SIMULATING CO_2 SEQUESTRATION IN A DEPLETED GAS RESERVOIR

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Prof. Dr. Canan ÖZGEN
Director

I certify that this thesis satisfies all the requirements as a thesis for the degree of Master of Science.

Prof. Dr. Birol DEMİRAL
Head of Department

This is to certify that we have read this thesis and that in our opinion it is fully adequate, in scope and quality, as a thesis for the degree of Master of Science.

Prof. Dr. Fevzi GÜMRAH
Supervisor

Examining Committee Members

Prof. Dr. Ender OKANDAN	(METU, PETE)	
Prof. Dr. Fevzi GÜMRAH	(METU, PETE)	
Prof. Dr. Birol DEMİRAL	(METU, PETE)	
Assoc. Prof. Dr. Serhat AKIN	(METU, PETE)	
Mrs. Ilhan TOPKAYA, Msc.	(METU, TPAO)	

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Öke İsmet ÖZKILIÇ

ABSTRACT

SIMULATING CO_2 SEQUESTRATION IN A DEPLETED GAS RESERVOIR

ÖZKILIÇ, Öke İsmet

M.S., Department of Petroleum and Natural Gas Engineering

Supervisor: Prof. Dr. Fevzi GÜMRAH

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Carbon dioxide is one of the greenhouse gases which have strong impacts on the environment and its amount in the atmosphere is far beyond to be ignored. Carbon dioxide levels are projected to be reduced by sequestering it directly to the underground.

High amounts of carbon dioxide can be safely stored in underground media for very long time periods. Storage in depleted gas reservoirs provides an option for sequestering carbon dioxide.

In 2002, production of Kuzey Marmara gas reservoir has been stopped due to gas storage plans. Carbon dioxide sequestration in Kuzey Marmara field has been considered in this study as an alternative to the gas storage projects.

Reservoir porosity and permeability maps were prepared with the help of Surfer software demo version. These maps were merged with the available Kuzey Marmara production information to create an input file for CMG-GEM simulator and a three dimensional model of the reservoir was created.

History match of the field model was made according to the 1998-2002 production data to verify the similarity between the model and actual reservoir.

Kuzey Marmara field is regarded as a candidate for future gas storage projects. The reservoir still contains producible natural gas. Four different scenarios were prepared by considering this fact with variations in the regional field properties and implemented into previously built simulation model. These scenarios primarily focus on sequestering carbon dioxide while producing as much as natural gas possible.

After analyzing the results from the scenarios it is realized that; CO_2 injection can be applied to increase natural gas recovery of Kuzey Marmara field but sequestering high rate CO_2 emissions is found out to be inappropriate.

Keywords: CO_2, Carbon Dioxide, Sequestration, Depleted Gas Reservoir, Kuzey Marmara, CMG, GEM, Simulator, Simulation, Greenhouse Gases, Greenhouse Effect.

ÖZ

CO_2 TECRİDİNİN TÜKETİLMİŞ BİR GAZ REZERVUARLARINDA SİMÜLASYONU

ÖZKILIÇ, Öke İsmet

Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği Bölümü

Tez Yöneticisi: Prof. Dr. Fevzi GÜMRAH

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Sera gazlarından biri olan karbon dioksitin atmosferdeki miktarı göz ardı edilemeyecek miktarlara ulaşmıştır. Bu gazın konsantrasyonunu düşürmek amacı ile düşünülen projeler arasında karbon dioksitin yeraltına tecridi yer almaktadır.

Çok miktarlarda karbon dioksit, uzun süreler boyunca ve güvenli bir şekilde yer altında depolanabilmektedir. Yer altında yapılabilecek depolama ortamlarından biri de bitmiş gaz rezervarlarıdır.

Silivri açıklarındaki Kuzey Marmara sahasının üretimi 2002 yılında durdurulmuş, ileriki zamanlarda gaz depolaması amaçlı kullanılması düşünülmüştür. Bu çalışmada gaz depolaması projelerine alternatif olarak Kuzey Marmara sahasına karbon dioksit tecridi yapılması ele alınmıştır.

Surfer programının tanıtım versiyonu yardımı ile rezervuarın geçirgenlik ve gözeneklilik kontur haritaları hazırlanmıştır. Bu veriler elde bulunan Kuzey Marmara üretim bilgileri ile birleştirilerek CMG-GEM simulatörü için girdi dosyası oluşturulmuş ve rezervuarın üç boyutlu modeli yaratılmıştır.

Ortaya çıkan saha modelinde 1998-2002 yılları üretim verileri doğrultusunda geçmiş eşleştirmesi yapılmış ve modelin aslına olan benzerliği doğrulanmıştır.

Kuzey Marmara sahasının ileride gaz depolama amaçlı kullanılması düşünüldüğünden içerisinde hala üretilebilir gaz bulunmaktadır. Bu doğrultuda bölgesel kayaç özellikleri gözetilerek dört farklı senaryo yaratılmış ve tarihsel eşleştirme yapılmış olan modele aktarılmıştır. Senaryolarda bir taraftan sahadaki gaz üretilirken, diğer bir taraftan karbon dioksit tecridi yapılması ele alınmıştır.

Senaryolarda elde edilen sonuçlar incelendikten sonra farkedilmiştirki; Kuzey Marmara sahasında üretimi arttırmak amacı ile CO_2 enjeksiyonu kullanılabilirliğine karşın, saha yüksek debide CO_2 tecridi için uygun bulunmamıştır.

Keywords: CO_2, Karbon Dioksit, Tecrid, Tüketilmiş Gaz Rezervuarı, Kuzey Marmara, CMG, GEM, Simülatör, Simulasyon, Sera Gazları, Sera Etkisi.

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I would like to thank to Türkiye Petrolleri Anonim Ortaklığı for providing information about Kuzey Marmara field.

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ABBREVIATIONS AND ACRONYMS

2D	Two dimensional
3D	Three dimensional
C_1	CH_4 (Methane)
C_2	C_2H_6 (Ethane)
C_3	C_3H_8 (Propane)
CMG	Computer Modeling Group
CO_2	Carbon dioxide
CSC	Power plant fed by coal
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
EOS	Equation of state
GEM	Generalized equation of state model compositional reservoir simulator
H_2S	Hydrogen sulfide
HC	Hydrocarbon
$i - C_4$	$(CH_3)_2CH\text{-}CH_3$ (Isobutane)
$i - C_5$	$(CH_3)_2CH\text{-}C_2H_5$ (Isopentane)
IGCC	Integrated coal gasification combined cycle
Inj	Injection

MMscf	10^6 standard cubic feet
MMscfd	10^6 standard cubic feet per day
Mscf	10^3 standard cubic feet
Mscfd	10^3 standard cubic feet per day
n - C_4	C_4H_{10} (n - Butane)
n – C_5	C_5H_{12} (n - Pentane)
N/A	Not applicable
N_2	Nitrogen
NGCC	Natural gas combined cycle
OD	Outer diameter
OGIP	Original gas in place
OOIP	Original oil in place
OSC	Power plant fed by oil
OWIP	Original water in place
PF	Pulverized fuel fired power plants
Prod	Production
RMSE	Root mean square error
scf	Standard cubic feet
S_l	Liquid saturation
S_w	Water saturation
TPAO	Türkiye Petrolleri Anonim Ortaklığı

TVD	True vertical depth

CHAPTER 1

INTRODUCTION

Carbon dioxide forms less than one percent of the earth's atmosphere together with the rest of the greenhouse gases [17]. Existence of these gases keeps the earth warm and even little variations in the atmospheric concentrations triggers a change in climate.

The world's temperature has increased less than 1 ^{0}C since the beginning of human civilization and global temperatures had risen about 0.6 ^{0}C during the industrial revolution. It is estimated that current rate of greenhouse gas emissions will lead to a 1.4 ^{0}C temperature increase in the following century. Historical findings indicate mass extinction events every time the earth faces a temperature change in such a short period of time. [7]

The seriousness of the situation had already called the attention of many countries. Conferences and protocols about climate change continue to be held since 1979. Many of the countries have agreed on reducing their greenhouse gas emissions in the following years but there are still countries that haven't completed their industrial revolution and did not take part in such emission reduction agreements. [7]

The problem arose from the energy requirements for production. Mass production facilities require less human crew but much more energy to operate. Energy is supplied from power plants. Since cost per unit of energy is a great concern for developing countries, they prefer cheap ways of producing electricity with the cost of damaging environment. Today, about half of the world's carbon dioxide emissions result from power plants and half of the power plant emissions arose from coal fired power plants. [7, 10, 11]

Preventing whole world's carbon dioxide emissions would not be an ultimate solution even if it was possible and yet, preventing all the greenhouse gas emissions will not change the world's climate immediately. [7]

Sequestering carbon dioxide into underground offers a way of reducing its atmospheric concentrations. Underground media includes depleted gas and oil reservoirs, deep saline aquifers and coal beds. Alternatively ocean floors can store very large quantities of carbon dioxide.

Kuzey Marmara reservoir is a depleted gas reservoir which is also a candidate for future gas storage projects. The field is located about 2.5km away from Silivri coast. Availability of data makes this field a good example for planning and running simulations concerned with carbon dioxide sequestration. [1]

Kuzey Marmara reservoir will be the center of attention in this study. It will be modeled in CMG-GEM simulator and scenarios will be prepared to get the most out of this reservoir. One additional well is going to be drilled in far region of the field. Four scenarios will be prepared using previous wells together with the newly drilled well. Scenario alterations will be formed by creating variations among well types and surface flow rates. Simulation results will be evaluated according to the amount of sequestrated carbon dioxide and produced natural gas.

Before proceeding further in this study, it must be kept in mind that sequestering carbon dioxide into underground media is like sweeping the dirt of a room under a carpet. It is rather a workaround than a complete solution. An ultimate solution will be to include the carbon dioxide into one of the steps of the carbon cycle such as encouraging forestation or reducing the amount of fossil fuels burned.

CHAPTER 2

LITERATURE REVIEW

Greenhouse Effect

The earth's atmosphere is a mixture of gases which is mainly formed up of nitrogen and oxygen. Carbon dioxide, methane, water vapor, ozone, nitrous oxide and industrial gases forms less than one percent of the atmosphere and even this amount is enough to keep earth's surface 30 ^{0}C warmer than otherwise be. [7]

Sun keeps supplying energy to earth mainly in the form of visible light. 30% of this energy is immediately reflected back to space and the remaining 70% passes through the atmosphere and warms the earth. Unlike the sun, earth can not emit this energy as visible light. Instead it emits this energy in the form of infrared or thermal radiation. Greenhouse gases prevent infrared radiation from escaping directly to the space. Most of this energy is carried by air currents to higher levels of the atmosphere and released to space. [7]

Sun's energy input is distributed between the space and earth's climate. Thicker layers of greenhouse gases result a reduction in energy loss to space. The energy balance is always kept constant. Energy that remains trapped due to greenhouse gases is used to warm up the climate. [7]

Greenhouse Gases

Apart from the industrial gases, greenhouse gases have been present in the atmosphere for millions of years. Humans have affected the balance of these gases by introducing new sources. This supplementary increase in the sources caused an increase in the greenhouse gas releases which is also known as the “enhanced greenhouse effect”. [7]

Water vapor is the largest contributor to the greenhouse effect but its amount in the atmosphere is not directly dependent on human activities. Rising amount of greenhouse gases trigger an increase in the temperature of weather and warmer weather can hold greater amounts of water vapor causing an additional impact to the greenhouse effect. [7]

Carbon dioxide emissions contribute 60% of the enhanced greenhouse effect. This gas naturally occurs in the atmosphere but human activities such as burning fossil fuels and deforestation releases the carbon in their structure, sending them to the atmosphere. [7]

During the 10000 years before the industrial revolution, the carbon dioxide levels varied about 10% whereas a variation of 30% was observed in 200 years period between 1800 and 2000 (Figure 1). With these high rates of carbon dioxide releases, it is predicted that the levels will continue to rise about 10% in every passing 20 years. [7]

Methane emissions are responsible for 20% of the greenhouse effect. Its amount in the atmosphere has started to increase recently but its increment rate is quite fast. During the industrial era its level has increased 50% (Figure 1). The atmospheric lifetime of methane is 12 years, making this emission a little less dangerous when compared to carbon dioxide which has an atmospheric lifetime between 5 to 200 years. [7, 26]

The remaining 20% enhanced greenhouse gas effect is formed by nitrous oxide, ozone and a number of industrial gases. Nitrous oxide levels have risen about 16% in recent years (Figure 1). Although some of the industrial gas levels such as chlorofluorocarbons have been reduced by taken precautions, there are still long lived gases that their concentrations are continuously increasing. On the other hand, ozone concentrations are increasing in some lower portions of the atmosphere although its concentration tends to decrease globally. [7]

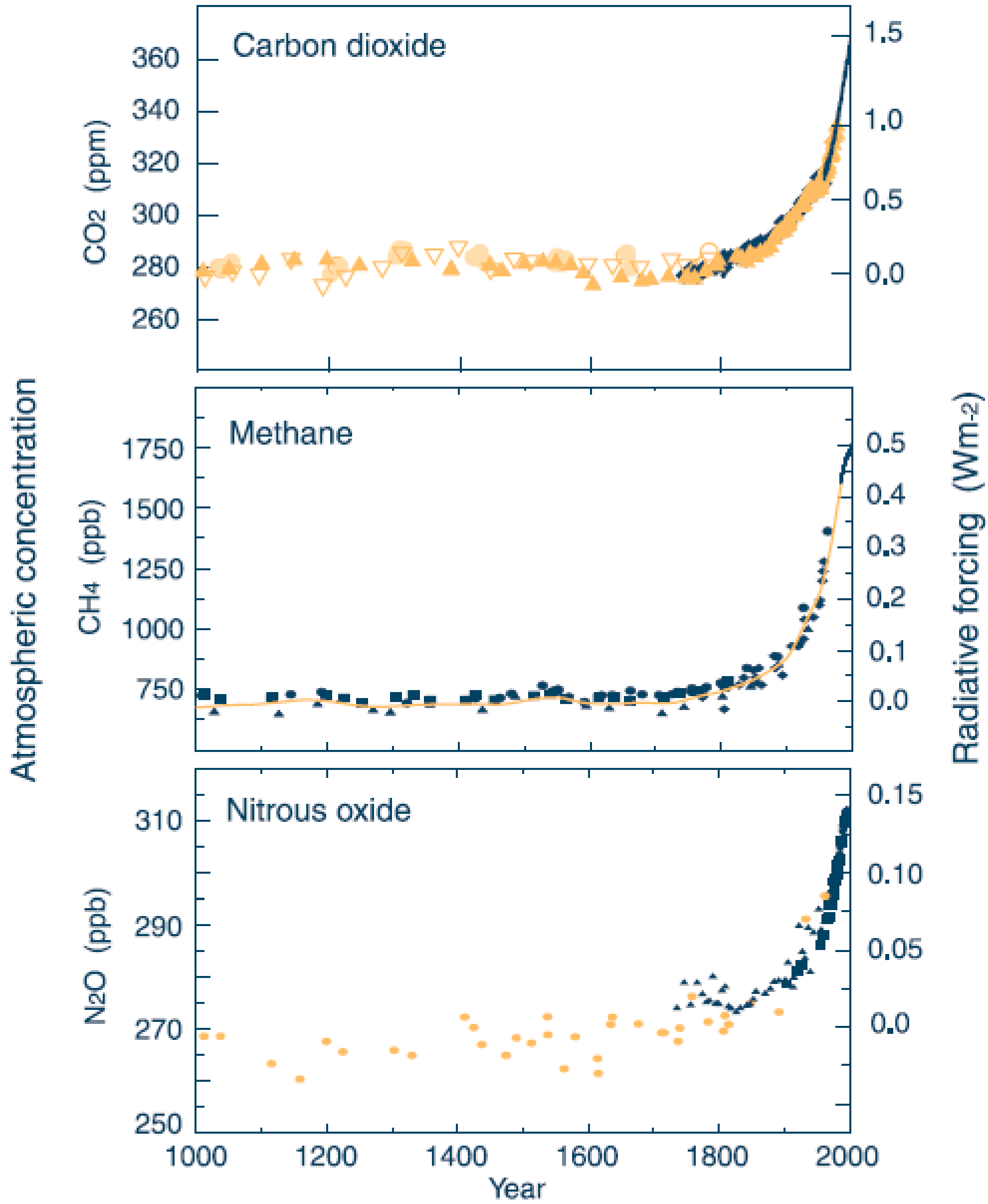


Figure 1 Global atmospheric concentrations of greenhouse gases: Carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) [9]

Future Climate Predictions

Current climate models estimate a global warming about 1.4 – 5.8 ^{0}C between 1990 – 2100 (Figure 2 and Figure 3). Of course, these temperature variations are based on many assumptions. Yet, a 1.4 ^{0}C change in the average temperature would be greater than happened in the previous 10000 years.

Even if the greenhouse concentrations stop rising at the end of 2100, the earth's atmosphere continue to warm for hundreds of years. This is due to the delaying effect of the oceans which is also called "oceanic inertia". [7]

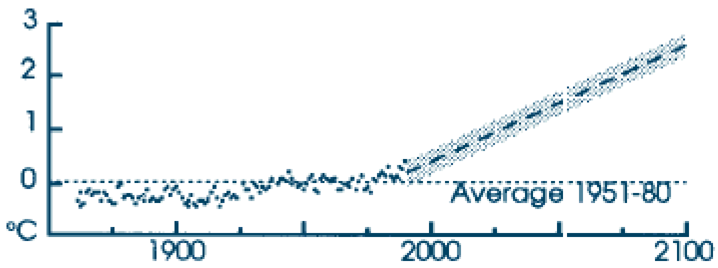


Figure 2 Observed global temperature 1861 – 1990 and model projection to 2100 [7]

It is estimated that the sea levels will rise by 9 to 88 cm at the end of 2100. This would be mainly because of melting of polar icecaps and thermal expansions of the upper ocean layers as they warm. Temperature of the oceans will continue to increase after the year 2100 just like the earth's temperature. [7]

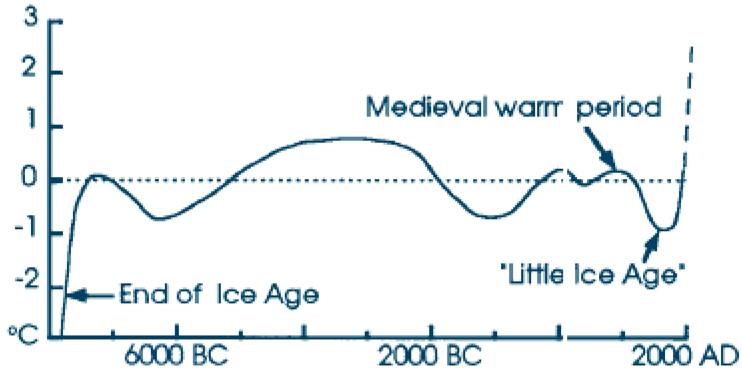


Figure 3 Schematic global temperature from 8000 BC and model projection to 2100 [7]

Although some areas are expected to warm, some of them will warm much more than the others. Ice and snow reflects the sunlight thus reducing the absorption of the energy. The regions which have less ice and snow will warm more because of this positive strong feedback. By the year 2100 winter temperatures of these regions are expected to be 40% higher than today. [7]

Regions that are away from the coasts and oceans will warm much faster since they are also away from the delaying effect of the seas. The area of this delaying effect depends on how deep any warming penetrates into the oceans. In any case, the land warms much faster than the surface of the seas. [7]

Global snow and rainfalls are estimated to increase with the global warming. Higher precipitation may lead to wetter soil conditions during winter but warmer summers will lead to drier soils. It is quite hard to estimate the precipitation effects due to their complexity.

With extreme rainfall and weather changes the frequency of weather events. It is most likely that the occurrences of disasters such as storms and tornados will increase.

Past Climate Changes

The climate seems to remain at a stable condition since the last ice age has ended 10000 years ago. Global temperatures have changed by less than 1 ^{0}C since the beginning of human civilization. [7]

Abnormal climate variations have always been traumatic for the life on earth. It is true that there are many possibilities for mass extinctions, but these events coincides with the sudden climate changes which is very similar to the one that has been forecasted for the 21st century (Figure 4). [7]

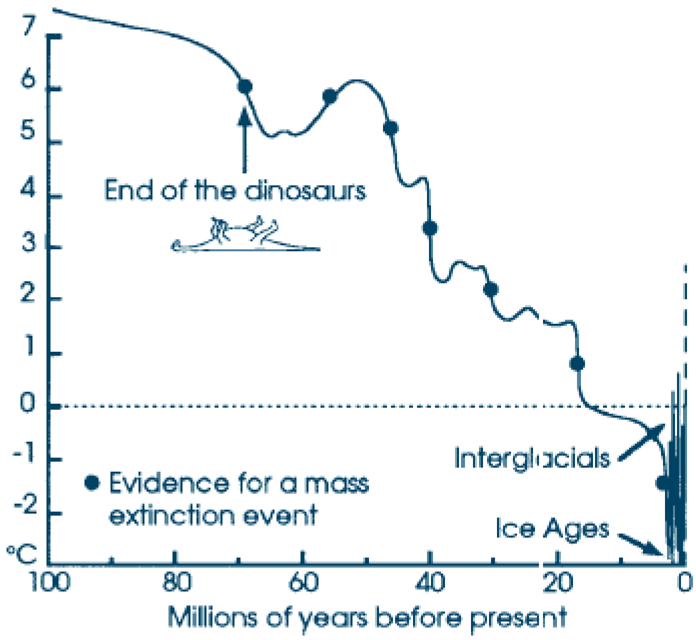


Figure 4 Schematic global temperature from 100 million years ago and model projection to 2100 [7]

Greenhouse levels in the atmosphere have deviated from their normal levels and in reaction to this, earth’s climate change has already begun.

This means that the climate change will continue until greenhouse gas levels keep raising.

Past measurements indicate an average 0.6±0.2 ^0C change in the earth's temperature during the last century (Figure 5). Also, sea level has risen by 10 to 20 cm. Scientists confirm that a 0.6 ^0C increase should lead to such a sea level rise. [7]

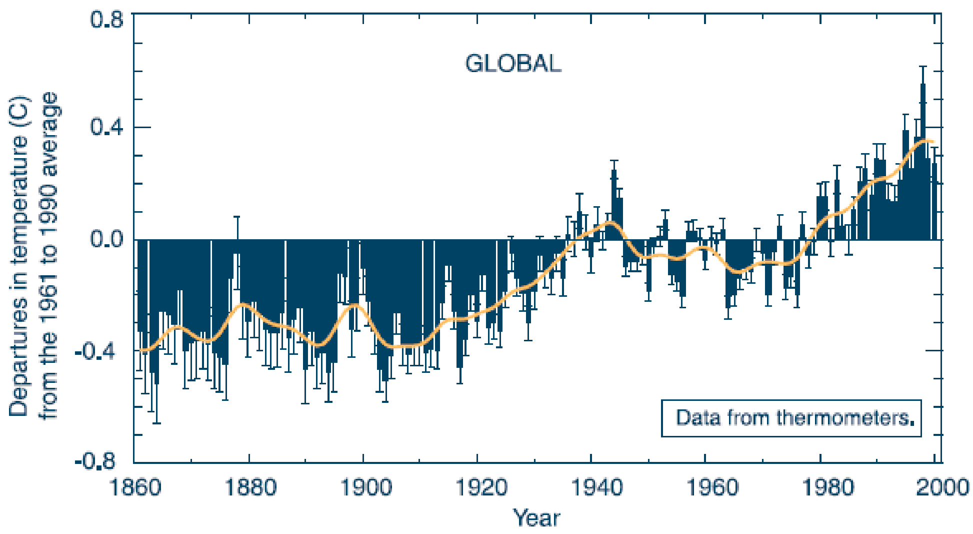


Figure 5 Variation of the earth's surface temperature for the past 140 years [9]

Snow coverage has reduced about 10% since 1960s. It is also likely that the duration of ice cover on the lakes and rivers has shortened by about two weeks during the past century. Almost all mountain glaciers in the non-polar regions are shortened as well. [7]

Snow and rainfalls increase during the past decades. Tropical areas of the world had increased rainfall about 0.2 - 0.3% per decade. An increase of 0.5 – 1% per decade has been measured in the continents of the world. In parts of Africa and Asia the frequency and intensity of the droughts seem to have worsened. [7]

Energy Concern

Energy Related CO_2 Emissions

Detailed future scenarios indicate that world's CO_2 total generation will increase 1.8% per year from 2000 to 2030. This amount will be 38 billion tones at the end of 2030 which is 70% higher than current CO_2 levels. It is also estimated that about 66% of these emission will be produced by developing countries (Figure 6). [10]

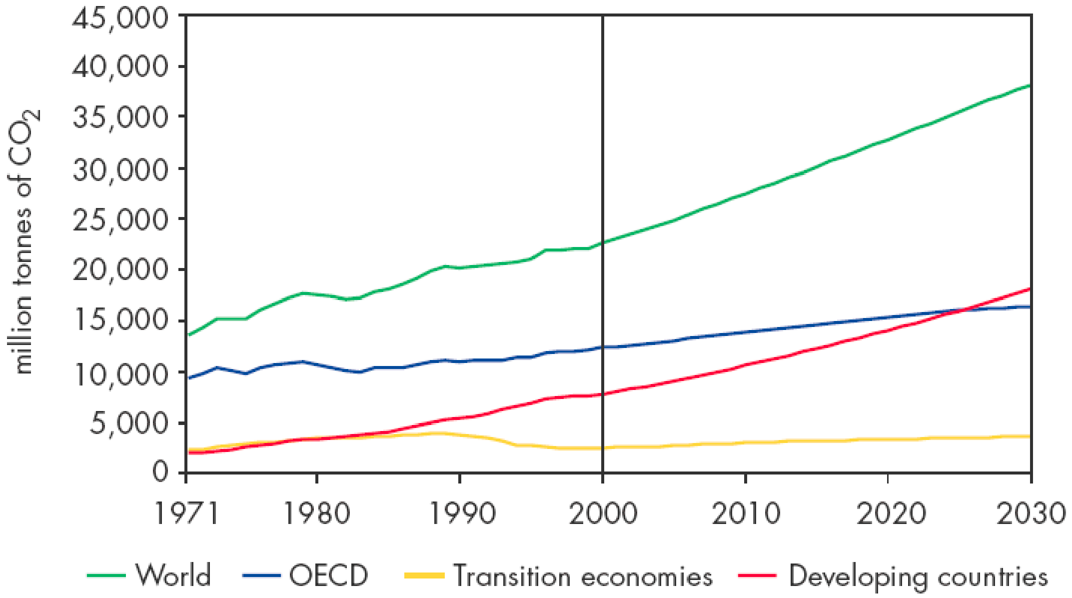


Figure 6 Energy related CO_2 emissions by region [10]

During the last 30 years, 40% of CO_2 emission increase has been due to burning of coal. Oil has produced 31% increase and the remaining 29% increase was because of natural gas. [10]

It is estimated that percentage increase in the energy demand will be less than the increase in the CO_2 production. Emissions will rise at a speed of 1.8% per year while energy production increase will be about 1.7% per year.

Power generation will cover about 48% emission increase while transportation services will follow with a rate of 27%. Industry based emissions is estimated about 12% and the remaining increase will be provided by agriculture, commercial, public services, residential and miscellaneous sources (Table 1, Table 2, and Figure 7). [10]

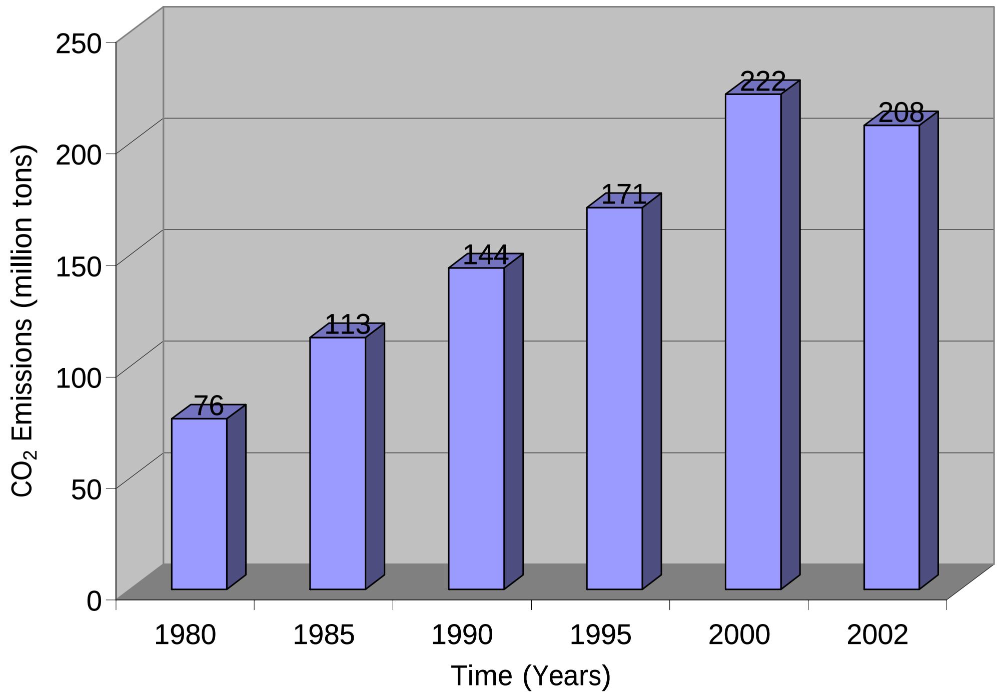


Figure 7 CO_2 Emissions of Turkey in 1980 – 2002 (million tones of CO_2) [27]

Table 1 Increase in CO_2 emissions by sector in 1990 – 2010 (million tones of CO_2) [10]

	OECD	Transition Economies	Developing Countries	World
Power Generation	1 373	44	2 870	4 287
Industry	11	-309	739	440
Transport	1 175	-52	1 040	2 163
Other	244	-428	620	436
TOTAL	2 803	-746	5 268	7 325

Table 2 Increase in CO_2 emissions by sector in 2000 – 2030 (million tones of CO_2) [10]

	OECD	Transition Economies	Developing Countries	World
Power Generation	1 800	341	5 360	7 500
Industry	211	341	1 298	1 850
Transport	1 655	242	2 313	4 210
Other	363	234	1 365	1 962
TOTAL	4 028	1 158	10 336	15 522

Electricity generation will be the major source of CO_2 emissions in the future. Even the technological achievements in this sector will not be able to reduce CO_2 releases to desired rates. More than two thirds of this rate will be accounted by developing countries. Coal fired power plants in these countries will account for more than half of the global CO_2 emissions in the following 30 years (Figure 8). [10]

Emissions per unit of power production are expected to decrease over time. Though, regional differences will still be high.

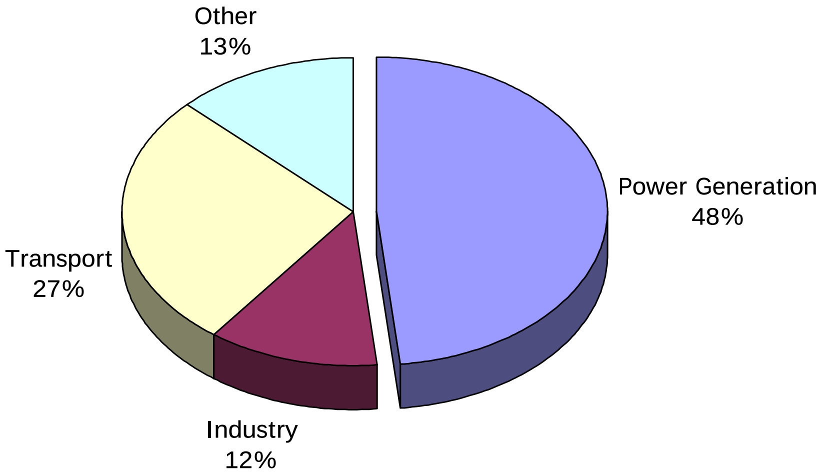


Figure 8 Increase in CO_2 emissions by sector in 2000 – 2030 [10]

Power Plants

Fossil fired power plants are the major sources of electricity in both developed and developing countries. Relatively lower costs for both capital and fuel make them attractive investments in power generation business. Though, it must be kept in mind that these power plants produce high amount of emissions and they have a greater share in the global CO_2 emission rates.

Coal Fired Plants

Pulverized fuel fired (CSC) plants are widely used throughout the world. In terms of both numbers and electricity generation rate they dominate the global market. CSC plants are characterized by their thermal efficiencies. Current CSC plant efficiencies change between 36 – 45%. [11, 12]

In these power plants pulverized coal is burned to obtain a high pressure steam and the steam is then passed through a steam turbine to produce electricity. [11]

Another type of coal fired power plant is the integrated gasification combined cycle (IGCC) plants which have higher efficiency rates even with low quality coals. Unlike the CSC plants, these plants are not widely in use. [11, 12]

Coal is mixed with steam and air in a gasifier to produce a fuel gas that primarily consists of carbon monoxide and hydrogen. The gas is burned in a gas turbine to produce electricity. High temperature exhaust gas is then used to operate a separate steam cycle to produce additional electricity. [11]

Natural Gas Fired Power Plants

Natural gas power plants are suitable for various configurations. Natural gas combined cycle (NGCC) power plant type is one of the most common designs that is used to produce electricity. Natural gas is burned in a gas turbine and the hot exhaust gas is used to drive a steam turbine. These two combined cycles result an increase in the output efficiency. [11]

Oil Fired Power Plants

Oil and air mixture is sprayed and burned in a furnace to produce heat. The heat is used to obtain high pressure steam and drive the steam cycle. If waste heat can be recovered than another steam cycle can be implemented forming a combined cycle (OSC). Oil plant efficiencies vary between 23 – 40%. [11, 12]

CO_2 Capture and Sequestration

CO_2 Capture

There are a number of solutions present for capturing CO_2 from sources. Each method provides a different mechanism and cost option for various cases.

Solvent Scrubbing

This is the most common method used to separate CO_2 exhaust gases. It provides high removal rates with the cost of high energy requirements.

The flue gas is cooled and its impurities are removed. It is then send to an absorption tower and put in contact with an amine solution. The amine reacts selectively with CO_2 forms a loosely bonded compound with CO_2. This compound is pumped into a stripper tower and CO_2 is separated from the amine. Amine is recovered for further CO_2 binding and CO_2 is obtained. This method's capturing efficiency can be as high as 98% and the purity of separated CO_2 is more than 99%. [11, 12]

Cryogenics

CO_2 is captured from the flue gases by means of cooling and condensation. This method is most useful for gases which require high amounts of CO_2 separation. High energy needs reduces the application of this method. [11]

Membranes

Membrane technology exploits the physical and chemical differences between the gases and the membrane itself. The diffusion speed of molecules differs through membrane allowing modest amount of separation through the process. [11, 13]

Membrane technology allows construction of many different designs. Due to their variable sized and operating conditions, these membrane systems are preferred for natural gas producing wells that require CO_2 reduction. [13]

Adsorption

Adsorption ability of certain solids can be used for CO_2 separation. However, selectivity of the solids is very low and the capacity of the system is below the requirements to adept it to a power plant. [11]

Capture Efficiency

Capturing CO_2 from flue gases has a cost. The process requires considerable amount of energy, especially if the processing amount is high. This required energy is expressed in terms of cost increase per unit of electricity generated or efficiency loss. Independent of its representation, companies do not approach the idea sympathetically unless taxation or a similar sanction is present.

Following table (Table 3) shows typical power plant emission rates and efficiencies before any of the capturing methods are applied. Even preferring NGCC plants instead of coal and oil fired power plants results a reduction in CO_2 emission rates. [12]

Table 3 Performance of power plants without CO_2 recovery [12, 8]

	Plant Efficiency (%)	CO_2 Volume (%)	CO_2 Rate (lb/kWh)
OSC	40.6	11.7	1.42
CSC	39.6	13.7	1.81
NGCC	55.7	3.5	0.78
IGCC	46.0	7.9	1.56

After recovery operation with the solvent scrubbing system, the CO_2 emission rates reduce significantly (Table 4, Figure 10). The efficiency of the plants degrades as well. The most efficiency loss is observed in the coal fired plants since their CO_2 output was high and thus required greater amount of solvents to do the separation. OSC plant performance is slightly better than CSC since it is fed by higher hydrogen containing fuel. Finally, NGCC plant gives the best results under both conditions (Figure 9). [12]

Table 4 Performance of power plants with CO_2 recovery [12, 8]

	Plant Efficiency (%)	CO_2 Removal Rate (lb/kWh)	CO_2 Emission Rate (lb/kWh)
OSC	30.4	1.92	0.27
CSC	27.0	2.40	0.09
NGCC	47.8	0.82	0.16
IGCC	38.4	1.72	0.09

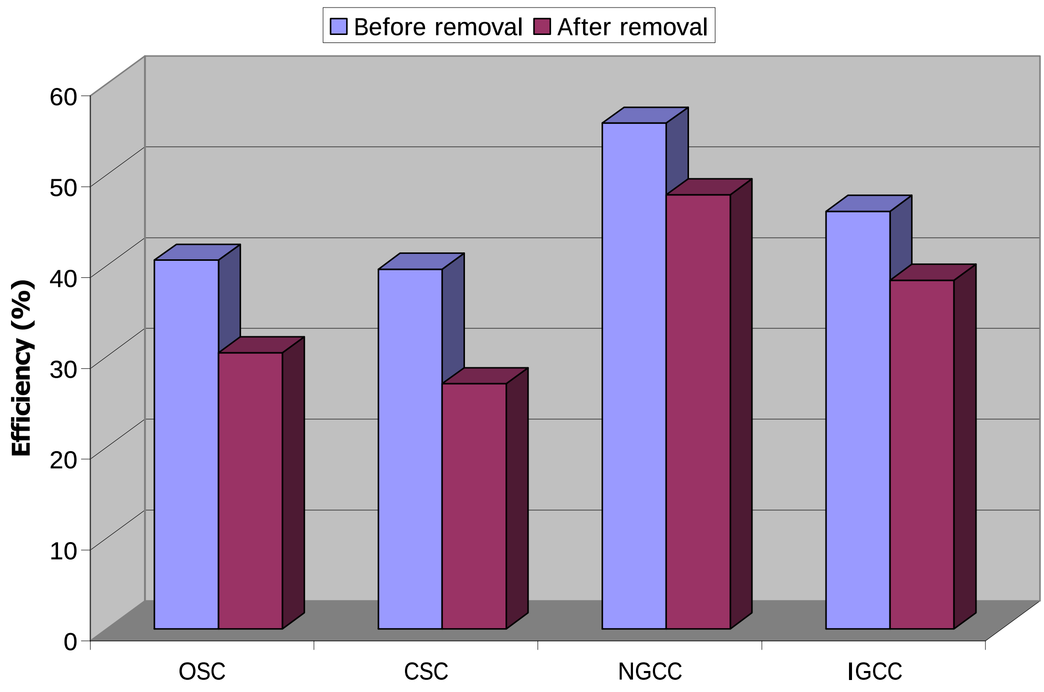


Figure 9 Power plant efficiencies after/before removal of CO_2. [12]

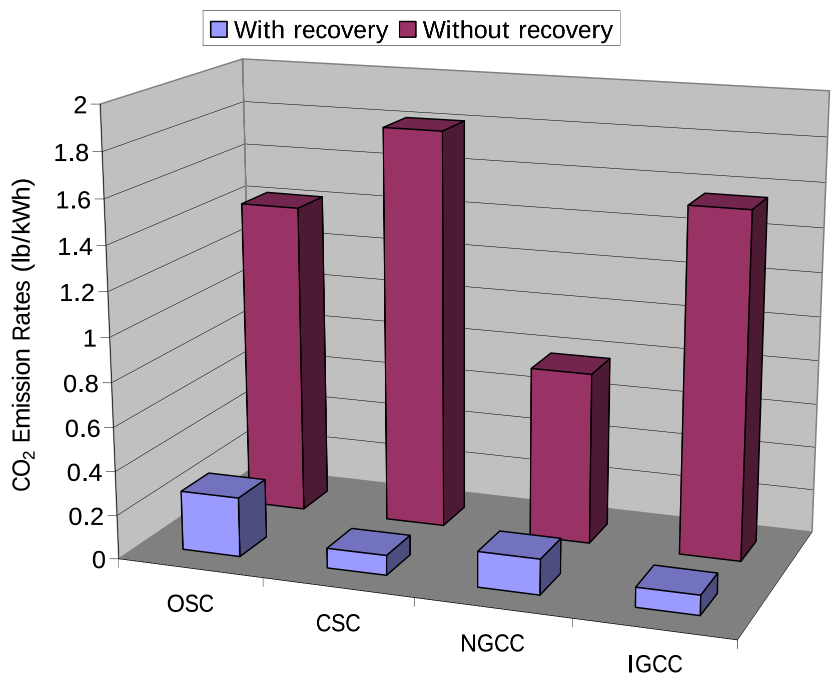


Figure 10 Power plant emission rates with/without CO_2 separation. [12]

Table 5 and Table 6 show the financial facts of building and maintaining a power plant with CO_2 removal facility. Considering the uncertainties in the economical changes and technological advancements, it is necessary to remember that the values may not reflect exact results. However, the comparison gives an idea on the relative investment and running costs among the plants which are directly related with cost of the electricity produced. [12]

Table 5 Capital costs of power plants ($/kW) [12]

	OSC	CSC	NGCC	IGCC
Power Plant	1 100	1 250	600	1 550
CO_2 Removal Plant	270	340	220	230
TOTAL	1 370	1 590	820	1 780

Table 6 Annual costs of power plants ($/kW-year) [12]

	OSC	CSC	NGCC	IGCC
Capital charges of power plant	129	147	70	182
Capital charges of CO_2 recovery plants	32	40	26	27
Fuel feedstock	148	108	152	93
Operation and maintenance costs of power plant	40	45	22	56
Operation and maintenance costs of recovery plants	10	12	8	8
TOTAL	359	352	278	366

CO_2 Storage

Capturing the CO_2 is only part of the problem. The gas must then be transported and stored permanently. There are a number of important options applicable for the storage of CO_2. These include storage in oil and gas reservoirs, coal seams, deep saline formations and the oceans. The main idea behind the storage step is to keep as much CO_2 as possible away from the atmosphere for a long amount of time, so the capacity and the long term stability of the media automatically become key properties for the operation. [14]

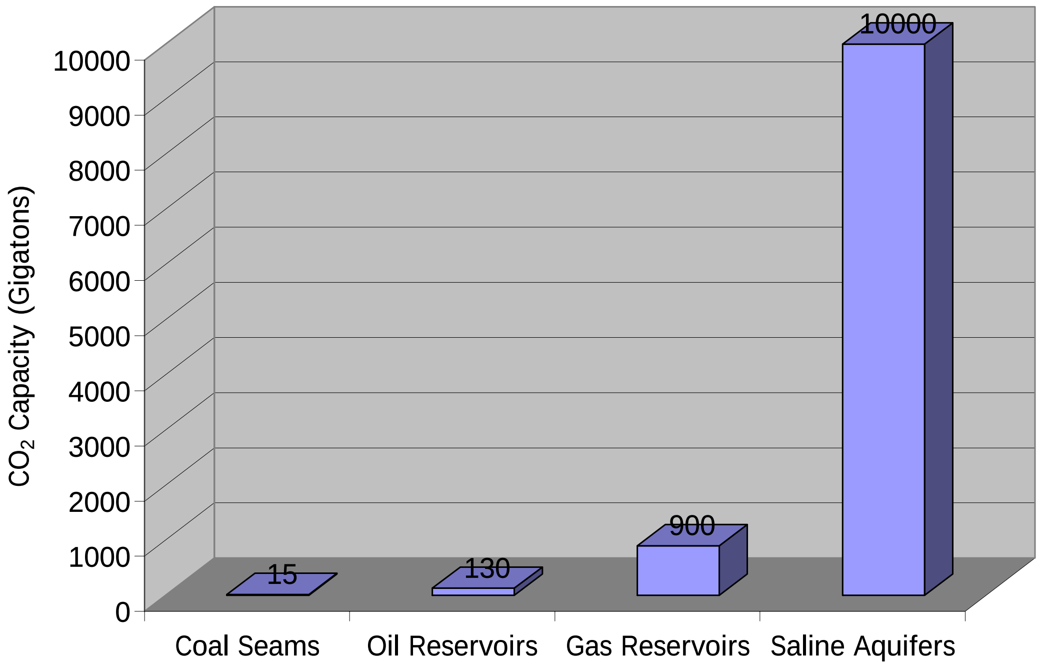


Figure 11 Global CO_2 storage capacities of geological media [10]

Deep Saline Aquifers

These are underground, water filled layers that are distributed widely below many major land masses and the oceans. They are generally found in carbonate or sandstone formations and contain large amounts of saline water. CO_2 can be injected into such reservoirs using techniques similar to those applied to enhanced oil recovery schemes. Highly saline underground reservoirs could provide an enormous CO_2 storage capacity. However more experiments in injecting CO_2 into aquifers are needed to gain a better understanding of the process and potential risks. Saline reservoirs throughout the world might store as much as 10 trillion tones of CO_2, equivalent to more than ten times the total energy related emissions projected for the next 30 years. [10, 14]

M. Sc. study of Başar Başbuğ demonstrates sequestration of CO_2 in a deep saline aquifer in detail. [31]

Coal Seams

Coal beds represent a large potential geological storage medium for CO_2, with value added benefit. The production of methane, naturally present in coals, can be enhanced by injecting CO_2 into the seam. This displaces the methane present, which is then drained and used as a valuable fuel source. Global coal bed storage capacity is estimated at about 15 billion tones. [14]

Oil and Gas Reservoirs

Reinjecting CO_2 into oil fields may lead to enhanced oil recovery, and this would offset part of the cost of dealing with the gas. Global storage potential in reservoirs has been estimated at about 1030 billion tones. [10]

With EOR, CO_2 is injected into operational oil reservoirs in order to increase the mobility of the oil. As well as boosting or maintaining oil output, much of the injected CO_2 remains trapped in the reservoir. Based on some current estimates, it is suggested that, globally, 130 billion tons of CO_2 could be stored in this manner. The costs associated with injection of the CO_2 can be compensated from the increased revenue generated from the additional oil produced. While most of the CO_2 currently used for EOR operations is sourced from naturally occurring CO_2 reserves, efforts are continuing to develop viable, cost effective techniques for utilizing CO_2 from sources such as fossil fuel combustion plants and other major point sources. [14]

It has been suggested that CO_2 may have the potential to displace gas from natural gas fields, maintaining or boosting output. EGR issues are being investigated as component parts of several major initiatives. These are looking at development and application of enhanced modeling and monitoring techniques, reductions in operational costs, site characterization and mapping, as well as capacity estimation. Another 900 billion tones could be stored in depleted gas fields. [10, 14]

Oceans

Disposal of CO_2 in the ocean might be the solution for regions with no depleted oil and gas fields or aquifers. The oceans potentially could store all the carbon in known fossil fuel reserves. Tests are underway on a small scale to assess the behavior of CO_2 dissolved in the ocean and its impact on the ocean fauna. [10]

It is not yet clear how geological and oceanic systems will react to large-scale injection of CO_2. Key technologies for capture and geological storage of CO_2 have all been tested on an experimental or pilot basis, but they will be deployed on a commercial scale only if the risks and costs can be sufficiently reduced and a market value is placed on reducing CO_2 emissions. [10]

CHAPTER 3

STATEMENT OF THE PROBLEM

Earth's climate has already begun to change due to the increased amount of greenhouse gases in the atmosphere. Countries are searching for finding a way to reduce their emissions. Sequestering carbon dioxide in geological media provides safe and long term storage conditions.

This study will concentrate on sequestering carbon dioxide into Kuzey Marmara gas reservoir. Field's simulation model will be created with CMG software and reservoir properties will be determined by history matching.

Four different scenarios will be developed in order to find the best sequestration scheme. Remaining natural gas content of the reservoir will be produced during the injection of supercritical carbon dioxide.

CHAPTER 4

KUZEY MARMARA FIELD

Field History

Kuzey Marmara offshore gas field has been discovered with the drilling of Kuzey Marmara – 1 well in 1988. This well has been abandoned due to unsuitable conditions for gas production. Deviated Kuzey Marmara – 2 well has been drilled from onshore and again abandoned due to very low permeability and porosity values of the geological structure. [2, 6, 30]

Data from both of the wells have been analyzed and Turkey's first offshore field project was initiated. [6]

After careful investigations field's probable shape has been determined and the field was planned to be produced with 3 wells at first stage. The third (Kuzey Marmara – 1/A) well has been drilled 250 ft away from Kuzey Marmara – 1. Kuzey Marmara – 1/A is located 7 km southwest of Silivri, 2.5 km away from the coast (Figure 11, Figure 12). Kuzey Marmara – 3 and Kuzey Marmara – 4 were drilled as deviated wells from Kuzey Marmara – 1/A offshore platform. [2, 6, 28, 29, 30]

Taking Kuzey Marmara – 1/A well as origin, Kuzey Marmara – 3 well has been drilled at location S42.88E 3150 ft and Kuzey Marmara – 4 has been drilled at the opposite location N33.71W 2550 ft (Figure 13). Drilling of these wells has been completed at 1995. [1, 6]

During the drilling operations, underground storage options were considered. Two more wells were drilled to increase the depletion rate in order to accelerate the utilization of the field for gas storage. These two deviated wells were completed about 1600 ft away from Kuzey Marmara – 1/A platform. The wells were completed in 1996 and the field was put to commercial production in October 1997. The field was produced with an unmanned well head platform located at 141 ft water depth. Natural gas production stopped in 2002 in order to leave the remaining gas as a cushion for the gas storage. [1, 2, 28, 29]

6 more wells were drilled until 08-05-2003. According to the agreements with BHI field, Kuzey Marmara – 10 well drilling had started in 05-07-2003 and the project was completed successfully with the drilling of Kuzey Marmara – 9Z well in 21-06-2003. [28]

Geology

Kuzey Marmara structure has an elongated shape with major axis striking from northwest to southeast. It is bounded by two normal faults at east and west (Figure 13). The reservoir rock is Soğucak formation which consists of primarily reefal and bioclastic limestone. The top of the reservoir is found at a depth of 3770 ft. The porosity is about 20% and average water saturation is about 10%. There is no water gas contact in the reservoir and current production data do not indicate any aquifer support. Taking the existing data into account, the reservoir is considered to be volumetric. Average permeability changes between 20 – 200 md. The thickness of the pay formation is about 214 ft. At the time of discovery, reservoir pressure was determined as 2050 psi and average reservoir temperature was 135 ^{0}F. [2]

The caprock of the reservoir is Ceylan formation which consists of marl and tuff with a varying thickness of 30 – 200 ft. [2]

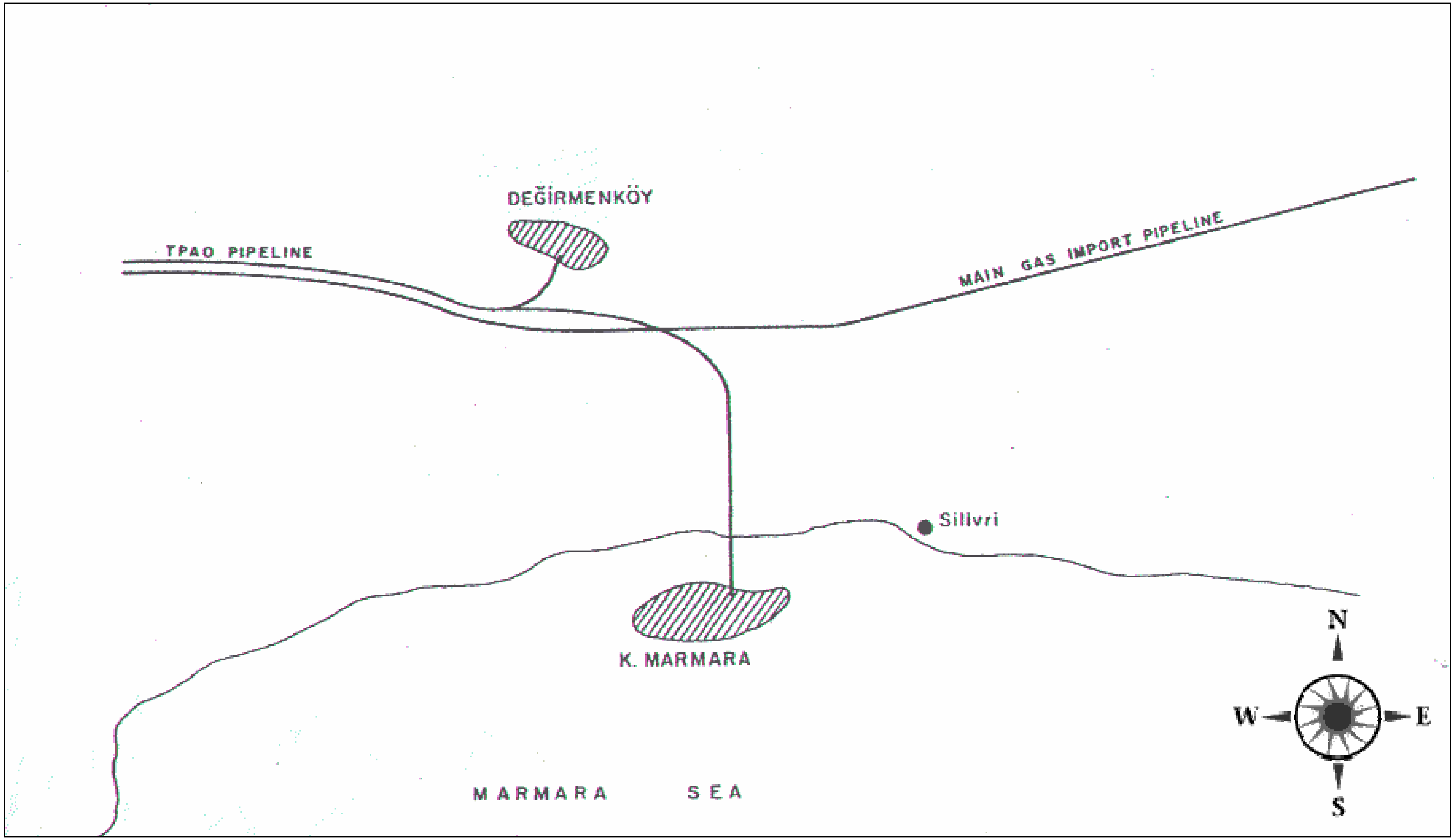


Figure 12 Location map of Kuzey Marmara [2]

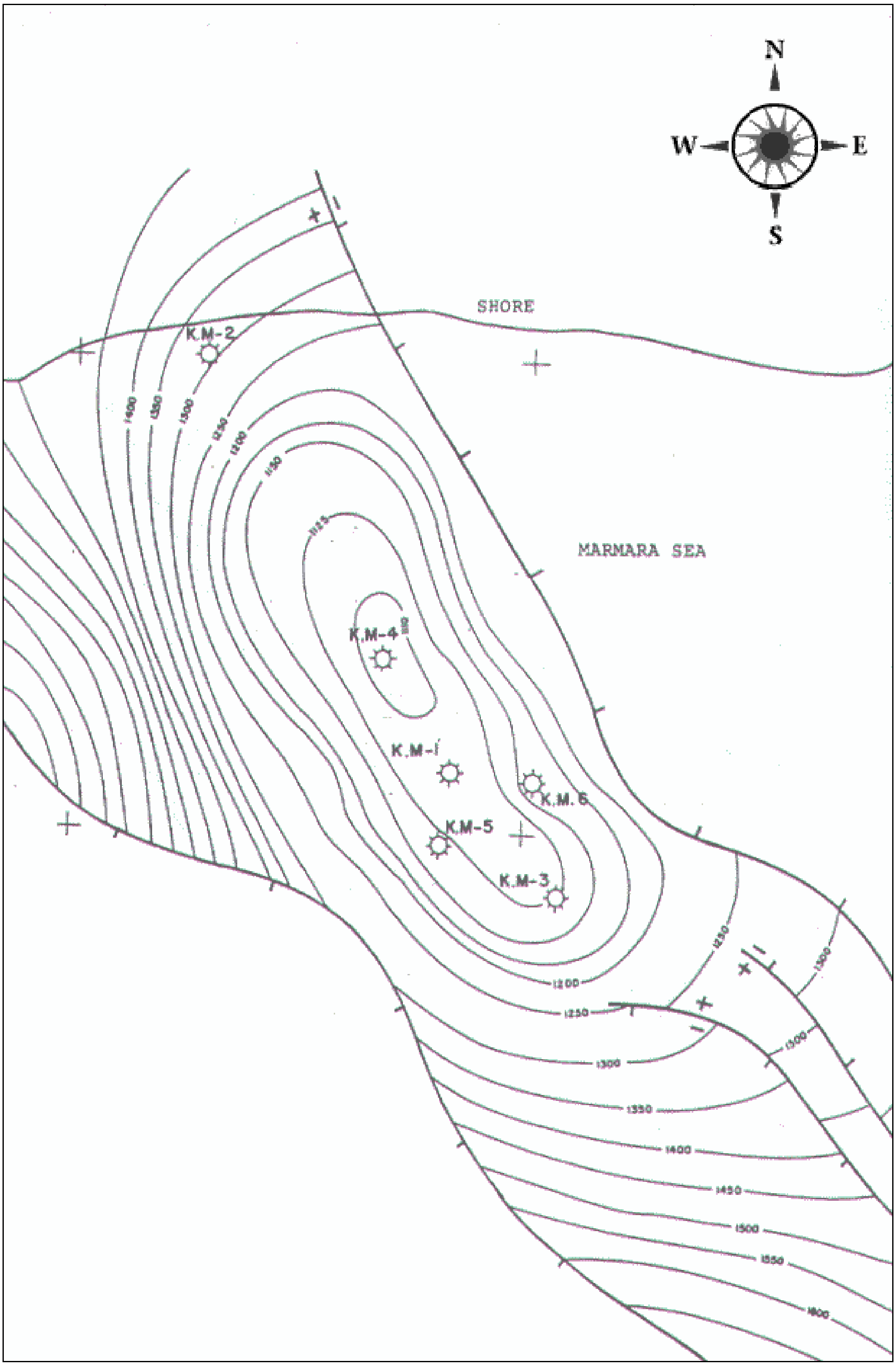


Figure 13 Structure map of Kuzey Marmara reservoir [2]

Reservoir Content

The reservoir gas consists of primarily methane and very little amount of CO_2. Available production data reveal no presence of H_2S in the produced gas. Reservoir gas content and fluid properties are given in Table 7 and Table 8 respectively.

Table 7 Kuzey Marmara reservoir gas content [16]

Component	Molar Fraction (%)
N_2	2.23
CO_2	0.76
H_2S	0.00
C_1	92.85
C_2	2.47
C_3	0.96
$i-C_4$	0.23
$n-C_4$	0.29
$i-C_5$	0.11
$n-C_5$	0.10

Table 8 Fluid properties of the field [22]

Property	Value
Specific Gravity	0.6030
Density of Gas	0.1109 lb/ft^3
Viscosity of Gas	0.016 cp
Compressibility of Gas	5.02 *10^{-4} 1/psi
Compressibility of Water	3.52 *10^{-6} 1/psi

The wells produce little amount of condensate and condensate production increase with decreasing wellhead pressures (Table 9).

Table 9 Condensate production rates

Well	Condensate production rate (bbl/day)
Kuzey Marmara – 1/A	18.2
Kuzey Marmara 3	9.3
Kuzey Marmara 4	20.6
Kuzey Marmara 5	11.7
Kuzey Marmara 6	20.3

The reservoir is saturated with about 10% water. Water content is almost completely immobile and little amount of water is produced. (Table 10)

Table 10 Water production rates

Well	Water production rate (bbl/day)
Kuzey Marmara – 1/A	3.5
Kuzey Marmara 3	1.7
Kuzey Marmara 4	3.9
Kuzey Marmara 5	2.2
Kuzey Marmara 6	3.9

Gas Storage Project

Kuzey Marmara field's good characteristic properties make it suitable for underground gas storage. A feasibility study for converting the field was performed in 1997. The reservoir and caprock structures were found suitable for natural gas storage. [2]

In the injection period, natural gas will be withdrawn from the main import pipeline and measured with the help of a measuring system. With the help of the compressors the pressure of the gas will be raised according to the reservoir conditions. The temperature of the compressed gas will be decreased and the gas will be injected to the reservoir. [2]

In the production interval, gas will be produced and flow to the processing facilities. Compressors will raise the pressure of the gas to pipeline pressure. After quality standard measurements, the gas will be transferred to the pipeline system. [2]

CHAPTER 5

METHOD OF SOLUTION

Software

Kuzey Marmara field model was created by using both Computer Modeling Group's Generalized Equation of State Model Compositional Reservoir Simulator and demo version of Golden Software's Surfer software. Field equation of state (EOS) model was created using CMG's WinProp and integrated into GEM. Properties of CO_2 and field gas content were obtained from WinProp libraries and implemented together with the EOS data.

Porosity and permeability grids were modeled with the help of Surfer software and the output data were imported into GEM data file using Microsoft Excel.

Appendix E contains a valid GEM data file as an example.

Computer Modeling Group (CMG)

CMG is a computer software engineering and consulting firm engaged in the development, sale and technology transfer of reservoir simulation software. [19]

CMG began as a company known for its expertise in heavy oil, and expanded its expertise into all aspects of reservoir flow modeling. Over the past 20 years, CMG has remained focused on the development and delivery of reservoir simulation technologies that assist oil and gas companies to determine reservoir capacities and maximize potential recovery. [19]

Generalized Equation of State Model Compositional Reservoir Simulator (GEM)

GEM is an efficient, multidimensional, equation of state compositional simulator which can simulate all the important mechanisms of a miscible gas injection process, such as vaporization and swelling of oil, condensation of gas, viscosity and interfacial tension reduction, and the formation of a miscible solvent bank through multiple contacts. [19, 20]

GEM utilizes either the Peng Robinson or the Soave Redlich Kwong equation of state to predict the phase equilibrium compositions and densities of the oil and gas phases, and supports various schemes for computing related properties such as oil and gas viscosities. [20]

The quasi-Newton successive substitution method is used to solve the nonlinear equations associated with the flash calculations. A robust stability test based on a Gibbs energy analysis is used to detect single phase situations. GEM can align the flash equations with the reservoir flow equations to obtain an efficient solution of the equations at each time step. [20]

GEM uses CMG's grid module for interpreting the reservoir definition keywords used to describe a complex reservoir. Grids can be of variable thickness - variable depth type, or be of corner point type, either with or without user controlled faulting. Other types of grids, such as Cartesian and cylindrical, are supported as well as locally refined grids of both Cartesian and hybrid type. [20]

Regional definitions for rock-fluid types, initialization parameters, EOS parameter types, sector reporting, aquifers are available. Initial reservoir conditions can be established with given gas-oil and oil-water contact depths. Given proper data fluid composition can be initialized such that it varies with depth. A linear reservoir temperature gradient may also be specified.

Aquifers are modeled by either adding boundary cells which contain only water or by the use of the analytical aquifer model proposed.

WinProp

WinProp is CMG's equation of state multiphase equilibrium property package featuring fluid characterization, lumping of components, matching of laboratory data through regression, simulation of multiple contact processes, phase diagram construction and solids precipitation. [19, 21]

WinProp analyzes the phase behavior of reservoir gas and oil systems, and generate component properties for CMG's compositional simulator GEM. [21]

WinProp creates keyword data files to drive the phase behavior calculation engine. These files contain regular keywords that were required by the simulator. [21]

Golden Software

Golden Software is one of the leading providers of scientific graphics software in the world. They develop software for researchers in mining, engineering, and medicine, as well as thousands of applied scientists and engineers. [18]

Surfer

Surfer is a contouring and 3D surface mapping program. It converts data points into contour, surface, wireframe, vector, image, shaded relief, and post maps. Virtually all aspects of maps can be customized to produce the presentation wanted. [18]

Demo version of Surfer software is fully featured except print, save, copy, cut, and export functionalities. [18]

Reservoir Model Construction

Production Data

Scaled contour maps and average values of field properties at drilled well locations were not enough for creating a realistic model of a reservoir. For this purpose, Kuzey Marmara production data were obtained from reference "Simulation of Depleted Gas Reservoir for Underground Gas Storage" [22]. These data were used for generating porosity and permeability grids and checking the validity of these properties afterwards.

Production information of Kuzey Marmara field between years 1998 – 2002 can be seen in Appendix D. Production tables contain wellhead pressures, production rate, gas production, condensate production and water production for each well.

Field

Field property values vary slightly in the publications. The properties considered in this study are shown in Table 11.

Reservoir properties are the values that obtained at the end of the history matching simulations. Average reservoir pressure has been changed from 2050 psi to 1050 psi to represent the initial conditions at the beginning of scenarios.

Table 11 Field properties [2, 22]

	Property	Value
Reservoir	**Average Pressure**	2 047 psi
	Average Porosity	9.67%
	Average Permeability	16.9 md
	Temperature	135 ^{0}F
	Pay Thickness	214 ft
	Rock Compressibility	4 $*10^{-6}$ 1/psi
	Bulk Volume	15.38 $*10^9$ ft^3
	Pore Volume	1.49 $*10^9$ ft^3
	HC Pore Volume	1.34 $*10^9$ ft^3
Oil	**Saturation**	0%
	Moles	0 mol
	OOIP	0 bbl
Gas	**Saturation**	90%
	Moles	228.58 $*10^9$ mol
	OGIP	190.71 $*10^9$ scf
Water	**Saturation**	10%
	Moles	235.32 $*10^9$ mol
	OWIP	26.64 $*10^6$ bbl

Grid Top

Inputs of the simulator were needed to be in Cartesian grid form. Structure map of Soğucak formation was obtained and copied (Figure 13) [2, 3, 4]. The reservoir was divided into 40 columns in east – west direction and 50 rows in north – south direction totaling 2000 grid cells in a two dimensional plane. 937 of the cells were marked as inactive and the remaining active grid cells were assigned an approximate value considering the structural contours. Created two dimensional map, was divided into 5 equal height grid layers to provide three dimensional movements for both CO_2 and natural gas (Figure 14). Total number of grid cells in three-dimensional map became 10000 which is also the cell limit for educational version of GEM. Due to high number of grid cells used, some cell values in a few areas were completed with the help of Surfer program.

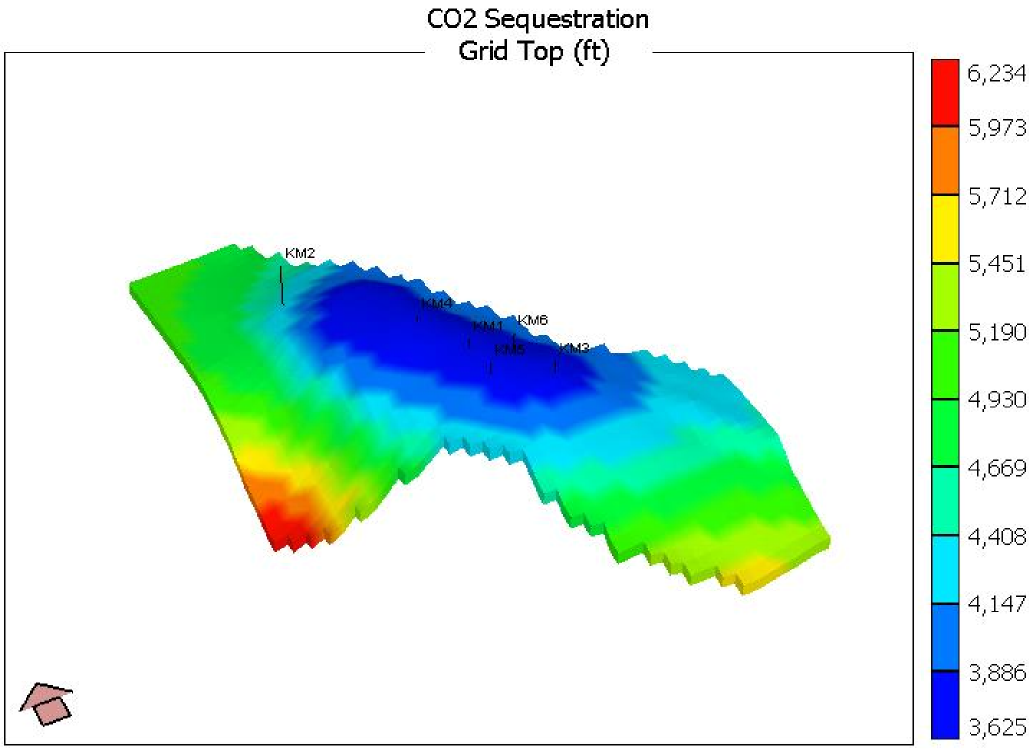


Figure 14 Initial 3D structure map of Kuzey Marmara field

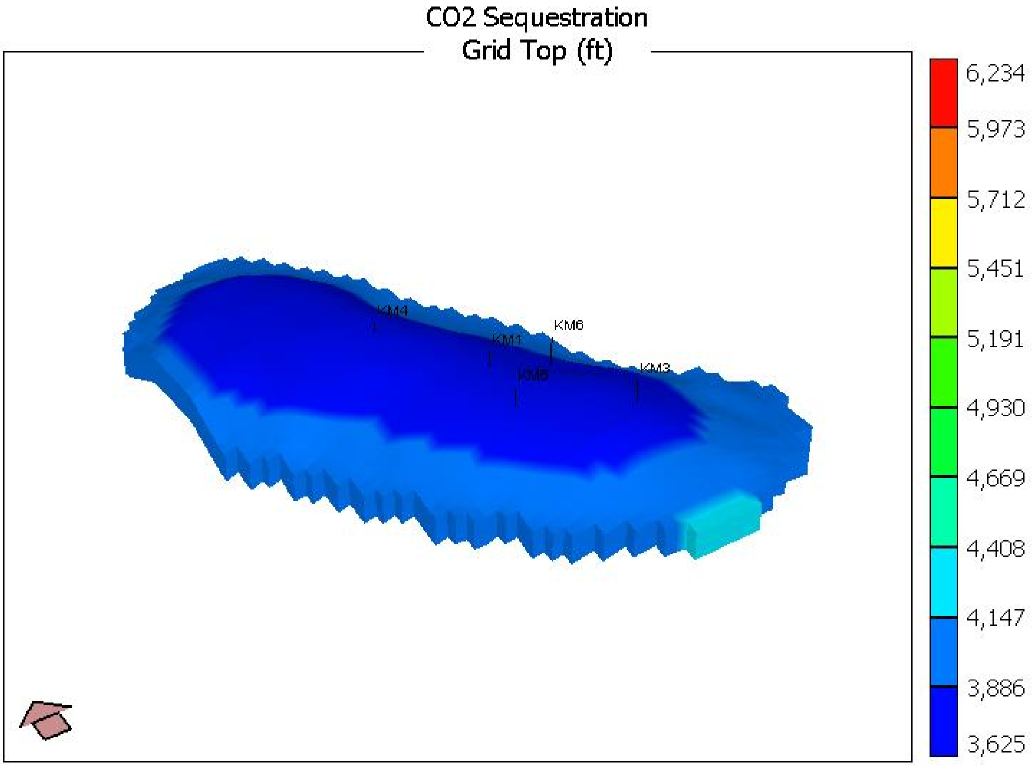


Figure 15 Final 3D structure map of Kuzey Marmara field

After assigning all initial properties of the field, history match runs were made and reservoir capacity and boundaries were determined. Reservoir section was extracted from the initial structure map. A new map was generated according to newly defined boundaries. Once again, total number of cells increased to 10000 by using Microsoft Excel (Figure 15).

At the final stage, the number of active grid blocks was 5315 out of 10000 and a single block's dimensions were defined as 260*260*42.8 feet (Figure 16). Total volume of a grid block became 2.89 million cubic feet.

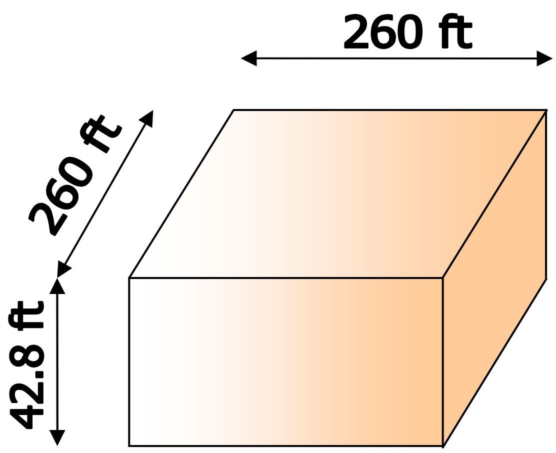


Figure 16 Dimensions of a single reservoir grid block

Porosity

Together with the permeability map, reservoir porosity map was one of the time consuming studies that had to be accomplished. Unlike the structure map, the reservoir had no porosity data except the average porosity values that were taken from the drilled well locations. Well locations and estimated porosity values were entered into Surfer software and probable porosity maps of the field were generated by using Kriging method. It was realized that the field porosity distribution was not even at every place of the reservoir. In fact, it is true that carbonate reservoirs are characterized by extreme heterogeneity in their porosity and permeability properties [3]. The porosity values tended to decrease with increasing true vertical depth (TVD). Higher regions of the reservoir had high porosities as much as 20% while these values rapidly drop towards the edges of the boundaries (Figure 12). Thus, northwest and southeast boundaries of the reservoir were defined with very low porosities (Figure 17).

Average permeability at well locations was 32 md while average field porosity was found out to be 18% (Table 12 and Table 13).

Table 12 Map properties that vary with respect to grid locations

	Maximum	Minimum	Average
TVD (ft)	4 186	3 625	3 865
Pressure (psi)	2 064	2 039	2 050
Porosity (%)	20.52	0.10	9.06
Permeability (md)	50.00	0.01	16.90

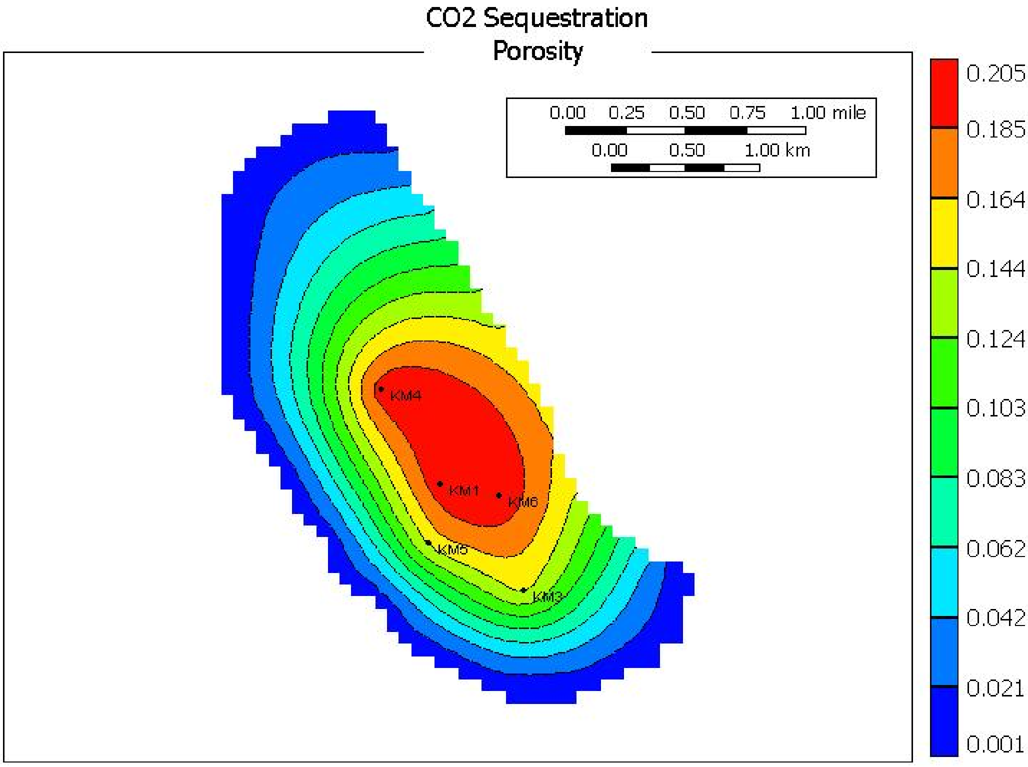


Figure 17 2D porosity map of Kuzey Marmara reservoir

Permeability

Permeability map was created very similar to the porosity map. The same procedure was followed to generate various maps with Surfer software and simulation results were checked to verify the correctness of the map. Northwest and southeast boundaries had very low permeability values just like the porosity (Figure 18).

Average permeability value at well locations was 18% while average field porosity was found out to be 9.06% (Table 12 and Table 13).

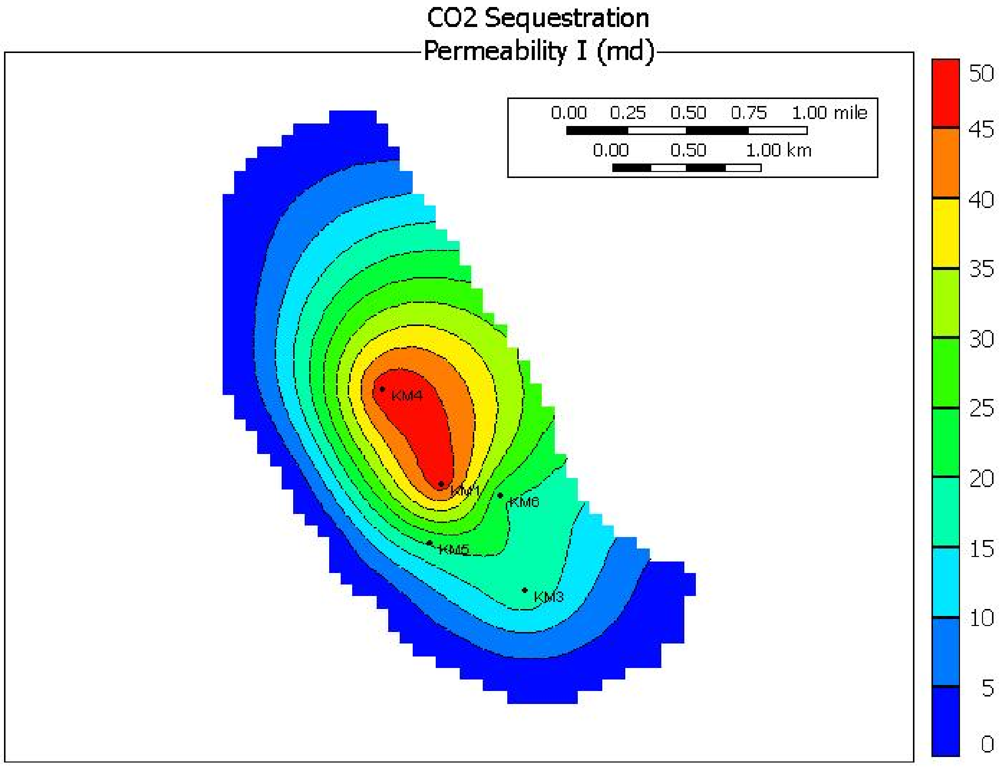


Figure 18 2D permeability map of Kuzey Marmara reservoir

Relative Permeability

Relative permeability tables were among required properties. Unfortunately, the data was not available. These curves are generated with GEM software relative permeability tools by trial and error method.

Average water saturation value is known and it is 10% [2]. The reservoir has no oil content so all irreducible and residual oil saturations are assumed to be zero since these values will never be required. All water content is considered to be immobile since the wells produce very little amount of water [22]. The rest of the variables, including the concaveness of the permeability curves, are determined according to history matching results (Figure 19).

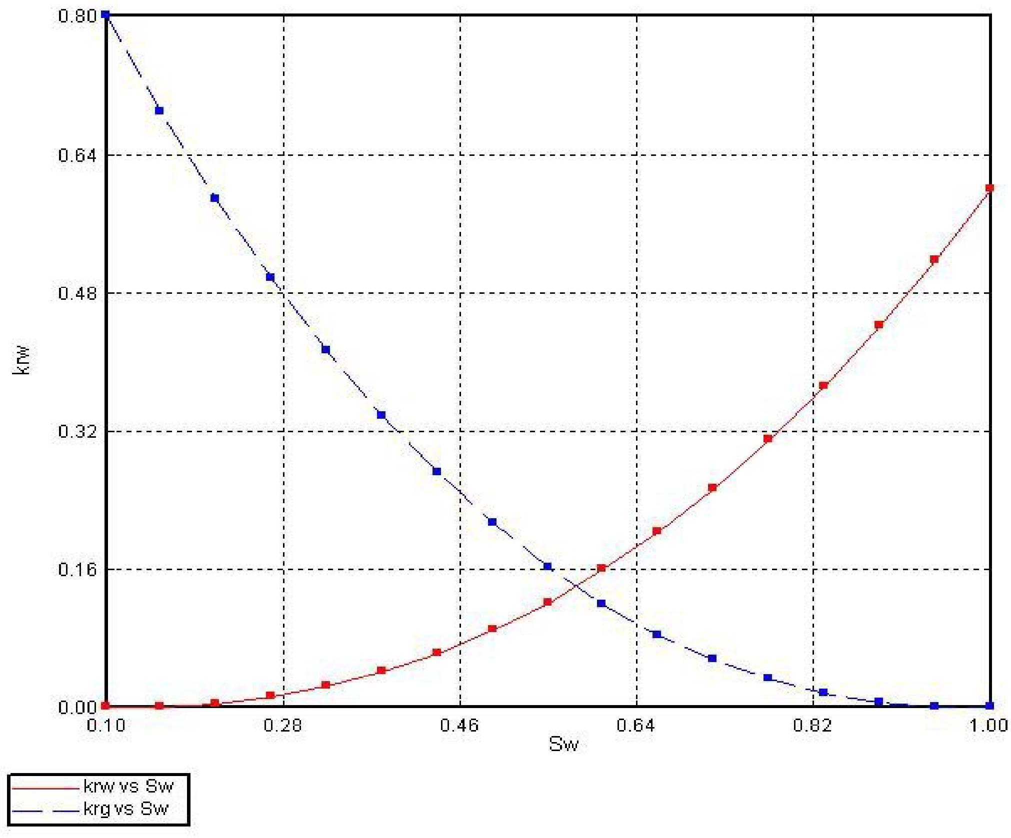


Figure 19 Relative permeability chart (k_{rw} vs. S_w)

Appendix B contains the relative permeability data that is used to sketch the following relative permeability curve.

Wells

All wells were drilled from the location of KM1 well and their perforation locations were placed according to the structure contour map [2]. Grid properties at these wells locations are given in Table 13.

Table 13 Map properties at well locations

	KM1	KM3	KM4	KM5	KM6	Average
Grid Location	19,32	26,41	14, 24	18, 37	24, 33	N/A
TVD (ft)	3 669	3 722	3 627	3 707	3 790	3 703
Porosity (%)	20	15	20	15	20	18
Permeability (md)	50	20	50	20	20	32

Location of the wells that are used in simulation runs were picked to form a line-drive pattern in the two dimensional view of the reservoir. This condition was satisfied by removing KM5 and KM6 wells from the region. Due to unpredictable structure of KM6 well region, it would be better to ignore its presence for getting better results in the simulations.

One new well was drilled in the northwest region of the reservoir. The new well was captioned as "KMNew" and its perforations were defined at the grid location (X: 7, Y: 13). Similar to the rest of the wells, this well had been drilled horizontally from the location of KM1. Table 14 shows the properties of KMNew well.

Table 14 Properties of KMNew well

Property	Value
Location	7, 13
TVD	3 854 ft
Length	8 911 ft
Grid Porosity	4.69 %
Grid Permeability	10.12 md

Wellbore Model

Wellbore model is an important fact to determine the wellhead pressures and without tubing data GEM was unable to calculate this value. Model flow correlation tool of GEM was used to create tubing properties.

Relative roughness of the tubing was calculated according to the following equation. Inside pipe roughness value of steel tubing was used for calculations. [25]

$$\mathrm{Re}\,lativeRoughness = \frac{InsidePipeRoughness}{InsidePipeDiameter} \tag{1}$$

$$InsidePipeRoughness = 1.50919 * 10^{-4}\, ft$$
$$InsidePipeDiameter = 0.20342\, ft$$
$$\mathrm{Re}\,lativeRoughness = \frac{1.50919 * 10^{-4}}{0.20342} = 0.000742$$

Tubing sizes were assumed as 2 7/8 and their inner diameters were obtained from Schlumberger i-Handbook [23]. Bottomhole temperature was obtained from TPAO studies [2].

Table 15 Common wellbore properties

Property	Value
Relative Roughness	0.000742
Wellhead Temperature	80 ^{0}F
Bottomhole Temperature	135 ^{0}F
Tubing OD	2 7/8 in
Tubing Inner Radius	0.10171 ft

TDV of the wells were determined from the created structure map. KM3 and KM4 tubing lengths were obtained from TPAO drilling group studies [6]. KM4 and KM5 tubing lengths were estimated by considering their maximum and minimum distances from KM1 well.

Table 16 Well tubing lengths and true vertical depths

	True Vertical Depth (ft)	Length (ft)
KM1	3 776	3 776
KM3	3 829	5 942
KM4	3 734	5 833
KM5	3 814	4 625
KM6	3 897	4 701

Perforations

KM1 well was the first producing well of the field. This well had been drilled vertically and the rest had been drilled as deviated wells. TVD of deviated well perforations was unknown so they are assumed to be opened in the middle grid layer of the field in all simulation cases. Considering the disposal project, KM1 well perforations were opened in all grid layers for scenario runs. For history matching only middle grid layer was opened to production like rest of the wells (Table 17).

Table 17 Perforation interval of wells with respect to grid layers

	KM1	KM3	KM4	KMNew
Grid Layer 1	Open	Closed	Closed	Closed
Grid Layer 2	Open	Closed	Closed	Closed
Grid Layer 3	Open	Open	Open	Open
Grid Layer 4	Open	Closed	Closed	Closed
Grid Layer 5	Open	Closed	Closed	Closed

History Match

History matching is a way of verifying the accuracy of hypothetically generated properties. In this case these properties are mainly, permeability and porosity values. Values of these properties are known at the well locations but allocation of these properties in the rest of the field must be determined by means of a trial and error method.

Surfer software data helped to build the most suitable properties for Kuzey Marmara reservoir. This would be made by obtaining the most approximate values in the output of GEM simulator with respect to existing field data. Numerous simulation runs were made to match wellhead pressures of the available wells. The accuracy of each history match attempt was determined by means of root mean square error method until a satisfactory result was obtained.

Root Mean Square Error (RMSE)

The RMSE is a kind of generalized standard deviation. It arises whenever the differences between subgroups or relationship between variables are needed to be compared. [23]

The root mean squared error E_i of an individual program i is evaluated by the following equation.

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n}\left(P_{(ij)} - T_j\right)^2} \qquad \textbf{(2)}$$

$P_{(ij)}$ is the value predicted by the individual program i for sample case j out of n sample cases; and T_j is the target value for sample case j.

Simulations

In the case of Kuzey Marmara, natural gas content of the field is an important reason to consider while projecting a sequestration operation. At 1050 psi, field's gas in place was calculated as 85 MMscf. Producing this gas would be economically advantageous and replacing the produced gas would allocate extra space for further CO_2 deposition.

Immediately starting production of natural gas would lower the wellhead pressures in a short period of time. Therefore, it would be wise to produce the gas from a region of the reservoir while injecting CO_2 from another region. Three of the scenarios are built on the idea of regional variation effects.

Constraints

Common priority target of these scenarios was to produce the remaining natural gas in the reservoir as much as possible. Wellhead pressures had to be kept above 500 psi to make most of the surface equipment work and the bottomhole pressures had to be above 1070 psi to maintain supercritical state of CO_2.

Kuzey Marmara gas field has been discovered at an average pressure of about 2050 psi and the maximum average reservoir pressure constraint was defined as 2300 psi. This was approximately 10% more of the initial reservoir pressure.

Also, the amount of CO_2 percentage in produced gas was an important constraint. It was aimed that this value must be below 2%. After this value was reached, a CO_2 separator was installed to the system and 2% limitation was raised to 10% to produce more natural gas from the field.

Assumptions

Practically it is nearly impossible to simulate every detail of a modeled system due to several reasons. The following characteristics of Kuzey Marmara reservoir could not be included in the scenarios:

- GEM software had some limitations on the desired runs. Thus, some of the reservoir parameters could not be included in the simulations. The most important fact that could not be simulated was the lack of representing the temperature changes. All scenarios were considered to occur under isothermal conditions.

- 2004 version of GEM software was not able to handle mineral interactions within the simulations. CMG company had already declared implementation of a reaction interface for the upcoming releases.

- Provided production data include water and condensate production rates of the field. GEM software required production ratios with bottomhole pressures of wells at specific time points to build necessary tubing tables. Lack of bottomhole pressure information prevented construction of detailed tubing data. Water and condensate productions were fairly low so both of them had to be ignored in the simulations.

- Soğucak limestone is a very variable formation as it is a carbonate type formation. This kind of formation continuity and thickness patterns are very complex. This is due to the complexities of processes in the depositional environment [3]. The properties of the reservoir were considered to be homogeneous in various situations such as in porosity and permeability determination.

- Kuzey Marmara reservoir consists of four different layers of formations which vary in terms of their properties. Absence of well log data prevented modeling of these formations as separate. All of these layers were assumed as one single combined layer which shows average characteristics of actual layers. [1]

- Captured injection fluid was considered to be containing 100% CO_2. Actually, the purity of separated CO_2 is about 99%.

- Less than 0.12% of injected CO_2 was produced together with the natural gas after the installation of CO_2 separators. Efficiency of the separators depends on a variety of factors such as temperature, pressure and CO_2 percentage of the input gas. Since the separators were assumed virtual designs, the technical output data was unknown. Cumulative production results include little amounts of produced but separated CO_2 gas.

Scenarios

Simulation timelines can be divided into three basic parts.

First one is the “pre injection” period. In this part, assigned injector wells sequester CO_2 while the production wells remains closed. The aim of this step is to increase the pressure of the reservoir a little so that required constraints can be satisfied.

Second part is the “natural gas recovery” period. After a suitable reservoir pressure is reached, production wells are opened and start producing natural gas while the injector wells continue their CO_2 injection. CO_2 separators are installed during this period when the CO_2 production in the produced gas exceeds 2%.

Third and final part is the “disposal” period. When the CO_2 amount in the produced gas reaches 10% production wells are shut and converted to injector wells. Also previous well injection rates are increased.

Table 18 shows information about well injection and production rates for all scenarios.

Table 18 Well flow rates of each scenario

	Date	KM1		KM3		KM4		KMNew	
		State	Rate (MMscfd)	State	Rate (MMscfd)	State	Rate (MMscfd)	State	Rate (MMscfd)
Scenario 1	2010-01-01 2027-09-01	Inj	10	Inj	10	Inj	10	Inj	10
Scenario 2	2010-10-01 2011-01-01	Shutin	-	Inj	7	Shutin	-	Inj	7
	2011-01-01 2016-11-01	Prod	5	Inj	7	Prod	5	Inj	7
	2016-11-01 2019-10-01	Prod	5	Inj	7	Shutin	-	Inj	7
	2019-10-01 2037-12-01	Inj	10	Inj	10	Inj	10	Inj	10
Scenario 3	2010-01-01 2015-02-01	Inj	7	Shutin	-	Inj	7	Shutin	-
	2015-02-01 2018-05-01	Inj	7	Prod	5	Inj	7	Prod	5
	2018-05-01 2019-09-01	Inj	7	Prod		Inj	7	Shutin	-
	2019-09-01 2034-05-01	Inj	10	Inj	10	Inj	10	Inj	10
Scenario 4	2010-01-01 2015-01-01	Shutin	-	Shutin	-	Shutin	-	Inj	7
	2015-01-01 2043-04-01	Shutin	-	Prod	5	Shutin	-	Inj	7
	2043-04-01 2063-01-01	Inj	10	Inj	10	Inj	10	Inj	10

Scenario 1

This scenario considers immediate injection of CO_2 from all of the available wells. None of the wells produce natural gas and injection rates were assigned as 10 MM scf/day for each of the wells (Table 18).

This was the simplest CO_2 sequestration case that was simulated to demonstrate the minimum limits of the cumulative injection amount. The result of Scenario 1 was helpful for making a comparison among the rest of the simulations.

Scenario 2

In this scenario CO_2 deposition was made through both flanks of the reservoir and the producers were placed in the middle region. Middle region of the reservoir had higher porosity and permeability values when compared to the flank regions.

Two of the initial injector rates were assigned as 7 MM scf/day each. One year after injection has started; two production wells were opened with a rate of 5 MM scf/day. First CO_2 constraint was reached at KM4 well 5 years and 11 moths after it had started production and the well is shutin. Producer KM1 reached CO_2 constraint after 8 years and 10 months of production period. Both of the producers were converted to injector wells and all four well injection rates were assigned as 10 MM scf/day until average reservoir pressure constraint of 2300 psi was reached (Table 18).

Scenario 3

This scenario is very similar to the Scenario 2 except for the injector and producer wells types are exchanged. Wells placed in the flanks of the reservoir were used for production and injector wells were placed in the middle.

Two of the initial injector rates were assigned as 10 MM scf/day. After five years of injection period, KMNew and KM3 production wells were opened with production rates of 5 MM scf/day and 4MM scf/day respectively. KMNew well reached its CO_2 constraint after producing for 3 years and 3 months time and was shutin. The other producer, KM3 well, was closed 4 years 7 months after it had started producing. Both of the producers were converted to injector wells and all their injection rates were assigned as 10 MM scf/day each until average reservoir pressure constraint was reached (Table 18).

Scenario 4

KMNew well was assigned as injector in the northwest flank of the field. CO_2 injection rate was assigned as 7MM scf/day. After 5 years of injection period KM3 producer was opened in the south eastern flank side and its production rate was set to 5MM scf/day. Both wells remained open for 28 years and 3 months period. KM4 and KM1 wells were opened as injectors and the producer KM3 was converted to an injector well. All of the four well injection rates were set to 10MM scf/day and these wells remained open until an average reservoir pressure of 2300 psi was reached (Table 18).

Unlike the previous scenarios, the simulation was ended because of wellhead pressure constraint. CO_2 separator was installed when it was necessary but the produced CO_2 amount never reached 10%.

CHAPTER 6

RESULTS AND DISCUSSION

History Match

Virtually created Kuzey Marmara field returned satisfactory results with only one exception. Well and field production rates matched without a problem (Figure 20, Figure 22, Figure 24, Figure 26, Figure 28 and Figure 30) but KM6 wellhead pressure values failed to match any of the prepared reservoir models (Figure 29). Its calculated wellhead values deviated as much as 400 psi at several time points. Wellhead pressures of rest of the wells were matched approximately within 4.5% of field data (Figure 21, Figure 23, Figure 25 and Figure 27). Table 19 displays the results of RMSE calculations for wellhead pressures and cumulative gas productions. Details of these calculations are given in Appendix A.

According to TPAO production group study [1], the behavior of KM6 well cannot be explained with regular modeling of porosity and permeability values. KM6 production is more than expected and measured wellhead pressures are higher than estimated. This unexpected behavior is clarified with the existence of a major fault joining a gas containing region at northern section of the field [1].

Unfortunately, condition of KM6 well was failed to be created with existing data at hand so this well has been removed from scenarios.

Table 19 Calculated RMSE values and cumulative production rates

	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	RMSE Cumulative Production (MMscf)	RMSE Wellhead Pressure (psi)
KM1	13.82	13.05	0.366	27.74
KM3	6.83	6.17	0.307	55.60
KM4	15.03	13.99	0.413	89.89
KM5	7.55	6.48	0.608	80.68
KM6	15.11	13.79	0.715	253.35
Field	58.35	53.49	2.414	N/A

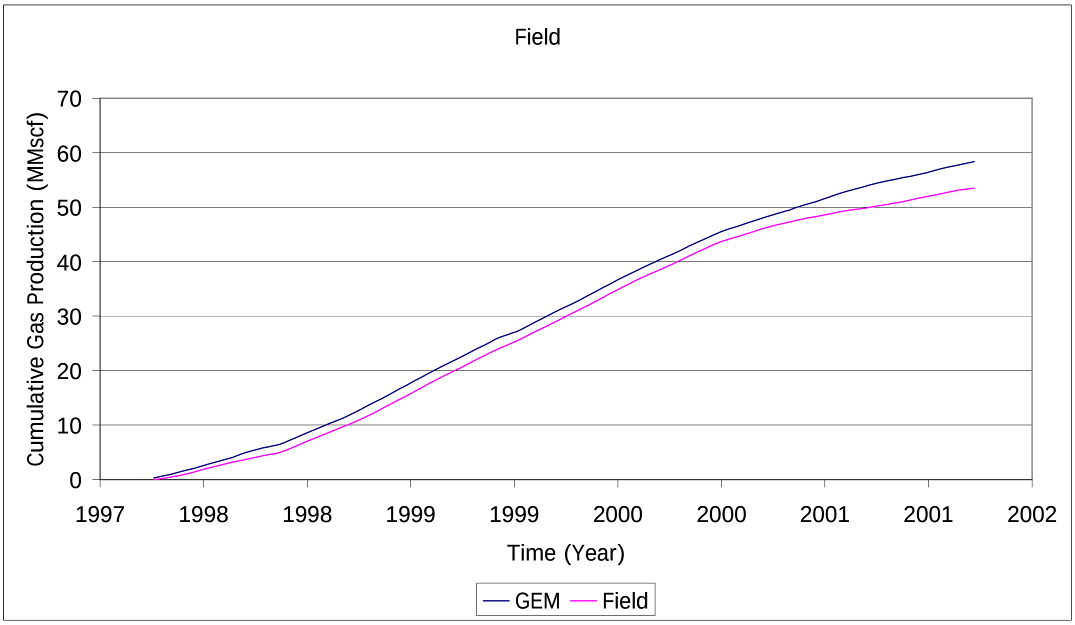


Figure 20 Cumulative gas production comparison between field data and simulator results

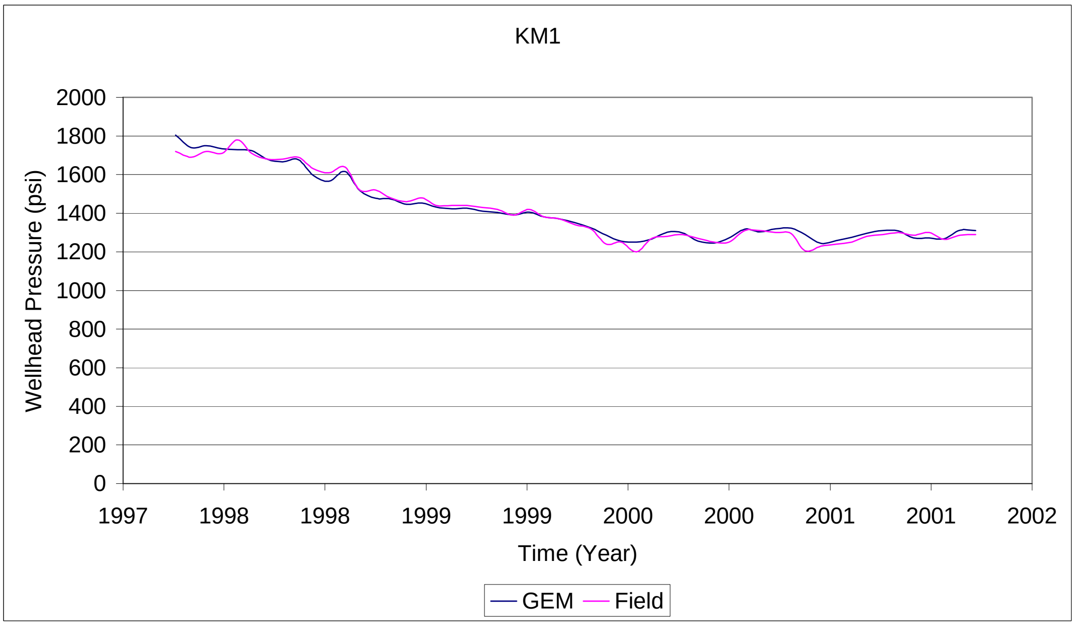


Figure 21 Wellhead pressure comparison of KM1 between field data and simulator results

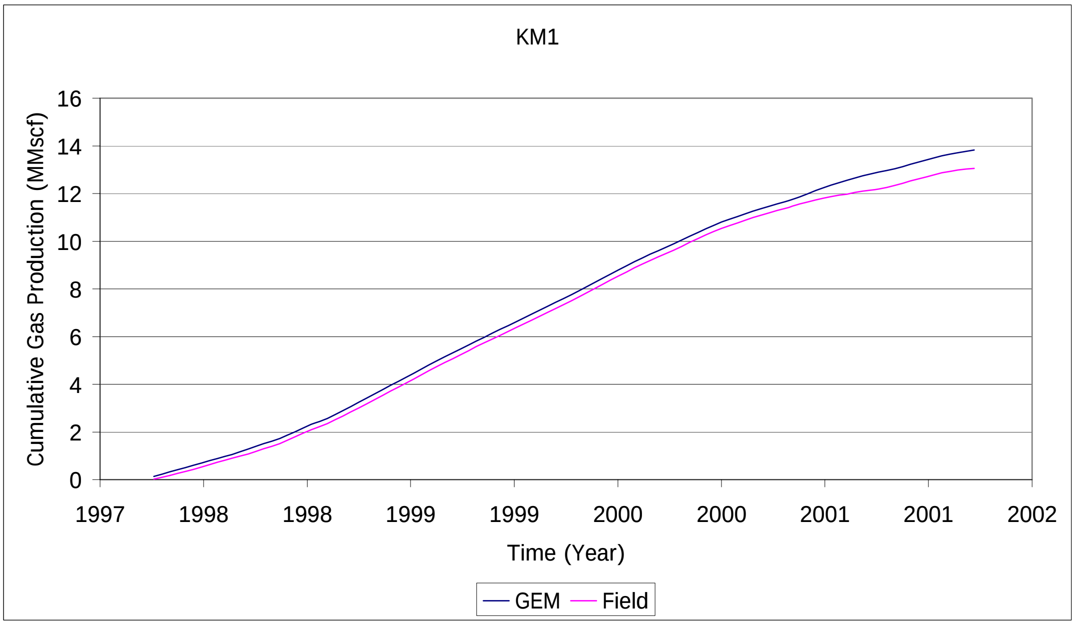


Figure 22 Cumulative gas production comparison of KM1 between field data and simulator results

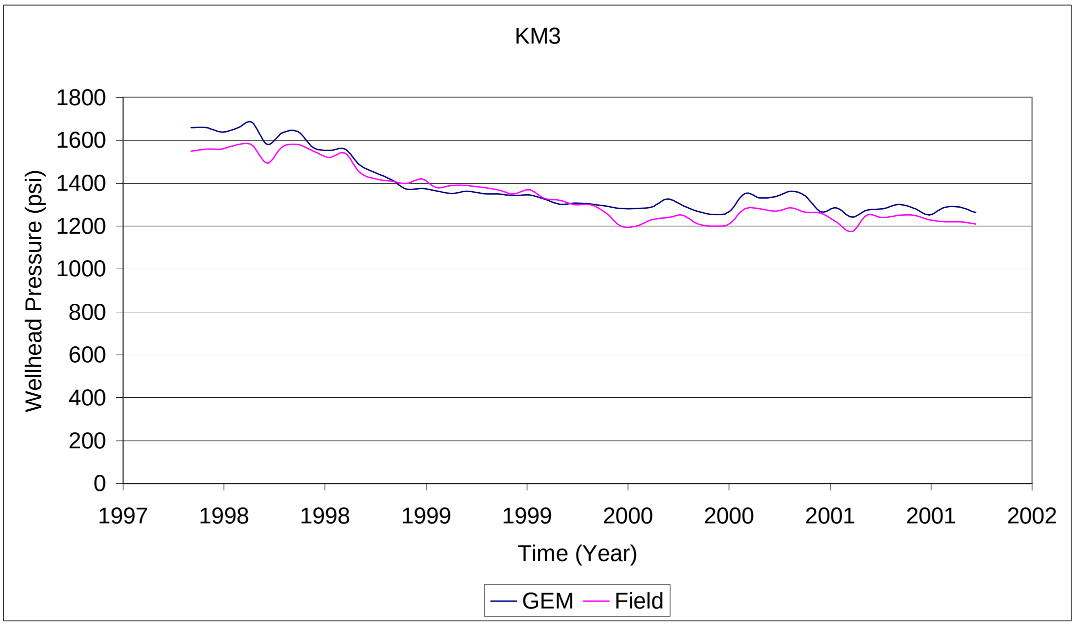


Figure 23 Wellhead pressure comparison of KM3 between field data and simulator results

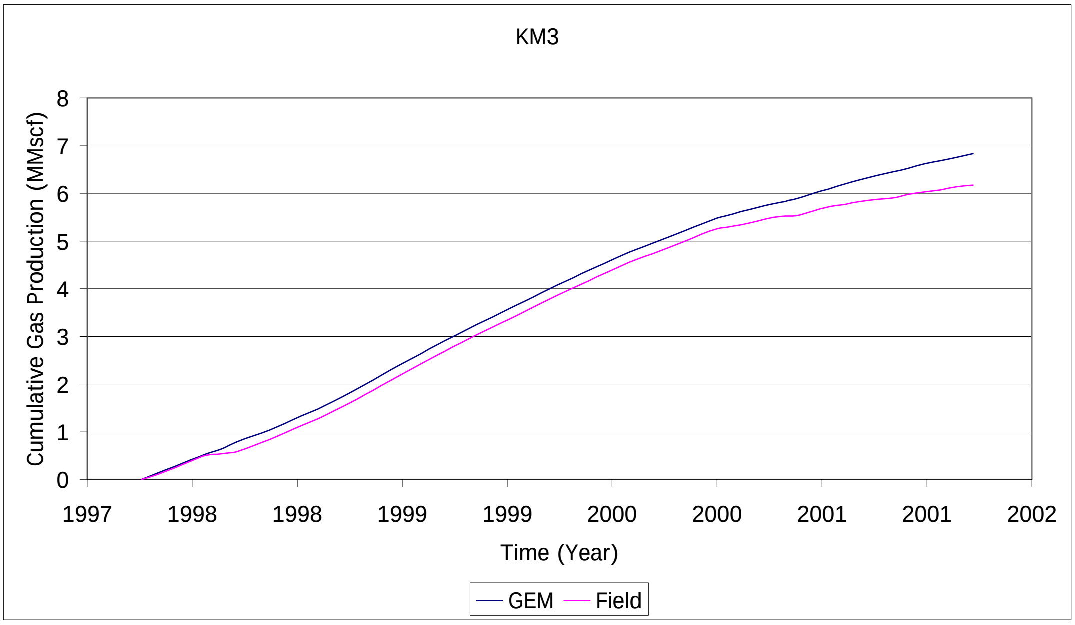


Figure 24 Cumulative gas production comparison of KM3 between field data and simulator results

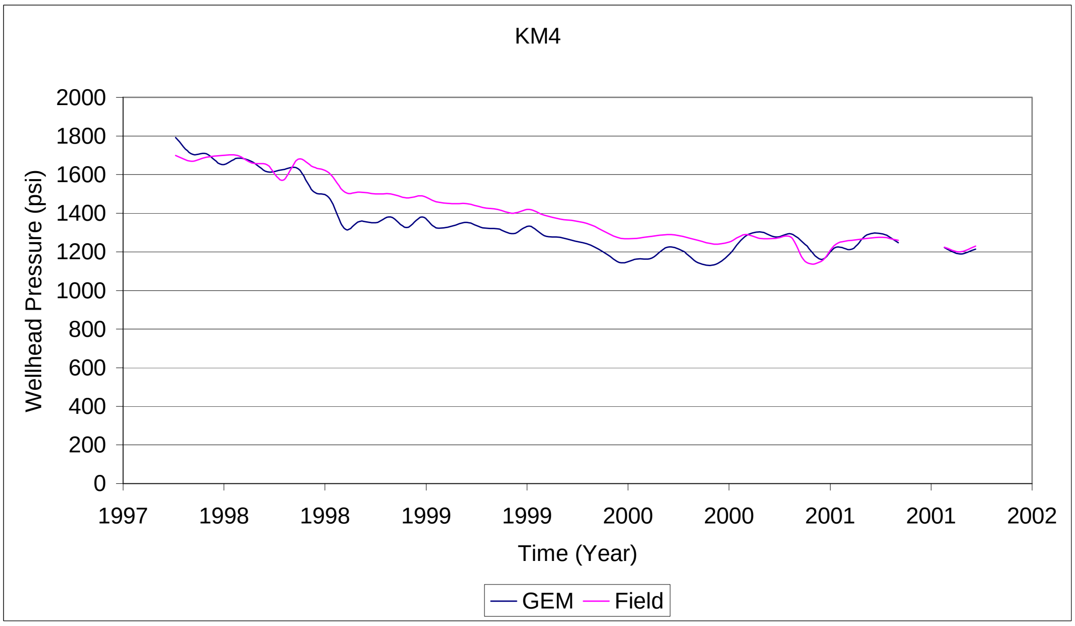


Figure 25 Wellhead pressure comparison of KM4 between field data and simulator results

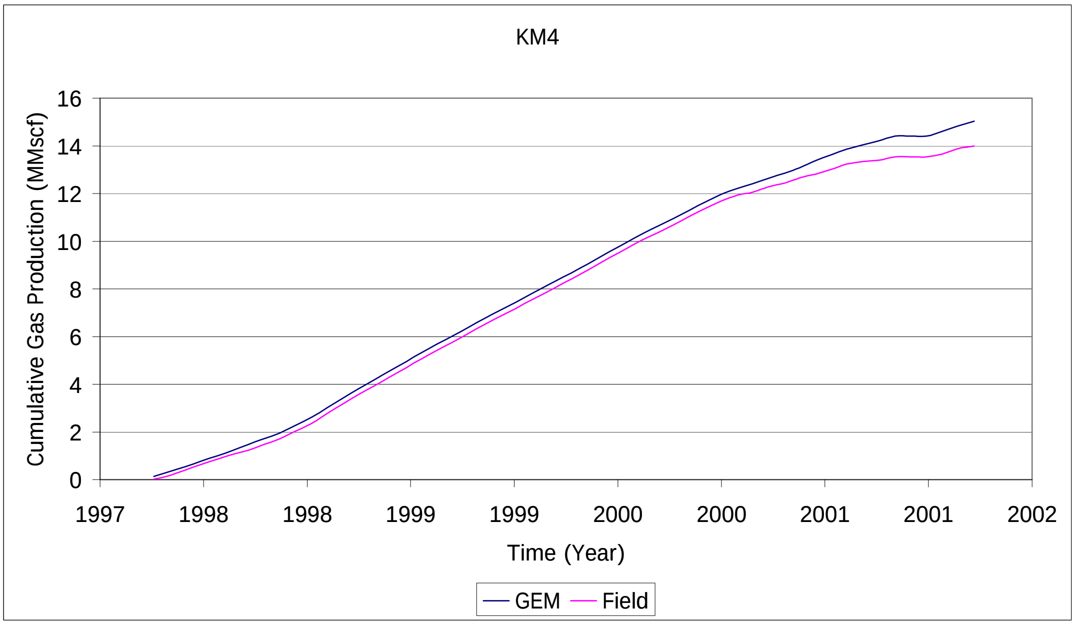


Figure 26 Cumulative gas production comparison of KM4 between field data and simulator results

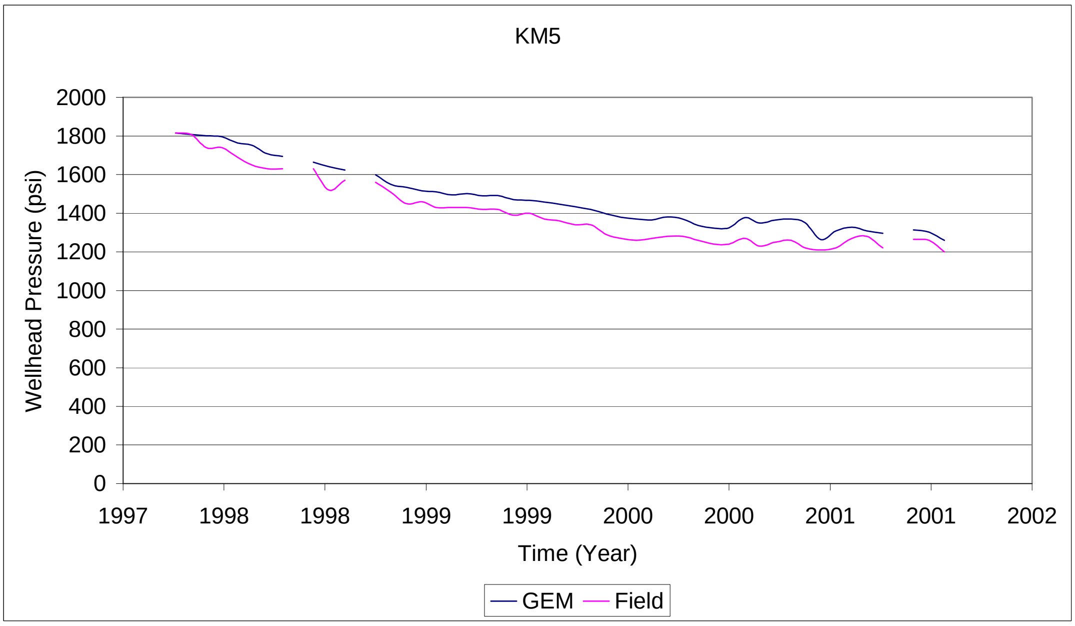


Figure 27 Wellhead pressure comparison of KM5 between field data and simulator results

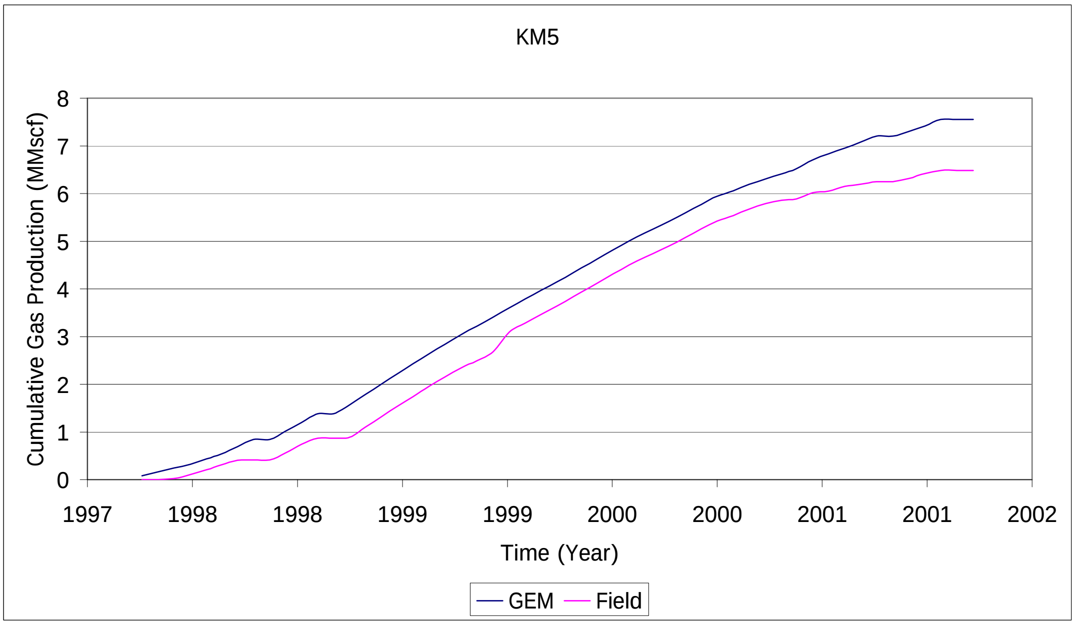


Figure 28 Cumulative gas production comparison of KM5 between field data and simulator results

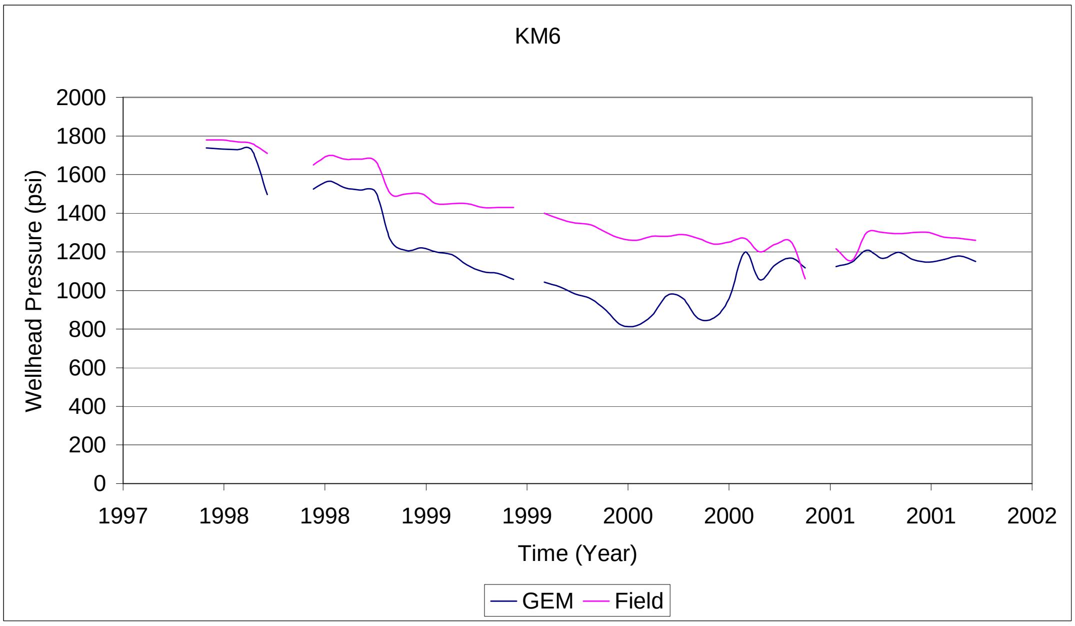


Figure 29 Wellhead pressure comparison of KM6 between field data and simulator results

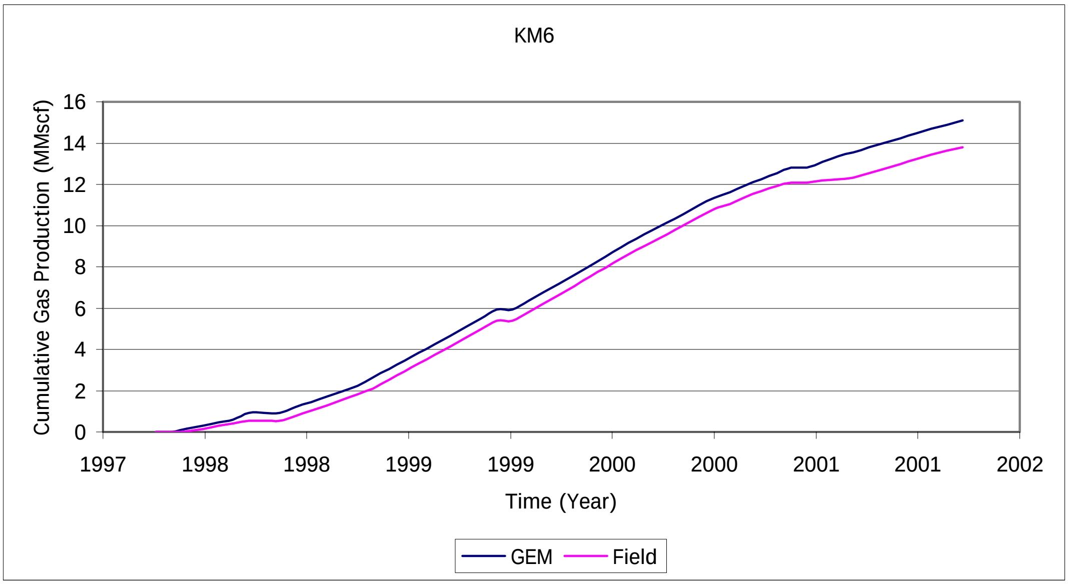


Figure 30 Cumulative gas production comparison of KM6 between field data and simulator results

Scenarios

Power plants are good sources of CO_2 emissions. In fact, daily CO_2 gross emission rate of a 250 MW NGCC power plant is about 40.1 MMscf (4.68 million lb) per day which is barely enough to be sequestered in any of the scenarios. [12]

Pressure distribution within the reservoir was pretty even. Maximum and minimum observed pressure differences were about 200 psi at the end of injection periods.

Scenario 1

This simple injection scenario indicated that in the worst cases Kuzey Marmara reservoir has the ability to store 258 billion ft^3 (30 billion lb) of CO_2 at standard conditions (Figure 36).

Table 20 and Table 21 show the numerical results of the scenario. Figure 35 shows average reservoir pressure change during the simulation. CO_2 propagation and natural gas movement is displayed through Figure 31 to Figure 34.

Although the reservoir had no producing wells, injected CO_2 was not totally mixed with natural gas. A mixing zone formed between natural gas and CO_2 and CO_2 propagated to the lower levels. Natural gas was withdrawn to the upper grid layers and compressed due to increasing amount of CO_2.

CO_2 front velocity was faster in low porosity regions with respect to high porosity regions. However, CO_2 was still prone to moving towards lower grid layers due to gravitational differences.

KMNew and KM3 wells had the most spread CO_2 area throughout the simulation. This was due to the region of the well which has relatively lower permeability and porosity values. Lower permeability slowed downward movement and lower porosity increased the front velocity through the grid layers. Even well regions in the uppermost grid layer had wider area coverage.

KM1 and KM4 wells were placed in high permeability and high porosity regions so CO_2 propagation was towards the deepest grid layer while the front velocity was almost none in the uppermost grid layer.

Table 20 Scenario 1 production results

KMNew	KM3	KM1	KM4	Time	Average Reservoir Pressure (psi)	Cumulative Produced Natural Gas (MMscf)	Remaining Natural Gas in Place (MMscf)	Natural Gas Recovery (%)
Injection	Injection	Injection	Injection	2010-01	1 048	0	84 974	55.44
				2027-09	2 300	0	84 974	55.44

Table 21 Scenario 1 injection results

KMNew	KM3	KM1	KM4	Time	Average Reservoir Pressure (psi)	Cumulative Injected CO_2 (MMscf)	Average CO_2 content of HC pore volume (%)
Injection	Injection	Injection	Injection	2010-01	1 048	0	0.76
				2027-09	2 300	258 078	73.30

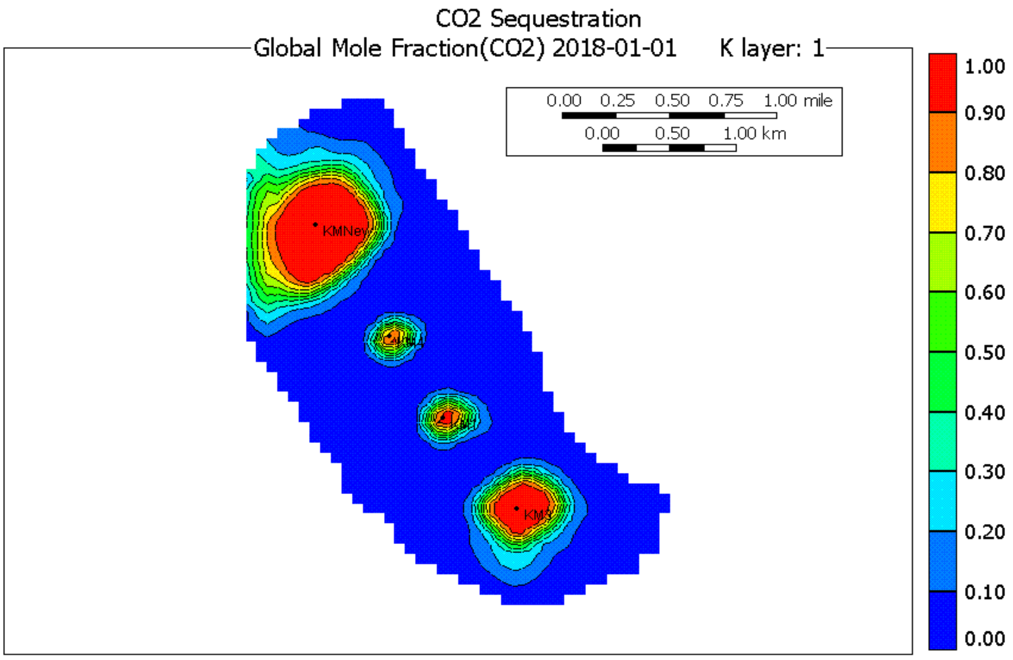


Figure 31 Scenario 1, CO_2 molar fraction distribution of grid layer 1 in 2018-10-01

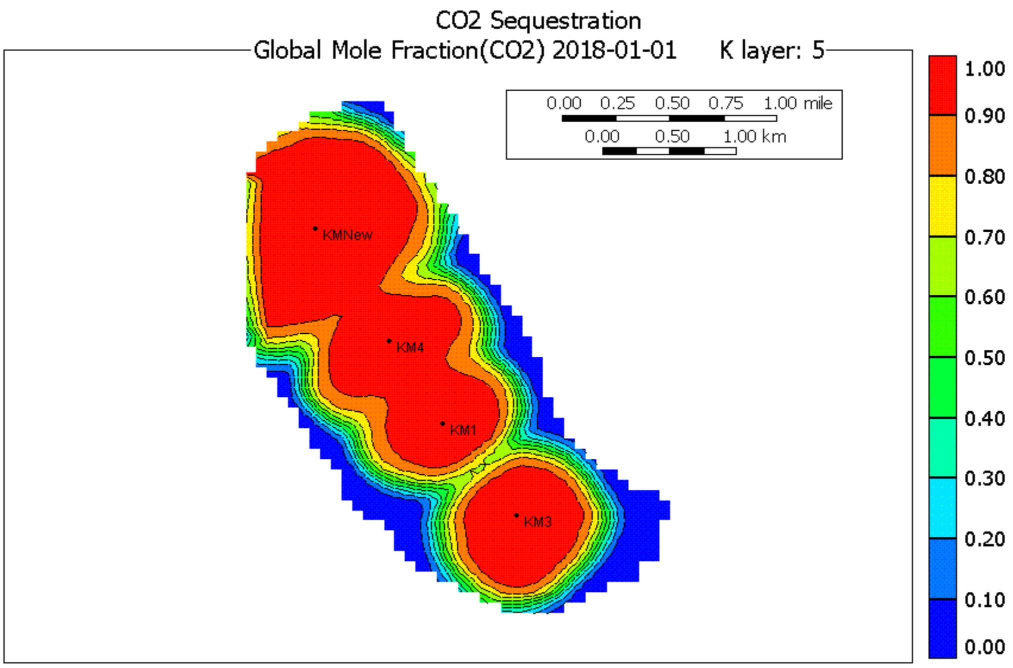


Figure 32 Scenario 1, CO_2 molar fraction distribution of grid layer 5 in 2018-10-01

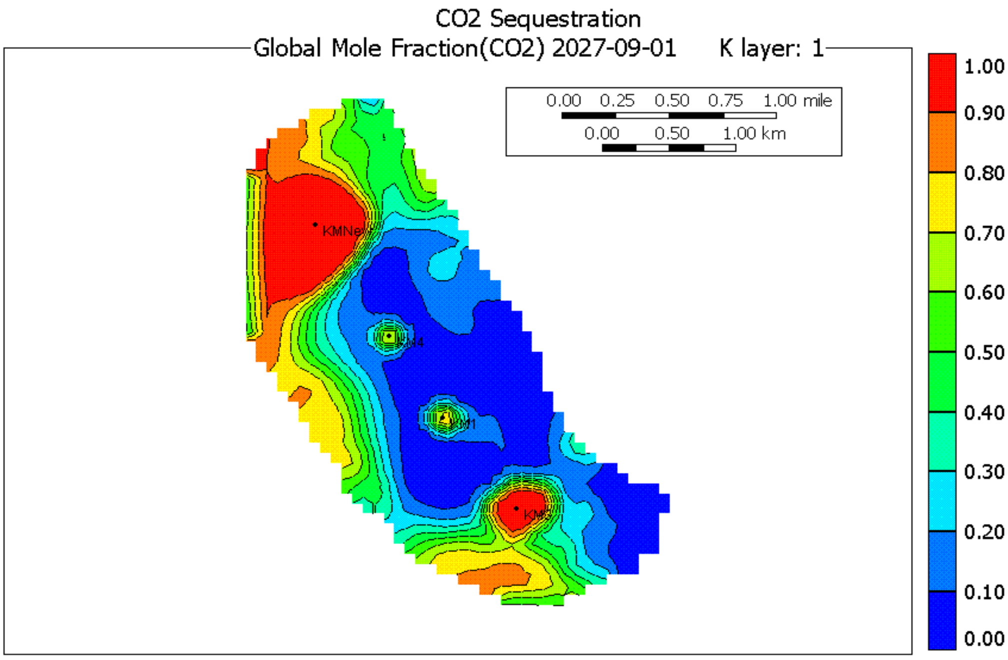


Figure 33 Scenario 1, CO_2 molar fraction distribution of grid layer 1 in the end

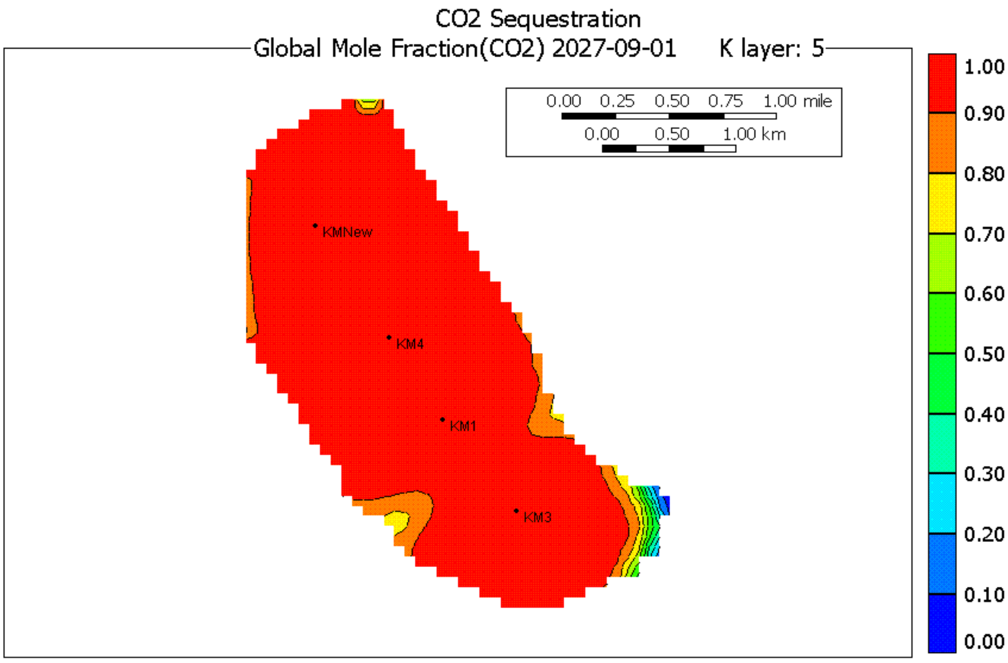


Figure 34 Scenario 1, CO_2 molar fraction distribution of grid layer 5 in the end

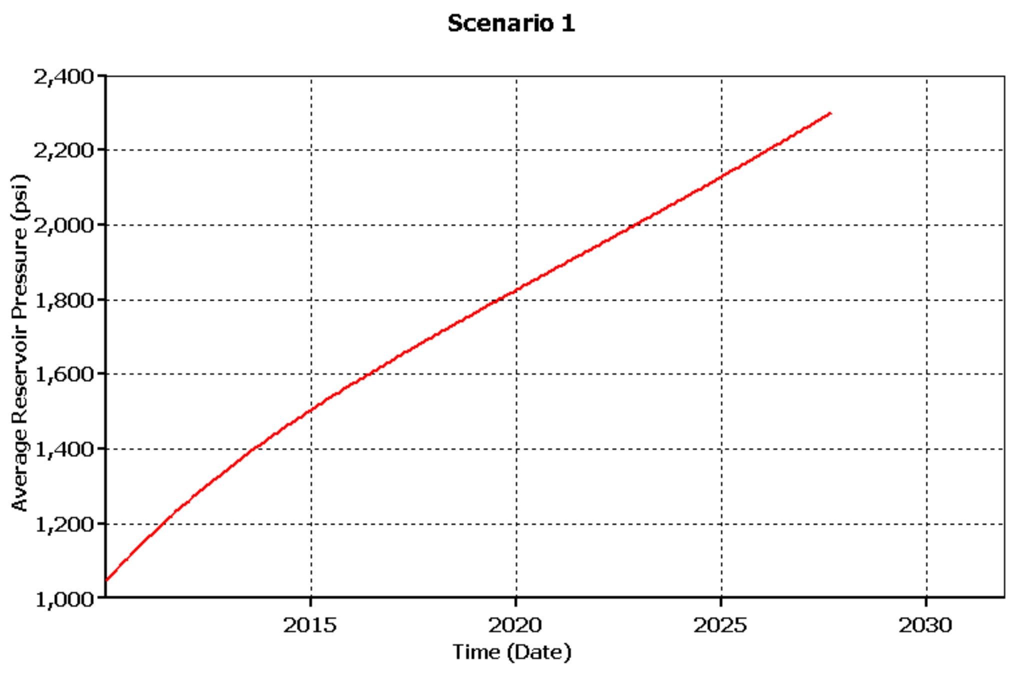


Figure 35 Scenario 1, average reservoir pressure

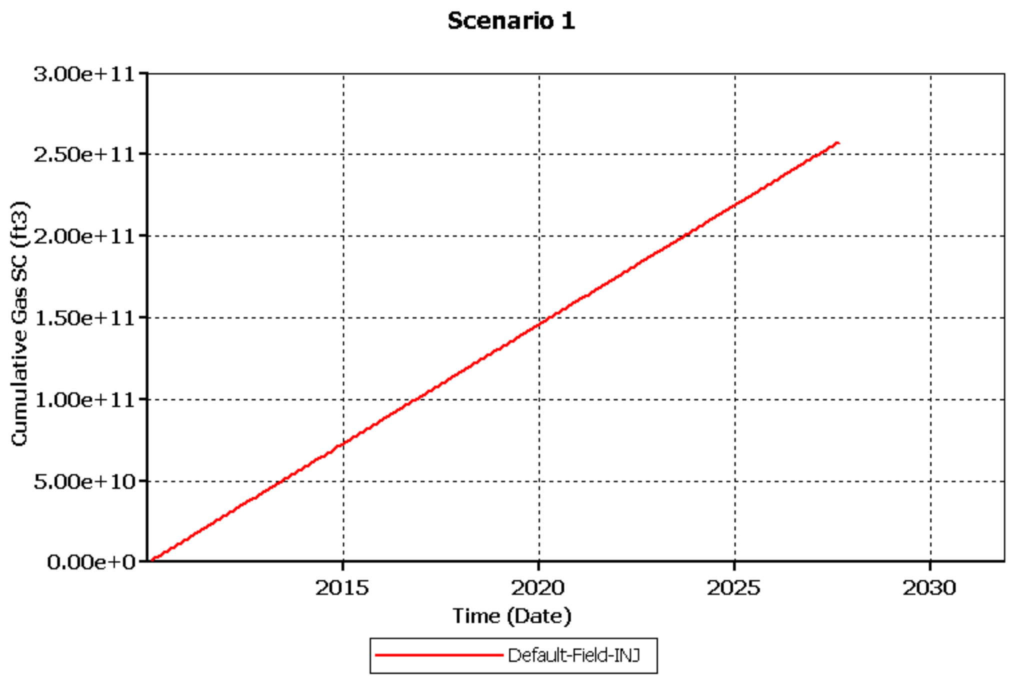


Figure 36 Scenario 1, cumulative CO_2 injection

Scenario 2

Scenario 2 revealed better results in terms of both cumulative natural gas production and cumulative CO_2 injection. Injected CO_2 propagated towards closest boundaries of the reservoir and pushed natural gas towards the producer wells.

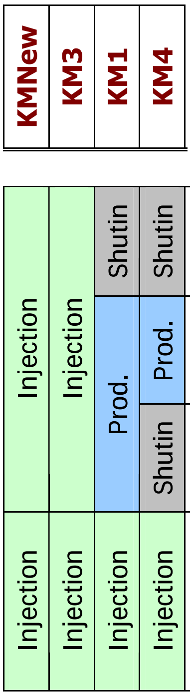
First CO_2 constraint was reached at KM4 well which has a closer distance to the KMNew injector. Until shutin time KM4 well was able to produce 10655 MMscf of natural gas. About three years later KM1 well has been shutin due to the same simulation constraint. KM1 well produced 5320 MMscf more natural gas summing 15975 MMscf. Total production of the field was 26630 MMscf which corresponds to 69.41% recovery rate (Figure 50).

Table 22 and Table 23 show the numerical results of the scenario. Figure 45 to Figure 49 show constraints that were used in the simulation. The figures include bottomhole pressures (Figure 46) of producers and wellhead pressures (Figure 45) of injectors. Molar fractions of produced gas content are displayed in Figure 47 and Figure 48. Average reservoir pressure change can be seen in Figure 49. Figure 50 shows cumulative injection and production rates. CO_2 propagation and natural gas movement is displayed in Figure 51 Figure 58. CO_2 propagation and natural gas movement can be seen through Figure 37 to Figure 44.

The distance between KMNew Injector and KM1 producer (3400 ft) was farther than the distance between KM4 and KM3 wells (3000 ft). In spite of the distance difference, CO_2 breakthrough was observed in KM4 well before KM1 (Figure 37 to Figure 44). This was mainly due to the porosity differences between KM4 (5%) and KM1 (15%) well regions. Low porosity regions filled faster and CO_2 front covered more distance at the same time period.

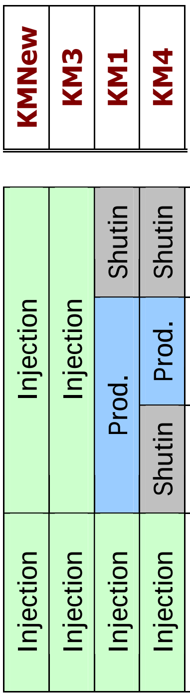
It should be noted that, GEM simulator stops monitoring wellhead pressures when a well state is defined as “shutin”. During the shutin times all wellhead pressures are shown as zero which is only a style or representation.

Table 22 Scenario 2 production results



Time	Average Reservoir Pressure (psi)	Cumulative Produced Natural Gas (MMscf)	Remaining Natural Gas in Place (MMscf)	Natural Gas Recovery (%)
2010-01	1 048	0	84 974	55.44
2011-01	1 089	0	84 974	55.44
2016-11	1 104	21 310	63 664	66.62
2019-10	1 157	26 630	58 344	69.41
2037-12	2 302	26 630	58 344	69.41

Table 23 Scenario 2 injection results



Time	Average Reservoir Pressure (psi)	Cumulative Injected CO_2 (MMscf)	Average CO_2 content of HC pore volume (%)
2010-01	1 048	0	0.76
2011-01	1 089	5 110	6.35
2016-11	1 104	34 944	33.07
2019-10	1 157	49 840	43.21
2037-12	2 302	315 279	84.07

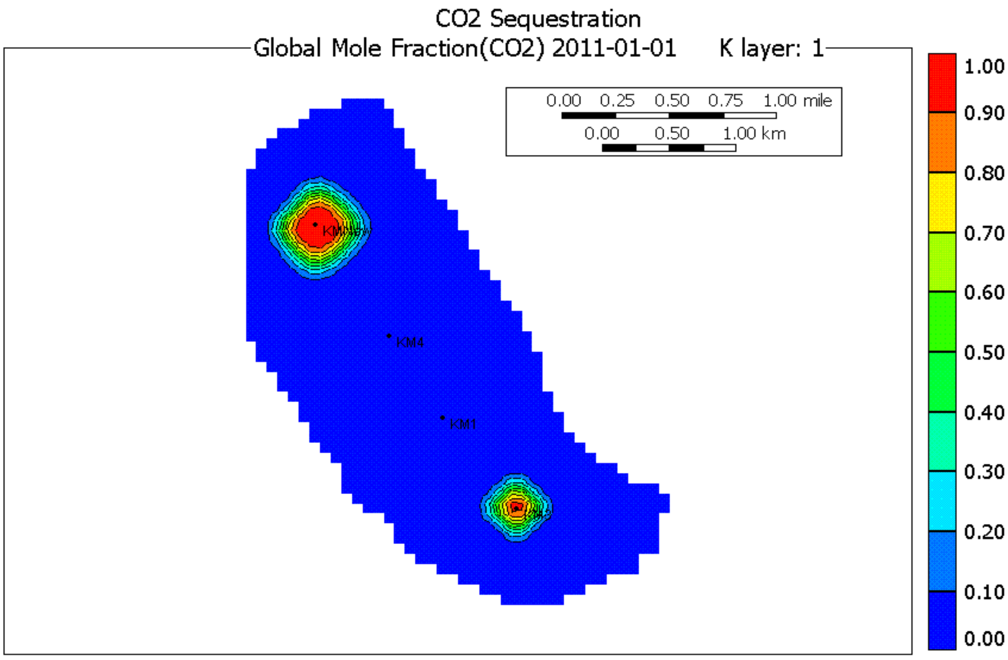


Figure 37 Scenario 2, CO_2 molar fraction distribution of grid layer 1 at production start date

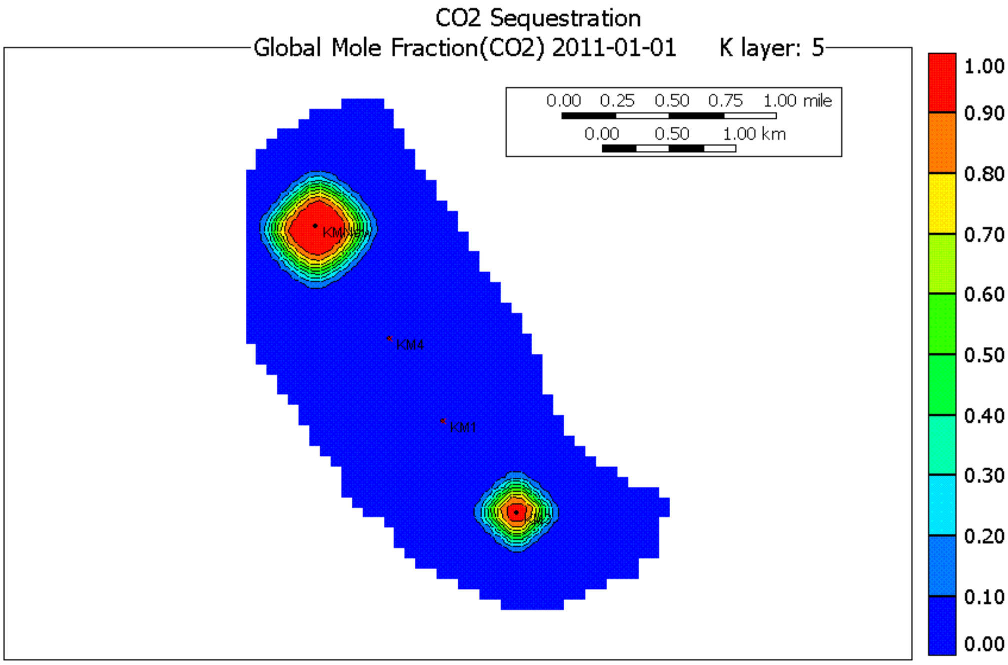


Figure 38 Scenario 2, CO_2 molar fraction distribution of grid layer 5 at production start date

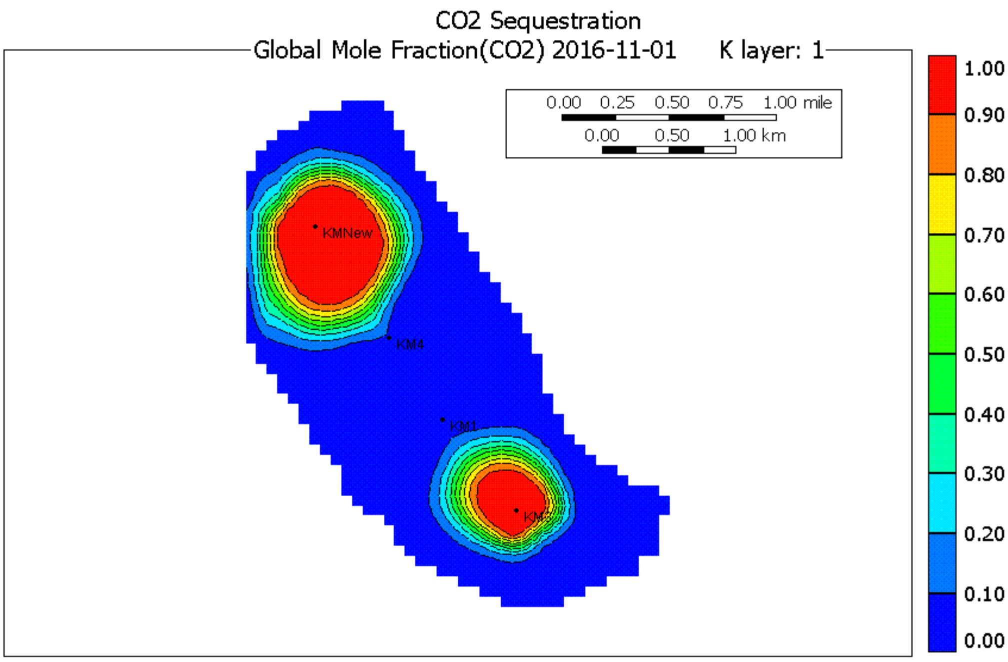


Figure 39 Scenario 2, CO_2 molar fraction distribution of grid layer 1 at KM4 shutin date

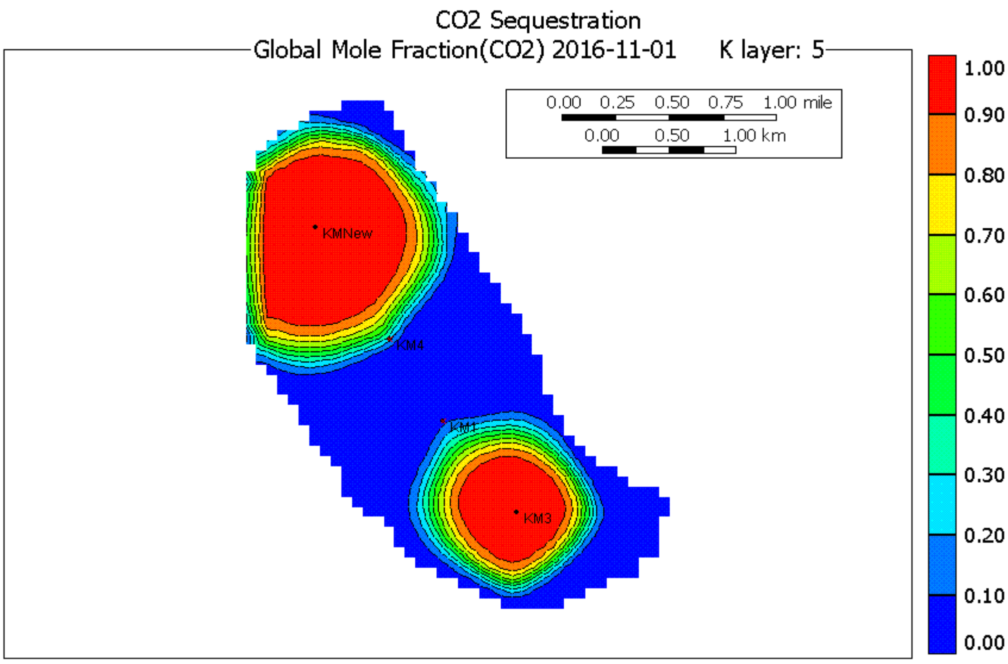


Figure 40 Scenario 2, CO_2 molar fraction distribution of grid layer 5 at KM4 shutin date

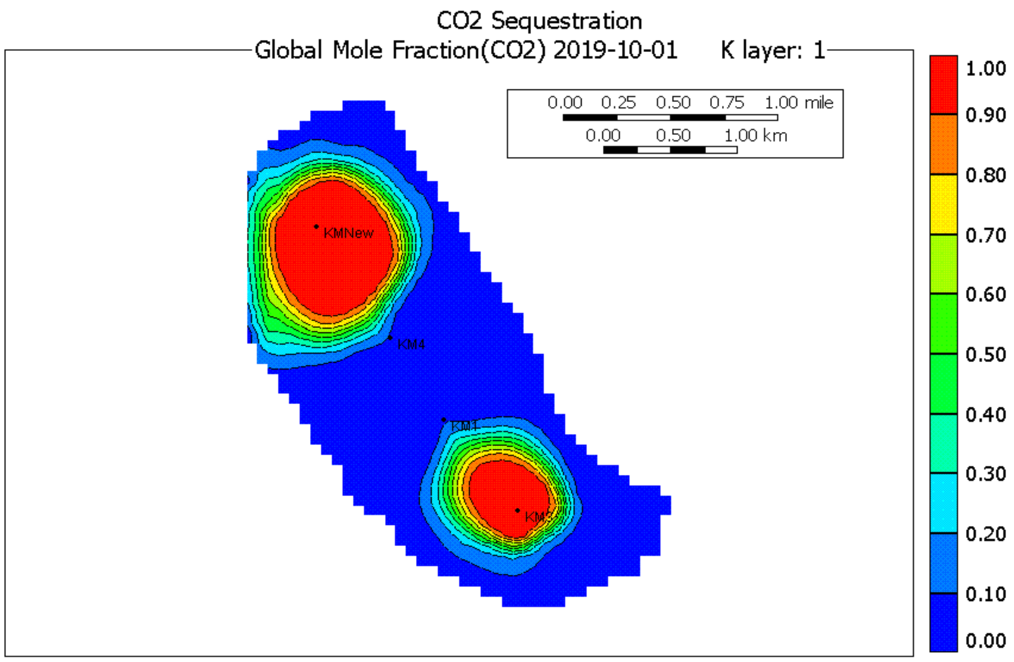


Figure 41 Scenario 2, CO_2 molar fraction distribution of grid layer 1 at KM1 shutin date

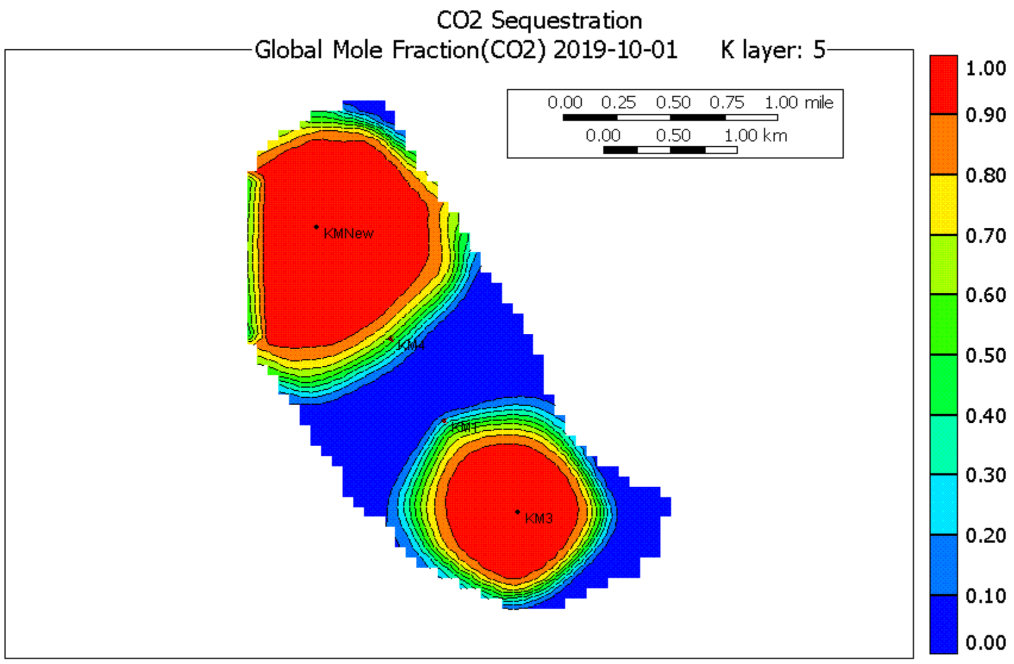


Figure 42 Scenario 2, CO_2 molar fraction distribution of grid layer 5 at KM1 shutin date

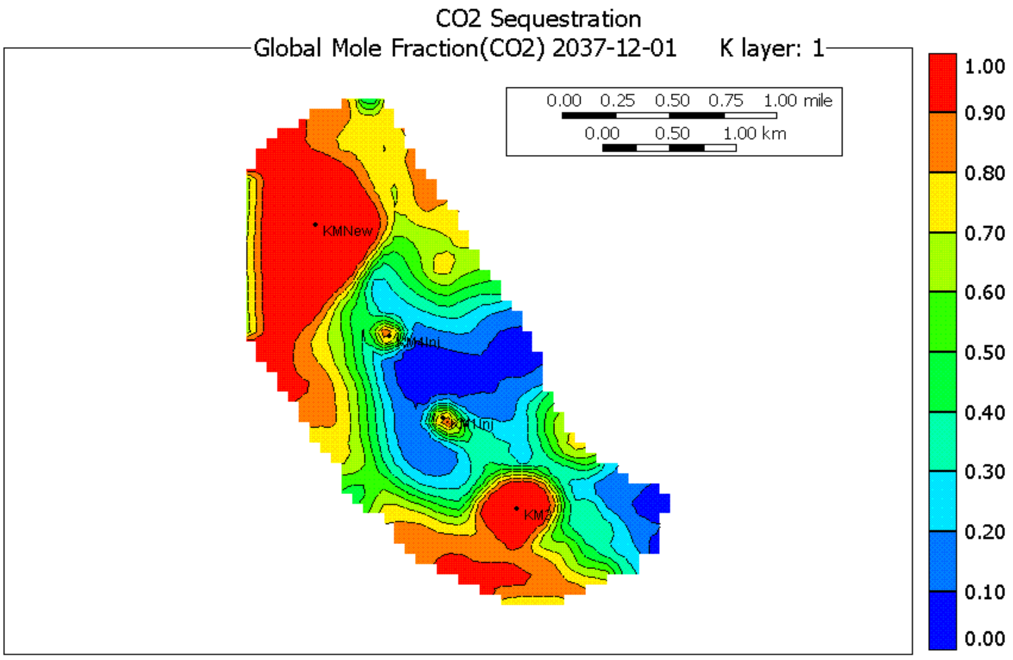


Figure 43 Scenario 2, CO_2 molar fraction distribution of grid layer 1 in the end

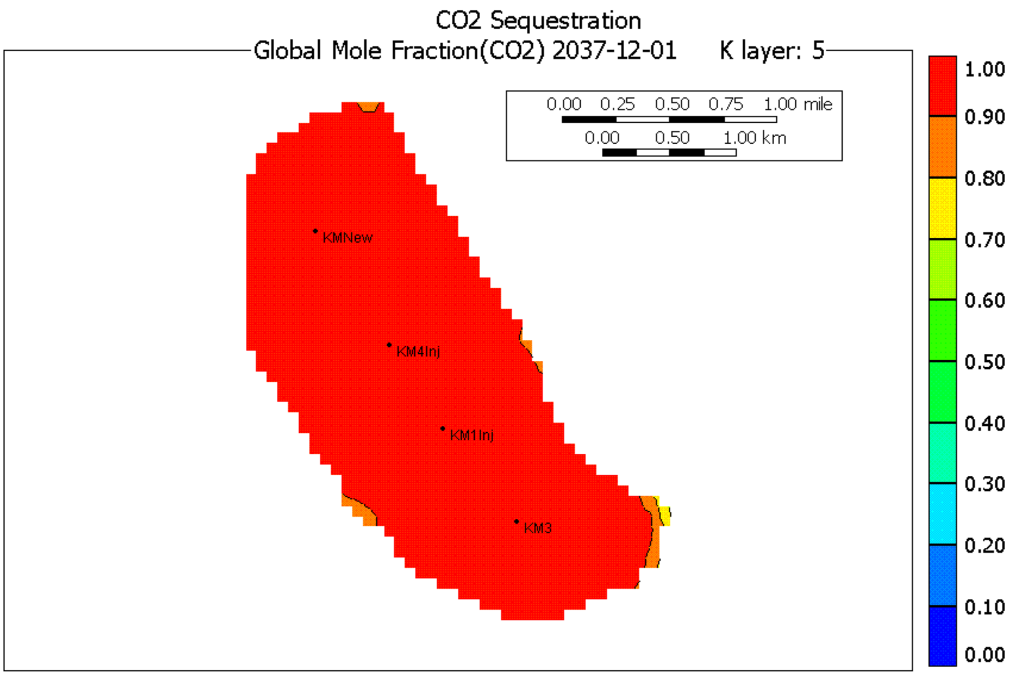


Figure 44 Scenario 2, CO_2 molar fraction distribution of grid layer 5 in the end

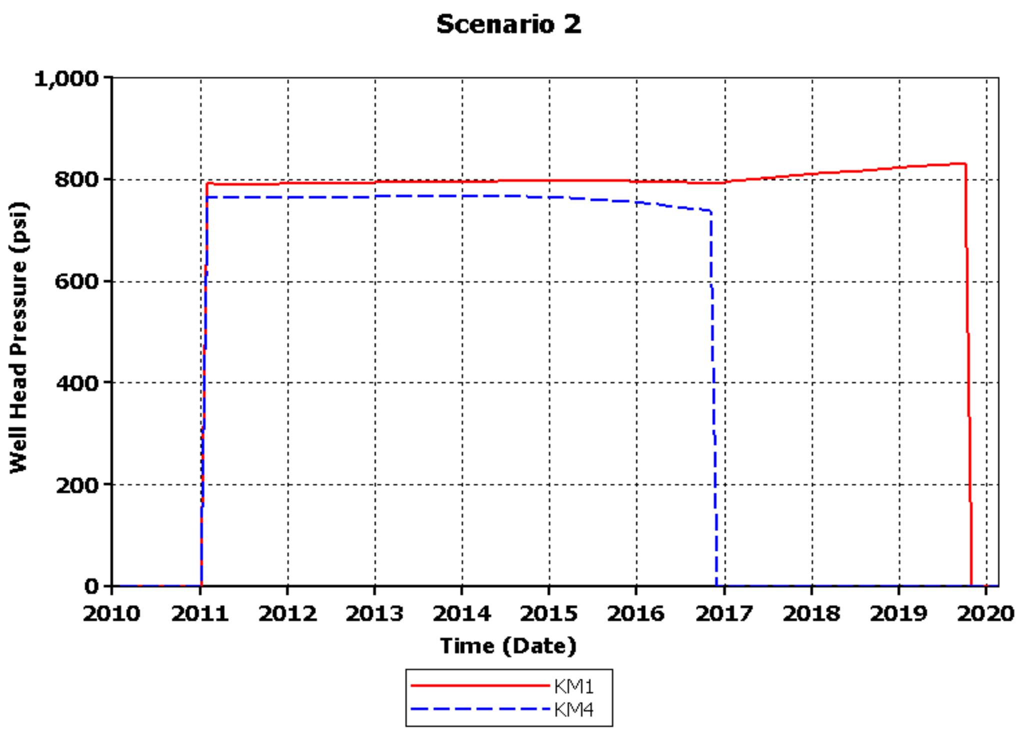


Figure 45 Scenario 2, wellhead pressures of producers (KM1 and KM4)

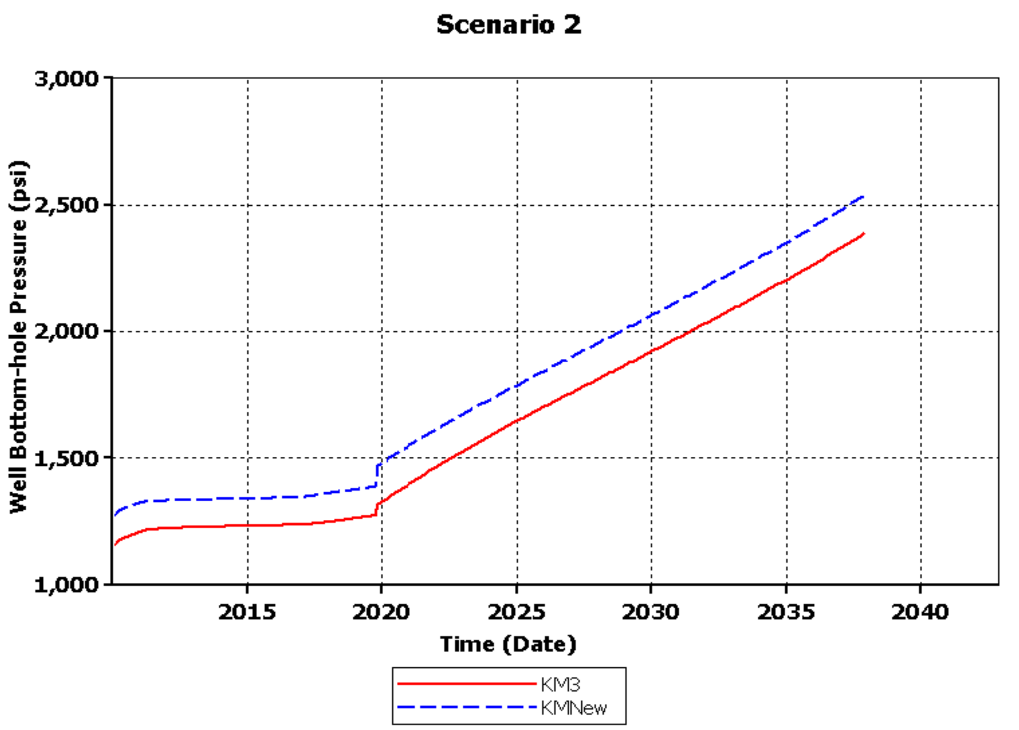


Figure 46 Scenario 2, bottomhole pressures of injectors (KM3 and KMNew)

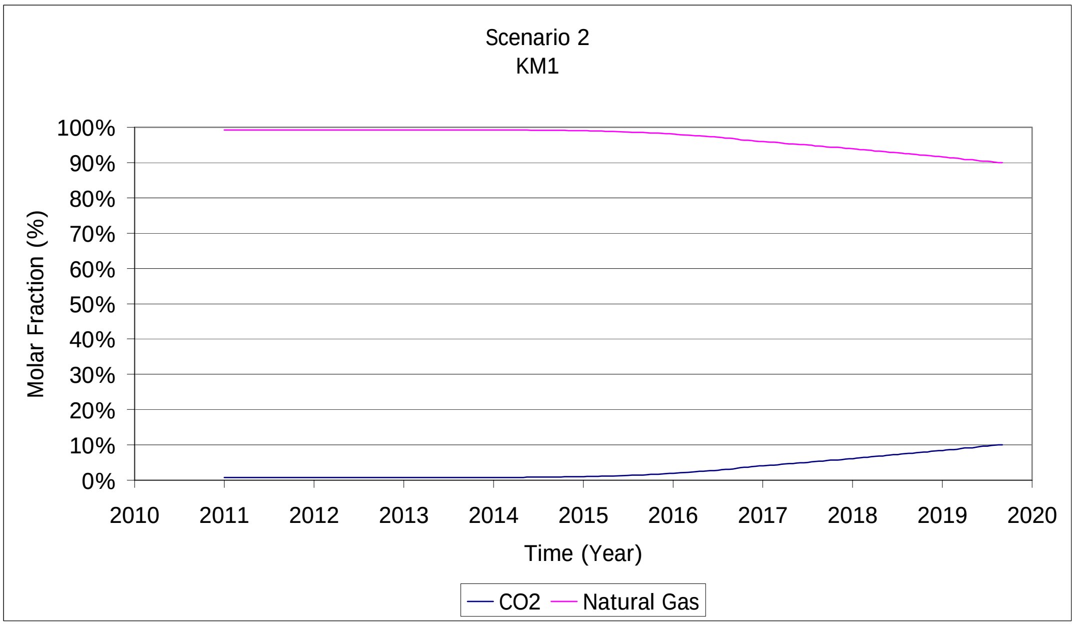


Figure 47 Scenario 2, KM1 molar production rates

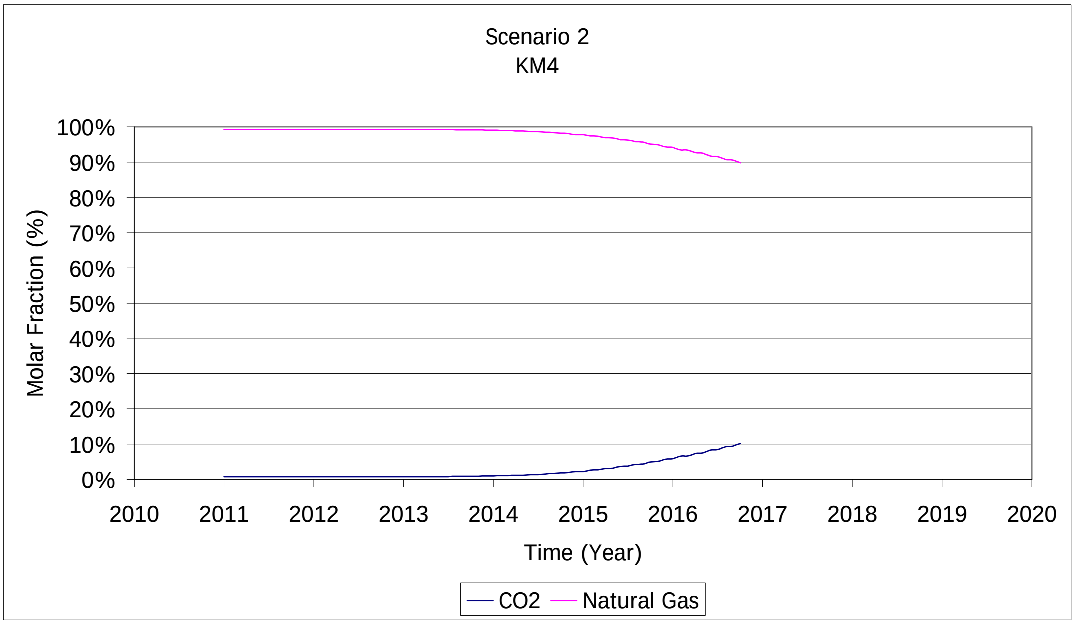


Figure 48 Scenario 2, KM4 molar production rates

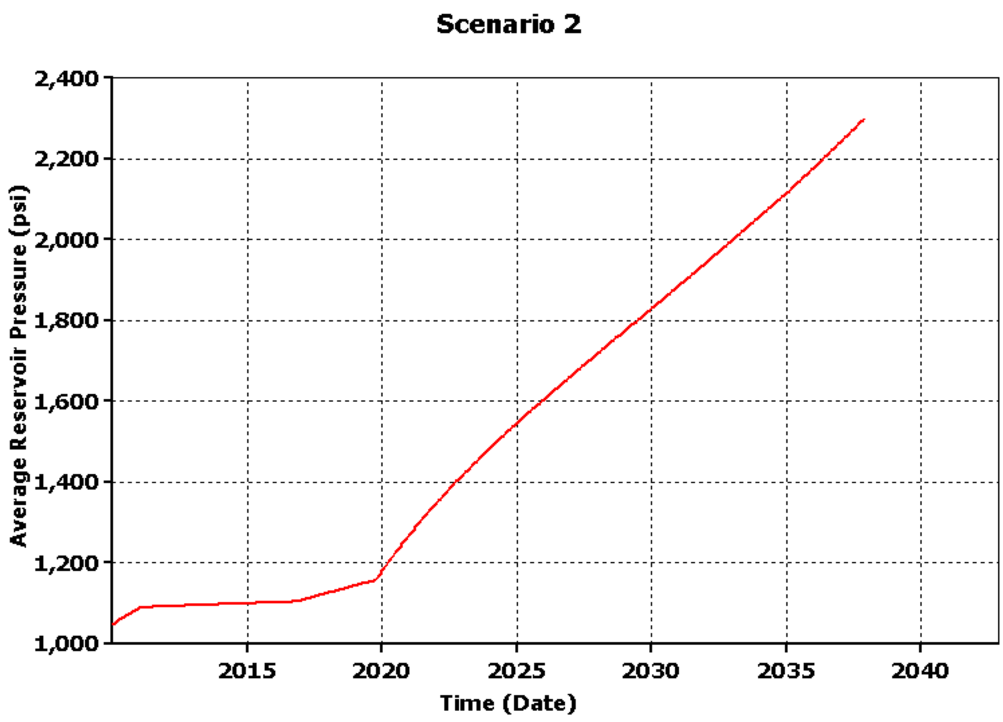


Figure 49 Scenario 2, average reservoir pressure

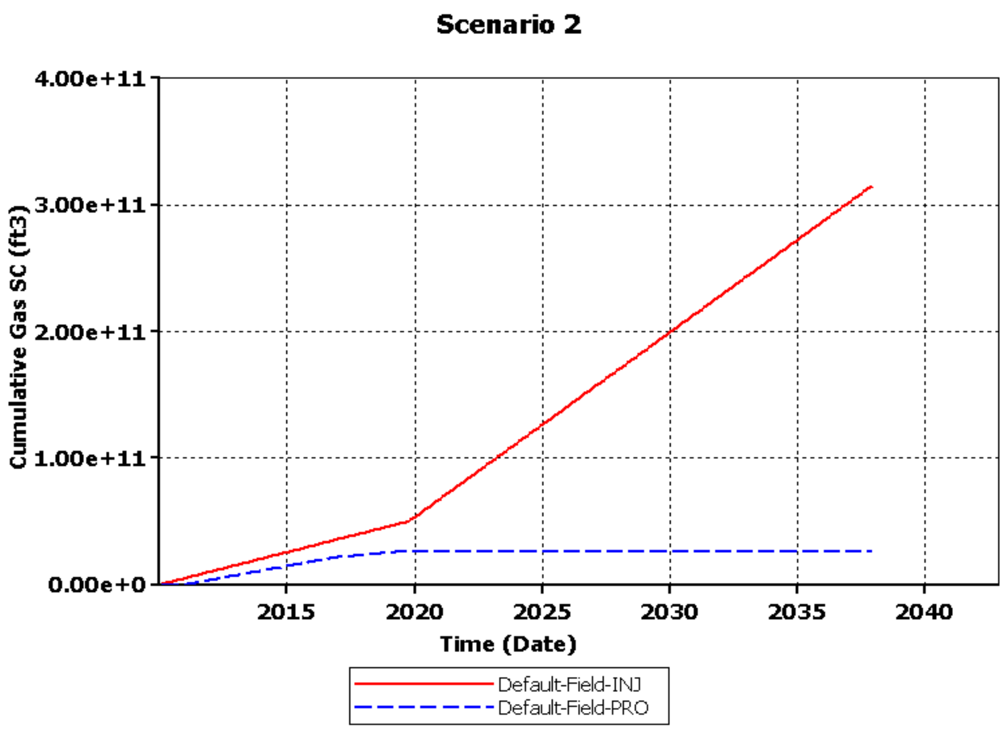


Figure 50 Scenario 2, cumulative field injection and production

Scenario 3

Producers required longer time before starting production because their wellhead pressures could not be maintained if they had been opened earlier. During 5 years of injection time CO_2 propagated far towards the low permeability regions and this shortened the CO_2 breakthrough times in both of the producers (Figure 51 and Figure 52). KMNew remained in production about 3.5 years (Figure 53 and Figure 54) and KM3 production time was about 4.5 years (Figure 55 and Figure 56).

Throughout the production period these wells produced 5472 MMscf and 7912 MMscf natural gas respectively. Total production from the field was 13384 MMscf with a recovery rate of 62.46%.

Less natural gas production lowered CO_2 storage capacity of the reservoir. Maximum amount of CO_2 to be stored in the field became 284839 MMscf for this case (Figure 64).

Table 24 and Table 25 show the numerical results of the scenario. Figure 59 to Figure 63 show constraints that were used in the simulation. CO_2 propagation and natural gas movement is displayed in Figure 51 Figure 58.

Placing producers in high permeability region had negative effects in this scenario. Since higher grid layers could not hold much CO_2, CO_2 penetrated into lower grid layers easily. This caused a faster front velocity within lower grid layers. Reaching the lower porosity regions made the front velocity even faster and CO_2 front reached the injector wells in a considerably shorter time.

CO_2 breakthrough occurs once any one of the CO_2 containing grid layers reaches a well grid (Figure 54 and Figure 56). In the case of Kuzey Marmara this grid layer is the deepest one. If permeability of the grid layers is high CO_2 within the grid layers is able to reach faster to the producing well locations and this causes a significant reduction in CO_2 breakthrough times.

Table 24 Scenario 3 production results

KM1	KM4	KM3	KMNew
Injection	Injection	Shutin	Shutin
Injection	Injection	Prod.	Prod.
Injection	Injection	Prod.	Shutin
Injection	Injection	Injection	Injection

Time	Average Reservoir Pressure (psi)	Cumulative Produced Natural Gas (MMscf)	Remaining Natural Gas in Place (MMscf)	Natural Gas Recovery (%)
2010-01	1 048	0	84 974	55.44
2015-02	1 308	0	84 974	55.44
2018-05	1 359	10 944	74 030	60.79
2019-09	1 392	13 384	71 590	62.46
2034-05	2 304	13 384	71 590	62.46

Table 25 Scenario 3 injection results

KM1	KM4	KM3	KMNew
Injection	Injection	Shutin	Shutin
Injection	Injection	Prod.	Prod.
Injection	Injection	Prod.	Shutin
Injection	Injection	Injection	Injection

Time	Average Reservoir Pressure (psi)	Cumulative Injected CO_2 (MMscf)	Average CO_2 content of HC pore volume (%)
2010-01	1 048	0	0.76
2015-02	1 308	36 520	14.04
2018-05	1 359	60 840	23.48
2019-09	1 392	70 600	26.84
2034-05	2 304	284 839	74.43

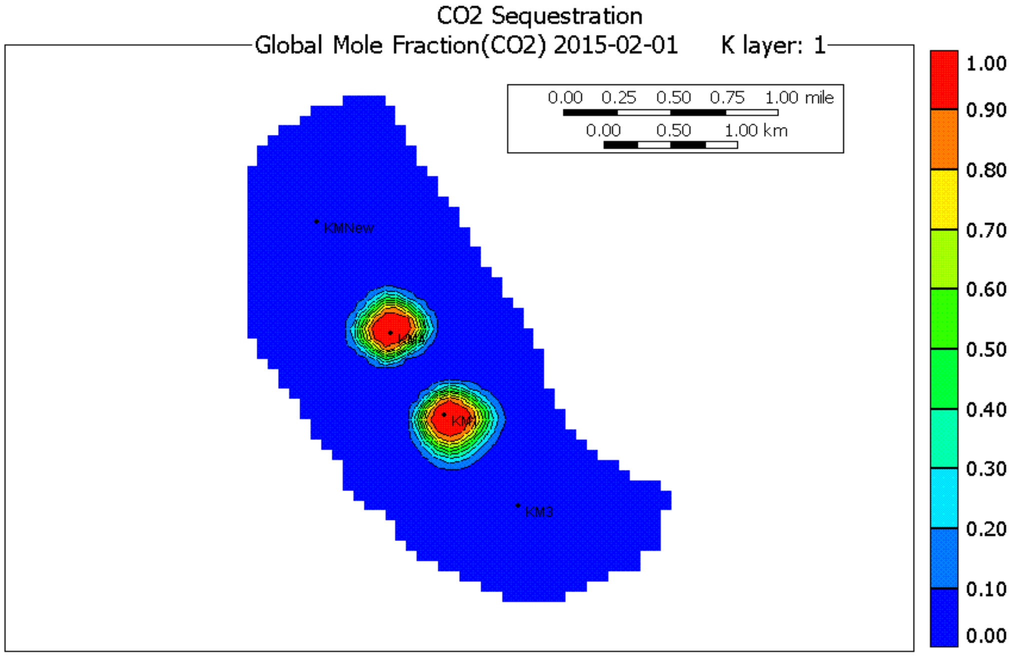


Figure 51 Scenario 3, CO_2 molar fraction distribution of grid layer 1 at production start date

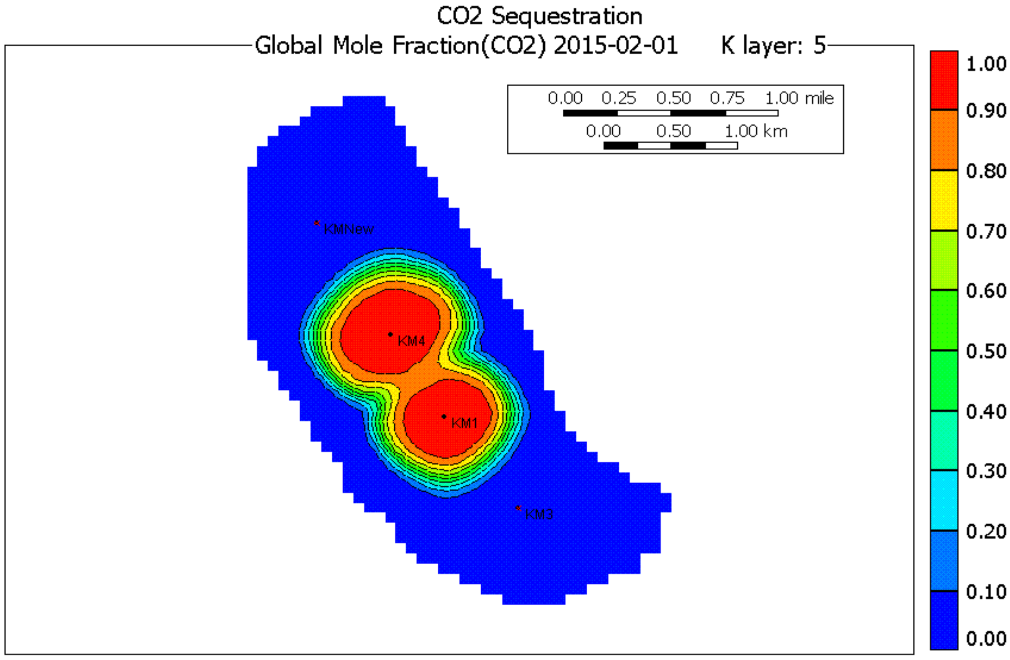


Figure 52 Scenario 3, CO_2 molar fraction distribution of grid layer 5 at production start date

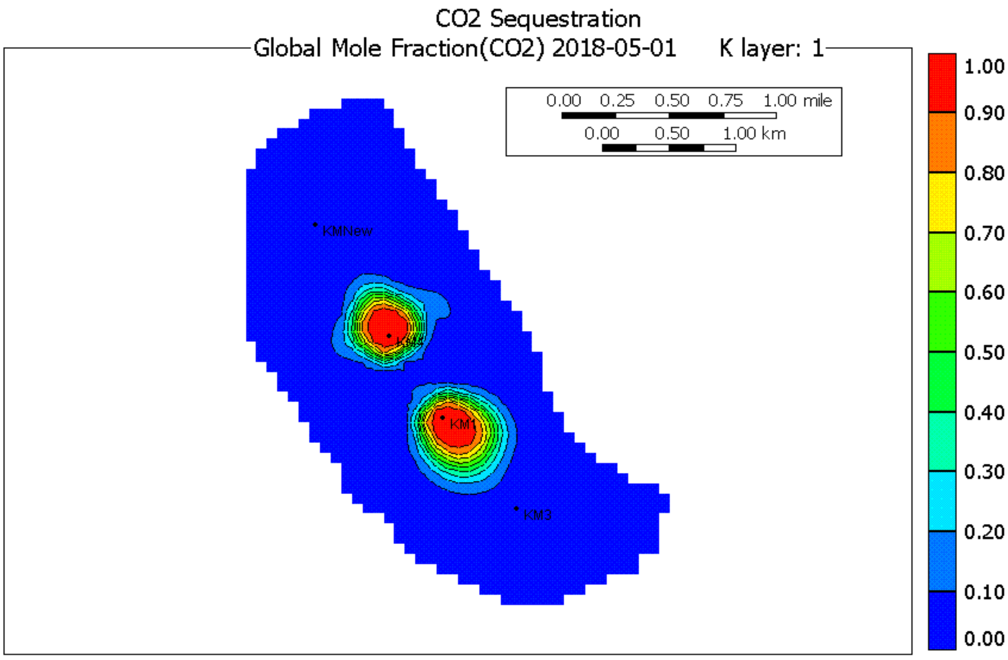


Figure 53 Scenario 3, CO_2 molar fraction distribution of grid layer 1 at KMNew shutin date

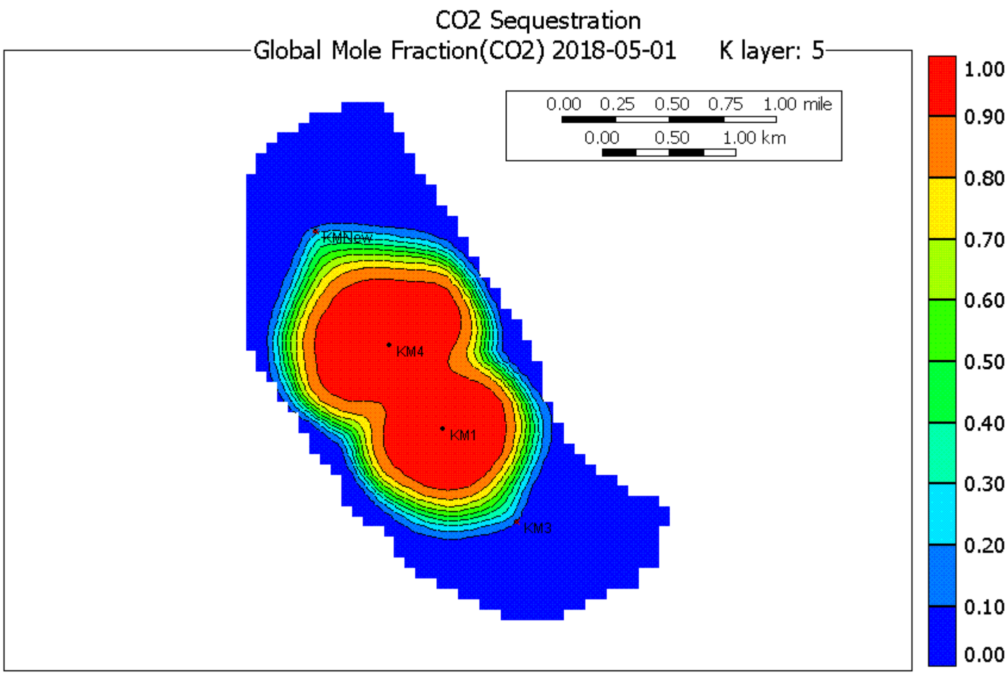


Figure 54 Scenario 3, CO_2 molar fraction distribution of grid layer 5 at KMNew shutin date

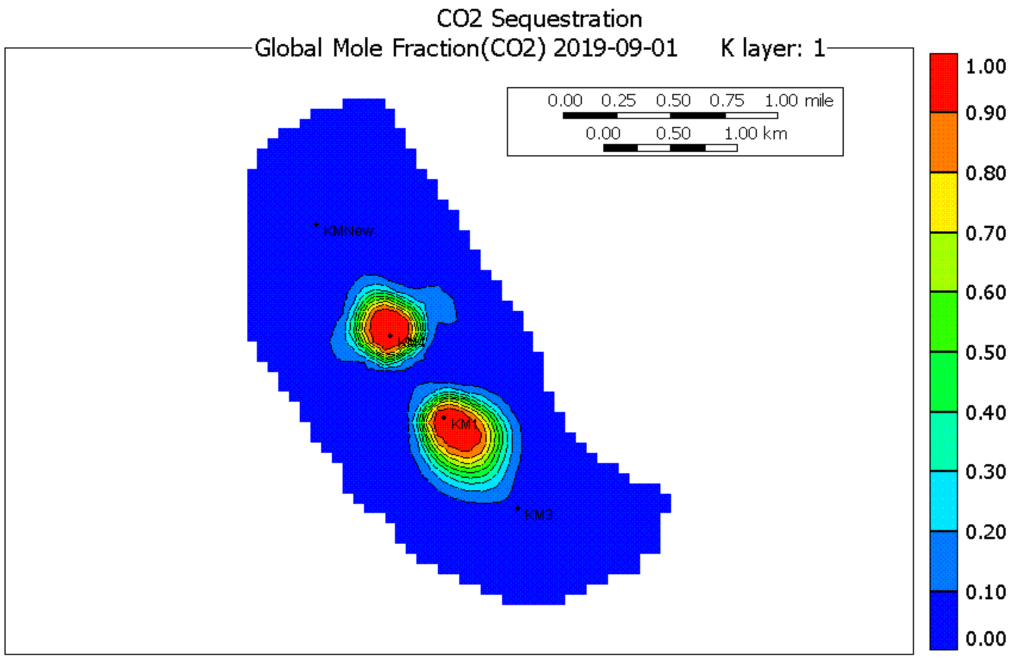


Figure 55 Scenario 3, CO_2 molar fraction distribution of grid layer 1 at KM3 shutin date

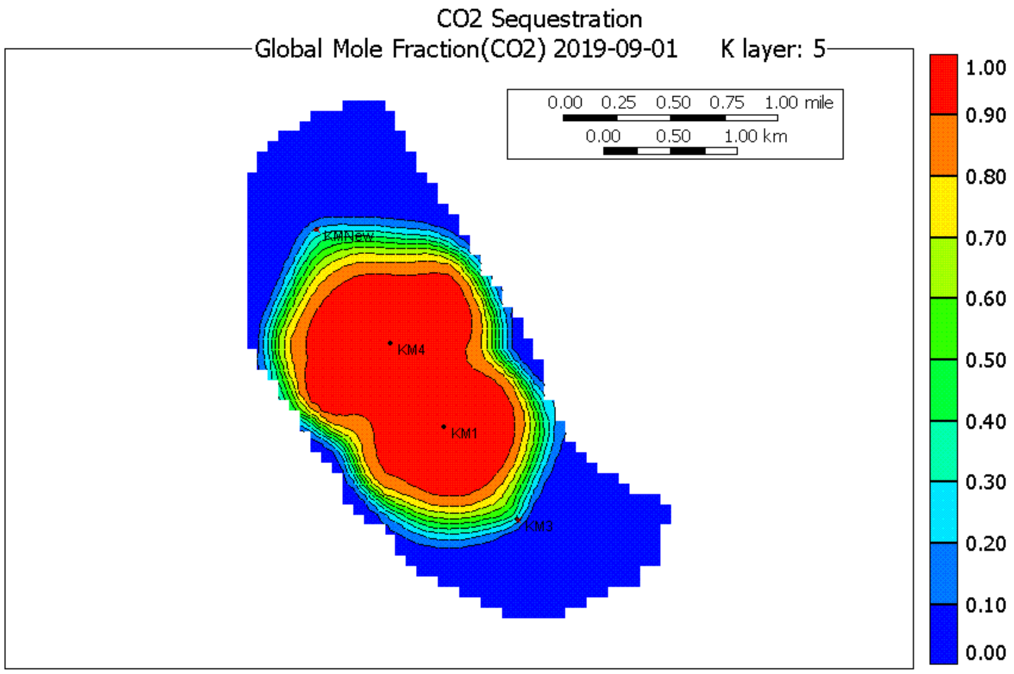


Figure 56 Scenario 3, CO_2 molar fraction distribution of grid layer 5 at KM3 shutin date

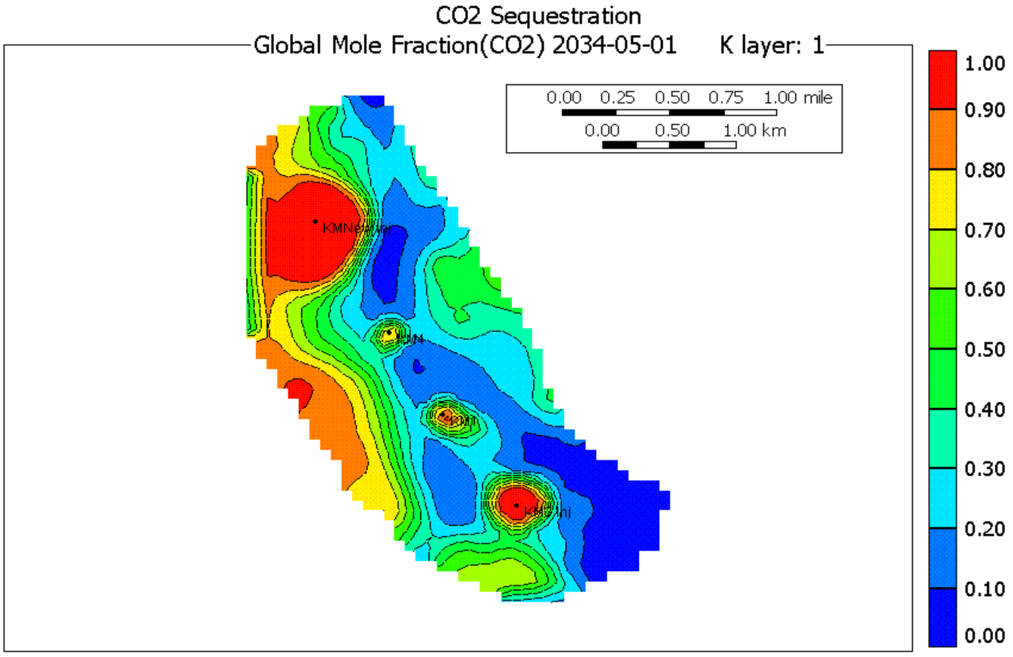


Figure 57 Scenario 3, CO_2 molar fraction distribution of grid layer 1 in the end

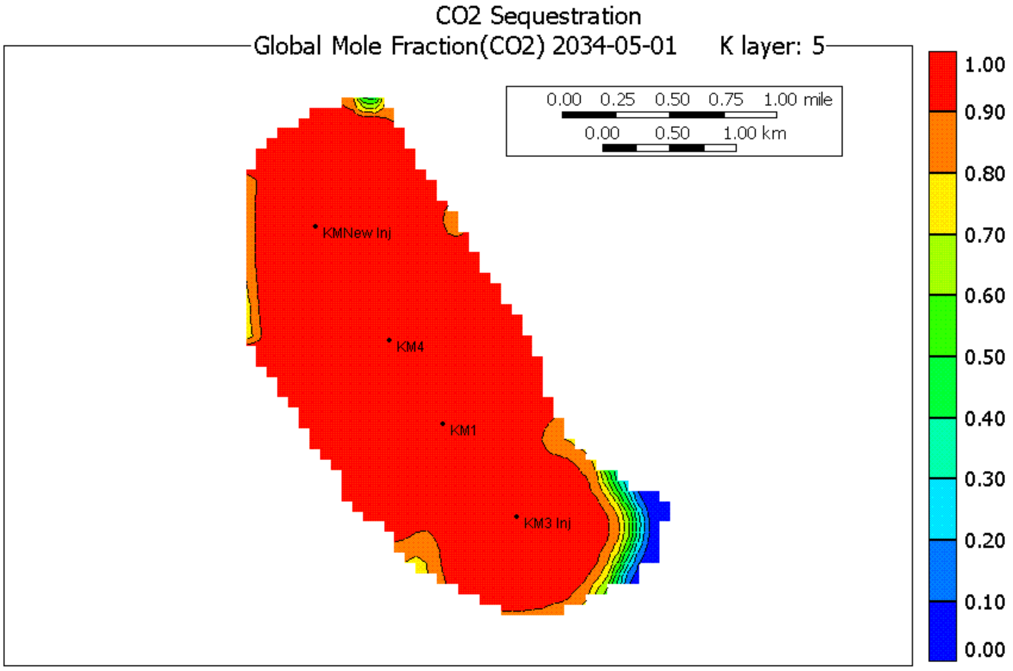


Figure 58 Scenario 3, CO_2 molar fraction distribution of grid layer 5 in the end

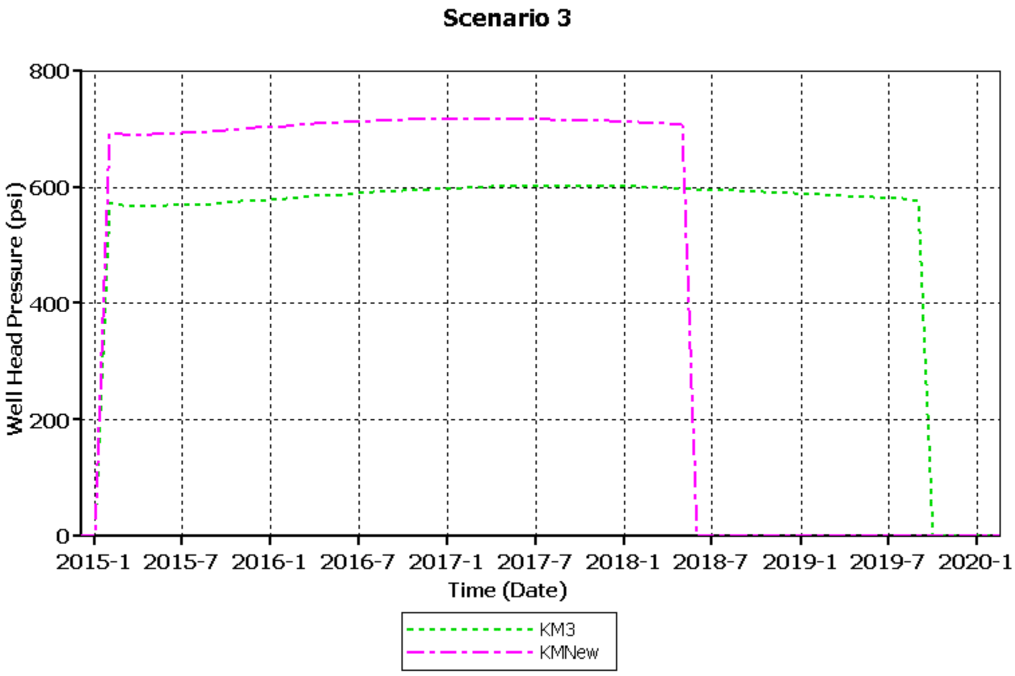


Figure 59 Scenario 3, wellhead pressures of producers (KM3 and KMNew)

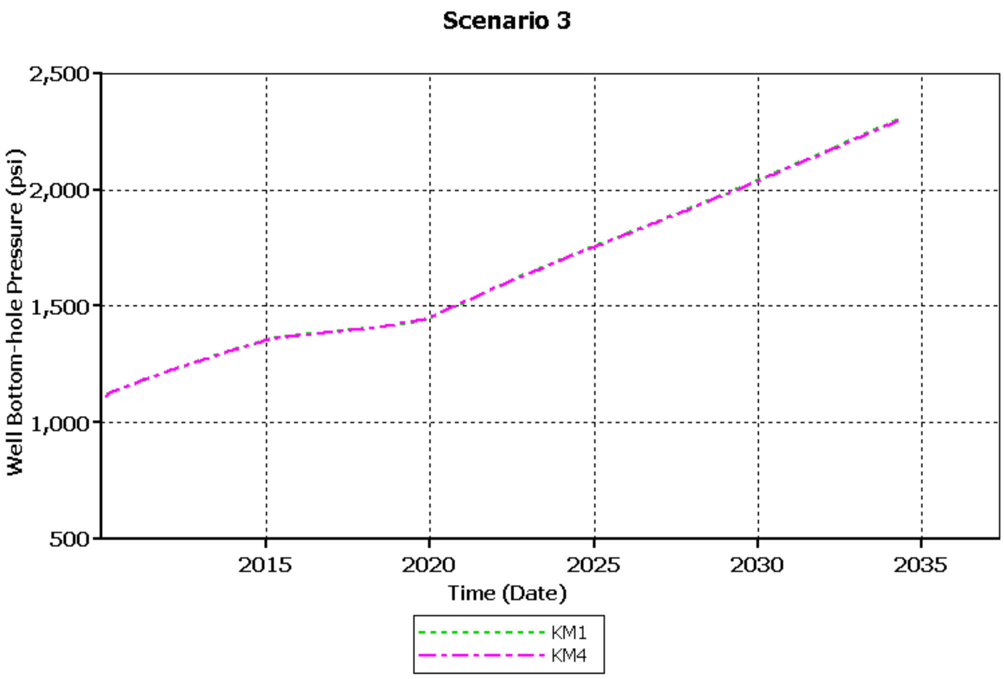


Figure 60 Scenario 3, bottomhole pressure of injectors (KM1 and KM4)

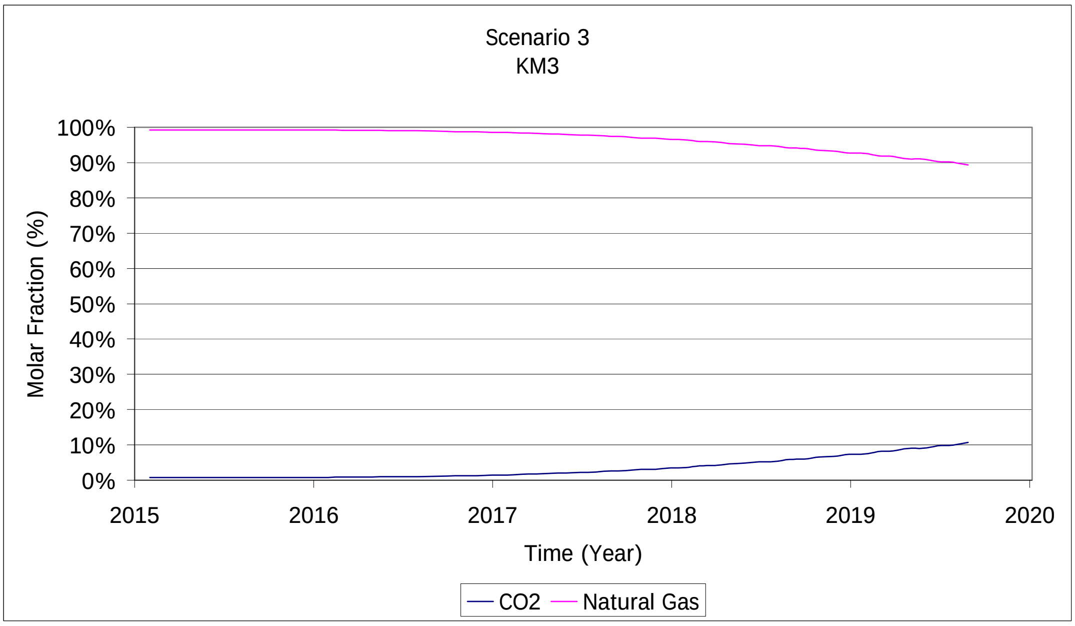


Figure 61 Scenario 3, KM3 molar production rates

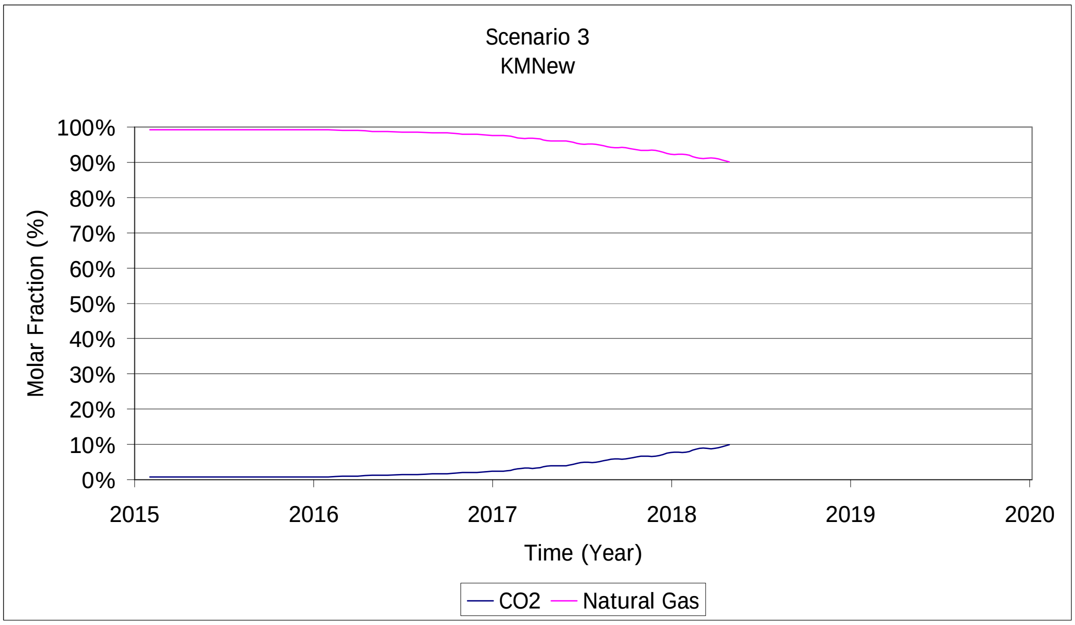


Figure 62 Scenario 3, KMNew molar production rates

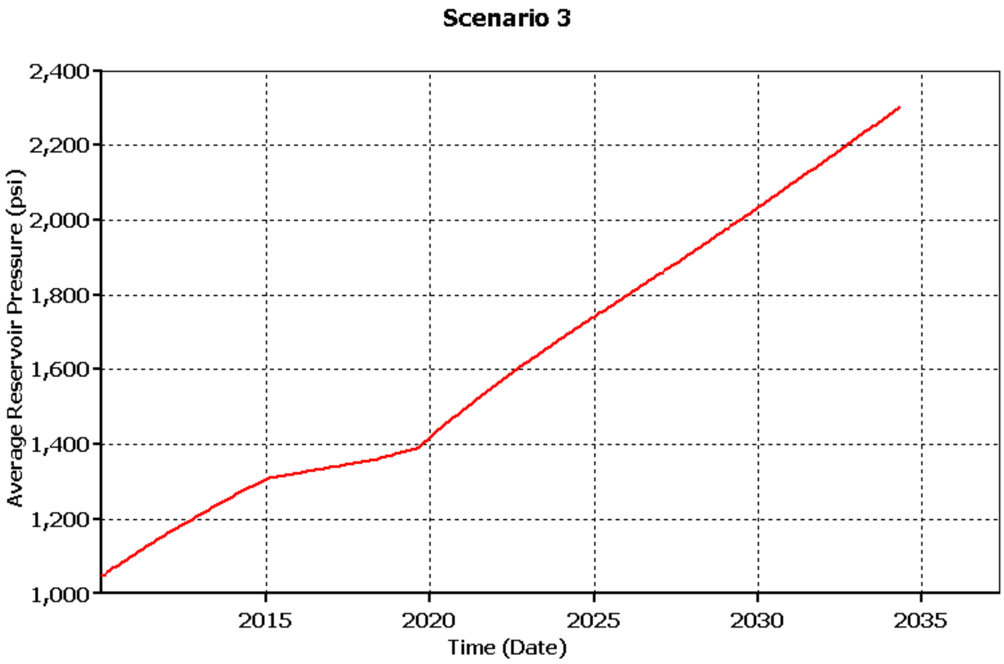


Figure 63 Scenario 3, average reservoir pressure

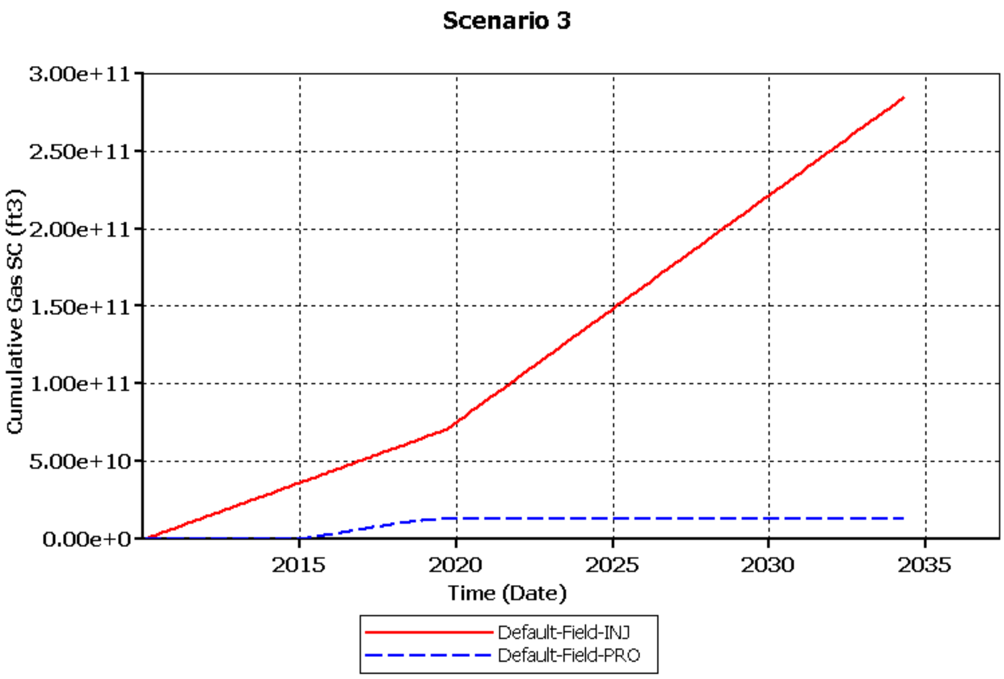


Figure 64 Scenario 3, cumulative field injection and production

Scenario 4

Best production results were obtained in this simulation while total simulation time period was longer than all of the remaining scenarios. Pressure increase in the production flank delayed because of the long distance between two wells. KM3 well had to remain closed for 5 years and its maximum production rate could not be assigned more than 5 MMscfd due to wellhead pressure maintenance concern.

KM3 has produced 51585 MMscf of natural gas. Recovery rate of the field calculated as 82.49% while total injection amount was 373600 MMscf (Figure 75).

The disadvantages of this scenario were reduced injection and production rates. The amount of natural gas production was quite good but CO_2 injection rate to sustain the production was not satisfactory. Producing at a lower rate also delayed the final "disposal" time which became another disadvantage for this scenario.

Table 26 and Table 27 show the numerical results of the scenario. Figure 71 to Figure 74show constraints that were used in the simulation. Figure 75 shows cumulative injection and production amounts. CO_2 propagation and natural gas movement is displayed in Figure 65 to Figure 70.

Table 26 Scenario 4 production results

Period	KMNew	KM4	KM1	KM3
2010-01 – 2015-01	Injection	Shutin	Shutin	Shutin
2015-01 – 2043-04	Injection	Shutin	Shutin	Prod.
2043-04 – 2063-01	Injection	Injection	Injection	Injection

Time	Average Reservoir Pressure (psi)	Cumulative Produced Natural Gas (MMscf)	Remaining Natural Gas in Place (MMscf)	Natural Gas Recovery (%)
2010-01	1 048	0	84 974	55.44
2015-01	1 145	0	84 974	55.44
2043-04	1 156	51 585	33 389	82.49
2063-01	2 302	51 585	33 389	82.49

Table 27 Scenario 4 injection results

Period	KMNew	KM4	KM1	KM3
2010-01 – 2015-01	Injection	Shutin	Shutin	Shutin
2015-01 – 2043-04	Injection	Shutin	Shutin	Prod.
2043-04 – 2063-01	Injection	Injection	Injection	Injection

Time	Average Reservoir Pressure (psi)	Cumulative Injected CO_2 (MMscf)	Average CO_2 content of HC pore volume (%)
2010-01	1 048	0	0.76
2015-01	1 145	12 872	16.84
2043-04	1 156	85 001	65.05
2063-01	2 302	373 600	88.95

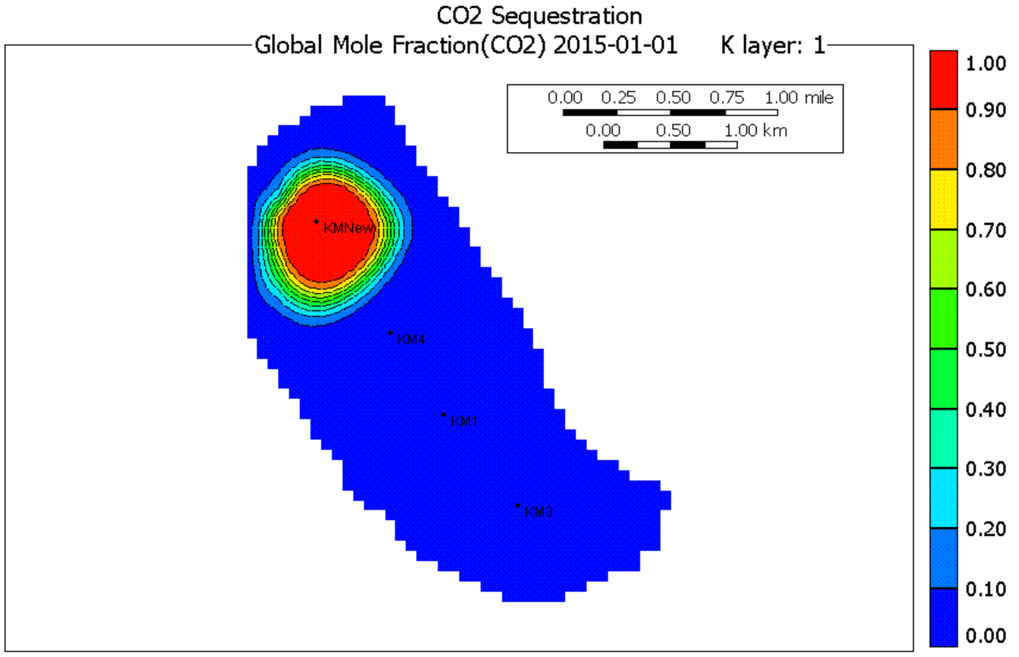


Figure 65 Scenario 4, CO_2 molar fraction distribution of grid layer 1 before production start

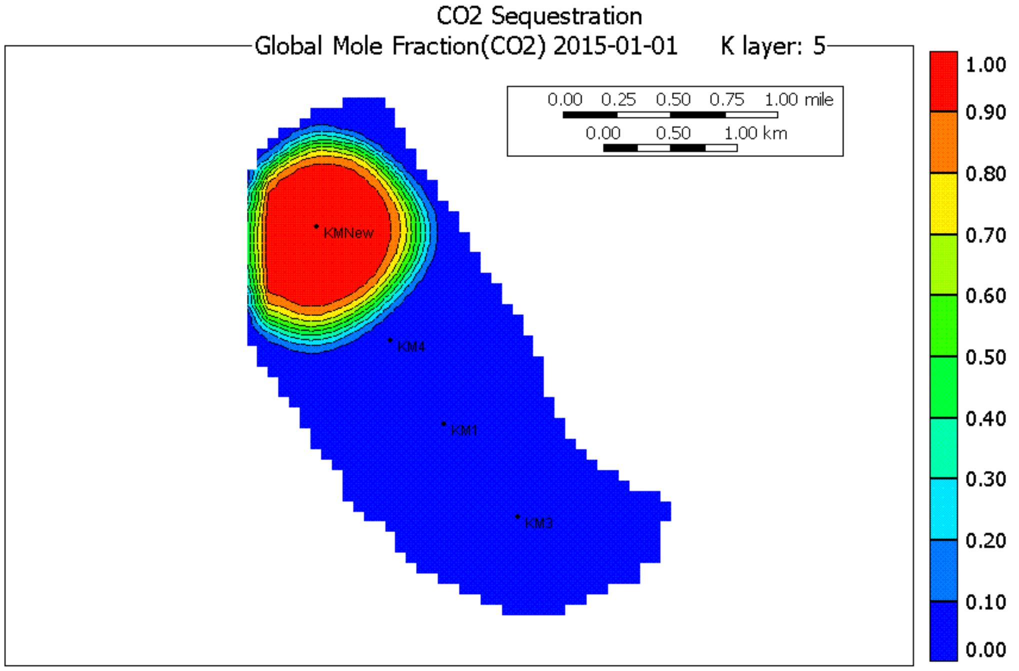


Figure 66 Scenario 4, CO_2 molar fraction distribution of grid layer 5 before production start

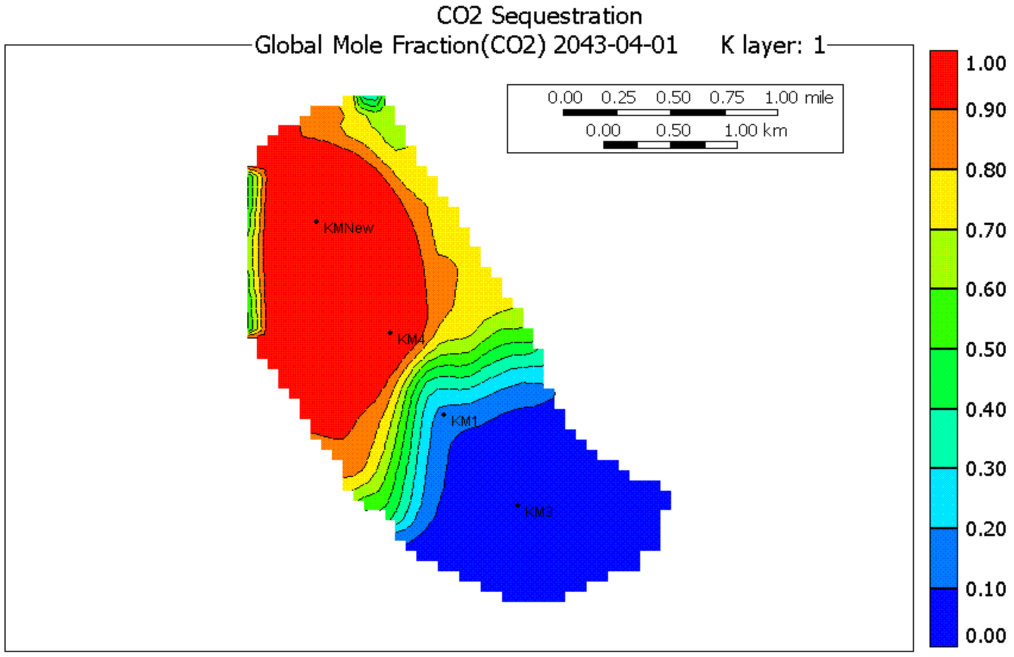


Figure 67 Scenario 4, CO_2 molar fraction distribution of grid layer 1 at KM3 shutin date

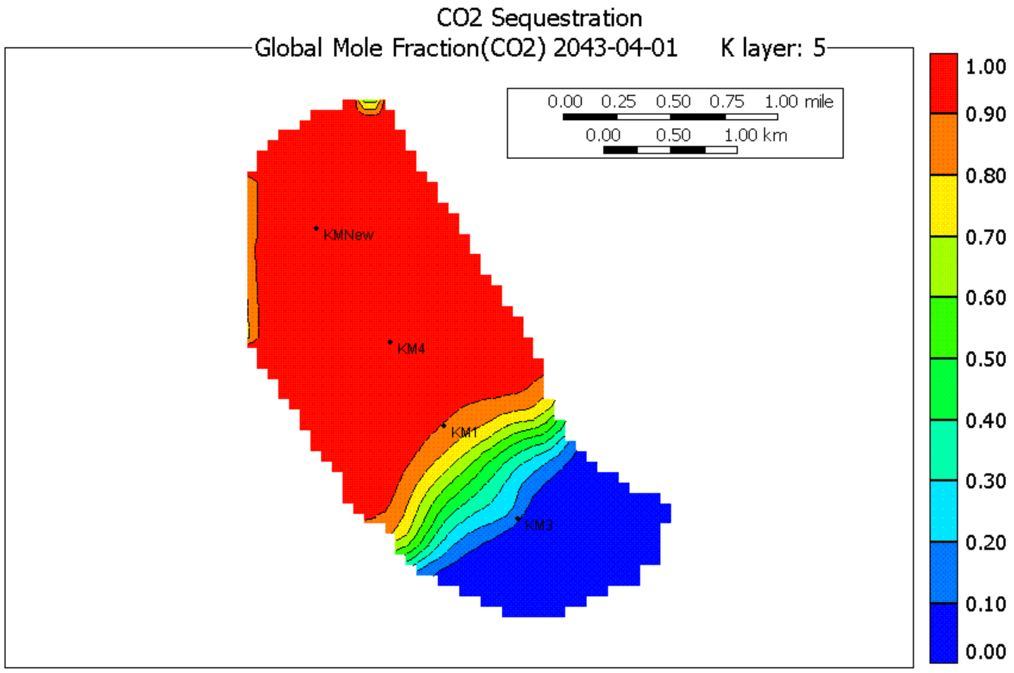


Figure 68 Scenario 4, CO_2 molar fraction distribution of grid layer 5 at KM3 shutin date

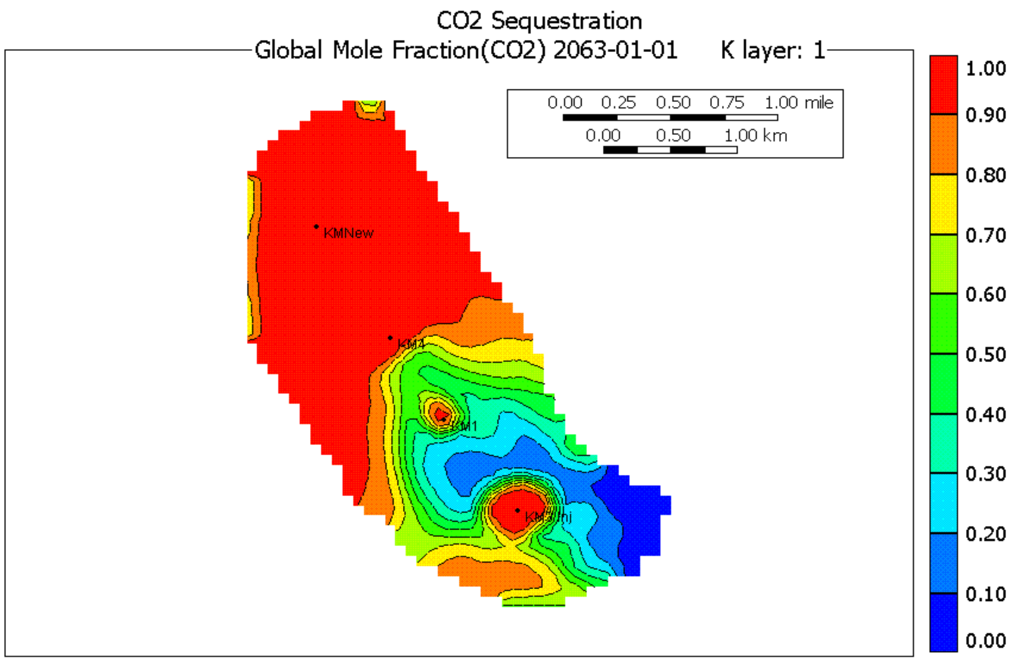


Figure 69 Scenario 4, CO_2 molar fraction distribution of grid layer 1 in the end

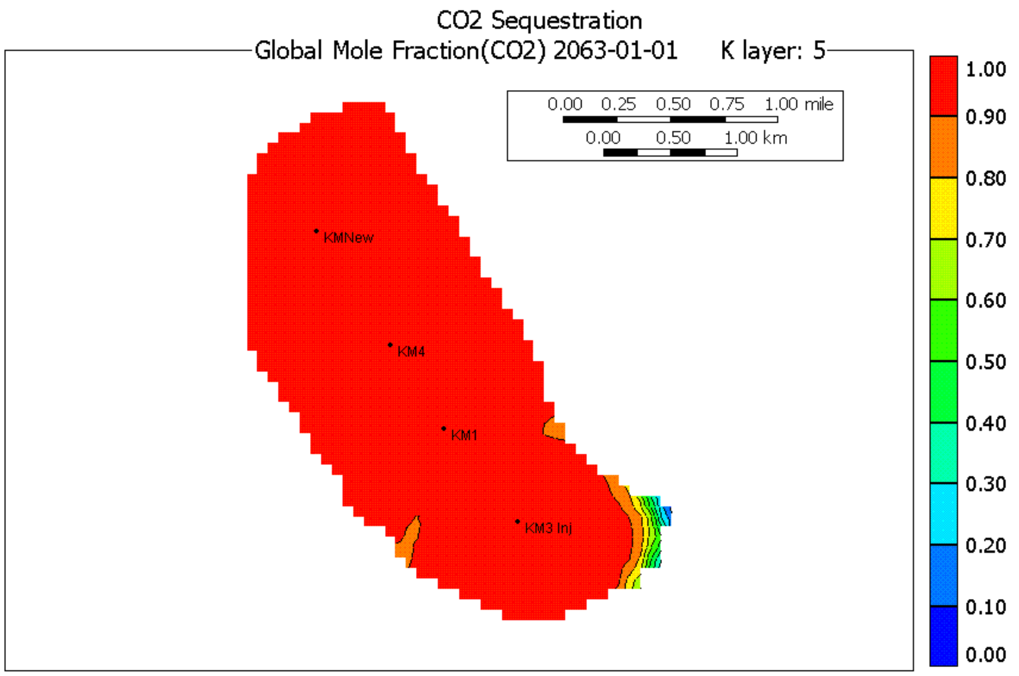


Figure 70 Scenario 4, CO_2 molar fraction distribution of grid layer 5 in the end

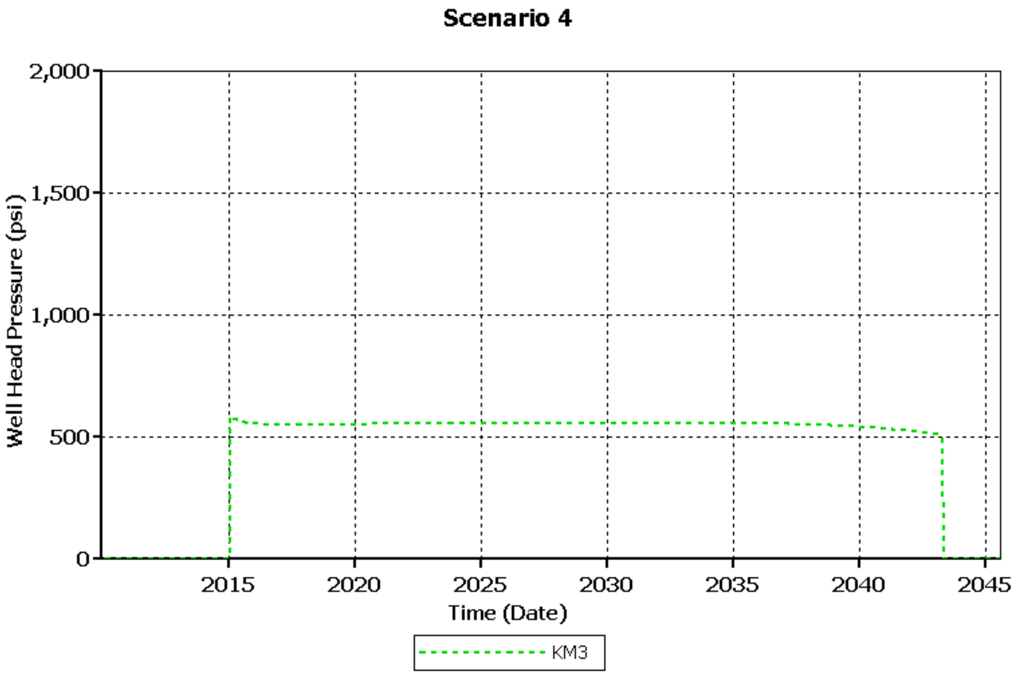


Figure 71 Scenario 4, wellhead pressure of KM3

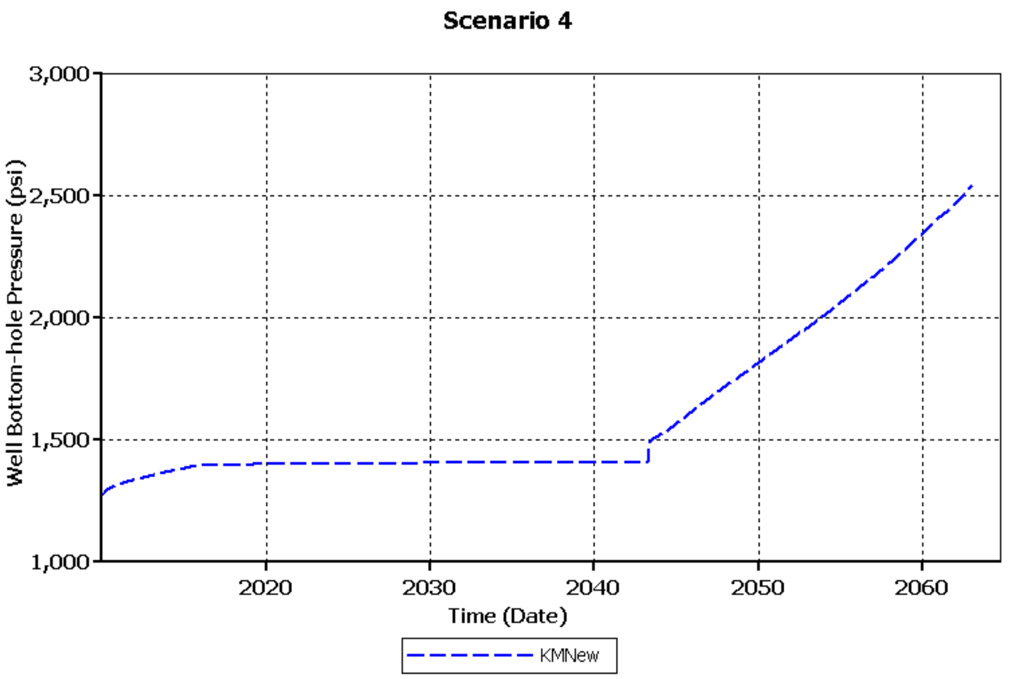


Figure 72 Scenario 4, bottomhole pressure of KMNew

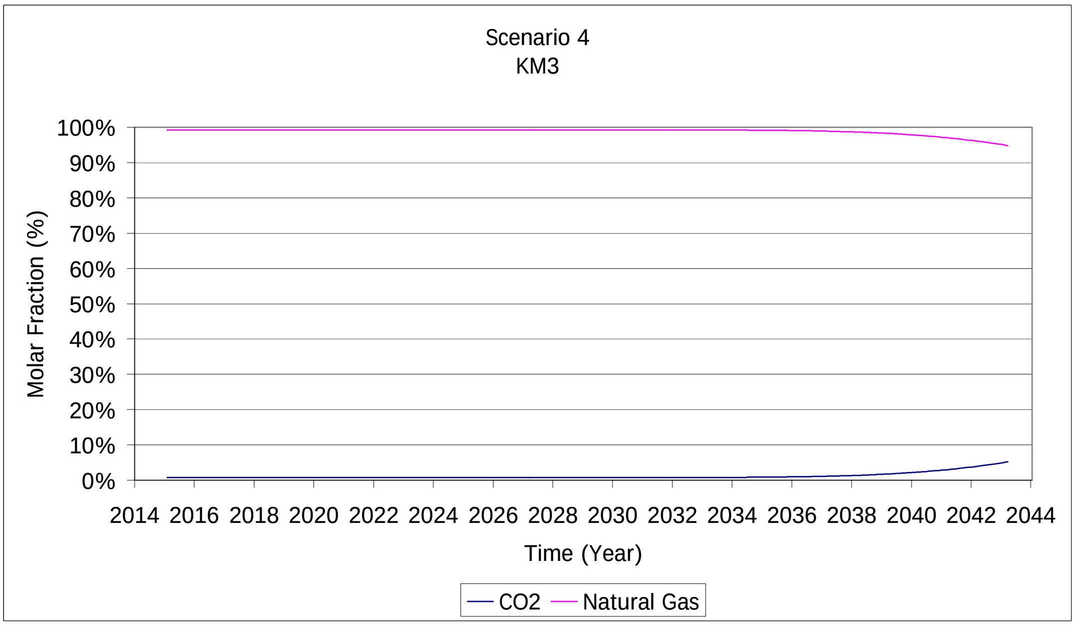


Figure 73 Scenario 4, KM3 molar production rates

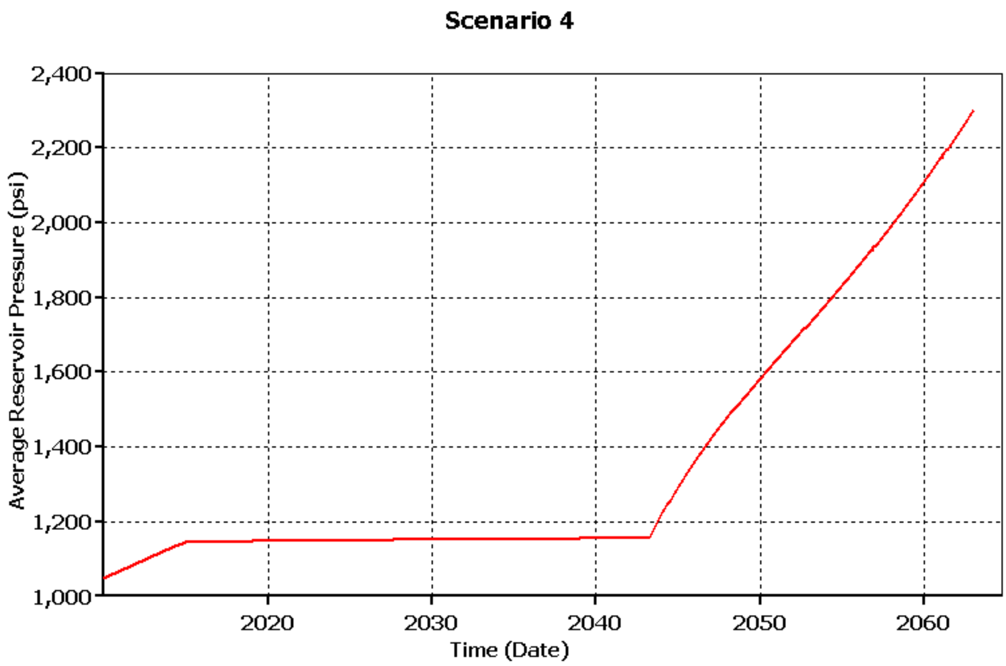


Figure 74 Scenario 4, average reservoir pressure

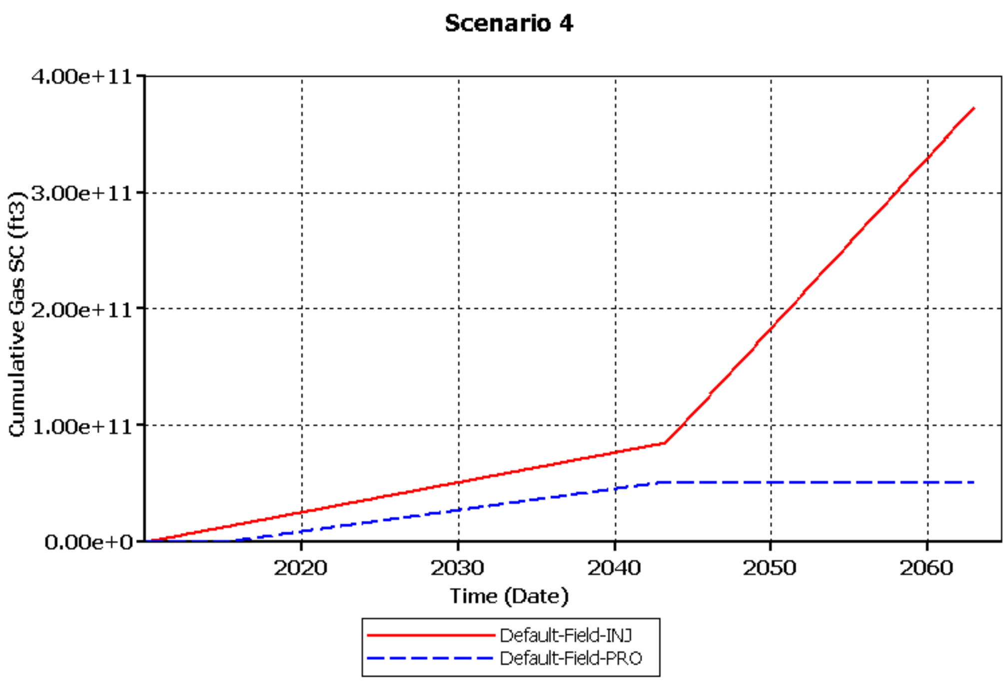


Figure 75 Scenario 4, cumulative field injection and production

Scenario Review

Logically, CO_2 injection capacity of Kuzey Marmara reservoir increases with increasing amount of natural gas production. It is clearly seen that, Scenario 4 provides the most injection space with respect to rest of the scenarios (Table 28).

However, project time is another important factor together with capacity. Figure 76 and Figure 77 indicate that scenario running times also increase with increasing disposal capacity. Scenario 4 running interval is about two times more than Scenario 2 which has the second longest running period. Optimum results are obtained in Scenario 2 when time concept is introduced as a determining factor.

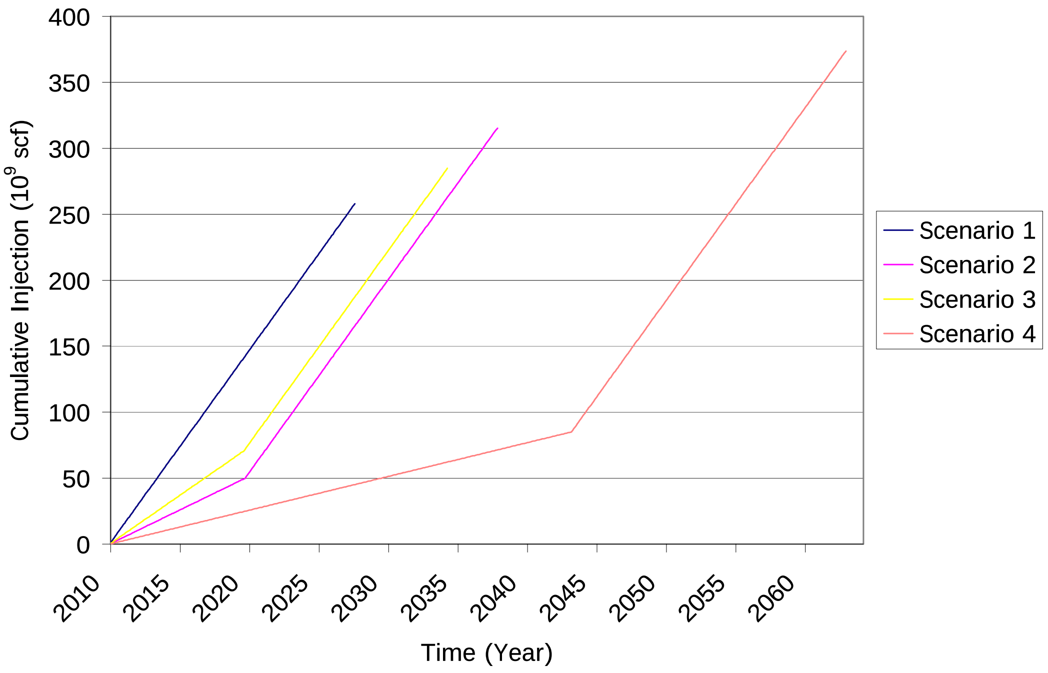


Figure 76 Cumulative injections of scenarios

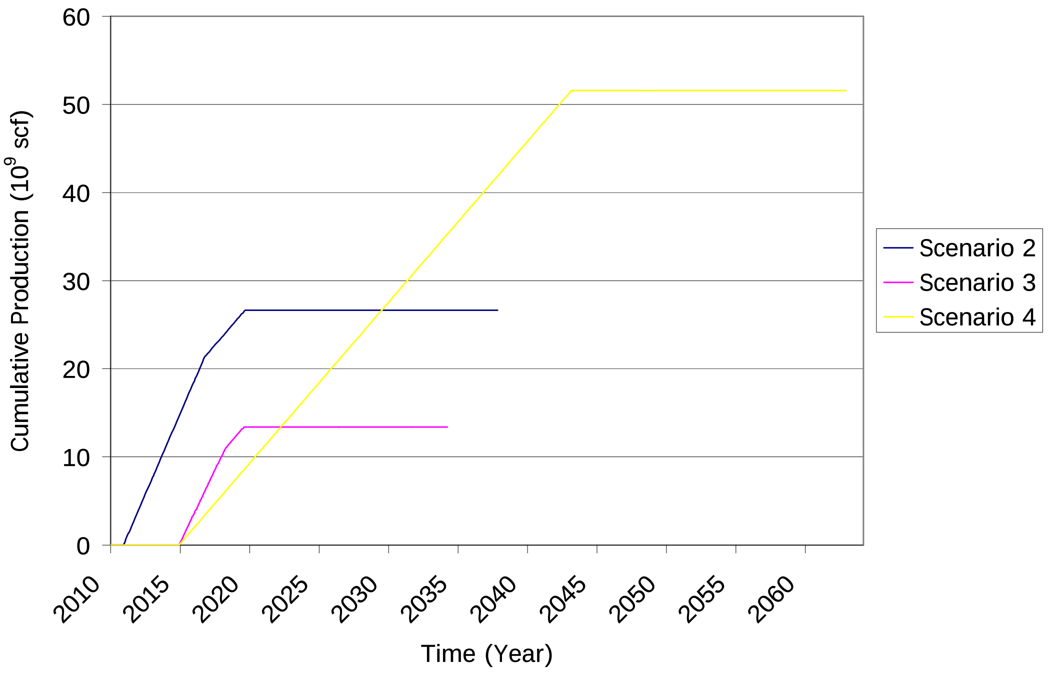


Figure 77 Cumulative productions of scenarios

Table 28 Scenario results overview

	Scenario Length (Years)	Cumulative Injection (MMscf)	Cumulative Production (MMscf)	ΔInjection $S_i - S_1$ (MMscf)
Scenario 1	17.7	258 078	0	0
Scenario 2	27.9	315 279	26 630	57 201
Scenario 3	24.3	284 839	13 384	26 761
Scenario 4	53.0	373 600	51 585	115 522

CHAPTER 7

CONCLUSIONS

A virtual model of Kuzey Marmara field had been created and four sequestration scenarios were simulated in this reservoir. The following conclusions were drawn at the end of this study:

- Formation properties of the reservoir provide ideal conditions for CO_2 storage but the capacity of the reservoir is found to be inadequate. A medium sized power plant generates 12000MWh energy per day. Depending on the type of the plant, amount of CO_2 emissions produced vary significantly. At its initial condition CO_2 storage capacity of Kuzey Marmara reservoir has been estimated as $30.11 *10^9$ lb. This capacity is sufficient to store the emissions of a natural gas power plant for about 8.3 years. If the plant is fed by coal as fuel then this time is reduced to 2.8 years. These times never double even under most suitable conditions.

- Sustaining CO_2 injection amounts may bring problems within. Average natural gas power plant (500 MW) emits 80 MMscf CO_2 in a day. If a well is supposed to inject 10 MMscfd CO_2, then 8 wells are required to fulfill this operation. Similarly covering CO_2 emissions of a coal power plant requires 24 wells all working at the same injection rate. Drilling and operating costs of the new wells should be considered. Also defining many new well locations can be problematic since actual field properties are quite heterogeneous and the wells can not be drilled too close to each other.

- Injected CO_2 have tendency to propagate through lower grid layers of the reservoir, filling these layers faster than the higher ones. As a result, natural gas was moved towards the upper grid layers and away from the injection wells.

- Injecting CO_2 from high porosity regions demonstrates the best conditions for sequestration. High porosity limits front velocity while providing much space to store injected fluid.

- Permeability is another fact that effects fluid propagation. Permeability variation effects direction of propagation rather than propagation velocity. Downward movement of CO_2 becomes easier in high permeability regions. At the same time front velocity in lower regions decreases.

Finally, CO_2 injection can be applied to increase natural gas recovery of Kuzey Marmara field but sequestering high rate CO_2 emissions is found out to be inappropriate.

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APPENDIX A

Table 29 RMSE applications for wellhead pressure and cumulative production of KM1 well [22]

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ij)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ij)} - T_j)^2$ Cumulative Production ($MMscf^2$)
1997-10-01	1 805	1 720	7 222	0.12	0.01	0.013
1997-11-01	1 740	1 690	2 461	0.32	0.17	0.025
1997-12-01	1 751	1 720	931	0.50	0.34	0.025
1998-01-01	1 734	1 710	595	0.69	0.53	0.025
1998-02-01	1 729	1 780	2 601	0.88	0.72	0.025
1998-03-01	1 724	1 710	204	1.05	0.89	0.025
1998-04-01	1 680	1 680	0	1.28	1.07	0.044
1998-05-01	1 666	1 680	186	1.51	1.29	0.047
1998-06-01	1 677	1 690	163	1.73	1.51	0.047
1998-07-01	1 595	1 630	1 243	2.01	1.79	0.047
1998-08-01	1 566	1 610	1 950	2.32	2.10	0.047
1998-09-01	1 617	1 640	532	2.56	2.34	0.047
1998-10-01	1 518	1 520	6	2.89	2.67	0.047
1998-11-01	1 478	1 520	1 757	3.25	3.01	0.058
1998-12-01	1 474	1 480	36	3.59	3.35	0.058
1999-01-01	1 446	1 460	183	3.95	3.71	0.058
1999-02-01	1 453	1 480	708	4.30	4.06	0.058
1999-03-01	1 432	1 440	62	4.62	4.38	0.058
1999-04-01	1 423	1 440	305	4.98	4.74	0.058
1999-05-01	1 427	1 440	164	5.30	5.06	0.058
1999-06-01	1 410	1 430	402	5.65	5.40	0.058
1999-07-01	1 404	1 420	250	5.97	5.73	0.058
1999-08-01	1 392	1 390	4	6.31	6.06	0.063
1999-09-01	1 405	1 420	219	6.62	6.37	0.063
1999-10-01	1 380	1 380	0	6.94	6.69	0.063
1999-11-01	1 370	1 370	0	7.27	7.02	0.063
1999-12-01	1 351	1 340	113	7.59	7.34	0.063
2000-01-01	1 325	1 320	21	7.93	7.67	0.063
2000-02-01	1 286	1 240	2 111	8.28	8.03	0.063
2000-03-01	1 256	1 250	34	8.62	8.36	0.063
2000-04-01	1 251	1 200	2 613	8.97	8.72	0.063
2000-05-01	1 266	1 270	18	9.30	9.04	0.063
2000-06-01	1 302	1 280	496	9.60	9.34	0.068
2000-07-01	1 298	1 290	58	9.89	9.63	0.068
2000-08-01	1 256	1 270	197	10.21	9.95	0.068
2000-09-01	1 245	1 250	30	10.53	10.26	0.068
2000-10-01	1 271	1 250	452	10.80	10.53	0.073

Table 29 continued…

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ij)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ij)} - T_j)^2$ Cumulative Production ($MMscf^2$)
2000-11-01	1 318	1 310	57	11.03	10.76	0.073
2000-12-01	1 303	1 310	52	11.25	10.98	0.073
2001-01-01	1 319	1 300	353	11.46	11.19	0.073
2001-02-01	1 323	1 295	788	11.65	11.38	0.077
2001-03-01	1 290	1 205	7 144	11.85	11.55	0.089
2001-04-01	1 243	1 230	181	12.12	11.74	0.148
2001-05-01	1 258	1 240	330	12.35	11.87	0.235
2001-06-01	1 276	1 250	659	12.56	11.97	0.344
2001-07-01	1 296	1 280	258	12.74	12.10	0.408
2001-08-01	1 311	1 290	455	12.89	12.19	0.496
2001-09-01	1 309	1 300	76	13.05	12.34	0.496
2001-10-01	1 272	1 285	158	13.23	12.52	0.496
2001-11-01	1 272	1 300	786	13.41	12.70	0.496
2001-12-01	1 268	1 265	9	13.58	12.87	0.496
2002-01-01	1 312	1 285	708	13.70	12.99	0.513
2002-02-01	1 311	1 290	428	13.82	13.05	0.600
Sum			40 770			7.088

RMSE calculation for wellhead pressure

$$n = 53$$

$$\sum_{j=1}^{n}\left(P_{(ij)} - T_j\right)^2 = 40770$$

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n}\left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{53}(40770)} = 27.74\,psi$$

RMSE calculation for cumulative production

$$n = 53$$

$$\sum_{j=1}^{n}\left(P_{(ij)} - T_j\right)^2 = 7.088$$

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n}\left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{53}(7.088)} = 0.366\,MMscf$$

Table 30 RMSE applications for wellhead pressure and cumulative production of KM3 well [22]

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ij)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ij)} - T_j)^2$ Cumulative Production ($MMscf^2$)
1997-10-01						
1997-11-01	1 659	1 550	11 966	0.14	0.11	0.001
1997-12-01	1 659	1 560	9 898	0.27	0.24	0.001
1998-01-01	1 638	1 560	6 059	0.41	0.37	0.001
1998-02-01	1 657	1 580	5 957	0.53	0.50	0.001
1998-03-01	1 684	1 578	11 251	0.63	0.54	0.010
1998-04-01	1 582	1 494	7 672	0.79	0.58	0.041
1998-05-01	1 636	1 570	4 309	0.91	0.71	0.041
1998-06-01	1 640	1 580	3 658	1.03	0.83	0.041
1998-07-01	1 566	1 550	261	1.18	0.97	0.041
1998-08-01	1 553	1 520	1 109	1.33	1.13	0.041
1998-09-01	1 560	1 540	394	1.47	1.27	0.041
1998-10-01	1 484	1 450	1 182	1.64	1.43	0.041
1998-11-01	1 448	1 420	805	1.81	1.60	0.046
1998-12-01	1 419	1 410	84	1.99	1.78	0.046
1999-01-01	1 373	1 400	734	2.19	1.97	0.046
1999-02-01	1 376	1 420	1 909	2.37	2.16	0.046
1999-03-01	1 364	1 380	255	2.54	2.33	0.046
1999-04-01	1 352	1 390	1 476	2.73	2.52	0.046
1999-05-01	1 364	1 390	696	2.90	2.69	0.046
1999-06-01	1 353	1 380	752	3.08	2.86	0.046
1999-07-01	1 351	1 370	365	3.24	3.03	0.046
1999-08-01	1 342	1 350	57	3.41	3.20	0.046
1999-09-01	1 345	1 370	630	3.58	3.36	0.046
1999-10-01	1 327	1 330	11	3.74	3.52	0.046
1999-11-01	1 301	1 320	378	3.91	3.70	0.046
1999-12-01	1 308	1 300	69	4.07	3.85	0.046
2000-01-01	1 303	1 300	6	4.23	4.02	0.046
2000-02-01	1 293	1 260	1 116	4.39	4.17	0.046
2000-03-01	1 282	1 200	6 659	4.54	4.32	0.046
2000-04-01	1 282	1 200	6 785	4.69	4.47	0.046
2000-05-01	1 289	1 230	3 492	4.83	4.61	0.046
2000-06-01	1 326	1 240	7 434	4.95	4.73	0.048
2000-07-01	1 297	1 250	2 200	5.08	4.86	0.048
2000-08-01	1 268	1 210	3 311	5.22	5.00	0.048
2000-09-01	1 254	1 200	2 955	5.35	5.14	0.048
2000-10-01	1 266	1 210	3 161	5.48	5.26	0.050
2000-11-01	1 351	1 280	5 099	5.57	5.31	0.067
2000-12-01	1 331	1 280	2 629	5.66	5.38	0.079
2001-01-01	1 339	1 270	4 694	5.74	5.46	0.079
2001-02-01	1 363	1 285	6 050	5.81	5.51	0.089
2001-03-01	1 340	1 265	5 679	5.88	5.53	0.124
2001-04-01	1 267	1 260	46	5.99	5.63	0.134

Table 30 continued…

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ij)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ij)} - T_j)^2$ Cumulative Production ($MMscf^2$)
2001-05-01	1 286	1 220	4 335	6.08	5.72	0.134
2001-06-01	1 243	1 175	4 672	6.19	5.77	0.182
2001-07-01	1 274	1 250	573	6.28	5.83	0.205
2001-08-01	1 280	1 240	1 612	6.37	5.87	0.251
2001-09-01	1 301	1 250	2 603	6.45	5.90	0.302
2001-10-01	1 284	1 250	1 148	6.53	5.98	0.302
2001-11-01	1 253	1 230	510	6.62	6.03	0.342
2001-12-01	1 286	1 220	4 393	6.69	6.07	0.382
2002-01-01	1 289	1 220	4 782	6.76	6.13	0.387
2002-01-01	1 263	1 210	2 856	6.83	6.17	0.436
Sum			160 733			4.914

RMSE calculation for wellhead pressure

$$n = 52$$

$$\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2 = 160733$$

$$E_i = \sqrt{\frac{1}{n} \sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{52}(160733)} = 55.60\, psi$$

RMSE calculation for cumulative production

$$n = 52$$

$$\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2 = 4.914$$

$$E_i = \sqrt{\frac{1}{n} \sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{52}(4.914)} = 0.307\, MMscf$$

Table 31 RMSE applications for wellhead pressure and cumulative production of KM4 well [22]

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ij)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ij)} - T_j)^2$ Cumulative Production ($MMscf^2$)
1997-10-01	1 792	1 700	8 425	0.13	0.01	0.014
1997-11-01	1 709	1 670	1 496	0.34	0.17	0.027
1997-12-01	1 709	1 690	347	0.54	0.39	0.021
1998-01-01	1 651	1 700	2 384	0.78	0.64	0.021
1998-02-01	1 685	1 700	239	1.00	0.86	0.021
1998-03-01	1 668	1 660	59	1.21	1.06	0.023
1998-04-01	1 615	1 650	1 254	1.47	1.22	0.060
1998-05-01	1 625	1 570	3 028	1.71	1.47	0.060
1998-06-01	1 631	1 680	2 441	1.95	1.71	0.060
1998-07-01	1 512	1 640	16 297	2.26	2.02	0.060
1998-08-01	1 482	1 610	16 499	2.60	2.35	0.060
1998-09-01	1 319	1 510	36 542	3.02	2.78	0.060
1998-10-01	1 358	1 510	23 253	3.42	3.17	0.060
1998-11-01	1 351	1 500	22 350	3.82	3.57	0.060
1998-12-01	1 381	1 500	14 075	4.19	3.93	0.066
1999-01-01	1 327	1 480	23 372	4.59	4.33	0.066
1999-02-01	1 380	1 490	12 058	4.95	4.70	0.066
1999-03-01	1 325	1 460	18 333	5.30	5.05	0.066
1999-04-01	1 333	1 450	13 619	5.68	5.42	0.066
1999-05-01	1 353	1 450	9 364	6.03	5.77	0.066
1999-06-01	1 325	1 430	10 991	6.39	6.14	0.066
1999-07-01	1 319	1 420	10 237	6.74	6.49	0.066
1999-08-01	1 295	1 400	10 996	7.11	6.85	0.066
1999-09-01	1 333	1 420	7 536	7.45	7.19	0.066
1999-10-01	1 285	1 390	11 052	7.79	7.54	0.066
1999-11-01	1 275	1 370	8 998	8.15	7.89	0.066
1999-12-01	1 256	1 360	10 904	8.50	8.24	0.066
2000-01-01	1 234	1 340	11 181	8.86	8.60	0.066
2000-02-01	1 189	1 300	12 397	9.23	8.97	0.066
2000-03-01	1 144	1 270	15 851	9.59	9.33	0.066
2000-04-01	1 163	1 270	11 513	9.96	9.70	0.066
2000-05-01	1 169	1 280	12 352	10.30	10.05	0.066
2000-06-01	1 224	1 290	4 339	10.63	10.37	0.071
2000-07-01	1 204	1 280	5 747	10.95	10.69	0.071
2000-08-01	1 143	1 260	13 790	11.31	11.04	0.071
2000-09-01	1 133	1 240	11 406	11.66	11.39	0.071
2000-10-01	1 185	1 250	4 187	11.97	11.69	0.077
2000-11-01	1 279	1 290	126	12.21	11.93	0.077
2000-12-01	1 303	1 270	1 060	12.42	12.06	0.130
2001-01-01	1 277	1 270	52	12.65	12.28	0.130
2001-02-01	1 292	1 275	304	12.85	12.45	0.166
2001-03-01	1 239	1 150	7 898	13.08	12.65	0.180
2001-04-01	1 161	1 150	124	13.38	12.81	0.325

Table 31 continued…

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ij)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ij)} - T_j)^2$ Cumulative Production ($MMscf^2$)
2001-05-01	1 223	1 240	274	13.62	13.02	0.362
2001-06-01	1 214	1 260	2 146	13.87	13.23	0.402
2001-07-01	1 287	1 270	296	14.04	13.34	0.493
2001-08-01	1 293	1 275	333	14.20	13.40	0.646
2001-09-01	1 248	1 260	147	14.40	13.53	0.753
2001-10-01						
2001-11-01						
2001-12-01	1 223	1 225	6	14.60	13.65	0.898
2002-01-01	1 188	1 200	136	14.83	13.88	0.898
2002-01-01	1 213	1 230	275	15.03	13.99	1.092
Sum			412 094			8.708

RMSE calculation for wellhead pressure

$$n = 51$$

$$\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2 = 412094$$

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{51}\left(412094\right)} = 89.89\, psi$$

RMSE calculation for cumulative production

$$n = 51$$

$$\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2 = 8.708$$

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{51}\left(8.708\right)} = 0.413 MMscf$$

Table 32 RMSE applications for wellhead pressure and cumulative production of KM5 well [22]

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ii)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ii)} - T_j)^2$ Cumulative Production ($MMscf^2$)
1997-10-01	1 815	1 815	0	0.08	0.00	0.006
1997-11-01	1 809	1 809	0	0.16	0.00	0.026
1997-12-01	1 802	1 740	3 817	0.24	0.02	0.047
1998-01-01	1 796	1 740	3 109	0.32	0.10	0.047
1998-02-01	1 764	1 690	5 477	0.43	0.21	0.050
1998-03-01	1 753	1 650	10 517	0.54	0.30	0.053
1998-04-01	1 707	1 630	5 994	0.69	0.41	0.079
1998-05-01	1 694	1 630	4 137	0.84	0.41	0.184
1998-06-01						
1998-07-01	1 665	1 630	1 200	1.01	0.55	0.209
1998-08-01	1 641	1 520	14 578	1.19	0.74	0.209
1998-09-01	1 624	1 570	2 880	1.38	0.87	0.268
1998-10-01						
1998-11-01	1 599	1 560	1 526	1.57	0.89	0.469
1998-12-01	1 550	1 510	1 624	1.79	1.10	0.469
1999-01-01	1 534	1 450	7 112	2.01	1.32	0.469
1999-02-01	1 517	1 460	3 199	2.23	1.54	0.469
1999-03-01	1 511	1 430	6 610	2.42	1.74	0.469
1999-04-01	1 495	1 430	4 239	2.64	1.96	0.469
1999-05-01	1 502	1 430	5 206	2.84	2.15	0.469
1999-06-01	1 490	1 420	4 965	3.04	2.34	0.487
1999-07-01	1 492	1 420	5 172	3.22	2.49	0.530
1999-08-01	1 471	1 390	6 590	3.41	2.68	0.530
1999-09-01	1 467	1 400	4 465	3.60	3.10	0.257
1999-10-01	1 459	1 370	7 916	3.79	3.28	0.257
1999-11-01	1 446	1 360	7 398	3.97	3.47	0.257
1999-12-01	1 434	1 340	8 810	4.15	3.65	0.257
2000-01-01	1 419	1 340	6 216	4.34	3.83	0.257
2000-02-01	1 397	1 290	11 488	4.53	4.03	0.257
2000-03-01	1 379	1 270	11 988	4.72	4.21	0.257
2000-04-01	1 370	1 260	12 025	4.91	4.40	0.257
2000-05-01	1 364	1 270	8 883	5.09	4.58	0.257
2000-06-01	1 381	1 280	10 185	5.26	4.74	0.262
2000-07-01	1 370	1 280	8 105	5.41	4.90	0.268
2000-08-01	1 336	1 260	5 800	5.59	5.08	0.268
2000-09-01	1 323	1 240	6 901	5.78	5.26	0.268
2000-10-01	1 324	1 240	7 054	5.94	5.42	0.268
2000-11-01	1 378	1 270	11 645	6.06	5.54	0.272
2000-12-01	1 350	1 230	14 299	6.19	5.67	0.272
2001-01-01	1 366	1 250	13 405	6.31	5.79	0.272
2001-02-01	1 370	1 260	12 208	6.41	5.86	0.312
2001-03-01	1 351	1 220	17 177	6.52	5.89	0.402
2001-04-01	1 263	1 210	2 759	6.70	6.02	0.472

Table 32 continued…

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ij)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ij)} - T_j)^2$ Cumulative Production ($MMscf^2$)
2001-05-01	1 309	1 220	7 957	6.84	6.05	0.616
2001-06-01	1 328	1 270	3 385	6.95	6.15	0.646
2001-07-01	1 308	1 280	780	7.07	6.19	0.776
2001-08-01	1 296	1 220	5 779	7.20	6.25	0.915
2001-09-01						
2001-10-01	1 315	1 265	2 486	7.31	6.31	0.989
2001-11-01	1 302	1 260	1 805	7.42	6.42	0.989
2001-12-01	1 260	1 200	3 584	7.55	6.48	1.147
2002-01-01						
2002-01-01						
Sum			312 455			17.736

RMSE calculation for wellhead pressure

$$n = 48$$

$$\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2 = 312455$$

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n}\left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{48}(312455)} = 80.68\,psi$$

RMSE calculation for cumulative production

$$n = 48$$

$$\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2 = 17.736$$

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n}\left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{48}(17.736)} = 0.608\,MMscf$$

Table 33 RMSE applications for wellhead pressure and cumulative production of KM6 well [22]

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ii)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ii)} - T_j)^2$ Cumulative Production ($MMscf^2$)
1997-10-01						
1997-11-01						
1997-12-01	1 739	1 780	1 702	0.15	0.03	0.015
1998-01-01	1 732	1 780	2 304	0.31	0.14	0.028
1998-02-01	1 730	1 770	1 609	0.46	0.29	0.028
1998-03-01	1 727	1 760	1 118	0.59	0.42	0.031
1998-04-01	1 498	1 710	45 135	0.91	0.54	0.139
1998-05-01						
1998-06-01						
1998-07-01	1 525	1 650	15 640	1.19	0.77	0.176
1998-08-01	1 565	1 700	18 266	1.44	1.02	0.176
1998-09-01	1 533	1 680	21 633	1.71	1.29	0.176
1998-10-01	1 520	1 680	25 485	1.97	1.55	0.176
1998-11-01	1 510	1 670	25 606	2.23	1.81	0.176
1998-12-01	1 259	1 500	57 989	2.63	2.10	0.276
1999-01-01	1 208	1 500	85 527	3.05	2.53	0.276
1999-02-01	1 222	1 500	77 562	3.46	2.94	0.276
1999-03-01	1 201	1 450	62 245	3.84	3.31	0.276
1999-04-01	1 185	1 450	70 252	4.25	3.72	0.276
1999-05-01	1 132	1 450	100 914	4.66	4.13	0.276
1999-06-01	1 097	1 430	110 723	5.09	4.56	0.276
1999-07-01	1 089	1 430	116 090	5.50	4.97	0.276
1999-08-01	1 056	1 430	139 569	5.93	5.39	0.291
1999-09-01						
1999-10-01	1 043	1 400	127 213	6.34	5.80	0.291
1999-11-01	1 018	1 370	123 911	6.77	6.23	0.291
1999-12-01	981	1 350	135 917	7.19	6.65	0.291
2000-01-01	957	1 340	146 446	7.62	7.08	0.291
2000-02-01	895	1 300	164 058	8.06	7.52	0.291
2000-03-01	821	1 270	201 714	8.49	7.95	0.291
2000-04-01	818	1 260	195 566	8.94	8.40	0.291
2000-05-01	868	1 280	169 362	9.36	8.82	0.291
2000-06-01	975	1 280	93 163	9.76	9.21	0.305
2000-07-01	961	1 290	108 450	10.14	9.59	0.305
2000-08-01	855	1 270	171 925	10.57	10.01	0.305
2000-09-01	859	1 240	145 258	10.98	10.43	0.305
2000-10-01	956	1 250	86 375	11.35	10.80	0.305
2000-11-01	1 199	1 270	5 109	11.62	11.04	0.345
2000-12-01	1 055	1 200	20 967	11.95	11.36	0.345
2001-01-01	1 135	1 240	11 101	12.25	11.66	0.345
2001-02-01	1 168	1 250	6 706	12.53	11.91	0.389
2001-03-01	1 117	1 060	3 199	12.80	12.07	0.533
2001-04-01						

Table 33 continued

Time (Date)	GEM Wellhead Pressure (psi)	Field Wellhead Pressure (psi)	$(P_{(ij)} - T_j)^2$ Wellhead Pressure (psi^2)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ij)} - T_j)^2$ Cumulative Production ($MMscf^2$)
2001-05-01	1 123	1 215	8 396	13.08	12.20	0.791
2001-06-01	1 147	1 155	58	13.36	12.24	1.248
2001-07-01	1 208	1 300	8 440	13.56	12.31	1.551
2001-08-01	1 165	1 300	18 125	13.80	12.55	1.550
2001-09-01	1 199	1 295	9 278	14.00	12.76	1.551
2001-10-01	1 159	1 300	19 743	14.23	12.99	1.551
2001-11-01	1 147	1 300	23 381	14.47	13.23	1.550
2001-12-01	1 160	1 275	13 172	14.69	13.44	1.550
2002-01-01	1 179	1 270	8 370	14.89	13.64	1.550
2002-01-01	1 150	1 260	12 036	15.11	13.79	1.734
Sum			3 016 809			24.059

RMSE calculation for wellhead pressure

$$n = 47$$

$$\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2 = 3016809$$

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{47}\left(3016809\right)} = 253.35\,psi$$

RMSE calculation for cumulative production

$$n = 47$$

$$\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2 = 24.059$$

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{47}\left(24.059\right)} = 0.715\,MMscf$$

Table 34 RMSE application for cumulative production of total field [22]

Time (Date)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ii)} - T_i)^2$ Cumulative Production ($MMscf^2$)
1997-10-01	0.33	0.02	0.097
1997-11-01	0.96	0.44	0.267
1997-12-01	1.69	1.02	0.452
1998-01-01	2.51	1.79	0.515
1998-02-01	3.31	2.58	0.525
1998-03-01	4.02	3.20	0.669
1998-04-01	5.14	3.83	1.720
1998-05-01	5.88	4.41	2.153
1998-06-01	6.46	5.00	2.153
1998-07-01	7.65	6.11	2.377
1998-08-01	8.88	7.34	2.377
1998-09-01	10.15	8.55	2.569
1998-10-01	11.29	9.69	2.569
1998-11-01	12.69	10.88	3.256
1998-12-01	14.18	12.26	3.697
1999-01-01	15.79	13.86	3.697
1999-02-01	17.32	15.40	3.697
1999-03-01	18.73	16.81	3.697
1999-04-01	20.27	18.35	3.697
1999-05-01	21.73	19.80	3.697
1999-06-01	23.24	21.30	3.747
1999-07-01	24.67	22.71	3.865
1999-08-01	26.17	24.18	3.963
1999-09-01	27.18	25.41	3.132
1999-10-01	28.60	26.83	3.132
1999-11-01	30.07	28.30	3.132
1999-12-01	31.49	29.72	3.132
2000-01-01	32.97	31.20	3.132
2000-02-01	34.49	32.72	3.132
2000-03-01	35.95	34.18	3.132
2000-04-01	37.47	35.70	3.132
2000-05-01	38.88	37.11	3.132
2000-06-01	40.20	38.39	3.284
2000-07-01	41.48	39.66	3.303
2000-08-01	42.89	41.07	3.303
2000-09-01	44.29	42.48	3.303
2000-10-01	45.54	43.70	3.390
2000-11-01	46.49	44.57	3.675
2000-12-01	47.47	45.45	4.086
2001-01-01	48.41	46.39	4.086
2001-02-01	49.27	47.10	4.694
2001-03-01	50.14	47.70	5.951
2001-04-01	51.00	48.26	7.502
2001-05-01	51.98	48.85	9.783
2001-06-01	52.93	49.36	12.722

Table 34 continued…

Time (Date)	GEM Cumulative Production (MMscf)	Field Cumulative Production (MMscf)	$(P_{(ij)} - T_j)^2$ Cumulative Production ($MMscf^2$)
2001-07-01	53.69	49.77	15.369
2001-08-01	54.47	50.26	17.733
2001-09-01	55.10	50.78	18.695
2001-10-01	55.69	51.33	19.021
2001-11-01	56.31	51.92	19.328
2001-12-01	57.10	52.52	21.030
2002-01-01	57.73	53.13	21.182
2002-01-01	58.35	53.49	23.698
Sum			308.785

RMSE calculation for cumulative production

$$n = 53$$

$$\sum_{j=1}^{n} \left(P_{(ij)} - T_j\right)^2 = 308.785$$

$$E_i = \sqrt{\frac{1}{n}\sum_{j=1}^{n}\left(P_{(ij)} - T_j\right)^2} = \sqrt{\frac{1}{53}(308.785)} = 2.414 MMscf$$

APPENDIX B

Table 35 Kuzey Marmara relative permeability chart (k_r vs. S_w)

S_w	k_{rw}	k_{rg}
0.10	0.000	0.792
0.15	0.002	0.699
0.20	0.003	0.611
0.25	0.006	0.529
0.30	0.014	0.454
0.35	0.027	0.384
0.40	0.044	0.320
0.45	0.066	0.262
0.50	0.092	0.209
0.55	0.122	0.163
0.60	0.157	0.122
0.65	0.196	0.088
0.70	0.240	0.059
0.75	0.288	0.036
0.80	0.340	0.019
0.85	0.397	0.008
0.90	0.458	0.003
0.95	0.524	0.001
1.00	0.594	0.000

APPENDIX C

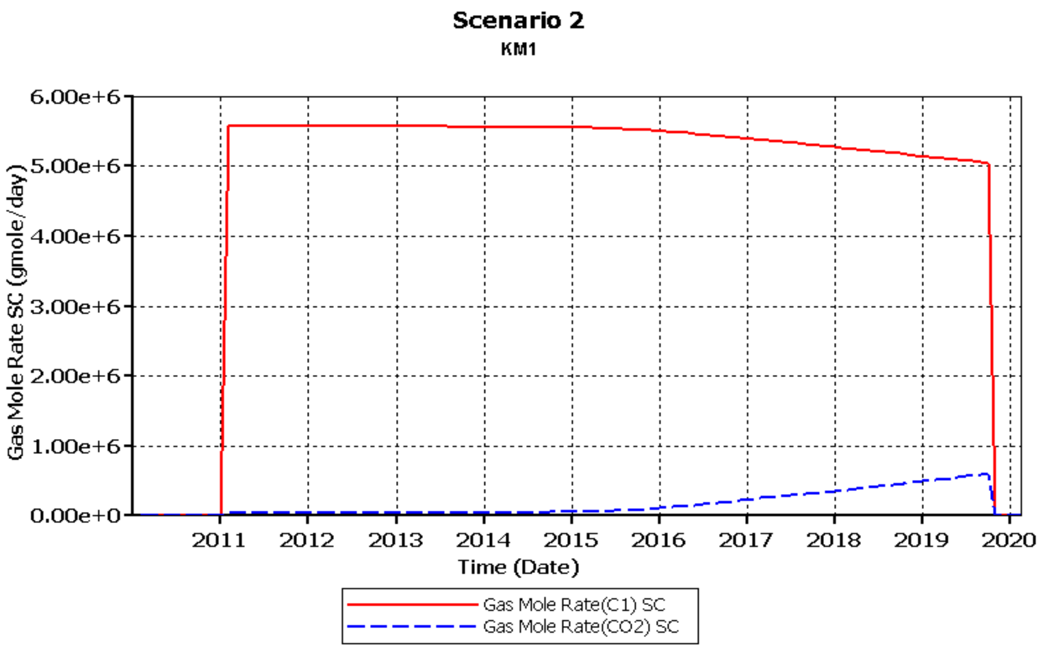

Figure 78 Scenario 2, molar production rates of CO_2 and CH_4 in KM1

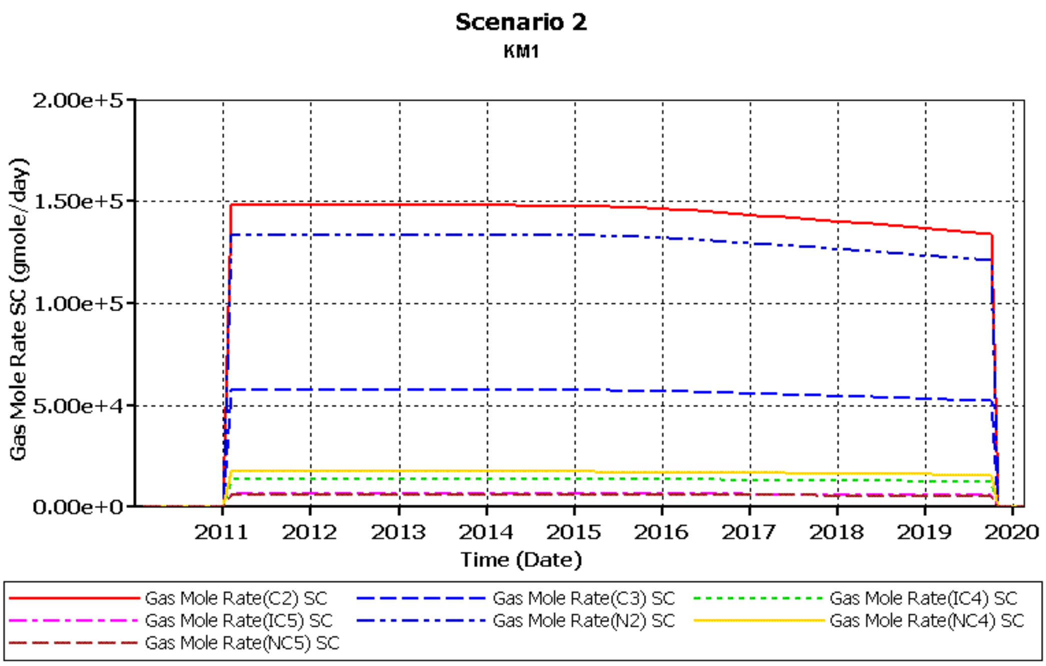

Figure 79 Scenario 2, molar production rates of minor gases in KM1

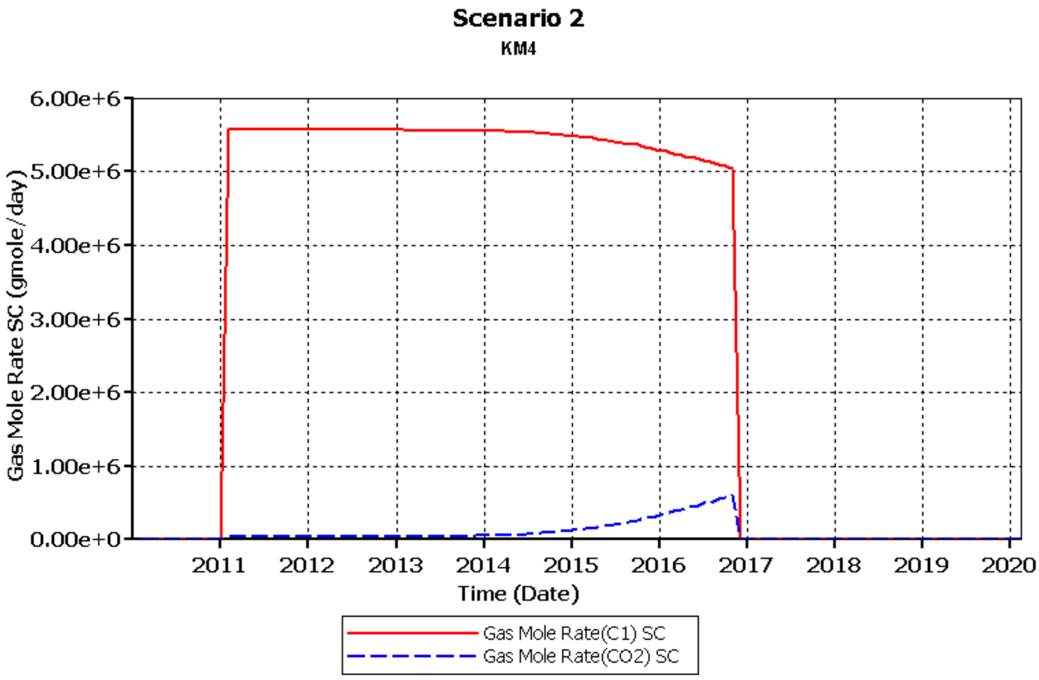

Figure 80 Scenario 2, molar production rates of CO_2 and CH_4 in KM4

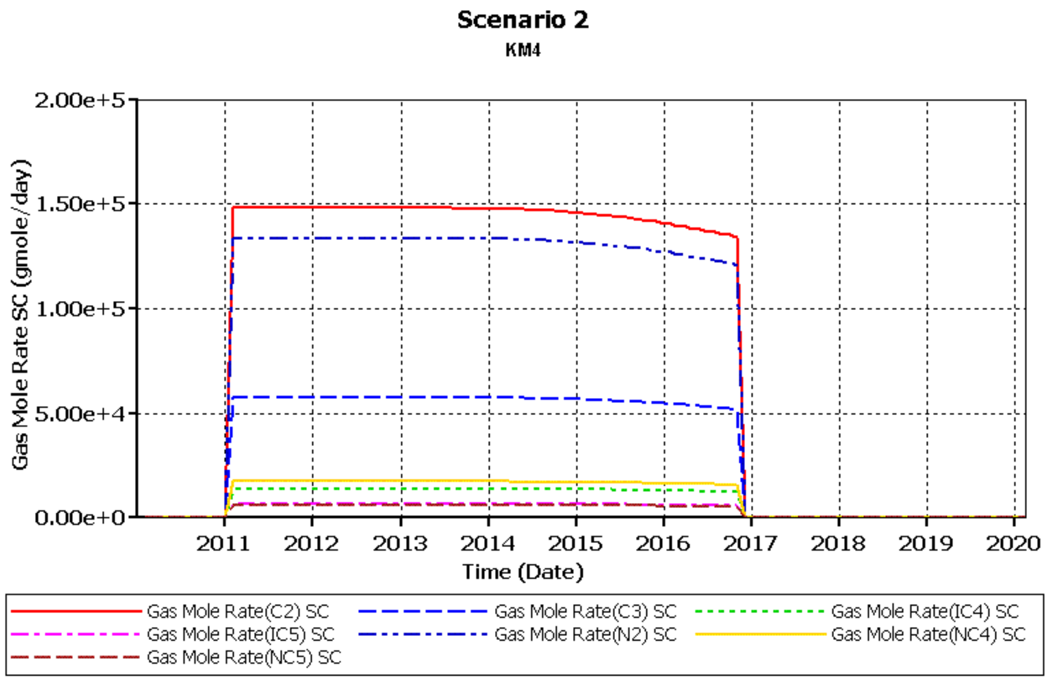

Figure 81 Scenario 2, molar production rates of minor gases in KM4

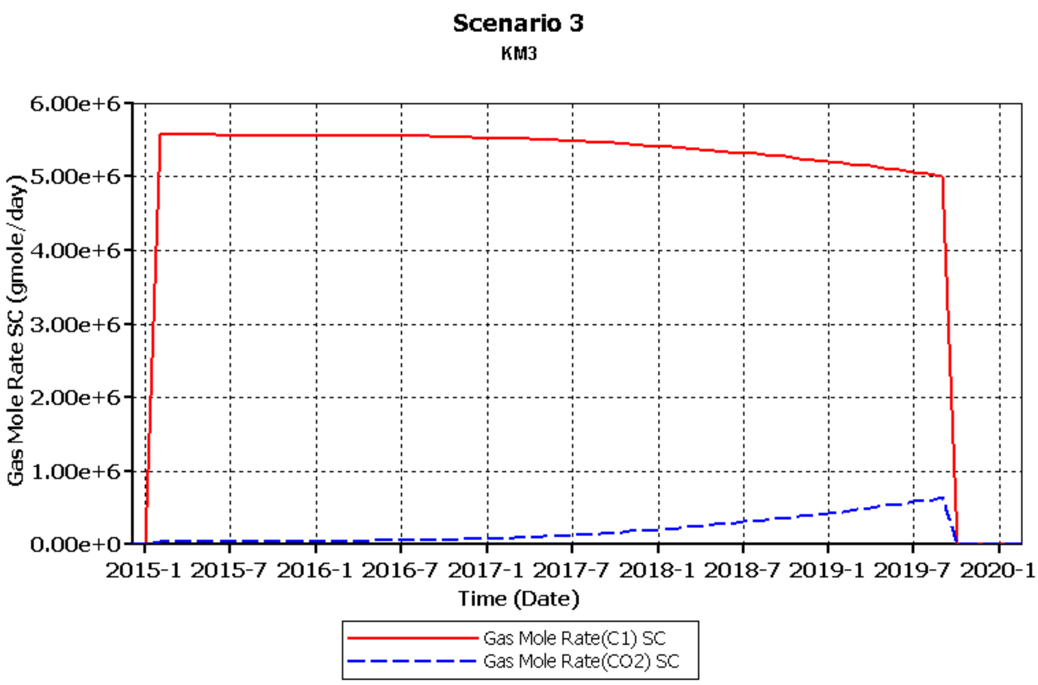

Figure 82 Scenario 3, molar production rates of CO_2 and CH_4 in KM3

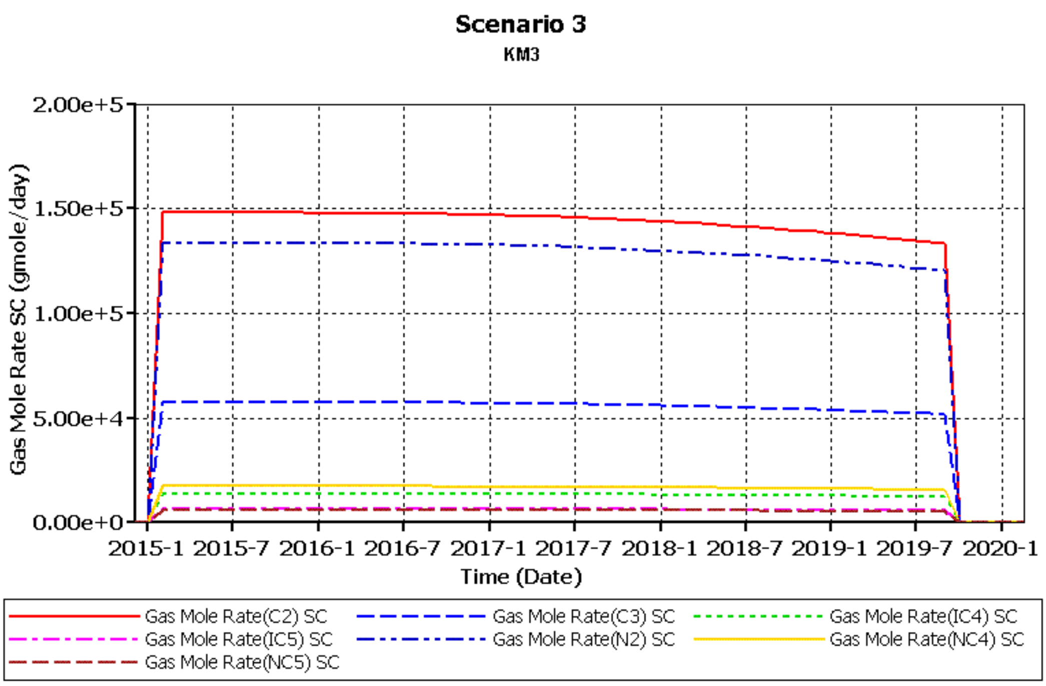

Figure 83 Scenario 3, molar production rates of minor gases in KM3

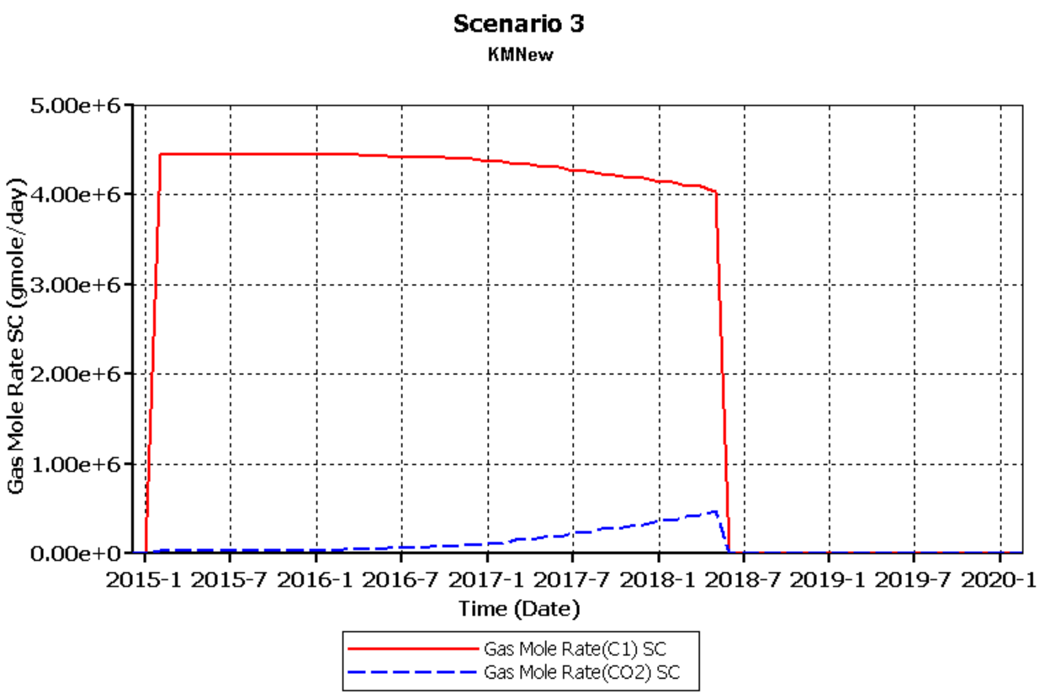

Figure 84 Scenario 3, molar production rates of CO_2 and CH_4 in KMNew

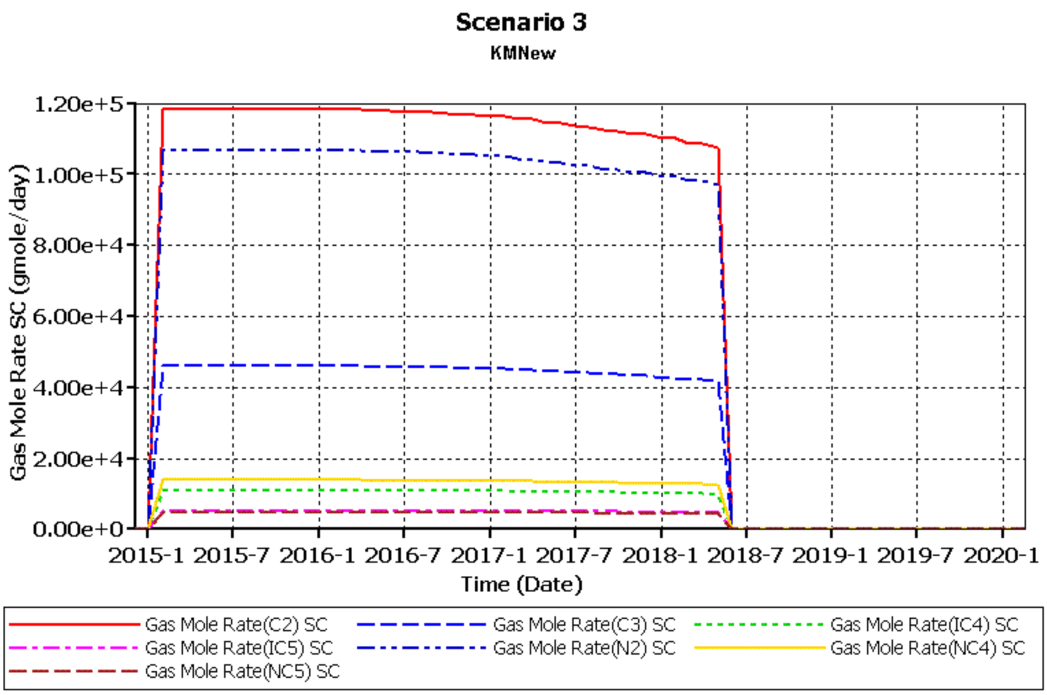

Figure 85 Scenario 3, molar production rates of minor gases in KMNew

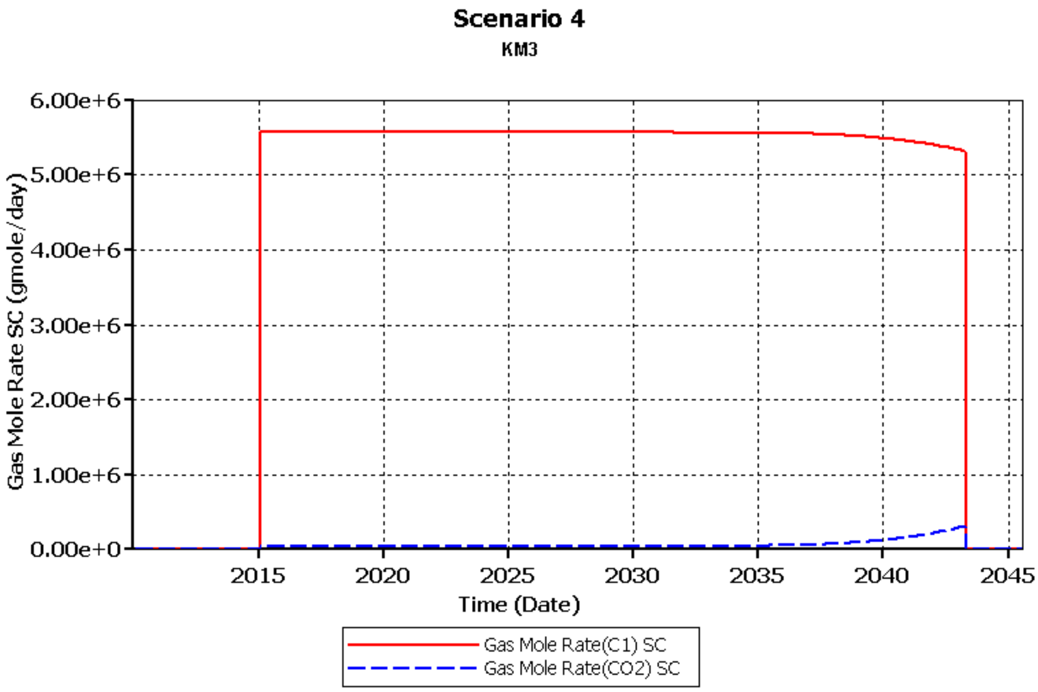

Figure 86 Scenario 4, molar production rates of CO_2 and CH_4 in KM3

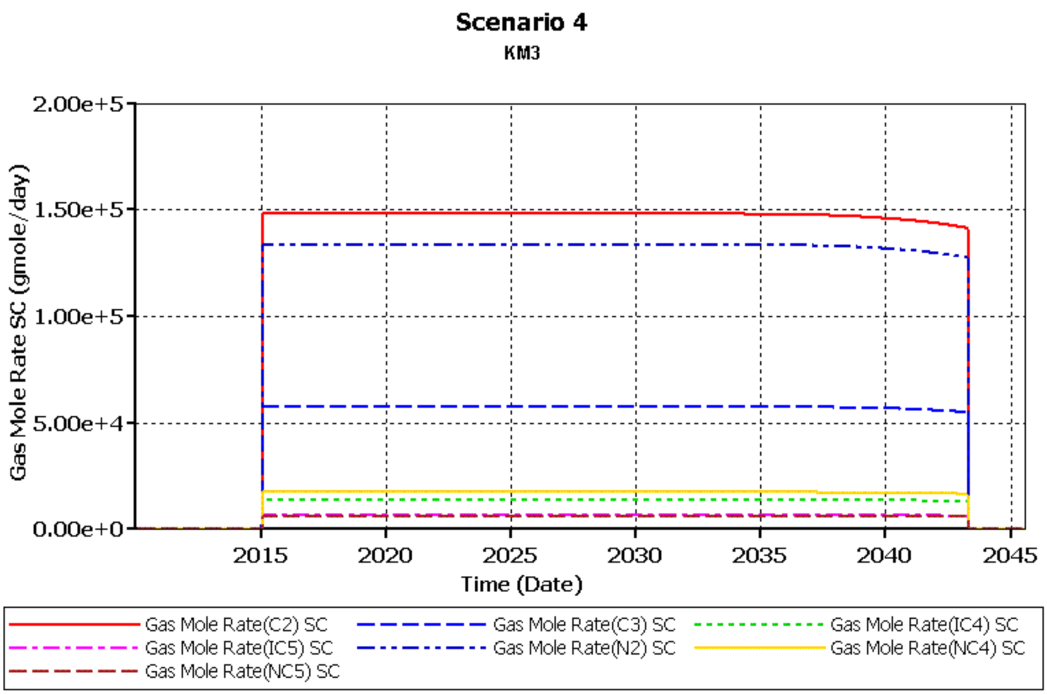

Figure 87 Scenario 4, molar production rates of minor gases in KM3

APPENDIX D

Table 36 Reservoir information of KM1-A [22]

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
1997-09-01	1 720	4 058	8 116	0	0
1997-10-01	1 690	6 538	156 912	373	0
1997-11-01	1 720	5 865	175 950	457	10
1997-12-01	1 710	6 210	192 510	540	39
1998-01-01	1 780	6 143	190 433	547	32
1998-02-01	1 710	6 085	170 380	451	26
1998-03-01	1 680	7 298	175 152	466	19
1998-04-01	1 680	7 577	219 733	673	16
1998-05-01	1 690	7 106	220 286	664	6
1998-06-01	1 630	9 379	281 370	748	101
1998-07-01	1 610	9 907	307 117	760	122
1998-08-01	1 640	7 965	246 915	621	96
1998-09-01	1 520	10 801	324 030	829	123
1998-10-01	1 520	11 644	337 676	817	125
1998-11-01	1 480	11 353	340 590	731	139
1998-12-01	1 460	11 822	366 482	810	164
1999-01-01	1 480	11 175	346 425	909	163
1999-02-01	1 440	11 521	322 588	813	151
1999-03-01	1 440	11 425	354 175	881	157
1999-04-01	1 440	10 859	325 770	682	145
1999-05-01	1 430	11 044	342 364	724	154
1999-06-01	1 420	10 839	325 170	666	144
1999-07-01	1 390	10 845	325 350	609	145
1999-08-01	1 420	10 151	314 681	606	138
1999-09-01	1 380	10 612	318 360	671	145
1999-10-01	1 370	10 538	326 678	655	144
1999-11-01	1 340	10 677	320 310	638	144
1999-12-01	1 320	10 909	338 179	656	154
2000-01-01	1 240	11 360	352 160	651	159
2000-02-01	1 250	11 633	337 357	624	152
2000-03-01	1 200	11 427	354 237	652	164
2000-04-01	1 270	10 880	326 400	622	149
2000-05-01	1 280	9 852	295 560	591	140
2000-06-01	1 290	9 623	288 690	508	129
2000-07-01	1 270	10 291	319 021	538	145
2000-08-01	1 250	10 234	317 254	517	145
2000-09-01	1 250	9 291	269 439	458	122
2000-10-01	1 310	7 246	224 626	409	102
2000-11-01	1 310	7 471	224 130	400	110
2000-12-01	1 300	6 636	205 716	344	94
2001-01-01	1 295	6 239	187 170	335	93
2001-02-01	1 205	7 140	178 500	339	97
2001-03-01	1 230	8 664	181 944	341	78
2001-04-01	1 240	7 690	130 730	259	62
2001-05-01	1 250	6 747	107 952	267	57

Table 36 continued...

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
2001-06-01	1 280	5 809	121 989	229	40
2001-07-01	1 290	5 037	90 666	174	41
2001-08-01	1 300	4 986	154 566	296	82
2001-09-01	1 285	6 025	180 750	343	91
2001-10-01	1 300	5 828	180 668	398	91
2001-11-01	1 265	5 716	171 480	329	82
2001-12-01	1 285	4 037	113 036	197	50
2002-01-01	1 290	3 897	62 352	112	31

Table 37 Reservoir information of KM3 [22]

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
1997-09-01					
1997-10-01	1 550	4410	105 840	245	0
1997-11-01	1 560	4 309	129 270	332	9
1997-12-01	1 560	4 499	139 469	388	25
1998-01-01	1 580	4 125	127 875	366	28
1998-02-01	1 578	3 624	32 616	85	1
1998-03-01	1 494	4 923	49 230	122	5
1998-04-01	1 570	4 090	122 700	372	5
1998-05-01	1 580	3 943	122 233	368	4
1998-06-01	1 550	4 846	145 380	385	46
1998-07-01	1 520	4 869	150 939	371	57
1998-08-01	1 540	4 641	143 871	363	55
1998-09-01	1 450	5 453	163 590	418	65
1998-10-01	1 420	5 736	166 344	403	62
1998-11-01	1 410	5 916	177 480	388	71
1998-12-01	1 400	6 277	194 587	429	98
1999-01-01	1 420	6 061	187 891	493	91
1999-02-01	1 380	6 049	169 372	428	86
1999-03-01	1 390	6 024	186 744	465	84
1999-04-01	1 390	5 712	171 360	363	72
1999-05-01	1 380	5 675	175 925	372	79
1999-06-01	1 370	5 531	165 930	341	78
1999-07-01	1 350	5 465	169 415	323	78
1999-08-01	1 370	5 304	164 424	320	69
1999-09-01	1 330	5 390	161 700	339	72
1999-10-01	1 320	5 548	171 988	346	80
1999-11-01	1 300	5 283	158 490	314	74
1999-12-01	1 300	5 182	160 642	312	77
2000-01-01	1 260	5 120	158 720	297	72
2000-02-01	1 200	5 099	147 871	273	59
2000-03-01	1 200	4 906	152 086	280	64
2000-04-01	1 230	4 648	139 440	267	61

Table 37 continued…

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
2000-05-01	1 240	4 006	120 180	236	59
2000-06-01	1 250	4 232	126 960	224	59
2000-07-01	1 210	4 441	137 671	234	65
2000-08-01	1 200	4 438	137 578	224	62
2000-09-01	1 210	4 127	119 683	199	56
2000-10-01	1 280	2 841	51 138	97	24
2000-11-01	1 280	3 010	69 230	123	37
2000-12-01	1 270	2 780	86 180	147	33
2001-01-01	1 285	2 291	52 693	92	24
2001-02-01	1 265	2 535	17 745	37	11
2001-03-01	1 260	3 462	93 474	175	44
2001-04-01	1 220	3 091	92 730	183	48
2001-05-01	1 175	3 532	49 448	102	22
2001-06-01	1 250	3 013	63 273	136	27
2001-07-01	1 240	2 819	39 466	75	18
2001-08-01	1 250	2 428	26 708	47	15
2001-09-01	1 250	2 592	77 760	145	37
2001-10-01	1 230	2 928	55 632	120	27
2001-11-01	1 220	2 351	37 616	65	16
2001-12-01	1 220	2 227	64 583	107	27
2002-01-01	1 210	2 535	40 560	71	18

Table 38 Production information of KM4 [22]

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
1997-09-01	1 700	4 224	8 448	0	0
1997-10-01	1 670	6 778	162 672	375	0
1997-11-01	1 690	7 371	221 130	573	12
1997-12-01	1 700	8 023	248 713	695	51
1998-01-01	1 700	6 996	216 876	628	39
1998-02-01	1 660	7 305	197 235	529	25
1998-03-01	1 650	8 472	169 440	449	17
1998-04-01	1 570	8 034	241 020	732	19
1998-05-01	1 680	7 735	239 785	722	12
1998-06-01	1 640	10 377	311 310	828	112
1998-07-01	1 610	10 868	336 908	825	127
1998-08-01	1 510	13 768	426 808	1 080	161
1998-09-01	1 510	13 064	391 920	1 005	136
1998-10-01	1 500	12 970	402 070	968	156
1998-11-01	1 500	12 297	356 613	770	152
1998-12-01	1 480	12 878	399 218	882	180
1999-01-01	1 490	11 826	366 606	961	172
1999-02-01	1 460	12 487	349 636	884	163
1999-03-01	1 450	12 128	375 968	928	163

Table 38 continued...

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
1999-04-01	1 450	11 597	347 910	728	151
1999-05-01	1 430	11 795	365 645	778	156
1999-06-01	1 420	11 665	349 950	714	153
1999-07-01	1 400	11 787	365 397	692	161
1999-08-01	1 420	10 977	340 287	655	151
1999-09-01	1 390	11 538	346 140	731	152
1999-10-01	1 370	11 463	355 353	712	158
1999-11-01	1 360	11 533	345 990	689	200
1999-12-01	1 340	11 613	360 003	679	166
2000-01-01	1 300	12 010	372 310	686	170
2000-02-01	1 270	12 367	358 643	669	170
2000-03-01	1 270	11 911	369 241	683	175
2000-04-01	1 280	11 617	348 510	667	158
2000-05-01	1 290	10 613	318 390	642	154
2000-06-01	1 280	10 706	321 180	565	143
2000-07-01	1 260	11 358	352 098	590	156
2000-08-01	1 240	11 271	349 401	568	155
2000-09-01	1 250	10 333	299 657	506	133
2000-10-01	1 290	7 830	242 730	441	113
2000-11-01	1 270	6 928	124 704	233	62
2000-12-01	1 270	7 381	228 811	384	101
2001-01-01	1 275	6 724	161 376	294	83
2001-02-01	1 150	8 014	208 364	395	113
2001-03-01	1 150	9 742	155 872	303	77
2001-04-01	1 240	7 942	206 492	413	98
2001-05-01	1 260	7 986	215 622	493	100
2001-06-01	1 270	5 704	102 672	177	55
2001-07-01	1 275	5 348	64 176	117	33
2001-08-01	1 260	6 402	134 442	268	78
2001-09-01					
2001-10-01					
2001-11-01	1 225	6 648	119 664	211	58
2001-12-01	1 200	7 406	229 586	390	101
2002-01-01	1 230	6 493	103 888	187	48

Table 39 Production information of KM5 [22]

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
1997-09-01					
1997-10-01					
1997-11-01	1 740	2 642	23 776	74	1
1997-12-01	1 740	2 579	79 946	226	23
1998-01-01	1 690	3 561	103 270	305	25
1998-02-01	1 650	3 744	97 346	264	10
1998-03-01	1 630	4 933	103 592	287	7

Table 39 continued...

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
1998-04-01	1 630	5 114	5 114	16	1
1998-05-01	1 820				
1998-06-01	1 630	5 608	140 194	381	45
1998-07-01	1 520	5 931	183 846	462	52
1998-08-01	1 570	6 102	128 151	329	38
1998-09-01	1 780				
1998-10-01	1 560	6 179	24 715	59	8
1998-11-01	1 510	7 076	212 279	461	73
1998-12-01	1 450	7 082	219 542	491	83
1999-01-01	1 460	7 165	222 115	591	88
1999-02-01	1 430	6 966	195 048	501	75
1999-03-01	1 430	7 020	217 620	539	95
1999-04-01	1 430	6 496	194 880	409	90
1999-05-01	1 420	6 449	187 021	402	85
1999-06-01	1 420	6 070	151 750	313	72
1999-07-01	1 390	6 269	194 339	365	90
1999-08-01	1 400	13 290	411 990	791	183
1999-09-01	1 370	6 056	181 680	385	86
1999-10-01	1 360	6 037	187 147	377	91
1999-11-01	1 340	6 008	180 240	360	-
1999-12-01	1 340	6 042	187 302	368	88
2000-01-01	1 290	6 237	193 347	359	87
2000-02-01	1 270	6 341	183 889	344	87
2000-03-01	1 260	6 227	193 037	357	92
2000-04-01	1 270	6 032	180 960	346	77
2000-05-01	1 280	5 290	158 700	317	71
2000-06-01	1 280	5 288	153 352	269	67
2000-07-01	1 260	5 836	180 916	308	84
2000-08-01	1 240	5 833	180 823	294	79
2000-09-01	1 240	5 514	165 420	283	75
2000-10-01	1 270	3 844	115 320	210	54
2000-11-01	1 230	4 420	132 600	241	60
2000-12-01	1 250	3 748	116 188	192	54
2001-01-01	1 260	3 408	68 160	122	34
2001-02-01	1 220	3 762	30 096	57	17
2001-03-01	1 210	5 885	129 470	231	64
2001-04-01	1 220	4 448	35 584	71	15
2001-05-01	1 270	3 702	96 252	221	45
2001-06-01	1 280	4 075	44 825	102	19
2001-07-01	1 220	4 210	54 730	100	26
2001-08-01					
2001-09-01	1 265	3 412	64 828	124	33
2001-10-01	1 260	3 564	110 484	242	53
2001-11-01	1 200	4 517	58 721	120	28
2001-12-01					
2002-01-01					

Table 40 Production information of KM6 [22]

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
1997-09-01	1 780	5 063	30 378	100	6
1997-10-01	1 780	5 027	110 594	319	23
1997-11-01	1 770	4 857	150 567	443	30
1997-12-01	1 760	4 758	123 708	344	18
1998-01-01	1 710	10 357	124 284	345	4
1998-02-01	1 820				
1998-03-01	1 820				
1998-04-01	1 650	9 295	232 375	633	70
1998-05-01	1 700	8 052	249 612	629	74
1998-06-01	1 680	8 564	265 484	685	77
1998-07-01	1 680	8 620	258 600	678	74
1998-08-01	1 670	8 571	265 701	655	75
1998-09-01	1 500	13 263	291 786	646	98
1998-10-01	1 500	13 655	423 305	949	157
1998-11-01	1 500	13 249	410 719	1 090	156
1998-12-01	1 450	13 302	372 456	955	145
1999-01-01	1 450	13 267	411 277	1 017	175
1999-02-01	1 450	13 676	410 280	857	174
1999-03-01	1 430	13 853	429 443	912	180
1999-04-01	1 430	13 743	412 290	836	177
1999-05-01	1 430	13 888	416 640	780	174
1999-06-01					
1999-07-01	1 400	13 749	412 470	865	181
1999-08-01	1 370	13 782	427 242	847	189
1999-09-01	1 350	13 941	418 230	768	-
1999-10-01	1 340	13 968	433 008	831	198
1999-11-01	1 300	14 317	443 827	808	201
1999-12-01	1 270	14 716	426 764	785	199
2000-01-01	1 260	14 551	451 081	834	213
2000-02-01	1 280	13 980	419 400	799	194
2000-03-01	1 280	12 843	385 290	785	184
2000-04-01	1 290	12 821	384 630	670	176
2000-05-01	1 270	13 599	421 569	710	193
2000-06-01	1 240	13 391	415 121	683	191
2000-07-01	1 250	12 323	369 690	628	173
2000-08-01	1 270	8 799	237 573	433	112
2000-09-01	1 200	10 944	328 320	587	161
2000-10-01	1 240	9 705	300 855	508	139
2000-11-01	1 250	9 030	243 810	434	126
2000-12-01	1 060	9 714	165 138	317	87
2001-01-01	1 400				
2001-02-01	1 215	9 354	121 602	234	59
2001-03-01	1 155	8 753	43 765	94	22
2001-04-01	1 300	6 746	74 206	147	26
2001-05-01	1 300	7 731	239 661	444	119
2001-06-01	1 295	6 662	206 522	399	113
2001-07-01	1 300	7 560	226 800	431	114
2001-08-01	1 300	7 734	239 754	526	127
2001-09-01	1 275	7 160	214 800	415	107

Table 40 continued…

Time (Date)	Wellhead Pressure (psi)	Production Rate (Mscfd)	Gas Production (bbl)	Condensate Production (bbl)	Water Production (bbl)
2001-10-01	1 270	6 542	202 802	345	92
2001-11-01	1 260	7 171	150 591	258	56
2001-12-01	1 780	5 063	30 378	100	6
2002-01-01	1 780	5 027	110 594	319	23

APPENDIX E

```
**----------------------------------------------------------------**
** GMGRO002.DAT:  WAG Process Model.  5th SPE Problem.  Corner Point  **
**----------------------------------------------------------------**
**----------------------------------------------------------------**
**                                                    **
** FILE:  GMGRO002.DAT                                      **
**                                                    **
** MODEL: CORNER POINT GRIDS       INTERFACIAL TENSION DEPENDENT KR'S **
**        6 COMPONENTS            PRIMARY FOLLOWED BY WAG PROCESS    **
**        SPE5 COMPOSITIONAL RUN   USER SPECIFIED INITIALIZATION      **
**        FIELD UNITS             5TH SPE COMPARATIVE PROBLEM        **
**                                                    **
**----------------------------------------------------------------**
**                                                    **
** This template is based on the SPE 5 problem.  It models primary    **
** production and a WAG process.  User specified initial conditions   **
** and interfacial tension effects on relative permeability curves    **
** are modelled.  This problem is a base case for Corner point        **
** comparisons.                                             **
**                                                    **
**----------------------------------------------------------------**
** CONTACT CMG at (403)531-1300 or support@cmgl.ca                   **
**----------------------------------------------------------------**
*RESULTS *SIMULATOR *GEM
*FILENAMES *OUTPUT *SRFOUT *RESTARTOUT  *INDEXOUT *MAINRESULTSOUT

*TITLE1 'SPE5 :  SPE5 COMPOSITIONAL RUN 1'
*TITLE2 'Corner Point Grid'
*INUNIT  *FIELD

*WSRF *GRID *TIME
*WSRF *WELL 1
```

```
*OUTSRF *GRID *SO *SW *SG *PRES
*OUTSRF *WELL *PAVG
*OUTPRN *GRID *PRES *SO *SG *SW *SIG


**-----------------------------------------------------------------------**
** Reservoir Description Section
**-----------------------------------------------------------------------**

*GRID *CART 10 10  3

*DI *CON  1000.0
*DJ *CON  1000.0
*DK *KVAR 50.0 30.0 20.0
*DEPTH 1 1 1 8400.0

*POR *CON 0.3

*CPOR   5.0E-6
*PRPOR  3990.30

*PERMI *KVAR  200.0   50.0  500.0
*PERMJ *KVAR  200.0   50.0  500.0
*PERMK *KVAR   20.0   40.0   60.0

**--------------------------------------------------FLUID COMPONENT DATA
*MODEL *PR
*NC 6 6
*TRES  160.0
*PHASEID *DEN
*HCFLAG      0        0        0        0        0        0
*PCRIT    45.44     41.94     29.73     20.69     13.61     11.02
*VCRIT 0.099800  0.200500  0.369800  0.629700    1.0423    1.3412
*TCRIT    190.6     369.8     507.4     617.7     705.6     766.7
*AC     0.0130    0.1524    0.3007    0.4885    0.6500    0.8500
*MW      16.04     44.10     86.18    142.29    206.00    282.00
```

```
*COMPNAME 'C1'     'C3'     'C6'    'C10'    'C15'    'C20'
*BIN        0.
          2*0.
          3*0.
          0.05    0.005     2*0.
          0.05    0.005     3*0.
*RHOW   1571.10
*CW     3.3E-06
*REFPW  14.6960
*VISW   0.70
**-------------------------------------------------ROCK FLUID----------
*ROCKFLUID
*SIGMA     0.1   1.0   0.00001
*RPT
*SGT
      0.0       0.0   1.00000       0.0
 0.0500000       0.0 0.8800000       0.0
 0.0889000 0.0010000 0.7023000       0.0
 0.1778000 0.0100000 0.4705000       0.0
 0.2667000 0.0300000 0.2963000 0.0010000
 0.3556000 0.0500000 0.1715000 0.0100000
 0.4444000 0.1000000 0.0878000 0.0300000
 0.5333000 0.2000000 0.0370000 0.8000000
 0.6222000 0.3500000 0.0110000 3.0000000
 0.6500000 0.3900000       0.0   4.00000
 0.7111000 0.5600000       0.0   8.00000
 0.8000000   1.00000       0.0  30.00000
*SWT
 0.2000000       0.0   1.00000  45.00000
 0.2899000 0.0022000 0.6769000  19.03000
 0.3778000 0.0180000 0.4153000  10.07000
 0.4667000 0.0607000 0.2178000   4.90000
 0.5556000 0.1438000 0.0835000   1.80000
 0.6444000 0.2809000 0.0123000 0.5000000
 0.7000000 0.4089000       0.0 0.0500000
 0.7333000 0.4855000       0.0 0.0100000
```

```
 0.8222000 0.7709000       0.0       0.0
 0.9111000   1.00000       0.0       0.0
   1.00000   1.00000       0.0       0.0
**---------------------------------------------------INITIAL CONDITION---
*INITIAL
*VERTICAL *OFF
*PRES *KVAR 4000.0  3990.3  3984.3
*SW   *CON     0.2
*ZGLOBAL  *CON
 0.50  0.03  0.07  0.20  0.15  0.05
**---------------------------------------------------NUMERICAL-----------
*NUMERICAL
*NORM  *PRESS  1000.0
*NORM  *SATUR  0.15
*NORM  *GMOLAR 0.15
**---------------------------------------------------WELL DATA-----------
*RUN
*DATE  1986 1 1
  *DTMAX  125.0
  *DTMIN    0.1
  *DTWELL   1.0
  *AIMWELL *WELLN
  *WELL 1 'PROD'
  *PRODUCER 1                           ** First year primary prod.
    *OPERATE *MAX *STO  12000.0
    *OPERATE *MIN *BHP   1000.0
    *MONITOR *MAX *WCUT    0.833 *STOP
    *MONITOR *MAX *GOR  10000.0  *STOP

  *GEOMETRY *K  0.25  0.34  1.0  0.0
    *PERF *GEO 1
    10 10 1  1.0

*DATE 1987 1 1
  *AIMSET  *CON 0
  *AIMWELL *WELLN                       ** Second year primary prod.
```

```
*DATE 1988 1 1
  *DTWELL 2.0
  *AIMSET  *CON 0
  *AIMWELL *WELLN
  *WELL 2 'INJ-H2O'
  *INJECTOR 2
    *INCOMP  *WATER                    ** Water injection
    *OPERATE *MAX *STW 12000.0           ** WAG of 1 year cycle

    *PERF *GEO 2
    1 1 3 1.0

  *WELL 3 'INJ-GAS'
  *INJECTOR 3
    *INCOMP *SOLVENT  0.77  0.20  0.03  0.0  0.0  0.0
    *OPERATE *MAX *STG 1.20E+7

    *PERF *GEO 3
    1 1 3 1.0

  *SHUTIN 3

*DATE 1989 1 1
  *DTWELL 5.0
  *SHUTIN 2
  *OPEN   3                        ** Solvent injection
*DATE 1990 1 1
  *SHUTIN 3
  *OPEN   2
*DATE 1991 1 1
*STOP
```