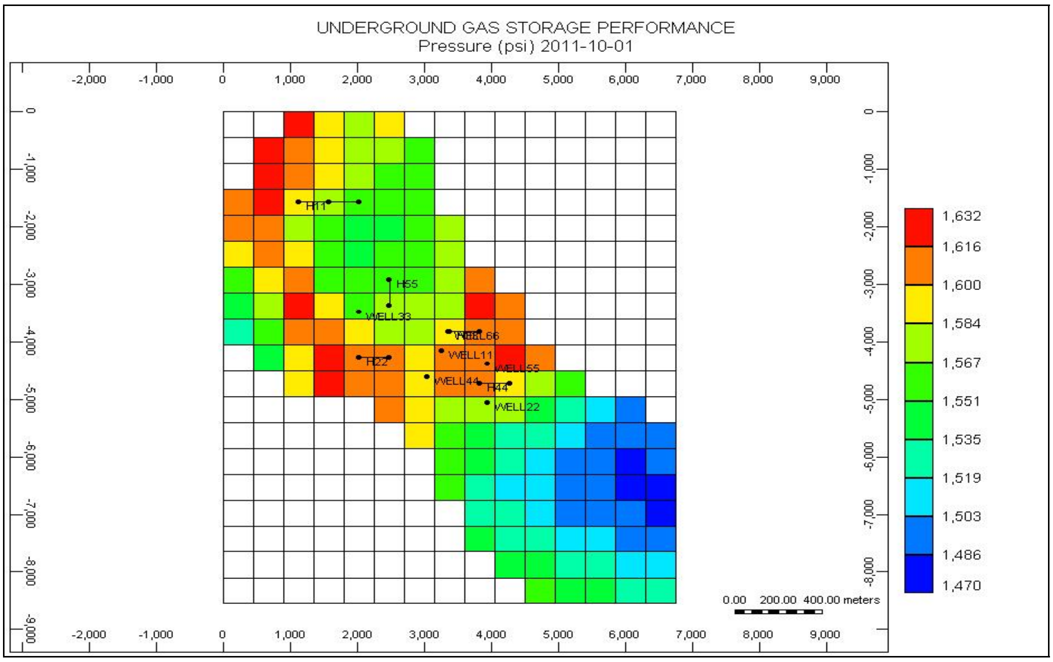

Figure 7.5.4 Pressure distribution at the end of gas injection for the Scenario 5 in 2011

7.6 Comparison of the Scenarios

The above scenarios were compared with respect to production and injection data and also average reservoir pressure values. The Figures 7.6.1, 7.6.2, 7.6.3 and 7.6.4 shows the comparison of the use of five different combination of 6 existing vertical and 5 newly drilled horizontal wells in UGS project.

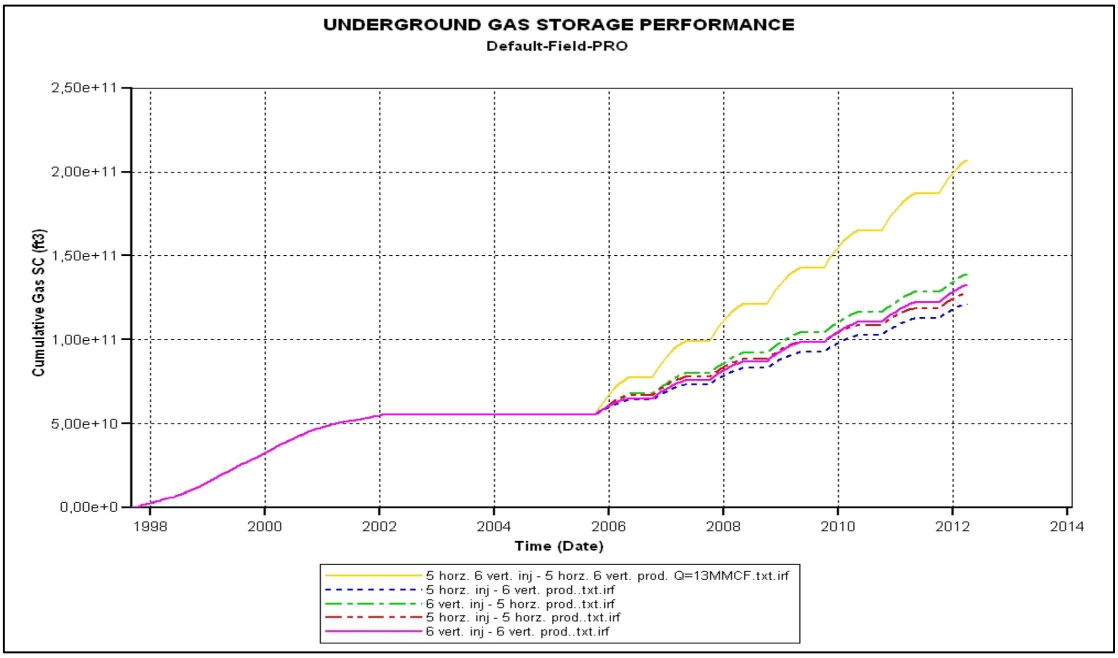

Figure 7.6.1 Comparison of the scenarios with respect to cumulative gas production

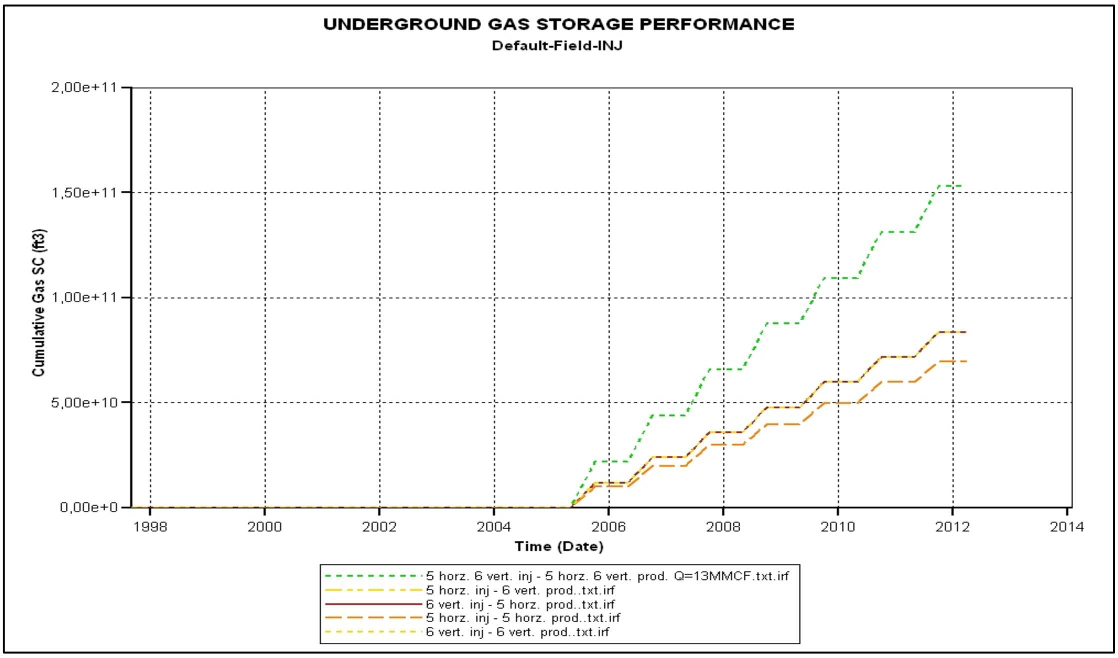

Figure 7.6.2 Comparison of the scenarios with respect to cumulative gas injection

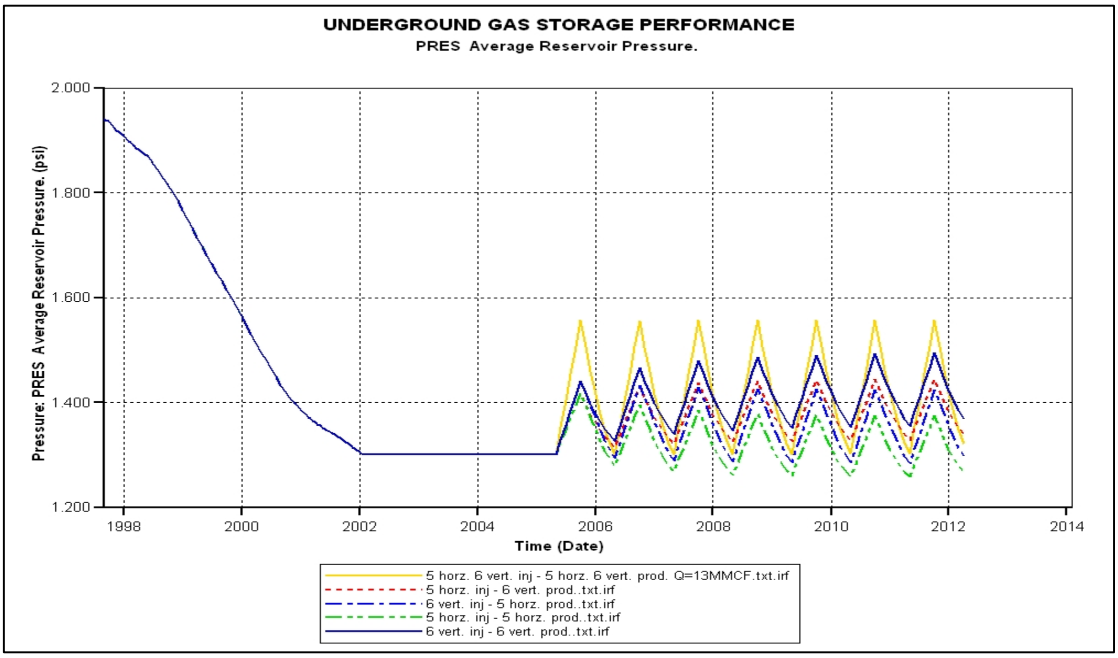

Figure 7.6.3 Comparison of the scenarios with respect to average reservoir pressure

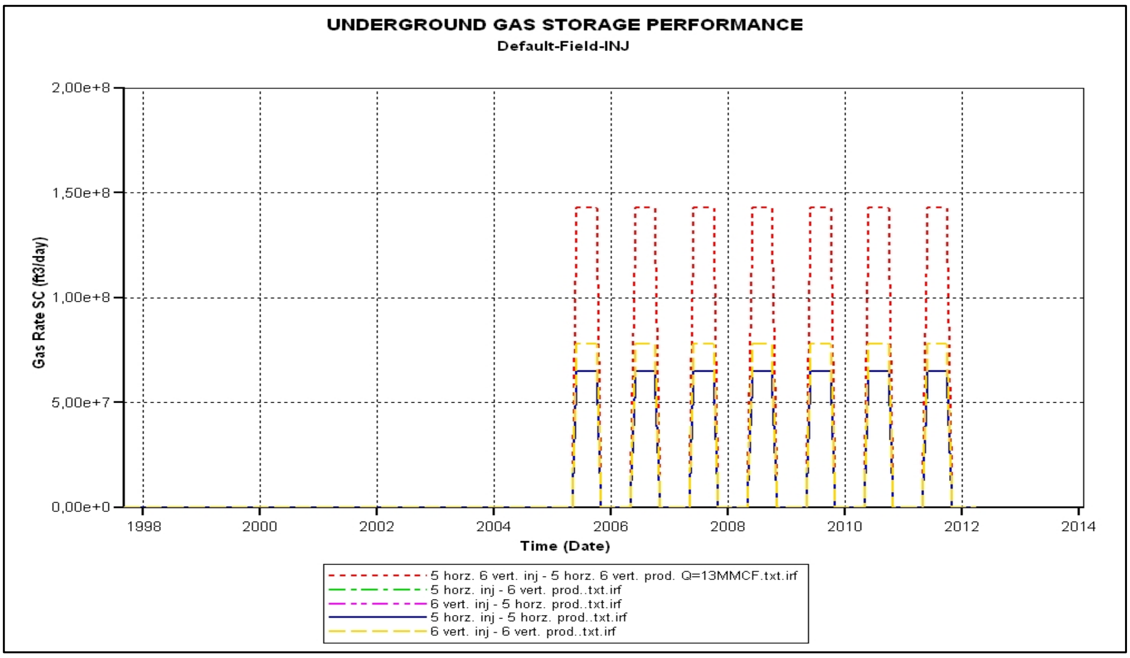

Figure 7.6.4 Comparison of the scenarios with respect to gas injection rates

From the above figures it is apparent that the 5th scenario in which 5 horizontal – 6 vertical injectors & 5 horizontal - 6 vertical producers were used showed the best performance during the injection and production periods until the year 2012.

7.7 Injection Rate

The second stage in this project is to find the optimum injection rate for the UGS project in this field for the best well configuration found above which is drilling 5 horizontal wells and completing them in the way described above and using the existing 6 vertical wells with the new horizontal wells.

First of all, the common injection rate for the whole field was changed and two different rates were applied and the results was compared. The graphs were drawn to show the best fit for the application of the compression station.

7.7.1 Qinj=130 MMcf/d

This injection rate is applied to the entire field throughout the UGS project and the performance data for gas saturation and pressure distribution is given in Figures 7.7.1.1, 7.7.1.2, 7.7.1.3 and 7.7.1.4 respectively.

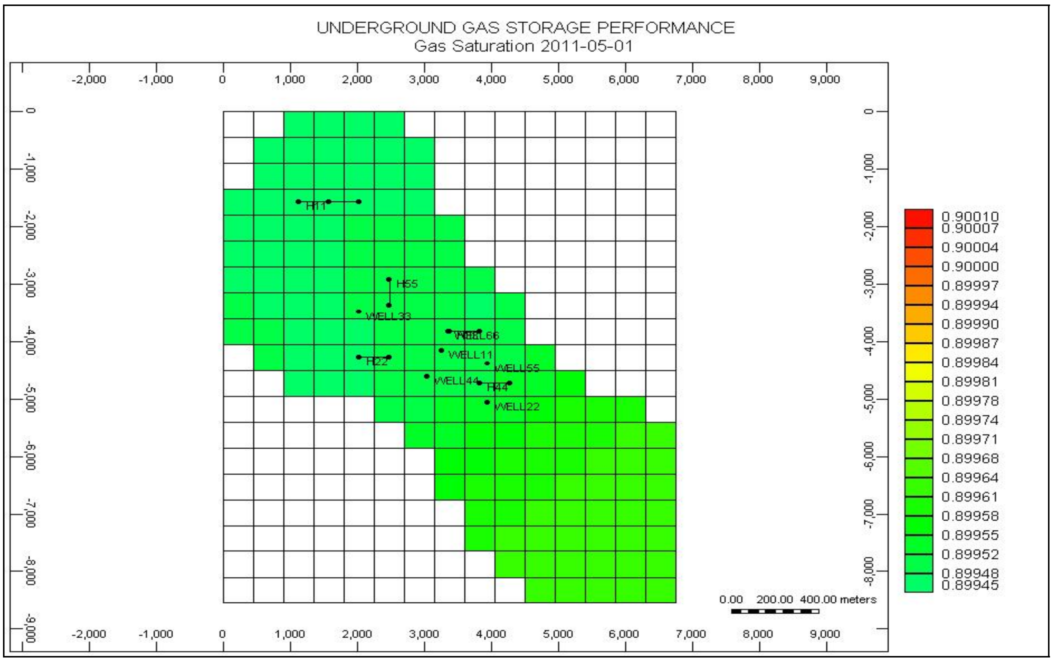

Figure 7.7.1.1 Gas saturation distribution at the end of gas withdrawal for the Scenario 5$_{@\ Qinj=130MMcf/d}$ in 2011

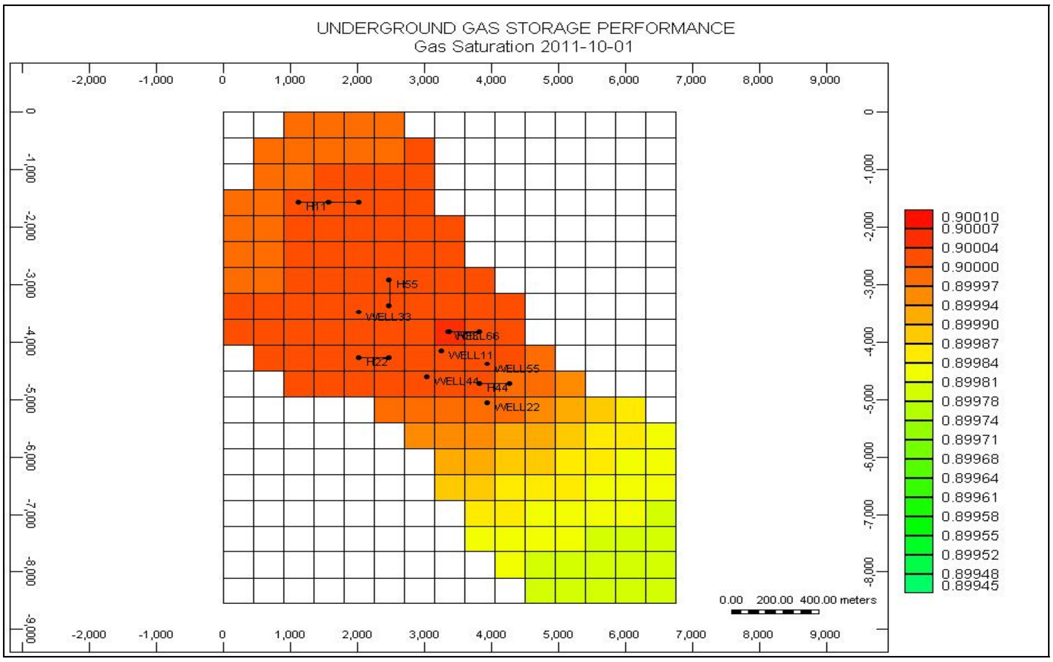

Figure 7.7.1.2 Gas saturation distribution at the end of gas injection for the Scenario $5_{@\ Qinj=130MMcf/d}$ in 2011

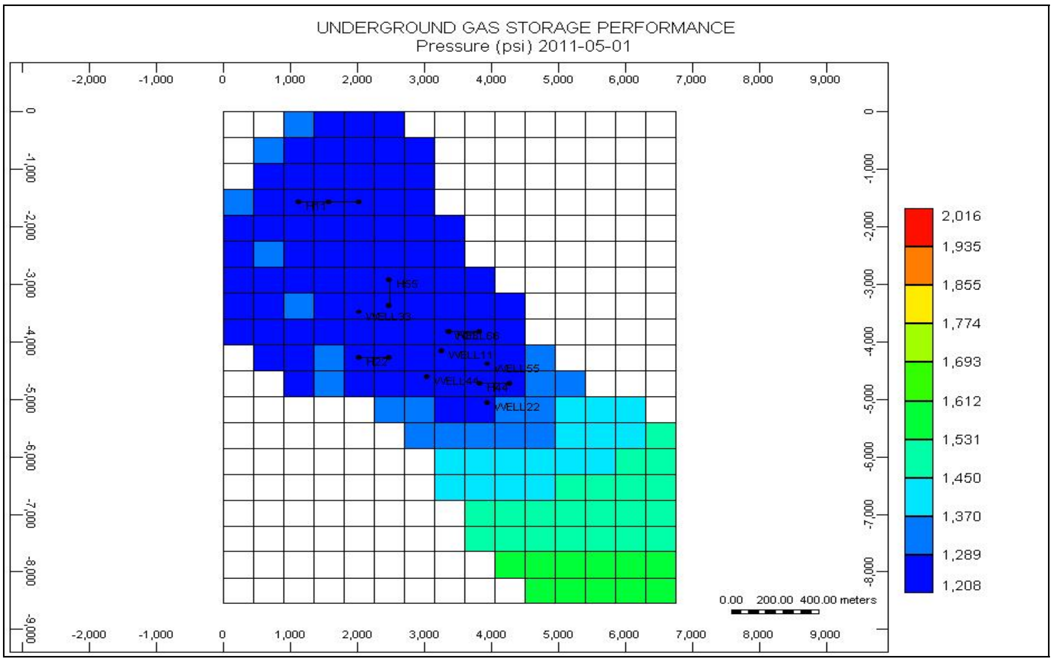

Figure 7.7.1.3 Pressure distribution at the end of gas withdrawal for the Scenario $5_{@\ Qinj=130MMcf/d}$ in 2011

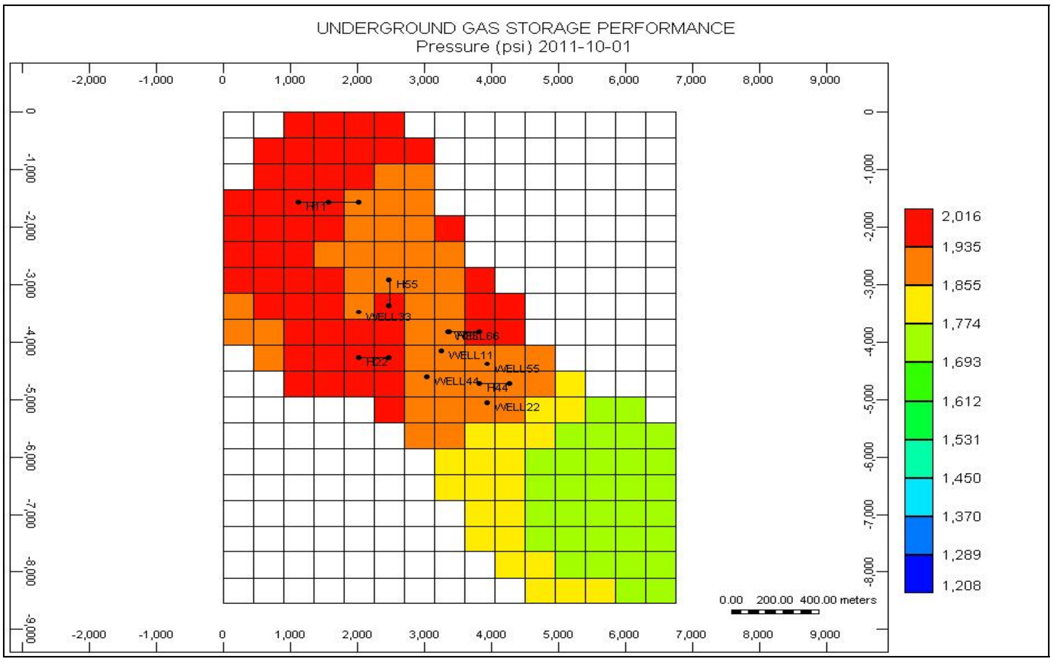

Figure 7.7.1.4 Pressure distribution at the end of gas injection for the Scenario 5@ Qinj=130MMcf/d in 2011

7.7.2 Qinj=1.3 Bcf/d

This injection rate is applied to the entire field throughout the UGS project and the performance data for gas saturation and pressure distribution is given in Figures 7.7.2.1, 7.7.2.2, 7.7.2.3 and 7.7.2.4 respectively.

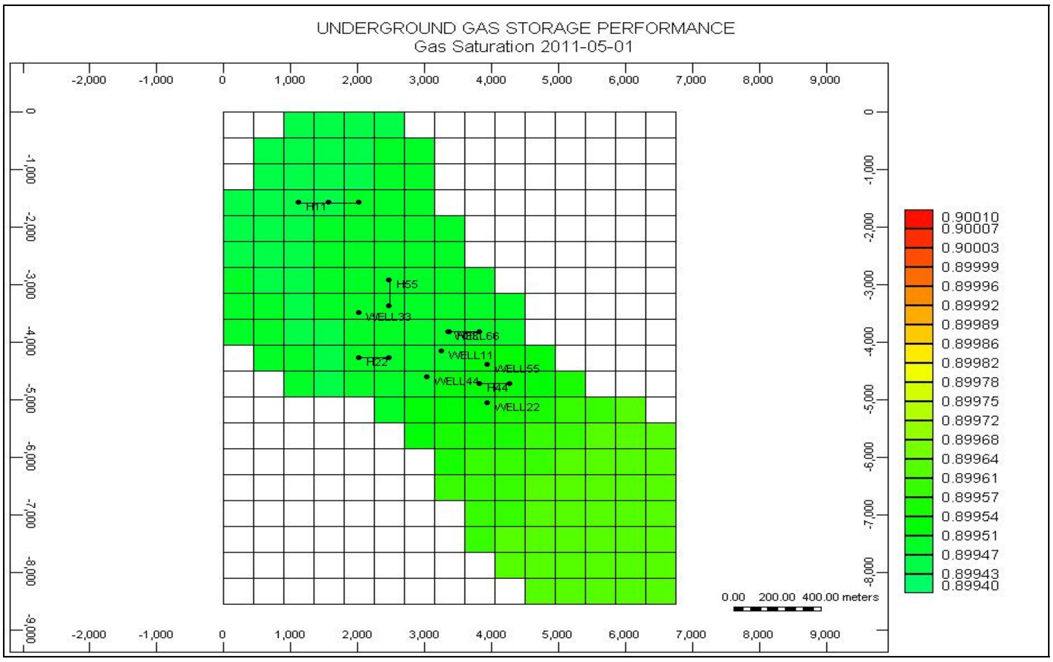

Figure 7.7.2.1 Gas saturation distribution at the end of gas withdrawal for the Scenario $5_{@\ Qinj=1.3\ Bcf/d}$ in 2011

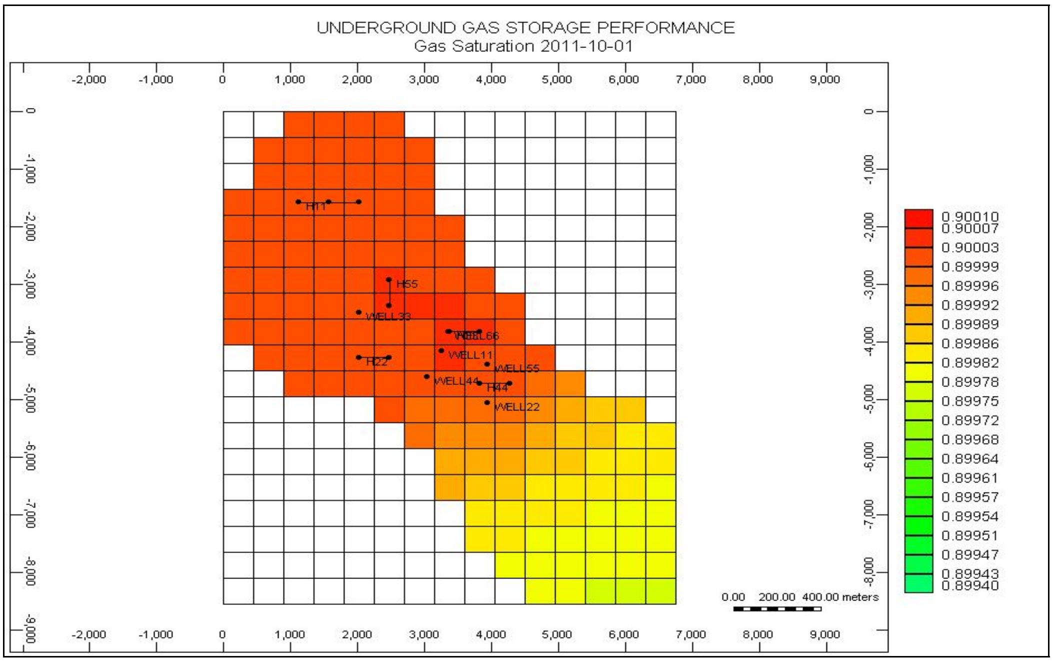

Figure 7.7.2.2 Gas saturation distribution at the end of gas injection for the Scenario $5_{@\ Qinj=1.3\ Bcf/d}$ in 2011

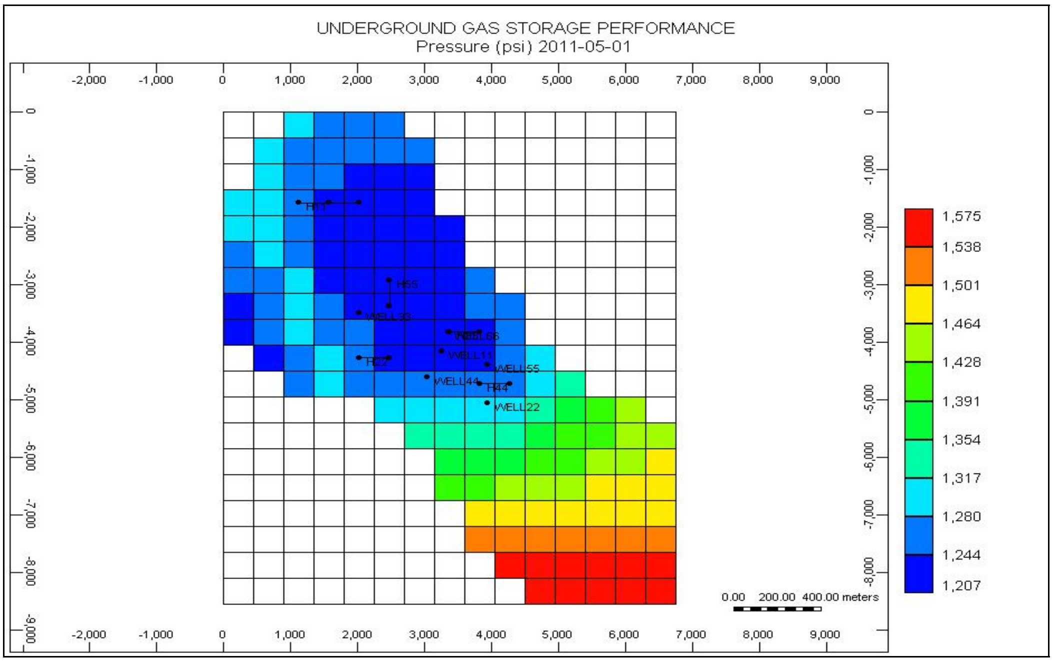

Figure 7.7.2.3 Pressure distribution at the end of gas withdrawal for the Scenario 5$_{@\ Qinj=1.3\ Bcf/d}$ in 2011

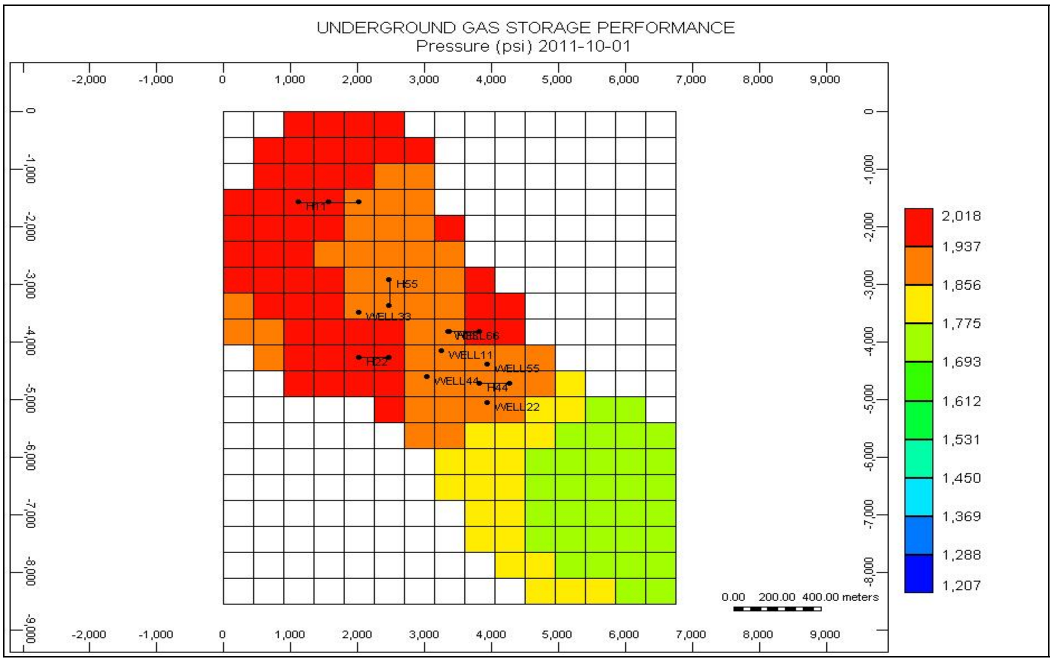

Figure 7.7.2.4 Pressure saturation distribution at the end of gas injection for the Scenario 5$_{@\ Qinj=1.3\ Bcf/d}$ in 2011

Under these circumstances, the results was compared in graphical manners in which cumulative gas production and injection amounts, injection rates and average reservoir pressure data which were obtained from the application of the latter injection rates to the Scenario 5, shown in Figures 7.1, 7.2, 7.3 and 7.4 respectively.

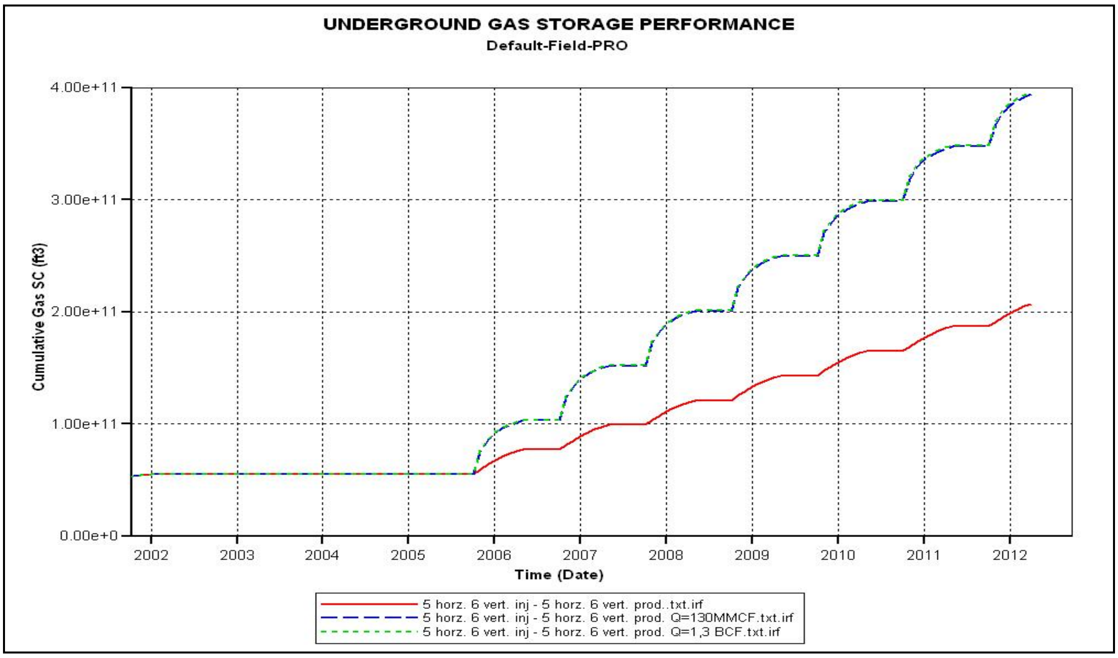

Figure 7.1 Comparison of the injection rates applied to Scenario 5 with respect to cumulative gas production

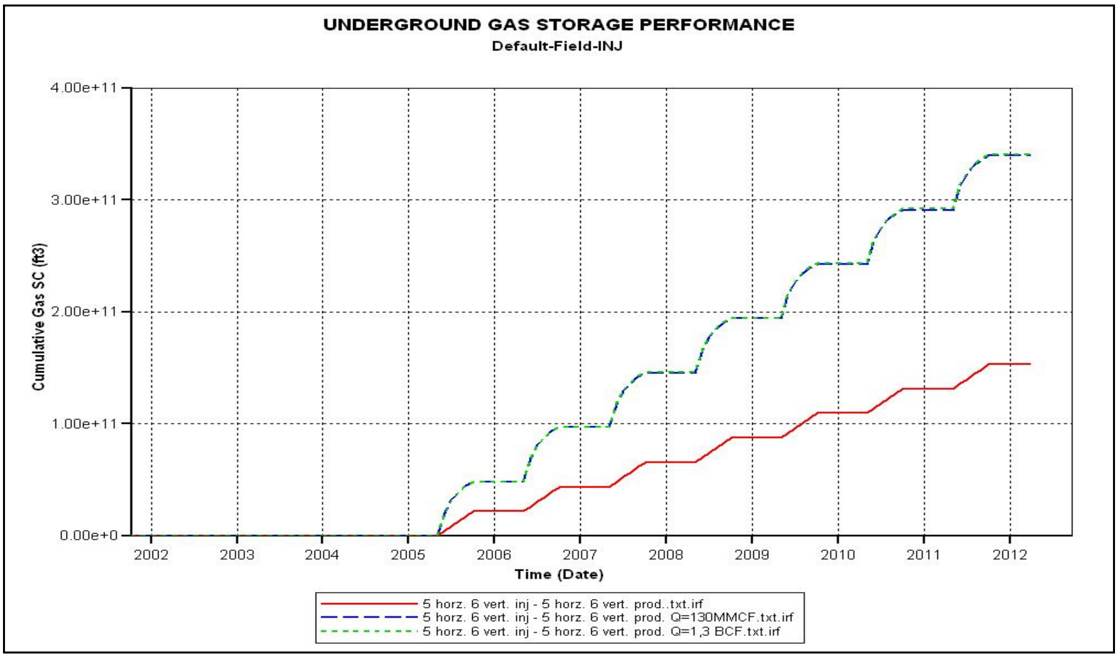

Figure 7.2 Comparison of the injection rates applied to Scenario 5 with respect to cumulative gas injection

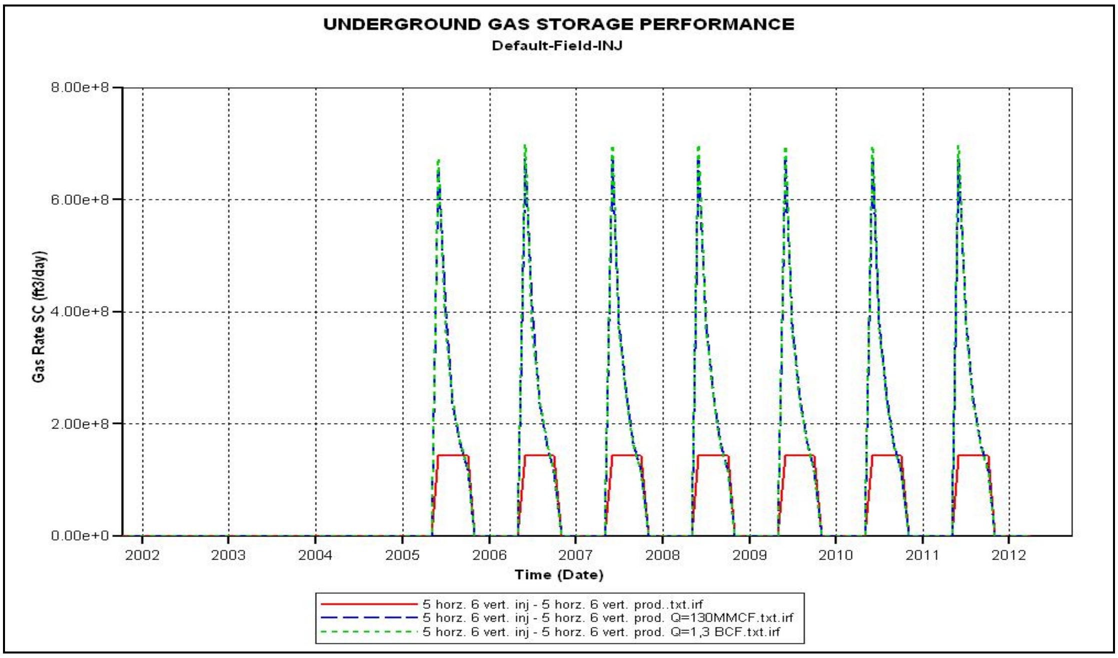

Figure 7.3 Comparison of the injection rates applied to Scenario 5 with respect to gas injection rates

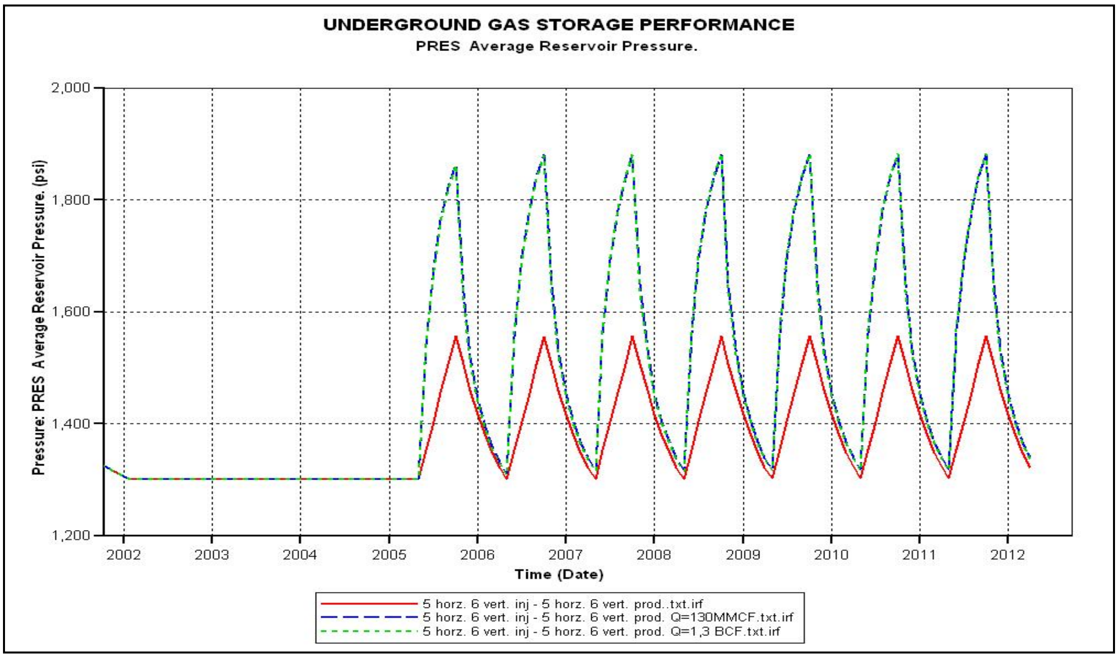

Figure 7.4 Comparison of the injection rates applied to Scenario 5 with respect to average reservoir pressure

From the above figures, it is apparent that increasing the injection rate from 13 MMcf/d to 130 MMcf/d effects the performance positively which means the average reservoir pressure was approached to the original reservoir pressure better than the previous injection rate and also the total injected gas and gas recovery from the field was improved. But if the injection rate will be increased to 1.3 Bcf/d, there would be no difference between the 130 MMcf/d and 1.3 Bcf/d injection rates, thus it is better to operate the field with an injection rate of 130 MMcf/d.

Since there are two types of wells, the performance of horizontal wells should be inspected with different injection rates while the rate for vertical wells remains constant at 130 MMcf/d. For this reason new runs were done by setting the horizontal well injection rates to 1.3 Bcf/d and 13 Bcf/d respectively. The following Figures 7.5, 7.6, 7.7 and 7.8 are showing the comparison with respect to cumulative gas production and injection, injection rates and average reservoir pressure respectively.

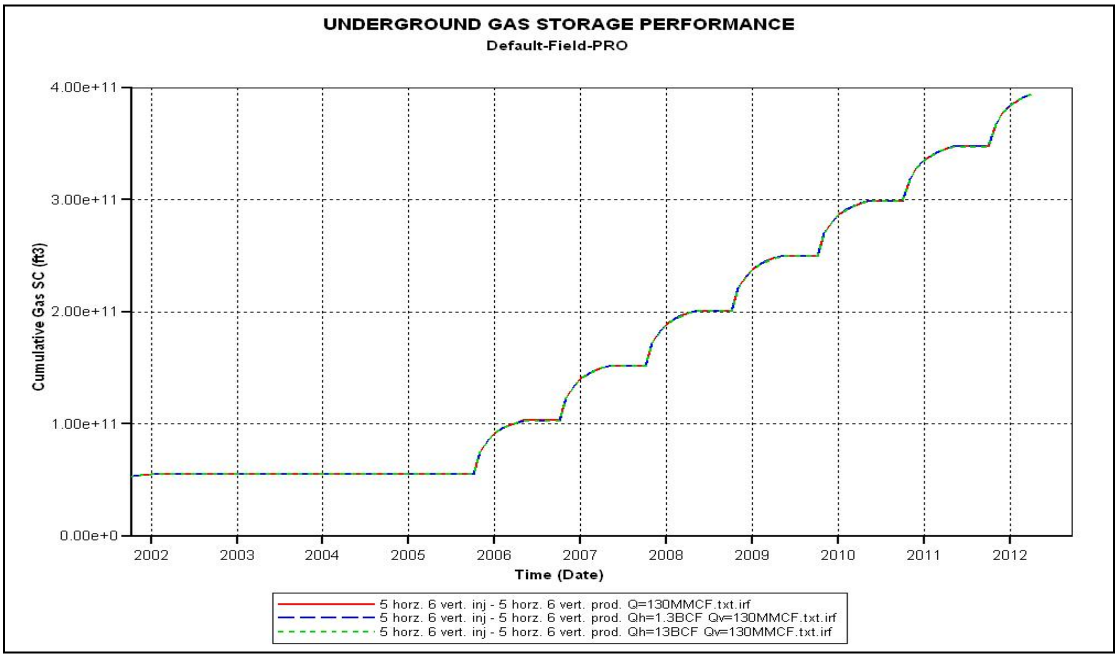

Figure 7.5 Comparison of the injection rates applied to horizontal wells in Scenario 5 with respect to cumulative gas production

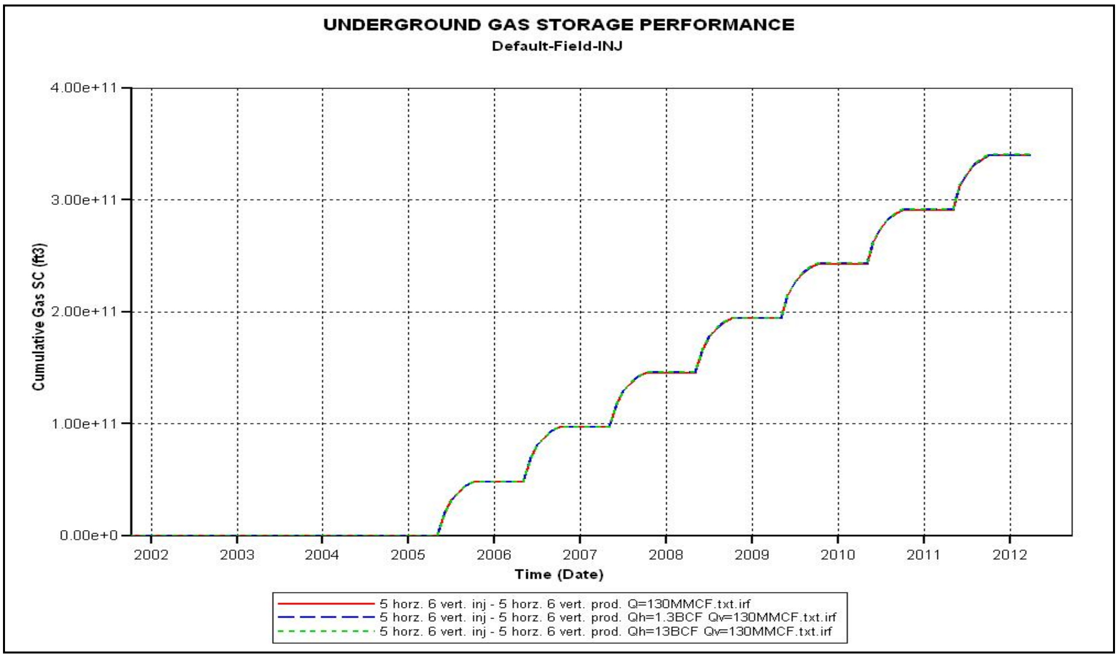

Figure 7.6 Comparison of the injection rates applied to horizontal wells in Scenario 5 with respect to cumulative gas injection

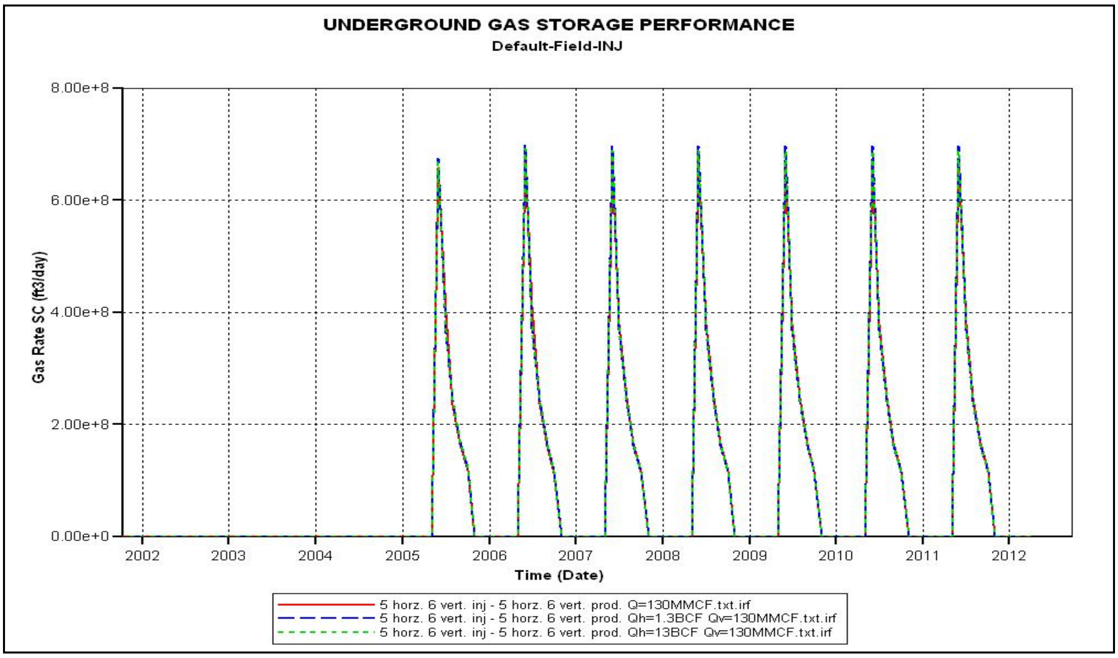

Figure 7.7 Comparison of the injection rates applied to horizontal wells in Scenario 5 with respect to gas injection rates

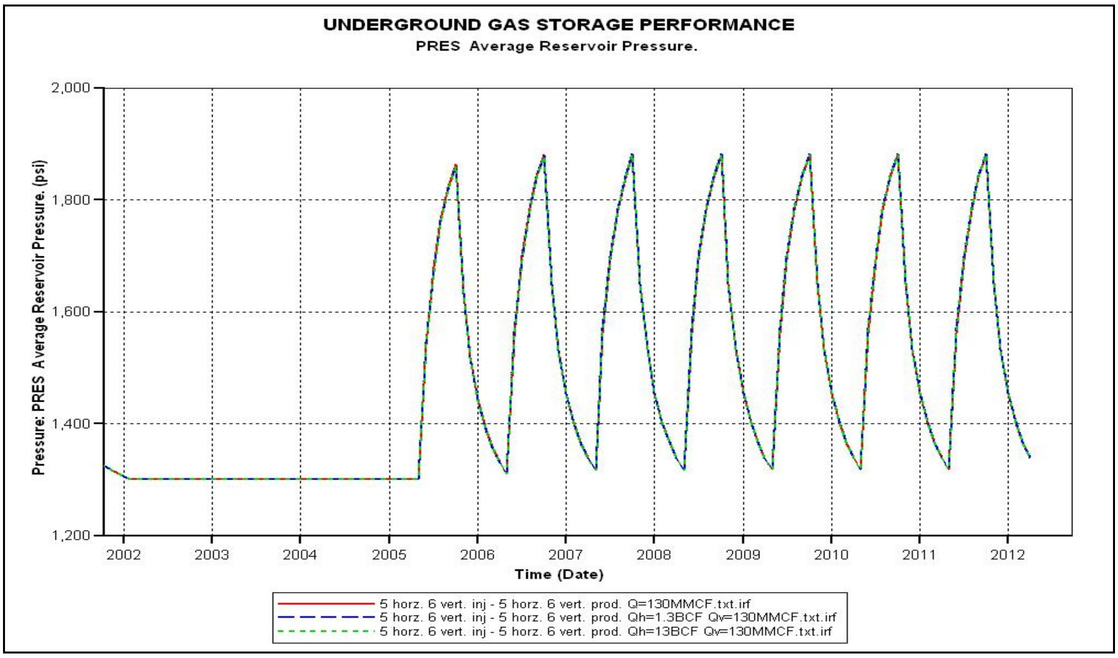

Figure 7.8 Comparison of the injection rates applied to horizontal wells in Scenario 5 with respect to average reservoir pressure

Applying different injection rates to horizontal wells shows no affect in performance of this UGS project, thus it is better to use the injection rate of 130 MMcf/d for all wells to approach the original average reservoir pressure. Table 8.1 summarizes the results of the scenarios.

From the Table 8.1, it can be concluded that it is better to apply the 5th scenario which includes 5 horizontal – 6 vertical injectors & 5 horizontal - 6 vertical producers having an injection rate of 130 MMcf/d for horizontal and vertical wells. Since within the 5th scenario, changing the injection rate to 1.3 Bcf/d and 13 Bcf/d, did not effect and change the average reservoir pressure significantly, it is best to carry out the project with the optimum injection rate which is 130 MMcf/d.

Table 8.1 Summary of the scenarios

Scenario	Injection Rates , MMcf/d		Inj. Period, month	Withdrawal Period, month	Max. Ave. Res. Pres. Reached
	$Q_{vert.\ wells}$	$Q_{horz.\ wells}$			
1	13	13	5	7	1494 psi
2	13	13	5	7	1395 psi
3	13	13	5	7	1433 psi
4	13	13	5	7	1444 psi
5	13	13	5	7	1557 psi
	130	130	5	7	1881 psi
	1300	1300	5	7	1882 psi
	130	1300	5	7	1882 psi
	130	13000	5	7	1881 psi

For the determination of the optimum injection rate to be applied for the injection wells, a nodal analysis should be carried out in well based. This procedure is briefly described in Appendix F. After the calculations done for the vertical injectors an injection rate of 102 MMcf/d rate is found to be optimum for the wells.

CHAPTER 8

8. CONCLUSION

In an underground gas storage project, since the injected fluid is very valuable, careful investigation for the candidate should be done and all the necessary data should be gathered to decide a scenario for a satisfactory and successful injection-withdrawal periods.

Using the gathered data, a successful history matching was achieved for the production between years 1997 and 2002. For future performance prediction, history matching was a reference point and all the scenarios was constructed on this base. 5 different scenarios in which 5 new horizontal wells were located in the reservoir were ran in the simulator program with combinations of new drilled horizontal wells and existing vertical wells either producers or injectors.

With a predetermined injection rate of 13 MMcf/D was set for all the wells and among the all scenarios, 5 horizontal – 6 vertical injectors & 5 horizontal - 6 vertical producers is the most successful in handling the gas inventory and the time it takes for a gas injection and production period. After the determination of the well configuration, the optimum injection rate for the entire field was obtained and found to be 130 MMcf/D by running different injection rates for all wells and then for only horizontal wells different injection rates were applied with a constant injection rate of 130 MMcf/d.

From the Table 8.1, it is better to apply the 5th scenario which includes 5 horizontal – 6 vertical injectors & 5 horizontal - 6 vertical producers having an injection rate of 130 MMcf/d for horizontal and vertical wells. Since within the 5th scenario, changing the injection rate to 1.3 Bcf/d and 13 Bcf/d, did not effect and change the average reservoir pressure significantly, it is best to carry out the project with the optimum injection rate which is 130 MMcf/d.

The total gas produced untill 2012 is 394 BCF and the gas injected is 340 BCF where the maximum average reservoir pressure was recovered and set into a new value of 1881 psi by injection and cushion gas pressure as 1371 psi by withdrawal. If this scenario is compared with the others, there is an increase in injection and production performance about 90% with respect to the usage of the existing wells in this study.

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APPENDIX A

RESERVOIR FLUID PROPERTIES

Reference 17 is used for calculations of Reservoir Fluid Properties.

Gas Composition

Table A.1 Composition of gas

COMPONENT	%	MW	%MW
C1	91,45	16	14,6320
C2	3,21	30	0,9630
C3	1,21	44	0,5324
NC4	0,30	58	0,1740
IC4	0,24	56	0,1344
NC5	0,070	72	0,0504
IC5	0,090	70	0,0630
N2	2,28	28	0,6384
CO2	1,15	44	0,5060
Molecular weight of gas =			17,6936

M_a : Molecular weight 17,6936 gr/mole

γ_g : Specific Gravity of gas; Molecular weight / 29 = 17,6936 / 29 = 0,6101

T_{pc} : Pseudocritical temperature, °R

$$T_{pc} = 169{,}2 + 349{,}5\ \gamma_g - 74\ \gamma_g^2 = 354{,}8917\ °R$$

P_{pc} : Pseudocritical pressure, psia

$$P_{pc} = 758{,}8 - 131\ \gamma_g - 3{,}6\ \gamma_g^2 = 675{,}5336,\ psia$$

R : Universal gas constant, 10,732 psi.ft^3/(lbm.mol. °R)

P : Pressure, psi

T : Temperature, R, T(h) = 69°C

T_{pr} : Pseudoreduced temperature

$T_{pr} = T / T_{pc} = 612,2 / 354,8917 = 1,7363$

P_{pr} : Pseudoreduced pressure

$P_{pr} = P / P_{pc} = 2000 / 675,5336 = 2,96$

ρ_{re} : Pseudoreduced gas density

$\rho_{re} : 0,27*(P_{pr}/(z*T_{pr}))$

where, z is gas compressibility factor.

$z = 1+(A_1+A_2/T_{pr}+A_3/T_{pr}^3+A_4/T_{pr}^4+A_5/T_{pr}^5)*\rho_{re}+(A_6+A_7/T_{pr}+A_8/T_{pr}^2)*\rho_{re}^2-A_9(A_7/T_{pr}+A_8/T_{pr}^2)*\rho_{re}^5+A(1+A_{11}*\rho_{re}^2)(\rho_{re}^2/T_{pr}^3)*\exp(-A_{11}*\rho_{re}^2)$

where;

$A_1 = 0,3265$	$A_7 = -0,7361$
$A_2 = -1,07$	$A_8 = 0,1844$
$A_3 = -0,5339$	$A_9 = 0,1056$
$A_4 = 0,01569$	$A_{10} = 0,6134$
$A_5 = -0,05165$	$A_{11} = 0,721$
$A_6 = 0,5475$	

ρ_g : Gas density, lbm/ft^3

$\rho_g = 0,0433*P*\gamma*z*T$

μ_g : Gas viscosity, cp

$\mu_g = A*\exp(B*\rho_g^C)*10^{-4}$

where;

$A = ((9,379+0,01607*M_a)*T^{1,5})/(209,2+19,26*M_a+T)$

$B = 3,448+(986,4/T)+0,01009*M_a$

$C = 2,447-0,2224*B$

B_g : Formation volume factor, ft^3/scf

$B_g = 0,00502*(z*T/P)$

Table A.2 Calculation of Pressure vs. fluid properties

P, psi	P_{pr}	ρ_{re}	z	μ_g, cp	B_g
14,7	0,0217606	0,003389277	0,9987	0,01268	0,210150
50	0,0740156	0,012252836	0,9945	0,0127	0,061529
100	0,1480311	0,024640064	0,9891	0,012736	0,030597
200	0,2960622	0,049820943	0,9784	0,012827	0,015132
400	0,5921245	0,101821476	0,9574	0,013059	0,007404
700	1,0362178	0,183887226	0,9278	0,013509	0,004100
1000	1,4803112	0,270516133	0,9009	0,014073	0,002787
1300	1,9244046	0,36087988	0,8780	0,014748	0,002089
1600	2,3684979	0,45356142	0,8598	0,01553	0,001662
1827	2,7045286	0,524076705	0,8496	0,016187	0,001439
2000	2,9606224	0,57741317	0,8442	0,016721	0,001306
2250	3,3307002	0,653012292	0,8398	0,017533	0,001154

APPENDIX B

PRODUCTION DATA

Well 1

YEAR	MONTH	Pwh (psi)	RATE(mscf/d)	GAS PROD. (mscf)	REMARKS (days)	Cum. Gas Production (mscf)
1997	9	1.720	4.058	8.116	2	8.116
1997	10	1.690	6.538	156.912	24	165.028
1997	11	1.720	5.865	175.950	30	340.978
1997	12	1.710	6.210	192.510	31	533.488
1998	1	1.780	6.143	190.433	31	723.921
1998	2	1.710	6.085	170.380	28	894.301
1998	3	1.680	7.298	175.152	24	1.069.453
1998	4	1.680	7.577	219.733	29	1.289.186
1998	5	1.690	7.106	220.286	31	1.509.472
1998	6	1.630	9.379	281.370	30	1.790.842
1998	7	1.610	9.907	307.117	31	2.097.959
1998	8	1.640	7.965	246.915	31	2.344.874
1998	9	1.520	10.801	324.030	30	2.668.904
1998	10	1.520	11.644	337.676	29	3.006.580
1998	11	1.480	11.353	340.590	30	3.347.170
1998	12	1.460	11.822	366.482	31	3.713.652
1999	1	1.480	11.175	346.425	31	4.060.077
1999	2	1.440	11.521	322.588	28	4.382.665
1999	3	1.440	11.425	354.175	31	4.736.840
1999	4	1.440	10.859	325.770	30	5.062.610
1999	5	1.430	11.044	342.364	31	5.404.974
1999	6	1.420	10.839	325.170	30	5.730.144
1999	7	1.390	10.845	325.350	30	6.055.494
1999	8	1.420	10.151	314.681	31	6.370.175
1999	9	1.380	10.612	318.360	30	6.688.535
1999	10	1.370	10.538	326.678	31	7.015.213
1999	11	1.340	10.677	320.310	30	7.335.523
1999	12	1.320	10.909	338.179	31	7.673.702
2000	1	1.240	11.360	352.160	31	8.025.862
2000	2	1.250	11.633	337.357	29	8.363.219
2000	3	1.200	11.427	354.237	31	8.717.456
2000	4	1.270	10.880	326.400	30	9.043.856

2000	5	1.280	9.852	295.560	30	9.339.416
2000	6	1.290	9.623	288.690	30	9.628.106
2000	7	1.270	10.291	319.021	31	9.947.127
2000	8	1.250	10.234	317.254	31	10.264.381
2000	9	1.250	9.291	269.439	29	10.533.820
2000	10	1.310	7.246	224.626	31	10.758.446
2000	11	1.310	7.471	224.130	30	10.982.576
2000	12	1.300	6.636	205.716	31	11.188.292
2001	1	1.295	6.239	187.170	30	11.375.462
2001	2	1.205	7.140	178.500	25	11.553.962
2001	3	1.230	8.664	181.944	21	11.735.906
2001	4	1.240	7.690	130.730	17	11.866.636
2001	5	1.250	6.747	107.952	16	11.974.588
2001	6	1.280	5.809	121.989	21	12.096.577
2001	7	1.290	5.037	90.666	18	12.187.243
2001	8	1.300	4.986	154.566	31	12.341.809
2001	9	1.285	6.025	180.750	30	12.522.559
2001	10	1.300	5.828	180.668	31	12.703.227
2001	11	1.265	5.716	171.480	30	12.874.707
2001	12	1.285	4.037	113.036	28	12.987.743
2002	1	1.290	3.897	62.352	16	13.050.095

Well 3

YEAR	MONTH	Pwh (psi)	RATE(mscf/d)	GAS PROD. (mscf)	REMARKS (days)	Cum. Gas Production (mscf)
1997	10	1.550	4.410	105.840	24	105.840
1997	11	1.560	4.309	129.270	30	235.110
1997	12	1.560	4.499	139.469	31	374.579
1998	1	1.580	4.125	127.875	31	502.454
1998	2	1.578	3.624	32.616	9	535.070
1998	3	1.494	4.923	49.230	10	584.300
1998	4	1.570	4.090	122.700	30	707.000
1998	5	1.580	3.943	122.233	31	829.233
1998	6	1.550	4.846	145.380	30	974.613
1998	7	1.520	4.869	150.939	31	1.125.552
1998	8	1.540	4.641	143.871	31	1.269.423
1998	9	1.450	5.453	163.590	30	1.433.013
1998	10	1.420	5.736	166.344	29	1.599.357
1998	11	1.410	5.916	177.480	30	1.776.837
1998	12	1.400	6.277	194.587	31	1.971.424

1999	1	1.420	6.061	187.891	31	2.159.315
1999	2	1.380	6.049	169.372	28	2.328.687
1999	3	1.390	6.024	186.744	31	2.515.431
1999	4	1.390	5.712	171.360	30	2.686.791
1999	5	1.380	5.675	175.925	31	2.862.716
1999	6	1.370	5.531	165.930	30	3.028.646
1999	7	1.350	5.465	169.415	31	3.198.061
1999	8	1.370	5.304	164.424	31	3.362.485
1999	9	1.330	5.390	161.700	30	3.524.185
1999	10	1.320	5.548	171.988	31	3.696.173
1999	11	1.300	5.283	158.490	30	3.854.663
1999	12	1.300	5.182	160.642	31	4.015.305
2000	1	1.260	5.120	158.720	31	4.174.025
2000	2	1.200	5.099	147.871	29	4.321.896
2000	3	1.200	4.906	152.086	31	4.473.982
2000	4	1.230	4.648	139.440	30	4.613.422
2000	5	1.240	4.006	120.180	30	4.733.602
2000	6	1.250	4.232	126.960	30	4.860.562
2000	7	1.210	4.441	137.671	31	4.998.233
2000	8	1.200	4.438	137.578	31	5.135.811
2000	9	1.210	4.127	119.683	29	5.255.494
2000	10	1.280	2.841	51.138	18	5.306.632
2000	11	1.280	3.010	69.230	23	5.375.862
2000	12	1.270	2.780	86.180	31	5.462.042
2001	1	1.285	2.291	52.693	23	5.514.735
2001	2	1.265	2.535	17.745	7	5.532.480
2001	3	1.260	3.462	93.474	27	5.625.954
2001	4	1.220	3.091	92.730	30	5.718.684
2001	5	1.175	3.532	49.448	14	5.768.132
2001	6	1.250	3.013	63.273	21	5.831.405
2001	7	1.240	2.819	39.466	14	5.870.871
2001	8	1.250	2.428	26.708	11	5.897.579
2001	9	1250	2.592	77.760	30	5.975.339
2001	10	1230	2928	55.632	19	6.030.971
2001	11	1220	2351	37.616	16	6.068.587
2001	12	1220	2227	64.583	29	6.133.170
2002	1	1210	2535	40.560	16	6.173.730

Well 4

YEAR	MONTH	Pwh (psi)	RATE(mscf/d)	GAS PROD. (mscf)	REMARKS (days)	Cum. Gas Production (mscf)
1997	9	1.700	4.224	8.448	2	8.448
1997	10	1.670	6.778	162.672	24	171.120
1997	11	1.690	7.371	221.130	30	392.250
1997	12	1.700	8.023	248.713	31	640.963
1998	1	1.700	6.996	216.876	31	857.839
1998	2	1.660	7.305	197.235	27	1.055.074
1998	3	1.650	8.472	169.440	20	1.224.514
1998	4	1.570	8.034	241.020	30	1.465.534
1998	5	1.680	7.735	239.785	31	1.705.319
1998	6	1.640	10.377	311.310	30	2.016.629
1998	7	1.610	10.868	336.908	31	2.353.537
1998	8	1.510	13.768	426.808	31	2.780.345
1998	9	1.510	13.064	391.920	30	3.172.265
1998	10	1.500	12.970	402.070	31	3.574.335
1998	11	1.500	12.297	356.613	29	3.930.948
1998	12	1.480	12.878	399.218	31	4.330.166
1999	1	1.490	11.826	366.606	31	4.696.772
1999	2	1.460	12.487	349.636	28	5.046.408
1999	3	1.450	12.128	375.968	31	5.422.376
1999	4	1.450	11.597	347.910	30	5.770.286
1999	5	1.430	11.795	365.645	31	6.135.931
1999	6	1.420	11.665	349.950	30	6.485.881
1999	7	1.400	11.787	365.397	31	6.851.278
1999	8	1.420	10.977	340.287	31	7.191.565
1999	9	1.390	11.538	346.140	30	7.537.705
1999	10	1.370	11.463	355.353	31	7.893.058
1999	11	1.360	11.533	345.990	30	8.239.048
1999	12	1.340	11.613	360.003	31	8.599.051
2000	1	1.300	12.010	372.310	31	8.971.361
2000	2	1.270	12.367	358.643	29	9.330.004
2000	3	1.270	11.911	369.241	31	9.699.245
2000	4	1.280	11.617	348.510	30	10.047.755
2000	5	1.290	10.613	318.390	30	10.366.145
2000	6	1.280	10.706	321.180	30	10.687.325
2000	7	1.260	11.358	352.098	31	11.039.423
2000	8	1.240	11.271	349.401	31	11.388.824
2000	9	1.250	10.333	299.657	29	11.688.481
2000	10	1.290	7.830	242.730	31	11.931.211
2000	11	1.270	6.928	124.704	18	12.055.915

2000	12	1.270	7.381	228.811	31	12.284.726
2001	1	1.275	6.724	161.376	24	12.446.102
2001	2	1.150	8.014	208.364	26	12.654.466
2001	3	1.150	9.742	155.872	16	12.810.338
2001	4	1.240	7.942	206.492	26	13.016.830
2001	5	1.260	7.986	215.622	27	13.232.452
2001	6	1.270	5.704	102.672	18	13.335.124
2001	7	1.275	5.348	64.176	12	13.399.300
2001	8	1.260	6.402	134.442	21	13.533.742
2001	9	0	0	0	0	13.533.742
2001	10	0	0	0	0	13.533.742
2001	11	1.225	6.648	119.664	18	13.653.406
2001	12	1.200	7.406	229.586	31	13.882.992
2002	1	1.230	6.493	103.888	16	13.986.880

Well 5

YEAR	MONTH	Pwh (psi)	RATE(mscf/d)	GAS PROD. (mscf)	REMARKS (days)	Cum. Gas Production (mscf)
1997	11	1.740	2.642	23.776	9	23.776
1997	12	1.740	2.579	79.946	31	103.722
1998	1	1.690	3.561	103.270	29	206.992
1998	2	1.650	3.744	97.346	26	304.338
1998	3	1.630	4.933	103.592	21	407.930
1998	4	1.630	5.114	5.114	1	413.044
1998	5	1.820	0	0	0	413.044
1998	6	1.630	5.608	140.194	25	553.238
1998	7	1.520	5.931	183.846	31	737.084
1998	8	1.570	6.102	128.151	21	865.235
1998	9	1.780	0	0	0	865.235
1998	10	1.560	6.179	24.715	4	889.950
1998	11	1.510	7.076	212.279	30	1.102.229
1998	12	1.450	7.082	219.542	31	1.321.771
1999	1	1.460	7.165	222.115	31	1.543.886
1999	2	1.430	6.966	195.048	28	1.738.934
1999	3	1.430	7.020	217.620	31	1.956.554
1999	4	1.430	6.496	194.880	30	2.151.434
1999	5	1.420	6.449	187.021	29	2.338.455
1999	6	1.420	6.070	151.750	25	2.490.205
1999	7	1.390	6.269	194.339	31	2.684.544
1999	8	1.400	13.290	411.990	31	3.096.534

1999	9	1.370	6.056	181.680	30	3.278.214
1999	10	1.360	6.037	187.147	31	3.465.361
1999	11	1.340	6.008	180.240	30	3.645.601
1999	12	1.340	6.042	187.302	31	3.832.903
2000	1	1.290	6.237	193.347	31	4.026.250
2000	2	1.270	6.341	183.889	29	4.210.139
2000	3	1.260	6.227	193.037	31	4.403.176
2000	4	1.270	6.032	180.960	30	4.584.136
2000	5	1.280	5.290	158.700	30	4.742.836
2000	6	1.280	5.288	153.352	29	4.896.188
2000	7	1.260	5.836	180.916	31	5.077.104
2000	8	1.240	5.833	180.823	31	5.257.927
2000	9	1.240	5.514	165.420	30	5.423.347
2000	10	1.270	3.844	115.320	30	5.538.667
2000	11	1.230	4.420	132.600	30	5.671.267
2000	12	1.250	3.748	116.188	31	5.787.455
2001	1	1.260	3.408	68.160	20	5.855.615
2001	2	1.220	3.762	30.096	8	5.885.711
2001	3	1.210	5.885	129.470	22	6.015.181
2001	4	1.220	4.448	35.584	8	6.050.765
2001	5	1.270	3.702	96.252	26	6.147.017
2001	6	1.280	4.075	44.825	11	6.191.842
2001	7	1.220	4.210	54.730	13	6.246.572
2001	8		0	0	0	6.246.572
2001	9	1.265	3.412	64.828	19	6.311.400
2001	10	1.260	3.564	110.484	31	6.421.884
2001	11	1.200	4.517	58.721	13	6.480.605

Well 6

YEAR	MONTH	Pwh (psi)	RATE(mscf/d)	GAS PROD. (mscf)	REMARKS (days)	Cum. Gas Production (mscf)
1997	11	1.780	5.063	30.378	6	30.378
1997	12	1.780	5.027	110.594	22	140.972
1998	1	1.770	4.857	150.567	31	291.539
1998	2	1.760	4.758	123.708	26	415.247
1998	3	1.710	10.357	124.284	12	539.531
1998	4	1.820	0	0	0	539.531
1998	5	1.820	0	0	0	539.531
1998	6	1.650	9.295	232.375	25	771.906
1998	7	1.700	8.052	249.612	31	1.021.518

1998	8	1.680	8.564	265.484	31	1.287.002
1998	9	1.680	8.620	258.600	30	1.545.602
1998	10	1.670	8.571	265.701	31	1.811.303
1998	11	1.500	13.263	291.786	22	2.103.089
1998	12	1.500	13.655	423.305	31	2.526.394
1999	1	1.500	13.249	410.719	31	2.937.113
1999	2	1.450	13.302	372.456	28	3.309.569
1999	3	1.450	13.267	411.277	31	3.720.846
1999	4	1.450	13.676	410.280	30	4.131.126
1999	5	1.430	13.853	429.443	31	4.560.569
1999	6	1.430	13.743	412.290	30	4.972.859
1999	7	1.430	13.888	416.640	30	5.389.499
1999	8		0	0	0	5.389.499
1999	9	1.400	13.749	412.470	30	5.801.969
1999	10	1.370	13.782	427.242	31	6.229.211
1999	11	1.350	13.941	418.230	30	6.647.441
1999	12	1.340	13.968	433.008	31	7.080.449
2000	1	1.300	14.317	443.827	31	7.524.276
2000	2	1.270	14.716	426.764	29	7.951.040
2000	3	1.260	14.551	451.081	31	8.402.121
2000	4	1.280	13.980	419.400	30	8.821.521
2000	5	1.280	12.843	385.290	30	9.206.811
2000	6	1.290	12.821	384.630	30	9.591.441
2000	7	1.270	13.599	421.569	31	10.013.010
2000	8	1.240	13.391	415.121	31	10.428.131
2000	9	1.250	12.323	369.690	30	10.797.821
2000	10	1.270	8.799	237.573	27	11.035.394
2000	11	1.200	10.944	328.320	30	11.363.714
2000	12	1.240	9.705	300.855	31	11.664.569
2001	1	1.250	9.030	243.810	27	11.908.379
2001	2	1.060	9.714	165.138	17	12.073.517
2001	3	1.400	0	0	0	12.073.517
2001	4	1.215	9.354	121.602	13	12.195.119
2001	5	1.155	8.753	43.765	5	12.238.884
2001	6	1.300	6.746	74.206	11	12.313.090
2001	7	1.300	7.731	239.661	31	12.552.751
2001	8	1.295	6.662	206.522	31	12.759.273
2001	9	1.300	7.560	226.800	30	12.986.073
2001	10	1.300	7.734	239.754	31	13.225.827
2001	11	1.275	7.160	214.800	30	13.440.627
2001	12	1.270	6.542	202.802	31	13.643.429
2002	1	1.260	7.171	150.591	21	13.794.020

FIELD

YEAR	MONTH	GAS RATE (mscf/day)	GAS PROD. (mscf)	CUM.GAS PROD. (mscf)
1997	9	8.281	16.564	16.564
1997	10	17.726	425.424	441.988
1997	11	19.350	580.504	1.022.492
1997	12	24.878	771.232	1.793.724
1998	1	25.452	789.021	2.582.745
1998	2	22.189	621.285	3.204.030
1998	3	20.125	621.698	3.825.728
1998	4	19.619	588.567	4.414.295
1998	5	18.784	582.304	4.996.599
1998	6	37.021	1.110.629	6.107.228
1998	7	39.626	1.228.422	7.335.650
1998	8	41.040	1.211.229	8.546.879
1998	9	37.948	1.138.140	9.685.019
1998	10	38.597	1.196.506	10.881.525
1998	11	45.959	1.378.748	12.260.273
1998	12	51.714	1.603.134	13.863.407
1999	1	49.477	1.533.756	15.397.163
1999	2	50.326	1.409.100	16.806.263
1999	3	49.863	1.545.784	18.352.047
1999	4	48.339	1.450.200	19.802.247
1999	5	48.401	1.500.398	21.302.645
1999	6	50.014	1.405.090	22.707.735
1999	7	47.456	1.471.141	24.178.876
1999	8	45.506	1.231.382	25.410.258
1999	9	47.344	1.420.350	26.830.608
1999	10	47.368	1.468.408	28.299.016
1999	11	47.441	1.423.260	29.722.276
1999	12	47.712	1.479.134	31.201.410
2000	1	49.043	1.520.364	32.721.774
2000	2	50.156	1.454.524	34.176.298
2000	3	49.022	1.519.682	35.695.980
2000	4	47.157	1.414.710	37.110.690
2000	5	41.228	1.278.120	38.388.810
2000	6	41.123	1.274.812	39.663.622
2000	7	45.525	1.411.275	41.074.897
2000	8	45.167	1.400.177	42.475.074
2000	9	40.796	1.223.889	43.698.963
2000	10	28.109	871.387	44.570.350
2000	11	29.300	878.984	45.449.334
2000	12	30.250	937.750	46.387.084
2001	1	23.007	713.209	47.100.293

2001	2	21.423	599.843	47.700.136
2001	3	18.089	560.760	48.260.896
2001	4	19.571	587.138	48.848.034
2001	5	16.549	513.039	49.361.073
2001	6	13.128	406.965	49.768.038
2001	7	15.765	488.699	50.256.737
2001	8	16.846	522.238	50.778.975
2001	9	18.338	550.138	51.329.113
2001	10	18.921	586.538	51.915.651
2001	11	20.076	602.281	52.517.932
2001	12	19.678	610.007	53.127.939
2002	1	11.529	357.391	53.485.330

APPENDIX C

INPUT DATA

INPUT/OUTPUT CONTROL SECTION

```
*INUNIT   *FIELD
*WRST          *TIME
*WPRN     *WELL *TIME
*WPRN     *GRID *TIME
*OUTPRN   *WELL *LAYER
*OUTPRN   *GRID *IMEXMAP *SG     *SW *PRES
*WSRF     *WELL *TIME
*WSRF     *GRID *TIME
*OUTSRF   *GRID *IMEXMAP *SG     *SW *PRES
*OUTDIARY       *PRESAQ  *HEADER  20
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RESERVOIR DESCRIPTION

```
*GRID   *VARI  15  19  3
*KDIR   *DOWN
*DI *CON 450
*DJ *CON 450
*DK *KVAR 66 66 116
```

*DTOP

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	4593	4593.	4839.	4511	4429.	4511.	4593.	4593	4593.	4593.	4593.	4593.	4593	4593.	4593.
2	4593	4839.	4593.	4389	4265.	4191.	4130.	4593	4593.	4593.	4593.	4593.	4593	4593.	4593.
3	4593	4757.	4494.	4265	4101.	4009.	4007.	4593	4593.	4593.	4593.	4593.	4593	4593.	4593.
4	4757	4757.	4429.	4148	3904.	3827.	3875.	4593	4593.	4593.	4593.	4593.	4593	4593.	4593.
5	4626	4675.	4224.	4039	3766.	3722.	3745.	3925	4593.	4593.	4593.	4593.	4593	4593.	4593.
6	4447	4733.	4429.	3937	3748.	3677.	3672.	3819	4593.	4593.	4593.	4593.	4593	4593.	4593.
7	4148	4476.	4593.	3998	3762.	3666.	3608.	3752	3969.	4593.	4593.	4593.	4593	4593.	4593.
8	3906	4183.	4757.	4194	3838.	3707.	3608.	3663	4196.	4002.	4593.	4593.	4593	4593.	4593.
9	3793	4039.	4511.	4429	4019.	3814.	3649.	3610	3732.	3926.	4593.	4593.	4593	4593.	4593.
10	4593	3916.	4347.	4634	4201.	3987.	3737.	3648	3690.	3841.	4002.	4593.	4593	4593.	4593.
11	4593	4593.	4288.	4757	4390.	4101.	3834.	3690	3864.	3721.	3847.	4002.	4593	4593.	4593.
12	4593	4593.	4593.	4593	4593.	4244.	4075.	3794	3696.	3694.	3800.	3937.	4063	4169.	4593.
13	4593	4593.	4593.	4593	4593.	4593.	4203.	4035	3827.	3783.	3855.	3991.	4108	4183.	4273.
14	4593	4593.	4593.	4593	4593.	4593.	4593.	4213	4119.	4002.	4050.	4079.	4152	4209.	4301.
15	4593	4593.	4593.	4593	4593.	4593.	4593.	4470	4347.	4254.	4246.	4265.	4329	4276.	4332.
16	4593	4593.	4593.	4593	4593.	4593.	4593.	4593	4634.	4527.	4497.	4452.	4449	4488.	4429.
17	4593	4593.	4593.	4593	4593.	4593.	4593.	4593	4937.	4839.	4757.	4702.	4675	4656.	4684.
18	4593	4593.	4593.	4593	4593.	4593.	4593.	4593	4593.	5132.	5085.	5003.	4954	4908.	4863.
19	4593	4593.	4593.	4593	4593.	4593.	4593.	4593	4593.	4593.	5352.	5319.	5272	5186.	5112.

*NULL *IJK

1:2	1:1	1:3	0
7:15	1:1	1:3	0
1:1	2:2	1:3	0
8:15	2:2	1:3	0
1:1	3:3	1:3	0
8:15	3:3	1:3	0
8:15	4:4	1:3	0
9:15	5:5	1:3	0
9:15	6:6	1:3	0
10:15	7:7	1:3	0
11:15	8:8	1:3	0
11:15	9:9	1:3	0
1:1	10:10	1:3	0
12:15	10:10	1:3	0
1:2	11:11	1:3	0
13:15	11:11	1:3	0
1:5	12:12	1:3	0
15:15	12:12	1:3	0
1:6	13:13	1:3	0
1:7	14:14	1:3	0
1:7	15:15	1:3	0
1:8	16:16	1:3	0
1:8	17:17	1:3	0
1:9	18:18	1:3	0
1:10	19:19	1:3	0

*POR

************LAYER1***************

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	0.12	0.12	0.16	0.16	0.16	0.16	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
2	0.12	0.12	0.20	0.20	0.20	0.16	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
3	0.13	0.16	0.20	0.20	0.20	0.16	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
4	0.14	0.16	0.20	0.20	0.20	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
5	0.14	0.14	0.20	0.20	0.20	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
6	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
7	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.16
8	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.16
9	0.17	0.17	0.17	0.17	0.17	0.20	0.20	0.20	0.20	0.20	0.17	0.17	0.17	0.17	0.17
10	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
11	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
12	0.17	0.17	0.17	0.17	0.17	0.17	0.20	0.20	0.20	0.20	0.20	0.17	0.17	0.17	0.17
13	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16
14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
17	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
18	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
19	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12

************LAYER2***************

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	0.12	0.12	0.16	0.16	0.16	0.16	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
2	0.12	0.12	0.20	0.20	0.20	0.16	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
3	0.13	0.16	0.20	0.20	0.20	0.16	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
4	0.14	0.16	0.20	0.20	0.20	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
5	0.14	0.14	0.20	0.20	0.20	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
6	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
7	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.16
8	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.16
9	0.17	0.17	0.17	0.17	0.17	0.20	0.20	0.20	0.20	0.20	0.17	0.17	0.17	0.17	0.17
10	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
11	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
12	0.17	0.17	0.17	0.17	0.17	0.17	0.20	0.20	0.20	0.20	0.20	0.17	0.17	0.17	0.17
13	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16
14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
17	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
18	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
19	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12

************LAYER3***************

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	0.12	0.12	0.16	0.16	0.16	0.16	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
2	0.12	0.12	0.20	0.20	0.20	0.16	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
3	0.13	0.16	0.20	0.20	0.20	0.16	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
4	0.14	0.16	0.20	0.20	0.20	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
5	0.14	0.14	0.20	0.20	0.20	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
6	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
7	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.16
8	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.16
9	0.17	0.17	0.17	0.17	0.17	0.20	0.20	0.20	0.20	0.20	0.17	0.17	0.17	0.17	0.17
10	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
11	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
12	0.17	0.17	0.17	0.17	0.17	0.17	0.20	0.20	0.20	0.20	0.20	0.17	0.17	0.17	0.17
13	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.16	0.16
14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
17	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
18	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
19	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12

*PERMI

************LAYER1***************

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
2	14	20	20	20	20	20	20	20	14	14	14	14	14	14	14
3	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
4	35	35	35	35	35	35	42	42	42	42	42	42	42	39.2	35
5	39.2	42	42	42	42	42	42	42	42	42	42	42	42	40.6	35
6	39.2	42	35	35	35	42	42	42	42	42	42	42	42	39.2	35
7	39.2	42	35	26.6	35	42	42	42	42	42	42	42	42	37.8	35
8	39.2	42	35	35	35	42	39.2	39.2	42	42	42	42	42	36.4	35
9	35	42	42	35	35	35	35	35	42	42	42	42	42	39.2	35
10	28	28	28	28	22.4	26.6	25.2	26.6	28	28	28	28	28	28	28
11	14	14	14	14	20	18	16	20	20	20	20	14	14	14	14
12	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
13	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
15	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
16	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
17	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
18	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
19	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14

************LAYER2***************

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
2	14	20	20	20	20	20	20	20	14	14	14	14	14	14	14
3	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
4	35	35	35	35	35	35	42	42	42	42	42	42	42	39.2	35
5	39.2	42	42	42	42	42	42	42	42	42	42	42	42	40.6	35
6	39.2	42	35	35	35	42	42	42	42	42	42	42	42	39.2	35
7	39.2	42	35	26.6	35	42	42	42	42	42	42	42	42	37.8	35
8	39.2	42	35	35	35	42	39.2	39.2	42	42	42	42	42	36.4	35
9	35	42	42	35	35	35	35	35	42	42	42	42	42	39.2	35
10	28	28	28	28	22.4	26.6	25.2	26.6	28	28	28	28	28	28	28
11	14	14	14	14	20	18	16	20	20	20	20	14	14	14	14
12	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
13	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
15	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
16	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
17	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
18	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
19	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14

************LAYER3***************

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
2	14	20	20	20	20	20	20	20	14	14	14	14	14	14	14
3	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
4	35	35	35	35	35	35	42	42	42	42	42	42	42	39.2	35
5	39.2	42	42	42	42	42	42	42	42	42	42	42	42	40.6	35
6	39.2	42	35	35	35	42	42	42	42	42	42	42	42	39.2	35
7	39.2	42	35	26.6	35	42	42	42	42	42	42	42	42	37.8	35
8	39.2	42	35	35	35	42	39.2	39.2	42	42	42	42	42	36.4	35
9	35	42	42	35	35	35	35	35	42	42	42	42	42	39.2	35
10	28	28	28	28	22.4	26.6	25.2	26.6	28	28	28	28	28	28	28
11	14	14	14	14	20	18	16	20	20	20	20	14	14	14	14
12	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
13	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
15	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
16	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
17	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
18	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
19	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14

*PERMJ *EQUALSI

*PERMK *EQUALSI * 0.7

*CPOR 4.0E-6

*PRPOR 2100.0

**---FLUID---

*MODEL *GASWATER

*PVTG *BG 1

P	B_g	μ_g
psi	RB/Scf	cp
14.7	0.19844	0.01204
50.0	0.05812	0.01206
100.0	0.02891	0.01211
200.0	0.01430	0.01221
400.0	0.00700	0.01246
700.0	0.00388	0.01295
1000.0	0.00264	0.01356
1300.0	0.00198	0.01428
1600.0	0.00158	0.01512
1827.0	0.00137	0.01582
2000.0	0.00124	0.01640
2250.0	0.00110	0.01727

*DENSITY *GAS 0.1109

*DENSITY *WATER 62.46

*BWI 0.5

*CW 3.58E-6

*REFPW 2075.0

*VWI 1.0

*CVW 0.0

**---ROCKFLUID---

*ROCKFLUID

*RPT 1

*SWT

S_w, %	K_{rw}, %
0.1	0.0
0.2	0.001371742
0.3	0.010973937
0.4	0.037037037
0.5	0.087791495
0.6	0.171467764
0.7	0.296296296
0.8	0.470507545
0.9	0.702331962
1.0	1.0

*SGT

S_g, %	K_{rg}, %
0.0	0.0
0.1	0.039458497
0.2	0.110825515
0.3	0.20206671
0.4	0.308559693
0.5	0.427363331
0.6	0.55620369
0.7	0.6930621
0.8	0.835995131
0.9	0.96

***---INITIALIZATION--

*INITIAL

*VERTICAL *DEPTH_AVE *WATER_GAS

*REFDEPTH   5565.5

```
*REFPRES    2075.0
*DWGC       5700.0

**---NUMERICAL CONTROL-----------------------------------------------------

*NUMERICAL
*DTMAX    30.0
*NCUTS     4

**---WELL AND RUN DATA-----------------------------------------------------

*RUN
*DATE 1997 09 01

**---PRODUCERS-------------------------------------------------------------
*WELL  1 'KM1'   *VERT   8  10
*WELL  2 'KM2'   *VERT   4   3
*WELL  3 'KM3'   *VERT  10  12
*WELL  4 'KM4'   *VERT   7   8
*WELL  5 'KM5'   *VERT   8  11
*WELL  6 'KM6'   *VERT  10  10

**---INJECTORS-------------------------------------------------------------
*WELL   7 'KM11'   *VERT   8  10
*WELL   8 'KM22'   *VERT   4   3
*WELL   9 'KM33'   *VERT  10  12
*WELL  10 'KM44'   *VERT   7   8
*WELL  11 'KM55'   *VERT   8  11
*WELL  12 'KM66'   *VERT  10  10

**---HORIZANTALS-----------------------------------------------------------
```

```
*WELL       13 'H1'            *VERT  6  4
*WELL       14 'H2'            *VERT  4 10
*WELL       15 'H3'            *VERT 10  9
*WELL       16 'H4'            *VERT 11 11
*WELL       17 'H5'            *VERT  6  6

**---HORIZONTAL INJECTORS----------------------------------------------
*WELL       18 'H11'    *VERT  6  4
*WELL       19 'H22'    *VERT  4 10
*WELL       20 'H33'    *VERT 10  9
*WELL       21 'H44'    *VERT 11 11
*WELL       22 'H55'    *VERT  6  6

*PRODUCER 'KM1'
** Composition    C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
*PWELLBORE  *MODEL  0.9145  0.0321  0.0121  0.0024  0.0030
0.0009 0.0007 0 0.0115
** wdepth wlength rel_rough whtemp bhtemp wradius
        3797. 3797. 0.0001 80. 155. 0.29
*OPERATE *MAX *STG  11.65E+06 CONT
*OPERATE  *MIN *BHP     500.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 0.
*PERF *GEO   'KM1'
        8 10 3 1. OPEN FLOW-TO 'SURFACE'
*LAYERXYZ 'KM1'
 8 10 3
**$ (PERF  BEGIN)  X1  Y1  Z1     (PERF  END)  X2  Y2  Z2      (PERF
LENGTH) XPLEN
        3262.5     4162.5     3673.81409765625     3262.5     4162.5
3773.38609765625 100
```

```
*PRODUCER 'KM2'
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
*PWELLBORE  *MODEL  0.9145  0.0321  0.0121  0.0024  0.0030 0.0009 0.0007 0 0.0115
** wdepth wlength rel_rough whtemp bhtemp wradius
3747. 3747. 0.0001 80. 155. 0.29
*OPERATE *MAX *STG  8.3E+06 CONT
*OPERATE  *MIN *BHP      500.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 10.
*PERF *GEO   'KM2'
    4 3 3 1. OPEN FLOW-TO 'SURFACE'

*LAYERXYZ 'KM2'
4 3 3
**$ (PERF BEGIN) X1 Y1 Z1    (PERF END) X2 Y2 Z2     (PERF LENGTH) XPLEN
    3937.5    5062.5    3739.41395117187    3937.5    5062.5 3839.98595117188 100

*PRODUCER 'KM3'
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
*PWELLBORE  *MODEL  0.9145  0.0321  0.0121  0.0024  0.0030 0.0009 0.0007 0 0.0115
** wdepth wlength rel_rough whtemp bhtemp wradius
    3829. 3829. 0.0001 80. 155. 0.29
*OPERATE *MAX *STG  6.3E+05 CONT
*OPERATE  *MIN *BHP      500.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'KM3'
    10 12 3 1. OPEN FLOW-TO 'SURFACE'
```

*LAYERXYZ 'KM3'

10 12 3

**$ (PERF BEGIN) X1 Y1 Z1 (PERF END) X2 Y2 Z2 (PERF LENGTH) XPLEN

2025 3487.5 4018.214 2025 3487.5 4118.786 100

*PRODUCER 'KM4'

** Composition C1 C2 C3 IC4 NC4 IC5 NC5 C6 CO2

*PWELLBORE *MODEL 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115

** wdepth wlength rel_rough whtemp bhtemp wradius

3829. 3829. 0.0001 80. 155. 0.29

*OPERATE *MAX *STG 13.8E+06 CONT

*OPERATE *MIN *BHP 500.0 *CONT *REPEAT

*GEOMETRY *K 0.1875 0.37 1. 3.

*PERF *GEO 'KM4'

7 8 3 1. OPEN FLOW-TO 'SURFACE'

*LAYERXYZ 'KM4'

7 8 3

**$ (PERF BEGIN) X1 Y1 Z1 (PERF END) X2 Y2 Z2 (PERF LENGTH) XPLEN

3037.5 4612.5 3854.214 3037.5 4612.5 3954.786 100

*PRODUCER 'KM5'

*PWELLBORE *MODEL 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115

3731. 3731. 0.0001 80. 155. 0.29

*OPERATE *MAX *STG 13.29E+06 CONT

*OPERATE *MIN *BHP 500.0 *CONT *REPEAT

*GEOMETRY *K 0.1875 0.37 1. 3.

```
*PERF *GEO   'KM5'
  8 11 3 1. OPEN FLOW-TO 'SURFACE'

*LAYERXYZ 'KM5'
8 11 3
**$ (PERF BEGIN) X1 Y1 Z1   (PERF END) X2 Y2 Z2    (PERF LENGTH)
XPLEN
  3937.5    4387.5    3673.81409765625    3937.5    4387.5
3773.38609765625 100

*PRODUCER 'KM6'
*PWELLBORE *MODEL 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009
0.0007 0 0.0115
  3251. 3251. 0.0001 80. 155. 0.29
*OPERATE *MAX *STG  14.8E+06 CONT
*OPERATE  *MIN *BHP     500.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'KM6'
  10 10 3 1. OPEN FLOW-TO 'SURFACE'

*LAYERXYZ 'KM6'
10 10 3
**$ (PERF BEGIN) X1 Y1 Z1   (PERF END) X2 Y2 Z2    (PERF LENGTH)
XPLEN
  3348.5    3827.5    3201.81409765625    3348.5    3827.5
3301.38609765625 100

**---INJECTORS---------------------------------------------------------------

  *INJECTOR 'KM11'
  *IWELLBORE
```

```
** wdepth wlength rel_rough whtemp bhtemp wradius
        3797. 3797. 0.0001 80. 155. 0.29
*INCOMP  *GAS  *GLOBAL
0.98 0.0152 0.21 0.0003 0.0005 0.0004 0.0003 0 0.0012
*OPERATE *MAX *STG  10E+15 CONT
*OPERATE  *MAX *BHP      2000.0 *CONT   *REPEAT

*GEOMETRY *K 0.1875 0.37 1. 0.
*PERF *GEO   'KM11'
        8 10 3 1.
*LAYERXYZ 'KM11'
 8 10 3
**$ (PERF BEGIN) X1 Y1 Z1 (PERF END) X2 Y2 Z2 (PERF LENGTH) XPLEN
        3262.5 4162.5 3673.81409765625 3262.5 4162.5 3773.38609765625 100

*INJECTOR 'KM22'
*IWELLBORE
** wdepth wlength rel_rough whtemp bhtemp wradius
  3747. 3747. 0.0001 80. 155. 0.29
*INCOMP      *GAS *GLOBAL
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
         0.98 0.0152 0.21 0.0003 0.0005 0.0004 0.0003 0 0.0012

*OPERATE *MAX *STG  8E+15 CONT
*OPERATE  *MAX *BHP      2000.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 10.
*PERF *GEO   'KM22'
  4 3 3 1.
```

*LAYERXYZ 'KM22'

4 3 3

**$ (PERF BEGIN) X1 Y1 Z1 (PERF END) X2 Y2 Z2 (PERF LENGTH) XPLEN

3937.5 5062.5 3739.41395117187 3937.5 5062.5 3839.98595117188 100

*INJECTOR 'KM33'

*IWELLBORE

** wdepth wlength rel_rough whtemp bhtemp wradius

3829. 3829. 0.0001 80. 155. 0.29

*INCOMP *GAS *GLOBAL

** Composition C1 C2 C3 IC4 NC4 IC5 NC5 C6 CO2

0.98 0.0152 0.21 0.0003 0.0005 0.0004 0.0003 0 0.0012

*OPERATE *MAX *STG 6E+15 CONT

*OPERATE *MAX *BHP 2000.0 *CONT *REPEAT

*GEOMETRY *K 0.1875 0.37 1. 3.

*PERF *GEO 'KM33'

10 12 3 1.

*LAYERXYZ 'KM33'

10 12 3

**$ (PERF BEGIN) X1 Y1 Z1 (PERF END) X2 Y2 Z2 (PERF LENGTH) XPLEN

2025 3487.5 4018.214 2025 3487.5 4118.786 100

*INJECTOR 'KM44'

*IWELLBORE

** wdepth wlength rel_rough whtemp bhtemp wradius

3829. 3829. 0.0001 80. 155. 0.29

```
*INCOMP     *GAS *GLOBAL
** Composition    C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
          0.98 0.0152 0.21 0.0003 0.0005 0.0004 0.0003 0 0.0012

*OPERATE *MAX *STG  13E+15 CONT
*OPERATE  *MAX *BHP     2000.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'KM44'
  7 8 3 1.

*LAYERXYZ 'KM44'
7 8 3
**$ (PERF BEGIN) X1 Y1 Z1   (PERF END) X2 Y2 Z2    (PERF LENGTH) XPLEN
  3037.5 4612.5 3854.214 3037.5 4612.5 3954.786 100


*INJECTOR 'KM55'
*IWELLBORE
** wdepth wlength rel_rough whtemp bhtemp wradius
3731. 3731. 0.0001 80. 155. 0.29
*INCOMP *GAS      *GLOBAL
** Composition    C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
           0.98 0.0152 0.21 0.0003 0.0005 0.0004 0.0003 0 0.0012

*OPERATE *MAX *STG  13E+15 CONT
*OPERATE  *MAX *BHP     2000.0 *CONT   *REPEAT

*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'KM55'
  8 11 3 1.
```

```
*LAYERXYZ 'KM55'
8 11 3
**$ (PERF BEGIN) X1 Y1 Z1   (PERF END) X2 Y2 Z2    (PERF LENGTH) XPLEN
 3937.5  4387.5  3673.81409765625  3937.5  4387.5  3773.38609765625 100

*INJECTOR 'KM66'
*IWELLBORE
** wdepth wlength rel_rough whtemp bhtemp wradius
 3251. 3251. 0.0001 80. 155. 0.29
*INCOMP    *GAS GLOBAL
** Composition    C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
      0.98 0.0152 0.21 0.0003 0.0005 0.0004 0.0003 0 0.0012

*OPERATE *MAX *STG  14E+15 CONT
*OPERATE  *MAX *BHP     2000.0 *CONT   *REPEAT

*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'KM66'
 10 10 3 1.

*LAYERXYZ 'KM66'
10 10 3
**$ (PERF BEGIN) X1 Y1 Z1   (PERF END) X2 Y2 Z2    (PERF LENGTH) XPLEN
 3348.5  3827.5  3201.81409765625  3348.5  3827.5  3301.38609765625 100

**---HORIZONTALS-----------------------------------------------------------
```

*PRODUCER 'H1'
** Composition C1 C2 C3 IC4 NC4 IC5 NC5 C6 CO2
*PWELLBORE *MODEL 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115
** wdepth wlength rel_rough whtemp bhtemp wradius
3829. 3829. 0.0001 80. 155. 0.29
*OPERATE *MAX *STG 13.8E+06 CONT
*OPERATE *MIN *BHP 500.0 *CONT *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO 'H1'
3:5 4 3 1. OPEN FLOW-TO 'SURFACE'

*PRODUCER 'H2'
** Composition C1 C2 C3 IC4 NC4 IC5 NC5 C6 CO2
*PWELLBORE *MODEL 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115
** wdepth wlength rel_rough whtemp bhtemp wradius
3829. 3829. 0.0001 80. 155. 0.29
*OPERATE *MAX *STG 13.8E+06 CONT
*OPERATE *MIN *BHP 500.0 *CONT *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO 'H2'
5:6 10 3 1. OPEN FLOW-TO 'SURFACE'

*PRODUCER 'H3'
** Composition C1 C2 C3 IC4 NC4 IC5 NC5 C6 CO2
*PWELLBORE *MODEL 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115

```
** wdepth wlength rel_rough whtemp bhtemp wradius
  3829. 3829. 0.0001 80. 155. 0.29
*OPERATE *MAX *STG  13.8E+06 CONT
*OPERATE  *MIN *BHP      500.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'H3'
  8:9 9 3 1. OPEN FLOW-TO 'SURFACE'


*PRODUCER 'H4'
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
*PWELLBORE *MODEL 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009
0.0007 0 0.0115
** wdepth wlength rel_rough whtemp bhtemp wradius
  3829. 3829. 0.0001 80. 155. 0.29
*OPERATE *MAX *STG  13.8E+06 CONT
*OPERATE  *MIN *BHP      500.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'H4'
  9:10 11 3 1. OPEN FLOW-TO 'SURFACE'


*PRODUCER 'H5'
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
*PWELLBORE *MODEL 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009
0.0007 0 0.0115
** wdepth wlength rel_rough whtemp bhtemp wradius
  3829. 3829. 0.0001 80. 155. 0.29
*OPERATE *MAX *STG  13.8E+06 CONT
*OPERATE  *MIN *BHP      500.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
```

```
*PERF *GEO   'H5'
  6 7:8 3 1. OPEN FLOW-TO 'SURFACE'


**---HORIZONTAL INJECTORS-----------------------------------------------

*INJECTOR 'H11'
*IWELLBORE
** wdepth wlength rel_rough whtemp bhtemp wradius
  3829. 3829. 0.0001 80. 155. 0.29
*INCOMP     *GAS *GLOBAL
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115
*OPERATE *MAX *STG  13.8E+06 CONT
*OPERATE  *MAX *BHP     2000.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'H11'
  3:5 4 3 1.



*INJECTOR 'H22'
*IWELLBORE
** wdepth wlength rel_rough whtemp bhtemp wradius
  3829. 3829. 0.0001 80. 155. 0.29
*INCOMP  *GAS  *GLOBAL
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115

*OPERATE *MAX *STG  13.8E+06 CONT
*OPERATE  *MAX *BHP     2000.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
```

```
*PERF *GEO   'H22'
  5:6 10 3 1.


*INJECTOR 'H33'
*IWELLBORE
** wdepth wlength rel_rough whtemp bhtemp wradius
  3829. 3829. 0.0001 80. 155. 0.29
*INCOMP  *GAS  *GLOBAL
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115

*OPERATE *MAX *STG  13.8E+06 CONT
*OPERATE  *MAX *BHP      2000.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'H33'
  8:9 9 3 1.


*INJECTOR 'H44'
*IWELLBORE
** wdepth wlength rel_rough whtemp bhtemp wradius
  3829. 3829. 0.0001 80. 155. 0.29
*INCOMP *GAS  *GLOBAL
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115

*OPERATE *MAX *STG  13.8E+06 CONT
*OPERATE  *MAX *BHP      2000.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'H44'
```

```
  9:10 11 3 1.


*INJECTOR 'H55'
*IWELLBORE
** wdepth wlength rel_rough whtemp bhtemp wradius
  3829. 3829. 0.0001 80. 155. 0.29
*INCOMP  *GAS  *GLOBAL
** Composition     C1   C2  C3  IC4  NC4 IC5 NC5  C6  CO2
 0.9145 0.0321 0.0121 0.0024 0.0030 0.0009 0.0007 0 0.0115

*OPERATE *MAX *STG  13.8E+06 CONT
*OPERATE  *MAX *BHP      2000.0 *CONT   *REPEAT
*GEOMETRY *K 0.1875 0.37 1. 3.
*PERF *GEO   'H55'
  6 7:8 3 1.



*OPEN 'KM1'
*OPEN 'KM2'
*OPEN 'KM4'
*SHUTIN 'KM5'
*SHUTIN 'KM6'
*SHUTIN 'KM11'
*SHUTIN 'KM22'
*SHUTIN 'KM33'
*SHUTIN 'KM44'
*SHUTIN 'KM55'
*SHUTIN 'KM66'
*SHUTIN 'H1'
*SHUTIN 'H2'
```

```
*SHUTIN 'H11'
*SHUTIN 'H22'
*SHUTIN 'H33'
*SHUTIN 'H44'
*SHUTIN 'H55'
*SHUTIN 'H3'
*SHUTIN 'H4'
*SHUTIN 'H5'
*DATE 1997 09 02
    ALTER
 'KM1'      'KM2'      'KM4'
 4058000.   8281000.   4224000.

*DATE 1997 09 05
*SHUTIN 'KM1'
*SHUTIN 'KM4'

*SHUTIN 'KM2'
*OPEN 'KM3'

 *DATE 1997 10 01
    ALTER
 'KM1'      'KM3'      'KM4'
 6538000.   4410000.   4224000.

 *OPEN 'KM5'
    *OPEN 'KM6'

 *DATE 1997 10 25
 *SHUTIN 'KM4'
```

```
*DATE 1997 11 01
    ALTER
'KM1'       'KM3'       'KM4'       'KM5'       'KM6'
5865000.    4309000.    6778000          2642000          5063000

*DATE 1997 11 07
*SHUTIN 'KM6'

*DATE 1997 11 10
*SHUTIN 'KM5'

   *DATE 1997 12 01
*OPEN 'KM6'
    ALTER
'KM1'       'KM3'       'KM4'       'KM5'       'KM6'
6210000.    4499000          8023000          2579000
5027000

   *DATE 1998 01 01
    ALTER
'KM1'       'KM3'       'KM4'       'KM5'       'KM6'
6143000.    4125000          6996000          3561000
4857000

   *DATE 1998 02 01
    ALTER
'KM1'       'KM3'       'KM4'       'KM5'       'KM6'
6085000.    3624000          7305000          3744000
4758000

*DATE 1998 02 10
```

```
*SHUTIN 'KM3'

    *DATE 1998 03 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
7298000.     4923000            8472000             4933000
10357000

*DATE 1998 03 11
*SHUTIN 'KM3'

*DATE 1998 03 13
**ALTER
*SHUTIN 'KM6'

*DATE 1998 03 22
*SHUTIN 'KM5'

    *DATE 1998 04 01
*OPEN 'KM6'
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
7577000.     4090000            8034000             5114000             0.

*DATE 1998 04 02
*SHUTIN 'KM5'

    *DATE 1998 05 01
     ALTER
'KM1'        'KM3'        'KM4'              'KM6'
7106000.     3943000.           7735000.     0.
```

```
*DATE 1998 06 01
 ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
9379000.     4846000            10377000   5608000           9295000

*DATE 1998 06 26
*SHUTIN 'KM5'


*DATE 1998 07 01
 ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
9907000.     4869000            10868000   5931000           8052000

*DATE 1998 08 01
 ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
7965000.     4641000            13768000   6102000           8564000

*DATE 1998 08 22
*SHUTIN 'KM5'

*DATE 1998 09 01
 ALTER
'KM1'        'KM3'        'KM4'                  'KM6'
10801000.    5453000      13064000               8620000

*DATE 1998 10 01
 ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
```

```
11644000.  5736000            12970000   6179000            8571000

*DATE 1998 10 05
*SHUTIN 'KM5'

    *DATE 1998 11 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
11353000.  5916000            12297000   7076000
13263000

    *DATE 1998 12 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
11822000.  6277000            12878000   7082000
13655000

    *DATE 1999 01 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
11175000.  6061000            11826000   7165000
13249000

    *DATE 1999 02 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
11521000.  6049000            12487000   6966000
13302000

    *DATE 1999 03 01
     ALTER
```

```
'KM1'         'KM3'         'KM4'         'KM5'         'KM6'
11425000.  6024000           12128000   7020000
13267000

    *DATE 1999 04 01
     ALTER
'KM1'         'KM3'         'KM4'         'KM5'         'KM6'
10859000.  5712000           11597000   6496000
13676000

    *DATE 1999 05 01
     ALTER
'KM1'         'KM3'         'KM4'         'KM5'         'KM6'
11044000.  5675000           11795000   6449000
13853000

    *DATE 1999 06 01
     ALTER
'KM1'         'KM3'         'KM4'         'KM5'         'KM6'
10839000.  5531000           11665000   6070000
13743000

*DATE 1999 06 26
*SHUTIN 'KM5'

    *DATE 1999 07 01
     ALTER
'KM1'         'KM3'         'KM4'         'KM5'         'KM6'
10845000.  5645000           11787000   6269000
13888000
```

```
    *DATE 1999 08 01
     ALTER
'KM1'          'KM3'          'KM4'          'KM5'          'KM6'
10151000.  5304000             10977000   13290000   0

    *DATE 1999 09 01
     ALTER
'KM1'          'KM3'          'KM4'          'KM5'          'KM6'
10612000.  5390000             11538000   6056000
13749000

    *DATE 1999 10 01
     ALTER
'KM1'          'KM3'          'KM4'          'KM5'          'KM6'
10538000.  5548000             11463000   6037000
13782000

    *DATE 1999 11 01
     ALTER
'KM1'          'KM3'          'KM4'          'KM5'          'KM6'
10677000.  5283000             11533000   6008000
13941000

    *DATE 1999 12 01
     ALTER
'KM1'          'KM3'          'KM4'          'KM5'          'KM6'
10909000.  5182000             11613000   6042000
13968000

    *DATE 2000 01 01
     ALTER
```

```
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
11360000.  5120000          12010000   6237000
14317000

    *DATE 2000 02 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
11633000.  5099000          12367000   6341000
14716000

    *DATE 2000 03 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
11427000.  4906000          11911000   6227000
14551000

    *DATE 2000 04 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
10880000.  4648000          11617000   6032000
13980000

    *DATE 2000 05 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
9852000.   4006000          10613000   5290000
12843000

    *DATE 2000 06 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
```

```
9623000.    4232000             10706000   5288000
12821000

    *DATE 2000 07 01
     ALTER
'KM1'          'KM3'          'KM4'          'KM5'          'KM6'
10291000.  4441000             11358000   5836000
13599000

    *DATE 2000 08 01
     ALTER
'KM1'          'KM3'          'KM4'          'KM5'          'KM6'
10234000.  4438000             11271000   5833000
13391000

    *DATE 2000 09 01
     ALTER
'KM1'          'KM3'          'KM4'          'KM5'          'KM6'
9291000.    4127000             10333000   5514000
12323000

    *DATE 2000 10 01
     ALTER
'KM1'          'KM3'          'KM4'          'KM5'          'KM6'
7246000.    2841000             7830000             3844000
8799000

*DATE 2000 10 19
*SHUTIN 'KM3'

    *DATE 2000 11 01
```

```
    ALTER
'KM1'      'KM3'      'KM4'      'KM5'      'KM6'
7471000.   3010000         6928000         4420000
10944000

*DATE 2000 11 19
*SHUTIN 'KM4'

*DATE 2000 11 24
*SHUTIN 'KM3'

   *DATE 2000 12 01
    ALTER
'KM1'      'KM3'      'KM4'      'KM5'      'KM6'
6636000.   2780000         7381000         3748000
9705000

   *DATE 2001 01 01
    ALTER
'KM1'      'KM3'      'KM4'      'KM5'      'KM6'
6239000.   2291000         6724000         3408000
9030000

*DATE 2001 01 21
*SHUTIN 'KM5'

*DATE 2001 01 24
*SHUTIN 'KM3'

*DATE 2001 01 25
*SHUTIN 'KM4'
```

```
    *DATE 2001 02 01
     ALTER
'KM1'         'KM3'         'KM4'         'KM5'         'KM6'
7140000.    2535000            8014000            3762000
9714000

*DATE 2001 02 08
*SHUTIN 'KM3'

*DATE 2001 02 09
*SHUTIN 'KM5'

*DATE 2001 02 18
**ALTER
*SHUTIN 'KM6'

*DATE 2001 02 27
*SHUTIN 'KM4'

    *DATE 2001 03 01
*OPEN 'KM6'
     ALTER
'KM1'         'KM3'         'KM4'         'KM5'         'KM6'
8664000.    3462000            9742000            5885000            0.

*DATE 2001 03 17
*SHUTIN 'KM4'

*DATE 2001 03 23
*SHUTIN 'KM5'
```

```
*DATE 2001 04 01
 ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
7690000.     3091000          7942000          4448000
9354000

*DATE 2001 04 09
*SHUTIN 'KM5'

*DATE 2001 04 14
**ALTER
*SHUTIN 'KM6'

*DATE 2001 04 18
*SHUTIN 'KM1'

*DATE 2001 04 27
*SHUTIN 'KM4'

*DATE 2001 05 01
*OPEN 'KM6'
 ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
6747000.     3532000          7986000          3702000
8753000

*DATE 2001 05 06
**ALTER
SHUTIN 'KM6'
```

```
*DATE 2001 05 15
*SHUTIN 'KM3'

*DATE 2001 05 17
*SHUTIN 'KM1'

*DATE 2001 05 27
*SHUTIN 'KM5'

*DATE 2001 05 28
*SHUTIN 'KM4'

    *DATE 2001 06 01
*OPEN 'KM6'
     ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
5809000.     3013000           5704000           4075000
6746000

*DATE 2001 06 12
**ALTER
*SHUTIN 'KM6'
*SHUTIN 'KM5'

*DATE 2001 06 19
*SHUTIN 'KM4'

*DATE 2001 06 22
*SHUTIN 'KM1'
*SHUTIN 'KM3'
```

```
   *DATE 2001 07 01
*OPEN 'KM6'
    ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
5037000.     2819000            5348000            4210000
7731000

*DATE 2001 07 13
*SHUTIN 'KM4'

*DATE 2001 07 14
*SHUTIN 'KM5'

*DATE 2001 07 15
*SHUTIN 'KM3'

*DATE 2001 07 19
*SHUTIN 'KM1'


   *DATE 2001 08 01
    ALTER
'KM1'        'KM3'        'KM4'        'KM5'        'KM6'
4986000.     2428000            6402000            0.           6662000

*DATE 2001 08 12
*SHUTIN 'KM3'

*DATE 2001 08 20
*SHUTIN 'KM5'
```

*DATE 2001 08 22
*SHUTIN 'KM4'

*DATE 2001 09 01
ALTER

'KM1'	'KM3'	'KM5'	'KM6'	
6025000.	2529000	3412000.	7560000.	

*DATE 2001 10 01
ALTER

'KM1'	'KM3'	'KM5'	'KM6'	
5828000.	2928000	3564000	7734000	

*DATE 2001 10 20
*SHUTIN 'KM3'

*DATE 2001 11 01
ALTER

'KM1'	'KM3'	'KM4'	'KM5'	'KM6'
5716000.	2351000	6648000	4517000	
7160000				

*DATE 2001 11 14
*SHUTIN 'KM5'

*DATE 2001 11 17
*SHUTIN 'KM3'

*DATE 2001 11 19

```
*SHUTIN 'KM4'

    *DATE 2001 12 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM6'
4037000.     2227000          7406000          6542000

    *DATE 2002 01 01
     ALTER
'KM1'        'KM3'        'KM4'        'KM6'
3897000.     2535000          6493000          7171000

*DATE 2002 01 17
*SHUTIN 'KM1'
*SHUTIN 'KM3'
*SHUTIN 'KM4'


*DATE 2002 01 22
**ALTER
SHUTIN 'KM6'
*DATE 2002 02 01
*DATE 2002 03 01
*DATE 2002 04 01
*DATE 2002 05 01
*DATE 2002 06 01
*DATE 2002 07 01
*DATE 2002 08 01
*DATE 2002 09 01
*DATE 2002 10 01
*DATE 2002 11 01
```

*DATE 2002 12 01

*DATE 2003 01 01

*DATE 2003 02 01

*DATE 2003 03 01

*DATE 2003 04 01

*DATE 2003 05 01

*DATE 2003 06 01

*DATE 2003 07 01

*DATE 2003 08 01

*DATE 2003 09 01

*DATE 2003 10 01

*DATE 2003 11 01

*DATE 2003 12 01

*DATE 2004 01 01

*DATE 2004 02 01

*DATE 2004 03 01

*DATE 2004 04 01

*DATE 2004 05 01

*DATE 2004 06 01

*DATE 2004 07 01

*DATE 2004 08 01

*DATE 2004 09 01

*DATE 2004 10 01

*DATE 2004 11 01

*DATE 2004 12 01

*DATE 2005 01 01

*DATE 2005 02 01

*DATE 2005 03 01

*DATE 2005 04 01

*DATE 2005 05 01

```
*OPEN 'H11'
*OPEN 'H22'
*OPEN 'H33'
*OPEN 'H44'
*OPEN 'H55'
*OPEN 'KM11'
*OPEN 'KM22'
*OPEN 'KM33'
*OPEN 'KM44'
*OPEN 'KM55'
*OPEN 'KM66'
    ALTER
'KM11'      'KM22'     'KM33'          'KM44'          'KM55'
     'KM66'
100000000000.  100000000000.  100000000000.  100000000000.
100000000000. 100000000000.
    ALTER
'H11'  'H22' 'H33'      'H44'      'H55'
100000000000.  100000000000.  100000000000.  100000000000.
100000000000.
*DATE 2005 06 01
*DATE 2005 07 01
*DATE 2005 08 01
*DATE 2005 09 01

*DATE 2005 10 01
*SHUTIN 'H11'
*SHUTIN 'H22'
*SHUTIN 'H33'
*SHUTIN 'H44'
*SHUTIN 'H55'
```

```
*SHUTIN 'KM11'
*SHUTIN 'KM22'
*SHUTIN 'KM33'
*SHUTIN 'KM44'
*SHUTIN 'KM55'
*SHUTIN 'KM66'
*OPEN 'KM1'
*OPEN 'KM2'
*OPEN 'KM3'
*OPEN 'KM4'
*OPEN 'KM5'
*OPEN 'KM6'
    ALTER
'KM1'  'KM2'     'KM3'     'KM4'     'KM5'     'KM6'
100000000000.  100000000000.  100000000000.  100000000000.
100000000000. 100000000000.
*TARGET  *BHP
'KM1'  'KM2'     'KM3'     'KM4'     'KM5'     'KM6'
1200  1200  1200     1200     1200     1200
*OPEN 'H1'
*OPEN 'H2'
*OPEN 'H3'
*OPEN 'H4'
*OPEN 'H5'

    ALTER
'H1'   'H2'  'H3'     'H4'     'H5'
100000000000.  100000000000.  100000000000.  100000000000.
100000000000.
*TARGET  *BHP
'H1'   'H2'  'H3'     'H4'     'H5'
```

```
1200  1200  1200           1200           1200
*DATE 2005 11 01
*DATE 2005 12 01
*DATE 2006 01 01
*DATE 2006 02 01
*DATE 2006 03 01
*DATE 2006 04 01

*DATE 2006 05 01
*SHUTIN 'H1'
*SHUTIN 'H2'
*SHUTIN 'H3'
*SHUTIN 'H4'
*SHUTIN 'H5'
*SHUTIN 'KM1'
*SHUTIN 'KM2'
*SHUTIN 'KM3'
*SHUTIN 'KM4'
*SHUTIN 'KM5'
*SHUTIN 'KM6'
*OPEN 'KM11'
*OPEN 'KM22'
*OPEN 'KM33'
*OPEN 'KM44'
*OPEN 'KM55'
*OPEN 'KM66'
*OPEN 'H11'
*OPEN 'H22'
*OPEN 'H33'
*OPEN 'H44'
*OPEN 'H55'
```

*DATE 2006 06 01

*DATE 2006 07 01

*DATE 2006 08 01

*DATE 2006 09 01

*DATE 2006 10 01

*SHUTIN 'H11'

*SHUTIN 'H22'

*SHUTIN 'H33'

*SHUTIN 'H44'

*SHUTIN 'H55'

*SHUTIN 'KM11'

*SHUTIN 'KM22'

*SHUTIN 'KM33'

*SHUTIN 'KM44'

*SHUTIN 'KM55'

*SHUTIN 'KM66'

*OPEN 'KM1'

*OPEN 'KM2'

*OPEN 'KM3'

*OPEN 'KM4'

*OPEN 'KM5'

*OPEN 'KM6'

*OPEN 'H1'

*OPEN 'H2'

*OPEN 'H3'

*OPEN 'H4'

*OPEN 'H5'

*DATE 2006 11 01

```
*DATE 2006 12 01
*DATE 2007 01 01
*DATE 2007 02 01
*DATE 2007 03 01
*DATE 2007 04 01

*DATE 2007 05 01
*SHUTIN 'H1'
*SHUTIN 'H2'
*SHUTIN 'H3'
*SHUTIN 'H4'
*SHUTIN 'H5'
*SHUTIN 'KM1'
*SHUTIN 'KM2'
*SHUTIN 'KM3'
*SHUTIN 'KM4'
*SHUTIN 'KM5'
*SHUTIN 'KM6'
*OPEN 'KM11'
*OPEN 'KM22'
*OPEN 'KM33'
*OPEN 'KM44'
*OPEN 'KM55'
*OPEN 'KM66'
*OPEN 'H11'
*OPEN 'H22'
*OPEN 'H33'
*OPEN 'H44'
*OPEN 'H55'
```

```
*DATE 2007 06 01
*DATE 2007 07 01
*DATE 2007 08 01
*DATE 2007 09 01

*DATE 2007 10 01
*SHUTIN 'H11'
*SHUTIN 'H22'
*SHUTIN 'H33'
*SHUTIN 'H44'
*SHUTIN 'H55'
*SHUTIN 'KM11'
*SHUTIN 'KM22'
*SHUTIN 'KM33'
*SHUTIN 'KM44'
*SHUTIN 'KM55'
*SHUTIN 'KM66'
*OPEN 'KM1'
*OPEN 'KM2'
*OPEN 'KM3'
*OPEN 'KM4'
*OPEN 'KM5'
*OPEN 'KM6'
*OPEN 'H1'
*OPEN 'H2'
*OPEN 'H3'
*OPEN 'H4'
*OPEN 'H5'

*DATE 2007 11 01
*DATE 2007 12 01
```

```
*DATE 2008 01 01
*DATE 2008 02 01
*DATE 2008 03 01
*DATE 2008 04 01

*DATE 2008 05 01
*SHUTIN 'H1'
*SHUTIN 'H2'
*SHUTIN 'H3'
*SHUTIN 'H4'
*SHUTIN 'H5'
*SHUTIN 'KM1'
*SHUTIN 'KM2'
*SHUTIN 'KM3'
*SHUTIN 'KM4'
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APPENDIX D

ROOT MEAN SQUARE ERROR (RMSE) CALCULATIONS

RMSE can be defined as,

$$\text{RMSE} = \frac{\sqrt{\sum\left(P_{\text{simulator}} - P_{\text{field}}\right)^2}}{N}$$

where;

N=Number of data

This approach is applied to the well head pressures of the wells and given in Table D.1, D.2, D.3, D.4 and D.5 respectively.

Table D.1 RMSE Calculation for P_{wh} values of Well 1

Number of data	**Time (day)**	**Date**	**P_{wh}, psi**		**RMSE**
			Calculated	**Measured**	**psi**
1	30	02.09.1997	1701,58	1720	18
2	61	01.10.1997	1654,78	1690	35
3	91	01.11.1997	1657,22	1720	63
4	122	01.12.1997	1645,76	1710	64
5	153	01.01.1998	1637,24	1780	143
6	181	01.02.1998	1635,18	1710	75
7	212	01.03.1998	1614,93	1680	65
8	242	01.04.1998	1612,07	1680	68
9	273	01.05.1998	1606,44	1690	84
10	303	01.06.1998	1568,07	1630	62
11	334	01.07.1998	1545,57	1610	64
12	365	01.08.1998	1552,46	1640	88
13	395	01.09.1998	1514,36	1520	6
14	426	01.10.1998	1502,85	1520	17
15	456	01.11.1998	1472,45	1480	8
16	487	01.12.1998	1448,56	1460	11
17	518	01.01.1999	1437,62	1480	42
18	546	01.02.1999	1418,69	1440	21
19	577	01.03.1999	1402,55	1440	37

Table D.1 RMSE Calculation for P_{wh} values of Well 1(Cont.).

20	607	01.04.1999	1392,59	1440	47
21	638	01.05.1999	1374,21	1430	56
22	668	01.06.1999	1363,41	1420	57
23	699	01.07.1999	1344,74	1390	45
24	730	01.08.1999	1339,17	1420	81
25	760	01.09.1999	1319,08	1380	61
26	791	01.10.1999	1302,88	1370	67
27	821	01.11.1999	1285,29	1340	55
28	852	01.12.1999	1266,11	1320	54
29	883	01.01.2000	1243,66	1240	4
30	912	01.02.2000	1223,63	1250	26
31	943	01.03.2000	1208,67	1200	9
32	973	01.04.2000	1199,26	1270	71
33	1004	01.05.2000	1197,54	1280	82
34	1034	01.06.2000	1186,56	1290	103
35	1065	01.07.2000	1162,54	1270	107
36	1096	01.08.2000	1147,09	1250	103
37	1126	01.09.2000	1144,75	1250	105
38	1157	01.10.2000	1164,87	1310	145
39	1187	01.11.2000	1154,5	1310	156
40	1218	01.12.2000	1152,45	1300	148
41	1249	01.01.2001	1151,62	1295	143
42	1277	01.02.2001	1138,99	1205	66
43	1308	01.03.2001	1114,23	1230	116
44	1338	01.04.2001	1121,03	1240	119
45	1369	01.05.2001	1131,4	1250	119
46	1399	01.06.2001	1133,77	1280	146
47	1430	01.07.2001	1138,47	1290	152
48	1461	01.08.2001	1136,5	1300	164
49	1491	01.09.2001	1111,74	1285	173
50	1522	01.10.2001	1108,96	1300	191
51	1552	01.11.2001	1102,36	1265	163
52	1583	01.12.2001	1115,43	1285	170
53	1614	01.01.2002	1113,51	1290	176
Average RMSE Well 1					**84**

Table D.2 RMSE Calculation for P_{wh} values of Well 3

Number of data	Time (day)	Date	P_{wh}, psi Calculated	Measured	RMSE psi
1	30	02.09.1997	0	0	0
2	61	01.10.1997	1625,1	1550	75
3	91	01.11.1997	1620,7	1560	61
4	122	01.12.1997	1608,93	1560	49
5	153	01.01.1998	1608,38	1580	28
6	181	01.02.1998	1616,69	1578	39
7	212	01.03.1998	1581,23	1494	87
8	242	01.04.1998	1602,28	1570	32
9	273	01.05.1998	1590,28	1580	10
10	303	01.06.1998	1555,34	1550	5
11	334	01.07.1998	1537,78	1520	18
12	365	01.08.1998	1533,39	1540	7
13	395	01.09.1998	1500,85	1450	51
14	426	01.10.1998	1492,58	1420	73
15	456	01.11.1998	1456,9	1410	47
16	487	01.12.1998	1429,43	1400	29
17	518	01.01.1999	1417,02	1420	3
18	546	01.02.1999	1401,75	1380	22
19	577	01.03.1999	1385,24	1390	5
20	607	01.04.1999	1376,66	1390	13
21	638	01.05.1999	1360,89	1380	19
22	668	01.06.1999	1351,29	1370	19
23	699	01.07.1999	1329,83	1350	20
24	730	01.08.1999	1328,61	1370	41
25	760	01.09.1999	1308	1330	22
26	791	01.10.1999	1286,69	1320	33
27	821	01.11.1999	1276,92	1300	23
28	852	01.12.1999	1262,73	1300	37
29	883	01.01.2000	1246,98	1260	13
30	912	01.02.2000	1230,85	1200	31
31	943	01.03.2000	1218,7	1200	19
32	973	01.04.2000	1209,96	1230	20
33	1004	01.05.2000	1213,16	1240	27
34	1034	01.06.2000	1193,65	1250	56
35	1065	01.07.2000	1171,92	1210	38
36	1096	01.08.2000	1156,03	1200	44
37	1126	01.09.2000	1150,97	1210	59
38	1157	01.10.2000	1181,46	1280	99

Table D.2 RMSE Calculation for P_{wh} values of Well 3(Cont.).

39	1187	01.11.2000	1169,06	1280	111
40	1218	01.12.2000	1162,32	1270	108
41	1249	01.01.2001	1169,98	1285	115
42	1277	01.02.2001	1160,57	1265	104
43	1308	01.03.2001	1130,08	1260	130
44	1338	01.04.2001	1133,04	1220	87
45	1369	01.05.2001	1117,28	1175	58
46	1399	01.06.2001	1125,84	1250	124
47	1430	01.07.2001	1125,99	1240	114
48	1461	01.08.2001	1131,54	1250	118
49	1491	01.09.2001	1115,64	1250	134
50	1522	01.10.2001	1098,67	1230	131
51	1552	01.11.2001	1109,43	1220	111
52	1583	01.12.2001	1105,13	1220	115
53	1614	01.01.2002	1092,67	1210	117
Average RMSE Well 3					**56**

Table D.3 RMSE Calculation for P_{wh} values of Well 4.

Number of data	Time (day)	Date	P_{wh}, psi		RMSE psi
			Calculated	Measured	
1	30	02.09.1997	1696,35	1700	4
2	61	01.10.1997	1681,94	1670	12
3	91	01.11.1997	1656,2	1690	34
4	122	01.12.1997	1632,87	1700	67
5	153	01.01.1998	1632,6	1700	67
6	181	01.02.1998	1627,65	1660	32
7	212	01.03.1998	1609,13	1650	41
8	242	01.04.1998	1607,81	1570	38
9	273	01.05.1998	1599,54	1680	80
10	303	01.06.1998	1564,35	1640	76
11	334	01.07.1998	1543,38	1610	67
12	365	01.08.1998	1507,71	1510	2
13	395	01.09.1998	1497,5	1510	13
14	426	01.10.1998	1496,38	1500	4
15	456	01.11.1998	1473,13	1500	27
16	487	01.12.1998	1449,28	1480	31
17	518	01.01.1999	1442,15	1490	48
18	546	01.02.1999	1420,43	1460	40
19	577	01.03.1999	1406,79	1450	43
20	607	01.04.1999	1396,17	1450	54

Table D.3 RMSE Calculation for P_{wh} values of Well 4 (Cont.).

21	638	01.05.1999	1377,76	1430	52
22	668	01.06.1999	1366,02	1420	54
23	699	01.07.1999	1346,24	1400	54
24	730	01.08.1999	1341,85	1420	78
25	760	01.09.1999	1320,22	1390	70
26	791	01.10.1999	1304,4	1370	66
27	821	01.11.1999	1287,77	1360	72
28	852	01.12.1999	1270,38	1340	70
29	883	01.01.2000	1249,02	1300	51
30	912	01.02.2000	1228,63	1270	41
31	943	01.03.2000	1216,27	1270	54
32	973	01.04.2000	1203,76	1280	76
33	1004	01.05.2000	1200,4	1290	90
34	1034	01.06.2000	1185,68	1280	94
35	1065	01.07.2000	1162,63	1260	97
36	1096	01.08.2000	1147,69	1240	92
37	1126	01.09.2000	1144,51	1250	105
38	1157	01.10.2000	1166,72	1290	123
39	1187	01.11.2000	1167,78	1270	102
40	1218	01.12.2000	1151,17	1270	119
41	1249	01.01.2001	1152,44	1275	123
42	1277	01.02.2001	1135,57	1150	14
43	1308	01.03.2001	1106,93	1150	43
44	1338	01.04.2001	1123,8	1240	116
45	1369	01.05.2001	1119,87	1260	140
46	1399	01.06.2001	1137,54	1270	132
47	1430	01.07.2001	1138,01	1275	137
48	1461	01.08.2001	1122,4	1260	138
49	1491	01.09.2001	0	0	0
50	1522	01.10.2001	0	0	0
51	1552	01.11.2001	1098,94	1225	126
52	1583	01.12.2001	1080,51	1200	119
53	1614	01.01.2002	1087,11	1230	143
Average RMSE Well 4					**67**

Table D.4 RMSE Calculation for P_{wh} values of Well 5.

Number of data	Time (day)	Date	P_{wh}, psi Calculated	Measured	RMSE psi
1	30	02.09.1997	0	0	0
2	61	01.10.1997	0	0	0
3	91	01.11.1997	1669,69	1740	70
4	122	01.12.1997	1663,64	1740	76
5	153	01.01.1998	1640,11	1690	50
6	181	01.02.1998	1634,9	1650	15
7	212	01.03.1998	1607,39	1630	23
8	242	01.04.1998	1606,08	1630	24
9	273	01.05.1998	0	0	0
10	303	01.06.1998	1567,78	1630	62
11	334	01.07.1998	1544,6	1520	25
12	365	01.08.1998	1532,6	1570	37
13	395	01.09.1998	0	0	0
14	426	01.10.1998	1514,6	1560	45
15	456	01.11.1998	1466,58	1510	43
16	487	01.12.1998	1446,59	1450	3
17	518	01.01.1999	1428,12	1460	32
18	546	01.02.1999	1415,53	1430	14
19	577	01.03.1999	1397,51	1430	32
20	607	01.04.1999	1390,86	1430	39
21	638	01.05.1999	1374,99	1420	45
22	668	01.06.1999	1368,56	1420	51
23	699	01.07.1999	1346,65	1390	43
24	730	01.08.1999	1209,2	1400	191
25	760	01.09.1999	1322	1370	48
26	791	01.10.1999	1305,52	1360	54
27	821	01.11.1999	1289,8	1340	50
28	852	01.12.1999	1272,33	1340	68
29	883	01.01.2000	1251,04	1290	39
30	912	01.02.2000	1232,05	1270	38
31	943	01.03.2000	1217	1260	43
32	973	01.04.2000	1205,41	1270	65
33	1004	01.05.2000	1206,51	1280	73
34	1034	01.06.2000	1193,19	1280	87
35	1065	01.07.2000	1166,05	1260	94
36	1096	01.08.2000	1149,96	1240	90
37	1126	01.09.2000	1143,3	1240	97
38	1157	01.10.2000	1173,03	1270	97
39	1187	01.11.2000	1154,21	1230	76
40	1218	01.12.2000	1155,89	1250	94

Table D.4 RMSE Calculation for P_{wh} values of Well 5(Cont.).

41	1249	01.01.2001	1157,34	1260	103
42	1277	01.02.2001	1147,77	1220	72
43	1308	01.03.2001	1097,23	1210	113
44	1338	01.04.2001	1121,7	1220	98
45	1369	01.05.2001	1136,44	1270	134
46	1399	01.06.2001	1121,31	1280	159
47	1430	01.07.2001	1114,95	1220	105
48	1461	01.08.2001	0	0	0
49	1491	01.09.2001	1113,33	1265	152
50	1522	01.10.2001	1105,03	1260	155
51	1552	01.11.2001	1078,71	1200	121
52	1583	01.12.2001	0	0	0
53	1614	01.01.2002	0	0	0
Average RMSE Well 5					**61**

Table D.5 RMSE Calculation for P_{wh} values of Well 6.

Number of data	Time (day)	Date	P_{wh}, psi		RMSE psi
			Calculated	**Measured**	
1	30	02.09.1997	0	0	0
2	61	01.10.1997	0	0	0
3	91	01.11.1997	1685,78	1.780	94
4	122	01.12.1997	1679,75	1.780	100
5	153	01.01.1998	1672,66	1.770	97
6	181	01.02.1998	1671,3	1.760	89
7	212	01.03.1998	1598,22	1.710	112
8	242	01.04.1998	0	0	0
9	273	01.05.1998	0	0	0
10	303	01.06.1998	1580,89	1.650	69
11	334	01.07.1998	1576,67	1.700	123
12	365	01.08.1998	1560,76	1.680	119
13	395	01.09.1998	1544,27	1.680	136
14	426	01.10.1998	1542,42	1.670	128
15	456	01.11.1998	1451,87	1.500	48
16	487	01.12.1998	1426,23	1.500	74
17	518	01.01.1999	1413,39	1.500	87
18	546	01.02.1999	1396,26	1.450	54
19	577	01.03.1999	1378,84	1.450	71
20	607	01.04.1999	1357,11	1.450	93
21	638	01.05.1999	1337,19	1.430	93
22	668	01.06.1999	1324,92	1.430	105

Table D.5 RMSE Calculation for P_{wh} values of Well 6 (Cont.).

23	699	01.07.1999	1303,21	1.430	127
24	730	01.08.1999	0	0	0
25	760	01.09.1999	1276,35	1.400	124
26	791	01.10.1999	1257,01	1.370	113
27	821	01.11.1999	1237,37	1.350	113
28	852	01.12.1999	1219,03	1.340	121
29	883	01.01.2000	1195,22	1.300	105
30	912	01.02.2000	1171,17	1.270	99
31	943	01.03.2000	1155,1	1.260	105
32	973	01.04.2000	1147,07	1.280	133
33	1004	01.05.2000	1149,97	1.280	130
34	1034	01.06.2000	1135,96	1.290	154
35	1065	01.07.2000	1106,55	1.270	163
36	1096	01.08.2000	1092,3	1.240	148
37	1126	01.09.2000	1094,63	1.250	155
38	1157	01.10.2000	1144,27	1.270	126
39	1187	01.11.2000	1104,7	1.200	95
40	1218	01.12.2000	1110,83	1.240	129
41	1249	01.01.2001	1115,36	1.250	135
42	1277	01.02.2001	1102,09	1.060	42
43	1308	01.03.2001	0	0	0
44	1338	01.04.2001	1097,61	1.215	117
45	1369	01.05.2001	1105,73	1.155	49
46	1399	01.06.2001	1127,68	1.300	172
47	1430	01.07.2001	1108,44	1.300	192
48	1461	01.08.2001	1118,48	1.295	177
49	1491	01.09.2001	1091,52	1.300	208
50	1522	01.10.2001	1083,18	1.300	217
51	1552	01.11.2001	1085,08	1.275	190
52	1583	01.12.2001	1086,79	1.270	183
53	1614	01.01.2002	1073,27	1.260	187
Average RMSE Well 6					**108**

APPENDIX E

WATER CONTENT OF NATURAL GAS

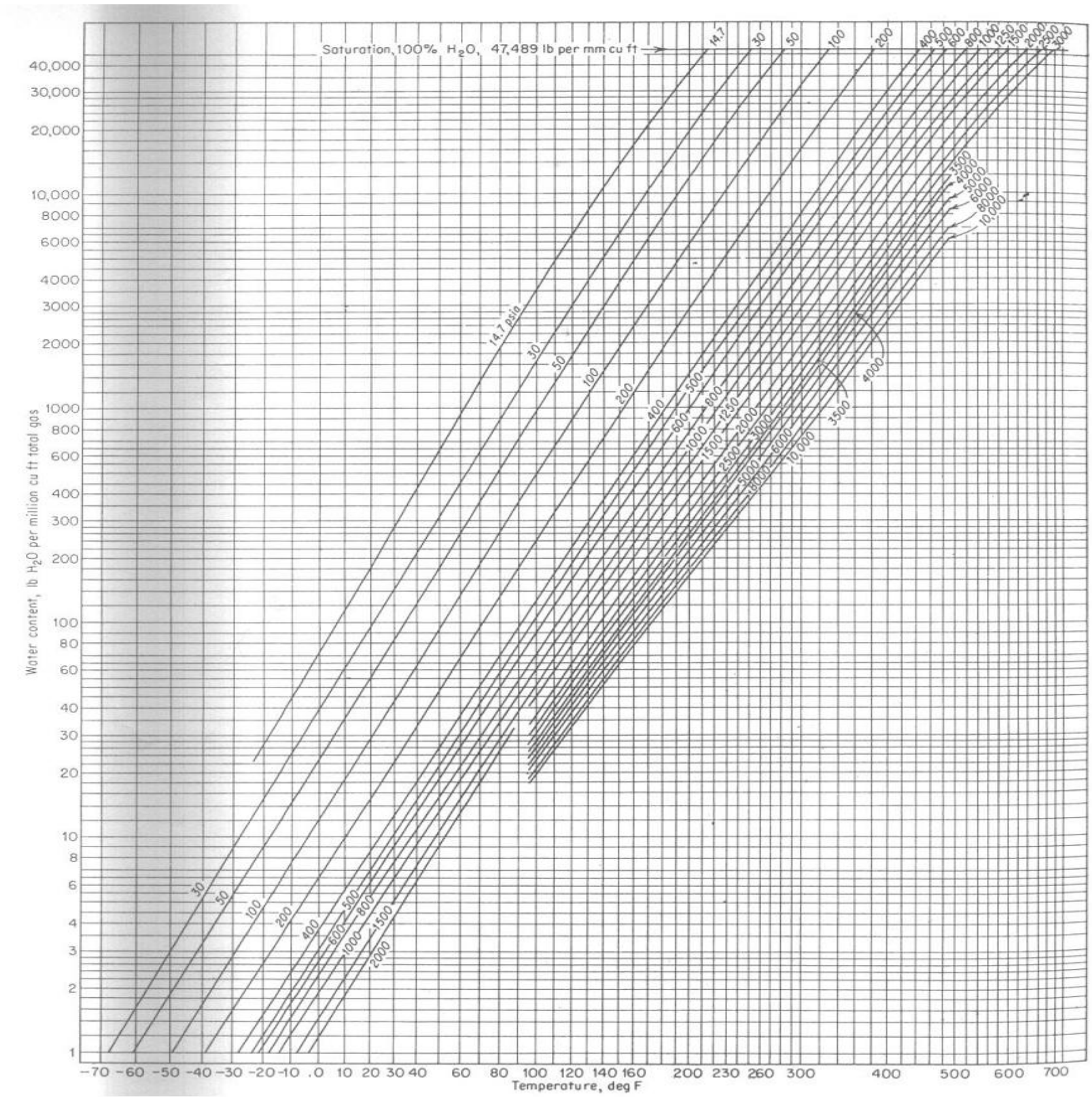

Figure E.1 Water content of natural gas in equilibrium with liquid water

Using the above figure following Table E.1 is obtained and necessary calculations are done to find the amount of water produced during the production history of the field. Cumulative water production data obtained from IMEX and the field is tabulated in Table E.2.

Table E.1 Water content of produced gas.

Date	**$P_{ave.\ res.}$**	**Water Content**		**Cum. Gas Prod, Imex**		**Water prod.**	**Water prod.,**
		lb/MMft^3 gas	*ft3/MMft3 gas*	*ft3*	*MMft3*	*ft3*	*bbl*
		A	B=A/62,4	C	D=C/10^6	E=B*D	F=E/5,615
01.09.1997	1939,3	140,00	2,24	3,44E+07	3,44E+01	7,71E+01	1,37E+01
01.10.1997	1938,15	140,65	2,25	1,02E+08	1,02E+02	2,31E+02	4,11E+01
01.11.1997	1923,45	141,30	2,26	1,41E+09	1,41E+03	3,20E+03	5,70E+02
01.12.1997	1917,13	141,95	2,27	1,98E+09	1,98E+03	4,50E+03	8,01E+02
01.01.1998	1907,96	142,60	2,29	2,79E+09	2,79E+03	6,38E+03	1,14E+03
01.02.1998	1899,03	143,25	2,30	3,59E+09	3,59E+03	8,24E+03	1,47E+03
01.03.1998	1891,78	143,90	2,31	4,23E+09	4,23E+03	9,77E+03	1,74E+03
01.04.1998	1883,17	144,55	2,32	5,00E+09	5,00E+03	1,16E+04	2,06E+03
01.05.1998	1876,47	145,20	2,33	5,60E+09	5,60E+03	1,30E+04	2,32E+03
01.06.1998	1869,91	145,85	2,34	6,18E+09	6,18E+03	1,44E+04	2,57E+03
01.07.1998	1856,8	146,50	2,35	7,34E+09	7,34E+03	1,72E+04	3,07E+03
01.08.1998	1842,87	147,15	2,36	8,56E+09	8,56E+03	2,02E+04	3,60E+03
01.09.1998	1829,11	147,80	2,37	9,78E+09	9,78E+03	2,32E+04	4,12E+03
01.10.1998	1816,13	148,45	2,38	1,09E+10	1,09E+04	2,60E+04	4,62E+03
01.11.1998	1802,06	149,10	2,39	1,21E+10	1,21E+04	2,90E+04	5,17E+03
01.12.1998	1784,88	149,75	2,40	1,36E+10	1,36E+04	3,27E+04	5,83E+03
01.01.1999	1766,44	150,40	2,41	1,52E+10	1,52E+04	3,67E+04	6,54E+03
01.02.1999	1748,76	151,05	2,42	1,68E+10	1,68E+04	4,06E+04	7,23E+03
01.03.1999	1732,48	151,70	2,43	1,82E+10	1,82E+04	4,42E+04	7,87E+03
01.04.1999	1714,61	152,35	2,44	1,97E+10	1,97E+04	4,82E+04	8,58E+03
01.05.1999	1697,83	153,00	2,45	2,12E+10	2,12E+04	5,19E+04	9,25E+03
01.06.1999	1680,31	153,65	2,46	2,27E+10	2,27E+04	5,59E+04	9,95E+03
01.07.1999	1664,02	154,30	2,47	2,41E+10	2,41E+04	5,96E+04	1,06E+04
01.08.1999	1646,6	154,95	2,48	2,56E+10	2,56E+04	6,36E+04	1,13E+04

Table E.1 Water content of produced gas(Cont.).

01.09.1999	1632,31	155,60	2,49	2,68E+10	2,68E+04	6,69E+04	1,19E+04
01.10.1999	1615,81	156,25	2,50	2,83E+10	2,83E+04	7,08E+04	1,26E+04
01.11.1999	1598,76	156,90	2,51	2,97E+10	2,97E+04	7,47E+04	1,33E+04
01.12.1999	1582,21	157,55	2,52	3,11E+10	3,11E+04	7,86E+04	1,40E+04
01.01.2000	1565,02	158,20	2,54	3,26E+10	3,26E+04	8,27E+04	1,47E+04
01.02.2000	1547,33	158,85	2,55	3,41E+10	3,41E+04	8,69E+04	1,55E+04
01.03.2000	1530,41	159,50	2,56	3,56E+10	3,56E+04	9,10E+04	1,62E+04
01.04.2000	1512,72	160,15	2,57	3,71E+10	3,71E+04	9,53E+04	1,70E+04
01.05.2000	1496,25	161,06	2,58	3,85E+10	3,85E+04	9,95E+04	1,77E+04
01.06.2000	1480,86	161,97	2,60	3,99E+10	3,99E+04	1,03E+05	1,84E+04
01.07.2000	1465,95	162,88	2,61	4,11E+10	4,11E+04	1,07E+05	1,91E+04
01.08.2000	1449,51	163,79	2,62	4,25E+10	4,25E+04	1,12E+05	1,99E+04
01.09.2000	1433,19	164,70	2,64	4,39E+10	4,39E+04	1,16E+05	2,07E+04
01.10.2000	1418,65	165,61	2,65	4,52E+10	4,52E+04	1,20E+05	2,14E+04
01.11.2000	1408,04	166,52	2,67	4,61E+10	4,61E+04	1,23E+05	2,19E+04
01.12.2000	1397,79	167,43	2,68	4,70E+10	4,70E+04	1,26E+05	2,25E+04
01.01.2001	1386,86	168,34	2,70	4,79E+10	4,79E+04	1,29E+05	2,30E+04
01.02.2001	1378,05	169,25	2,71	4,87E+10	4,87E+04	1,32E+05	2,35E+04
01.03.2001	1370,81	170,16	2,73	4,93E+10	4,93E+04	1,34E+05	2,39E+04
01.04.2001	1363,09	171,07	2,74	5,00E+10	5,00E+04	1,37E+05	2,44E+04
01.05.2001	1356,25	171,98	2,76	5,05E+10	5,05E+04	1,39E+05	2,48E+04
01.06.2001	1350,26	172,89	2,77	5,11E+10	5,11E+04	1,41E+05	2,52E+04
01.07.2001	1345,52	173,80	2,79	5,15E+10	5,15E+04	1,43E+05	2,55E+04
01.08.2001	1339,81	174,71	2,80	5,20E+10	5,20E+04	1,45E+05	2,59E+04
01.09.2001	1333,7	175,62	2,81	5,25E+10	5,25E+04	1,48E+05	2,63E+04
01.10.2001	1326,84	176,53	2,83	5,31E+10	5,31E+04	1,50E+05	2,67E+04
01.11.2001	1319,97	177,44	2,84	5,37E+10	5,37E+04	1,53E+05	2,72E+04
01.12.2001	1312,91	178,35	2,86	5,43E+10	5,43E+04	1,55E+05	2,76E+04

Table E.2 Comparison of cumulative water production data obtained from IMEX and field.

Date	Cum. Water Prod., bbl	
	IMEX	Field
01.09.1997	13,73724	0
01.10.1997	41,08152	0
01.11.1997	570,195	38
01.12.1997	800,7963	199
01.01.1998	1136,763	353
01.02.1998	1467,444	433
01.03.1998	1739,248	485
01.04.1998	2063,114	526
01.05.1998	2319,439	548
01.06.1998	2572,218	922
01.07.1998	3067,495	1354
01.08.1998	3597,018	1781
01.09.1998	4123,839	2179
01.10.1998	4624,212	2605
01.11.1998	5168,388	3138
01.12.1998	5830,82	3820
01.01.1999	6544,265	4490
01.02.1999	7233,782	5110
01.03.1999	7874,999	5784
01.04.1999	8580,841	6416
01.05.1999	9250,715	7070
01.06.1999	9953,641	7694
01.07.1999	10614,53	8342
01.08.1999	11323,27	8883
01.09.1999	11917,63	9519
01.10.1999	12600,79	10181
01.11.1999	13310,77	10599
01.12.1999	14005,91	11282
01.01.2000	14731,53	11971
01.02.2000	15481,36	12638
01.03.2000	16206,84	13346
01.04.2000	16967,51	13985
01.05.2000	17714,23	14593
01.06.2000	18424,84	15167
01.07.2000	19123,44	15810
01.08.2000	19890,02	16442
01.09.2000	20658,72	17001
01.10.2000	21362,55	17406

Table E.2 Comparison of cumulative water production data obtained from IMEX and field (Cont.).

01.11.2000	21912,61	17836
01.12.2000	22452,4	18257
01.01.2001	23025	18617
01.02.2001	23514,42	18942
01.03.2001	23942,58	19205
01.04.2001	24393,5	19487
01.05.2001	24811,43	19733
01.06.2001	25195,85	19900
01.07.2001	25530,36	20137
01.08.2001	25907,72	20425
01.09.2001	26304,41	20700
01.10.2001	26735,85	20998
01.11.2001	27170,74	21289
01.12.2001	27616,62	21559
01.01.2002	28078,11	21712

APPENDIX F

DETERMINATION OF OPTIMUM INJECTION RATE

The inflow performance can be calculated from:

$$P_{wf}^2 = P_{wh}^2 \; EXP(S) - \frac{25\,\gamma_g \,\bar{T}\, H(EXP(S)-1)\, f \,\bar{Z}\, q_{inj}^2}{S\, d^5}$$

where,

$$S = 0{,}0375\,\gamma_g \; H \Big/ (\bar{T}\,\bar{Z})$$

$$f = \left[1{,}14 - 2\log(\frac{\varepsilon}{d} + \frac{21{,}25}{N_{\mathrm{Re}}^{0{,}9}}) \right]^{-2}$$

$$N_{\mathrm{Re}} = 20011\,\gamma_g \; q_{inj} \big/ \mu_g$$

The solution for P_{wf} for any injection rate will be iterative since $\bar{Z}$ depends on the average of P_{wf} and P_{wh}. The iterative procedure will be illustrated for $2^{7/8}$" O.D. size tubing and one rate. For this project with the original gas composition at P_{wh} = 4000 psi, μ_g and $\bar{Z}$ are taken as constant value of 0,023 cp and 0,8991 respectively. The procedure is:

1. Assume a value for P_{wf} .
2. Calculate P_{ave}=(P_{wh} + P_{wf})/2.
3. Calculate P_{wf} and compare with the assumed value. If not close, use the calculated P_{wf} as next estimate and go to Step 2.

For q=4 MMcf/d the iteration is:

Assumed P_{wf}	P_{ave}	$\bar{Z}$	μ_g	N_{Re}	**f**	**S**	**Calculated** P_{wf}
4000	4000	0,8991	0,0230	8,60E+08	0,01824	0,154295	4778
4778	4389	0,8991	0,0230	8,60E+08	0,01824	0,154295	5242
5242	4621	0,8991	0,0230	8,60E+08	0,01824	0,154295	5519
5519	4760	0,8991	0,0230	8,60E+08	0,01824	0,154295	5685
5685	4842	0,8991	0,0230	8,60E+08	0,01824	0,154295	5784
5784	4892	0,8991	0,0230	8,60E+08	0,01824	0,154295	5843
5843	4921	0,8991	0,0230	8,60E+08	0,01824	0,154295	5878
5878	4939	0,8991	0,0230	8,60E+08	0,01824	0,154295	5899
5899	4950	0,8991	0,0230	8,60E+08	0,01824	0,154295	5912
5912	4956	0,8991	0,0230	8,60E+08	0,01824	0,154295	5919
5919	4960	0,8991	0,0230	8,60E+08	0,01824	0,154295	5924
5924	4962	0,8991	0,0230	8,60E+08	0,01824	0,154295	5926
5926	4963	0,8991	0,0230	8,60E+08	0,01824	0,154295	5928
5928	4964	0,8991	0,0230	8,60E+08	0,01824	0,154295	5929
5929	4964	0,8991	0,0230	8,60E+08	0,01824	0,154295	5930
5930	4965	0,8991	0,0230	8,60E+08	0,01824	0,154295	5930

This procedure was followed for the various injection rates to produce the following Table F.1 of inflow pressure and rates:

Table F.1 Inflow performance

İnjection Rate, MMcf/d	P_{wf}, psi 2$^{7/8"}$ tubing
4	5930
20	5920
80	5916
160	5875
320	5704
480	5400
640	4917
800	4124
932	2325

The outflow performance of the each vertical well is determined using the following plot shown in Figure. F.1. The results obtained from the plot is given in Table F.2.

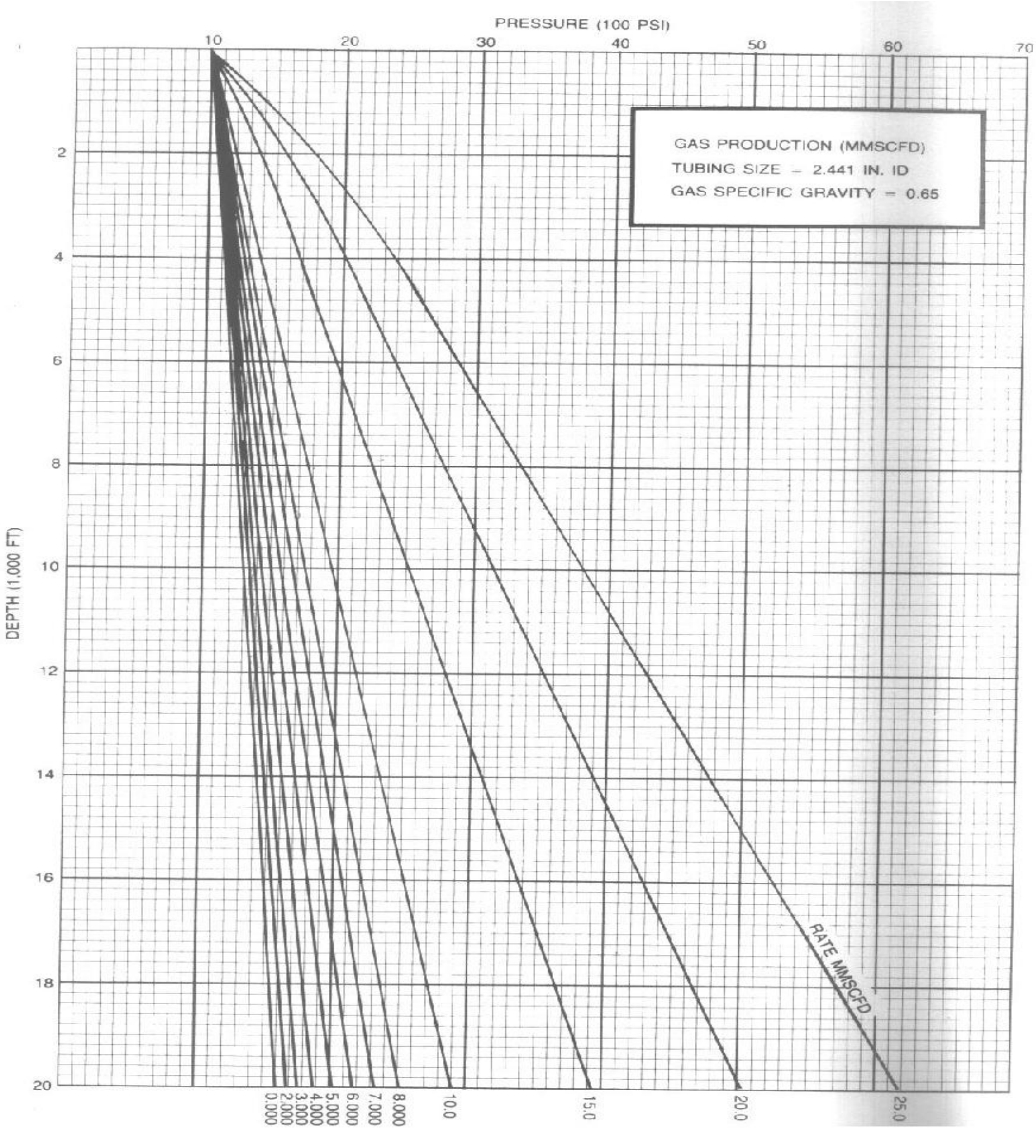

Figure F.1 Verical flowing gas gradients

Table F.2 Outflow performance of the vertical wells

q_{inj}, MMcf/d	**P_{wf}, psi**				
	Well 1	Well 3	Well 4	Well 5	Well 6
0	1500	1500	1450	1500	1500
2	1520	1530	1470	1540	1520
4	1580	1560	1500	1590	1580
8	1700	1670	1630	1700	1700
15	1950	1800	1900	1950	1950
20	2250	2250	2200	2260	2250
25	2550	2600	2500	2540	2550

The inflow and outflow performance data is plotted in the following Figure F.2. The intersections of the curves represent the injection rates possible for the 2$^{7/8}$" tubing of each well. This rate is found to be 103 MMcf/d.

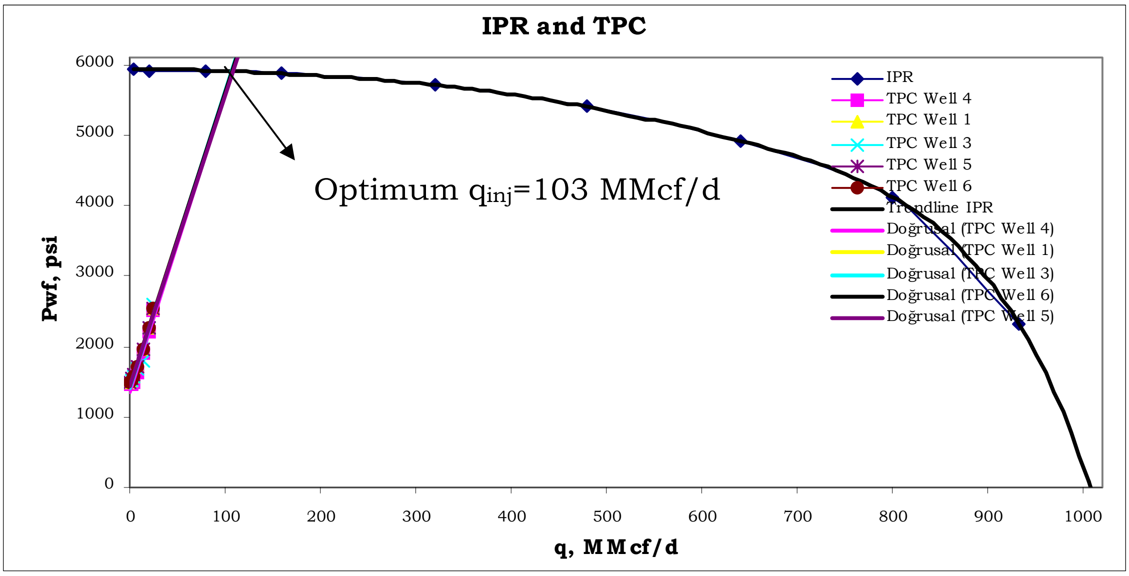

Figure F.2 Nodal analysis for the vertical wells for optimum gas injection rate.