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Assessment Strategic Plans Through the Influence of Associated Gas and Produced Water on Reservoir Performance, Environment Management and Economic Indicators for Giant Fractured Reservoir

A Dissertation

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Submitted By:
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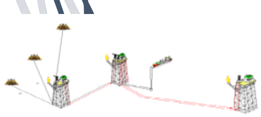

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Dedication:

To my Great parents and my wonderful family

Biography:

Over Three decades of a diverse technical and supervisory experience in reservoir engineering in the oil industry, the Experience in conventional and advanced reservoir engineering and other petroleum related activities. Gained a good experience in many aspects, **including:**

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Participation abroad (Italy) and completion of some 3D reservoir dynamic models.
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- **SPE -144565** Houston, USA, July 2012 (***as author and Speaker***)
- EPC 2018 by ETAP EPC 2018 Conference-Tunisia -Oct-2018.
- 3rd world Congress on oil, Gas and Petro chemistry, Aug.24-26,2017, **Barcelona, Spain**
- EPC by ETAP EPC Conference-**Tunisia** -2006.
- 20th symposium of Malaysian Chemical Engineers, **Malaysi**a 2006

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List of Acronyms and Abbreviations

2-D	Two-Dimensional
3-D	Three-Dimensional
4-D	Four-Dimensional
ACZ	Above Confining Zone
AMA	Active Monitoring Area
AMR	Annual Monitoring Report
ASTM	American Society for Testing and Materials
Bbl	Barrel
CCS	Carbon Dioxide Capture and Geologic Sequestration
CFR	Code of Federal Regulations
CH4	Methane
CO2	Carbon Dioxide
CO2FI	Total annual CO2 mass emitted (metric tons) as equipment leaks or vented emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
CO2FP	Total annual CO2 mass emitted (metric tons) as equipment leaks or vented emissions from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.
CO3- -	Carbonate
CZ	Confining Zone
DIAL	Differential Absorption Light Detection and Ranging
DIC	Dissolved Inorganic Carbon
DOE	Department of Energy
e-GGRT	Electronic Greenhouse Gas Reporting Tool
EOS	Equation of State
EM	Electromagnetic
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency

ER	Enhanced Oil and Gas Recovery
FTIR	Fourier Transform Infrared
GHG	Greenhouse Gas
GPA	Gas Processors Association
GPS	Global Positioning System
GS	Geologic Sequestration
H2CO3	Carbonic Acid
H2S	Hydrogen Sulfide
HCO3	Bicarbonate
HCPV	Hydrocarbon Pore Volume
He	Helium
InSAR	Interferometric Synthetic Aperture Radar
IOGCC	Interstate Oil and Gas Compact Commission
IRGA	Infrared Gas Analyzer
IZ	Injection Zone
km	Kilometer
LIDAR	Light Detection and Ranging
mcf	Thousand Cubic Feet
MIT	Mechanical Integrity Testing
MMA	Maximum Monitoring Area
MRV	Monitoring, Reporting, and Verification
NIST	National Institute of Standards and Technology
O&GJ	Oil and Gas Journal
PFC	Perfluorocarbons
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
psi	Pounds Per Square Inch
SDWA	Safe Drinking Water Act

STP	Standard Temperature and Pressure
TDL	Tunable Diode Laser
TSD	Technical Support Document
UIC	Underground Injection Control
U.S.	United States
USDW	Underground Source of Drinking Water
ZERT	Zero Emissions Research and Technology
API	American Petroleum Institute
CO2	carbon dioxide
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EISA	U.S. Energy Independence and Security Act of 2007
HCPV	hydrocarbon pore volume
MMP	minimum miscibility pressure
OOIP	original oil-in-place
ROZ	residual oil zone
TDS	total dissolved solids
TZ	transition zone
USGS	U.S. Geological Survey
WAG	water-alternating
ANN	Artificial Neural Network
A	Membrane Area or Feed Channel Cross-section
a	Membrane Width
Ak/Δx	Ratio of Membrane Porosity to Membrane Thickness
b	Channel Spacer Height
CoBR	Crude Oil-Brine-Rock
CP	Concentration Polarization
Cf	Feed Concentration

Cp	Permeate Concentration
Cc	Retentate Concentration
Cm	Concentration at the Membrane Surface
D	Hydraulic Diameter
EDS	Energy Dispersive X-Ray spectroscopy
EOR	Enhanced Oil Recovery
Eoil	Hydrocarbon Removal Efficiency
FW	Formation Water
hch	Channel Height
IR	Infrared
Jv, Js	Solvent and solute flux, respectively
k	Mass Transfer Coefficient
Lp	Pure Water Permeability
LS	Low Salinity
LSE	Low Salinity Effect
MF	Microfiltration
MWCO	Molecular Weight Cut-off
MSE	Mean Square Error
NF	Nanofiltration
NTU	Nephelometric Turbidity Unit
OOIP	Original Oil in Place
PV	Pore Volume
PW	Produced Water
PWRI	Produced Water Reinjection
Ps	Solute Permeability Coefficient
Δp	Pressure Difference
PV	Pore Volume
Qf	Feed Flow Rate

Qp	Permeate Flow Rate
Qr	Retentate Flow Rate
RO	Reverse Osmosis
Robs	Observed Rejection
rp	Pore Radius
SD	Steric Hindrance Factor for Diffusion
SF	Steric Hindrance Factor for Filtration Flow
SHP	Steric Hindrance Pore Model
SI	Spontaneous Imbibition
SK	Spiegler-Kedem Model
t	Filtration Time
TDS	Total Dissolved Solids
TFC	Thin Film Composite
UF	Ultrafiltration
v	Permeate Volume
VF	Viscous Flooding
wch	Channel Width
η	Efficiency of the pump
μ	Feed Viscosity or dynamic viscosity
πF	Feed Osmotic Pressure
$\Delta\pi$	Osmotic Pressure Difference
σ	Reflection Coefficient
υ	Cross-flow Velocity
ρ	Density of Feed Water
Ø	Flow Channel Porosity
PV	Net Present Value
POT	Pay Out Time
ROR	Rate of Return

DPIR	Discounted Profit Investment Ratio (PV/CAPEX)
2D	Two dimensional
3D	Three dimensional
CA or CAs	Competent Authority or Competent Authorities
CCS	Carbon Dioxide Capture and Storage
CO2	Carbon dioxide
CSLF	Carbon Sequestration Leadership Forum
	EU European Union
GD	Guidance Document
GHG	Greenhouse gas
IEA	International Energy Agency
P	Pressure
T	Temperature
UK	United Kingdom
USA	United States of America

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Chapter

1.0

Introduction

1.1 Abstract:

More than three decades of production in offshore Libyan field and Due to heterogeneity and fracture reservoir, the main problem in the largest offshore mature carbonate reservoir of oil field in Mediterranean Sea is **water and gas breakthrough in early production** stage which caused a well ceased to flow either due to low well head pressure or closed for gas handling surface facilities consequently this problem will have a negative impact on optimizing recovery and maximizing the oil long term production rate, however the selection of wells trajectory were selected as far as possible from gas cap and oil water contact .recently a real challenging issue was occurred : sharp increasing of GOR , with gradually water increasing, in fact this phenomena is common and is experienced after more than two decade of production . so my research will be divided in two parts/section. the first one is problem of the associated gas production: EOR / IOR of Re-Injection / Sequestration Acid Gas in Offshore Oil. Actually the volume of gas production is steadily increasing as the mature Offshore Field is depleted. In fact to meet the proper field exploitation strategies , various activities in the Offshore Field , have been planned which characterize in many projects such as , Artificial lift project, Low pressure gathering system project, infilling wells from existing platforms, Work over, de-bottle necking of the existing surface facilities, development of eastern nose of the structure by drilling some subsea wells , water injection and second phase of field development.

In spit that the gas utilization project will reduce the gas flaring, the problem of acid gas is still not completely solved , on the other hand an additional production of acid gas from phase II of Offshore Field is expected This turned to think deeply of EOR or sequestration of acid gas (*H2S and CO2, with minor traces of hydrocarbons*) .

Based on 2004 update of the 3D reservoir simulation model, the gas and oil production over the period 2004-2039, are **1102** Bscf and **443 M**stb respectively.

Acid gas is ranging in composition from 2.5% H_2S and 43 % CO_2(at stage of membrane stage)to 3.4% H_2S and 74 % CO_2 (at stage of acid gas compression) .

Hence, a strong need appears for supplementary methods to deal with the discharge problem. Three scenarios have been investigated in this study, underground sequestration of impurities of acid gas into isolated formation or re-injection in neighboring structure like D and S structure located at north of DP4 in alternative reservoir such as Metaloui ,Abiod and Zebage formation.. The most likely applicable scenario is the injection of acid gas into the oil zone of Offshore Field as an EOR project.

The various activities mentioned above will allow to increase the maximum gas production rate from 102 MMscf/d up to 131 MM scf/day consequently the utilization of associated gas is mandatory ***to***:

I- Eliminate the emission of pollutions into atmosphere, to match the international agreements of environmental protocols and possible application in EOR and as a result to maintain the reservoir pressure.

II- Preserve natural resource in terms of LPG, gas condensate recovery.

While second part will describe the problem of associated water production it will exhibited on : (disposal System of Produced formation Water associated with Risk Analysis for Environmental impact)

In fact, due to existing of a huge aquifer, the volume of produced formation water is

steadily increasing as the mature field is depleted and According to present and near future activities for the increasing the oil production in one of largest offshore fields in Mediterranean Sea by

- Artificial lift project. (ESP)
- Low pressure gathering system project.
- Infilling wells from existing platforms.
- Additional well close to the platforms (such subsea wells).
- Utilizing the new area.
- Work over for some wells.

As water production in field is increasing, the surface treatment facilities for water in platform will reach soon it's design working limit, enhancing the existing difficulties regarding the handling of production water, consequently, a strong need appears for a new method to deal with the problem either by underground disposal of water into shallow formation or by upgrading the treatment facilities in order to avoid environmental and pollution problems. As consequence to various offshore activities through two platforms, a risk assessment study is strongly recommended to overcome all the uncertainties problems could be a risky for people on platforms, facilities and environment.

the key benefit provided by risk and environmental analysis is that can summarize for decision-maker's available data about hazard and Potential effects of exposure. Besides, to find an effective and economical solution for oily wastewater treatment in shadow of employment the technique of multiple regression analysis in order to develop a reasonable mathematical model which can use for prediction purpose

In one paragraph it assists the client in identifying the critical activities and task that deemed to be reported, in prioritization of both the sub surface and surface uncertainties and development of the plan forward

1.2 Background of the Case/field:

Offshore Field is an offshore Libyan field located at 135 km NW of Tripoli (figure 1), in average water depth of 510 ft, the reservoir is an anticline 33 km long and 7 km wide, with some secondary culmination along the main axis, the average reservoir depth is 8353 ft and the area is 190 km^2, the estimated oil column exceeds 322 ft. Offshore Field was discovered and delineated by the drilling and testing of 7 appraisal wells, namely in the 70's, and another appraisal well, namely B8 in 1985 (*all the 8 appraisal wells were abandoned*). Production started on June 1988.

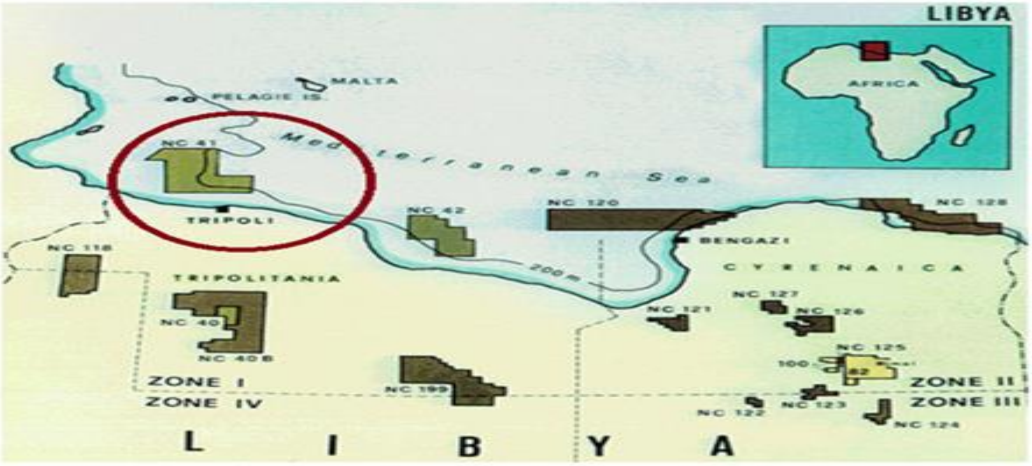


Figure 1.1: Field Location Map

The current development scheme includes two platforms with 72 oil producers drilled (*45 from DP4, 24 from DP3 and 3 subsea wells connected to DP3*); 69 wells are completed in the Upper Nummulitic Mbr., 2 subsea wells are completed in the

Dolomitic Mbr. of the Metlaoui Gr and H4-20 inside Melqart Fmt for future water disposal.

The avg. production parameters over the period September 2004- March 2005 were as follows: Qo=59,100 bopd, GOR=1,720 Scf/stb, WC=21 %. The cumulative oil production up to the 31st March 2005 was 209.130 MMstb, At the same date, the avg. reservoir pressure, based on the latest SGS, new well results and the ongoing 3D Model Reservoir update, was estimated as 3,421 psia. These results indicate a pressure lower than the initial value (*3,720 psia*), only 6 psia lower than the value of March 2004 (*3,412 psia*) and 56 psi higher than the saturation pressure (*3,350 psia*).
Gas production has been limited at the beginning of August 2004 and cut by nearly 34%. Overall oil production has been at same time decreased by 12%.
In fact the huge aquifer connected to the Offshore Field southern flank was sustaining the reservoir pressure also before the reduction resulting in a negligible pressure decline in the last 4 years of less than 10 psi/year.

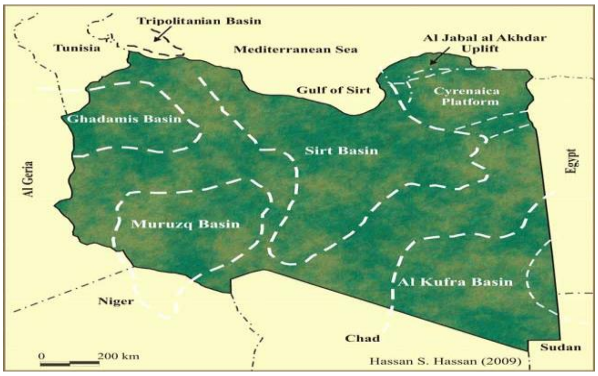
1.3 Field Discovery and Development

1.3-1 <u>Reservoir characteristics</u>

The reservoir consists of Eocenic fossiliferous lime stone (Metaloui Group) with macro and microfractures that was deposited on a shallow carbonaceous platform superimposed on EL haria shales, after middle Eocen marine regerssion with emersion and erosion of the upper part, it was covered by a uniform sequence of deep rgillaceous deposits(source formation) which act as a cap rock.
The average porosity is 15 % .The Metloui group has been subdivided as follows : Nummalatic member,Dolomatic member and micrtic member
The field is a saturated-oil bearing structure characterized by a highly faulted anticline oriented along the E-W direction .Consequently, an extensive fracture network exists across the field playing an important role in reservoir fluid dynamics. With fair petrophysical properties, fractures and non-sealing faults form the basis behind a uniform

pressure regime that exists throughout the field and in different geologic layers, while also being responsible for sudden gas and/or water breakthroughs in producer wells. The reservoir consists of carbonate and dolomitic sediments, and can be subdivided into 4 main member formations : - Upper Nummulitic Member (El Garia Formation) - Lower Nummulitic Member (El Garia Formation) - Dolomitic Member (Jarani Formation) - Micritic Member (Chouabin Formation) .

The nummulatic members account for bout 85 % of the reserve The remaining 15 % being proved by dolomitic members. (this section is *illustrated graphically in figure 1.2*)



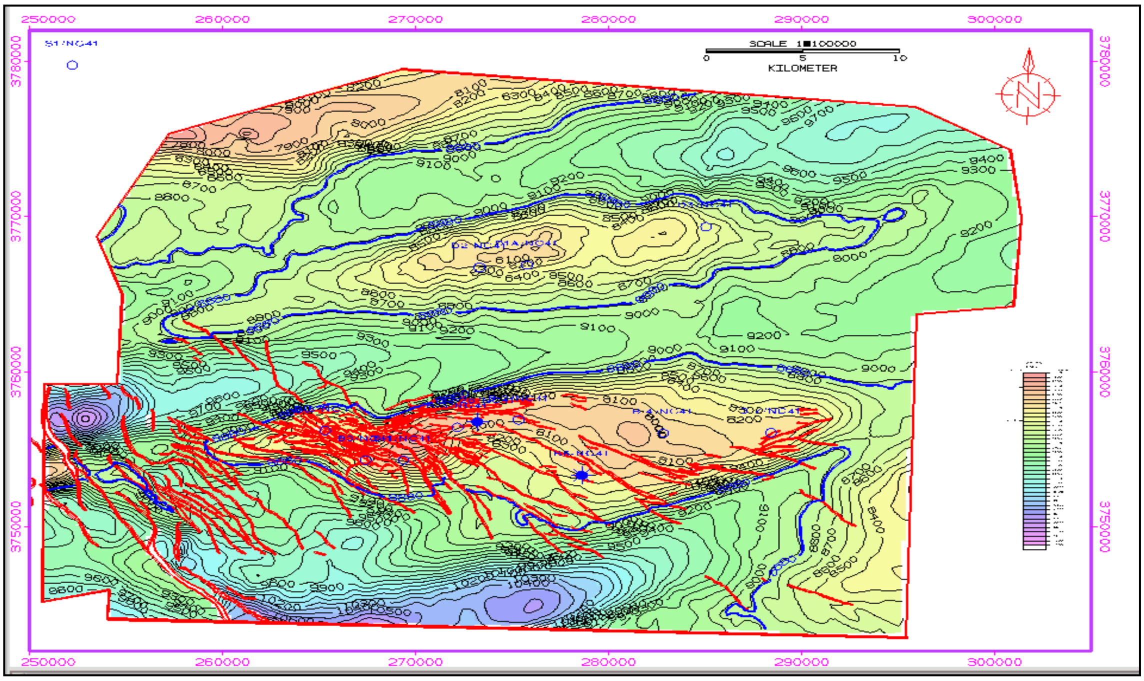


Figure 1.2: Geological Structure Map

1.3-2 Exploration phase:

The exploration phase took nine years (1977-1985), 8 appraisal wells were drilled along the main axis of the structure. All 8 wells were cored, tested and finally abandoned. The main oil-bearing formations are named "Nummulatic member " and Dolomitic member"

1.3-3 Development Phase I

Phase I was completed in four years (1988-1992) , two platforms were built and more than 55 development wells were drilled and put on stream with single completion (tubing 3.5 inch) *as given in figure 3*

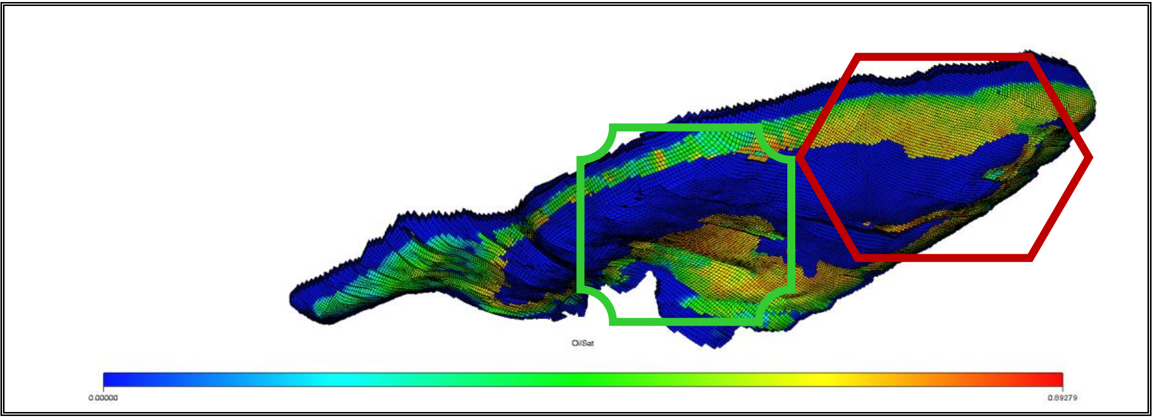


Figure 1.3: Field Development Phase

The following actions have been taken:

- Extended reach wells were drilled to reach Favorable producing zones outside gas-cap
- Horizontal wells were drilled for reducing gas production and increasing oil rate below the gas cap in the upper nummulatic.
- sub-sea wells were completed in the Dolomitic member,

1.3-4 Development Phase II:

Phase II development consists of expanding field development to the Western area including the Dolomitic layers and to the Northern flank not reachable from DP3. The recommended well scenario includes 19 oil producers, 12 in Metlaoui, and 7 in Dolomitic formations and 5 water injectors.

1.3-5 Future plans:

- ✓ De-bottlenecking of existing surface facilities: the oil production is constrained by the water and gas productions. This project will allow increasing the maximum gas production rate from the current 102 MM scf/D to 130 MMscf/Day.
- ✓ Slot recovery campaign on DP3 has been finalized in 2005 (three wells).
- ✓ East Area Development: Development of the eastern nose of the structure through the drilling of four sub-sea wells. Start up production is foreseen for January 2006.
- ✓ Water Injection: maximum water treatment capacity will be raised to 30'000 bwpd and the produced water will be re-injected into the reservoir through well H4-25. The test phase of this project is foreseen for April 2007. The WI project design foresees:

- Increase water treatment capacity to 30 Mbwpd
- Deepening & completing H4-25 as a water injector
- Connect disposal well H4-20 completed inside Melqart Fmt for back-up
- Water handling system should be flexible:
- Choice between disposal (in Melqart or Sea) or re-injection in the reservoir should always be possible
- After 2 years of field and well performance monitoring, the opportunity of adding another injector in the Northern flank of the structure to be evaluated.

Recovery of associated gas: This project considers the possibility to recover the produced gas through the re injection or flaring of the separated gas impurities and the export to the nearby “C” Structure of the sweet gas.

Based upon the results of the 2001 3D Reservoir Study, the artificial lift project on DP4 platform was suspended due to the negligible contribution to oil recovery when implemented in conjunction with the low pressure facilities. Economics for artificial lift should be re-run based on the new oil prices, and to the fact that, the existing LP system on DP-4 (manifold and treatment plant) is under-dimensioned. On Dp-3, a pilot test of electric submersible pump (E.S.P.)

Taking into consideration the following schedule of the planned projects:

- Three new wells from slot recovery (1st Quarter 2005), EAD & De Bottlenecking (4th Quarter 2005) and Water Re-Injection (2nd Qrt 2007)
- Phase II: 25 wells + 6 water injectors (start 2010)

1.4 Statement of the Problem:

As matter of fact, there are two major problems face the reservoir, surface facilities well as the environment concern, the first one: During the long production period of mature field it was clear that the volume of gas production is steadily increasing as well as high water cut increasing sharply as the field depleted. in fact, to meet the proper field exploration strategies, various activities in the field, have been planned which characterize in many projects such as, Artificial lift project, Low pressure gathering system project, Infilling wells from existing platforms, Work over, de-bottlenking of the existing surface facilities. development of eastern nose of the structure by drilling some sub- wells, water injection and second phase of development field. (figure *1.4*)

The various activities mentioned above will allow to increase the maximum gas production rate from 100 MMscf/d up to 136 MM scf/day consequently the recovery of associated gas is ***mandatory to:***
Eliminate the emission of pollutions into atmosphere, to match the international agreement of environmental protocols.
Improve preserve natural resource in terms of LPG, gas condensate which believe that has an economic viability in terms of returns from product sale. Increase oil recovery and Maintain reservoir pressure.
In the same track, as water production in field is increasing, the surface treatment facilities for water in platform will reach soon it’s design working limit, enhancing the existing difficulties regarding the handling of production water, consequently, a strong need appears for a new method to deal with the problem either by underground disposal of water into shallow formation or by upgrading the treatment facilities in order to avoid environmental and pollution problems.

It will be discussed under the subject of Water disposal & environmental Impact though this thesis.

The volume of produced formation water is steadily increasing as the mature Offshore Field (one of the largest Libyan offshore oil fields) is depleted. Additional volumes will be presented by near future activities for improving oil recovery by Artificial lift project, Low pressure gathering system project, Infilling wells from existing platforms, Work over for some wells and second phase of development field.

Hence, a strong need appears for supplementary methods to deal with the discharge problem. two scenarios have been investigated in this study, underground disposal of water into isolated formation and/or by upgrading the treatment facilities. The former meets the field requirements, because the surface treatment facilities for water in platform will reach soon its design working limit. As outcome to various offshore activities through two platforms, a risk assessment study is strongly recommended to overcome all the uncertainties problems, which could be a risky for people on platforms, facilities and environment.

The key benefit provided by risk and environmental analysis is that can summarize for decision-makers integrating available data about hazard and Potential effects of exposure. Revealing an effective and economical solution for oily wastewater treatment in shadow of employing the technique of multiple regression analysis functioning, and to develop a reasonable mathematical model which can used for prediction purposes.

The risk analysis can assist the client in identifying the critical activities and task that deemed to be reported, in prioritization of both the sub surface and surface uncertainties and development of the plan forward.

As consequence of risk analysis it was observed that the produced formation water discharge into the sea present a very law environmental risk ,due to high dilution rates this has brought the average concentration of oil in the water below the limit of international regulation for produced formation water.aw environmental risk ,due to high dilution rates this has brought the average concentration of oil in the water below the limit of international regulation for produce]d formation water.

Figure 1.4: Block-Field & Prospects sketch map with the Study Area

Offshore Field was discovered and delineated by the drilling and testing of seven appraisal wells, namely H1-H2-H3-H4-H5-H6-H7, in the 70's, and another appraisal well, namely H8 in 1985 (*all the 8 appraisal wells were abandoned*). Production started on June 1988.

The current development scheme includes two platforms (*DP3 and DP4*) with 72 oil producers drilled (*45 from DP4, 24 from DP3 and 3 subsea wells connected to DP3*); 69

wells are completed in the Upper Nummulitic Mbr., 2 subsea wells are completed in the Dolomitic Mbr. of the Metlaoui Gr and H4-20 inside Melqart Fmt for future water disposal.

The well status at the end of March 2005 is as follows: 45 wells are flowing (*31 from DP4, 13 from DP3*), 21 wells are shut-in for high WC and low wellhead pressure or high GOR (*10 on DP4, 11 on DP3*) and 6 wells are abandoned (Slot recovery Project).

The current production contribution through Low Pressure facilities installed on DP4 (wells H4-04/26/30/34/35/37) is about 4205 Bopd. Wells H4-16 and H4-21 have been re-routed to 1st stage separator due the insufficient capacity of the LP-header.

According to well H4-44, a new G.O.C. has been found at 8139 ft , 16 feet higher than in well H4-51 and 33 ft higher than OGOC.

The avg. production parameters over the period September 2004- March 2005 were as follows: Qo=58,600 bopd, GOR=1,800 Scf/stb, WC=22.5 %. At the same date, the avg. reservoir pressure, based on the latest SGS, new well results and the ongoing 3D Model Reservoir update, was estimated as 3,406 psia. These results indicate a pressure 300 psia lower than the initial value (*3,730 psia*).

Gas production has been limited at the beginning of August 2004 and cut by nearly 30%. Overall oil production has been at same time decreased by 12%.

In fact the huge aquifer connected to the Offshore Field southern flank was sustaining the reservoir pressure also before the reduction resulting in a negligible pressure decline in the last 4 years of less than 11 psi/year.

Oil production is currently limited by gas treatment capacity.

When evaluating the different approaches (reference case & development case), the feasibility and effectiveness of different approaches has to be assessed. the following important points should be taken into consideration:

- The areal fracturing degree is generally affecting individual well productivity, production behavior and areal recovery factors more than absolute values of primary porosity and permeability.

- Actual field recovery factor is low due to:
  - The presence of a gas cap;
  - Generally, absence of vertical barriers;
  - Unfavorable oil mobility with respect to water.
- Phase II Development area is fully connected to the reservoir in production since 1988 (wells of DP3 and DP4) and the only static pressure data for Phase II area after production start-up are the RFT measurements of the wells H3-21 (May 1995) and H3-26 (Mar 1996).

Chapter

2.0

Literature Review

2.0 Acid Gas Streams:

Acid gas streams, consisting primarily of hydrogen sulfide (H_2S) and carbon dioxide (CO_2), are commonly generated as a by-product of the gas sweetening process used to bring produced gases and solution gases up to pipeline specifications for sales and transport. In the past, the conventional methods for acid gas disposal are to use a Claus process or to flare the acid gas. A new technology called acid gas reinjection has emerged over the past ten years in Canada as an effective way of ensuring that acid gases are not emitted into the atmosphere. There are 38 acid gas reinjection projects presently operating in Alberta. This technology involves compressing the acid gas and injecting it into a suitable underground zone, similar to deep well disposal of produced water. Essentially, the sulfur compounds and CO_2 are permanently stored in the deep geological formation preventing their release to the atmosphere. Therefore, most acid gas reinjection projects can be considered as existing examples of CO_2 geological storage projects. These projects provide important practical experience with CO_2 storage. In addition, this technology could be extended to capture a significant fraction of the natural gas-associated CO_2 stream at low cost.

<u>2.1 Acid Gas re-injection:</u>

Raw natural gas may contain significant impurities, with CO_2, H_2S, and N_2 being the most important. "Sour gas" by definition is natural gas that contains H_2S. In order to meet sales gas contract specification, sour gas must be treated for the removal of virtually all of the H_2S. For very low H_2S content (ppm level), disposable chemical such as SulfaTreat may be used to remove the sulfur. For higher H_2S content, a chemical absorption process with amine may be used. Typically, the amine absorption method captures most of the CO_2 in addition to the H_2S. The resulting CO_2 + H_2S (acid gas) must then be processed to eliminate the H_2S. The least cost method to eliminate H_2S is to flare the acid gas stream burning the H_2S to SO_2 and releasing the CO_2 to the atmosphere, along with the SO_2. Over recent decades, concerns for the environmental effects of sulfur emissions have eliminated flaring as an option for all except the smallest facilities. Another option is to process the acid gas in a sulfur recovery unit such as a Claus plant, which produces sulfur as a salable byproduct, but releases the CO_2 as before. In response to falling sulfur prices and increasingly stringent restrictions on residual SO_2 emissions, the industry has recently begun to abandon sulfur recovery in favor of acid gas disposal. For the largest plants, the lowest cost route may still be sulfur recovery, but for plants with lower H_2S fluxes the lowest cost option is to compress the full acid gas stream (CO_2 and H_2S) and dispose of it in a suitable geological formation (*see Figure 2.1 below*)

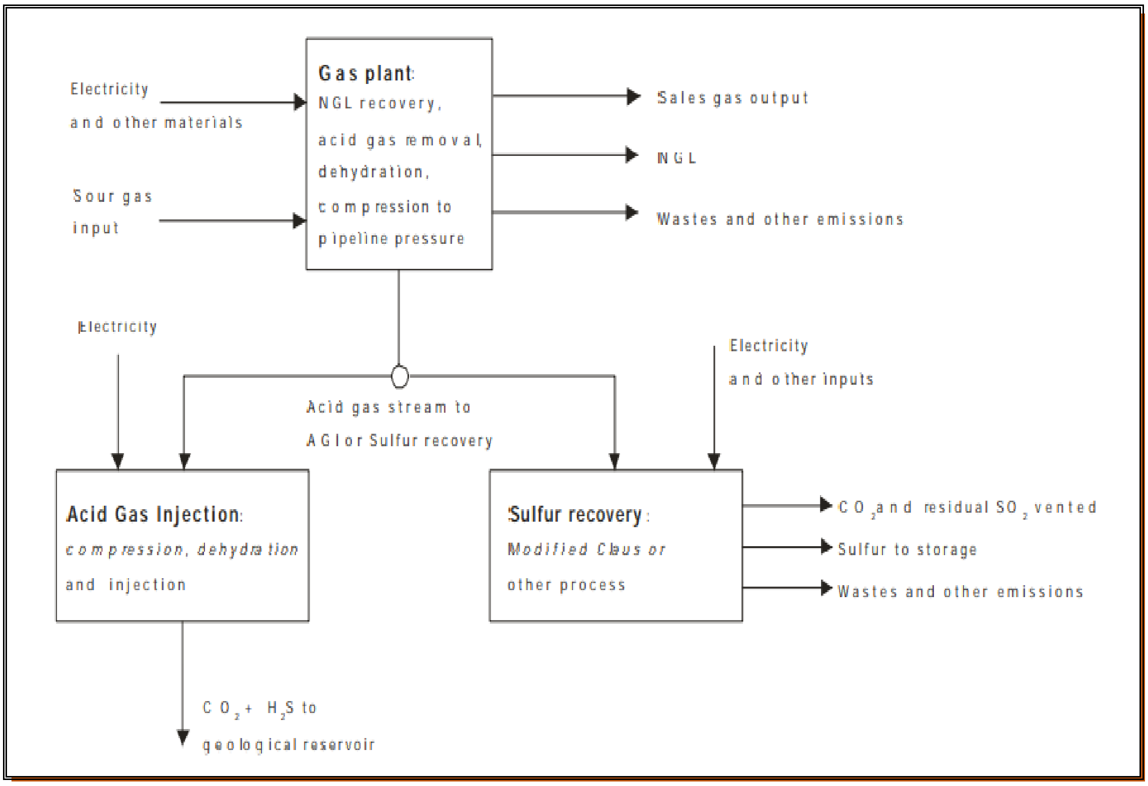


Figure 2.1: flow chart of acid gas stream

2.2 Sour Gas Reservoirs:

Sour gas reservoirs have faced critics for environmental concerns and hazards, necessitating a novel outlook to how the produced sour gases could be either utilized or carefully disposed. Over the years of research and practice, several methods of sour gas processing and utilization have been developed, from the solid storage of sulfur to reinjecting the sour gas into producing or depleted light oil reservoir for miscible flooding enhanced oil recovery. In designing a miscible gas flooding project, empirical correlations are used and the key parameter which impacts the phase behavior is identified to be the minimum miscibility pressure (MMP). A compositional simulator was utilized in this research work to study the effect of injection parameters such as minimum miscibility pressure, acid gas concentration, injection pressure and injection rate on the performance of miscible sour gas injection for enhanced oil recovery. The findings showed that methane concentration had a significant impact on the MMP of the process. Additionally, an increase in acid gas concentration decreases the MMP of the process because of an increase in gas viscosity, consequently extending the plateau period resulting in late gas breakthrough and increased overall recovery of the process

A major cause for concern in the development of sour gas reservoir is the disposal of the produced gas. The gases are usually sweetened using different methods. Amine extraction is one of the most commonly used methods in the petroleum industries. The separation process results in the production of a waste stream composing of acid gases (CO2 and

H2S) and requires a huge capital and operation cost which has raised a cause of concern, given that the companies must ensure their waste is eco-friendly before disposal.
Over the years, a lot of strategies have been developed to handle acid gas mixture, with primary concerns being the reduction of the toxic hydrogen sulfide gas to an inert/ non-toxic reactive product. The most common technique is the Claus reaction process where gases containing H2S are catalytically converted to elemental sulfur. Also, a viable alternative is the reinjection of the produced gas into the reservoir as an enhanced recovery technique or for storage. However, concerns have been raised as to possible leakages to the surfaces through faults or unsealing traps. Sour gas injection for enhance oil recovery (EOR) is a viable option that presents a solution to many problems currently in the industry. It eliminates current taxation or future liability associated with emission or surface storage of sulfur. EOR programs using gas injection have shown that sour gas has better sweep efficiency

2.2.1 CO2 Capture & storage concept :

Carbon dioxide capture and storage (CCS) in geological media has been identified as an important means for reducing anthropogenic greenhouse gas emissions currently vented to the atmosphere. Several means for geological storage of acid gas are available, such as in depleted oil and gas reservoirs, in deep saline formations,. Understanding the fate of the injected CO2 is an important aspect of the emerging CCS technology. MMV activities are critical components of geological storage locations for two key reasons. First, the public must be assured that CO2 geological storage is a safe operation. Second, markets need assurance that credits are properly assigned, traded, and accounted for. Integrated geological and hydrogeological characterization and geochemical sampling and analysis programs are technologies that can document the movement of the injected gases and detect potential leakage from the storage unit.

Through enhanced resource recovery methods, CO2 storage can provide an economic benefit. The GUP project will address the following Projects Interaction Review Team (PIRT) Gaps Analysis, which is one of the selection criteria for recognition:

- Reservoir engineering aspects – Challenges in dealing with acid gas as a miscible fluid for EOR and the ultimate sequestration of associated CO2 will be identified in the project.
- EOR lessons to be applied to other storage reservoirs – Acid gas which is increasingly being produced as deeper sour gas pools are produced, could be used for additional EOR projects, thereby increasing energy supplies from remote, dispersed, and smaller oil pools that do not justify major CO2 infrastructure.
- Depleted oil and gas fields viability – The utilization of depleted oil fields for sequestration purposes will be validated throughout the life of this project. In addition, as recovery is from carbonate pinnacle reefs, using a different strategy than in the case of reservoirs of large lateral extent, if successful, could be applied to other similar reservoirs elsewhere.

2.2.2. Source Description:

Preliminary estimates indicate that the amount of carbon dioxide (CO_2) captured from industrial processes, including combustion and chemical manufacturing, and produced from naturally occurring subsurface CO_2 reservoirs is approximately 44 million metric tons carbon dioxide equivalent .2,3 Currently more than 95 percent of this CO_2 supplied to the economy is injected underground for enhanced oil and gas recovery (ER).2 CO_2 may be injected underground for geologic sequestration (GS). GS is the long-term containment of a CO_2 stream in subsurface geologic formations and is a key component of a set of climate change mitigation technologies known as carbon dioxide capture and geologic sequestration (CCS). CCS has the potential to enable large emitters of CO_2 such as coal fired power plants to significantly reduce greenhouse gas (GHG) emissions.

2.2.3 Categories of Source:

Three sectors were considered for inclusion in this rule: injection of CO_2 underground for GS, injection of CO_2 underground for ER, and end uses of CO_2 by other industries:

- Geologic Sequestration Underground geologic formations that can be used for GS include deep saline formations, oil, and natural gas reservoirs, and unmineable coal seams. In addition, CO_2 may be injected into other types of subsurface geologic formations, such as basalt formations. The UIC program, which is authorized by Part C of the SDWA, regulates underground CO_2 injection. Geologic sequestration occurs through a combination of structural and stratigraphic trapping, residual CO_2 trapping, solubility trapping, mineral trapping, and preferential adsorption trapping. These mechanisms are functions of the physical and chemical properties of CO_2 and the geologic formations into which the CO_2 is injected. For more background information on GS trapping mechanisms, .

- **Enhanced Oil and Gas Recovery**

CO_2 is currently being injected into subsurface geologic formations in the United States (U.S.) for ER. The CO_2 currently being used in ER is primarily produced from naturally occurring underground CO_2 reservoirs but is also captured from industrial processes, including combustion and chemical manufacturing.

ER involves injecting CO_2 into oil or natural gas reservoirs via injection wells for the purposes of increasing crude oil production or to enhance recovery of natural gas. The crude oil and CO_2 mixture is produced from production wells and sent to a two-phase separator where the crude oil is separated from the gaseous hydrocarbons and CO_2. The gaseous CO_2-rich stream then is typically dehydrated, recompressed, and reinjected into the oil or natural gas reservoir to further enhance recovery. If the concentration of hydrocarbons in the CO_2 stream from the dehydrator is significant, then an acid gas recovery unit is used to separate the hydrocarbons from the CO_2.

There are currently 80 ER fields operating in the United States where CO_2 is being injected for the purposes of ER. ER projects operating in the United States range from new pilot-scale projects with one or two injection wells to CO_2 floods that commenced operation in the 1970s and that have hundreds of injection wells. Approximately 44 million metric tons of CO_2 was received for injection underground for ER in 2008. Of this amount approximately 80 percent was produced from naturally occurring underground CO_2 reservoirs and 20 percent was captured from industrial processes, including combustion and chemical manufacturing.

Natural gas processing plants and wellhead treatment units condition incoming natural gas from the wellhead to meet sales and natural gas pipeline specifications. In some fields the natural gas may contain a significant quantity of hydrogen sulfide (H_2S) or CO_2, which is separated from the natural gas by the processing plants and treatment units. Because of the highly corrosive nature of this stream, the combination of H_2S and CO_2 separated from the natural gas is called acid gas. The composition is quite variable and can range from 2 percent H_2S and 98 percent CO_2 to about 85 percent H_2S and 15 percent CO_2. 7 Most acid gas is disposed of by underground injection under a UIC Class II permit. These permits may allow for disposal of other oil and gas production wastes, including brine, well completion and work-over fluids, and spent dehydration unit fluids, in addition to the acid gas.

- Others

EPA identified and considered a total of 22 commercial end use sectors that use gaseous, liquid, or solid CO_2, excluding ER and GS.. EPA received comments to subpart PP suggesting that at least one of these end-uses – precipitated calcium carbonate production – may be a non-emissive use. At proposal for this rule, EPA sought comment on whether applications, such as precipitated calcium carbonate and some cement production, permanently sequester CO_2 and if so, which industries this would include how many facilities operate in each of these industries; how much of the CO_2 consumed in each industry would be sequestered; whether a sequestration factor would be reasonable in any case; and what methodologies could be used to verify this sequestration. These sectors were not included in this final rule.

2.2.4 Reporting Threshold Analysis:

EPA recognizes that this is likely an oversimplification of the actual volume of CO_2 received by each facility, but notes that it follows the principle that higher production is a function of higher CO_2 injection volumes. The volume of CO_2 received by a particular ER project is a function of many factors, including:

- Reservoir characteristics: Heterogeneity is a significant design consideration, along with porosity, permeability, oil gravity, production history, depth, and reservoir pressure.
- Flood design: The injection design (e.g., continuous, simultaneous water and gas, water alternating gas), and number of injector wells are major factors in overall CO_2 use. Injection well pattern, miscible or immiscible processes, CO_2 saturation target as a percent of hydrocarbon pore volume (HCPV), and use of surfactants and additives also influence CO_2 use.
- Project age: The stage of the project is a significant factor in determining CO_2 use. New CO_2 floods use more purchased CO_2 and produce less oil because the CO_2 has not fully penetrated the reservoir. It may take 6–12 months to see an increase in oil

production upon initiation of injection. As the reservoir becomes saturated with CO2, the amount of new CO2 added to the project is reduced, and the majority of the injected CO2 is recycled from producing wells.

2.3 Applying CO2 for EOR:

The study originates from a reservoir modelling simulation that evaluated the applicability of different IOR/EOR methodologies on the Armatella field, with the aim to individuate the most promising technologies and suggesting the EOR/IOR process to test in the field by a pilot project. Among the different scenarios, the CO2 injection resulted one of the most promising and has been selected for the pilot project phase, taking into account the availability of a CO2 source at high purity (> 95% vol.) from the flue gas stream of the Gela Refinery, located 15 km from the Armatella field. An important feature of this initiative is based on the integration between downstream and upstream operations. The project includes the CO2 capture from the refinery flue gas, transport and injection into the reservoir for EOR and the partial sequestration of the injected CO2. The CO2 capture achieves two goals: to increase the efficiency of oil recovery and to sequester a substantial amount of CO2 for an extended period of time. The eni initiative has a great strategic relevance and will be the first example of EOR-CO2 treatment in Italy.

2.3.1 Techniques for Oil Recovery:

During the lifetime of an oil reservoir, the oil production is typically implemented in two or, if economical, three phases. In particular through :

- ✓ *Primary recovery* techniques are usually applied in the initial production phase, exploiting the difference in pressure between the reservoir and the producing well's bottom. This "reservoir natural drive" forces the oil to flow to the well and, from then, to the surface. Pumps are employed to maintain the production once the reservoir drive diminished, due to the oil/gas extraction, and the primary recovery is, generally, completed when the reservoir pressure is too low, the production rate is no more economical and the gas-to-oil or water-to-oil ratio is too high. The oil recovered from the well during the primary stage is typically in the range 5-25% of OOIP (Originally Oil In Place), varying as a function of oil and geological characteristics and reservoir pressure.

- ✓ *Secondary Recovery* techniques are applied when primary recovery methods are no longer effective and/or economical. In secondary recovery, fluids (typically water, but other liquids or gases can also be employed) are injected into the reservoir through injection wells in order to increase/maintain the reservoir pressure, acting as "artificial drive" and then replacing the natural reservoir drive. CO2 has been tested with limited success in this context. Economic criteria are applied to conclude secondary recovery practices. The recovery factor for this kind of operations ranges from 6 to 30% of OOIP, depending on oil and reservoir characteristics.

- ✓ *Tertiary recovery* operations, also called Enhanced Oil Recovery (EOR) or Improved Oil recovery (IOR), are applied in oilfields approaching the end of their life and can produce additional oil in the range 5-15% of OOIP for light to medium oil reservoirs, lower for heavy oil reservoirs. These operations are applied in order to improve the oil flow in the reservoir, by altering its flow properties or its interaction with the rock. One of these techniques is EOR promoted by CO2 injection.

Recovery factor after primary and secondary recoveries is typically in the range 30-50%, on average between 45-55% in the North Sea fields, where 66% recovery can be reached in some fields without EOR , Nevertheless, it has recently been evaluated that approximately 2,000 billions bbls of conventional oil and 5,000 billions bbls of heavy oil would remain un-produced worldwide after conventional primary and secondary recoveries. The contribution of EOR to the oil production can, then, be enormous: a 1% increase of the recovery factor globally would involve an increase of conventional oil reserves of 70 billions barrels, not including the possible contribution from unconventional sources exploitation. The application of this technique to eni's Italian Heavy Oil Reservoirs could interest 3 to 4 billions of OOIP (almost 3 billions bbls in Sicily)

2.3.2 EOR/Tertiary Recovery Techniques

The major EOR processes include gas injection, thermal recovery, and chemical methods. The screening criteria for EOR selection are reported in Table 2.1 and Table 2.2 as a function of reservoir and crude oil characteristics**, respectively**.:

EOR Process	Reservoir Characteristics				
	Oil Saturation (% Pore Volume)	**Type of Formation**	**Permability (mD)**	**Depth (m)**	**Temperature (°C)**
Steam Flooding	> 40	High porosity and permeability sandstones	> 200	< 1,500	Not critical
In-situ Combustion	> 50	Sandstones with high porosity	> 50	< 3,833	> 60
Gel Treatment/Polymer Flooding	> 50	Sandstones preferred. Can also be used for carbonates	> 10	< 3,000	< 90
Alkali Surfactant Polymer, Alkali Flooding	> 35	Sandstones preferred	> 10	< 3,000	< 90
CO_2 Flooding	> 20	Sandstones, carbonates	Not critical if sufficient injection rate can be maintained	Appropriate to allow injection pressure > than MMP, which increases with temperature	
Hydrocarbon	> 30	Sandstones, carbonates with minimum fractures	Not critical if uniform	> 1,333	T can have significant effect on MMP
N_2, Flue Gas	> 40	Sandstones, carbonates with few fractures	Not critical	> 2,000	Not critical

. EOR screening Criteria as a function of Reservoir Characteristics

Table 2.1: E.O.R Screening

EOR Process	Crude Oil Characteristics				
	Oil Specific Gravity (°API)		Oil Viscosity (cP)		Composition
	Recommended	Current Projects	Recommended	Current Projects	
Steam Flooding	8 to 25	8 to 30	< 100,000	2 to 5,000,000	Not critical
In-situ Combustion	10 to 27	13.5 to 38	< 5,000	1.44 to 550	Asphaltic components to help coke deposition
Polymer Flooding	> 15	13 to 34	< 150	5 to 4,000	Not critical
Alkaline Surfactant Polymer, Alkaline Flooding	> 20	32 to 39	< 35	3	Organic acids needed to achieve lower IFT with alkaline methods
CO_2-Flooding	> 22 Miscible > 13 Immiscible	28-45 Miscible 11-35 Immiscible	< 10	0.35-6 Miscible 0.6-6 Immiscible	High percentage of Intermediate HC
Hydrocarbon Miscible/Immiscible	> 23	21 to 57	< 3	0.1 to 140	High percentage of Light HC
N_2 Miscible/Immiscible and Flue Gas	> 35	16 to 51	< 0.4	0.2 to 25	High percentage of Light HC

EOR screening Criteria as a function of Oil Characteristics

Table 2.2: E.O.R Screening Criteria

- Gas Injection.

These methods are based on the injection of gas (HC, N2, Flue gas, CO2) into the oil-bearing layer where, under reservoir conditions and high pressure, the gas will mix with the oil, decreasing its viscosity and displacing more oil from the reservoir. A very good oil recovery can be guaranteed if the reservoir pressure is higher than the minimum miscibility pressure (MMP) that is a function of temperature and crude oil characteristics (Ref. 3). In 2008 the EOR production through gas injection methods was around 566,000 bpd (580,000 bpd forecasted in 2010)

- **Thermal Recovery**

adds heat to the reservoir, in order to reduce the oil viscosity, through steam injection, in-situ combustion or hot water. Reservoir depth for steam applications is limited due to heat loss associated with wells. Steam Injection can be applied to shallow reservoirs (< 1,500 m) of heavy oil deposits that cannot be produced economically by primary or secondary methods, due to their very high viscosity. In-situ combustion finds application in reservoirs containing light oils (> 30 °API). In 2008 the EOR production through thermal methods was around 1,252,000 bpd (1,016,000 bpd forecasted in 2010). The thermal methods are best suited for heavy oil and tar sands reservoirs.

- **Chemical Injection**.

The addition of chemicals (e.g. polymers/surfactants) to the injected water improves the recovery efficiency, through the interfacial tension reduction or increasing solution water viscosity. This technique never had a wide diffusion and is currently declining, due to the high cost of chemicals, limitations for temperature applications, depth and oil density (15-30 °API). In 2008 the EOR production through chemical methods was quite limited (35,800 bpd).

2.4 Acid gas at Offshore field -Case study

The hydrocarbons produced from the reservoirs of the offshore fields may contain large amounts of sour gases, i.e., H2S and CO2. Their concentrations in natural gases may be as high as 20% and some percent, respectively. The Claus type installations with sulphur production rate over 5 ton of sulfur per day are used for conversion of H2S to the elementary sulfur. Recently the oversupply of sulfur on the world market and problems with sulfur disposal caused that the sulfur recovery methods became less attractive. Moreover, the discharge of H2S combustion products like SO2 and CO2 to atmosphere, which was used up to the 1980s, is nowadays unacceptable because of environmental regulations. The reinjection of acid gases produced during gas sweetening process, seems to be a promising and economically attractive alternative Up to now, the reinjection of acid gases into oil reservoirs was used to increase the recovery or maintain the reservoir pressure. The other option, which is worth considering, is disposal of acid gases into the water bearing zones. In previous projects reported in the literature the acid gases were injected into oil reservoirs, depleted gas reservoirs or water zones which had no direct hydrodynamic contact with gas horizon being produced. In the present paper the authors indicated that reinjection of acid gases into an aquifer underlying produced gas reservoir, seems to be a possible and good solution to the sour gas disposal problem. Obviously, the reservoir flow rate must be controlled to avoid excessive contamination of produced gas with H2S and CO2. The present paper shows results of computer simulation which demonstrates how the acid gas injection affects the composition of produced gas.
In the middle 1980s the two-acid gas -injection facilities started to operate in Poland.

2.4.1 Injection acid gas into oil reservoir:

The first acid gas injection facility reported here has been used for injecting gas containing H2S and CO2, the concentrations of which are about 15% and 4%, respectively. The gas released in the oil separation process is injected into oil zone of Kamień Pomorski reservoir with average rate of 250000 scum/month (*as illustrated by figure 2.2*). The previous feasibility studies indicated that sweetening of gas from oil separation process was unprofitable because of small gas production rate, very high concentration of H2S and CO2 and large distance to the potential users. Before starting the injection, the routine procedure over the past 20 years was to burn the gas; 0.3 bln of scum of gas were flared and 80 000 tons of sulfur were burned and released to atmosphere.
Analyses of reservoir parameters and results of laboratory experiments carried out using the slim tube model indicated that the oil displacement by gas was an immiscible process characterized by interactions between flowing phases. The laboratory experiments indicated that the gas pressure equal to reservoir pressure (i.e. 44.9 MPa in analyzed case) results in a higher recovery factor and initiates the miscible displacement process. For the actual reservoir pressure (equal to 19 Mpa), the oil displacement process is immiscible, and the theoretical recovery factor is 60%. Presently, the total oil recovery factor is above 40% of the geological reserves

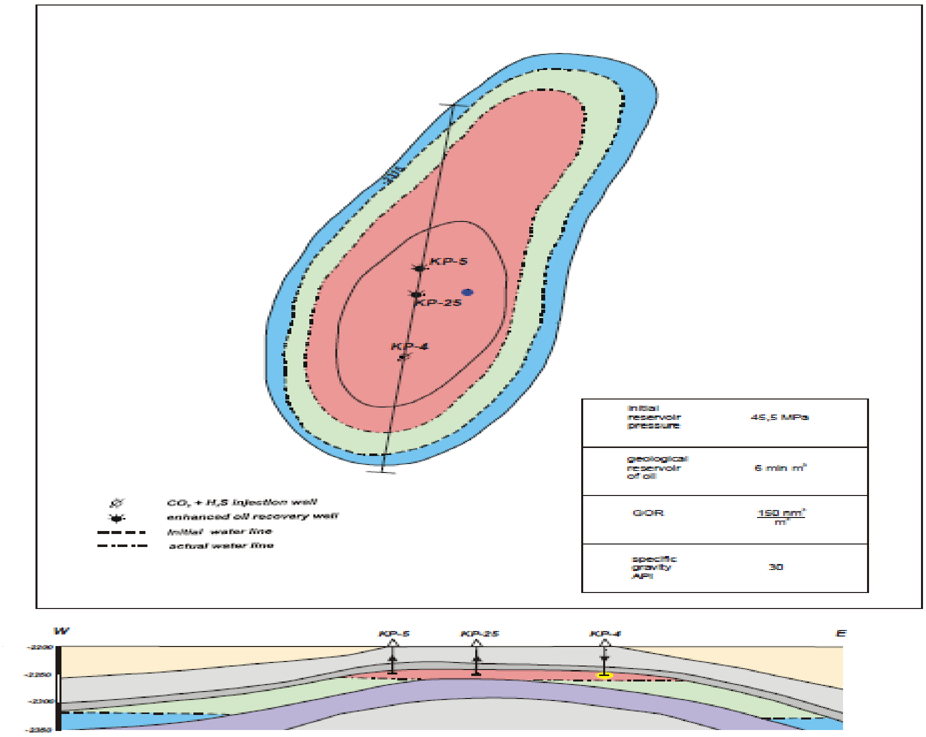


Fig.1. Kamień Pomorski oil reservoir

Figure 2.2: field Pomorski oil reservoir

2.4.2 Injection acid gas into Gas reservoir

The second facility reported here is used for reinjecting acid gases containing 60% of CO_2 and 15% of H_2S into an aquifer directly underlying the Borzęcin gasreservoir, as given in **figure 2.3** The reinjected gases are by-products of amine gas sweetening process. Such a method of acid gas disposal where the injection zone is in hydrodynamical contact with a gas-bearing reservoir has not been referenced to in the literature. In this method the injected gas dissolves in the underlying water which has a hydrodynamic contact with the gas horizon and thus may influence the composition of the produced gas. The acid gas reinjection into the Borzęcin gas horizon has been in operation since 1995, i.e. from the moment when 67% of gas (3.5 bln scum) was produced. The original gas reserves of the Borzęcin gas field were 5.2 bln of scum of gas.

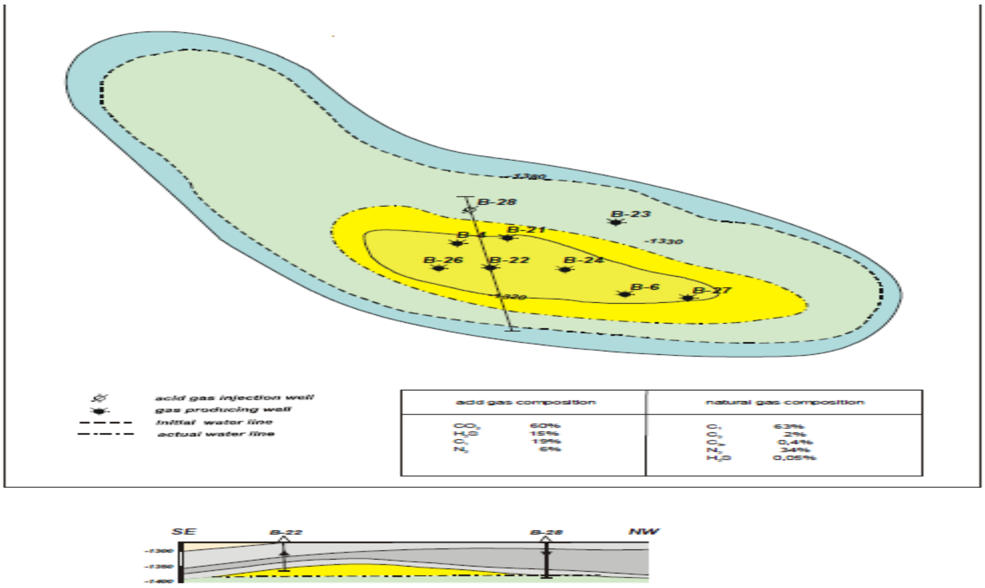


Fig.2. Borzęcin gas reservoir

Figure 2.3: Field Pomorski Gas reservoir

Before designing the for injection facility, the PVT experiments were carried out. They indicated that the upward movement of H2S and CO2 to the gas cap would be very slow owing to the high solubility of these gases in the reservoir waters, which was much higher than that of the native gas. The laboratory experiments indicated that:

- Solubility of native gas which contained 65% of hydrocarbons, 35% of nitrogen and small volumes of H2S and CO2 was 1.55 scum of gas per one cum of reservoir water at 58oC and 97 bars.
- Solubility of acid gas which contained 60% of CO2, 15% of H2S, 20% of hydrocarbons and 5% of nitrogen was 13 scum of gas per one cum of reservoir water at the same temperature and pressure as specified above; this means that it was 8.4 times greater than solubility of native gas
- Phase diagram, presented in ***Figure 2. 3*** (constructed using the computer simulation of PVT
  experiments) indicated that the gas remained in a gaseous phase at the reservoir conditions.
- Acid gas dissolvers in reservoir water preferentially displacing the originally dissolved natural gas.

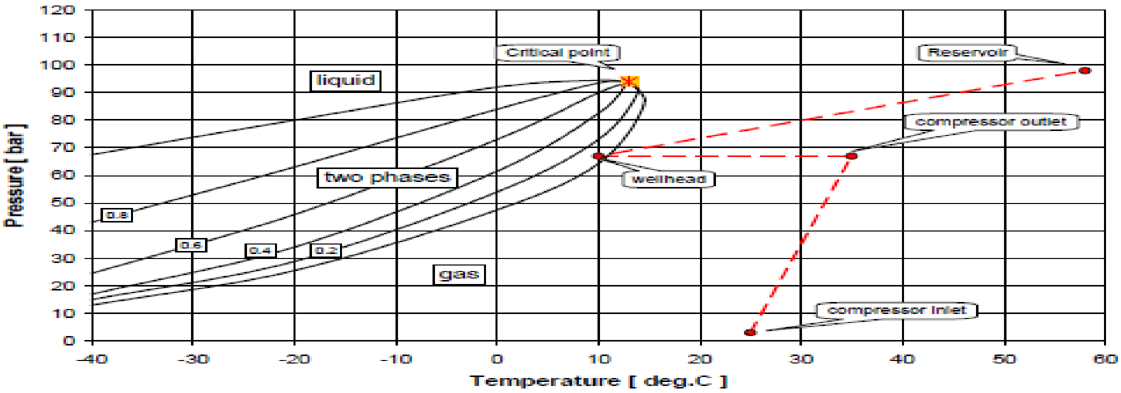


Fig.3. P-T diagram of acid gas injected into Borzęcin reservoir

Figure 2.4: P.T. diagram of AG

Displacement of the native gas which originally saturated the underlying water with acid gases injected into reservoir may increase the recoverable gas reserves. Such a displacement process enables replenishing the gas cap by volume equivalent to the methane gas dissolved in the underlying waters.
The PVT test results indicated [7] that volume of methane gas displaced from reservoir water is an increasing function of volume of CO2 injected into reservoir (illustrate in fig 4).
A considerable drop of injection pressure from 10.4 MPa to 6.6 MPa was recorded after 18 000 of scum of acid gas was injected into reservoir. This drop of injection pressure was probably caused by an increased permeability due to a chemical interaction between carbonate reservoir rocks and injected acid gas with high CO2 concentration (60%). The decrease of injection pressure and related decrease of power consumption improved the economical effectiveness of the whole project.

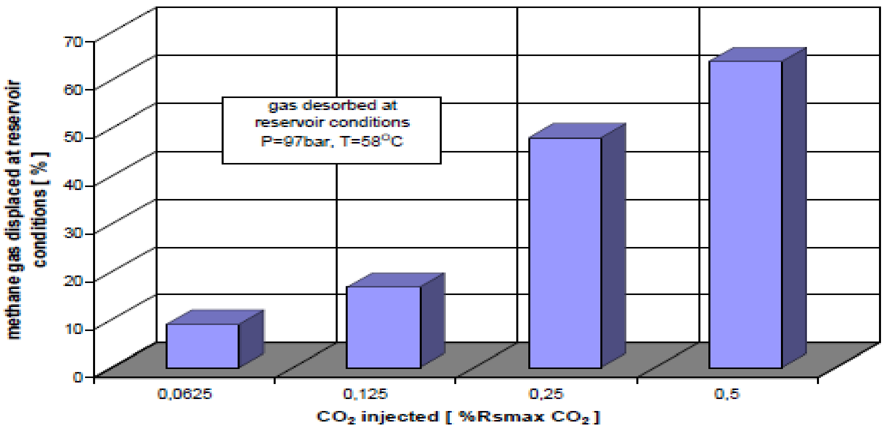


Fig. 4. Methane displacement from reservoir water by acid gas injection

Figure 2.5: Methan & Acid Gas Injction

2.4.3 Compositional Model & Results:

The computer models simulating the acid gas injection into reservoir were developed in 1995. They were used for predicting the acid gas distribution pattern and for evaluation of possible changes in the chemical composition of the produced gas. The simulation was carried out using the Eclipse 300 compositional simulator which was commercially available on the market. Eclipse 300 is based on compositional mathematical model which assumes that the phase equilibrium constants may be computed using the Peng-Robinson equation of state. The Soreide and Whitson modification was included to account for water solubility of N2, CO2 and H2S, respecting actual salinity and temperature of reservoir water.

The results of computer simulation are shown in ***figures 2.5 and 2.6.*** The predicted CO2 and H2S concentrations in produced gas are shown *in fig. 2.5* which indicates that an increase of CO2 content appears much earlier than an increase of H2S concentration. This is caused by a high CO2 content in the injected gases which is four times as large as H2S concentration. The predicted concentration of CO2 in production wells is shown in **fig.2.6** . The CO2 content was expected to increase in two wells already in 2004, i.e. after 8 years of continued injection. The CO2 concentration (and so H2S content) in the remaining wells will be on a constant level by 2010. The reduced concentration of CO2 in some wells is caused by an invasion of reservoir waters.

As shown in table 2.3 , a good agreement between predicted and measured data is observed, i.e. increase of CO2 concentration was initially observed in B4 well, followed by an increase of H2S content in the same well in 2005.

The applied technological solution and good control enable a trouble-free exploitation of injection

facilities in spite of unfavorable chemical composition of gases involved. The economical effectiveness and correct technology of acid gas injection facility were confirmed during the ten years of its exploitation. The presently available data speak in a favor of the presented method when compared with the results of the existing methods used for developing H2S containing reservoirs. Actually, the application of the acid gas reinjection technology is being considered for two other gas reservoirs and one oil reservoir in Poland.

Our experiences indicate that the acid-gas reinjection may be a safe and cheap alternative for

traditional acid-gas neutralization technology. The computer aided simulation of gas injection process allowed us to predict and optimize the process parameters including chemical composition of produced gases.

Nowadays, similar technologies are used in other countries but usually the gas is injected into isolated water zones which do not have hydrodynamic contact with reservoir being produced. The technology tested in Poland consists in injection of acid gases directly to water zone underlying the gas reservoir without inflicting the detrimental impact on quality of produced gas. Up to now 2 bln of cum of acid gases were injected into water bearing Rotliegendes formations and only a small change in the produced gas composition was observed. In one well a negligible increase of CO2 concentration observed in 2004 (See table 2.3) was followed by an increase of H2S concentration in the same well in 2005. The PVT experiments indicated that methane dissolved in reservoir water may be displaced by acid gases due to a considerable difference in solubility of these gases. A similar downhole injection technology may be also used for sequestration of CO2 or some combustion products generated by the power industry. This may open new prospects for oil companies in Poland and Europe.

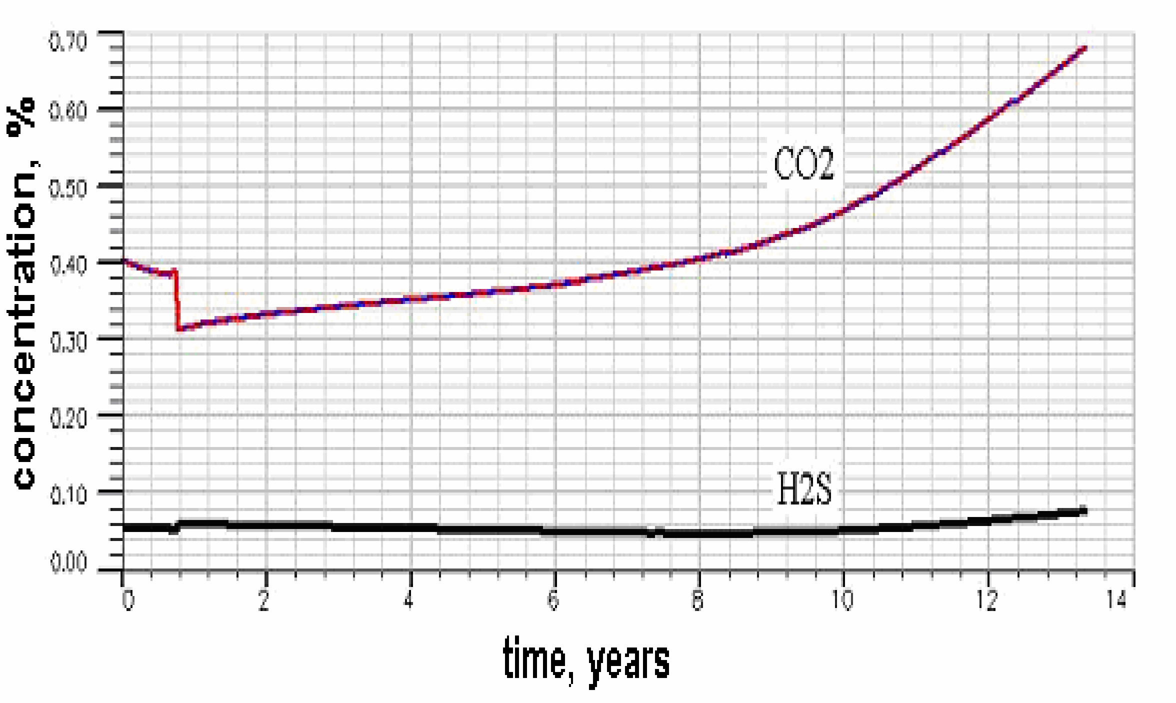


Fig. Simulated concentration of CO_2 and H_2S in produced gas

Figure 2.6: Acid Gas simulated concertation

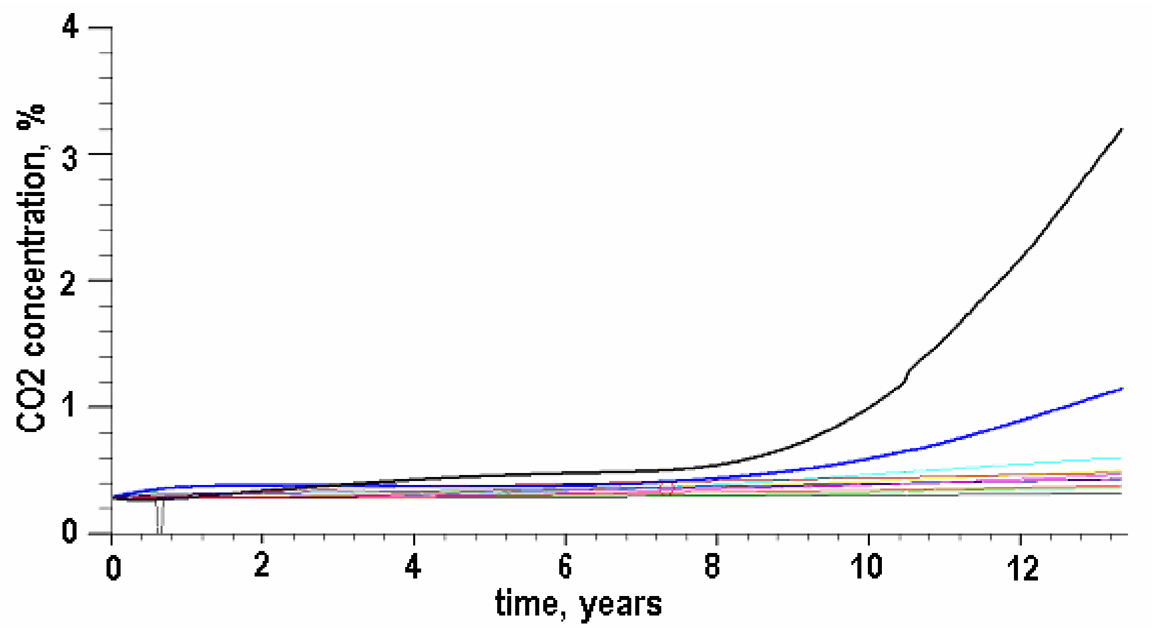


Fig.. Simulated CO_2 concentration in gas produced from various wells

Figure 2.7: CO2 simulated concertation

Wells	CO_2 (H_2S) content in the produced gas in the years 2001 to 2005					
	05. 2001	06. 2002	06. 2003	03. 2004	12. 2004	12.2005
Ż-1	0.263 (<0.05)	0.328(<0.05)	0.277(<0.05)	0.302(<0.05)		
B-4	0.445 (<0.05)	0.428(<0.05)	0.752(<0.05)	0.883(<0.05)	1.415(<0.05)	1.446 (0.152)
B-6	0.292 (<0.05)	0.328(<0.05)	0.354(<0.05)	0.337(<0.05)	0.348(<0.05)	0.31(<0.05)
B-21	0.223(<0.05)	0.273(<0.05)	0.296(<0.05)	0.275(<0.05)	0.278(<0.05)	0.291(<0.05)
B-22	0.272(<0.05)	0.322(<0.05)	0.342(<0.05)	0.296(<0.05)	0.331(<0.05)	0.314(<0.05)
B-24	0.264(<0.05)	0.340(<0.05)	0.308(<0.05)	0.313(<0.05)	0.353(<0.05)	0.335(<0.05)
B-27	0.254(<0.05)	0.374(<0.05)	0.361(<0.05)	0.343(<0.05)	0.363(<0.05)	0.308(<0.05)
B-29	0.235(<0.05)	0.200(<0.05)	0.125(<0.05)			
B-30	0.126(<0.05)		0.148(<0.05)			

Table 1. Observed CO_2 and H_2S concentration in gases produced from various wells of the Borzęcin reservoir

Table 2.3: Acid Gas Simulated Concertation

2.5 The principle of Carbone dioxide captures and storage:

Carbon Capture and Storage (CCS) refers to the set of technologies developed to capture carbon dioxide (CO2) gas from the exhausts of power stations and from other industrial sources, the infrastructure for handling and transporting CO2 and those for injection and storage in deep geological formations. All the individual elements operate today in the oil and gas and chemical processing sectors. However, their integration for CO2 capture from power plants and heavy emitting industry is a challenge and the storage of huge quantities of CO2 underground raises new issues of liability and risk. The focus of this Briefing Paper is on the storage of carbon deep underground; a companion Briefing Paper addresses the capture element of CCS, discussing the set of technologies developed to capture carbon dioxide (CO2) gas from the exhausts of power stations and from other industrial sources.

CCS is a potentially critical transitional technology, offering a near-term way to mitigate climate change consistent with continued extensive fossil fuel use while progress is made towards establishing a truly sustainable low-carbon energy system in the medium to longer term. Indeed, the costs of mitigation are expected to be considerably higher if CCS is not included in future low-carbon energy technology portfolios. The deployment of CCS in countries with very large indigenous fossil fuel reserves could also reinforce energy security while achieving climate mitigation goals. Equally, decoupling the use of coal from CO2 emissions is attractive in terms of allowing a more diverse range of energy sources for countries heavily reliant on imported fuels.

There are over a hundred sites worldwide where CO2 is injected underground as part of normal oilfield operations, either as part of an enhanced oil recovery (EOR) scheme or to prevent toxic acid gases being released to the atmosphere (CO2 is injected mixed with hydrogen sulphide - H2S) . There are also several current and planned storage projects, specifically designed to reduce atmospheric emissions of CO2 which store around 1 Mt (one million tonnes) of CO2 per year2. The challenge is how to design storage such that the CO_2 remains underground for thousands of years and how to handle the huge volumes necessary to make an impact on global CO_2 emissions—we will need to store several thousand times more CO_2 than is captured by current projects if CCS is to have a significant impact.

2.5-1 Challenges

Credible policy and regulatory frameworks are needed to manage the economic, health and environmental risks associated with the full-scale demonstration phase and deployment if CCS is to gain public acceptance across the globe. Public perceptions will likely be formed based on the performance of the demonstration projects; early failures may have serious implications for the credibility and estimated cost of CCS as a major mitigation option. Cost reduction is the major challenge for carbon capture technology because more fuel must be burnt (about 20–30%) to produce the same amount of electricity, and thus, there are significant implications for fuel security and energy efficiency, which must be considered alongside emission mitigation strategies.

The risks associated with carbon storage are generally considered more important than those associated with capture.

However, as we discuss, with careful injection design it should be possible to ensure long-term safe storage. Initial demonstration projects need to be chosen carefully and it is likely that most of the first storage sites will be offshore; the real challenge though is establishing an infrastructure capable of handling the large volumes of CO_2 necessary.

2.6 Description of Gaseous Impurities:

To meet natural gas transportation and market specifications, hydrogen sulfide, carbon dioxide

(CO_2), and other gaseous impurities, collectively known as “acid gas,” must be removed from produced, impure natural gas. In the past, generally these gases were removed from the gas stream and then flared to the atmosphere. However, hydrogen sulfide, when flared to the atmosphere, produces sulfur dioxide which contributes to air quality problems and acid deposition. Tighter regulations in many countries now *prohibition* the flaring of hydrogen sulfide for all but the smallest natural gas processing plants. Another option to manage the hydrogen sulfide is to remove it from the hydrocarbons and convert it to elemental sulfur that can be sold as a raw chemical for manufacturing processes. A recent drop in global sulfur prices, however, has made this option less attractive (Bachu *et al.*, 2003). Therefore, a number of natural gas plants have turned to acid gas injection as a means of disposing of hydrogen sulfide and related gases.

Acid gas injection has been practiced in Canada since 1989, and data on acid gas projects may provide relevant information for carbon dioxide sequestration. The general properties of acid gas injection and carbon dioxide streams for sequestration are similar. In both cases, the gases are mixtures containing carbon dioxide with other gases and water vapor, and therefore can have a wide range of properties, which must be calculated for each individual case. Although the physical properties of acid gas cannot be directly applied to CO_2 sequestration, the methods of calculating the properties will be the same. Therefore, models derived for calculation of acid gas properties can be used to calculate properties for carbon dioxide mixtures as well.

2.6.1 Injection process in Acid Gas

The first step in the acid gas injection process is separation of the gaseous impurities that constitute acid gas from the hydrocarbon product stream. This is generally done by contacting the hydrocarbon gas stream with an amine solution. The hydrogen sulfide and carbon dioxide impurities are adsorbed into the amine solution and then desorbed to isolate these acid gas constituents. At this point, the acid gas is at a slight vacuum and high temperature, and is usually saturated with water from the adsorption/desorption process.

The resulting acid gas is a mixture of primarily hydrogen sulfide and carbon dioxide with trace amounts of water, light hydrocarbons (methane, ethane, and propane) and nitrogen. The composition can range widely from 2 percent hydrogen sulfide and 98 percent carbon dioxide to about 85 percent hydrogen sulfide and 15 percent carbon dioxide (Bachu and Gunter, 2004). Because it is a mixture, the properties of acid gas are highly variable and dependent on the concentration of the components.

Properties, such as density and viscosity of the gas, can be calculated using equations of state and experimental data. There are also computer programs available which can calculate physical properties of the gas (Carroll, 2002).

2.6.2 Description of the Target Formations

The geologic formations targeted for acid injection most commonly are depleted oil or gas fields, depleted salt caverns, or saline aquifers. Saline aquifers and depleted oil and gas reservoirs are also likely candidates for CO2 geosequestration. Much of the research and criteria on the lithology required for acid gas confinement can be applied to CO2 sequestration projects. For example, research on fracture pressures of various formations will be useful in planning CO2 sequestration projects and guidelines on maximum injection pressures for acid gas projects can be directly applied to CO2 sequestration projects. Criteria for proper sealing and abandonment of wells can also be applied to CO2 sequestration projects. In some cases, research done on existing wells in various reservoirs for acid gas injection facilities may be used to select appropriate sites for CO2 sequestration.

Perhaps the most similar aspect between acid gas injection and CO2 sequestration is that they both are intended for the long term isolation of a waste or commodity in a deep geologic reservoir. For acid gas injection (i.e., disposal) to be successful, the targeted reservoir should be able to contain acid gas indefinitely, which requires a confining layer or caprock that is impermeable to the injected gas.

The cap rock should extend across the entire reservoir and be effectively free of faults or fractures that would compromise the caprock and create conduits for leakage. Fractures can be induced if injection pressure exceeds the fracture pressure of the caprock (Hawkes *et al.*, 2005). Active production wells in the reservoir and improperly abandoned wells can also potentially become conduits that allow the acid gas to leak into overlying formations, aquifers, or even into the atmosphere. Consideration should also be made for injection induced migration of fluid in the reservoir that might eventually lead to migration to an area with poorer caprock qualities or into active oil and gas fields or an underground source of drinking water (USDW).

Over the long term, interactions between the injected acid gas and the fluids and rocks in the reservoir should be considered. Dissolution of the gas into the existing formation fluids will affect whether the spread of the acid gas plume is largely in a horizontal direction (flowing with formation fluids) or is dominated by buoyancy forces and has a significant vertical component (acting more as a less dense gas within fluids) (Bachu *et al.*, 2003; Michael and Haug, 2005). In addition to the density of the formation fluid, the

relative buoyancy of the injected acid gas depends on the injection rate and the permeability of the formation. If the acid gas is less dense than the formation fluid and there is low
permeability and a high injection rate, the acid gas plume will spread more quickly in the vertical
direction until it reaches the caprock and begins to spread horizontally. If the acid gas is denser than the formation fluid and injection rates are low and permeability is high, the plume will primarily spread horizontally (Bachu et al. 2004). Chemical interactions with reservoir fluids and rocks can lead to reactions which may help or hinder the injection process. Dissolution of the gas into reservoir fluids and subsequent reactions to form ionic compounds can lead to ionic trapping of the gas (Gunter *et al.*, 2004).
Further, reaction of the gas components with the fluids and surrounding rocks may also cause minerals to dissolve or precipitate. This can change the porosity and/or permeability of the reservoir. If precipitation causes a decrease in porosity near the well, this can negatively affect injectivity, resulting in diminished reservoir storage capacity. Precipitation away from the well bore, however, can lead to a more stable sequestration as components of the gas may become trapped in rocks (Gunter *et al.,* 2004; Buschkuehle,2004). Information on the chemical reactions that are likely to occur can be obtained by performing experiments on cuttings from the well drilling. The chemical reaction parameters obtained from these experiments can then be used to model likely reactions in the reservoir.
Tools used to contribute to ensuring long term storage of acid gas such as reservoir geochemical and pressure modeling and testing well bore integrity can be directly applied to CO2 sequestration projects. Essentially the same types of geologic studies of reservoirs done for potential acid gas injection sites can also be applied to CO2 sequestration projects.

2.6.3 Comparison of Acid Gas Injection and CO2 Sequestration

Carbon dioxide sequestration and acid gas injection both serve as ways to sequester carbon dioxide in underground reservoirs (in the case of acid gas injection, the carbon dioxide also contains hydrogen sulfide). As noted above, the two processes share some significant similarities, including the equipment used and the deep geologic reservoirs that are suitable for both acid gas injection and carbon dioxide sequestration There are some important differences between acid gas injection and CO2 sequestration. Among these are the magnitude of the operations and the composition of the gas being injected.

The sizes of current acid gas injection projects are much smaller than those anticipated for CO2 sequestration. Currently all 42 sites in Canada inject a total of 450 kilotons/yr of acid gas. Current estimates are that CO2 sequestration projects will need to inject 3.5 gigatons/yr just to obtain 1/7th of the reduction in carbon dioxide emissions necessary to stabilize global carbon levels (Wilson, 2004). On a practical level, this means that CO2 sequestration projects will require much larger and/or greater numbers of reservoirs. Therefore, issues such as identifying other production or abandoned wells in the area of review and safeguarding existing oil and gas fields and USDWs will be much more important with CO2 sequestration than with acid gas injection. Although the overall level of acid gas injection does not approach the amount anticipated for commercial-scale CO2 geo sequestration, some individual acid gas wells are similar in size to those being contemplated for CO2 sequestration. The recently completed review and safeguarding existing oil and gas fields and USDWs will be much more important with CO2 sequestration than with acid gas injection. Although the overall level of acid gas injection does not approach the amount anticipated for commercial-scale CO2 geo sequestration, some individual acid gas wells are similar in size to those being contemplated for CO2 sequestration. The recently completed LA Barge acid gas injection wells are only slightly smaller than the wells being used for the Weyburn sequestration project. (Although the Weyburn facility is only a demonstration-scale CO2 sequestration project, it illustrates the similar scales of acid gas injection and CO2 sequestration projects.) Thus, information on equipment and wells for acid gas injection, rather than target formations, would be most applicable to CO2 sequestration.

The other major difference between acid gas injection and carbon dioxide sequestration is the composition of the injected gas. Acid gas is obtained from underground commercial hydrocarbon reservoirs which are anoxic; therefore, there are high levels of reduced sulfur in the form of hydrogen sulfide. Generally, the gas used for carbon dioxide sequestration projects will be a much purer gas and will be largely carbon dioxide. Current amine absorption techniques can produce a gas that is 99.7 percent carbon dioxide (Thomas, 2005) and which thermodynamically can be treated as a pure gas Thermodynamic data for predicting properties of pure carbon dioxide are well known because of the extensive use of carbon dioxide in enhanced oil recovery techniques for over 30 years. In this aspect, CO2 sequestration projects may be, from a chemical composition perspective, simpler than acid gas injection.

Newer absorption techniques, proposed to get around the high costs and corrosivity of amine absorption, can produce less pure gas with impurities such as hydrogen sulfide, sulfur and nitrogen oxides, oxygen, and nitrogen. For carbon dioxide with hydrogen sulfide impurities, thermodynamic properties used in acid gas injection could be applied. Other impurities would need to be treated as mixtures and thermodynamic data and experiments would be required to predict the properties for injection. Models would also be required to predict the interaction between the gas and geologic formations.

2.6.4 section Conclusions and Next Steps

Overall, acid gas injection is a good analogue for carbon dioxide sequestration projects. Although the main purpose of acid gas injection is disposal of hydrogen sulfide, it does in fact sequester carbon dioxide in underground reservoirs along with the hydrogen sulfide.

The equipment used, and therefore the design considerations, for the two processes are very similar. For example, corrosion studies on acid gas injection wells would be useful for determining corrosion in CO2 sequestration wells. Very few systematic studies have been published concerning corrosion in acid gas injection wells. Cooperation between industry, State, and Federal agencies could provide useful information on this and other aspects of well design. In addition, the deep geologic reservoirs used for acid gas injection are also being considered for carbon dioxide sequestration. Therefore, much of the work done on studying and modeling gas containment and integrity of confining layers for acid gas injection will be applicable to CO2 sequestration as well.

The main areas in which carbon dioxide sequestration will depart from acid gas injection are the scale of the projects and the composition of the gases. Carbon dioxide sequestration will require much larger storage reservoirs which may require increased effort both to ensure that nearby existing (or future) oil and gas fields are not compromised, and to identify locations (and conditions) of other wells, producing and abandoned, that could contribute to leakage of the carbon dioxide from the storage reservoir. The properties of the gases injected will also differ between carbon dioxide sequestration and acid gas injection so information regarding acid gas only partly contributes to carbon dioxide injection storage. Thermodynamic and experimental data

will be required for the specific mixtures of gases to be injected for carbon dioxide sequestration. This may require additional thermodynamic experiments to be
conducted on these gas mixtures to determine properties such as density, viscosity, and conductivity.

Continued modeling and experimental work on the interactions between the injected carbon dioxide mixture and geological formations in which they are contained will also be needed. Cooperation between local agencies and industry will also help to study existing plume migration, improve migration models and determine if any leaks from target formations have occurred.

Several possibilities exist for follow-on research to better understand how well acid gas injection serves as a regulatory analogue for CO2 sequestration.

More detailed review of selected U.S. and Canadian acid gas sites that inject gas with the highest carbon dioxide component (e.g., U.S. site in Dumas, TX; Canadian sites # 581, 1189, 1734, 1971, etc.)
may yield useful insight to the process of geologic sequestration. Additional information on U.S. sites would also be helpful. For example, gas composition is difficult to obtain for many of the wells; even though the information is recorded, it is not organized in any useful form. Temperature and pressure both within the formation and at the point of injection would help to determine the mass of carbon dioxide injected. Much of this information can be obtained by industry and the States in order to design and permit these wells. A cooperative effort could enable this information to be put to the best use.

Work will also need to be done to develop a scientifically-sound regulatory framework to properly oversee carbon dioxide sequestration. While criteria and guidelines do exist, and acid gas operations have been successfully overseen for a considerable time, there is no unified or agreed upon set of regulations. With the anticipated scope of commercial-scale CO2 sequestration, many projects will cross jurisdictional boundaries so a national and even international set of standards will be necessary to effectively manage these projects and to ensure their safety and effectiveness

2.7 Characterization of the Storage Complex

Geological storage of CO2 is at an early stage of implementation and practical development. It is based largely on well-established petroleum geology, reservoir engineering practices, and oilfield technology developed over the last 100 years.

Currently, there is a limited amount of practical experience in identifying, characterizing, and injecting CO2 for the purpose of geological storage in underground formations from pilot, demonstration, and a small number of commercial projects. Hence, practices for geological storage will likely evolve as large-scale CO2 injection projects proceed.

Selecting an appropriate storage site is a crucial first step in improving the viability of a carbon dioxide capture and storage (CCS) project. A key consideration in site selection is the characterization and assessment of the potential storage complex and surrounding area, so that risks of environmental and human health impacts can be either avoided or reduced. Poor storage site selection can increase financial and environmental risks enormously, and could set back the eventual CCS deployment, as new potential storage complexes and surrounding areas will have to be screened, selected, and characterized (see CO2 storage life cycle risk management framework elaborated in GD1).

Over the last decade, there have been a number of articles published that describe approaches for assessment ranging in scale from a local site to regional and country assessments. Each have emphasized various aspects of the characterization process, with some others only describing the technical disciplines and issues that may need to be addressed. Some, such as IEA GHG (2009), have provided prescriptive measures and acceptable ranges in table format of what the authors believe may or may not constitute a favorable or desirable site; e.g. be it onshore or offshore or poor or good reservoir quality.

At this early stage in the evolution of the assessment and development of a potential storage complex and surrounding area, what ultimately is deemed to be a favorable site, provided it has high integrity and will provide a safe and secure outcome, will probably be an interplay of geological and commercial aspects. In some instances, sites that may from an engineering perspective present some undesirable features (e.g. poor injectivity) when compared with other sites, might be more commercially viable to develop (albeit with more wells or horizontal wells) than perhaps building a long pipeline to a location with a more technically favorable reservoir interval.

Some aspects of a storage site may be able to be 'engineered' to be more favorable; e.g. by 'fraccing' the reservoir to increase injectivity or by the use of smart well designs. Thus, as a site is assessed and modelled, what may appear at a first aspect, could with engineering intervention, or smart ally and commercially viable. Some technical issues that might now appear to be providing uncertainty for geological storage (e.g. reservoir pressure build up), could evolve with time (through improved technological developments and industrial field scale experience) to become less critical in an assessment process. Thus, reliance on prescriptive measures of the necessary geological characteristics to consider or approve a storage site should be used with caution, and instead a holistic overview should be taken beyond just the local site characteristics and performance measures. Many models and scenarios will have to be developed and considered for any potential storage complex and surrounding area. Each new observation of the deep surface (by drilling and remote imaging) will update, modify and question each previous consideration and assessment.

2.8 Sour gas & environmental concerns :

Sour gas reservoirs have faced critics for environmental concerns and hazards, necessitating a novel outlook to how the produced sour gases could be either utilized or carefully disposed. Over the years of research and practice, several methods of sour gas processing and utilization have been developed, from the solid storage of sulfur to reinjecting the sour gas into producing or depleted light oil reservoir for miscible flooding enhanced oil recovery. This paper seeks to investigate the impact of injection parameters on the performance of sour gas injection for enhance oil recovery. In designing a miscible gas flooding project, empirical correlations are used and the key parameter which impacts the phase behavior is identified to be the minimum miscibility pressure (MMP). A compositional simulator was utilized in this research work to study the effect of injection parameters such as minimum miscibility pressure, acid gas concentration, injection pressure and injection rate on the performance of miscible sour gas injection for enhanced oil recovery. The findings showed that methane concentration had a significant impact on the MMP of the process. Additionally, an increase in acid gas concentration decreases the MMP of the process as a result of an increase in gas viscosity, consequently extending the plateau period resulting in late gas breakthrough and increased overall recovery of the process.

A major cause for concern in the development of sour gas reservoir is the disposal of the produced gas The gases are usually sweetened using different methods.

Amine extraction is one of the most commonly used methods in the petroleum industries (Bennion et al. 1999; Chen 2016). The separation process results in the production of a waste stream composing of acid gases (CO2 and H2S) and requires a huge capital and operation cost which has raised a cause of concern, given that the companies must ensure their waste is eco-friendly before disposal (Bennion et al. 1999).

Over the years, a lot of strategies have been developed to handle acid gas mixture, with primary concerns being the reduction of the toxic hydrogen sulfide gas to an inert/non-toxic reactive product (Bennion et al.1999). The most common technique is the Claus reaction process where gases containing H2S are catalytically converted to elemental sulfur (Bennion et al. 1999). Also, a viable alternative is the reinjection of the produced gas into the reservoir as an enhanced recovery technique or for storage (Abou-Sayed et al. 2004; Bhatti et al. 2019; Ceragioli and Gianelli 2008; Ghoodjani and Bolouri 2011; Hawez and Ahmed 2014; Nwidee et al. 2016). However, concerns have been raised as to possible leakages to the surfaces through faults or unsealing traps.

Sour gas injection for enhance oil recovery (EOR) is a viable option that presents a solution to many problems currently in the industry. It eliminates current taxation or future liability associated with emission or surface storage of sulfur (Abou-Sayed et al. 2004). EOR programs using gas injection have shown that sour gas has better sweep efficiency and voidage replacement ability compared to other gases used for miscible injection EOR. Therefore, this increases the amount of recoverable hydrocarbon (Abou-Sayed et al. 2004; Al-Hadhrami et al. 2007; Battistelli et al. 2011; Chugh et al. 2006; Metcalfe et al. 1973). This also translates to better economics as the cost of many surface treatments is eliminated, thus reducing the operational cost of the process.

This research work seeks to provide insight into the impact of injection parameters on the viability of miscible flooding of a light oil reservoir by the reinjection of sour gas (Abou-Sayed et al. 2004; Benham et al. 1960; Christiansen and Haines 1987; Eakin 1988; Elsharkawy et al. 1992; Green and Willhite 1998; Haynes et al. 2008; Holm and Josendal 1974; Khan et al. 2013; Lake 1989; Orr and Silva 1987; Orr et al. 1982). The reinjection of a rich waste acid gas stream directly into the producing light oil reservoir for the purpose

of miscible flooding enhanced oil recovery using numerical simulation was studied putting into consideration the impact of certain injection parameters on the overall performance of the recovery process.

2.9 CO2 & EOR

The main objective of this thesis is to investigate the possibility of using CO2 as injection gas for enhanced oil recovery and estimate the potential of additional oil recovery from mature oil fields on the Norwegian Continental Shelf (NCS). Because of the lack of CO2 data from offshore oil fields, a literature study on CO2 flood experience worldwide was undertaken. In addition, the physical properties of CO2 and CO2 as a solvent have been studied.

The literature study makes it possible to conclude that CO2 has been an excellent solvent for enhanced oil recovery from onshore oil fields, especially in the USA and Canada. Almost 30 years of experience and more than 80 CO2 projects show that the additional recovery is in the region of 7 to 15 % of the oil initially in place.

The estimation is based on specific field data for all fields and reservoirs included in the

thesis. CO_2 data are limited to studies and reservoir simulations from Forties, Ekofisk, Brage and Gullfaks. Since Forties is a UK oil field, most of the data used are from the three Norwegian oil fields.
This thesis includes all oilfields currently in production. Fields under development, fields with approved plan for development and operation (PDO), or discoveries under evaluation are not included. However, they may have potential for use of CO_2 in the future. The candidates are screened according to their capability of being CO_2 flooded, based on current industry experience and miscibility calculations. Then a model based on the most critical parameters is developed. Finally, risk analysis and Monte Carlo simulations are run to estimate the total potential. Applying the model developed and compensating for uncertainties, the additional recovery is estimated between 240 and 320 million Sm^3 of oil. This potential constitutes large increases in oil production from the Norwegian Continental Shelf if CO_2 can be made available at competitive prices. For some of the time critical fields, immediate action is called upon, but for the majority of the fields dealt with in this thesis, CO_2 injection can be postponed 5 years or more.
With production from many mature oil fields on the Norwegian Continental Shelf declining and approaching tail production, the field owners have to consider enhanced oil recovery as a way of recovering more oil from the fields. Enhanced oil recovery through the injection of CO_2 as a tertiary recovery mechanism, preferably after water flooding, is one mechanism with which to recover more oil, extend the field life and increase the profitability of the fields.
Experience gained from CO_2 flooding worldwide indicates that enhanced oil recovery by using CO_2 as injection gas may result in additional oil ranging from 7 to 15 % of the oil initially in place. As regards oil fields on the Norwegian Continental Shelf, it is not granted that this additional recovery can be obtained, but field studies indicate that there is potential.
With initially oil in place close to 8000 million Sm^3 in the oil fields currently in production, also small percentages represent large volume of extra oil. Few other tertiary recovery mechanisms seem to be able to compete with this, and albeit years of research have been invested in them, other methods are not considered to be economically viable. Miscible gas flooding by using hydrocarbon gas might be an alternative, but because of the high market price for gas, it is more profitable to sell the gas An estimation of this potential is in great demand, both from the industry and the authorities.
However, too little CO_2 data has been available from the Norwegian Continental Shelf to predict the overall potential of CO_2 flooding. The Norwegian Petroleum Directorate, in cooperation with the operators, has initiated reservoir studies to be performed by the operators of three representative fields in production, the Ekofisk, Gullfaks and Brage fields. Data from these studies will be made available for this thesis, in addition to available information from other studies, field experience and pilot projects worldwide. There are also several papers dealing with this subject.
This thesis generally uses available information, does calculations on critical field data and develops a method of estimating the enhanced oil recovery potential of CO_2 floods. Reservoir studies and simulations are not required for all fields, but nevertheless a significant amount of data will be used to establish a method of estimating the overall potential. In addition, an overview of industry experience worldwide and how CO_2 act as a solvent will be given and used as background material for the estimation.
CO_2 is a greenhouse gas, and Norway has entered into international agreements to reduce the emission of greenhouse gasses. This thesis will not look into the environmental impacts of reducing CO_2 emissions, but may contribute some useful material in that

respect. By using CO_2 as injection gas, significant amounts of CO_2 can be stored in the reservoirs upon flooding

2.9.1 Technique Analysis

The @RISK analysis and simulation tool has been used to do Monte Carlo simulations on the most critical variable parameter, the CO_2 EOR recovery factor. In addition, three other variables have been chosen to best describe the uncertainties involved. Figure 8.1 and table 8.1 show the method used. The three parameters, heterogeneity, recovery and residual oil saturation are given a low and high possibility instead of low, medium and high, as 27 and not 8 different adjustment factors would have had to be dealt with then, which is too much within this scope of work. One could also have used a set of distribution curves for each of the parameters and performed a risk analysis, but it is considered more correct to establish a set of fixed correlation factors.

The heterogeneity parameter is defined as high if the reservoir is faulted or layered. Also reservoirs with abnormal high well density are defined to have high heterogeneity.

Homogeneous reservoirs or partly faulted reservoirs are defined to have low heterogeneity.

The recovery factor is defined as the recovery (% of STOIIP) before EOR initiatives. This is a characteristic that says something about the reservoirs' productivity, and high recovery should indicate that CO_2 solvents should have good possibilities of contacting large volumes of residual oil during the flow through the reservoir. The third factor is the residual oil saturation. The factor is not only restricted to residual oil saturation after water or gas flooding, but includes bypassed oil and attic oil (see figure 6.3). The reservoirs are therefore described according to what kind of drive mechanism they have, water injection, gas injection, WAG or pure pressure depletion (see table 7.1). One may assume that reservoirs that have been water flooded have more residual oil left than reservoirs that have been gas or WAG flooded. This may not always be true, but usually, reservoirs suitable for secondary gas injection have lower Sorg then Sorw for a water flooded reservoir. All in all, the combination of these three parameters with fluid, temperature and pressure data should give a good indication of the reservoir properties and impact on CO_2 EOR.

2.9.2 Section Conclusions:

The results of this thesis indicate that there are great EOR potential from CO_2 injection in mature oil field on the Norwegian Continental Shelf. The potential is estimated to between 242 and 323 million Sm3 of additional oil. Compared to a traditional new field development,

this corresponds to a 600 million Sm3 STOIIP field. (Gullfaks size). Development costs and operating costs for implementing CO_2 floods are not included, but considering the large amount of additional oil, such flooding is definitely an alternative to any other EOR techniques.

The result must, however, be regarded as a provisional estimate because of the lack of CO_2 experience on offshore oil fields. The method of calculation is based on a combination of detailed reservoir data and a limited number of CO_2 data, but compared to industry experience, the expected total EOR potential should not be overestimated. The MMP calculations may also be conservative in that it has rejected some candidates. However, the intention was not to give an accurate answer, but to inspire further investigation and research.

Finally, the author of this thesis realizes that the field owners may not agree with the results, or the interpretation of the data used in this thesis.

An interesting finding from the literature study is that an oilfield that has behaved well under water flooding seems to behave well under CO_2 flooding. Another finding is that (not surprisingly) increased oil production, up to a certain point, is almost linear to the amount of CO_2 injected. This is also seen for the North Sea candidates dealt with in this thesis.

2.10 what is acid gas disposal? case study

This article focuses on Alberta's experience with AGD. While attention in the short term will likely focus on EOR projects (such as the much studied Weyburn project) because of their potential to provide revenue stream to offset the costs of capture, AGD schemes are also worth studying since CCS and AGD schemes share some similarities that are not present in other analogies. In particular, CCS and AGD share a common concern with the long term secure disposal and segregation of a waste stream.6 Furthermore, insofar as public concerns for the safety of CCS projects may pose a barrier to adoption, success in dealing with the far more dangerous gas stream (principally hydrogen sulphide) that is the subject of AGD schemes should help allay those public concerns. The article begins by describing AGD and then moves to consider each of the property, regulatory and liability issues associated with this activity and concludes with some preliminary reflections on the adequacy of Alberta's overall Acid gas disposal or injection refers to the injection and geological disposal of mixed streams of CO_2 and hydrogen sulphide (H_2S). AGD began in Alberta in 1989 as a response to the dual challenge posed by the need to reduce sulphur dioxide emissions from natural gas rocessing plants and by falling prices for elemental sulphur produced as part of conventional processing. In essence, the idea is to take the Sulphur emissions stream and inject it back into the ground While the principal emissions target has always been H_2S, the waste stream from the typical processing plant also contains CO_2 as an impurity. The injection ratios for approved injection projects vary between 83% H_2S and 14% CO_2 to 2% H_2S and 95% CO_2.

Since 1989, the Energy and Utilities Board (EUB) has approved 48 AGD schemes for a variety of target formations including saline formations (26), depleted oil and gas reservoirs (18) and in four cases into the water leg of a producing oil reservoir.7 Those living close to processing plants see AGD schemes as providing significant environmental benefits since such schemes offer the opportunity to cut sulphurous emissions to essentially zero.

2.10.1 property of AGD

We shall simplify the property issues by considering only the most straightforward scenario, namely disposal into a Crown-owned depleted oil or gas reservoir in which there are no outstanding rights.9 In this scenario the proponent of an AGD scheme must acquire the consent of the Crown under the *Mines and Minerals Act*. By contrast with other forms of rights acquired under this Act (including storage rights) there is no formal disposition document and no bidding for the acquisition of disposal rights. Instead the relevant

section of the Act, section 56, seems to conflate the property right to inject with the regulatory approval of the activity insofar as the section provides that "a person has, as against the Crown in right of Alberta, … the right to use a well or drill a well for the injection

of any substance into an underground formation, if the person is required by or has the approval of the Alberta Energy and Utilities Board to do so". In practice, however, and as we shall see in the next section, the EUB requires a letter of consent from the Crown as part of an application package for regulatory approval. The Crown has developed a standard form consent letter which states (subject to a series of conditions) that "authorization is granted for acid gas disposal into the xx formation." The authorization has no habendum governing duration; duration is simply understood to be for the duration of the relevant EUB approval.

2.10.2 regulatory to AGD :

AGD is regulated in Alberta by the province's oil and gas regulator the Energy and Utilities Board under the terms of the *Oil and Gas Conservation Act*11 (OGCA) and regulations. The purposes of the statute include conservation of the resource, prevention of pollution and the economic development of the resource.12 The Act itself has very little to say about geological disposal beyond a number of generic sections that require EUB approval before a person may engage in a particular activity. Thus a person requires EUB approval before: (1) drilling a well (including evaluation and injection wells) (s. 11), (2) operating or constructing a facility (including a facility for the disposal of hydrocarbon wastes) (s. 12), (3) proceeding with a scheme for (a) an EOR operation, (b) the processing or underground storage of gas, (c) *the storage or disposal of any fluid or substance to an underground formation through a well*, or (d) the storage treatment or disposal of oilfield waste (s. 39).

The italicized language is particularly pertinent to an AGD scheme. The regulations offer some limited additional guidance as to the content of applications but the EUB provides much more detailed instructions through a series of "Directives" including Directive 51 dealing with "Injection and Disposal Wells" and the more general Directive 65 with the generic title "Resources Applications".13 This latter includes a series of units dealing respectively with general disposal schemes, acid gas disposal schemes and gas storage schemes.

Directive 65 requires an applicant for AGD approval to provide information on containment of injected substances, reservoir characteristics, hydraulic isolation, equity and safety.14

Under the heading of *containment*, the EUB expects the applicant to be able to show that the injected fluids will be contained within a defined area and geologic horizon and ensure that there will be no migration to a hydrocarbon-bearing zone or groundwaters. Hence the applicant will be expected to provide a complete and accurate drilling history of offsetting wells within several kilometers as well as information on the permeability of the cap rock and any fracturing. The applicant will also be expected to identify folding and faulting and comment on how this relates to seismic risk – both the effect of seismic activity on the integrity of the project and the effect of disposal schemes on (increased) seismic activity. Under the heading of *reservoir characteristics*, the applicant will need to describe and analysis the native reservoir, the composition of the waste stream and phase behavior as well as migration calculations and proposed bottom hole injection pressures. Board approvals will be limited to 90% of formation fracture pressures. The Board will expect an assessment of the effect of the acid gas on the target zones. Under the heading of *hydraulic isolation*, the Board expects the applicant to demonstrate that all potable water bearing zones as well as hydrocarbon bearing zones are hydraulically isolated from the proposed injection wells by cement and/or casing with all injection occurring through tubing appropriately isolated from the casing by packer with casing integrity confirmed by an inspection log. Many of the *safety* concerns that apply to AGD projects are the same as those that apply to all sour gas wells and facilities including pipelines. These include a requirement for the development of an emergency response plan (ERP) including an emergency planning zone that is the area of land that may be impacted by an H2S release and may include the processing plant, the injection well and the connecting pipeline. The Board expects to see evidence of broad public consultation on both the ERP and all other matters related to the proposed project. Finally, under equity issues the Board expects the applicant to provide evidence that all offsetting mineral rights owners have been contacted as well as details of outstanding objections or concerns. Perhaps surprisingly, very few AGD applications have triggered a public hearing and formal reasons for decision from the Board approving a project. This suggests that in most cases the applicant has been able to allay possible public concerns through its consultation activities. The following paragraphs discuss some of the issues that have been raised in the few published EUB decisions that relate to AGD.

The concern that seems to have been raised most frequently is the potential for flaring (and therefore acid gas emissions) in the event that the injection facility is shut down for any reason. Past decisions of the EUB dealt with this issue somewhat inconsistently.

In some cases the EUB seems to have been content with a commitment from the operator to reduce throughput15 while in other cases the Board has accepted or required an undertaking from the operator that it will shut down operations in such an event thereby confining any flaring to those small volumes necessary to depressure and render equipment safe.

In one case an intervenor has raised concerns as to containment of the acid gas at the disposal site and especially concerns that there was perhaps an unrecorded abandoned well that might affect the integrity of the disposal scheme.17 The Board assessed these concerns but satisfied itself that: (1) proposed bottomhole pressures would be significantly lower than fracture pressures, (2) the existing data confirmed the hydraulic isolation of the target formation, (3) the proponent would monitor producing wells for any increase in H2S levels which might

indicate problems with acid gas containment, and (4) a review of Board records, interviews with longtime residents as well as the "checks and balances" in the energy sector made it "extremely unlikely for a company to have drilled an unlicensed well in the 1970s."

Other concerns that have been raised include concerns as to whether other operators will know of the existence of an AGD project when carrying out operations many years into the future, and concerns as to contamination of groundwater sources.19 Another general concern relates to the length of acid gas pipeline – a concern that the Board has generally dealt with by requiring the close co-location of processing and injection facilities.20 In sum, AGD disposal schemes present a range of regulatory challenges that will be similar to those which will have to be faced in the design of a CCS regulatory scheme. In some cases the risks associated with CCS will be lower than those associated with AGD. For example, length of pipeline will be far less of a concern with a CO2 pipeline than it is with respect to an H2S pipeline given the significantly more hazardous properties of H2S.21 On the other hand, the sheer scale of CCS projects suggests that lateral migration issues will be far more significant than the migration issues associated with the disposal of relatively small volumes of acid gas

into well-defined physical/structural traps.

2.10.3 liability t o A G D

The potential liability issues associated with an AGD operation include tort-based liability for the consequences of an escape of acid gas (either to the surface or contaminating potable groundwater or interfering with a producing oil and gas reservoir) and statutory responsibility for future remedial operations that may be required in the event that a problem is detected. The Crown purports to deal with any potential liability that it may have as a result of its ownership of the disposal space by imposing a statutory indemnity as part of the same section that authorizes injection activities. Thus subsection 56(2) of the Mines and Minerals Act provides that any person exercising the right to inject “shall indemnify the Crown in right of Alberta for loss or damage suffered by the Crown in respect of any claims or demands made by reason of anything done by that person or any other person on that person’s behalf in the exercise or purported exercise of that right”. The Department’s standard form consent letter reiterates this indemnity. As for the liability of the operator, it would seem that the usual rules apply and that by contrast with oilfield waste injection projects,22 for which the operator is required to post security, acid gas injection wells are subject to the same rules as other exploratory and production wells. Thus the *Oil and Gas Conservation Act* contemplates that all suspension and abandonment activities are the responsibility of the licensee and that in default thereof the EUB may authorize any person to carry out those operations for the account of the licensee and other working interest owners in the well or facility. In the event that the EUB is unable to recover these suspension, abandonment and related reclamation costs from those persons, the EUB may recover them from the “orphan fund”. The fund is financed by a levy on the industry. The Act does not contemplate that abandonment will serve to transfer any continuing liability to the government. *In fact, section 29 states that*: “Abandonment of a well or facility does not relieve the licensee, approval holder or working interest participant from responsibility for the control or further abandonment of the well or facility or from the responsibility for the costs of doing that work.”

2.10.4section conclusion:

AGD projects provide a useful analogy that merits study in the context of implementing CCS. While AGD projects are all small scale by comparison with the projects that will be required if we are to have any significant impact on CO2 emissions, we can still learn from experiences to date and use those experiences to identify the relevant issues within the property, regulatory and liability baskets. In the context of the *property* issues we think that the AGD analogy suggests that at least four issues will require further clarification. These are:

- the nature and duration of the disposal right acquired from the Crown under the MMA,
- the mode of disposition of the disposal right (after all disposal space is a scarce resource),
- clarification as to the application of the *Water Act* when disposal occurs into an aquifer, and
- amendment (expansion) of those sections of the MMA that are designed to clarify ownership of private storage rights in the context of severed mineral estates.

In the context of the *regulatory* issues perhaps the greatest needs are for greater transparency and for more systematic and tailored treatment of the issues. The AGD regulatory scheme seems to have developed in a very *ad hoc* manner – a little tweaking here and there of existing guidelines for gas storage and other related disposal activities. If transparency is a concern it may be important to provide for the explicit treatment of CCS issues in the statute and regulations rather than deferring everything to the much more discretionary guidelines. It will also be necessary to deal explicitly with long-term monitoring. And perhaps projects over a certain size should require a full environmental assessment depending upon the preliminary screening of risks. While the regulators themselves may be confident that they have exercised their discretionary powers appropriately in the context of AGD one of the concerns identified by commentators and study groups examining obstacles to the introduction of CCS is the need to address public perceptions of risk.24 It is not clear that the current regime will meet this objective given the much greater scale of injection activities and the greater risks of lateral migration.

And finally, in the context of the *liability* issues, further thought will have to be given to the design of a liability scheme. Even if it is proposed to retain a scheme that is similar to that currently in force under the OGCA it seems likely that we will need a different orphan fund if only to identify and tap into the broader range of industries that will be contributing to the CO2 waste stream. Both fairness and efficiency require that these industries should be required to contribute to (and thereby internalize) these long-run potential liabilities

2.11 Associated formation Water :

Produced water is the largest waste stream from oil and natural gas production. The large volume (15 to 20 billion barrels generated annually in the U.S.) and high salinity (5,000 to 270,000 mg/L TDS) of produced water could pose severe environmental impacts upon inadequate disposal. Treatment of produced water through wastewater treatment facilities is a commonly used disposal method in Pennsylvania. This study is based on direct field sampling of effluents released into the streams of the Conemaugh, Alleghany and Monongahela Rivers in Western Pennsylvania. Major and trace element analyses show facility effluent concentrations three times higher than seawater (100,000 mg/L TDS), bromide and trace element levels up to 4,000 times higher than values upstream of facilities. The study reveals a zone up to 500 meters downstream from the facility outfall in which the contamination largely exceeds values upstream of the outfall. High levels of naturally occurring radioactive material (NORM) is retained to stream sediments. Dissolved salts, metals and NORM are potentially contributing to long-term ecological effects on aquatic life. This study provides a systematic assessment of: (1) contaminant releases to the environment from oil and natural gas produced wastewater; (2) the fate of contaminants in surface water; (3) and the concerns regarding the long-term environmental impacts on waterways in Western Pennsylvania.

2.11.1 Outline of impact of formation water disposal

Sustainable use of scarce water resources and stringent environmental regulations are currently moving the focus towards environmentally friendly and cost-effective injection methods in the offshore oil industry.

Water injection is used for most oil reservoirs as pressure support and improved displacement of oil. Most water-based enhanced oil recovery (EOR) techniques consist of chemical injection into reservoirs resulting in hazardous flow back of chemicals and produced water (PW). Smart water injection is an alternative and simultaneously represents a sustainable environmental and economic EOR flooding technique. The optimized ionic composition of injection water improves the initial wetting towards more water-wet conditions, which improves displacement efficiency due to increased capillary forces.

Smart water improves oil recovery by wettability alteration in both carbonate and sandstone reservoirs. Seawater is the main injection brine offshore and when enriched in divalent ions such as SO_4^{2-} and Ca^{2+} and depleted in Na^+ and Cl^- is considered smart water in carbo nates. Injection brine with salinity below 5,000 mg/L and low in divalent cations are considered suitable as smart water in sandstone reservoirs.

Nanofiltration membranes (NF) are efficient in performing partial desalination of seawater and PW at low feed pressures resulting in high flux and low power consumption. The main focus of this research was to determine appropriate technical conditions and limitations of NF membranes for producing smart water from seawater and PW.

Special focus was on exploring NF membrane performance in terms of flux and rejection under varying feed compositions, pressures, pH and recoveries of polyamide and sulfonated polyethersulfone membranes.

Both permeate and retentate streams from NF membranes are used for producing smart water. The divalent ion rich retentate could be used in carbonate reservoirs, whereas the permeate with low divalent ion concentrations is optimal for sandstone reservoirs with seawater as membrane feed.

Produced water re-injection (PWRI) as smart water was evaluated as an alternative to PW discharge in terms of environmental and economic advantages. One of the main concerns in membrane treatment of PW is the presence of organics that cause membrane fouling. De-oiling of synthetic PW by media filtration upstream NF membranes eliminated fouling during short-term membrane experiments.

Additionally, the presence of barium and strontium ions in PW cause scaling if mixed with seawater. Membrane removal of Ba^{2+} and Sr^{2+} was optimized by increasing the concentration of scaling ions in the feed which resulted in efficient removal of Ba^{2+} and Sr^{2+} during NF experiments. However, the main challenge in reusing PW as smart water is low flux through NF membranes.

Experiments with altering pH of seawater were performed within pH limitations of the membrane materials to determine the effect of pH on membrane performance. A comparison between pH tolerance on polyamide and sulfonated polyethersulfone membranes were conducted during the experiments. A significant change in ion rejection was observed even with small changes in pH. Another limitation with NF membrane separation with PW is the high total dissolved solids (TDS) in PW yielding high osmotic and operating pressures. Dilution of PW with NF permeate with seawater as feed
reduces TDS.

Artificial neural network (ANN) was used to predict ion rejection based on multiple variable experimental data for feed pH, pressure and flux. An ANN structure was designed that were in close agreement between ANN predictions and experimental data, exceeding 95 % agreement for the tested membranes. Based on experimental data, a predictive model was developed to quantify individual ion rejection by polyamide membranes using Spiegler-Kedem model based on non-equilibrium thermodynamics and steric hindrance pore model. These models using rejection and flux values from six commercially available membranes determined the membrane transport parameters that included reflection coefficient and solute permeability. Membrane characterization was also accomplished by determining the effective pore radius of each membrane based on steric hindrance pore model for individual ions present in seawater.

Experimental data were implemented for modeling the rejection characteristics of polyamide NF membranes with pure water permeabilities suitable for smart water production. Equations were formulated from plots of pure water permeability versus reflection coefficient and solute permeability, which enable end users to choose suitable NF membranes without performing extensive membrane experiments.

Power consumption analysis of membrane operations was evaluated for smart water roduction in carbonates and sandstones using both seawater and PW as membrane feed. Power consumed per cubic meter of smart water produced for carbonates was 0.7 kWh/m^3 and 5.2 kWh/m^3 for sandstones using seawater as feed. A power consumption analysis using PW as feed was 0.88 kWh/m3 for carbonate reservoirs. For sandstone reservoirs, the power required for smart water production was 13.99 kWh/m3.

2.11.2 Smart Water in Carbonate Reservoirs:

The mechanisms by which modified brines or smart water change the wettability of carbonate reservoirs are explained in *Figure below*. (2.7) The initial wetting in carbonates is controlled by negatively charged acidic polar components adsorbed to positive sites at the mineral surface. The wettability alterations are promoted by desorption of acids from the mineral surface.

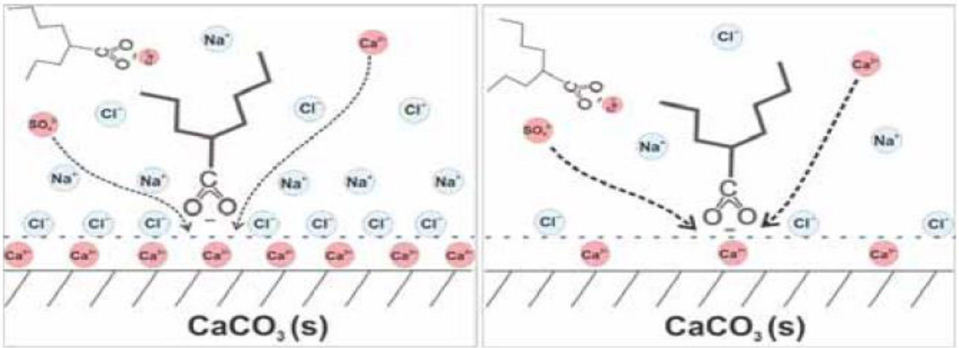


Figure 2.7: Schematic of mechanisms for wettability alteration in carbonates a) Mechanisms when monovalent ions are present b) Mechanisms with increased Ca^{2+} and SO_4^{2-} and decreased Na^+ and Cl concentrations

Figure 2. 8: Schematic of mechanisms for wettability

2.11.3 Definition of produced water

Produced water is defined as the water that exists in subsurface formations and is brought to the surface during oil and gas production. Water is generated from conventional oil and gas production, as well as the production of unconventional sources such as coal bed methane, tight sands, and gas shale. The concentration of constituents and the volume of produced water differ dramatically depending on the type and location of the petroleum product. Produced water accounts for the largest waste stream volume associated with oil and gas production.

2.11.4 Petroleum Resource Formation and Production

Conventional Oil and Gas

Oil is formed from plant and animal material that accumulates at the bottom of a water supply such as an ocean, river, lake, or coral reef. Over time, this material is buried by accumulating sediment and is pushed deeper into the earth's surface where the pressure increases from the weight of the overlying sediment and the temperature increases due to heat from the earth's core. Oil and gas reservoirs are created when hydrocarbon pyrolysis occurs in a confined layer of porous reservoir material. The confined material restrains the fossil fuel in the subsurface, while the permeable and porous reservoir material allows for accumulation. Oil exists underground as small droplets trapped inside the small void spaces in rock. When a well is drilled into an oil reservoir, the high pressure that exists in the reservoir pushes oil out of the small voids and to the surface.

2.11.5 Produced Water Management Practices

Water is considered a byproduct of oil and gas production and generally is treated by the oil and gas industry as a waste for disposal. Produced water management practices are driven by the cost of the hydrocarbon resource. Produced water is the largest volume waste stream associated with oil and gas production. Because produced water is viewed as a waste byproduct to the oil and gas industry, historically, the most commonly practiced management strategies are aimed at disposal rather than beneficial use. The most common practices for produced water disposal include land application or discharge, subsurface injection, and offsite trucking.

- Land application or discharge is a relatively inexpensive method of disposal for produced water. However, this is only an option for relatively high quality produced waters. If the water is of poor quality, contamination of the surrounding soil, water, and vegetation can occur. Regulatory guidelines also must permit land applications.

- Subsurface injection is the industry preferred alternative to produced water disposal. In some cases, re-injection of produce waters is not feasible because the subsurface formation does not have the capacity to receive the water.

- In the event that land application or re-injection is not feasible, the water may be trucked to offsite, re-injection facilities. Re-injection facilities commonly are located around a feasible accepting geologic formation for injection. These facilities sometimes include minor treatment applications aimed at lowering the scaling potential of the reinjection water or modify the chemistry of the water to aid in disposal.

Typically, producers have limited water treatment experience and are hesitant to employ produced water treatment technologies given their negative past experiences. From an oil and gas producer's perspective, the primary concern of beneficial use of produced water as a management strategy is liability; therefore, 8 re-injecting the water into the subsurface formation is the preferred disposal/ management method. However, in some areas, disposal is not possible because the geology of the subsurface formation cannot accommodate the water, or re-injection may cause contamination of other subsurface water supplies. Offsite trucking is another water management strategy preferred by producers from a liability standpoint; however, it is very costly.

2.11.6 Environmental Impacts Caused by Produced Water

Environmental impacts caused by the disposal of produced water have been reported since the mid-1800s when the first oil and gas wells were drilled and operated. The most commonly reported environmental concerns are as follows: degradation of soils, ground water, surface water, and ecosystems they support (Otton 2006). Because many produced waters contain elevated levels of dissolved ions (salts), hydrocarbons, and trace elements, untreated produced water discharges may be harmful to the surrounding environment.

Large water volumes also can cause environmental impacts through erosion, large land area disposal basins, and pipeline and road infrastructure. Water hauling spills and unplanned discharges are all risks when managing produced water. The volume of the receiving body is critical in determining environmental impacts as ocean discharge offers substantive dilution, while small streams offer low dilution capacity. Physical water properties of concern include temperature, effervescence, low dissolved oxygen concentrations, as well as high and low pH depending on the well type.

Sodium is the most commonly occurring dominant cation in produced water. High sodium levels compete with calcium, magnesium, and potassium for uptake by plant roots; therefore, excess sodium can prompt deficiencies of other cations. Elevated levels of sodium also can cause poor soil structure and inhibit water infiltration in soils (Davis, Waskom et al. 2007). Infiltration into shallow ground water sources is also a concern when water is applied for irrigation use. Mineral accumulation due to subsurface ion exchange can change the water quality of shallow, underlying aquifers.

Trace elements, including boron, lithium, bromine, fluorine, and radium, also occur in elevated concentrations in some produced waters. Many trace elements are phytotoxic and are adsorbed in the soil. These elements may even remain in soils after the saline water has been flushed away. Radium-bearing scale and sludge found in oilfield equipment and discarded on soils pose additional hazards to human health and ecosystems. Meteoric water applied to contaminated soils has the potential to solubilize metals and transport them through the subsurface. Precipitation of metals and metal solubility are important considerations in applying these constituents to soils.

2.11.7 Study Objectives:

The objectives of this project are as follows:

(1) Describe the characteristics of produced water: constituent concentration and volumes produced.

(2) Identify potential beneficial uses of produced water and the geographical relationship between produced water generation and potential beneficial uses. Three case studies are presented.

(3) Identify constituents in produced water that exceed water quality requirements of beneficial uses and constituents that will be problematic for treatment of produced water

(4) Evaluate produced water treatment technologies (organic/particulate removal technologies, desalination, brine management technologies, and post-treatment or stabilization technologies) and describe benefits and limitations of each technology based on produced water specific design requirements.

2.11.8. Section Conclusions and Recommendations

Produced water is generated in large volumes across the Western United States from both conventional and unconventional petroleum production with the majority of the water produced in Texas, Oklahoma, Kansas, California, and the Rocky Mountain region including Montana, Wyoming, Utah, Colorado, and New Mexico. Given the large volume of water generated during operations, produced water could be considered an alternative water resource in locations experiencing water shortage.

Produced water could be used to augment conventional water supplies for use in irrigation and livestock watering, streamflow augmentation, and industrial applications. Water quality issues may need to be addressed for produced water to be used for these beneficial uses. For agricultural purposes, most produced water sources contain elevated levels of sodium and high conductivity that require treatment to eliminate the possibility of damage to crops and livestock. In some states, produced water volumes are large enough to make a significant contribution to the water demand for irrigation and livestock.

Numerous treatment technologies have been suggested for produced water. This document provides a qualitative comparison of the different technologies and provides guidance on the benefits and limitations of each technology. Water quality constraints and site-specific

design criteria should be used to select the most appropriate treatment technology for a given produced water source and desired beneficial use.
Three case studies were presented, which illustrate the large potential for beneficial use in the Western United States for different types of applications: agriculture, stream low augmentation, and industrial use. Appropriate management techniques will allow produced water to be used as a resource rather than treated as a waste to meet the growing water demand in the Western United States.
This work, along with research conducted by others (through the Department of Energy, National Energy Technology Laboratory, and the Research Partnership to Secure Energy for America), has thoroughly evaluated produced water occurrence, quality, quantity, beneficial uses of produced water, and produced water treatment technologies. Future work should focus on simultaneously considering all of this information to develop site-specific produced water management strategies that are both environmentally and economically efficient.

2.12 Assessment of Produced Water Reinjection

What is Produced Water?
Produced water is a byproduct of oil and gas production. Oil and gas reservoirs often contain plenty of groundwater, creating a slurry when pumped to the surface. Before the oil and gas can be used, the water and any solids mixed in need to be separated and disposed of.

While separating the produced water from the oil and gas is straightforward, the real challenge is what to do with the produced water afterwards. Produced water is by far the most common byproduct of oil and gas production. In the United States alone, approximately 21 billion barrels are pumped out every year.
To make matters worse, regulations don’t allow oil companies to dispose of produced water anywhere they prefer. In offshore oil fields, the water must be treated first and pass through environmental guidelines before it can be dumped into the sea.
In an onshore oil field, things get far more complicated. The regulations onshore are more stringent since the hazard of the produced water mixing with drinking water is very real.
Oil companies must find ways to recycle the water or dispose of it safely. One of the most common methods for this is fracking, which we will look at below.
This is a headache for companies since the cost of managing produced water can get very high. In some instances, whole operations were called off due to there being no feasible way to get rid of the produced water without spending too much.

2.12-1 Produced Water Composition :

The composition of produced water varies greatly depending on the rocks it is extracted from. At times, the water can be saltier than seawater (brine), while on others, it will contain hardly any salt.

Aside from salt, other materials of interest on produced water include:

- Oil and grease
- Naturally occurring radioactive materials
- Heavy metals
- Dissolved organic compounds

Treatment of produced water involves removing these materials from the water until it is safe for reuse. How pure the water needs to be depends on what the water is going to be used for.

2.12-2 **Produced Water Treatment**

As mentioned above, produced water management is one of the biggest oil and gas industry challenges. To understand why dealing with produced water can cost so much, it is helpful to understand the water treatment technologies needed for safe and compliant disposal or reuse of produced water.

Typical treatment of produced water undergoes three stages, with an optional fourth stage for reusable water. These stages are:

1. Pre-treatment
2. Main treatment
3. Polishing treatment
4. Tertiary treatment (optional)

- ***Pre-treatment***

Pre-treatment is the first stage. The fluid enters here as a slurry, full of large droplets of oil, gas bubbles, other organic compounds, and, of course, water. Equipment in this stage includes dehydration and storage tanks, strainers, and several others.

The materials are separated from one another through heating, settling, and the use of chemical additives are also sometimes used to help speed up the process.

- ***Main Treatment***

With the oil and gas separated and the solids discarded, the produced water then goes through several other treatments. The water will still have smaller particles of oil, gas, and solids that need to be removed before it can be reused or discarded.

The main treatment has two stages, the primary treatment, and the secondary treatment. The primary treatment employs API separators, skim tanks, and a few others, while the secondary treatment uses hydrocyclones, centrifuges, and gas floatation.
These will get rid of the smaller particles that the pre-treatment couldn't get rid of.

- ***Polishing Treatment***

The third and often final stage of treatment is the polishing stage. Here, even the smallest particles are removed from the water. This prepares the water for reinjection (PWRI) into the ground.

The equipment used at this stage is a variety of filters and membranes. They help remove the ultra-small droplets that are found in the water.

- ***Tertiary Treatment***

In some instances, the water will need to go through a tertiary treatment before it can be used. This is to remove ultra-fine particles mixed in the water.

Produced water is slightly radioactive, and it is considered industrial waste. That is why if it is to be disposed of or used, it must reach strict standards of quality, which includes the tertiary treatment.

2.13 Produced Water Disposal in Oil and Gas Production:

The term 'produced water' refers to the water mixture that is removed from a geological formation during the extraction of oil and gas, and potentially also includes water which was injected into the reservoir to maintain pressure and oil production (Holdway, 2002). Produced water is a complex mixture with many variables influencing its characteristics, including the age and location of the oil field, the geological characteristics of the formation from which the water is originating, the type of hydrocarbon product being produced, the production history of the reservoir, and the operational conditions under which it originates (Fakhru'l-Razi et al., 2009). While the composition of produced water is considered highly variable (Durell et al., 2006) and constituent concentrations can vary between different sources by orders of magnitude (Neff et al., 2011a; Fakhru'l-Razi et al., 2009), it is similar across oil production facilities in terms of its major constituents (Fakhru'l-Razi et al., 2009). Fakhru'l-Razi et al. (2009) summarize the components of produced water to include crude oil, which is a mixture of aliphatic and aromatic hydrocarbons; dissolved formation minerals, including heavy metals and radioactive materials; production chemicals, which are typically synthetic additives; solids such as formation solids, corrosion and scale materials, bacteria, waxes and asphaltenes; and dissolved gases. Oil is a generic term representing a wide array of compounds, mainly hydrocarbons, which may be present in produced water as dispersed droplets and/or dissolved in the water phase, depending on their solubility and structural properties (OGP, 2005). Aliphatic hydrocarbons are typically found in the dispersed phase, while carboxylic acids are most often found in the dissolved phase. Aromatics can be in either, or sometimes in both, depending on their molecular weight and structural complexity, with lower molecular weight compounds tending to be relatively more water soluble and thus more often present in the water (dissolved) phase (OGP, 2005). Produced water is generated in large volumes in the production phase of conventional oil wells. Approximately 1.1 m3 is generated for each 1.0 m3 of oil produced worldwide (Neff et al., 2011a), making it definitively the largest waste stream associated with the production process (Arctic Monitoring and Assessment Programme (AMAP), 2010). Produced water is typically treated to remove the dispersed crude oil content (that is, droplets of crude oil, typically ranging from 1 to 10 um in size) (Neff et al., 2011a) before it is either discharged as a waste material into the sea, or is reinjected into a sub-sea formation for disposal (Ekins et al., 2007; Yeung et al., 2015). Environmental regulations in most jurisdictions dictate the allowable water quality parameters for discharged waters and often include maximum oil-in-water concentration limits, ranging between 14 mg/L and 39 mg/L (OGP, 2005). Current treatment methods are not entirely effective, and small suspended oil particles, micro-emulsions, dissolved elements, and organic chemicals are often still present in treated produced water (Fakhru'l-Razi et al., 2009). Similar work has also demonstrated the presence of nonregulated compounds, specifically persistent organic contaminants such as hexachlorobenzene, decachlorobiphenyl, and octachlorodibenzofuran, in produced water

(Balaam, Chan-Man, Roberts & Thomas, 2009). The most abundant organic chemicals in most treated produced waters are watersoluble low molecular weight organic acids (primarily mono- and di-carboxylic acids) and monocyclic aromatic hydrocarbons (MAHs) including benzene, ethyl benzene, toluene, and xylenes (Neff et al., 2011a). Produced water components thought to contribute most to the ecological risk in marine environments based on their chemical characteristics are the MAHs, polycyclic aromatic hydrocarbons (PAHs), related heterocyclic aromatic compounds, and sometimes one or more metals such as iron, lead, mercury, and zinc (OGP, 2005).

2.13-1 Structure and Physicochemical Properties:

The structure and physicochemical properties of produced water compounds are significant in terms of their likelihood to be associated with adverse impacts, largely based on their potential to bioaccumulate and their susceptibility to biodegrade. Similarity in composition and commonalities in production operations allow for generalizations to be made about the characteristics and risk of produced water in marine environments.

2.13.2. Monocyclic Aromatic Hydrocarbons Benzene, toluene, ethylbenzene, and xylene (BTEX) are low molecular weight monocyclic aromatic hydrocarbons (MAHs). They are moderately soluble in seawater, highly volatile, and have a moderate affinity for partitioning into the lipid tissues of aquatic organisms (OGP, 2005; Neff, 2002). BTEX are rarely included when considering the ecotoxicological effects of produced water on marine environments (Bakke, Klungsøyr, & Sanni, 2013). This is largely because they are not accumulated to a large degree in marine organisms (OGP, 2005), and although total concentrations of BTEX may be as high 10,000 µg/L or greater in treated produced water, they dilute, evaporate, and are degraded very rapidly in the receiving water environment following discharge (Neff et al., 2011a; Neff, 2002). A study illustrating the dilution of BTEX showed a 14,900-fold reduction in BTEX concentration twenty meters down-current from a produced water discharge point (concentration in the treated produced water was 6,140 µg/L, versus 0.43 µg/L twenty meters downstream) (Neff, 2002). The main removal mechanisms for BTEX from the water column are evaporation, adsorption to sediment organic matter, biodegradation, and photolysis (Neff, 2002). Because of their high volatility, evaporation accounts for the greatest loss of BTEX from water (Neff, 2002). Under moderately calm open water conditions, the residence time of BTEX in the aqueous phase is roughly two days (Neff, 2002). Under more turbulent conditions, the half-life for BTEX in the water column may be only a few hours due to good vertical mixing (Neff, 2002). Mechanisms of acute BTEX toxicity to marine organisms are thought to include non-specific mode of action (non-polar narcosis), alterations of cell membrane permeability particularly in the gills (Meyerhof, 1975; Morrow et al., 1975 as cited in OGP 2005), and potentially also developmental defects (Kjorsvik et al, 1982 as cited in OGP, 2005). Toxicity generally increases with increasing molecular weight although the rapid loss of BTEX in seawater limits exposure (OGP, 2005).

2.14 Produced water :

is the largest waste-stream source in the entire exploration and production process. Over the economic life of a producing field, the volume of produced water can be more than 10 times the volume of hydrocarbon produced However, the volumes of produced water vary considerably both with the type of oil or gas production and throughout the lifetime of field. Thus, a cost effective and environmentally acceptable disposal of these waters is critical to the continued economic production of petroleum. Produced water contains impurities including:

- Dissolved solids, the most common is salt and heavy metals,
- Suspended and dissolved organic materials,
- Formation solids,
- Hydrogen sulphide,
- Carbon dioxide,
- Oxygen depletion

Produced water may also contain low levels of Naturally Occurring Radioactive Materials (NORM) and contamination of NORM can be expected at nearly every petroleum facility. Some NORM can be sufficiently severe that maintenance and other personnel may be exposed to hazardous concentrations. In addition to naturally occurring impurities, chemical additives like coagulants, corrosion inhibitors, emulsion breakers, biocides, paraffin control agents and scale inhibitors are often added to alter the chemistry of produced water. A variety of those chemicals are often added to the produced water to avoid problems such as corrosion, microbial growth, suspended particles, foams, scale, and dirty equipment. However, most of the water produced could it treated mechanically, chemically, and biologically and subsequently re-injected to the subsurface either for disposal or for secondary recovery operation.

2.15 Environmental laws in the Libya oil industry

In general, environmental protection was not influential in Libya over the past years, although a law on the environment exists (Law No 7/82). This might be due to the political problem that led to isolate Libya from the rest of world. The opening up of the economy of Libya to the rest of the world resulted in Libya an increased concern about environmental protection in priority of the government, which led to a new law on the environment in 2003 in the Libyan congress on the current environmental issues and created some awareness in the environmental issues [124]. This awareness also resulted in the issue of Libyan law on the environment (Law No 15/03) and the NOC HSE Work Programme. The Programme is overseen by the NOC which aims to promote national policies to protect health and the Households Exploration Refining Transport Crude oil terminal Decommissioning Production Used oil &oil waste Use Inland distrubtion and storage Power Generation Industry Upstream Industry Downstream Industry Transportation 82 environment and integrated approach to link economic, environmental and social policies. Therefore, companies are increasingly concerned to achieve and demonstrate sound environmental performance by controlling the impact of their activities, products, or services on the environment. The actual implementation of strategies and methods requires minimizing environmental impacts of petroleum operations. It is apparently difficult to effectively implement an EMS without strong legislative backing from the government. However, for a company to strictly adhere to the legislation and policy of environmental issues requires examination and consideration of operational and legal requirements of the law. International agreements on environment have also played an active role as far as awareness on Libyan environmental awareness is concerned, as a result of Libya being party to convention on Biological diversity, the United Nations Framework Convention on Climate Change, the Convention on the International Trade in Endangered Species of Wild Flora and Fauna, the Convention on the Control of Transboundary Movements of Hazardous Wastes and their Disposal, Convention of the prevention of Marine Pollution by Dumping Wastes and other Matter, the Convention to Combat Desertification in those Countries Experiencing Serious Drought and/or Desertification, and the Montreal Protocol on Substances that Deplete the Ozone Layer.

2.16 Method treatment Re-Injection / Sequestration of Raw or Acid Gas:

The presence of acid gases, H2 S and/or C02, in natural gas is undesirable from many standpoints. Perhaps the principal objection is the corrosion that results when free water is present. For this reason the H 2s and CO1 normally are removed at the wellhead or relatively close to it. There are a number of systems that can be used for removal of acid gases it so vital looking for the following topics -methods :.

2.16-1- Sweetening by Ethanolamines.

Perhaps the most widely used type of acid-gas-removal system involves the use of an ethanolamine.

In this process a solution of water and ethanolamine that may vary from about 15 to 60 wt% ethanolamine is used for removing HzS and CO? from the incoming gas stream. The process is based on the principle that the acid gases, HzS and CO2, will react with the ethanolamine at ordinary temperatures. The reaction can be reversed by reducing the pressure and heating the solution. The sour gas passes up through the contactor and the lean ethanolamine solution passes downward. The foul solution is discharged from the bottom of the contactor and flows through a heat exchanger before it discharges into the top of the still or regenerator column. The ethanolamine solution is boiled by application of heat in the reboiler.

This boiling action supplies vapors, primarily steam, that pass up through the still column sweeping the H2S and CO;? from the ethanolamine solution.

The regenerated ethanolamine leaves the reboiler and passes through the amine-to-amine heat exchanger into a storage tank from which it is recirculated to the contactor with the amine pump. The H2 S and CO? leaving the top of the still column have a large volume of steam with them. To keep down the quantity of makeup water required and to minimize ethanolamine losses the overhead product usually is cooled. The water condensed in this cooling is returned to the regenerator as reflux.

A number of different types of ethanolamine can be used in the process. Monoethanolamine (MEA), diethanolamine (DEA), diglycolamine (DGA), and methyldiethanolamine (MDEA) are among those that are the most popular. There are a number of things that can affect the choice of ethanolamine to be used in a given system. MEA is a stronger base and has a lower molecular weight .

2.16.2 - Iron Sponge Sweetening:

Hydrated iron oxide can also be used for removing Hz S from natural gas. This process is "selective" and removes only the HzS from the gas.

It is suitable for removing small quantities (a few grains **per** 100 scf) of H 2s from natural gas streams. The flow sheet is similar for that of a solid desiccant dehydration unit except for the fact that there is no regeneration gas stream. The iron oxide or sponge is generally suspended on wood chips to disperse it and limit the heat release caused by the reaction of H2.S with the iron oxide. The iron oxide must be kept in a basic environment (pH > 8) so that soda ash or caustic soda solution is normally injected into the bed with the natural gas. The gas leaving the bed has essentially all the H 2 S removed. Since the iron sponge is consumed in the process and must be replaced frequently, the vessels must be constructed in such a **way** that the bed can be replaced easily. Iron sulfide will self-ignite when exposed to air, so extreme caution must be used when replacing the iron sponge bed.

In addition, disposal of the spent sponge can present a problem because, when it burns, sulfur dioxide is formed.

In all desulfurization units, disposal of the HzS gas presents a problem. **Increasingly,** government agencies forbid exhausting the H2S to the atmosphere either as H2S or, after incineration or flaring, as SO;2. **For** this reason disposal of the removed HzS must be an integral part of the planning for any desulfurization unit.

2.17 Innovation in Carbon Dioxide:

it is frequently said that oil and gas reservoirs are likely to be the first category of geological formation where carbon dioxide (CO_2) shall be injected for greenhouse gas sequestration on a large scale, if sequestration proves feasible. Carbon dioxide is injected into comparatively few reservoirs at the present time. It is estimated, however, that 80% of oil reservoirs worldwide might be suitable for CO_2 injection to enhance oil recovery. Enhanced oil recovery operations with CO_2 have been limited by the availability and cost of CO_2, but not necessarily candidate reservoirs. The problem of co-optimizing oil production and CO_2 storage differs dramatically from current gas injection practice because of the cost–benefit difference due to the purchase cost of CO_2 for enhanced recovery projects. When low-cost CO_2 becomes widely available, injection into a wider range of reservoirs is foreseen, with the objective of maximizing the amount of CO_2 left in the reservoir at abandonment. In addition to discussion of the conventional oil reservoir setting, we demonstrate, using laboratory experiments, the applicability and potential of low-permeability unconventional hydrocarbon reservoirs to store significant volumes of CO_2.

2.18 Potential for geological sequestration of CO2: case study

The field validation test, conducted in the Zama oil field of northwestern Alberta, Canada, will evaluate the potential for geological sequestration of CO2 as part of a gas stream that includes high concentrations of H2S (20% to 40%). The results of this project will provide insight regarding the impact of H2S, in conjunction with CO2, on sink integrity (i.e., seal degradation); monitoring, mitigation, and verification techniques; and enhanced oil recovery success within a carbonate reservoir. Monitoringactivities are focused on the near-pinnacle environment, including cap rock integrity, wellbore leakage, and spillpoint

Carbon dioxide capture and storage (CCS) in geological media have been identified as important mechanisms for reducing anthropogenic greenhouse gas emissions currently vented to the atmosphere. Several means for geological storage of CO2are available, such as in depleted oil and gas reservoirs, in deep saline aquifers, in CO2flood enhanced oil recovery (EOR) operations, and in enhanced coalbed methane recovery. Studies in CO2 capture; transportation; storage; and monitoring, mitigation, and verification (MMV) have been, and continue to be, pursued to allow for the deployment of large demonstrations. Understanding the fate of the injected CO2 is an important aspect of the emerging CCS technology. MMV activities are critical components of geological storage locations for two key reasons. First, the public must be assured that CO2 geological storage is a safe operation. Second, markets neede assurance that credits are properly assigned, traded, and accounted for. Integrated geological and hydrogeological characterization and geochemical sampling and analysis programs are technologies that can facilitate documentation of the movement of the injected gases and detect any potential leakage from the storage unit . The Energy & Environmental Research Center (EERC), through the Plains CO2 Reduction (PCOR) Partnership, one of the U.S. Department of Energy (DOE) National Energy Technology Laboratory's Regional Carbon Sequestration Partnerships, is working with Apache Canada Ltd. to determine the effect of acid gas (H2S and CO2)injection for the simultaneous purpose of disposal, CO2sequestration, and EOR. The injection process, and subsequent hydrocarbon recovery, is being carried out by Apache Canada Ltd., while the EERC is conducting MMV activities at the site. The MMV activities have been designed in such a way as to be cost-effective, cause minimal disruption to ongoing oil production activities, and yet provide critical data on the behavior and fate of the injected acid gas mixture.

2.19 Sequestration of CO_2 and other associated waste gases

Sequestration of CO_2 and other associated waste gases in natural gas reservoirs is an option to mitigate greenhouse gases and enhanced gas recovery. This paper examines strategies to maximize enhanced gas recovery in a natural gas reservoir via subsurface storage of potential associated waste gases such as CO_2 and H_2S. Numerical simulations are performed with a compositional reservoir simulator 'Tempest' using experimental data initially produced by Clean Gas Technology Australia (CGTA) at Curtin University in 2009. The simulation results shows that additional gas is recovered by gas-gas displacement after injecting CO_2 and acid gas (CO_2–H_2S) in two separate scenarios. Importantly, when pure CO_2 is injected, CO_2 breakthrough at the production well occurred faster than the breakthrough under mixed CO_2–H_2S injection.

Greenhouse gas injection into geological formations is often considered when attempting to mitigate atmospheric emissions and enhanced hydrocarbon recovery. Sequestrating CO_2 to mitigate CO_2 atmospheric emissions is available and technologically feasible because of experience gained in enhanced oil recovery (EOR) by CO_2 injection. The majority of these operations are located in Canada and United States (Bachu et al. 2003). In particular, during the past decade, oil and gas producers in the Alberta basin of western Canada are increasingly being required to reduce atmospheric emissions by injecting acid gas into deep geological formations (Huerta et al. 2012).

The concept of CO_2-EOR, is now considered to be matured, in Canada for conventional oil reservoirs, and has been successfully applied in Zama (Huerta et al. 2012). Additionally, there are several current and planned projects for CO_2-EOR that involve the separation and geological storage of CO_2. The Sleipner gas field in the North Sea (operated by Statoil) is one such pilot project where separated CO_2 is injected into an underground saline aquifer for sequestration purposes. Other commercial projects are based in central Algeria in Salah (operated by BP) (Algharaib and Abu Al-Soof 2008). Similarly, similar processes are under consideration for sour reservoirs being produced in the Arabian Gulf and central Asia. In particular, producers in Iran, Arab Emirates and Kazakhstan are turning to acid gas disposal by deep injection.

However, data on these operations are only available for the CO_2 injection of enhanced oil recovery and storage, mostly in the Permian basin in west Texas (Bennion and Bachu 2008). Experimental data on impure acid gas injection into natural gas reservoirs for enhanced gas recovery and storage are not yet available. While some published simulation studies attempt to investigate the CO_2-EGR and storage processes, the focus of these studies is to achieve this task in depleted natural gas reservoirs. In addition, several studies are limited to considering only the economic aspects of CO_2 capture and storage. However, Hussen et al. (2012), Khan et al. (2012) simulate experimental data and outline factors that are favourable to enhanced gas recovery and the storage of CO_2 under supercritical CO_2 injection.

This study intends to examine the effects of pure CO_2 and acid gas injection into known natural gas reservoirs in Western Australia, and the displacement of native gases to better understand the mechanisms involved in enhanced gas recovery regarding geological storage.

2.20 Injection of Acid Gas (CO2/H2S) (case study)

Since December 2006, a stream of acid gas (approximately 70% CO and 30% H2 S) has been injected into a Devonian pinnacle reef structure in the Zama oil field in northwestern Alberta, Canada. The injection has been conducted at an average rate of approximately 750 mcf (thousand cubic feet) of acid gas per day, which includes approximately 15 tons of CO per day. The project includes a variety of efforts focused on examining the effects that high concentrations of H S can have on enhanced oil recovery (EOR) and carbon sequestration operations, particularly with respect to monitoring, mitigation, and verification. 2 2 2 2 Research activities are being conducted at multiple scales of investigation in an effort to predict and ultimately verify the fate of the injected gas. Geological, geomechanical, geochemical, and engineering data are being used to fully describe the injection zone, overlying seals, and other potentially affected strata. Validating the integrity of the anhydrite sealing formation and determining the nature of potential geochemical and geomechanical changes that may occur because of acid gas exposure are primary goals of the research. Challenges in dealing with acid gas as a miscible fluid for EOR and sequestration have been identified and examined. Lessons regarding the use of acid gas for EOR and sequestration may be widely applicable, as the exploitation of deeper sour gas pools increases throughout the world.

Carbon dioxide (CO) capture and storage (CCS) in geological media have been identified as important mechanisms for reducing anthropogenic greenhouse gas emissions currently vented to the atmosphere. Several means for geological storage of CO are available, such as in depleted oil and gas reservoirs, in deep saline aquifers, in CO -flood enhanced oil recovery (EOR) operations, and in coal seams for enhanced coalbed methane recovery. Studies in CO capture, transportation, storage, and monitoring, mitigation, and verification (MMV) have been, and continue to be, conducted to support for the deployment of large-scale demonstrations. 2 2 2 2 Understanding the fate of the injected CO is an important aspect of the emerging CCS technology. MMV activities are critical components of geological storage locations for two key reasons. First, the public must be assured that CO geological storage is a safe operation. Second, markets need assurance that credits are properly assigned, traded, and accounted for. Integrated geological and hydrogeological characterization programs that include the analysis and modeling of petrophysical, geochemical, and geomechanical properties of sinks and seals are technologies that can document the movement of the injected gases and detect potential leakage from the storage unit. 2 2 The Energy & Environmental Research Center (EERC), through the Plains CO Reduction (PCOR) Partnership, one of the U.S. Department of Energy (DOE) National Energy Technology Laboratory's Regional Carbon Sequestration Partnerships, is working with Apache Canada Ltd., the Alberta Geological Survey (AGS), and Natural Resources Canada (NRCan) to determine the effect of acid gas (H S and CO) injection for the simultaneous purpose of disposal, sequestration of CO , and EOR. The injection process, and subsequent hydrocarbon recovery, is being carried out by Apache Canada Ltd., AGS has developed baseline characterization data, and the EERC is conducting MMV activities at the site. The MMV activities have been designed in such a way as to be cost-effective and cause minimal disruption to ongoing oil production activities, yet provide critical data on the behavior and fate of the injected acid gas mixture and provide warning in the event leakage from the reservoir should occur. 2 2 2 2 The field validation test, conducted in the Zama oil field of northwestern Alberta, Canada (Figure 1), will evaluate the potential for geological sequestration of CO as part of a gas stream that includes high concentrations of H S (20% to 40%). The results of this project will provide insight regarding the impact of H S, in conjunction with CO , on sink integrity (i.e., seal degradation), MMV techniques, and EOR success within a carbonate reservoir. Monitoring activities are focused on cap rock integrity, wellbore leakage, and spillpoint breach in the near-pinnacle environment. 2 2 2 2 As part of the EOR scheme, acid gas is being injected into the top of pinnacle reef structures (a process referred to as "top-down" injection) that have been depleted of oil through primary and secondary (waterflood) production techniques. Incremental oil is produced from a second well in the reservoir completed near the base of the reservoir. A third well that formerly penetrated the production zone within the pinnacle but was subsequently plugged off and recompleted into a shallower stratigraphic horizon is being used to monitor fluid chemistry and pressure (Figure 2). The acid gas used in this project is obtained from the Zama gas-processing plant and injected into the reservoir at a depth of approximately 4900 feet (1500 meters). Approximately 12,000 tons of acid gas was injected between December 2006, when injection began, and March 2008. Injection is expected to continue for up to 15 years. Over the 4-year life of the project, between

40,000 and 60,000 tons of acid gas is expected to be injected into the pinnacle. Some recycling of this gas will occur through the EOR process, but it is anticipated that most of the injected gas will remain in the injection zone resulting in the sequestration of as much as 42,000 tons of CO in this single pinnacle. With over 800 pinnacle reef structures in the Zama oil field, the potential for CO sequestration through EOR activities is significan

The development and execution of effective MMV operations are a critical element in conducting large-scale injection projects. Successful MMV activities will result in data sets that 1) verify that injection operations do not adversely impact human health or the environment, and 2) validate the sequestration of greenhouse gases for the purpose of monetizing carbon credits from geological storage if such a market were to be developed. There is a broad range of technologies and approaches that can be, and in some cases have been, applied to CO sequestration projects of various scales around the world. Early geological sequestration research and demonstration projects deployed MMV strategies that were developed based on a lack of knowledge about the effectiveness and utility of many of the applied technologies. The absence of knowledge required early projects to gather as much data as possible using a wide variety of techniques. In particular, a desire to "see" the plume of injected CO led to a strong emphasis on the use of geophysical data, especially 3-D and 4-D seismic, to monitor the plume. While the use of geophysical-based approaches and techniques in early projects yielded valuable results that are essential to the development of geological sequestration as a CO mitigation strategy, their high costs of deployment and often limited ability to identify CO in many geologic settings may render them as being the exception rather than the rule when it comes to developing MMV plans for future projects

If the deployment of large-scale CO injection for geological sequestration is to become widespread, then MMV activities must be cost-effective. The use of existing data sets to develop background and baseline conditions should be maximized wherever possible. The use of invasive or disruptive technologies should be minimized not only to reduce costs, but also to limit the inadvertent development of leakage pathways through new monitoring wells. Where sequestration is associated with EOR operations, it is also important that MMV activities have minimal impact on commercial injection and production operations. MMV activities need to be coordinated and integrated as much as possible with ongoing and planned oil field operations. An emphasis on the collection of reservoir dynamics and monitoring well data (including the use of tracers) in conjunction with routine well operation and maintenance activities can, in some geological settings, be an appropriate and cost-effective strategy for MMV. An emphasis on cost-effectiveness and integration with routine oil field activities was the driving philosophical basis for developing the MMV plan that has been implemented at the Zama oil field.

The following techniques are being employed to monitor the effects of acid gas injection at the Zama site. The preinjection state of each of these parameters has been determined either by currently available historical field data or field activities conducted in 2005 and 2006 to acquire new baseline data:

1- To monitor the CO2/H2S plume: -
   Reservoir pressure monitoring –
   Wellhead and formation fluid sampling (oil, water, gas)
   - Geochemical changes identified in observation or production wells

   2-To provide early warning of storage reservoir failure: -

Injection well and reservoir pressure monitoring
- Pressure and geochemical monitoring of overlying formations

3. To monitor injection well condition, flow rates, and pressures: - Wellhead pressure gauges - Well integrity tests - Wellbore annulus pressure measurements - Surface CO_2 measured near injector points and high-risk areas

4. To monitor solubility and mineral trapping: - Formation fluid sampling using wellhead or deep well concentrations of CO_2 - Major ion chemistry and isotopes
5. To monitor for leakage up faults or fractures: - Reservoir and aquifer pressure monitoring – Perfluorocarbon tracer monitoring

2.21 Assessment Methodology for Hydrocarbon Recovery Using CO2-EOR:

After discovery, an oilfield is initially developed and produced using primary recovery mechanisms in which natural reservoir energy—expansion of dissolved gases, change in rock volume, gravity, and aquifer influx—drive the hydrocarbon fluids from the reservoir to the wellbores as pressure declines with fluid (oil, water, or gas) production. Primary oil recoveries range between 5 and 20 percent (Stalkup, 1984) of the original oil-in-place (OOIP). These low recoveries prompt field operators to find ways to improve recovery through the application of secondary recovery methods, which provide additional energy to the reservoir. Secondary recovery methods entail injecting either water and (or) natural gas into the reservoir for repressurizing and (or) pressure maintenance and to potentially act as a water and (or) gas drive to displace oil. This helps to sustain higher production rates and extends the productive life of the reservoir. Normal practice has been to inject natural gas into the gas cap or at the top of reservoir and inject water below the oil-water contact. The oil recoveries at the end of both the primary and secondary recovery phases are generally in the range of 20–40 percent of the OOIP, although in some cases, recoveries could be lower or higher (Stalkup, 1984). Tzimas and others (2005) have reported a slightly higher recovery range of 35–45 percent of OOIP at the end of secondary recovery in their study of North Sea oil reservoirs. A substantial amount of residual oil remains in the reservoir at the end of secondary recovery and becomes the target for additional recovery using tertiary recovery or enhanced oil recovery (EOR) methods. For the purpose of this paper, tertiary recovery or EOR methods refer to those methods used to recover oil not recovered from the secondary processes. The terminology improved oil recovery (IOR) is also used in the petroleum industry and is loosely defined as having a wider scope of practices to increase oil recovery as compared to tertiary recovery or EOR. In addition to what is classified as EOR, the IOR includes secondary recovery processes, such as waterflooding and gas pressure maintenance, and improvements for better sweep efficiency and conformance such as increasing mobility control, infill drilling, and horizontal wells (Taber and others, 1997; Stosur and others, 2003). A classification by van Poollen and Associates (1981) of EOR methods has the following three categories: 1. Thermal methods, which include steam stimulation (also known as “huff and puff”), steam flood (including hot water injection), and in situ combustion; 2. Chemical methods, which include surfactant-polymer injection, polymer

flooding, and caustic flooding; and, 3. Miscible displacement methods, which include injection of hydrocarbon gas, CO_2, or inert gas under high pressure. The immiscible displacement method with CO_2 injection, although not mentioned in the above classification, is also used for EOR and is briefly described in the section Fundamentals of the CO_2- EOR Process. CO_2-EOR has two major advantages: (1) additional hydrocarbon recovery that promotes energy independence and (2) CO_2 storage to reduce atmospheric emissions of CO_2. The focus in this report is only on additional oil recovery using CO_2-EOR. As part of the development work for a better understanding of the CO_2-EOR process, several researchers have reported higher oil recoveries with carbonated water based on their experimental work as early as 1951 (Martin, 1951; Johnson and others, 1952; Holm, 1959).The first field-wide application took place in 1972 at the SACROC (Scurry Area Canyon Reef Operators Committee)
Unit in the 3 Permian Basin where the CO_2 was transported via a 200-mile-long pipeline from the Delaware-Val Verde Basin. The process proved to be a technical success but required optimization of the CO_2 slug size or the amount of CO_2 injected for its economic viability (Kane, 1979). Because of the availability of CO_2 in adequate quantities from both natural and industrial sources in the region, there were more field-wide successful applications of the CO_2-EOR process in the Permian Basin than any other region in the United States, and the area continued to show an increasing number of reservoirs with CO_2-EOR as a preferred option.

2.21-1 Geologic Framework

All reservoir lithologies, including siliciclastic, carbonate, and others, are suitable for CO_2-EOR application as long as they have interconnected pore space for fluid accumulation and flow and also have an adequate seal to entrap hydrocarbons. Geology is a critical element in reservoir development and exploitation, particularly when CO_2-EOR is considered. The oil recovery is influenced by geologic features such as rock and fluid characteristics, porosity, permeability, and structural or stratigraphic features such as faults and other barriers to oil or gas movement. A good reservoir characterization leads to improved estimates of OOIP values as well as to a better understanding of reservoir behavior

2.21-2 Reservoir Engineering Aspect :

The CO_2 from a natural or industrial source is injected into a selected oil reservoir either as continuous gas or as water-alternating-gas injection also known as WAG, as described in the section CO_2 Flood Injection/Designs. Not all reservoirs are suitable for CO_2-EOR and are screened based on factors such as reservoir geology, minimum miscibility pressure (MMP), oil gravity, and viscosity to help identify the most likely candidates for miscible CO_2. In preliminary screening, reservoirs having a minimum mid-point reservoir depth of 3,000 feet or deeper were selected because the temperature and pressure at that depth foster miscibility of CO_2 with the reservoir oil and also helps to accommodate high-pressure CO_2 injection. Any deviation from the above criteria for choosing a reservoir would depend on the size of the reservoir and potential hydrocarbon recovery. The U.S Environmental Protection Agency (EPA) (2009, 2010) regulations for the protection of underground sources of drinking water (USDW) state that formations containing water with less than 10,000 mg/L .

2.22 ECONOMICS OF ACID GAS REINJECTION:

Acid gas streams, consisting primarily of hydrogen sulfide (H2S) and carbon dioxide (CO2), are commonly generated as a by-product of the gas sweetening process used to bring produced gases and solution gases up to pipeline specifications for sales and transport. In the past, the conventional methods for acid gas disposal are to use a Claus process or to flare the acid gas. A new technology called acid gas reinjection has emerged over the past ten years in Canada as an effective way of ensuring that acid gases are not emitted into the atmosphere. There are 38 acid gas reinjection projects presently operating in Alberta. This technology involves compressing the acid gas and injecting it into a suitable underground zone, similar to deep well disposal of produced water. Essentially, the sulfur compounds and CO2 are permanently stored in the deep geological formation preventing their release to the atmosphere. Therefore most acid gas reinjection projects can be considered as existing examples of CO2 geological storage projects. These projects provide important practical experience with CO2 storage. In addition, this technology could be extended to capture a significant fraction of the natural gas-associated CO2 stream at low cost.

In this paper, a cursory economic analysis is made on one of the Alberta acid gas reinjection projects relative to sulfur recovery for determining the amount of CO2 avoided.

INTRODUCTION

The capture of CO2 from the production and use of fossil fuels and its storage in geological formations may offer the ability to make early and deep reductions in CO2 emissions without abruptly abandoning our fossil-based energy infrastructure [1, 2, 3]. While the economics of CO2 mitigation are uncertain, to a rough approximation it appears that CO2 capture and storage (CCS) fills the gap between the lowest costs, most immediately available measures of CO2 mitigation, such as moderate energy efficiency improvements, and the higher costs associated with a transition to a non-fossil primary energy supply. Given its intermediate cost, one might expect that CCS technologies would play no role in achieving small, near term reductions in emissions. There is however an important, though limited, suite of technological niches where CCS technologies may be applied at low cost. The most important of these opportunities involve non-combustion sources of CO2. The cost of capturing CO2 and compressing it to the pressures required for geological storage (of order 100 atmospheres) is primarily dependent on the scale and purity of the CO2 stream to be captured. Combustion sources have CO2 concentrations of 5 to 15%; and for these dilute streams the cost of capturing CO2 dominates the cost of storage, accounting for perhaps 3/4 of the overall cost of CCS [4]. For non-combustion sources the cost of capture is smaller, and can be zero for sources of nearly pure CO2.

Although the great majority of CO2 emissions arise from combustion, significant non-combustion sources of CO2 exist. In Canada, the three most important non-combustion sources of CO2 are natural gas processing, hydrogen production and ammonia manufacture. These sources have high concentration of CO2 and they in turn can provide important opportunities for early application of CCS technologies.

2.23- ACID GAS REINJECTION

Raw natural gas may contain significant impurities, with CO_2, H_2S, and N_2 being the most important. “Sour gas” by definition is natural gas that contains H_2S. In order to meet sales gas contract specification, sour gas must be treated for the removal of virtually all of the H_2S. For very low H_2S content (ppm level), disposable chemical such as SulfaTreat may be used to remove the sulfur. For higher H_2S content, a chemical absorption process with amine may be used. Typically, the amine absorption method captures most of the CO_2 in addition to the H_2S. The resulting CO_2 + H_2S (acid gas) must then be processed to eliminate the H_2S. The least cost method to eliminate H_2S is to flare the acid gas stream burning the H_2S to SO_2 and releasing the CO_2 to the atmosphere, along with the SO_2. Over recent decades, concerns for the environmental effects of sulfur emissions have eliminated flaring as an option for all except the smallest facilities. Another option is to process the acid gas in a sulfur recovery unit such as a Claus plant, which produces sulfur as a salable byproduct, but releases the CO_2 as before. In response to falling sulfur prices and increasingly stringent restrictions on residual SO_2 emissions, the industry has recently begun to abandon sulfur recovery in favor of acid gas disposal. For the largest plants, the lowest cost route may still be sulfur recovery, but for plants with lower H_2S fluxes the lowest cost option is to compress the full acid gas stream (CO_2 and H_2S) and dispose of it in a suitable geological formation.

2.24 Removal of acid gases:

Natural gas is an important fuel gas and it is used extensively as a basic raw material in the petrochemical and other chemical process industries. The composition of natural gas varies widely from field to field. Many natural gas reservoirs contain relatively low percentages of hydrocarbons (less than 40%, for example) and high percentages of acid gases, principally carbon dioxide, but also hydrogen sulfide, carbonyl sulfide, carbon disulfide and various mercaptans. The acid gases are detrimental to hydrocarbon handling and usage, and therefore acid gases are typically removed from the produced hydrocarbons by processes that are well known. The natural gas may also contain inert gases such as nitrogen, which are also removed by methods that are well known. The separated acid gas and inert gas often has insufficient value to justify further treatment or purification for any further commercial usage. “Waste gas” is a term that will used in this patent to describe a gas containing acidic components such as hydrogen sulfide or carbon dioxide, and may or may not contain inert gases. The waste gas typically has little or no commercial value.

Proposals have been made to re-inject the separated waste gas into disposal strata through an injection well directly into a depleted or spent zone of the hydrocarbon-bearing formation from which the gas was produced (see for example U.S. Pat. No. 5,267,614) or re-injected into a separate subterranean strata (see for example U.S. Pat. No. 6,149,344 and World Intellectual Property Organization publication number WO 00/58603). However, the prior art does not address how to simultaneously produce a gas while re-injecting a waste gas into the same formation

A gas processing facility for processing a hydrocarbon gas stream is provided. The hydrocarbon gas stream comprises sulfurous components and carbon dioxide. The gas processing facility includes an acid gas removal facility for separating the hydrocarbon gas stream into (i) a sweetened gas stream, and (ii) an acid gas stream comprised primarily of hydrogen sulfide and carbon dioxide. The gas processing facility also includes a Claus sulfur recovery unit that generates a tail gas, and a tail gas treating unit for receiving the tail gas. In various embodiments, the gas processing facility captures CO2 from the tail gas and injects it under pressure into a subsurface reservoir. A method for processing a hydrocarbon gas stream such that additional CO2 is captured and injected into a subsurface reservoir is also provided.

2.25 Acid gas injection into a fully depleted Oil reservoir

This paper reports on an optimization study for acid gas injection into a fully depleted oil reservoir by numerical modeling. As a special case, the Zama Keg River Z3Z Oil Pool with one horizontal production well and previous acid gas disposal was considered. Acid gas generation (60 - 80% CO_2 and 20 - 40% H_2S) and safe geological disposal, or conversion to elemental sulphur with associated emissions, is an ongoing concern at Apache's Zama Gas Plant operations. The opportunity for a possible enhanced oil recovery application in the Zama field was foreseen given that use of CO_2 in combination with H_2S (acid gas) is known to reduce the minimum miscibility pressure with reservoir oils relative to using pure CO_2 as a miscible agent. Storing H_2S with the CO_2 in underground reservoirs will double the benefit for the environment in terms of both short- (mainly H_2S) and long-term (mainly CO_2) effects to the environment.
Ten (10) pinnacles were selected as potential candidates for a pilot project of acid gas injection (sequestration and EOR). Optimal conditions that maximize the oil recovery and the amount of acid gas sequestered were identified for one of these ten pinnacles- the Zama Keg River Z3Z Pool. Special attention was given to breakthrough times, incremental oil recovery and CO_2/H_2S sequestration volumes.
After constructing the static reservoir model using the available data with stochastic/geostatistical techniques, history matching was performed. The compositional simulation option of a commercial simulator (ECLIPSE) was used for this purpose. Available PVT data were used and other data needed were generated using correlations. A number of different injection scenarios were then tested for the combination of optimum incremental oil recovery and acid gas sequestration. The following parameters were considered in the optimization study:

- miscibility;
- gravity override;
- cyclic injection;
- injection rate;
- injection and production well constraints (completion).

Optimum injection strategies yielding maximum oil recovery and maximum acid gas storage, as well as delaying breakthrough time, were evaluated for these cases.
The natural gas sweetening process produces sales gas and acid gas (CO_2 and H_2S) as a waste with a high percentage of CO_2 in the Zama Field. The catalytic conversion of H_2S into element sulphur, commercially called a Clause process, is a good economic process during times of high demand and high prices for sulphur. Reduction in world price of sulphur and the environmental hazard of stockpiling elemental sulphur in large blocks is a cause for concern in the oil and gas industry.
Energy producers around the world are focusing on a value-added approach to enhanced oil recovery (EOR) or enhanced gas recovery (EGR) for greenhouse gas (GHG)

disposal . Different injection strategies for CO_2 injection, flue gas injection and Water Altering Gas (WAG) with CO_2 have been studied and implemented for EOR since the 1970's .
Acid gas was found to be an effective EOR agent since H_2S reduces the minimum miscibility pressure (MMP) of CO_2 . By 2003, approximately 2.5 Mt CO_2 and 2.0 Mt H_2S have been stored in depleted oil/gas reservoirs or deep saline aquifers).

2.26 Acid G as & EOR CASE STUDY Zama oil field:

Since October 2005, the Zama oil field in northwestern Alberta, Canada, has been the site of acid gas (approximately 80% CO2 and 20% H2S) injection for the simultaneous purpose of enhanced oil recovery (EOR), H2S disposal, and sequestration of CO2. Beginning in December 2006 and continuing through the present, injection has taken place at a depth of 1494 meters into one of over 800 pinnacle reef structures that have been identified in the Zama Subbasin. To date, over 36,000 metric tons of acid gas has been injected, resulting in incremental oil production over 25,000 barrels. Cost-effective monitoring at EOR sites that utilize H2S-rich acid gas as the sweep mechanism has been the overall goal of the project. The primary issues that have been addressed include 1) cap rock leakage, 2) long-term prediction of injectate, and 3) generation of data sets that will support the development and monetization of carbon credits. To address these issues, activities have been conducted at multiple scales of investigation in an effort to fully understand the ultimate implications of injection. Geological, geomechanical, geochemical, and engineering work has been used to fully describe the injection zone and adjacent strata in an effort to prove the long-term storage potential of this site. Through these activities, confidence in the ability of the Zama oil field to provide long-term containment of injected gas has been achieved. Results obtained from these activities can be applied not only to additional pinnacles in the Alberta Basin but to similar structures throughout the world.

Acid Gas EOR; MVA; Geology; Geomechanics The Energy & Environmental Research Center (EERC), through the Plains CO2 Reduction (PCOR) Partnership, one of the U.S. Department of Energy (DOE) National Energy Technology Laboratory’s Regional Carbon Sequestration Partnerships, is working with Apache Canada Ltd. to determine the effect of acid gas (H2S and CO2) injection for the simultaneous purpose of disposal, CO2 sequestration, and enhanced oil recovery (EOR). The reservoirs in the Zama oil field exist in the form of isolated, porous, and permeable pinnacle reefs (carbonate rocks) sealed by a thick layer of essentially impermeable anhydrite. The capture, transportation, and injection processes and subsequent hydrocarbon recovery operations are being carried out by Apache Canada at its oil field and natural gas-processing plant locations near Zama, Alberta, Canada (Figure 2). The role of the PCOR Partnership was to conduct monitoring, verification, and accounting (MVA) activities at a specific location/reservoir (referred to as the “F Pool”) within the Zama oil field. The MVA activities have been designed in such a way as to be cost-effective, cause minimal disruption to ongoing oil production activities, and yet provide critical data on the behavior and fate of the injected acid gas mixture within the reservoir.

The Zama project was designed with the following goals in mind:

- ✓ To demonstrate that the capture and injection of an acid gas stream into properly characterized and carefully selected underground reservoirs is feasible and safe within existing industry and regulatory standards.
- ✓ To design, implement, and demonstrate cost-effective MVA strategies for verifying and validating the containment integrity of the target reservoirs.
- ✓ To demonstrate that highly concentrated acid gas (in this case, 30% H_2S and 70% CO_2) can be successfully used for EOR operations in a type of geological feature (carbonate pinnacle reefs) that had previously been untested with respect to acid gas-based EOR.

Chapter 3.0

Research Methodology

The skeleton of work/study was built on the following methods and technique:

3.1 Alternative technique EOR / IOR:

Looking deeply through various Alternative technique such as:

- ☑ EOR (oil reservoir /gas cap)
- ☑ Re-injection in deep aquifer.
- ☑ Storage to a shallow formation.
- ☑ Re-injection to other formation or structure neighboring
- ☑ Down hole work separation
- ☑ Upgrading gas treatment unit
- ☑ Discharged to emission (flaring).

3.2 Reliability and validity:

The reliability and validity of the quantitative data analysis and measurement were evaluated through the examination of the Cronbach's Alpha. The tau-equivalent measurement model actually measures internal consistency of reliability (Hair, Black, Babin, Anderson, & Tatham, 2006). For most investigations and for the purpose of the research study, Cronbach's Alpha above 0.7 was considered acceptable (Allen & Bennett, 2014

3.3 Geoengineering (Reservoir Management)

- Evaluated and reviewed all available data such as production data, pressure data well log analysis, geological reports and maps, including petrophysical studies, production data, pressure data, deliverability tests.
- Reviewing and integrating all existing dynamic input data P: as PLT results, PVT, Well-test results, SCAL (Kr, Pc)
- Analyzing: critical reservoir issues (water cut and reservoir pressure) the water-coning / fingering phenomena

3.4 software application and static and dynamic models:

- History matching well and field dynamic parameters (aquifer strength, oil rate, WC, pressures- surface, bottom-hole, reservoir)
- Quantifying long-term required injection volumes and rates (full-field water injection optimization in terms of volumes, injectors and injection pattern)
- The study will be carried out using the following software:
    - ➢ Reservoir modeling: PETREL, Schlumberger.
    - ➢ Reservoir Simulation: ECLIPSE, Schlumberger
- utilized the results gained from:

  Static Reservoir Geological Model: Final PETREL Project. And reservoir Simulation model in ECLIPSE with all the input data necessary for its nitialization and the reproduction of the scenarios analyzed during the study (better if in PETREL RE)

3.4-1 3D model -Forecast cases definition

Forecast cases definition should be undertaken after the completion of the history matching phase

However, forecast cases should include (but not limited to) the following cases:

- Base case (Do Nothing) to be used as reference
- Maximum reserves case (regardless of economic criteria)
- Optimum development case (based on economic criteria)
- Minimum investment case to fulfill minimum contractual constraints
- Other sensitivity cases to be defined late

3.5: Data Review, Evaluation

- Identified all available collected data with the previous studies and the available structural maps. will include Geophysical, Geological, Petrophysical, and Petrographic studies and reports, in addition to Engineering, and Production data, reports and studies.
- Review the available data/studies and report on the completeness and suitability of the data used in creating the supplied geological model and the subsequent simulation study.
- Drilling, completion and workover history for each well including DST, MDT, etc. a Routine and SCAL data. a Fluid PVT reports. a Water analysis.
- Pressure history of individual wells and all available pressure transient test data.

3.6 Conventional Reservoir Engineering:

The revision of the following specific areas of data analysis:

Completion and work over history: the drilling, completion and work over history for all wells will be reviewed and incorporated into a file to be utilized during the history matching and will form part of the well summary. Completion and re-completion information will be used to correlate well-bore production events.

PVT data validation to establish reliable fluid properties for each zone of the reservoir: all available fluid reports will be reviewed and evaluated. This will include the sampling condition and comparison with well test data. The PVT data will be verified and analyzed with the objective of having a representative PVT to describe each one of the possible compartments/zones inside the reservoir.

Water analysis: all the available water analysis reports will be analyzed to determine any horizontal or vertical variation in the connate water properties. The produced water analysis will also be reviewed to check for the potential setbacks of scaling or other well-bore problems.

Routine and special core analysis: routine and special core analysis data, such as relative permeability, capillary pressure and wettability will be reviewed and correlated. The analysis should result in:

Production Data Analysis:

The historical production performance of every well will be analyzed and compared to test data and allocation factor. The following specific tasks will be performed to screen and evaluate the production data of each well and of the field

Focusing on Decline performance for the field and for the individual wells,

Chapter

4.0

Environmental Management & Risk Analysis

Chapter Recap

Influence of Disposal Produced Formation Water on marine Environment associated with Risk Analysis in Offshore Oil Field: Case Study

4.1 introduction:

The volume of produced formation water is steadily increasing as the mature offshore field (*one of the largest Libyan offshore oil fields*) is depleted. Additional volumes will be presented by near future activities for improving oil recovery by Artificial lift project, Low pressure gathering system project, Infilling wells from existing platforms, Work over for some wells and second phase of development field.

Hence, a strong need appears for supplementary methods to deal with the discharge problem. two scenarios have been investigated in this study, underground disposal of water into isolated formation and/or by upgrading the treatment facilities. The former meets the field requirements, because the surface treatment facilities for water in platform will reach soon its design working limit. As outcome to various offshore activities through two platforms, a risk assessment study is strongly recommended to overcome all the uncertainties problems, which could be a risky for people on platforms, facilities and environment.

The key benefit provided by risk and environmental analysis is that can summarize for decision-makers integrating available data about hazard and Potential effects of exposure. Revealing an effective and economical solution for oily wastewater treatment in shadow of employing the technique of multiple regression analysis functioning, and to develop a reasonable mathematical model which can used for prediction purposes.

The risk analysis can assist the client in identifying the critical activities and task that deemed to be reported, in prioritization of both the sub surface and surface uncertainties and development of the plan forward.

As consequence of risk analysis it was observed that the produced formation water discharge into the sea present a very law environmental risk, due to high dilution rates this has brought the average concentration of oil in the water below the limit of international regulation for produced formation water.

4.2 Water Disposal & Environmental Impact

On account to present & near future activities for the increasing the production by the new low pressure Gathering System followed with the Artificial lift project, the amount of the produced oily water will increase (between 20,000-40,000 BWPD)

From the two train(1&2) to feed existing Waste Water Treatment unit 28 (***unit is illustrated in the figure 4.1*)**, where the existing treating unit is not sufficient to treat this huge quantity of the produced oily water which designed only for 21,500 BWPD, so others options becomes mandatory to overcome the accession of the produced oily water either by upgrading the treatment facilities or by re-inject a part or total of produced water into the down hole formation via a candidate disposal well in order to avoid environmental and pollution problems.

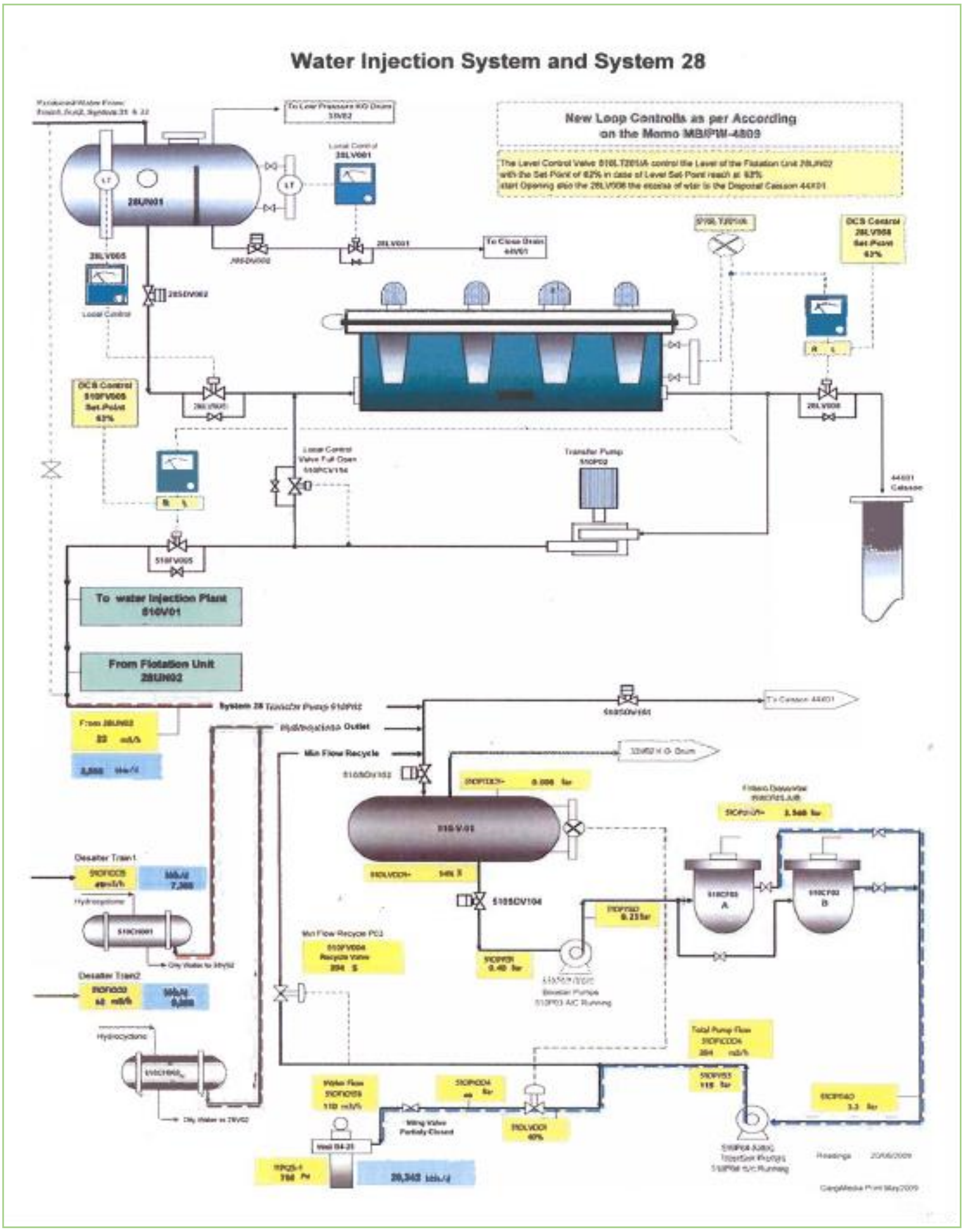


Figure 4.1: Water injection unit

This project strategy to be done first to carry-out a pilot test to verify the availability of the reservoir's formation to absorb the target of produced oily water in range of 12,000-40,000 BWPD, and the results will ensure to be better plan:

- Necessity of other disposal wells
- Necessity to upgrade the existing treatment facilities, if the Disposal well behavior will be negative (the oily water will plug the well during the test)

Therefore, a strong need appears for a new way of dealing with this problem, represented by the suggested underground disposal of water in Melqart formation , at depth of around 1500 ft .utilizing the flooded well H4-20. Efforts were concentrated on the acquisition and analyses of data of the formation and the well to be converted for disposal, to evaluate the technical feasibility of the project

4-3 Disposal Well - Reservoir Basic Data :

4-.3. 1 : Geological Data:

- Melquart formation pore volume about 78*10e 9 bbl.
- Vertical extension limited above by anhydrite section of Melqart and excluding and porous part above.
- Melqart formation represents a thick lime stone body with high orosity, with top at around 100-1200 ft ,characterized by the appearance of tight anhydrite layer of more than 200 ft.
- The formation extends over the whole area of field, and is underlined by shales and marls of Mahamud formation
- Good vertical continuity appears from logs, with average net thickness of 750 ft.

4.3.2 Reservoir Engineering :

- Reservoir salinity = 50,000 ppm
- Reservoir pressure = 1005 psi
- Reservoir temperature = 85 deg.F
- Average porosity = 30 %
- Fracture gradient = 0.67 psi/ft
- Injectivty index = 100 bwpd/psi
- Injecting pressure = 1000 psi

4.4 Contaminated Water, Literature review

The produced water mostly includes dissolved and organic compounds, oily hydrocarbons, trace metals, suspension, and many other substances that are components of formation water from reservoir.

Oil hydrocarbons are present in produced water, the levels of oil in discharges vary extremely. They depend on the fractional composition of the oil and the effectiveness of oil-water separation methods besides the specific technological situation

In general, the separator mainly removes particulate and dispersed oil, while dissolved hydrocarbon in concentration from 20-50 mg/l. go overboard as part discharged water.

The most produced water had a very high mineralization in terms of characteristic of the chemical composition .in some case it is even had a higher salinity than seawater.

Such mineralization is caused by the presence of dissolved ions of sodium, magnesium, potassium, chloride and sulfate in produced water, moreover some of heavy metals as well as corrosion inhibitors, descales, and other chemical

The produced water can mix with the extracted oil, gas and injection water, all the above make the composition of the discharged produced water so complex and my changeable.

Treatment, storage, and disposal facilities (TDSs)are the last link in the cradle-to-grave hazard us waste management system.

All TSDs handing hazardous waste must obtain an operating permit and abide by treatment, storage, and disposal regulations.

The TSD regulations establish performance standards that owners and operators must apply to minimize the release of hazardous east into the environment.

A TSD may perform one or more of the following functions:

- **Treatment**: any method technique, or process, including neutralization, designed to change the physical, Chomical, or biological character or composition of any hazardous waste so as to neutralized it or render it non hazardous or less hazardous : to recover it ; make it safer to transport ,store , or disposal of ;or make it amenable for recovery, storage, or volume reduction .
- **Storage**: the holding of hazardous waste for a temporary period, at the end of which the hazardous waste is treated, disposed, or stored elsewhere.
- **Disposal** : the discharge, deposit, injection, dumping, spilling , leaking, or placing of any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters

4.5 Environmental management &methods of disposing

Reduce: water cut could reduce by:

- Water shut- off treatment (chemical or cement)
- Re-perforation
- Choking down

Re-use : in some cases the produced water with reliable salinity, used for re-injection for reservoir pressure maintenance or sweep water flooding. in rare case with very low salinity, treated can be use for agriculture irrigation or for wash water

Treatment/disposal : a various methods were available for treatment process, which need to be selected to suit the ultimate disposal location and environment and be feasible from economical, technical point of view how ever there are many methods for disposing the produced water in oil field, the main methods are

- Re-injection to oil reservoir.
- Re-injection in deep aquifer.
- Down hole work separation.
- Water treatment unit.
- Discharged to sea.(or pits in onshore fields)
- Re-injecting to a shallow formation.

The last method (the above mentioned) technique has been aimed to select a layer or formation overlies the reservoir that will be serves a candidate for injecting a contaminated water , which can not be handle by existing water treatment unit .

4.6 Work description for system :

The scope of work mainly composed by following units:

- booster pumps.
- New filters up to 5 micro meter
- Re-injection pump 1450 psi
- New piping and measurement system
- New control, safety valves and isolation valves
- Pump capacity 15000 b/d
- Pressure per pump (max) 3000 psi
- Voltage 380 v, 50 Hz frequency
- Max. flow rate of processes water of 40,000 bwpd
- Min. flow rate of processes water of 12,000 bwpd

4.6.1 Basic data of exiting system :

The water treatment system consist of two main unit's skimmer (28-UN-01) and flotation (28_UN-02) units and caisson (as *given in previous figure)* (44-01),designed to treat 21509 bwpd. Operating conditions:

- T= 80c, P = 1.013 bar
- System design flow rate = **21509** bwpd
- inlet water max. oil content = **2000** ppm
- out let water oil content = **15** ppm

4.7 Environmental Data:

Sea hydrological condition:

Temperature on sea bottom about 57-60.8 deg. f

salinity:

Salinity (ppm)	Nacl	O2	C2	Mg	ph
Surface	35.34	5.5-5.0	440	1390	7.72
-90 m	35.920		440	1400	7.91
-144 m	35.920	4.5-3.9	440	1390	7.80

Solid content:

0.05-0.5 mg/l in deeper layers m : -70 to –170

0.05-1.5 mg/l in surface layers m : 0 to – 70

20-60 % consists of particulate organic carbon (p.o.c)

Waves:

- Max. height ……………… **16.**1 m
- Period ---------------------- **12.7** sec
- Max. significant height
  for operating from supply boats -----**2.16** m

- Period. --------------- ------------------- **2** sec

Wind:

- Max. speed ----------------(m/sec) : **45**
- Direction ---------------------------- : **N-NW**
- Max. gust ----------------(m/sec) : **54**
- Max. gust duration---------(sec) : **1-2**
- Max. win speed for operating
  from supply boats ---------(m/sec) : **15**

Rainfall

- max rainfall--------------(mm/d) : **45**

Ambient data:

- Temperature min/mean/max (f) **41/67/96**
  relative humidity min/mean/max (%) **40/75/95**
- Barometric pressure (Millbrae)
  min/mean/max **90/1015/1037**

4.8 Data and Methodology:

4.8.1 Oil Content in produced water samples:

Table 4.1 are Presented The_Monthly average measurements of produced water of inlet and outlet of unit 28 in terms of PPM, on the other hand the available oil in water data for field is presented in the *attached graph from 4.1 to 4.8* of PPM variation during last five years of production.

Date	INLET-PPM	OUTLET-PPM	bopd	BWPD	SCF/D	GOR Scf/stb	WC %
31/01/1998	104	37	33229.2	7426	65108	1959	0.183
28/02/1998	122	45	32656.9	8021	64124	1964	0.197
31/03/1998	139	53	33079.9	7994	65286	1974	0.195
30/04/1998	135	63	32640.5	851	64756	1984	0.207
31/05/1998	117	48	33076	8900	65147	1970	0.212
30/06/1998	170	51	32664.6	8643	64465	1974	0.209
31/07/1998	158	60	33779.8	9029	68377	2024	0.211
31/08/1998	137	46	32974.9	8110	65264	1979	0.197
30/09/1998	105	40	32219.7	8150	64636	2006	0.202
31/10/1998	61	31	33295	8023	64744	2009	0.199
30/11/1998	73	34	31934.3	8237	64556	2022	0.205
31/12/1998	49	20	31720.3	8590	64341	2028	0.213
31/01/1999	39	15	31764	8858	63023	1984	0.218
31/03/1999	31	13	31301.9	8774	62726	2004	0.219
30/04/1999	43	19	31396.7	8830	63340	2017	0.220
31/05/1999	43	13	31208.8	8945	62383	1999	0.223
30/06/1999	32	16	31213	9020	62628	2006	0.224
31/07/1999	42	13	32200.8	9168	61754	1918	0.222
31/08/1999	43	14	32356	9737	62145	1921	0.226
30/09/1999	37	16	32403.4	9320	62455	1927	0.223
31/10/1999	37	16	31671	9165	63348	2000	0.224
30/11/1999	48	23	32274.2	9319	62308	1931	0.224
31/12/1999	39	19	33095	9859	62915	1901	0.230

dat	INLET-PPM	OUTLET-PPM	bopd	BWPD	SCF/D	GOR Scf/stb	WC %
29/02/2000	27	16	31933.6	9436	58100	1819	0.228
30/09/2000	27	14	34403.8	9280	64707	1881	0.212
31/10/2000	28	14	35038.4	9366	66206	1890	0.211
30/11/2000	37	20	34795.2	9448	65095	1871	0.219
31/12/2000	22	11	34549.7	9793	65643	1900	0.221
31/01/2001	24	15	35863.4	9676	66380	1851	0.212
28/02/2001	27	16	35587.5	9582	65828	1850	0.212
31/03/2001	26	12	35397.5	9821	65818	1859	0.217
31/05/2001	18	12	34775	9951	66329	1907	0.222
30/06/2001	29	18	34438.7	9601	66707	1937	0.224
31/07/2001	35	25	35447.5	10951	67471	1903	0.236
31/01/2003	97	57	39555.9	12681	74785	1891	0.243
28/02/2003	66	41	40440.1	12337	75986	1879	0.234
31/03/2003	52	25	42000	11752	76436	1881	0.224
30/04/2003	51	27	40903.1	12860	76177	1862	0.239
31/05/2003	56	23	33975.8	9039	59738	1758	0.210
30/06/2003	50	20	40871.9	11980	72829	1782	0.227
31/07/2003	40	24	39639.7	12194	73991	1867	0.235
31/08/2003	68	36	39680.2	13283	73317	1848	0.251
30/09/2003	65	29	38918	12848	69134	1776	0.248
31/10/2003	65	27	39184.8	13215	69993	1786	0.252
30/11/2003	42	18	38936.3	13273	70541	1812	0.254
31/12/2003	51	21	39240.5	13669	71080	1811	0.258
31/01/2004	41	20	38992.2	14363	71126	1824	0.269
29/02/2004	53	23	39364.2	14180	68184	1852	0.265
31/03/2004	100	36	39427.3	13686	79155	1878	0.258
30/04/2004	92	39	40409.8	14029	72001	1841	0.258
31/05/2004	91	35	39758.6	13726	74007	1861	0.257
30/06/2004	75	33	39730.2	13417	74064	1864	0.252
31/07/2004	73	34	39095.4	12443	73746	1886	0.241
31/08/2004	87	44	37669.6	11145	66487	1765	0.228
30/09/2004	90	40	37474.3	12554	67595	1804	0.251
31/10/2004	81	38	34002.9	6815	60920	1734	0.167
30/11/2004	43	25	36725.1	14000	66257	1804	0.276
31/12/2004	45	27	36351.9	14715	66927	1841	0.288

Table 4.1: Production performance Vs. oily water in ppm

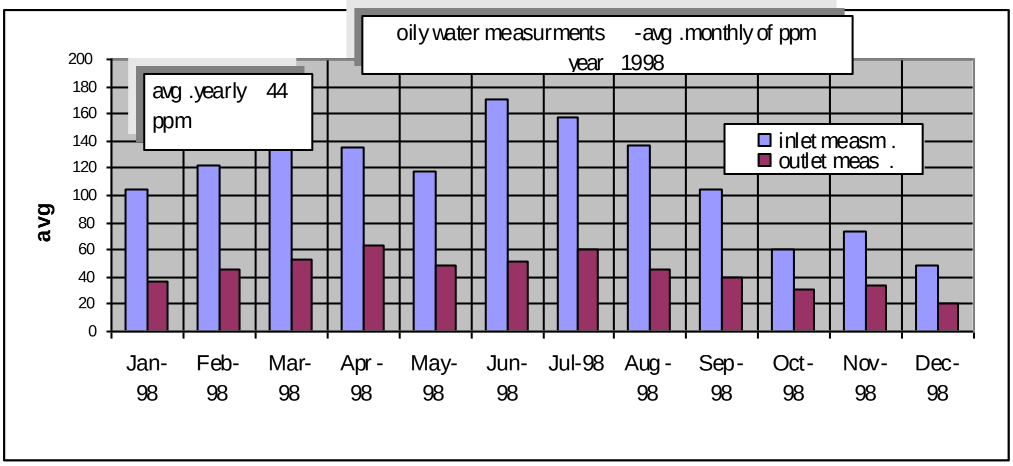


Figure 4.1 Water inj. Y- 1998

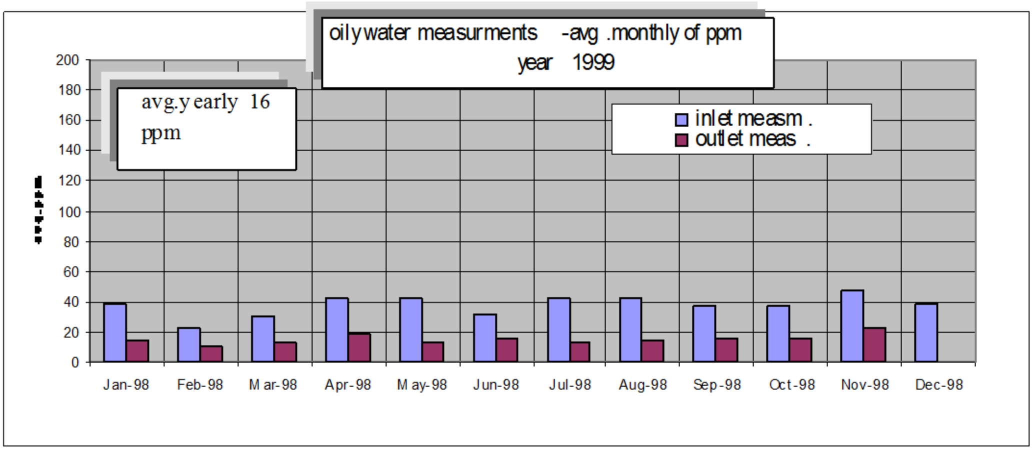


Figure 4.2 Water inj. -Y 1999

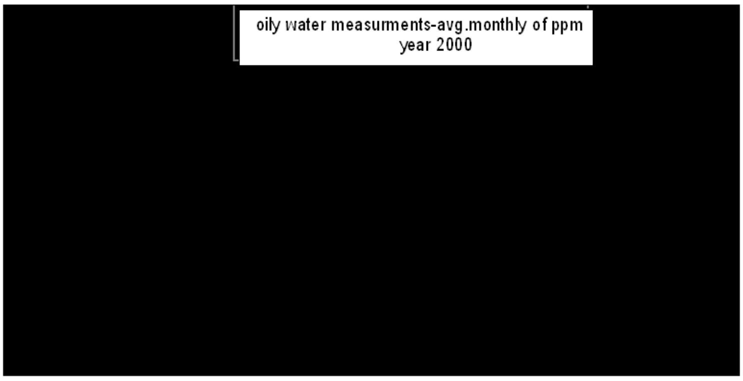


Figure 4.3 Water inj. -Y 2000

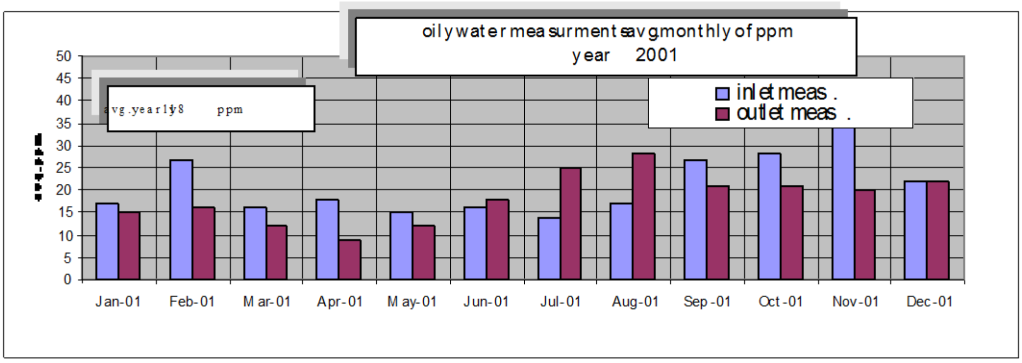


Figure 4.4 Water inj. -Y 2001

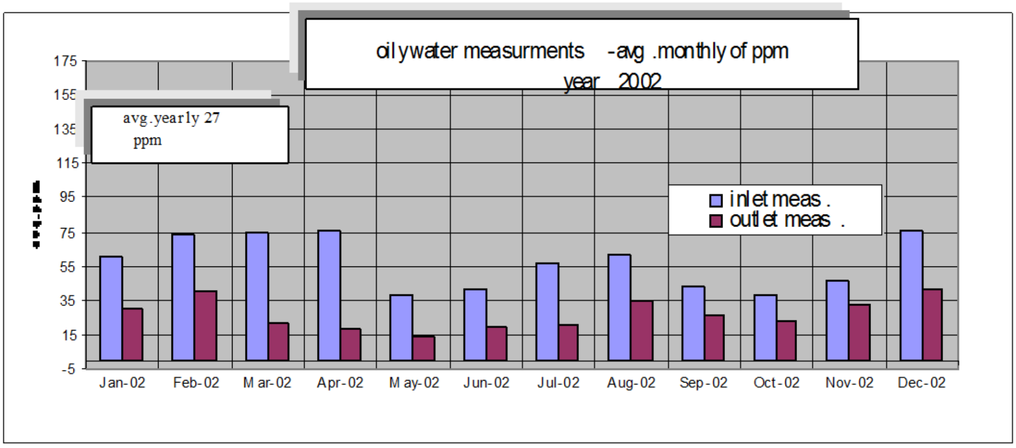


Figure 4.5 Water inj. -Y 2002

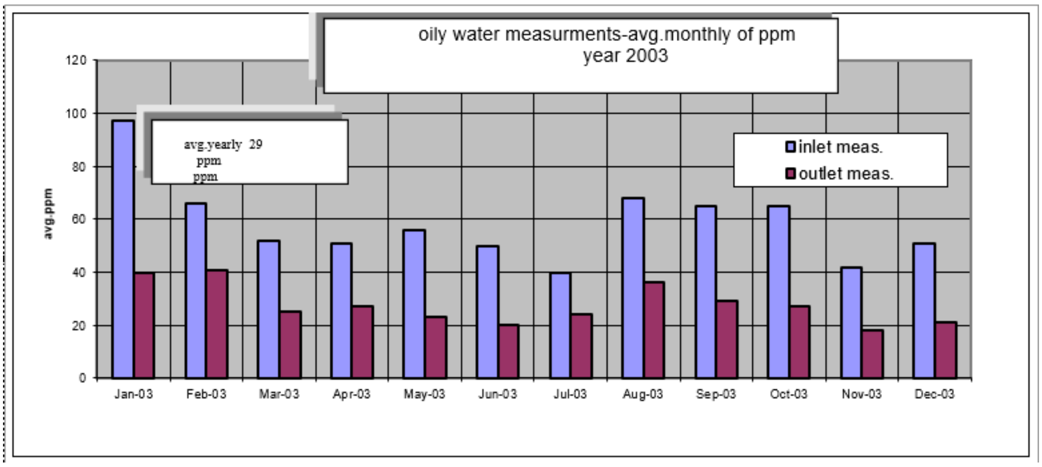


Figure 4.6 Water inj. -y 2003

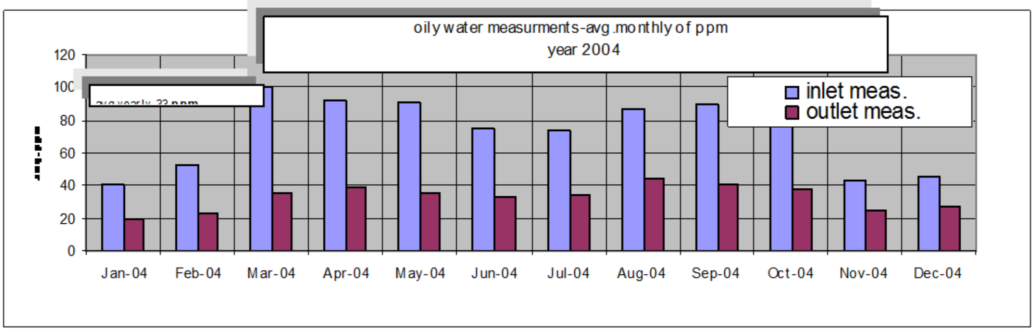


Figure 4.7 Water inj. Y-2004

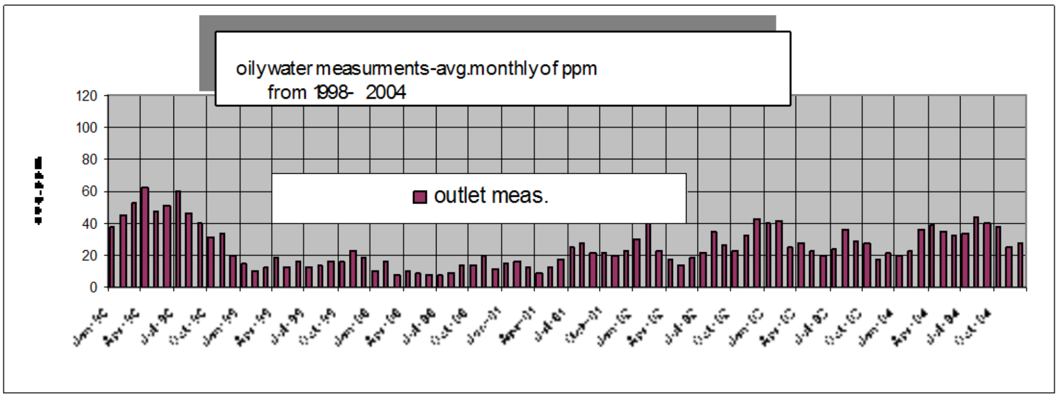


Figure 4.8 Water inj. Y-1998-2004

4.8-2 Methodology:

The first method was introduced to handle risk analysis assessment by HAZOP method due to different activities through topside facilities of produced water disposal system & existing water treatment unit 28.
The second method was focus on the regression equation that may use to estimate the oily water amount during field production

4.9 Risk analysis -HAZOP:

The technique of risk analysis assessment had been used of the available information to determine how often specific events may occur and magnitude of their consequence, it is a systematic apply to describing and calculating risk .and to identification of undesired events and the causes and the consequences of hat events

However the mentioned task of the water disposal system and water treatment unit has been outlined for installation to be provide under OFFSHORE Field are presented through the following :

Item /Position	Deviation	Possible causes	Consequence	Remarks/ Action required/ recommendation
Water Treatment unit 28	Produced water with contaminated oil more than 21500 bpd	Environmental risk ,corrosion to the body of platforms, risk of pollution problem specify for biological	Dump un treated the exceed volume of contaminated water (oily water) to sea	Risk will occurs unless the following suggestion be taking into consideration : ♦ Re-injection to aquifer. ♦ Re-injection to shallow formation such as Melquart formation. ♦ Down hole oil/water separator system ♦ Upgrading the existing water treatment facilities and maintain on the level average oily in water PPM (summary of available oil in water data for Offshore Field is presented in the attached graphs to end of this chapter.) according to international agreement
Booster pump	Less pressure	Leak of 6 “ network pipe	Simultaneous Shutdown of treatment unit	No risk /hazard
Filter	Very high pressure	Filter will be plugged due to Solids more than 5 micro meter	Unit will be shut down	No appearing risk
Discharge Pump	Less pressure	Leak of relevant pump	If Pressure decreasing below 100 bar The pump will stop	No risk

Item/ position	Deviation	Possible causes	consequence	Remarks/ action required/ recommendation
4 “ pipe	Less pressure	Shut down the unit	No consequence	No hazard or risk ,.
Piping & treatment unit material	corrosion	Leak , shut down the unit		Monitoring , injection frequently inhibitor corrosion
Well no. 16 4”-02 pipe	Increase of gas oil ratio	Reservoir phenomena	No consequence	Choking down the well , no risk
Well no. 16 4”-02 pipe	Water cut increasing	Reservoir phenomena	No consequence	No risk or hazardous assessed
Well no. 16 4”-02 pipe	No flow	Some valves along pipe 4” will be shutdown or in 8 “ pipe or manifold	Well closed	No risk
Well no. 16 4”-02 pipe	Less temperature	Failure of electrical tracing system	Possible difficulties in valves movement to hydrates formation (if any)	No risk
New low pressure manifold 8 inch	Decreasing in pressure	Gas leaking	The risk of fire is presence , explosions and gas poison	Reestablish a normal safety level

Item/ position	Deviation	Possible causes	consequence	Remarks/ action required/ recommendation
New low pressure manifold 8 inch	Pressure is decreasing	Schedule plant shutdown	Gas will be conveyed to flare	No risk or hazard assessed because the flare was designed to handle the extra volume of vented gas
New low pressure manifold 8 inch	Same as previous deviation	Emergency shut down for plant	Gas will be conveyed to flare	No risk or hazard assessed because the flare was designed to handle the extra volume of vented gas
New low pressure manifold 8 inch	High pressure (greater than 86 bar)	Risk of fire is presence around the piping network	Plant emergency shut down	Safety procedure should be strictly performed
New low pressure manifold 8 inch	Decreasing in temperature	Failure of the electrical tracing system	Difficulties of valves movements , consequent to the hydrate formation	No risk
New low pressure manifold 8 inch	No flow	Emergency shut down	Gas conveyed to flare	Flare has a suitability of gas handling so no risk.
3”-12 LP well 5 safety valves	Pressure increasing	The subjected well will be isolated from the remaining part of plant because the risk of fire is there.	Conveying the gas in flare to reestablish a proper pressure inside the pipe (4”-02-LP 004 riser)	To avoid the explosions or fire a strictly safety procedure is recommended

Item/ position	**Deviation**	**Possible causes**	**consequence**	**Remarks/ action required/ recommendation**
3”-12 LP well 5 safety valves	High flow	The subjected well will be isolated from the remaining part of plant	Conveying the gas in flare to have a right pressure inside pipe	No risk, however a safety procedure is recommended to avoid any probabilities of firing or explosion
3”-12 LP well 5 safety valves	Changing in GOR	Reservoir phenomena	No consequence	No hazard or risk
3”-11-LP blow down line	High pressure	scheduled plant shut down or plant emergency shut down	Gas will be conveyed to high pressure flare	No risk due to the ability of flare to handle the increasing of gas amount (925 kg/h)
3”-11-LP blow down line	Low temperature	Scheduled plant shut down / emergency shut down for all plant	Gas in to high pressure flare	No risk because the pipe material was designed (made) suitable for thermal cycling to low temperature and in addition the line traced
3”-11-LP blow down line	More flow	Scheduled plant shut down	Gas in to high pressure flare	No risk
1” drain line pressure	High pressure/ more flow	Could cause (during normal operation) an erroneous to open the drain valves (1 “-11-LP line) installed in the subjected line	Increasing in the inside vent network	It is preferable to locked at least one of the two drains valves
2” –12 drain line	More pressure/ more flow	Erroneous opening the drain valves on the 2”-12 LP-009	Pressure rising inside closed drain network	Closed at least one of the two drains valves

4.10 Regression analysis:

The multiple regression had been utilized for predication purpose of oil contaminated water during production stage, the method is dealing with many variables which effected on the dependent variable.

The relationship or correlation between these variables (independents) and the independent variable had been established as :

$$Y = a+b1x1+b2x2+\ldots\ldots\ldots+bnxn+E$$

That was the general form of multiple linear model

Where:

Y = dependent variable values

A= intercept

X= the independent value

B = the coefficient corresponding to the impendent variables

N= number of the independent variables

E= error term

4.10.1 Results of Regression Analysis :

- The regression model should be met the following statistical indicators:

- R^2 greater than 85 % (multiple coefficient)
- F-test
- A 45 deg line cross plot shows good scatter of data
- There should be no discernible patterns in the residuals
- Examination of results (residual against observation y^)
- Analysis of variance (ANOVA table)

The following output shows the results of regression analysis:

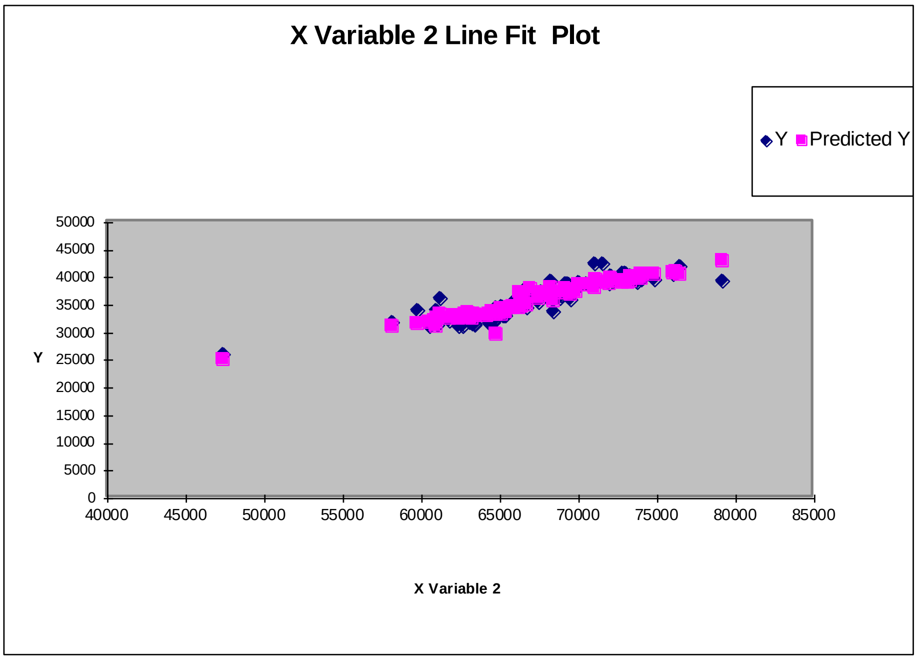
Regression Statistics	
Multiple R	**0.930592116**
R Square	**0.866001686**
Adjusted R Square	**0.858557335**
Standard Error	**1235.092921**
Observations	**58**

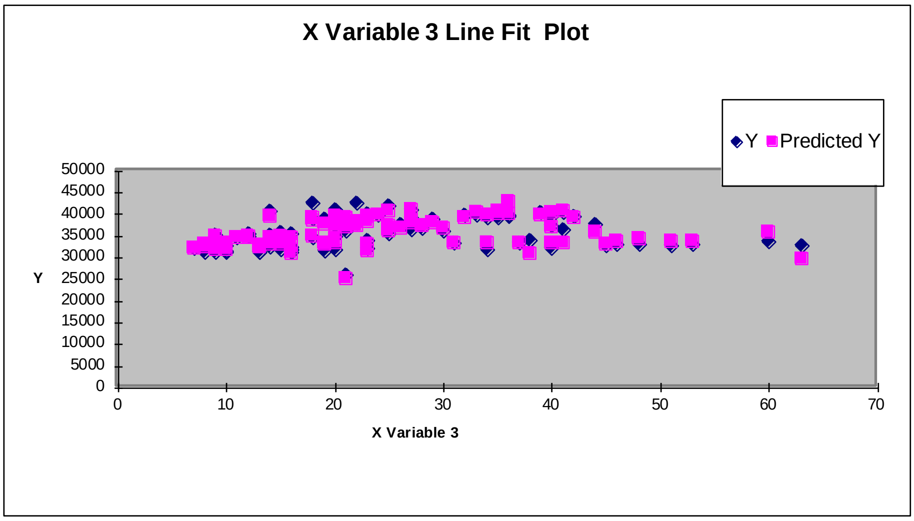
	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	532368594.6	177456198.2	116.33	1.49876E-23
Residual	54	82374544.23	1525454.523		
Total	57	614743138.8			

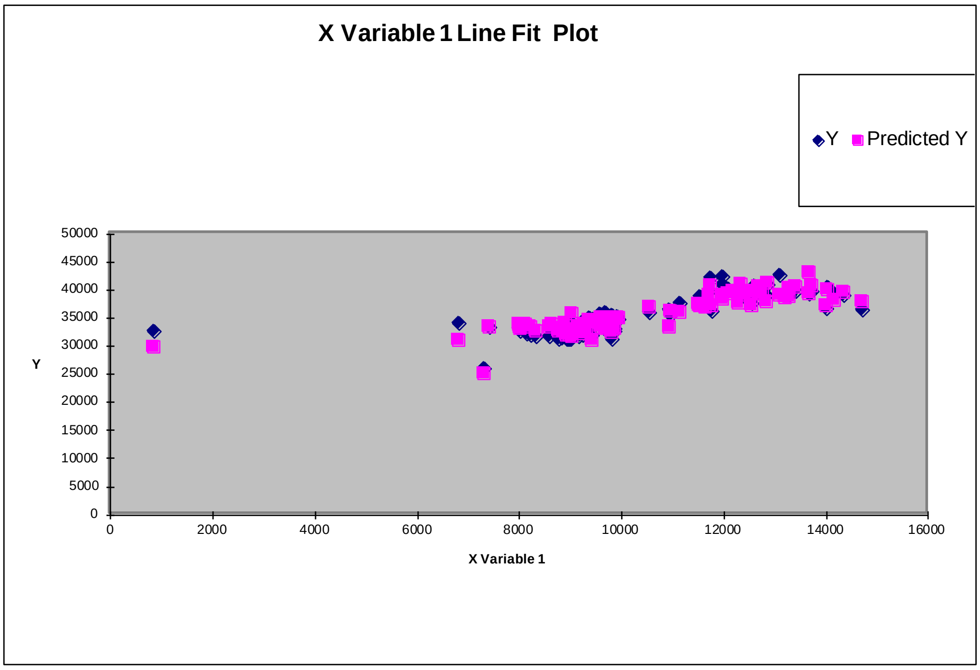
	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-45.54	2792.226	-0.016	0.987	-5643.626	5552.537	-5643.626	5552.537
X Variable 1	0.45	0.099	4.561	3E-05	0.254	0.652	0.254	0.652
X Variable 2	0.46	0.054	8.458	2E-11	0.350	0.567	0.350	0.567
X Variable 3	2.41	14.062	0.171	0.8648	-25.787	30.598	-25.787	30.598

Table 4.2 results of regression analysis

Regression analysis - examination of model

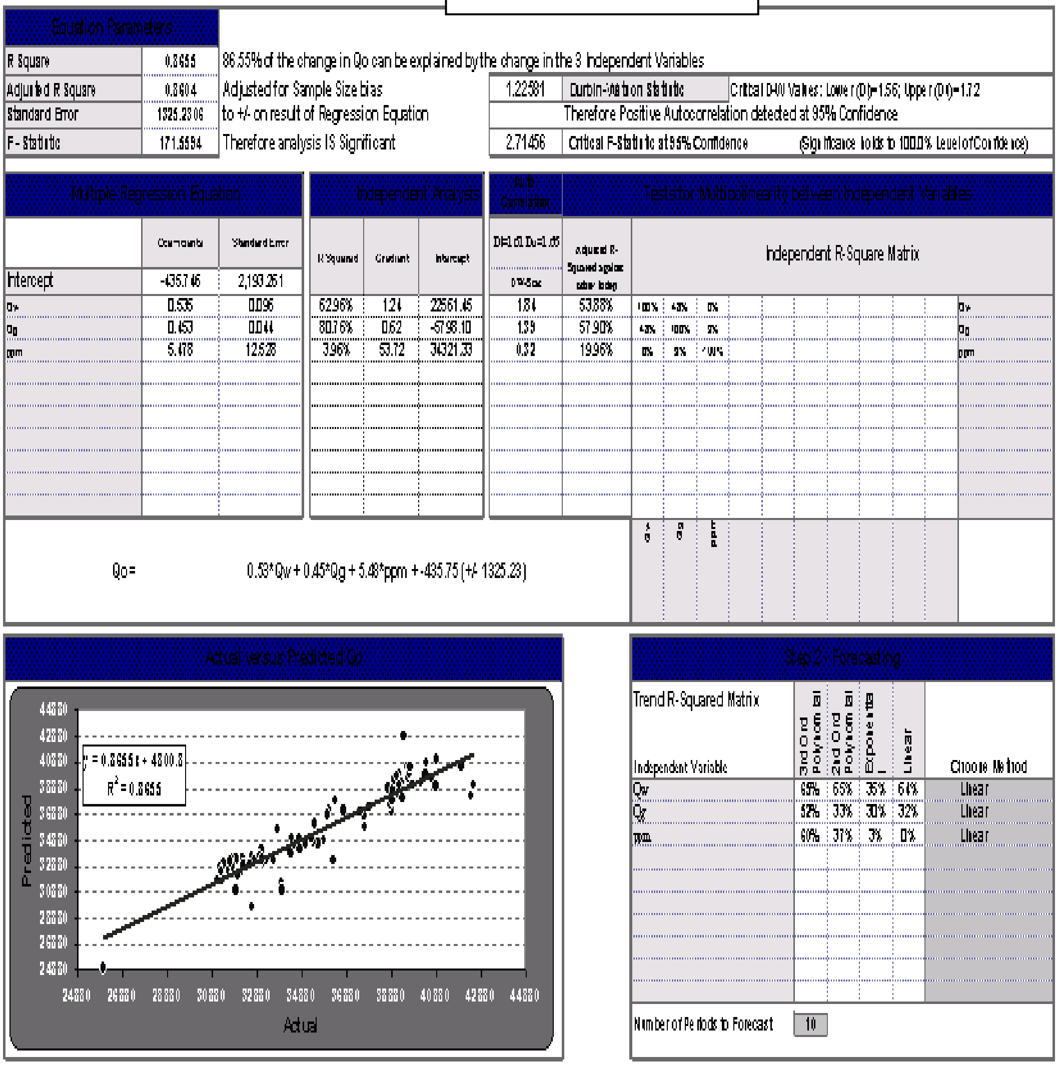






More over anther statistical software called "*excel business tools*" have run ,the results gained out are identical when compared to the traditional multiple regression analysis which supported by excel spreadsheet, sheet no.1 is exhibit the model equation and the most important parameters .

Sheet no.1



4.11 Data acquisition:

58 values of oil in water samples (ppm) have been collected during last 5 years of production, these data was used to build the subjected correlation.

The chemical analysis of formation water had been carried out through two sampling point, firs was before the skimmer (inlet) and the second sampling was collected from outlet of skimmer in the water treatment unit On the other hand the production data have taken from production separator.

A summary of the available data for the field is presented in **tables 4.1**

4.12 Mathematical model:

in this work the developed correlation based on field data such as oil ,water and gas as monthly production and oil in water as ppm per month , ,considering oil rate as dependent variable , the correlation for estimation oil production rate derived as function of the rest of three variables :

Qo(bopd)= f(Qw (bwpd),Qg(scfpd),oily water (ppm)

Thus regress Qo on Qw, Qg and valus of oil in water as ppm
Actually several models were tried as regression equation to have adequate mathematical model , the following equation was considered as best predication equation of oil in water as ppm

$$Q_o = -45.544 + 0.45X_1 + 0.46X_2 + 2.41X_3$$

Where:

$X1$ = water production rate
$X2$ = gas production rate
$X3$ = oil in water (ppm)

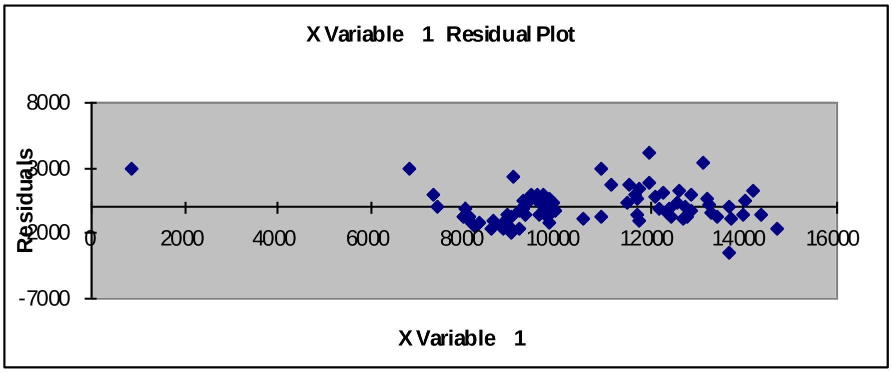
- **Correlation development:**

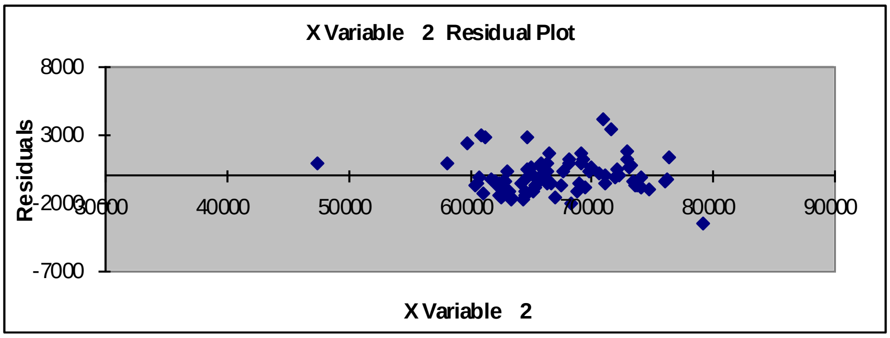
all the output of multiple regression analysis as tables

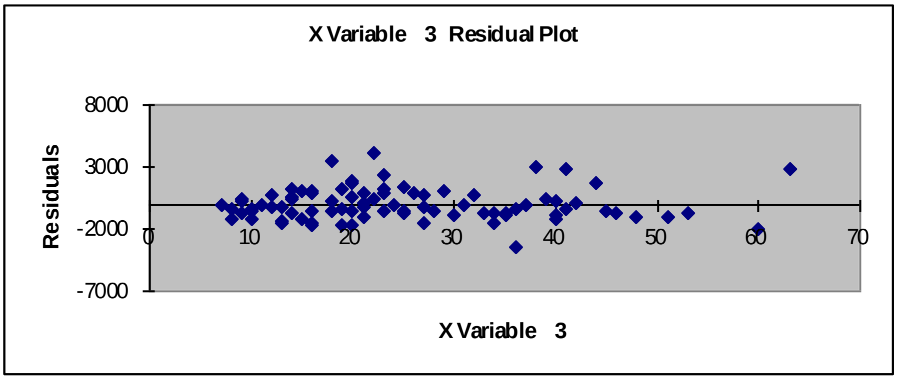
and graphical examination haven illustrated through

- Examination of residual

Figures 1-3 are illustrate the residuals plots against the dependent values, a clear horizontal band pattern have been showed among all plots







Regression analysis - examination of residual

Figures 1-3

4.13 Role of Risk Assessment

Risk assessment can:

- Facilitate communication between decision makers and technical experts by providing precise language (i-e mathematical language of probability and statistics) for describing the nature and extent of uncertainty in safety and environmental consequence

- Facilitate communication between the decision-makers and other interested parties by providing explicit data that are amenable to review by interested parties.

- Help the decision makers identifying the role and impact of policy consideration (e.g. social, political, economic and legal policy Judgment) in the assessment of scientific information

- Help decision makers separates a complex health, safety or environmental problem into its component, and more manageable parts.

- Help decision-makers identify and understand the impact of interactions and joint dependencies between variables and components of the problem might otherwise be overlooked.
- Help decision-makers identify research needed and set research priorities that would significantly reduce the important scientific uncertainties.

- Help decision-makers by providing a framework for explicitly examining the potential adverse consequences of alternative risk management Policy or action.

4.14 Terminology

Aquifer: An underground source of water caused by a geological formation (e.g., a layer of earth or porous stone) or group of formations.

Area source: A geographically dispersed collection of sources of pollution, such as automotive vehicles in an urban area.

Confidence interval: the definition depends on whether a subjective or objective view of probability is adopted. With the subjective view, the confidence limit specifies limits of an uncertain quantity between which there is a specified probability of occurrence-expressed as in “the X percent confidence interval” with the objective view, the confidence expresses a range of values that may not contain the rule value of an estimated parameter. The confidence limit is derived from a sample in such a way that repeated random sampled would yield confidence intervals such that a specified proportion of these intervals would include the true value of the estimated parameter, assuming that the actual population satisfies the initial hypothesis.

Consequence assessment: the process of developing a description of the relationship between specified exposures to a risk agent and the health an other consequences to the people or things exposed.

Contaminant: an physical, chemical, biological, or radioactive substance or matter that has been introduced to air , water , or soil.

Continuous random variable: (uncertainty) A random variable that can have an infinite number of values . for example , wind speed can have any value between zero and some upper limit.

Cumulative probability distribution: a curve or mathematical expression that quantifies uncertainty over a variable. it associates a probability with all values in the set of possible values. The probability associated with each value of the variable is that of the occurrence of a value less than or equal to the specified value.

Dose: the amount of a risk agent that enters or interacts with an organism. an administered dose is the amount of substance administered to an animal or human, usually measured in mg/kg body weight; mg/m2 body surface area; or PPM of the diet, drinking water or ambient air . an effective dose is the amount of the target orange

Dose-response relationship: functional relationship between the dosage level of substance received and lethality , morbidity, or level of health effect produced.
Emission: pollution discharged into the atmosphere from smokestacks, other vents, and surface areas of commercial or industrial facilities; from residential chimneys; and from motor vehicle, locomotive, or aircraft exhausts.

Environmental effect: effect on the living and nonliving components of the environment.
Environmental fate: the disposition of a substance in various environmental media such as air , water , or soil .
Environmental pathway: see exposure pathway.
Event tree analysis: A systematic method for identifying and analyzing the possible effects of events using interrelationships based on "if-then" assumptions. The method is often used to estimate the failure protective subsystems or of a technological system as a whole.

Exposure: an instance or condition of one or more people or things they value being open to interaction with a risk agent (e.g., an environmental contaminant or a communicable disease)
Exposure assessment: the process of developing a description of the relevant conditions and characteristics of human and other exposures to risk agents produced or released by a specified source of risk.
Exposure pathway: means by which risk agents are transmitted

(e.g., the route b which a given population is exposed to a toxic substance (via drinking water, air, dermal contact, etc.).

Hazard: A (potential) source of risk that does not necessarily produce risk. A hazard produces risk only if an exposure pathway exists and if exposures create the possibility of adverse consequences.

Hazard (risk) identification: the process of identification new sources of risk.

Hazardous substance: a substance that poses a threat to human health or the environment. The magnitude of the threat is potentially large but undefined and depends on whether an exposure pathway exists.

Hazardous waste: corrosive , ignitable, explosive, or toxic by – products of society that pose a hazard to humans or the environment.

Hydrocarbon: A substance made up primarily of carbon and hydrogen atoms, usually of biological origin (e.g., vegetables, petroleum, coal tar).

Media: specific environments (e.g., air, water , soil) that are the subject of regulatory concern and that may be the source of exposures to risk agents.

Monitoring: periodic or continuous surveillance or testing to determine the characteristics of a risk source , the pollutant levels in various media, or the health status of humans , animals, and other living things.

Monte Carlo analysis: the computation of a probability distribution over consequences by means of a random sampling method analogous to the game of roulette. Combinations of events and outcomes that yield possible consequences are randomly selected according to a specified probability distribution. The resulting consequences are counted and used to estimate other probability distributions.

Organism: any living thing.

Parts per million (PPM). Parts per billion (ppb): A means for expressing low concentrations of pollutants in air, water , soil , human tissue, food, or other materials, according to the fraction of mass or volume occupied by the pollutant; e.g., one part salt in a million parts water.

pH: A measure of the acidity or alkalinity of a liquid or solid material (pH is represented on a scale of 0 to 14 with 7 representing a neutral state, 0 representing the most acid, and 14 the most alkaline).

Reliability: the probability that a system will perform its required functions under conditions for a specified operating time.

Risk: A characteristic of a situation or action wherein a number of outcomes are possible, the particular one that will occur is uncertain, and at least one of the possibilities is undesirable.

Risk agents: fundamental agents for health , safety , and environmental risks , including hazardous chemicals, biological agents (e.g., viruses and bacteria) . and energies (e.g., heat and noise)

Risk analysis: A process involving hazard identification, risk assessment, an risk evaluation.

Risk assessment: a systematic process for quantifying and describing the risk associated with some substance, situation, or action.

Risk assessment method: A systematic procedure or mode of inquiry that may be used as part of risk assessment.

Risk estimation: the process of characterizing uncertainty (e.g., quantification of probabilities) and possible risk consequences.

Risk evaluation: the process of interpreting risks, including determining levels of risk acceptable to individuals, groups, or society as a whole.
Risk management: the process of selecting and implementing steps to alter levels of risk.

Sensitivity analysis: a method used to examine the behavior of a model by systematically measuring the deviation in its outputs produced as each input , parameter, or assumption is varied from its nominal or base-case value.

Source: A location where pollutants are emitted, e.g., a chimney stack.

Thermal pollution: discharge of heated water from industrial processes that can affect the life processes of aquatic organisms.
Toxicity: a measure of the degree of harm caused by a specified exposure of human , animal, or plant life to a substance.

Uncertainty: a situation where a number of possibilities exist and one dose not knows which of them has occurred or will occur.

Hazop

A qualitative method of identifying hazard and operability problems in process system

Hazard
Hazard is the potential for harm; or physical situation with a potential for human injury, damage to property, the environment or some combination of these "

Operability
Operability is the ability to operate the plant in the most efficient manner according to the design intent.

Process parameters or variable
These are the elements of the process e.g., flow, pressure, temperature etc.

Guidewords
These are the words used in conjunction with the process parameters to identify deviations, e.g. More, Less, Higher etc.

Deviations
Departures from the design of the system, which are identified by the application of guidewords (more, less, high, low etc.) to the process parameters (flow, pressure,etc.).

Causes
Reasons which can determine deviations. The causes can be internal excess pressure external e.g., human error etc.

Consequences:
Results of the deviations (i.e., gas leak, fire etc.)
Existing safety features inherent in the system, e.g., PSV, s level alarms, etc.

4.15 Produced water regulation

for production water, a maximum oil content of 40 ppm as an average any calendar month, for the hydrocarbon in the offshore operation discharge the content shall not at any time exceed 100 ppm. anything above 100 ppm considered as oil spills

Chapter 5.0

Disposal/injection Associated Produced Formation Water Case study.

IOR / EOR

5.0 Introduction:

As mentioned in earlier chapters, our offshore field is producing since 1988 in natural depletion. The average pressure decrease of the field per year is relatively small (11 psi/ in the last 4 years) mainly due to the pressure support of a very strong aquifer pressurizing the field from the southern flank of the structure. Static pressure distribution is comparatively homogeneous due to the high vertical and horizontal connectivity throughout the field as a result of medium-high permeability's reservoir and an important fracture network. The only area that shows a relative pressure sink is the northern flank of DP4 **(see isobaric map in figure 5.0)** because of its distance to the supporting aquifer and the number of producers in this area. The aim of the re-injection will be that of sustaining the pressure in this area, lower the overall production GOR and increase recoverable reserves.

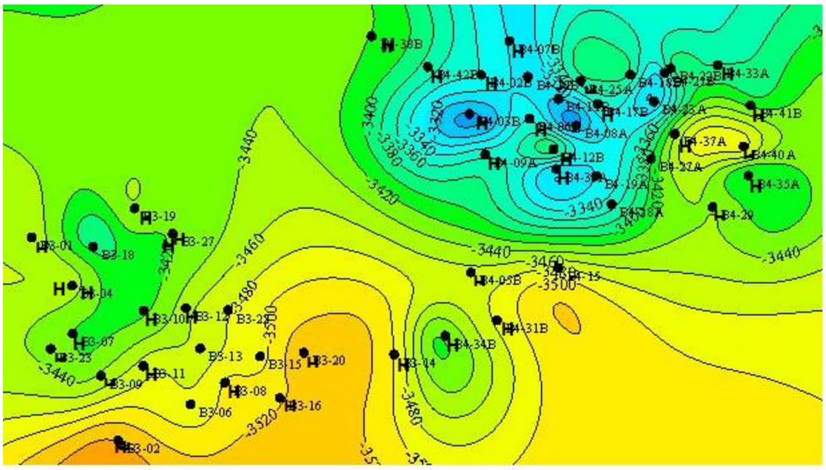


Figure 5.0 :isobaric map

The work and studies already carried out on the issue of water re-injection and disposal in Offshore Field are summarized herein. It has to be mentioned that profiles and reserves figures contained in this document are based on a recently updated 3D-dynamic model. The updating consisted in the extension of the history match until July 2004 and field tolerances in terms of simulated watercut and GOR of 3% during the last 2.5 years were met, increasing the confidence in the forecast results.

5.1 Objective of water re-injection (EOR)

The project of water injection has the following objectives:

- ✓ increase recoverable reserves by
  - sustaining the reservoir pressure in the northern part of the DP4 area
  - lower the overall production GOR
  - increase field water treatment capacity to 30'000 bwpd
- ✓ reduce water discharge to the sea to zero

Associated water production is reaching in this period the maximum treatment capacity on DP4 of 20'000 bwpd. It has to be highlighted that water production is steadily increasing as can be noticed in the **Figure 5.1** .

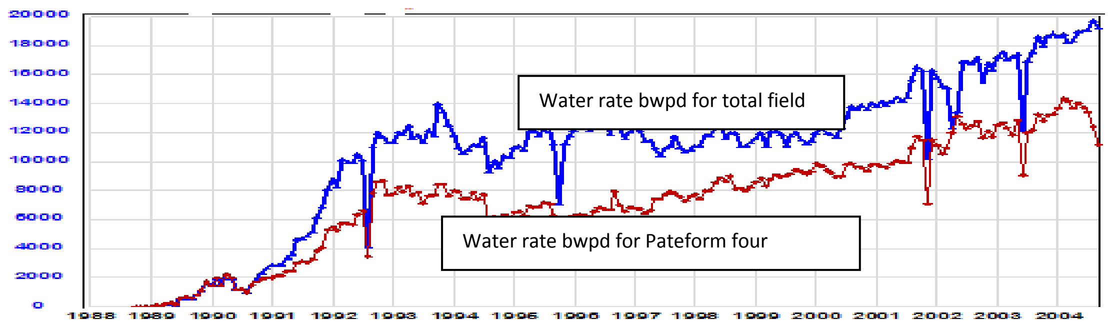


Figure 5.1: Water and oil production performance

5.2 Historical Events: disposal and injection

As IOR Before 2001 the AGIP Oil's focus was on the reduction of water quantities discharged into the sea and consequently the Melquart fmt overlaying the reservoir at a depth of approximately 1600 ft MD had been chosen as a potential aquifer to receive the produced water of both platforms. In fact in April 1999 an injectivity test was performed through the worked over well H4-20. During this test 15'000 bwpd have been injected with a pressure at wellhead of around 500 psia. For disposal purposes the well is ready and needs only to be connected.

AS EOR The integrated reservoir study finalised in 2001 highlighted the opportunity of using the produced water for re-injection purposes prospecting increased recoverable reserves. Water injection was considered to be performed by re-injecting the produced water. Sensitivities performed on the reservoir model indicated that WI is beneficial in the Northern flank of the structure, where the aquifer is weaker and pressure is locally lower as can be seen in the figure 5.2 .

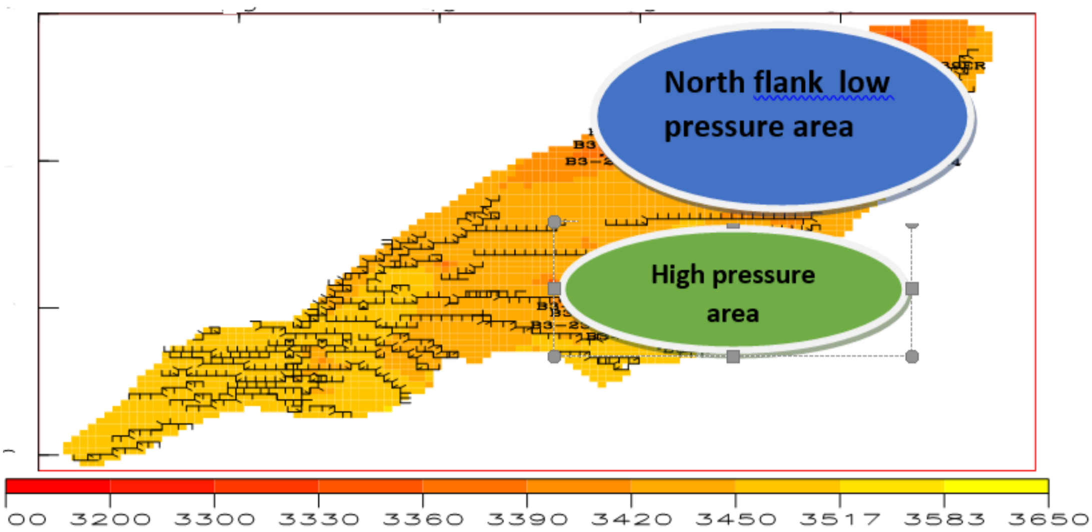


Figure 5.2: Pressure performance Map

Injecting water in DP3 area gave negative results. Well H4-25 (shut in) was detected as best candidate to perform the injection. The 2001 study considered a pilot water injection project in order monitor GOR and watercut performance of nearby wells for 1-2 years before extending WI to an additional well also drilled in the northern flank.

The actual model update 2004 confirmed the possibility of increasing the recoverable reserves through water injection in the northern flank of the DP4 production area.

5.3 EOR -Water Re-injection Project:

3D reservoir model was detected well H4-25 (shut in) as best candidate to perform the re-injection. Sensitivities on other wells as given in the above figure (***figure 5.3***) gave worse results due to earlier water encroachment in the nearby producers).

Well H4-25, at present is completed in layers 1-2-3, should be re-completed in the dolomitic layers 11-12-13-14 before starting the water injection.

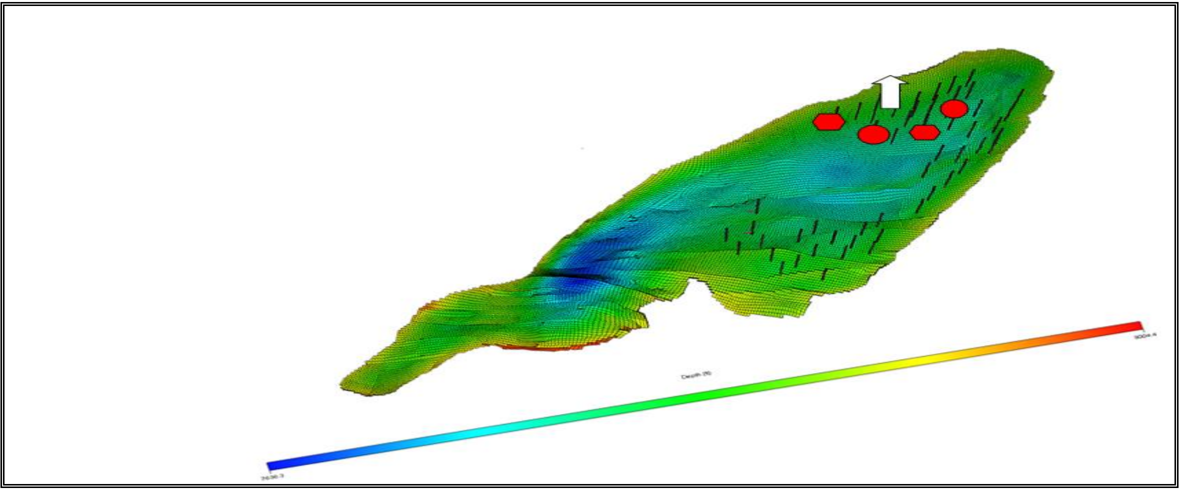


Figure 5.3: location of Water injection wells and neighboring oil wells

5.4 Project Updating (Reservoir Simulation) :

3D Dynamic reservoir model has been revised and updated. field tolerances in terms of simulated GOR and W.C. of +/- 3% during the last 3 years were met, increasing the confidence in the forecast results. The see figures here below shows the history matching trend.

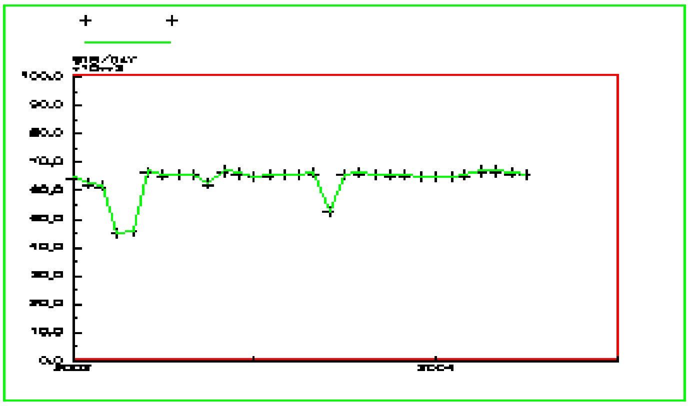


Figure 5.4: Oil Rate (stb/D), measured Vs. Simulated

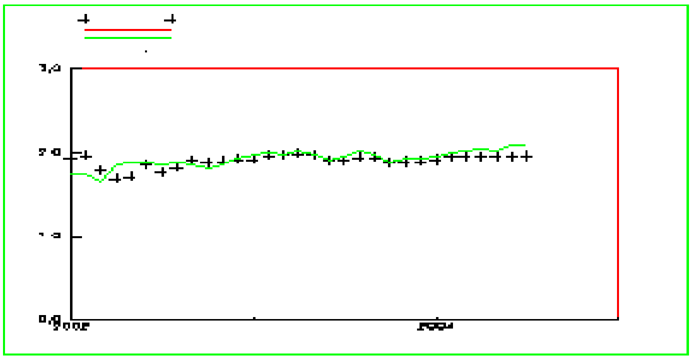


Figure 5.5: Gas oil ratio (MSCF/STB), measured Vs. Simulated

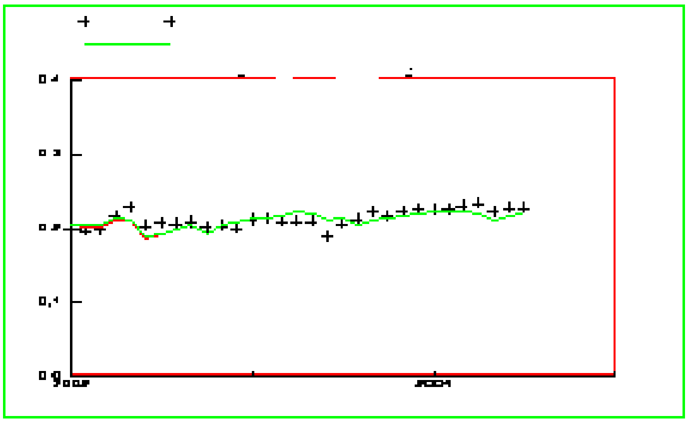


Figure 5.6: Water Cut (%), measured Vs. Simulated

5.5 Economic Evaluation:

The results of Cash Flow analysis are summarized here below in the table 5.1 :

Evaluated Period, year	Incremental oil recovery, MMstb	Gross Revenue, MM$	CAPEX MM$	OPEX MM$	Total Expend., MM$	PV (10%), MM$	ROR, %	POT, year	DPIR (10%) $/$
DEC. 2019	10	207	23	23.794	27	48	32	Mar. 2011	2.03
DEC. 2028	20	398	23	45.810	69	74	32	Mar. 2011	3.16

Table 5.1 : cash flow analysis

More details: Appendix A shows the Cash Flow Analysis performed on this scenario and evaluated until end 2028.

5.6 SUMMARY

- **The main objectives of the project are :**
  - Increase recoverable reserves by maintain the reservoir pressure in the northern part of the DP4 area
  - Lower the overall production GOR of the pressurised area
  - Reduce water discharge to the sea to zero
- **Water Re-Injection Project History**
  - Before 2001 reservoir study, focus was on water disposal in Melqart Fmt
  - 1999 injectivity test was performed on the worked over H4-20
  - The 2001 3D reservoir study showed increased recoverable reserves due to water re-injection into the reservoir
  - Pilot injection on H4-25 was recommended
  - The 2004 updating of the reservoir model confirmed the increase in oil reserves in case of water injection
  - Expected incremental reserves @ 2040 is 30.7 MMSTbbl

- **Water –re-injection Incremental production profile: illustrated in figure 5.7**

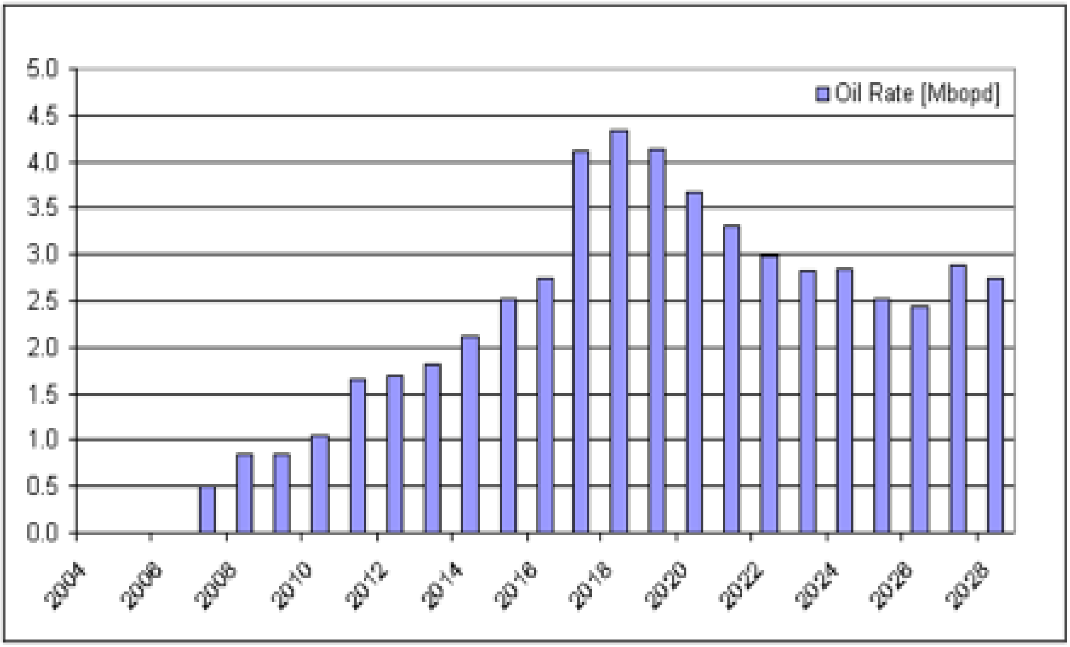


Figure 5.7 incremental production profile

➢ Water injection effecting in surrounding wells

The effect of Cumulative Oil Production differences (%) due to WI can observed in figure 5.8

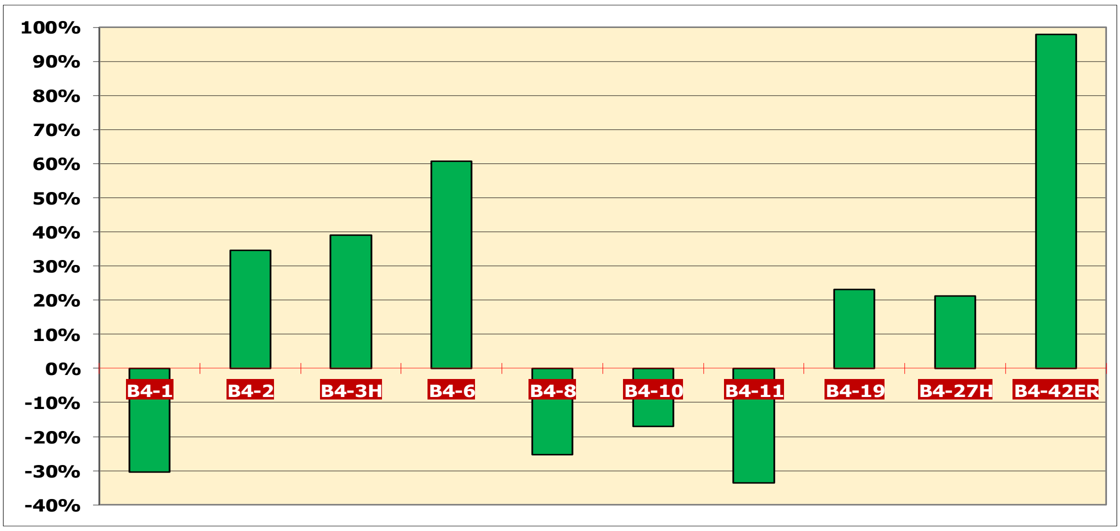


Figure 5.8 Water injection effecting in surrounding wells

Appendix A

No.	Time	Prod. Oil	Oil price	CAPEX	Prod. Cost	OPEX	Total Expen.	Gross Revenue	NCF	CNCF	NPV (10%)	Cum. NPV
	The end of year	MMSTBY	$/STB	MM$	$/STB	MM$	MM$	MM$	MM$	MM$	MM$	MM$
0	31-Dec-04	0.00	0	0.500	2.3	0.000	0.500	0.000	-0.500	-0.500	-0.500	-0.500
1	31-Dec-05	0.00	0	7.000	2.3	0.000	7.000	0.000	-7.000	-7.500	-6.364	-6.864
2	31-Dec-06	0.00	20	10.000	2.3	0.000	10.000	0.000	-10.000	-17.500	-8.264	-15.128
3	31-Dec-07	0.18	20	5.940	2.3	0.422	6.362	3.670	-2.692	-20.192	-2.023	-17.151
4	31-Dec-08	0.31	20	0.000	2.3	0.713	0.713	6.200	5.487	-14.705	3.748	-13.403
5	31-Dec-09	0.31	20	0.000	2.3	0.713	0.713	6.200	5.487	-9.218	3.407	-9.996
6	31-Dec-10	0.38	20	0.000	2.3	0.874	0.874	7.600	6.726	-2.492	3.797	-6.199
7	31-Dec-11	0.60	20	0.000	2.3	1.380	1.380	12.000	10.620	8.128	5.450	-0.750
8	31-Dec-12	0.62	20	0.000	2.3	1.426	1.426	12.400	10.974	19.102	5.119	4.370
9	31-Dec-13	0.66	20	0.000	2.3	1.518	1.518	13.200	11.682	30.784	4.954	9.324
10	31-Dec-14	0.77	20	0.000	2.3	1.771	1.771	15.400	13.629	44.413	5.255	14.579
11	31-Dec-15	0.92	20	0.000	2.3	2.120	2.120	18.434	16.314	60.727	5.718	20.297
12	31-Dec-16	1.00	20	0.000	2.3	2.300	2.300	20.000	17.700	78.427	5.640	25.936
13	31-Dec-17	1.50	20	0.000	2.3	3.450	3.450	30.000	26.550	104.977	7.691	33.627
14	31-Dec-18	1.58	20	0.000	2.3	3.634	3.634	31.600	27.966	132.943	7.364	40.991
15	31-Dec-19	1.51	20	0.000	2.3	3.473	3.473	30.200	26.727	159.670	6.398	47.390
16	31-Dec-20	1.34	20	0.000	2.3	3.082	3.082	26.800	23.718	183.388	5.162	52.551
17	31-Dec-21	1.21	20	0.000	2.3	2.783	2.783	24.200	21.417	204.805	4.237	56.789
18	31-Dec-22	1.09	20	0.000	2.3	2.507	2.507	21.800	19.293	224.098	3.470	60.259
19	31-Dec-23	1.03	20	0.000	2.3	2.369	2.369	20.600	18.231	242.329	2.981	63.240
20	31-Dec-24	1.04	20	0.000	2.3	2.392	2.392	20.800	18.408	260.737	2.736	65.976
21	31-Dec-25	0.92	20	0.000	2.3	2.116	2.116	18.400	16.284	277.021	2.200	68.176
22	31-Dec-26	0.89	20	0.000	2.3	2.047	2.047	17.800	15.753	292.774	1.935	70.111
23	31-Dec-27	1.05	20	0.000	2.3	2.415	2.415	21.000	18.585	311.359	2.076	72.187
24	31-Dec-28	1.00	20	0.000	2.3	2.305	2.305	20.040	17.735	329.094	1.801	73.988
TOTAL		19.917		23.440		45.810	69.250	398.344	329.094	329.094	73.988	

Economic Profit Indicators

Oil Price =	20	$/bbl
Interest rate =	0.10	

Results

Gross Revenue	398	MM$
Total Cost (CAPEX + OPEX	69	MM$
Net Cash Flow	329	MM$
Net Present Value @ 10%	74	MM$
ROR	32.4	%
POT (Date, Year)	Mar-11	
PIR (CNCF / CAPEX)	14.04	$/$
DPIR (PV / CAPEX)	3.16	$/$
G.R./T.C.	5.75	$/$

Chapter

6.0

A

EOR: Gas utilization - Re-Injection / Sequestration Acid Gas

IOR / EOR

Chapter Recap

GUP :

The main objectives of the Gas Utilization Project are to reduce environmental impact by diminishing emissions to the atmosphere on beside that it is looking for to Increase total recoverable hydrocarbon reserves in terms of gas, condensate, and LPG

This dissertation will elaborate on the following:

- **EOR scenarios:**

Through The 2^{nd} Phase of the GUP plans to re-inject the gas impurities, obtained after the treatment on the platform DP4, into the gas cap through extended reach wells to be drilled after slot recovery of watered out obsolete producers.

- **Sequestration or disposal scenario**

The aim of this work is to evaluate the number of injectors, the tubing size and the well head injection pressure necessary to re-inject the acid gas in the gas cap of Offshore Field .

6.1 Philosophies of Gas utilization Project (GUP):

The Gas Utilisation Project for Offshore Fieldis based on the following philosophies:

- Reduction of the environmental impact by applying a suitable gas recovery system able to reduce emissions to the atmosphere
- Improvement of field economics through additional revenues from recovered gas, condensate and LPG sales
- Increase total recoverable hydrocarbon reserves in terms of gas, condensate and LPG

The main objectives of the gas utilization project Are:

- ➢ Reduce environmental impact by diminishing emissions to the atmosphere
- ➢ Preserve natural resources
- ➢ Increase total recoverable hydrocarbon reserves in terms of gas, condensate and LPG

6.2 3D Reservoir Simulation Model:

- ✓ The updating consisted in the extension of the history match up to September 2005 and field tolerances in terms of simulated water-cut 4% and GOR of 8% during the last 2 years were met, increasing the confidence in the forecast results.
- ✓ Optimisation of the forecast constraints have been mainly the introduction of work-over in order to manage gas cap shrinkage and aquifer encroachment and the fact that high GOR wells have been allowed to continue production in order to keep the gas production plateau.

6.3 Overview of Sales gas & Economical Evaluation :

The sales products cumulative relative to the Gas Utilisation Project presented here after imply the implementation of the following projects:

- Slot Recovery
- East Area Development (4 new producers – start-up in March 2006)
- De-bottlenecking (Gas Treatment Capacity Increase – start-up in March 2006)
- Water Re-Injection (DP4 Area – start-up in June 2007)
- Gas Utilisation Project (end 2007)

OGP Base Case

Performance Summary Up to end 2028 only phase I

Total Sales Gas	**5.41**	**$*10^9$ Sm3**
Total Sales Cond&LPG	**19.86**	**$*10^6$ STB**
Total Fuel Gas (Blend Gas incl.)	**4.12**	**$*10^9$ Sm3**

OGP with PH2&Re-injection

Performance Summary Up to end 2038

Total Sales Gas	**6.62**	**$*10^9$ Sm3**
Total Sales Cond&LPG	**22.56**	**$*10^6$ STB**
Total Fuel Gas (Blend Gas incl.)	**4.23**	**$*10^9$ Sm3**

6.3.1 3D Model -Base - production profile :

Table 6.1A and figure 6.1A are presented production values as shown below:

reference case : 3D Model -Base (No Re-injection)

Offshore Field Gas Utilisation Project - Base EGP Case (No Re-injection)

DATE	Production profile										
	Year	Gas Production	Sales Gas (Mellitha)		Sales Condensate (Mellitha)	Sales LPG (Mellitha)	Sales Gas (Mellitha)	Fuel Gas (Actual DP4)	Fuel Gas (GU DP4)	Blend Gas (DP4)	Fuel Gas (Mellitha)
		(G Scf/Y)	(G Scf/Y)	(G Sm3/Y)	(t/Y)	(t/Y)	(M BOE/Y)	(MSm3/Y)	(MSm3/Y)	(MSm3/Y)	(MSm3/Y)
31-Dec-06	2006	46									
31-Dec-07	2007	49									
31-Dec-08	2008	49	14	0.39	112119	30585	2.4	47.1	54	129	16
31-Dec-09	2009	48	14	0.39	110544	30155	2.4	47.1	54	127	15
31-Dec-10	2010	47	13	0.38	108227	29523	2.3	47.1	54	124	15
31-Dec-11	2011	45	13	0.36	102609	27991	2.2	47.1	54	118	14
31-Dec-12	2012	43	12	0.34	97688	26648	2.1	47.1	54	112	14
31-Dec-13	2013	41	11	0.32	92717	25292	2.0	47.1	54	107	13
31-Dec-14	2014	38	11	0.30	86400	23569	1.9	47.1	54	99	12
31-Dec-15	2015	34	10	0.27	77347	21099	1.7	47.1	54	89	11
31-Dec-16	2016	32	9	0.25	72711	19835	1.6	47.1	54	84	10
31-Dec-17	2017	30	8	0.24	67575	18434	1.5	47.1	54	78	9
31-Dec-18	2018	28	8	0.22	63367	17286	1.4	47.1	54	73	9
31-Dec-19	2019	27	8	0.21	61431	16758	1.3	47.1	54	71	9
31-Dec-20	2020	27	7	0.21	60638	16541	1.3	47.1	54	70	8
31-Dec-21	2021	26	7	0.21	59108	16124	1.3	47.1	54	68	8
31-Dec-22	2022	26	7	0.20	58307	15906	1.3	47.1	54	67	8
31-Dec-23	2023	25	7	0.20	56699	15467	1.2	47.1	54	65	8
31-Dec-24	2024	24	7	0.19	55045	15016	1.2	47.1	54	63	8
31-Dec-25	2025	23	7	0.18	52832	14412	1.1	47.1	54	61	7
31-Dec-26	2026	23	6	0.18	51492	14047	1.1	47.1	54	59	7
31-Dec-27	2027	22	6	0.17	49682	13553	1.1	47.1	54	57	7
31-Dec-28	2028	21	6	0.17	48328	13183	1.0	47.1	54	56	7
		772	191	5.4	1544865	421425	33.2	989.1	1139	1777	215

GUP Performance Summary Up to end 2028

Total Sales Gas	**5.41**	**GSm3**
Total Sales Cond&LPG	**19.86**	**MSTB**
Total Fuel Gas (Blend Gas incl.)	**4.12**	**GSm3**

Table 6.1A: Gas Utilization Project - Base EGP Case

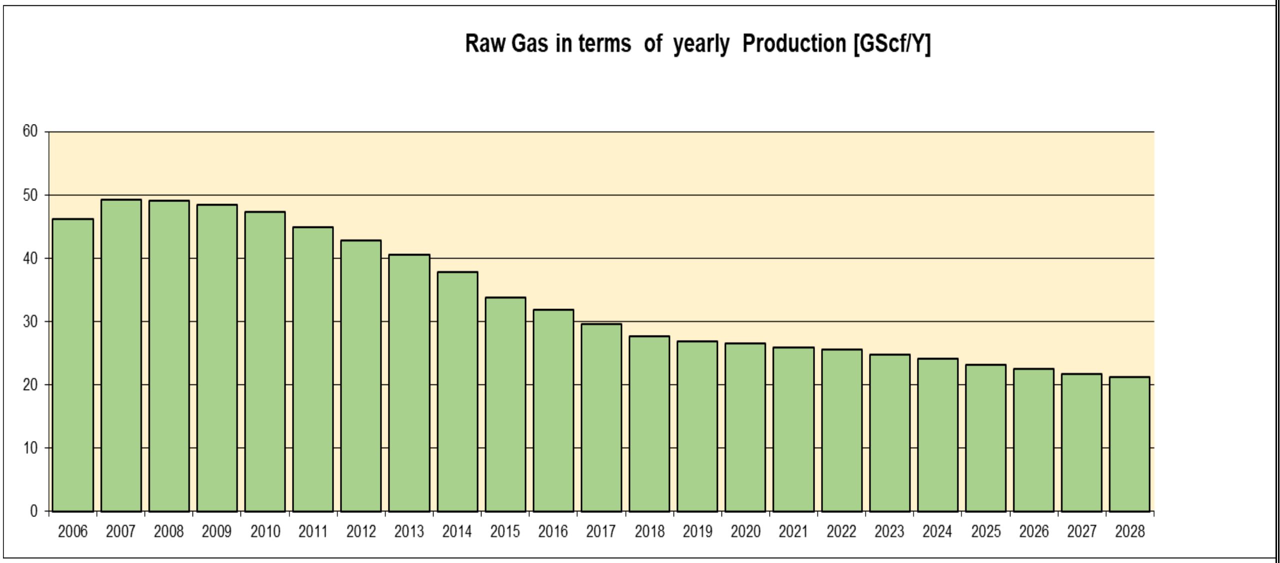


Figure 6.1A Raw Gas Production

<u>6.3.2 3D Model -Base – Cash Flow Analysis :</u>

CASH FLOW ANALYSIS OF "Offshore Field - Phase 1 only Development"

No.	Time	Sales Gas (Mellitha)	Sales Gas (Mellitha)	Sales Cond (Mellitha)	Sales LPG (Mellitha)	Gas. price	Cond. Price	LPG Price	CAPEX	Main. Cost	Melitah	WorkOver	OPEX	Total Expen.	Gross Revenue	NCF	CNCF	PV @8%
	The end of year	GScf/Y	10^3 x MBTU	t	t	$/MBTU	$/t	$/t	M$	M$/Y	M$/Y	M$/Y	M$	M$	M$	M$	M$	M$
-1	31-Dec-03	0.00	0.00	0	0	2.8	205.0	222.5	4.91	0.00			0	4.91	0.00	-4.91	-4.9	-5.30
0	31-Dec-04	0.00	0.00	0	0	2.8	205.0	222.5	25	0.00			0.00	25.00	0.00	-25.00	-29.9	-25.00
1	31-Dec-05	0.00	0.00	0	0	2.8	205.0	222.5	34	0.00			0.00	34.00	0.00	-34.00	-63.9	-31.48
2	31-Dec-06	0.00	0.00	0	0	2.8	205.0	222.5	163	0.00			0.00	163.00	0.00	-163.00	-226.9	-139.75
3	31-Dec-07	0.00	0.00	0	0	2.9	205.1	222.6	93.09	0.00	0.00	0.00	0.00	93.09	0.00	-93.09	-320.0	-73.90
4	31-Dec-08	13.85	14158.81	112,119	30,585	2.9	205.1	222.6	0	3.80	3.50	0.50	7.80	7.80	70.58	62.78	-257.2	46.14
5	31-Dec-09	13.66	13959.96	110,544	30,155	2.9	205.1	222.6	0	3.80	3.50	0.50	7.80	7.80	69.87	62.07	-195.2	42.24
6	31-Dec-10	13.37	13667.27	108,227	29,523	2.9	205.1	222.6	0	7.80	3.50	0.50	11.80	11.80	68.68	56.88	-138.3	35.84
7	31-Dec-11	12.68	12957.81	102,609	27,991	2.9	205.1	222.6	0	3.80	3.50	0.50	7.80	7.80	65.38	57.58	-80.7	33.60
8	31-Dec-12	12.07	12336.44	97,688	26,648	3.0	205.2	222.7	0	3.80	3.50	0.50	7.80	7.80	62.49	54.69	-26.0	29.55
9	31-Dec-13	11.46	11708.62	92,717	25,292	3.0	205.2	222.7	0	3.80	3.50	0.50	7.80	7.80	59.55	51.75	25.7	25.89
10	31-Dec-14	10.68	10910.96	86,400	23,569	3.0	205.2	222.7	0	3.80	3.50	0.50	7.80	7.80	55.71	47.91	73.7	22.19
11	31-Dec-15	9.56	9767.61	77,347	21,099	3.0	205.2	222.7	0	7.80	3.50	0.50	11.80	11.80	50.07	38.27	111.9	16.41
12	31-Dec-16	8.98	9182.18	72,711	19,835	3.0	205.2	222.7	0	3.80	3.50	0.50	7.80	7.80	47.25	39.45	151.4	15.67
13	31-Dec-17	8.35	8533.59	67,575	18,434	3.1	205.3	222.8	0	3.80	3.50	0.50	7.80	7.80	44.09	36.29	187.7	13.34
14	31-Dec-18	7.83	8002.19	63,367	17,286	3.1	205.3	222.8	0	3.80	3.50	0.50	7.80	7.80	41.51	33.71	221.4	11.48
15	31-Dec-19	7.59	7757.70	61,431	16,758	3.1	205.3	222.8	0	7.80	3.50	0.50	11.80	11.80	40.39	28.59	250.0	9.01
16	31-Dec-20	7.49	7657.56	60,638	16,541	3.1	205.3	222.8	0	3.80	3.50	0.50	7.80	7.80	40.03	32.23	282.2	9.41
17	31-Dec-21	7.30	7464.41	59,108	16,124	3.1	205.3	222.8	0	3.80	3.50	0.50	7.80	7.80	39.17	31.37	313.6	8.48
18	31-Dec-22	7.20	7363.25	58,307	15,906	3.2	205.4	222.9	0	3.80	3.50	0.50	7.80	7.80	38.79	30.99	344.6	7.75
19	31-Dec-23	7.01	7160.22	56,699	15,467	3.2	205.4	222.9	0	7.80	3.50	0.50	11.80	11.80	37.86	26.06	370.6	6.04
20	31-Dec-24	6.80	6951.35	55,045	15,016	3.2	205.4	222.9	0	3.80	3.50	0.50	7.80	7.80	36.90	29.10	399.7	6.24
21	31-Dec-25	6.53	6671.79	52,832	14,412	3.2	205.4	222.9	0	3.80	3.50	0.50	7.80	7.80	35.55	27.75	427.5	5.51
22	31-Dec-26	6.36	6502.66	51,492	14,047	3.2	205.4	222.9	0	3.80	3.50	0.50	7.80	7.80	34.78	26.98	454.4	4.96
23	31-Dec-27	6.14	6274.01	49,682	13,553	3.3	205.5	223.0	0	7.80	3.50	0.50	11.80	11.80	33.68	21.88	476.3	3.73
24	31-Dec-28	5.97	6103.04	48,328	13,183	3.3	205.5	223.0	0	3.80	3.50	0.50	7.80	7.80	32.89	25.09	501.4	3.96
TOTAL		190.89	195,091	1,544,865	421,425				320	99.8	73.5	10.5	184	504	1005	501.4	501	82

Table 6.3A **CASH FLOW ANALYSIS - Phase 1 only Development**

Cash flow Results:

Gas NHV =	**1022**	**BTU/SCF**
Gas Price =	**2.8**	**$/MBTU**
Cond. Price =	**205**	**$/t**
LPG. Price =	**222.5**	**$/t**
Interest rate =	**8.0**	**%**
Price Inflation Rate =	**2.0**	**%**

Gross Revenue		1005.2	M$	
Total Cost		503.8	M$	
Net Profit		501.4	M$	
NPV @8%		82.02	M$	
IRR		11.9	%	1
POT	**(Month, Year)**	7-13	9	2
PIR		1.57	$/$	3
DPIR, CPI		0.26	$/$	4
G.R./T.C.		2.00	$/$	

Abbreviation:

1- Rate Of Return =

2-Pay Out Time

3-Profit Investment Ratio (CNCF Over CAPEX)

4-Discounted Profit Investment Ratio (PV Over CAPEX)

6.3.3 3D Model –Development Case - Production Profile :

	Production Profiles											
DATE	Year	Gas Production (Recycled Exaust Gas Excluded)	Sales Gas (Mellitha)		Sales Condensate (Mellitha)	Sales LPG (Mellitha)	Sales Gas (Mellitha)	Fuel Gas*** (Actual DP4)	Fuel Gas (GU DP4)	Blend Gas (DP4)	Fuel Gas (Mellitha)
		(G Scf/Y)	(G Scf/Y)	G Sm3/Y)	(t/Y)	(t/Y)	(M BOE/Y)	(MSm3/Y)	(MSm3/Y)	(MSm3/Y)	(MSm3/Y)
31-Dec-06	2006	46									
31-Dec-07	2007	49									
31-Dec-08	2008	49	14	0.39	112119	30585	2.4	47	54	129	16
31-Dec-09	2009	48	14	0.39	110544	30155	2.4	47	54	127	15
31-Dec-10	2010	47	13	0.38	108227	29523	2.3	47	54	124	15
31-Dec-11	2011	45	13	0.36	103253	28166	2.2	47	54	119	14
31-Dec-12	2012	44	12	0.35	100185	27330	2.2	47	54	115	14
31-Dec-13	2013	42	12	0.33	95014	25919	2.0	47	54	109	13
31-Dec-14	2014	39	12	0.35	89284	24356	2.2	47	129	0	14
31-Dec-15	2015	37	12	0.33	84521	23057	2.0	47	129	0	13
31-Dec-16	2016	36	11	0.32	82759	22576	2.0	47	129	0	13
31-Dec-17	2017	35	11	0.31	79800	21769	1.9	47	129	0	12
31-Dec-18	2018	34	11	0.30	77279	21081	1.9	47	129	0	12
31-Dec-19	2019	33	10	0.29	74878	20426	1.8	47	129	0	12
31-Dec-20	2020	33	10	0.29	74839	20415	1.8	47	129	0	12
31-Dec-21	2021	33	10	0.29	74401	20296	1.8	47	129	0	12
31-Dec-22	2022	32	10	0.29	73530	20058	1.8	47	129	0	11
31-Dec-23	2023	32	10	0.28	72349	19736	1.7	47	129	0	11
31-Dec-24	2024	32	10	0.28	72211	19698	1.7	47	129	0	11
31-Dec-25	2025	31	10	0.28	70856	19329	1.7	47	129	0	11
31-Dec-26	2026	30	9	0.27	68529	18694	1.7	47	129	0	11
31-Dec-27	2027	29	9	0.26	66216	18063	1.6	47	129	0	10
31-Dec-28	2028	28	9	0.25	64166	17504	1.5	47	129	0	10
		864	234	6.6	1754962	478737	40.7	989	2256	724	263

GUP Performance Summary Up to end 2028

Total Sales Gas	**6.62**	**GSm3**
Total Sales Cond&LPG	**22.56**	**MSTB**
Total Fuel Gas (Blend Gas incl.)	**4.23**	**GSm3**

Table 6.4A: **3D Model –Development Case - Production Profile**

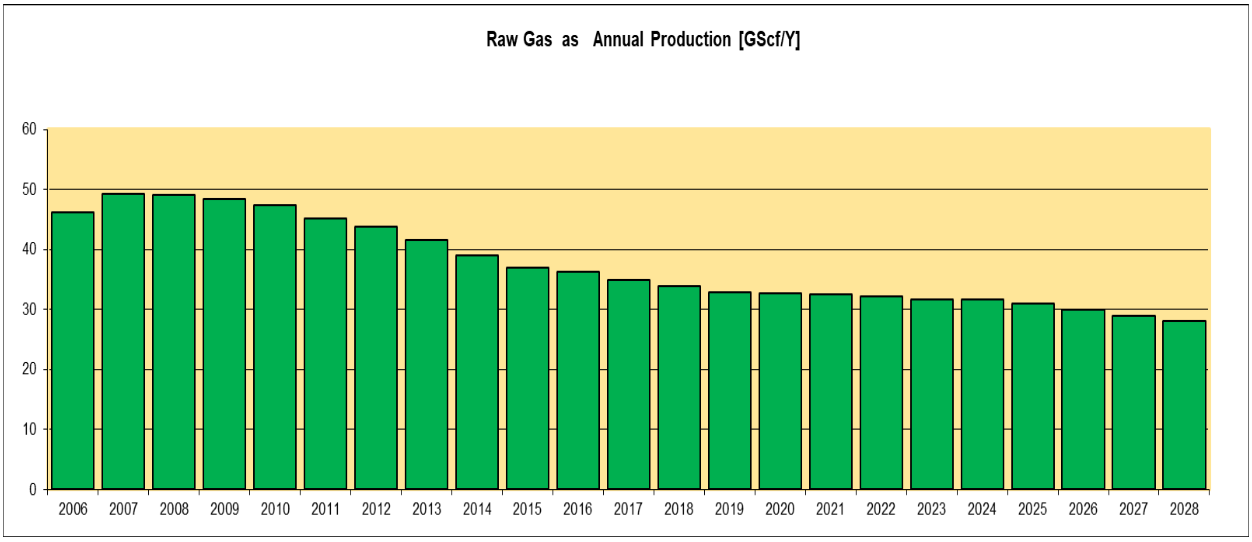


Figure 6.2A Raw Gas Production –Development Case

6.3.4 3D Model –development – Cash Flow Analysis :

No.	Time The end of year	Sales Gas GScf/Y	Sales Gas 10^3 x MBTU	Sales Cond t	Sales LPG t	Gas. price $/MBTU	Cond. Price $/t	LPG Price $/t	CAPEX M$	Main. Cost M$/Y	 M$/Y	WorkOver M$/Y	OPEX M$	Total Expen. M$	Gross Revenue M$	NCF M$	CNCF M$	PV @8% M$
-1	31-Dec-03	0.00	0.00	0	0	2.8	205	222.5	4.91	0.00			0	4.91	0.00	-4.91	-5	-5
0	31-Dec-04	0.00	0.00	0	0	2.8	205	222.5	25	0.00			0.00	25.00	0.00	-25.00	-30	-25
1	31-Dec-05	0.00	0.00	0	0	2.8	205	222.5	34	0.00			0.00	34.00	0.00	-34.00	-64	-31
2	31-Dec-06	0.00	0.00	0	0	2.8	205	222.5	163	0.00			0.00	163.00	0.00	-163.00	-227	-140
3	31-Dec-07	0.00	0.00	0	0	2.9	205	222.6	93.09	0.00	0.00	0.00	0.00	93.09	0.00	-93.09	-320	-74
4	31-Dec-08	13.86	14161	112119	30585	2.9	205	222.6	0	3.80	3.50	0.50	7.80	7.80	70.59	62.79	-257	46
5	31-Dec-09	13.66	13962	110544	30155	2.9	205	222.6	0	3.80	3.50	0.50	7.80	7.80	69.88	62.08	-195	42
6	31-Dec-10	13.38	13670	108227	29523	2.9	205	222.6	0	7.80	3.50	0.50	11.80	11.80	68.69	56.89	-138	36
7	31-Dec-11	12.76	13041	103253	28166	2.9	205	222.6	0	3.80	3.50	0.50	7.80	7.80	65.79	57.99	-80	34
8	31-Dec-12	12.38	12654	100185	27330	3.0	205	222.7	0	3.80	3.50	0.50	7.80	7.80	64.09	56.29	-24	30
9	31-Dec-13	11.74	12001	95014	25919	3.0	205	222.7	0	3.80	3.50	0.50	7.80	7.80	61.03	53.23	29	27
10	31-Dec-14	12.36	12635	89284	24356	3.0	205	222.7	0	3.80	3.50	0.50	7.80	7.80	61.65	53.85	83	25
11	31-Dec-15	11.70	11961	84521	23057	3.0	205	222.7	0	7.80	3.50	0.50	11.80	11.80	58.60	46.80	130	20
12	31-Dec-16	11.46	11712	82759	22576	3.0	205	222.7	0	3.80	3.50	0.50	7.80	7.80	57.62	49.82	180	20
13	31-Dec-17	11.05	11293	79800	21769	3.1	205	222.8	0	3.80	3.50	0.50	7.80	7.80	55.79	47.99	228	18
14	31-Dec-18	10.70	10936	77279	21081	3.1	205	222.8	0	3.80	3.50	0.50	7.80	7.80	54.24	46.44	274	16
15	31-Dec-19	10.37	10597	74878	20426	3.1	205	222.8	0	7.80	3.50	0.50	11.80	11.80	52.77	40.97	315	13
16	31-Dec-20	10.36	10591	74839	20415	3.1	205	222.8	0	3.80	3.50	0.50	7.80	7.80	52.96	45.16	360	13
17	31-Dec-21	10.30	10529	74401	20296	3.1	205	222.8	0	3.80	3.50	0.50	7.80	7.80	52.86	45.06	405	12
18	31-Dec-22	10.18	10406	73530	20058	3.2	205	222.9	0	3.80	3.50	0.50	7.80	7.80	52.45	44.65	450	11
19	31-Dec-23	10.02	10239	72349	19736	3.2	205	222.9	0	7.80	3.50	0.50	11.80	11.80	51.82	40.02	490	9
20	31-Dec-24	10.00	10219	72211	19698	3.2	205	222.9	0	3.80	3.50	0.50	7.80	7.80	51.92	44.12	534	9
21	31-Dec-25	9.81	10027	70856	19329	3.2	205	222.9	0	3.80	3.50	0.50	7.80	7.80	51.15	43.35	578	9
22	31-Dec-26	9.49	9698	68529	18694	3.2	205	222.9	0	3.80	3.50	0.50	7.80	7.80	49.67	41.87	619	8
23	31-Dec-27	9.17	9371	66216	18063	3.3	205	223.0	0	7.80	3.50	0.50	11.80	11.80	48.18	36.38	656	6
24	31-Dec-28	8.89	9081	64166	17504	3.3	205	223.0	0	3.80	3.50	0.50	7.80	7.80	46.87	39.07	695	6
Total		233.64	238784	1754962	478737				320	99.8	73.5	10.5	184	504	1199	694.8	695	135

Gas Utilization Project (with gas impurities re-injection from 2014)

Results

Gross Revenue		1198.6	M$
Total Cost		503.8	M$
Net Profit		694.8	M$
NPV @8%		134.82	M$
IRR		13.6	%
POT	(Date, Year)	13-Jun-13	8
PIR		2.17	$/$
DPIR, CPI		0.42	$/$
G.R./T.C.		2.38	$/$

Gas NHV =	**1022**	BTU/SCF
Gas Price =	**2.8**	$/MBTU
Cond. Price =	**205**	$/t
LPG. Price =	**222.5**	$/t
Interest rate =	**8.0**	%
Price Inflation Rate =	**2.0**	%

Table 6.5A **CASH FLOW ANALYSIS – Development case**

6.4 Gas treatment technique:

Gas production will be treated on DP4 platform and separation products (gas and condensates), separately sent to Sabratha platform about 20 km in the south of Offshore Field . In order to meet sales specifications gas and condensate streams will be treated also on-shore facilities.
Gas impurities are assumed to be flared at this stage in the Base Enhanced Gas Production (EGP) Case presented in this report.
Nevertheless, a sensitivity of re-injecting into the gas-cap the Field total (Phase I+Phase II) gas impurities through dedicated gas injectors positioned south of platform and showed in conjunction with the increased extraction pace positive results.
All production profiles presented here after imply the implementation of previous mentioned activities.

6.5 OGP & Model assumption:

- Introduction of workovers on the upper layers (for 14 wells) in order to manage gas cap shrinkage and aquifer encroachment
- The high GOR wells have been allowed to continue production in order to keep the gas production plateau.

Main constraints governing the optimized forecast run were:

- Field Qg max after debottlenecking 136 MMscft/d
- Well THP min = 300psia (Low Pressure Wells THP min=60 psia)

6.6 Updating of Reservoir Simulation Model

The 3D dynamic reservoir model has been revised and updated The updating consisted in the extension of the history match up to September 2005 and field tolerances in terms of simulated water-cut 3% and GOR of 5% during the last 2 years were met, increasing rebust the confidence in the forecast results. To obtain the history match only local changes on well basis had been necessary.

The main constraints governing the 2006 Optimized case are Field Qgmax after debottlenecking 136 MMscft/d and Well THPmin = 310 psia and Low Pressure Wells THPmin = 70 psia

The Cumulative production in the period 2006-2039 for case of Optimized Gas Production Case are:

- Np = 585 MMSTB
- GP = 1000 Bscft

The cumulative production in the period 2006-2039 of the "2006 Optimized Gas Production Case" are given **table 6. 5A** together with a "2006 Not Optimized case" (no WO and no prioritization of low GOR producers) for comparison reasons.:

PHASE I CUMULATIVE RAW GAS & OIL PRODUCTION						
Cases	31-Dec-19		31-Dec-28		31-Dec-39	
	GAS Bscft	OIL MMstb	GAS Bscft	OIL MMstb	GAS Bscft	OIL MMstb
Not Optimized - 2006	529	262	689	359	852	438
Optimized - 2006	556	275	772	390	964	482

Table 6.6A **Cum. raw gas & Oil production**

6.6.1 Optimized Gas Production Case with Phase II Implementation:

The well scenario for Phase II is containing 19 producers well positions (12 Metlaoui & 7 Dolomite) and 5 water injector wells Re-injection into the gas-cap of the field total (Phase I + Phase II) gas impurities through dedicated gas injectors positioned south of H3-25 was assumed

6.6.2 model constraints for Phase II

- ☑ Maximum Liquid Production per well : 2,000/3,000 stb/day;
- ☑ Minimum well Oil Production 100 stb/day;
- ☑ Minimum well THP constraints: 300 psia;
- ☑ Maximum well/field water cut per well 90%;
- ☑ Maximum well/field GOR 21 Mscf/stb;
- ☑ Automatic choke-down 10% in case of violating limits of WCT or GOR;
- ☑ Water Injection start-up August 2012;
- ☑ Maximum water injection rate per well 25'000 bwpd (5 water inj. Wells).
- ☑ The water injection is based on Voidage Replacement = 0.4 for Phase II area.
- ☑ Acid gas re-injection from Phase I and II is considered.

The acid gas re-injection is foreseen to start-up in Jan 2014. The total amount of gas impurities (Phase I + Phase II) is calculated making the following assumptions:

- Total fuel gas = 20.0 MMscf/day;
- 50% of the remaining is re-injected (impurities concentration is around 50% in the raw gas).

The raw gas and oil cumulative production for Phase I and Phase II wells from 2006 onwards are shown in the following table:

CUMULATIVE RAW GAS & OIL PRODUCTION		31-Dec-19		31-Dec-28		31-Dec-39	
		GAS Bscft	OIL MMstb	GAS Bscft	OIL MMstb	GAS Bscft	OIL MMstb
PHASE I	Optimized + PH2 + Acid gas reinj. 50%	585	272	874	384	1161	467
PHASE II	Optimized + PH2 + Acid gas reinj. 50%	224	102	377	159	510	199
TOTAL	Optimized + PH2 + Acid gas reinj. 50%	809	374	1251	543	1671	666

The recycled gas cumulative production for Phase I and Phase II wells from 2006 onwards are shown in the following table:

CUMULATIVE IMPURITIES PRODUCTION	31-Dec-19	31-Dec-28	31-Dec-39
	Bscft	Bscft	Bscft
PHASE I	negl.	10	32
PHASE II	negl.	7	32

Chapter

6.0

B

Re-Injection / Sequestration Acid Gas

6.1 Abstract:

33 years of production in offshore Libyan field and volume of gas production is steadily increasing as the mature Offshore Field (*one of the largest Libyan offshore oil fields*) is depleted. In fact to meet the proper field exploitation strategies , various activities in the Offshore Field , have been planned which characterize in many projects such as , Artificial lift project, Low pressure gathering system project, infilling wells from existing platforms, Work over, de-bottle necking of the existing surface facilities, development of eastern nose of the structure by drilling some sub sea wells , water injection and second phase of field development.

In spit that the gas utilization project will reduce the gas flaring , the problem of acid gas is still not completely solved , on the other hand an additional production of acid gas from phase II of Offshore Field is expected This turned to think deeply of EOR or sequestration of acid gas (*H_2S and CO_2, with minor traces of hydrocarbons*) .

Based on 2004 update of the 3D reservoir simulation model, the gas and oil production over the period 2004-2039 , are **1339** Bscf and **547 M**stb respectively .

Acid gas is ranging in composition from 0.5% H_2S and 42 % CO_2 (at stage of membrane stage) to 3.4 % H_2S and.73. % CO_2 (at stage of acid gas compression) .

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6.2 Introduction:

At July 2007, the field is producing an oil rate of 55 Mbopd with a field GOR of around 2200 scf/stb and WC 27 % through 50 wells. Produced gas that contains more than 50% of impurities (mostly CO_2 and N_2) *is flared.*

6.3 Field Discovery and Development:

5.3-1 Exploration phase:

8 appraisal wells were drilled along the main axis of the structure .All 8 wells were cored, tested and finally abandoned. The main oil-bearing formations are named "Nummulatic member " and Dolomatic member"

Phase I development

Phase I was completed in 4 years (1988-1992) , two platforms (DP3 & DP4) were built and 55 development wells were drilled and put on stream with single completion (tubing 3.5 inch) the following actions have been taken:

- Extended reach wells were drilled to reach Favorable producing zones outside gas-cap.
- Horizontal wells were drilled for reducing gas production and increasing oil rate below the gas cap in the upper nummulitic.
- sub-sea wells were completed in the Dolomtic member,
  The current development scheme includes two platforms (DP-3 and DP-4) with 75 oil producers model the current field development strategy an (45 from DP-4 and 30 from DP3), 73 wells are completed in the Metlaoui group and 2 subsea wells in the Dolomitic.

The production breakdown between the two platforms is given **in table No. 6.1**B

	DP3	DP4	TOTAL/Avg
Qo(bopd)	27066	33613	60679
Qg (MMscf/d)	46.20	63.12	109.32
GOR (scf/stb)	1707	1878	1802
Qw(bwpd)	4061	9616	13677
W.C.(%)	13	22.2	18.4

Table 6.1B : Platforms performance

6.3-1 Ongoing projects:

De-bottlenecking: The existing surface facilities constrain the oil production by its maximum gas treatment capacity. This project will allow increasing the maximum gas production rate from the current 100 MMscf/d to 130 MMscf/d. (1st Qrt 2006).

East Area Development: Development of the eastern nose of the structure through the drilling of 4 sub-sea wells. Wells drilled and completed waiting on connection with DP4. Start up production is foreseen for 1st Qrt 2006.

Water Re-Injection: maximum water treatment capacity will be raised to 30'000 bwpd and the produced water will be re-injected into the reservoir through well H4-25. The test phase of this project is foreseen for 3rd Qrt 2007. The WI project design foresees:

- Increase water treatment capacity to 30 Mbwpd
- Deepening & completing H4-25 as a water injector
- Connect disposal well H4-20 completed inside Melqart Fmt for back-up
- Water handling system should be flexible:
- Choice between disposal (in Melqart or Sea) or re-injection in the reservoir should always be possible.

6.4 3D reservoir simulation Model – Results :

6.4.1 Prediction Scenarios

Based on the 3D reservoir simulation model the gas and oil production during the period 2004 -2039, are 1331 Bscf and 546 MM stb In order to maintain a longer gas production plateau and introduce in the optimized case has been created. Optimisations of the forecast constraints *are mainly the following*:

☝ the introduction of work over on the upper layers (for 24 wells) to manage gas cap shrinkage and aquifer encroachment.

☝ The high GOR wells have been allowed to continue production to keep the gas production plateau.

Automatic work over for low THP on all wells by opening higher layers.

The results gained from 3D black oil model in terms of associated gas production profile is shown in figure 6.1b , note that the plateau gas production of 136 Mscf/d is held for around 8 years; then rate decreases, the cumulative gas production @2029 will be 1077 B scf.

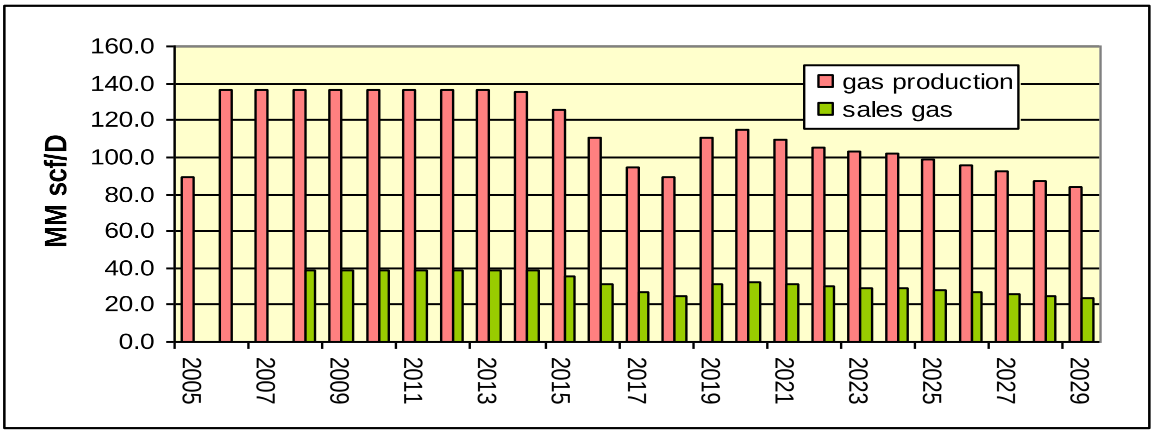


Figure 6.1B: gas production & Sales gas

6.4.2 (Phase II)

Based on the reservoir simulation study, the additional reserves due to the phase2 development project are given *in table 6.2B.* The associated gas production profile and the sales gases obtained from the 3D black oil model are shown graphically in figure 6.2b and 6.3b.

Table 6.2B : Production foreseen for Two Phase

Scenario	@ 31/12/2039 (BScf)	@ 31/12/2019 (BScf)
Base Case (PH2 : standalone)	**281.9**	**209.0**
Base Case (PH1 Synergy)	**408.9**	**109.0**

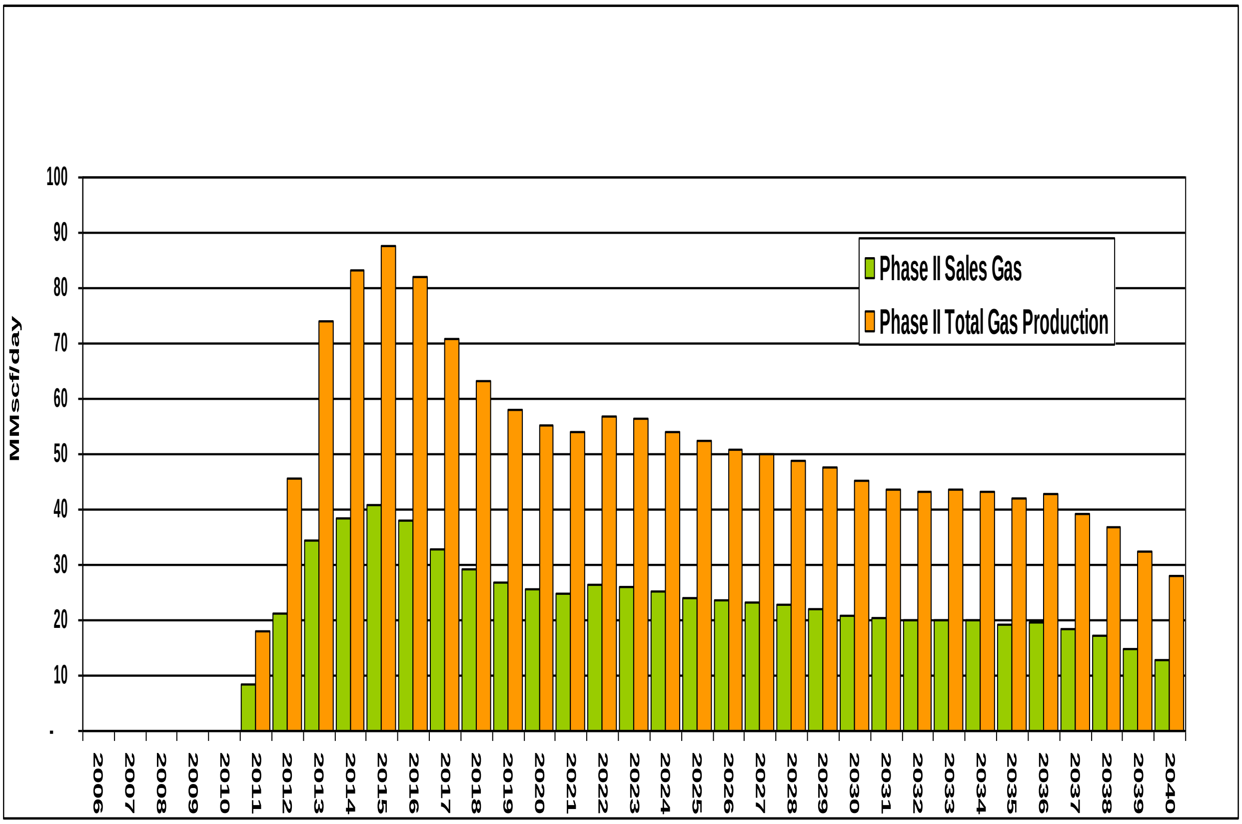


Figure 6.2B Gas Production Profile and sales gas (phase II)

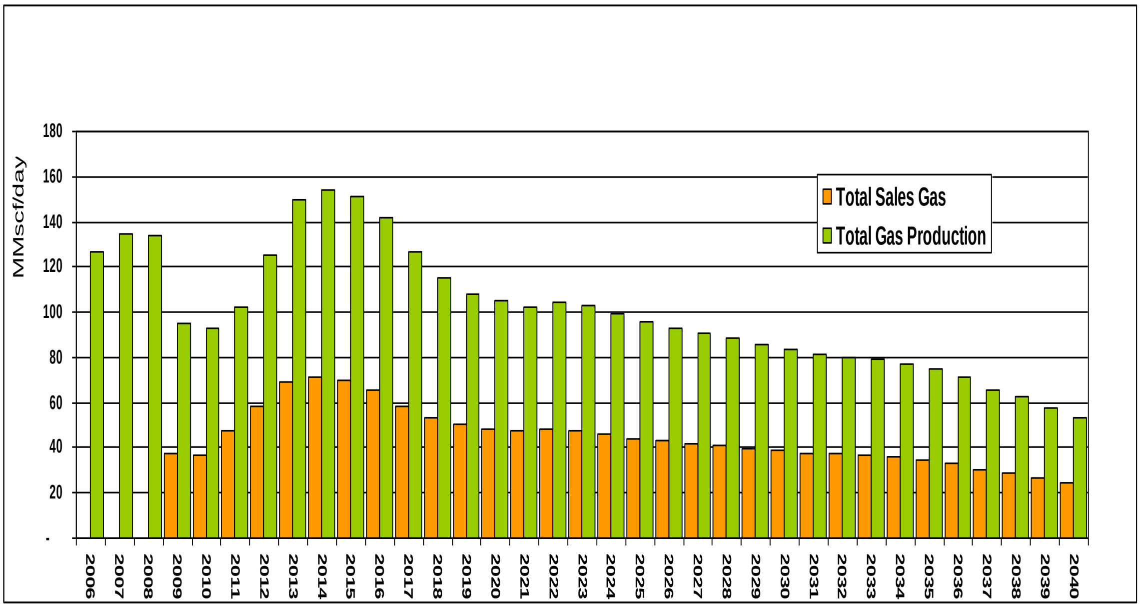


Figure 6.3B : Production and sales gas of two phase development

6.5 Economic Evaluation Analysis:

The economic analysis has been considered as a simple cash flow analysis built on the different gas production profiles for two phase developments.
In addition to the base economics, a sensitivity analysis had been performed for cases on the main input parameters to define the safety range of successful development**.**
The main outcome of the Cash-Flow analysis for (Phase I & II) gas production stream ,results and economic assumptions are summarized in **tables 6.3B and 6.4B**

Table 6.3B

		Development Phase I		Development Phase II	
Gas production		Gscf/y	1035	Gscf/y	827
Gas sles		Gscf/y	255	Gscf/y	262
Gross Revenue		1348.8	M$	12201	MM$
Total Cost		511.6	M$	3298	MM$
Net Profit		837.21	M$	8904	MM$
NPV @8%		179.35	M$	2208	MM$
IRR		15	%	36	%
POT	(Date, Year)	jan.2014		jan.2013	
PIR		2.6163	$/$	5.8	$/$
DPIR, CPI		0.5605	$/$	2.23	$/$
G.R./T.C.		2.6364	$/$	3.7	$/$

Table 6.4B

	Development phase I		**Development phase II**	
Gas NHV =	1022	BTU/SCF	1022	BTU/SCF
Gas Price =	2.8	$/MMBTU	5.6	$/MMBTU
Cond. Price =	205	$/t	475	$/t
LPG. Price =	222.5	$/t	541	$/t
Interest rate =	8.0	%	10.0	%
Price Inflation Rate =	2.0	%	2.0	%
Project start up	Jan. 2008		Jan. 2011	

6.6 Environmental impact assessment :

Even though the gas utilization project will reduce the gas flaring, the problem of acid gas is not completely solved, conversely an additional amount of acid gas production from phase II of Offshore Field will be added, this implies to think deeply of **EOR** or sequestration of acid gas (*H2S and CO2, with minor traces of hydrocarbons*)

As a result of implementing phase II project however the field gas production will be increased and consequently the acid gas volume will be increased.

Acid gas re injection or sequestration will have the following advantages:

☑ Eliminate the emission of pollutants into the atmosphere, to match the international agreement of environmental protocols.
☑ Preserve natural resource of LPG and gas condensate
☑ Increase oil recovery and Maintain reservoir pressure.

6.6.1 Gas Utilization Project

The main goal of gas utilization project is:

☑ Reduction of the environmental impact by applying a suitable gas recovery system able to reduce emissions to the atmosphere
☑ Improvement of field economics through additional revenues from recovered gas, condensate, and LPG sales.
Increase total recoverable hydrocarbon reserves in terms of gas, condensate, and LPG

6.6.2 Project description

Gas production will be treated on DP4 platform and separation products (gas and condensates), separately sent to Sabratha platform about 20 km south of Offshore Field . In order to meet sales specifications, gas and condensate streams will be treated also on-shore through Mellitha facilities.

6.6.3 Acid Gas contents

Gas composition:

Fig. **No 6.4B** shows Offshore Field gas composition. Acid gas composition ranges from 0.52% H2S and 40.76% CO2 (at first stage of separator train) while **figure 6.5B** shows Offshore Field gas composition that will be flared , the composition is ranging from 0.49 % H2S and 78.70% CO2.

The main composition of acid gas which supposed to be injected into the reservoir or nearby area are shown in **figure 6.6B.**

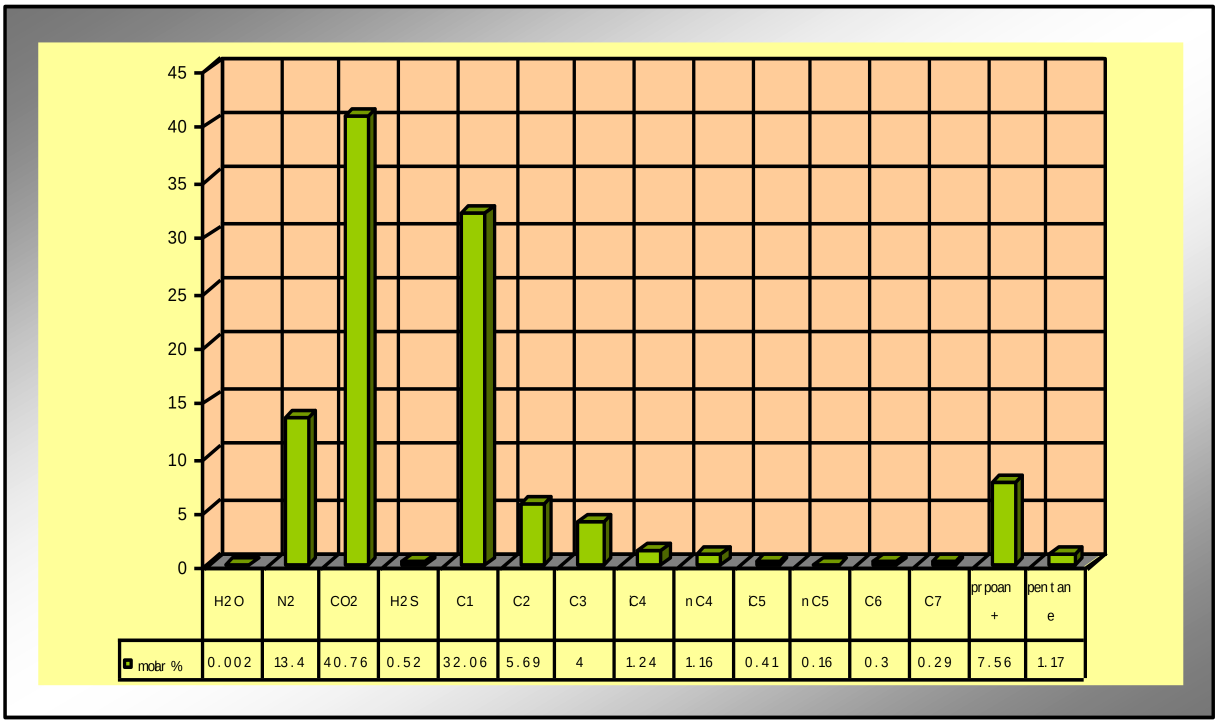


Figure 6.4B: gas sample analysis at 1st stage separator

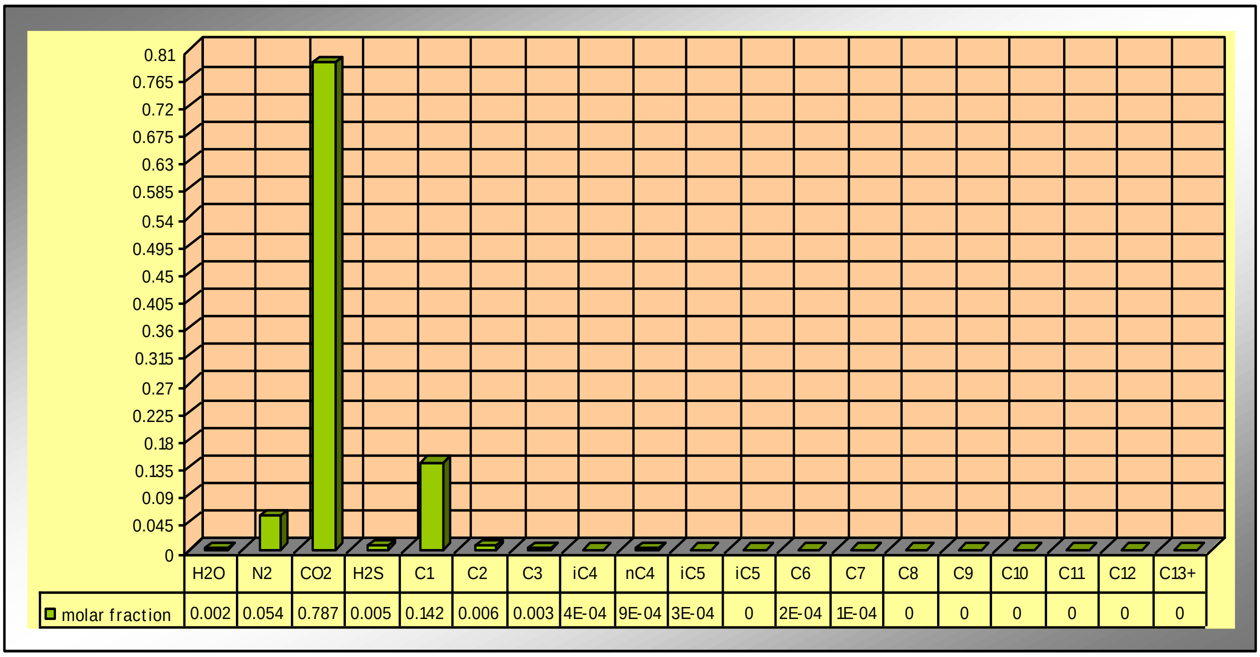


Figure 6.5B : Composition of acid gas flared

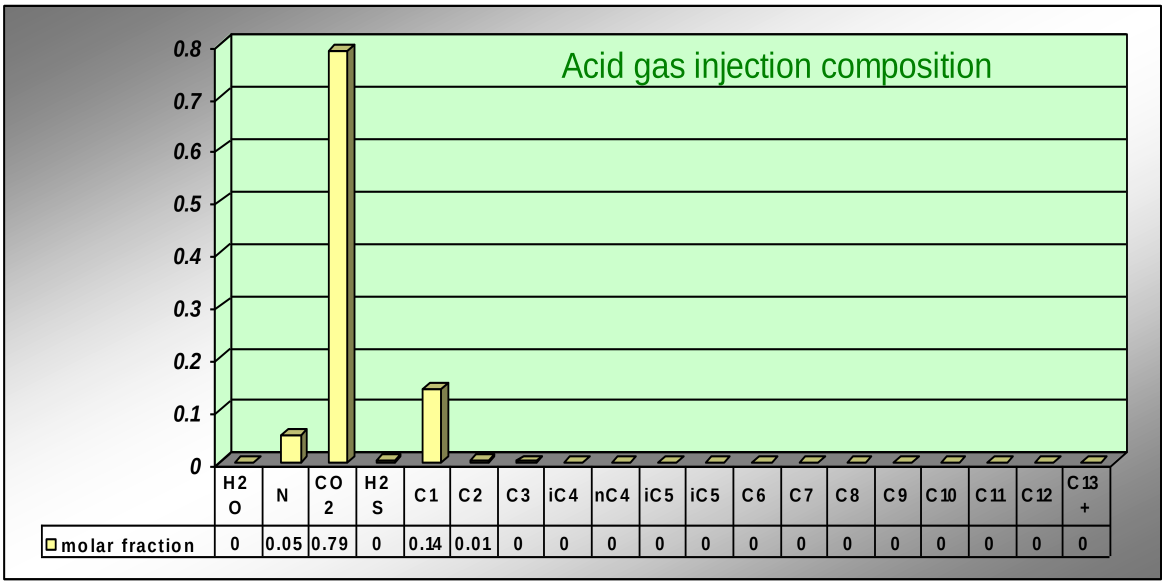


Figure 6.6B: composition of injected acid

6.6.4 Acid Gas Definition

Acid gas is a by-product of the gas sweetening process employed at natural gas processing plants. Depending on the composition of the raw gas stream, acid gas is typically composed of CO_2 and H_2S with small amounts of residual hydrocarbons. If the acid gas does not contain regulated concentrations of H_2S the acid gas may be vented to the atmosphere. This is sometimes the case at sweet gas processing plants that must remove CO_2 to meet pipeline specifications.

More frequently, however, the acid gas contains significant H_2S and must be flared, processed by a Sulphur recovery unit, or disposed of by injection into a suitable underground formation, depending on the regulatory requirements, costs involved and site-specific constraints.

The amount of acid gas production is usually metered and the CO_2 content, although not normally tracked by regulatory agencies, is known by the facility operators. The allowable options for disposal of the acid gas depend on the Sulphur inlet rate

6.6.5 Acid Gas : *Alternative reducing/eliminating scheme:*

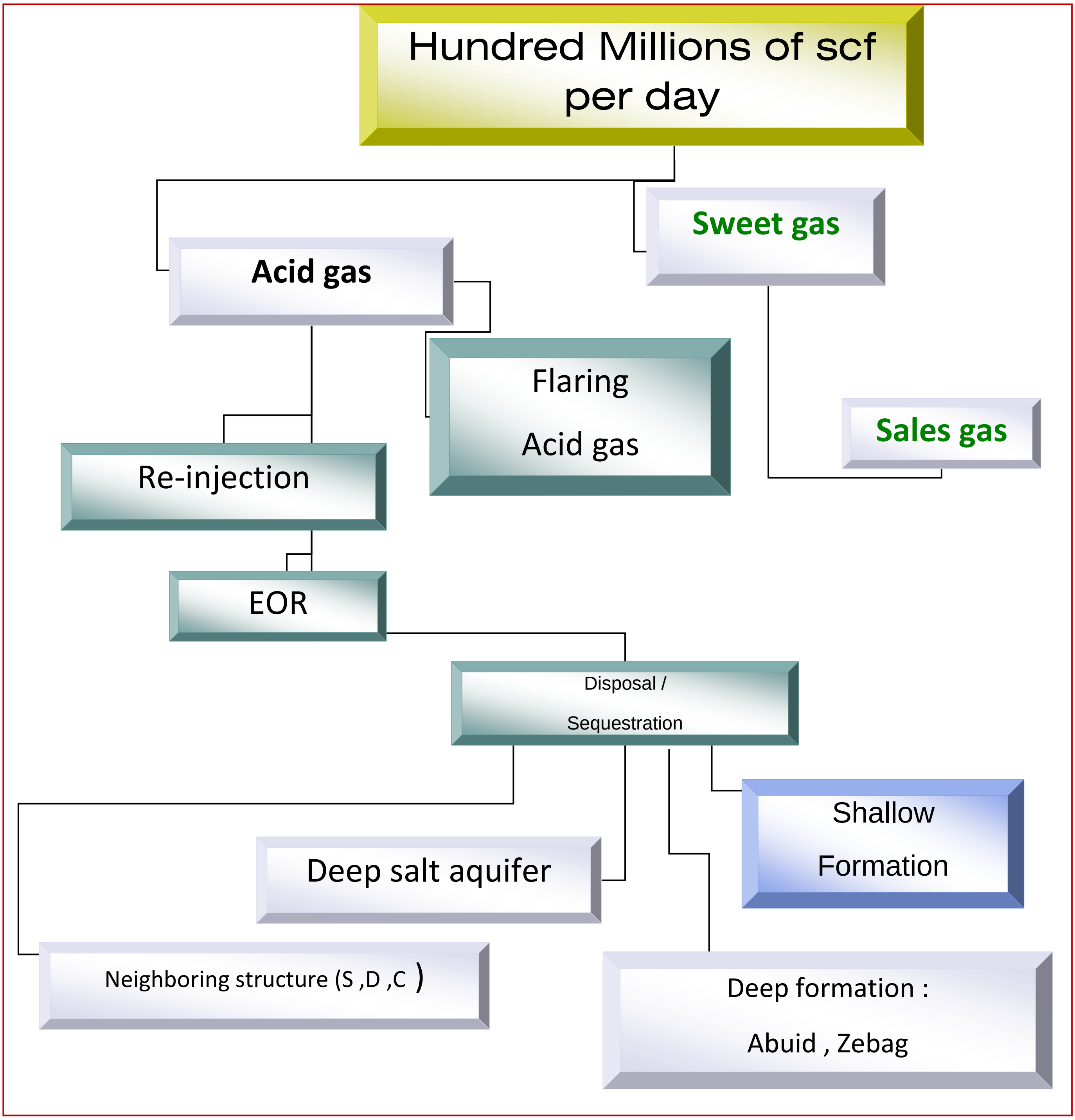
Alternative reducing/eliminating scheme:

To reduce CO_2 emissions, one must either reduce CO_2 production, or looking for other alternative disposal schemes.

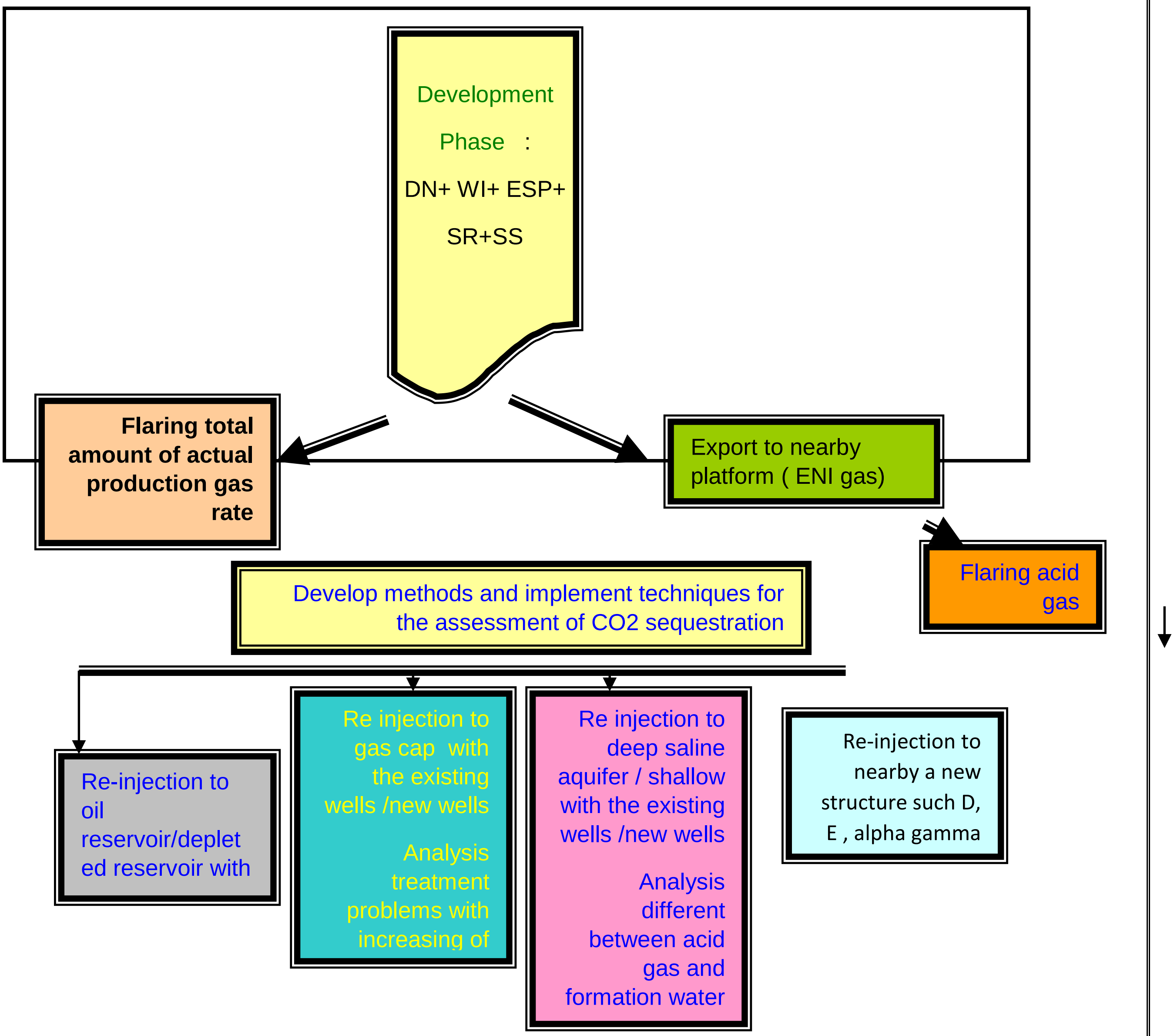
Several different sequestration schemes have been proposed to manage the problem of environmental pollution.

Implementation of technologies to capture carbon dioxide (CO_2) and sequester it in geological formations will be necessary to achieve significant reductions in atmospheric emissions of anthropogenic greenhouse gases. Oil and gas reservoirs and deep saline aquifers are believed to be safe suggestion for long-term geological sequestration.

The following flowcharts could be main entrance of this section which merged between the concept of environment impact and hydrocarbon improvement reserves .



More emphasizing given by The second flowchart ,the main goal is reducing or eliminated gas emission into atmosphere :


Development
Phase :
DN+ WI+ ESP+
SR+SS
Flaring total amount of actual production gas rate
Export to nearby platform (ENI gas)
Flaring acid gas
Develop methods and implement techniques for the assessment of CO2 sequestration
Re-injection to oil reservoir/deplet ed reservoir with
Re injection to gas cap with the existing wells /new wells
Analysis treatment problems with increasing of
Re injection to deep saline aquifer / shallow with the existing wells /new wells
Analysis different between acid gas and formation water
Re-injection to nearby a new structure such D, E , alpha gamma

6.6.6 Acid gas Removal /disposal

There are some common methods of acid gas removal, the first method using membranes system and the second one by using amine absorption system , but the gas sweetening by later technique is eliminated , due to huge rate required of amine solution (more than 1500 cubic meter per hour of diethyl amine (DEA) and needs high duty of power ranging between 150-200 MW). The third method of removal of acid gas is sweetening by hydrate iron oxide this process is selective and can remove only H2S form gas stream in fact it is suitable to remove a small amount of H2S (a few grains per 100 scf).

In fact the storage or removal of acid gas is critical mission ,it might has a primary concern due to its toxicity ,CO2 represent the largest component of gas stream. Where 45 % as CO2, while less than 0.2 % of H2S.

In all desulphurization units, disposal of the H2S gas presents an increasing problem**,** government agencies forbid exhausting the H2S to the atmosphere either as **H2S** or, after burning or flaring, as **SO2**. So, for this reason disposal of the removed H2S must be an integral part of the planning for any desulphurization unit.

The evaluation of suitability of acid gas storage in geological formation will be through the next sections.

Acid gas injection is designed to remove acid gas from oil or gas stream produced from a geological formation, compress, and transport these gases via pipeline to an injection well then re-inject the gases into a different geological formation and structure for disposal.

6.6.7 **Suitability of Sequestration**:

Generally speaking, the most common sequestration of acid gas in geological media are::

- ✓ Storage in salt caverns
- ✓ EOR
- ✓ Storage in depleted oil and gas reservoir
- ✓ Injection into deep saline aquifer

Various ways were available for treatment process, which need to be selected to suit the ultimate disposal location and environment and be feasible from economical and technical points of view however there are many methods for disposing the produced gas in oil field, the main methods are :

- Re-injection to oil reservoir.
- Re-injection to gas cap.
- Re-injection in deep aquifer.
- Re-injection to other formation or neighboring structure.
- Down hole work separation.
- Discharged to emission. (Flaring).
- Storage to a shallow formation

6.7 Sequestrations into Melquart Formation:

A : Geological Data

- Melquart formation pore volume about **75*10E 9 bbl**.
- Vertical extension limited above by anhydrite section of Melqart and excluding and porous part above.
- Melqart formation represents a thick lime stone body with high porosity, with top at around 100-1200 ft, characterized by the appearance of tight anhydrite layer of more than 200 ft.
- The formation extends over the whole area of field, and is underlined by shale and marls of Mohamud formation .
- Good vertical continuity appears from logs, with average net thickness of 752 ft.

B: Reservoir Engineering Data

- ♦ Reservoir salinity = 50,000 ppm
- ♦ Reservoir pressure = 1005 psi
- ♦ Reservoir temperature = 85 deg. f
- ♦ Average porosity = 20 %-30 %
- ♦ Fracture gradient = 0.67 psi/ft
- ♦ Injectivty index = 100 bwpd/psi
- ♦ Injecting pressure = 1000 psi

6.8 Re-injection into oil zone (EOR)

to investigate the possibility of enhanced oil recovery, meanwhile to develop methods and implement techniques for the assessment of CO_2 sequestration in oil and gas reservoirs, to investigate the potential enhanced oil recovery however, well H4-12 well had been candidate for injection purpose of CO_2 into oil reservoir (**figure 6.7B).**

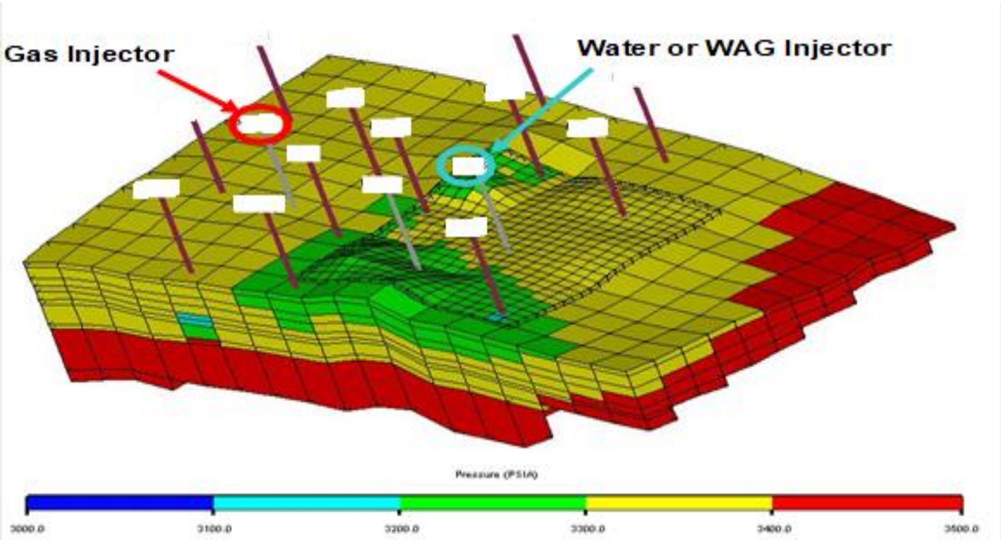


Figure 6.7B: candidate disposal media (Melquart Formation)

6.8-1Acid Gas in Saline Aquifer :

When the acid gas is stored in saline formation, the sequestration will be excepted in the following forms:

☑ The depositional of dissolved gas as minerals.
☑ Gas trapped.
☑ Dissolution into formation water (brine).
This scheme or approach should take into consideration the influence storage of petrophysical parameters and rock properties on gas phase .

The sequestration in this media could be a permanent for the time frame. It means that the gas sequestration will not reach the pay zone for long time.

Then large volume can be stored permanently in saline aquifer, the gas injected or stored can be expected immobilized by one or more of three mentioned storages modes.

6.8.2 Acid gas in deep formation

A- Abiod Formation

formation characterization:

- Deeply buried and separated from another reservoir.
- Doubt on the permeability properties of the reservoir
- Porosity ranging from 14-16 %

- Based on well H3-26 (subsea well) the water bearing is represented in Abiod formation ,and overpressure
- found in the same well while the same formation showing gas bearing (CO_2) in S structure (40 km from Offshore Field) the tested rate was 500 Msfc/d.
- Chalky reservoir, with diffuse micro porosity
- low perm.
- The sealing is the El Haria A (mudstone and shale) catch sight of **figure 6.8B.**
- Abiod Formation is not suitable for CO_2 sequestration because . re-injected gas leakage, from Aboid reservoir toward shallower levels might happen due to faulting and fracturing in El-Haria formation, (El Haria sealing efficiency non fully proved in Offshore Fieldarea since faults propagating from Upper Cretaceous Fm. to Metlaoui Fm.)

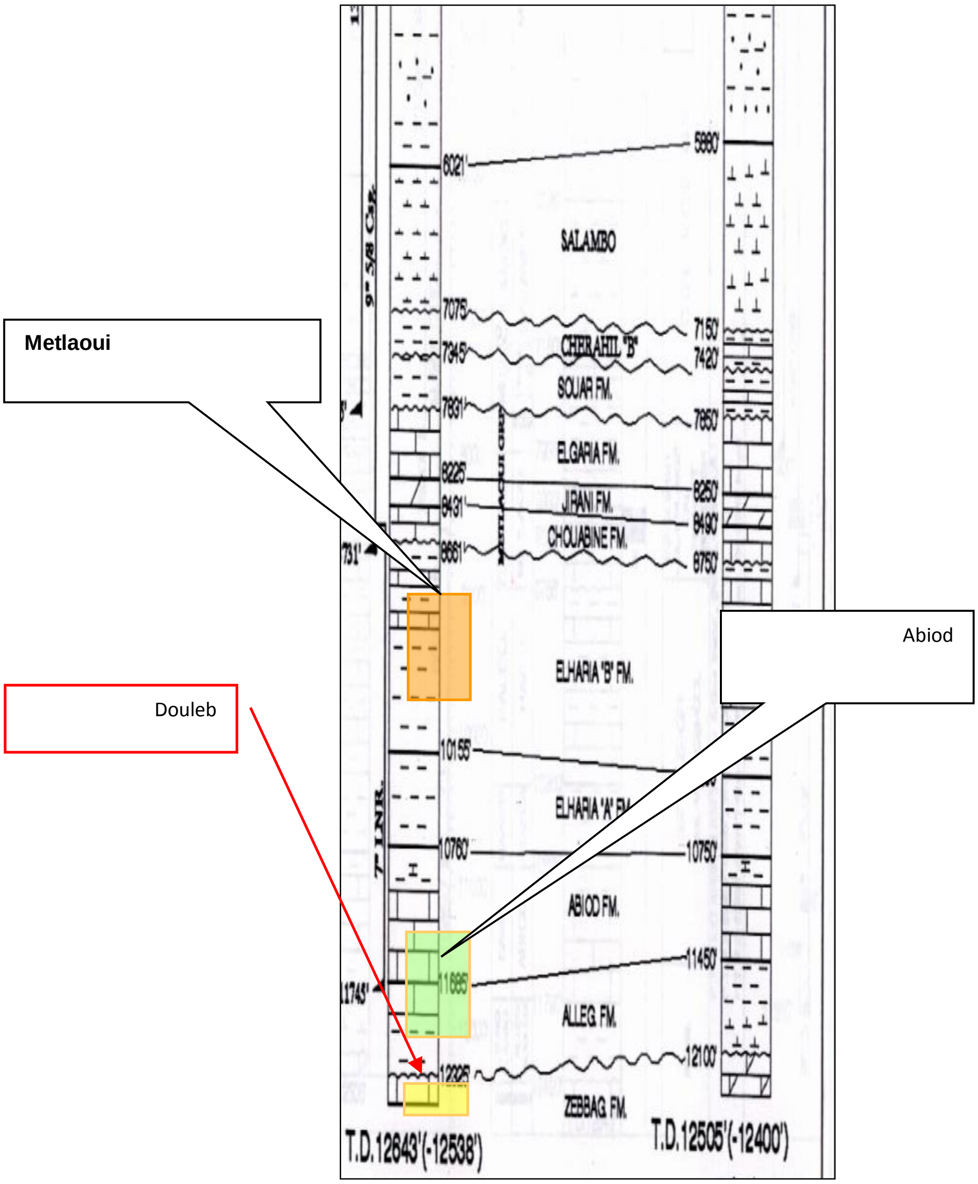


Figure 6.8B: Stratigraphic section for Candidate Units

B- Zebag formation

- Poor reservoir quality.
- Stratigraphic unit does not represent a candidate for CO_2 storage in this zone

The Stratigraphic section and interpreted horizons of the Candidate Units are presented in **figure 6.8B**

6.8.3- Acid gas in nearby structure

D structure

Although preliminary thermodynamic and reservoir modeling activities have shown that re-injection of carbon dioxide in the Metlauoi Fm in the Offshore Field does not result in appreciable EOR, the Nummulitic reservoir still represents a very interesting option for re-injection if the D Structure is considered.

The structure is located north of Offshore Field , about 11 km from the exiting platform (**figure 6.9B** , Metlaoui formation in D structure containing gas and condensate good petrophyscal parameters in terms of permeability and porosity ,the GWC was detected at 8890 ft- ssl and estimation of OGIP of about **3569** Bscf and OCIP of **about 627 MM bbl** . Well, D2-NC41 found gas and condensate in the Metlaoui Gr. with an extremely high concentration of impurities, more than 73%

Metlaoui formation in the subject structure might be suitable for CO_2 sequestration in geological media due to the following reason :

- D structure is not filled toward NC-41 Spill point was detected at 9150 ft ssl
- More than 70 % of gas impurities made D-structure poorly attractive for development of trapped hydrocarbon.
- Re-injection for other non hydrocarbon fluids in Metlaui formation of D structure might be valuable solution .
- surrounding area to Offshore Field facilities about 11 km
- The analysis of the structure shows that dynamic separation between Offshore Field and D structure exist, preventing from leakage of gas impurity injected in the D structure and toward the Offshore Field .

Accordingly Metlaoui Gr. in the *D structure* san be considered as good alternative for the re-injection of acid gas .

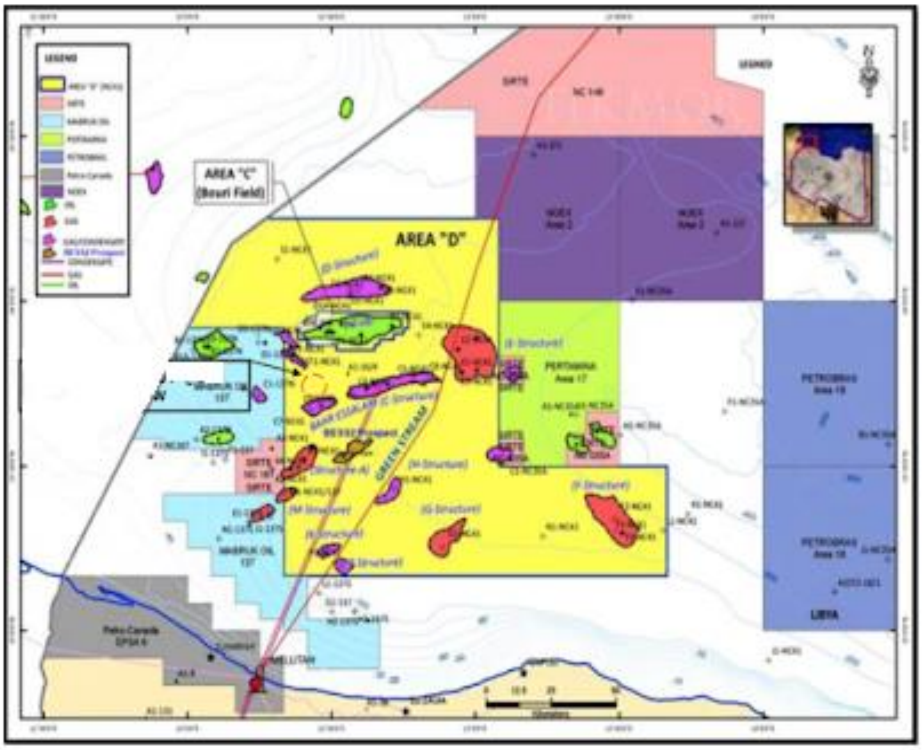


Figure 6.9B nearby structure

S Structure

The Douleb units includes oolitic bars with good reservoir properties (S1-NC41).
The sealing is the Aleg Fm (marls and shale)
Well, S1-NC41, to the north, found reservoir quality lithology in the upper part of the formation, that could be account for re-injection
The two regions of Abiod formation. and Douleb Formation is generally suitable for acid gas re-injection in S structure. But from economic point of view, it looks not due to the long distance from Offshore Field (about 40 km) and uncertainties on reservoir properties spatial distribution makes this solution poorly attractive, the second reason for non-suitability could be poor reservoir quality.

6.9.0 Risk Assessment of geological Storage

6. 9.1 Managing the risks of geological acid gas storage

The technique of risk analysis assessment had been used of the available information to determine how often specific events may occur and magnitude of their consequence, it is a systematic apply to describing and calculating risk, and to identification of undesired events and the causes and the consequences of that events

CO2 has less density and viscosity than formation water (brine) so the carbon dioxide will flow up wards until it is confined by barrier or non-sealing fault or law permeability of cap rocks. this can drive the a horizontal movement, as areal extent of gas sequestration, consequently the gas will eventually dissolve into pore fluid, eliminating floating forces that drive upward motion and greatly reducing transported rate to other formation, it may be trapped for couple of decades .

The classification of possible risks of geological storage or sequestration can be classified ***into two categories***:

gas surface release which will impact in atmosphere and ecosystem the second type of possible risk is related to the leak into subsurface formation due to metal mobilization or other containment mobilization raised from chemical reaction between the displaced and displacement , it may reach the fresh ground water resources or it may come in the form of fingering phenomena at hydrocarbon reservoir or early gas breakthrough, it had a negative impact on the potential and productivity of the field .

Risk assessment for sequestration projects must include predictions of sequestration zone performance.

These performance assessments will guide the selection of sequestration sites and/or operating parameters, such as injection pressure and rate, that mitigate leakage risks. If natural fractures or faults are present, then bottom-hole injection pressures higher than the minimum in-situ stress may open these fractures. Pressures higher than the fracture breakdown pressure will fracture the reservoir and/or cap rock. In both cases, CO_2 or acid gas will leak from the sequestration unit. Thus, it is essential to properly estimate the minimum stress and fracture breakdown pressure and devise injection strategies that will always maintain pressures below these.Risk analysis is an integral component of this assessment. It involves an evaluation of the types of events that may result in leakage, the likelihood of these events, and their potential consequences, the risks of geological sequestration ***are tabulated below***:

Item /Position	**Deviation**	**Possible causes**	**Consequence**	**Remarks/ Action required/ recommendation**
Platform : Producing Acid gas (Flaring case)	Flaring acid gas such as : H_2S ,CO_2, N,…	Environmental risk ,corrosion to the body of platforms, risk of pollution problem specify for biological	Gas emission to atmosphere	Risk will occurs unless the following suggestion be taking into consideration : ▪ Re-injection to deep aquifer. ▪ Re-injection to shallow formation such as Melquart formation. ▪ Down hole oil/water separator system ▪ Sequestration into saline formation ▪ Sequestration into other structure nearby ▪ Upgrading the gas treatment units

Gas injector: Well H4-12	Acid gas Non miscible At reservoir pressure and temperature	Fingering phenomena At reservoir	Early CO2 breakthrough Reducing the productivity of the reservoir EOR is limited	▪ No risk /hazard ▪ acid gas injection can not enhance the production of oil rate
Well H4-25 WAG process	Increase of CO2	Fingering phenomena At reservoir	The increase of co2 occurs sooner	No risk /hazard To atmospheric
Sequestration into oil zone	Only 30 % is stored	70 % of injected gas will be cycled through producing wells around the candidate injector	EOR is limited	▪ No risk /hazard ▪ acid gas injection can not enhanced the production of oil rate
Acid gas stream flare	Shut-in Of flare due to : sweet gas less than minimum limit or the rate of gas to sent flare is small	Environmental risk ,corrosion to the body of platforms, risk of pollution problem specify for biological	No consequence	Risk : Dangerous Special at wind condition Monitoring frequently the percentage of sweeten gas
Sequestration into Deep formation (Aboid , Zebag unit)	Leakages (Reservoir phenomena)	Acid gas Leakage	No consequence	Risk from reservoir point view due to faulted area and fracture zone
DP4 Gas recovery plant	Higher Capacity Treatment of produced gas More than 136 MM scf/day	Non sweetened gas	Diversion into flare system	(pollution) Acid gas will impact on atmospheric
sequestrations into nearby structure (S)	non suitability to store the acid gas in this formation	Doubt /Poor reservoir quality	difficulties of injection into this formation	Not visible from economic point view due to long distance from main platform

sequestrations into shallow formation	non suitability to store the acid gas in this formation	The continuity cannot be demonstrated	difficulties of injection into this formation	Risk to disposal due to : • Sealing integrity doubtful and risky because affected by intense and active faulting, reaching the sea bottom. • Doubts on the continuity of the sealing • Too shallow (<800 m) for CO2 re-injection

6.9.2 Assessment Impacts of Mitigation

In case of acid gas injection into sequestration reservoirs leaks to the atmosphere in significant quantities, then the operation will be failed to mitigate the global effect of global warming, its very purpose of being implemented.

In general locally, leaked CO2 may contaminate other energy and mineral resources in the sedimentary succession, and drinkable groundwater resources if it reaches shallow zones specially at onshore activities.

In extreme cases, where high-rate leakage occurs through a localized channel to the surface, CO2 may cause danger to environment Accordingly, it is essential to assess the potential for CO2 leakage and to implement site selection criteria and operating parameters that would mitigate the possibility of CO2 escaping from the sequestration reservoir.

6.9.3 Environmental Condition :

Main Tide level: +0.3 m
Sea water temperature: 15 -25-deg.C @surface, while temperature at seabed ranging from 7 - 14-deg. C.
Salinity varying from 35340-36000 ppm
Air temperature 5-36 deg.C
Relative humidity 40-95 %
Max rainfall 152 mm/day
Current speed : 1.1 m/s
Wind speed for 8 directional

6.10 Environmental Legislation

6.10.1 Libyan Components Authorized:

This section is describing competent authorities with responsibilities for environmental protection under Libyan law. , provided as a guide to the national regulatory provisions that may be relevant to the oil and gas exploration activities

One of The components authorized is Environment General Authority (EGA).

The (EGA), was established in 1998 following issuance of the General Peoples Committee decision No. 263. The EGA replaced the “Technical Centre for Protection of the Environment”. Also in 1998, the General Peoples Committee issued decision No. 386 concerning the Executive Regulations of Law No. 7 1982, containing 131 articles interpreting the law.

The EGA is an independent body, run by a peoples committee the secretary of which was nominated in decision No. 101 for 1999.

Law 7 was updated in 2003 and replaced by Law 15 of 1371. The Environment General Authority exercises the powers assigned to it by Law No.15.

The main environmental law in Libya is Law No. 15 of 1371 (2003) regarding Environmental Protection. Environment is defined as “the environment in which man and all living beings live, including air, waters, soil and food”. Law No. 15 sets the framework for

environmental protection and sets out methods for pollution measurement and plans and programs for pollution elimination. The Law specifies public duties towards preserving the environment.

of aquifers, and all matters related to the protection of agricultural lands: *Law on the Protection of Agricultural Lands (Law No. 33 of 1970), Law on Protecting Animals and Trees (Law No. 15 0f 1989).*

6.10.2 Legislative Screening Process:

The legislative screening process concern: how the operating company should translate the information highlighted into the appropriate and best environmental practice, contacting the appropriate departments of these authorities or viewing their published press or web sites, in order to locate the correct conventions and protocols relevant to this project. Identifying and listing the relevant competent authorities at all levels, including local, regional, national, and international. (Locally such as National Oil Corporation, Environment General Authority) Evaluating through each convention and its subsequent protocols to determine the articles and paragraphs pertinent to each phase for development or new project.

Chapter

6.0

C

Project Re-Injection / Sequestration Acid Gas

IOR / EOR

More Details

Case study

Reservoir simulation

3D model – Updating AGR

Chapter recap

Offshore Field Acid Gas Re-injection: Description

- Acid gas injection in gas cap has been addressed to evaluate reservoir response and ultimate oil recovery from Offshore Field .
- different injection cluster locations have been analyzed.
- In each case a cluster of 3 gas injectors has been assumed.
- The number of injectors are driven by the total field gas production rate and assuming that only 49% of produced total raw gas will be re n-Butane 0.09

6.1 Needs of AGR Project :

To avoid the current gas flaring (about 110 MMSCFD) the Compositional model has been considered the appropriate tool to study the feasibility of injecting the acid gas into the reservoir and to evaluate its impact on the recoverable oil reserves and the CO2 sequestration capacity of the reservoir. the purpose to evaluate:

- The impact of acid gas disposal from Offshore FieldGUP, Phase 2 and other nearby structures.
- Detect/ define the Well locations pattern of different gas re-injection/injection

6.2 Optimization / Forecast scenarios run:

After an initial screening the gas re-injection /injection in the field gas cap has been accepted as the only option to be considered in the further sensitivities that were including:

- Do nothing (no gas injection)
- GUP (no gas injection or with 49% of gas reinjection after installation of GUP on ph.1)

- Phase 2 development (no gas injection)
- Acid gas reinjection from Offshore Field (with analysis on different possible injection location)
- Additional acid gas injection from T&U
- Analysis of the impact on oil recovery in relation with different gas injection rates

In last 3D reservoir model, some additional sensitivities have been requested to assess the opportunity to:

- anticipate the north flank development (5 subsea wells planned for Ph2)
- Anticipate GUP @ Year 2018
- Introduce max GOR limit to producers (passing from 20,000 to 5000, 4000 and 3000 SCF/STB).

Table (6.1C) is summarizes the key results of the main sensitivities performed on **AGR**:

		Forecast				
Dev .Phase	RUN/ CASE	RF %	Max FGPR MMSCFD	Max FGIR MMSCFD	max CO2 %	Num. of Inj wells
Phase 1	**DN. (Reference Case)**	**18**	**<100**	**0**	**40**	**0**
	DN + actions	19.7	115	0	40	0
	DN + actions + AGR	20.4	120	50	50	3
Phase 1 + Phase 2	**Ref Case (no AGR)**	**22.7**	**210**	**0**	**40**	**0**
	Offshore FieldAGR (49% of produced gas) Sensitivities on 9 different injection clusters locations	22.8 23.2	200-225	100	45-60	3
	Offshore Field AGR + T&U structures gas	23.4 23.6	230	160	55	5
	Injection 150 MMSCFD	24.0	210	150	55	5
	Injection 200 MMSCFD	24.3	220	200	57	7
	Injection 300 MMSCFD	24.1	270	300 for	60	10
	Sensitivities with variable gas injection rate (variable number of injectors)	23.2 24.4	200-290	90-385	45-65	4-11

Table 6.1C - results of 3D model Reservoir study - summary

6.3 Geological Overview

after the end of 3 new drilled wells. A full geological analysis was conducted as well as The well tops and the maps have been updated. The 3D structural grids were also updated the well correlation between these and the surrounding wells have been updated.

In term of petrophysical characteristics the 3 new wells resulted in line with the model expectations and the surrounding existing wells. ***Figure 6*** *.1c* shows correlation

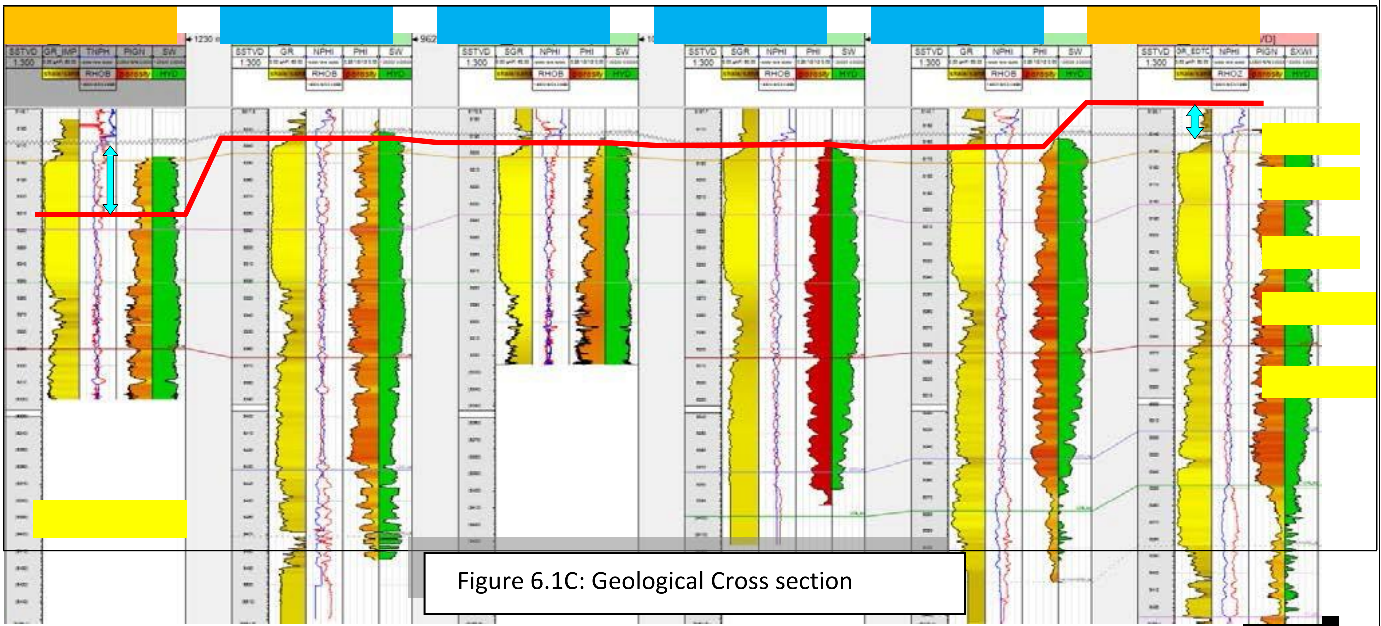


Figure 6.1C: Geological Cross section

Figure 6.2C shows a cross section of Offshore Fieldreservoir layers showing Upper Nummulitic,
Lower Nummulitic and Dolomitic formation members. It is possible to notice that the Dolomitic member is present in all the reservoir, but hydrocarbons are present only in the not yet developed western area.

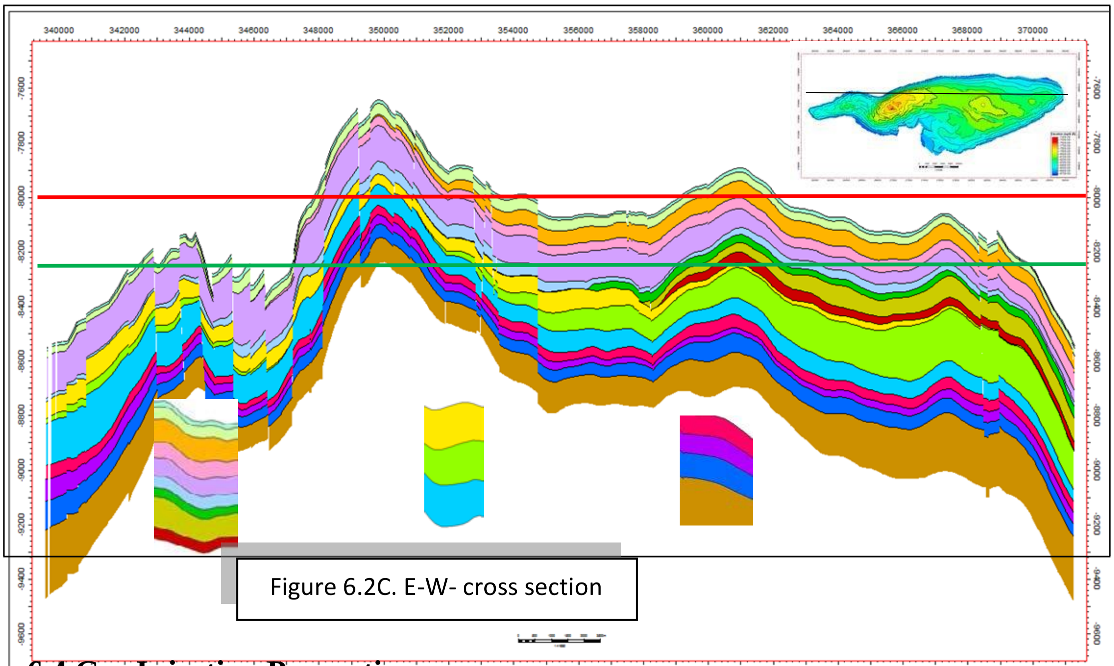


Figure 6.2C. E-W- cross section

6.4 Gas Injection Properties:

One of the requests specified in the SOW is the evaluation of Acid Gas Reinjection (AGR) on the reservoir performance. With this purpose the prosper model has been defined as compositional model utilising the 10 component Equation of State from dynamic simulation and using for injection fluid stream that one shown in the **next table (Table 6.2C).**

	% mol
CO_2	77.67
H_2O	0.01
H_2S	0.48
N_2	4.85
CH_4	15.05
C2	1.43
C3	0.34
i-Butane	0.02
n-Butane	0.09
i-Pentane	0.02
n-Pentane	0.02
n-Hexane	0.01
n-Heptane +	0.00
Total	100.0

Table 6.2C Gas Composition

6.5 Comparison of sensitives runs :

6.5.1 – Basic Case (DN)

The do-nothing case considers only the production from the wells open at 1-04-2013. No other interventions are assumed, and the following production constraints have been applied:

Field & Group	
Field Max gas prod. Rate [MMscf/d]	137
DP4 Plt. Max gas prod. Rate [MMscf/d]	85
DP3 Plt Max gas prod. Rate [MMscf/d]	52
Well	
Max Water Cut [%]	70
Max GOR [Mscf/STB]	21
Min Oil Prod. Rate [bopd]	100

• The expected cumulative oil production is as reported in below table:

	Cum. Oil Prod. [MMSTB]	
	@2040	@2050
Do Nothing	715	745

• The field gas production rate is always below the 100MMscfd and the water production rate does not exceed 20kbwpd.

The production profiles in graphical formats are given in figures 6.3C

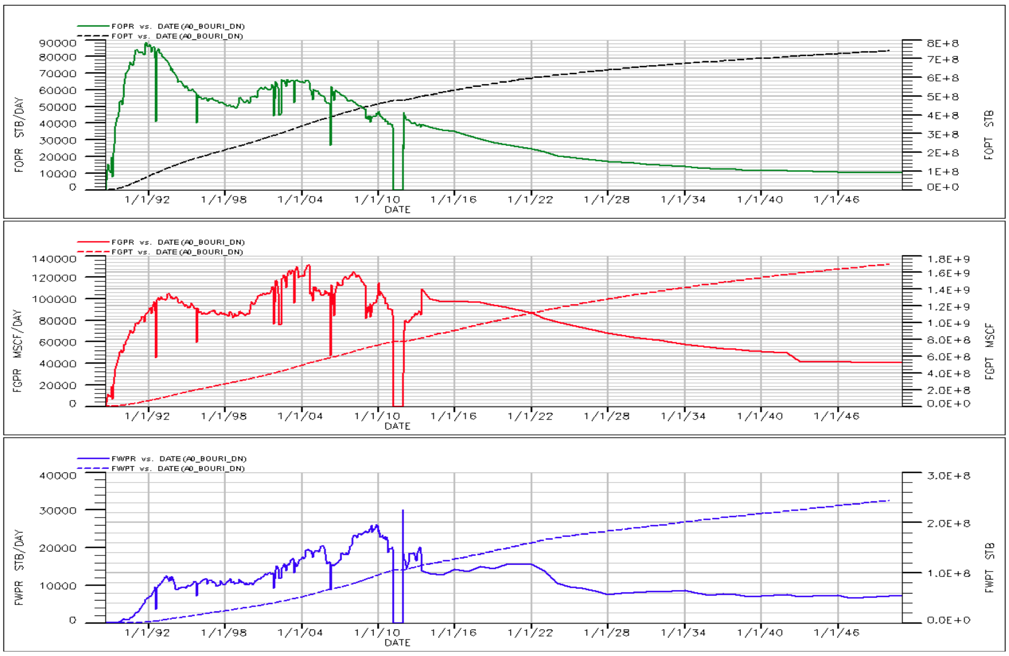


Figure 6.3C profile of Production forecast

6.5.2 Screening sensitivities on oil rim versus gas cap re-injection:

Preliminary evaluation of acid gas reinjection in *offshore* field envisaged screening sensitivities on either injecting acid gas in oil rim or in gas cap. The target was to find optimum location for injection by analyzing the impact on final oil recovery.
Initial sensitivities have been performed on Phase I development only, with further extension of analysis to full field PH1+PH2 development as given below (figure 6.4C)

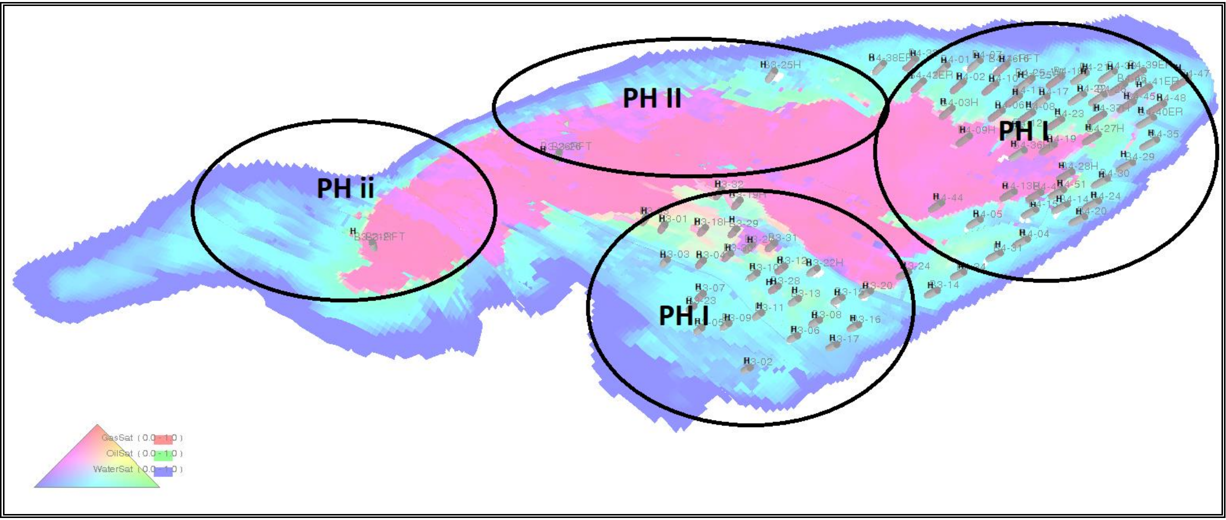


Figure 6.4C projects locations

6.5.3 Gas re-injection in Nummulitic member :

6.5.3.1 Case Description

All the locations of gas injection wells have been carefully selected to avoid crossing faults that, acting as high transmissibility channels, might cause gas or water channeling to producers and consequent reduction of sweep efficiency and storage capacity of acid gas (CO_2). *Figure 6.5C* shows the top reservoir map with the faults and wells location. It is evident that the Western area of the field is highly faulted and less known in terms of production behavior and reservoir response (no development wells and no production history available).

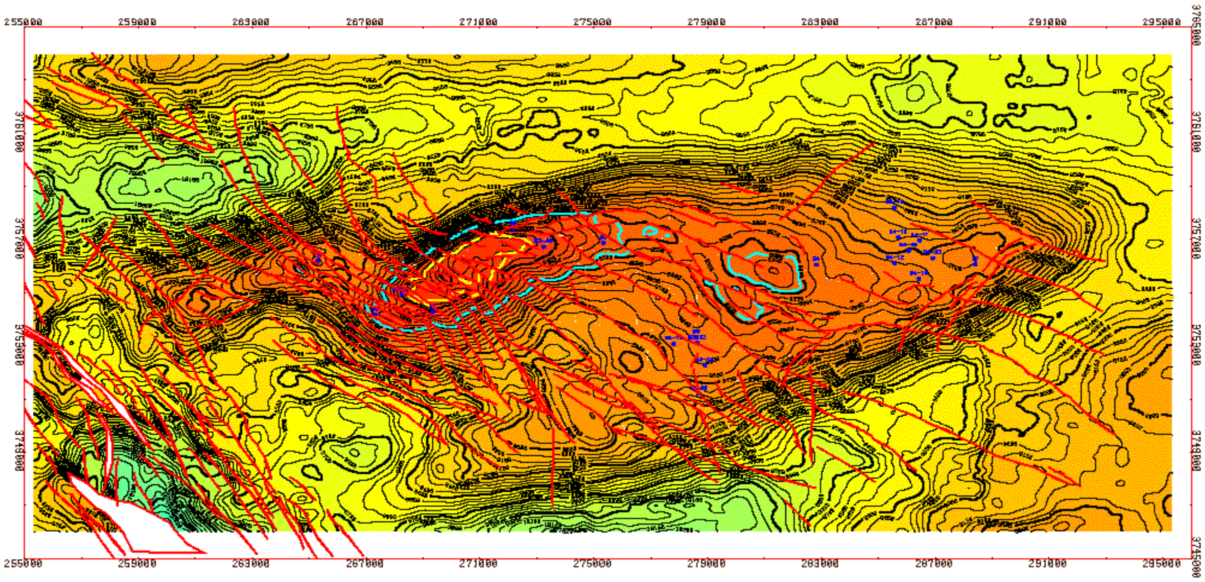


Figure 6 .5C structure map

Nine different injection cluster locations (Figure 6.6C) has been analyzed. In each case a cluster of 3 gas injectors has been assumed. In all the sensitivities the wells have been perforated in the Upper Nummulitic Member only.

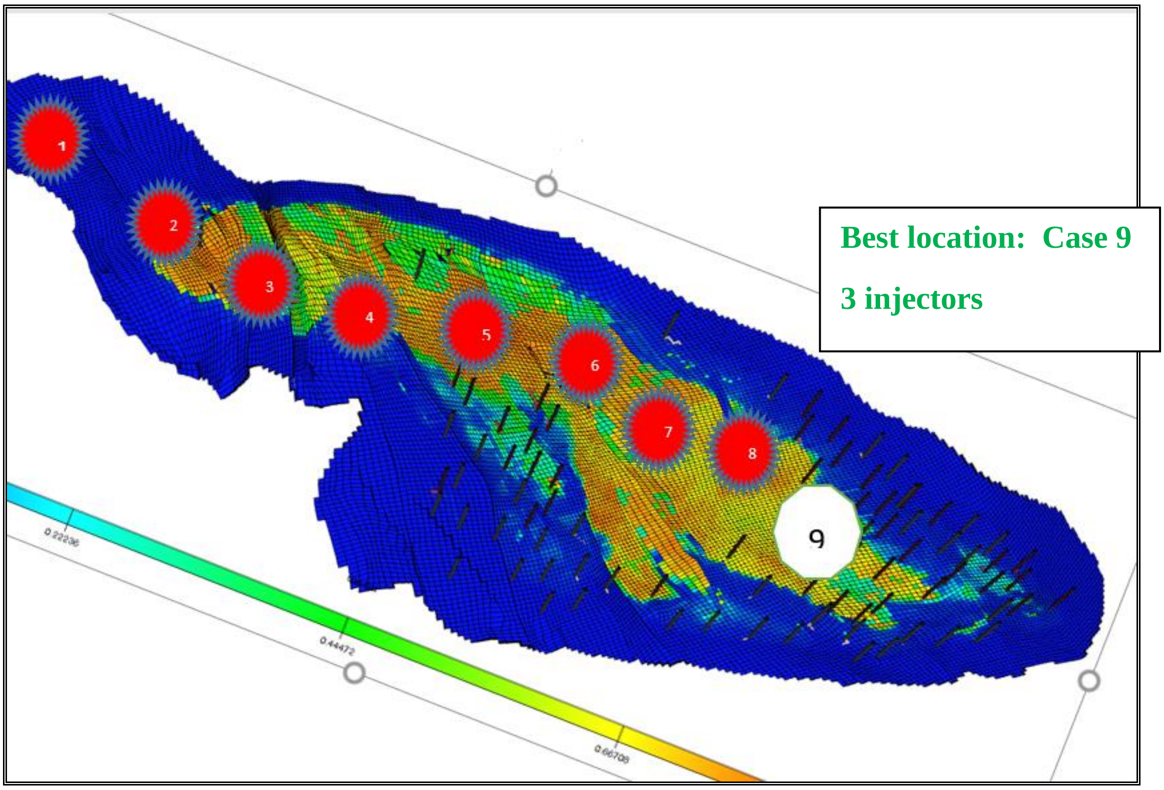


Figure 6 .6C: 9 location of AG

.

6.6 Consequences of runs:

The forecasted oil production rate and cumulative oil production for the reference case in comparison with the 9 sensitivity cases with acid gas reinjection are shown in Figure

6.7C and while Figure 6.8C summarizes the cumulative oil recovery in the form of bar chart.

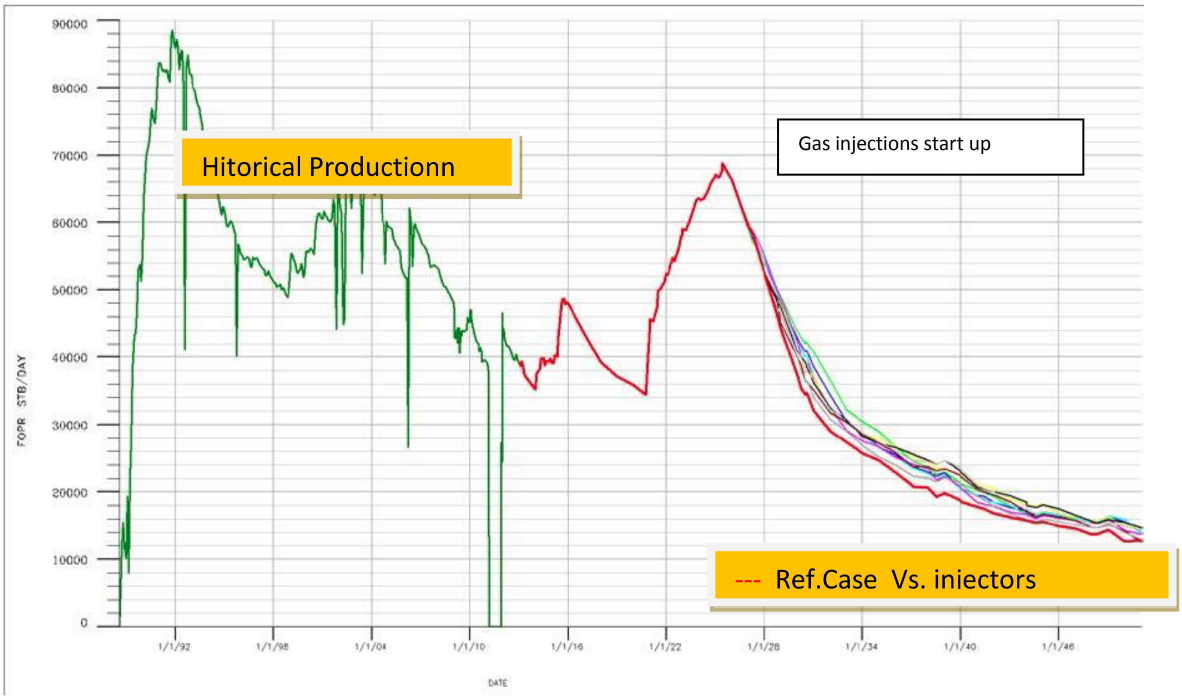


Figure 6 .7C Production Rate: Ref. Case Vs. injection cases

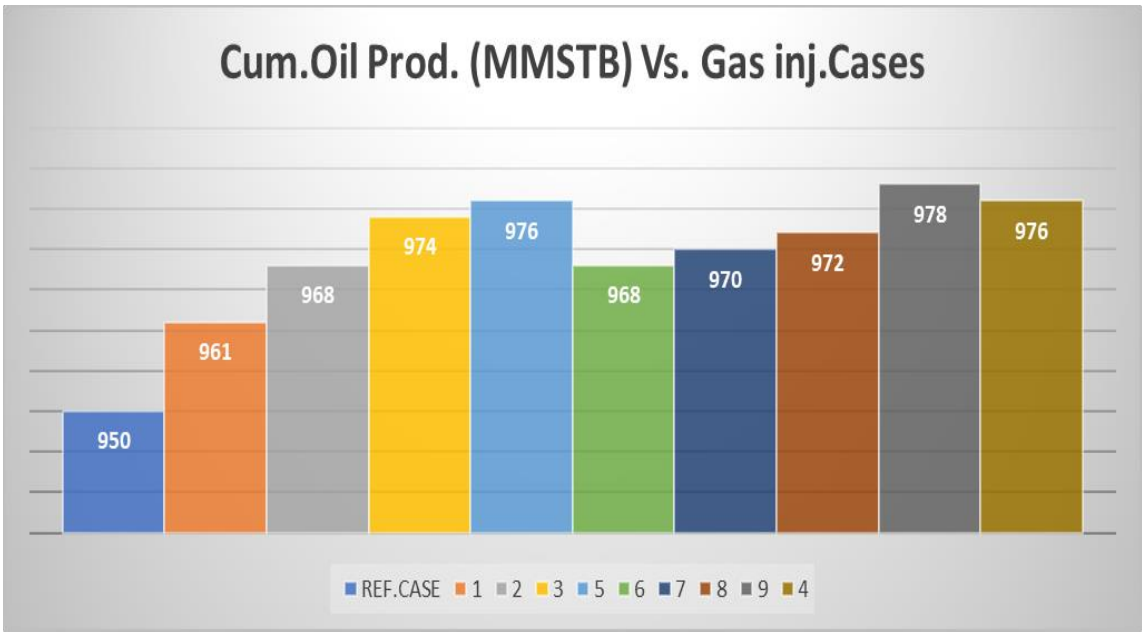


Figure 6 .8C Gas Injection Cases

Comparing the results of sensitivities performed on acid gas reinjection, the following observations can be made:

- In all the gas re-injection cases the final oil recovery is above the reference case scenario that is without gas re-injection. In fact, gas re-injection helps to sustain the pressure and delay the water encroachment in most depressurized area.

- The cases considering the injectors in gas cap close to the area already developed (Case 5 & Case 9) provide the most interesting results with an increment wrt the reference case of about 26 MM STB for case-5 and 29 MMSTB for case-9 at Dec-2050. This is due to the fact that those areas are near producing wells and the pressure has been already decreased by about 500 psi from original reservoir pressure.

- Cases 3 and 4 show similar increment of final oil recovery with cases 5 and 9, but the location area of these clusters are in highly faulted zones with limited reservoir information and the final recovery could be overestimated.

- Case 9 has been finally selected as representative for the AGR scenarios
  The total field cumulative oil production is very similar between case 5 and case 9 but the cumulative production by platforms varies. In case 5, where the acid gas injection is envisaged closer to platform **three** cumulative production is higher for DP3 wells than in case 9. In case 9 instead, where the injection cluster location is close to DP4 wells, the cumulative oil production for DP4 wells is higher than in case 5.
  As one of the constraints field gas injection rate has been limited at 105 MM SCF/D which is 35 MMSCF/D per well.
  As it can be seen from the graph the gas injection rate for the case 1 and case 2 remains far below the maximum field gas injection rate due to the flowing bottom hole pressure limit constraint of 3700 psi. Whereas for other cases the injectivity is better.

  The field gas injection rate is 49% of total gas produced from the field.

6.7 AGR & CO2 Injection from nearby fields:

For this scenario the sensitivities performed are the following:

- ✓ Simulate the additional injection of the CO2 coming from T-U base case development (about 60 MMSCFD constant from year 2025 till the end of simulation)
- ✓ Perform a screening analysis to define the max gas injection threshold for which the oil cumulative start to reduce.

Chapter 7.0

Research Findings

➢ Produced Water Treatment

produced water management is one of the biggest oil and gas industry challenges. To understand why dealing with produced water can cost so much, it is helpful to understand the water treatment technologies needed for safe and compliant disposal or reuse of produced water.

Typical treatment of produced water undergoes three stages, with an optional fourth stage for reusable water. These stages are:

- ✓ Pre-treatment
- ✓ Main treatment
- ✓ Polishing treatment
- ✓ Tertiary treatment (optional)

➢ Environmental Data:

- ✓ Sea hydrological condition:

temperature on sea bottom about 57-60.8 f

- **salinity:**

Salinity (ppm)	**Nacl**	**O2**	**C2**	**Mg**	**ph**
Surface	35.34	5.5-5.0	440	1390	7.72
-90 m	35.920		440	1400	7.91
-144 m	35.920	4.5-3.9	440	1390	7.80

- **Solid content:**
- ✓ 0.05-0.5 mg/l in deeper layers m : -70 to –170
- ✓ 0.05-1.5 mg/l in surface layers m : 0 to – 70
- ✓ 20-60 % consists of particulate organic carbon (p.o.c)

➢ Oil content in produced water samples:

Table below are Presented The_Monthly average measurements of produced water of inlet and outlet of unit of water treatment in terms of PPM :

Date	INLET-PPM	OUTLET-PPM	bopd	BWPD	SCF/D	GOR Scf/stb	WC %
31/01/1998	104	37	33229.2	7426	65108	1959	0.183
28/02/1998	122	45	32656.9	8021	64124	1964	0.197
31/03/1998	139	53	33079.9	7994	65286	1974	0.195
30/04/1998	135	63	32640.5	851	64756	1984	0.207
31/05/1998	117	48	33076	8900	65147	1970	0.212
30/06/1998	170	51	32664.6	8643	64465	1974	0.209
31/07/1998	158	60	33779.8	9029	68377	2024	0.211
31/08/1998	137	46	32974.9	8110	65264	1979	0.197
30/09/1998	105	40	32219.7	8150	64636	2006	0.202
31/10/1998	61	31	33295	8023	64744	2009	0.199
30/11/1998	73	34	31934.3	8237	64556	2022	0.205
31/12/1998	49	20	31720.3	8590	64341	2028	0.213
31/01/1999	39	15	31764	8858	63023	1984	0.218
31/03/1999	31	13	31301.9	8774	62726	2004	0.219
30/04/1999	43	19	31396.7	8830	63340	2017	0.220
31/05/1999	43	13	31208.8	8945	62383	1999	0.223
30/06/1999	32	16	31213	9020	62628	2006	0.224
31/07/1999	42	13	32200.8	9168	61754	1918	0.222
31/08/1999	43	14	32356	9737	62145	1921	0.226
30/09/1999	37	16	32403.4	9320	62455	1927	0.223

- **Regression analysis:**

The multiple regression had been utilized for predication purpose of oil contaminated water during production stage, the method is dealing with many variables which effected on the dependent variable.

The relationship or correlation between these variables (independents) and the independent variable had been established as :

$$Y= a+b1x1+b2x2+………+bnxn+E$$

That was the general form of multiple linear model

Where :

Y = dependent variable values

A= intercept

X= the independent value

B = the coefficient corresponding to the impendent variables

N= number of the independent variables

E= error term

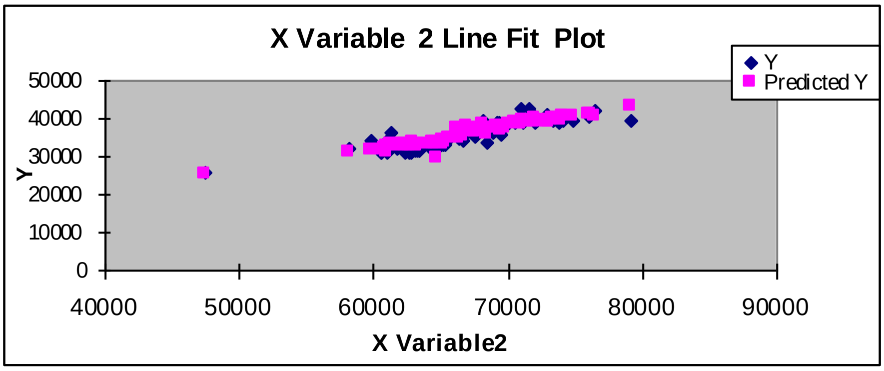
The following output shows the results of regression analysis:

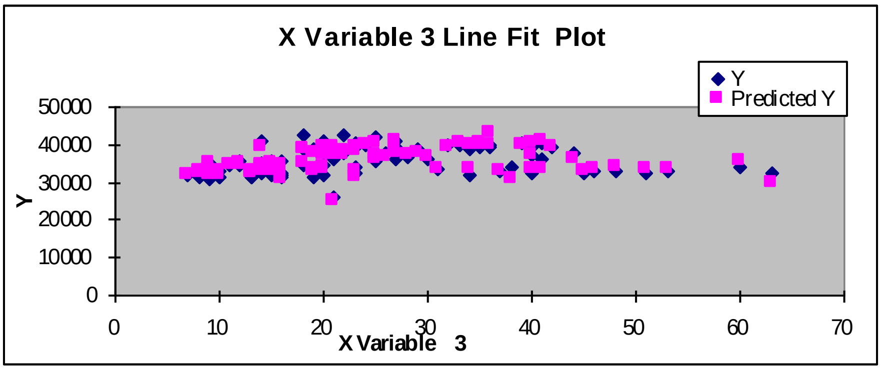
Regression Statistics	
Multiple R	**0.930592116**
R Square	**0.866001686**
Adjusted R Square	**0.858557335**
Standard Error	**1235.092921**
Observations	**58**

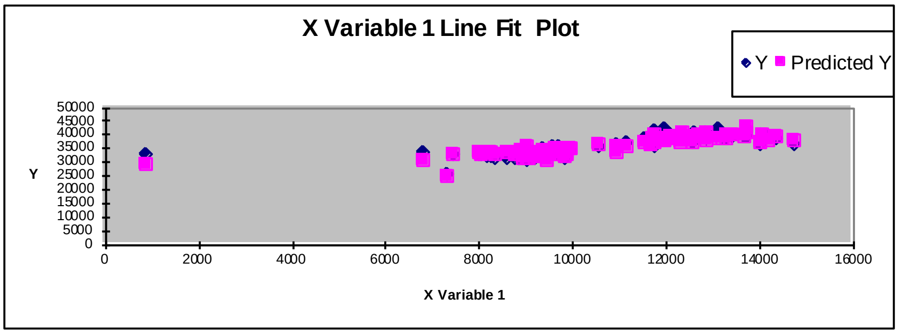
	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	532368594.6	177456198.2	116.33	1.49876E-23
Residual	54	82374544.23	1525454.523		
Total	57	614743138.8			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-45.54	2792.226	-0.016	0.987	-5643.626	5552.537	-5643.626	5552.537
X Variable 1	0.45	0.099	4.561	3E-05	0.254	0.652	0.254	0.652
X Variable 2	0.46	0.054	8.458	2E-11	0.350	0.567	0.350	0.567
X Variable 3	2.41	14.062	0.171	0.8648	-25.787	30.598	-25.787	30.598

Regression analysis - examination of model

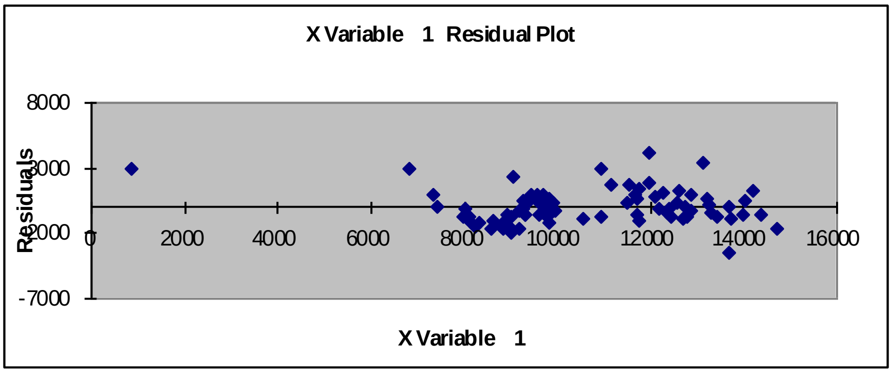


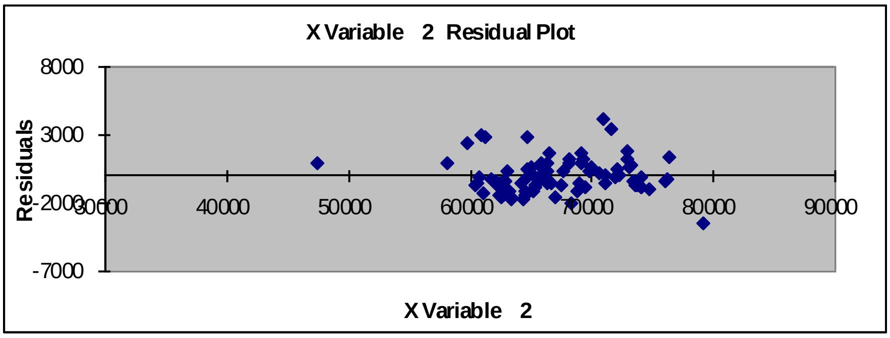


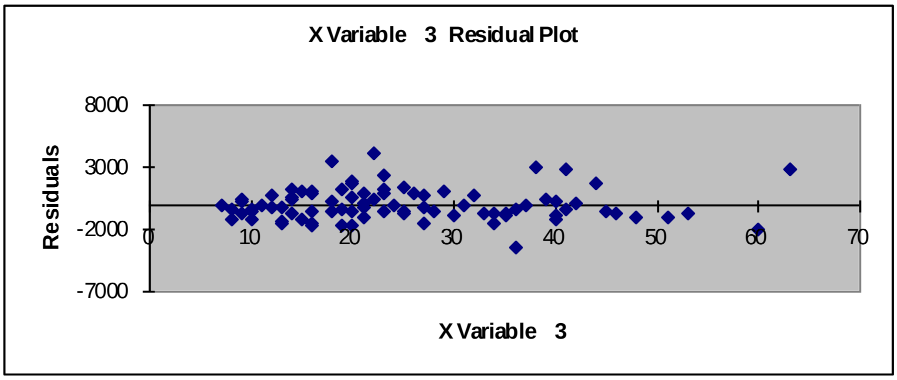


- **Examination of residual**

Figures below (7.1- 7.3) are illustrating the residuals plots against the dependent values, a clear horizontal band pattern have been showed among all plots





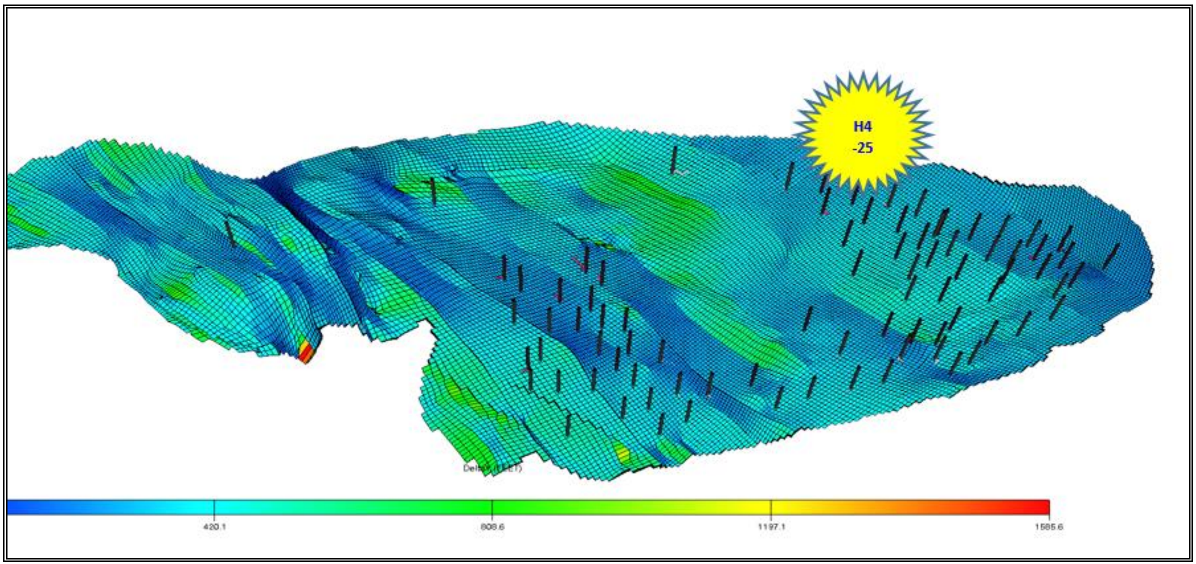


Figures 7.1-7.3

➢ Water Re-injection Project

- 3D simulation model was identified that well H4-25 (shut in) as best candidate to perform the re-injection. Sensitivities on other wells as given in the below figure gave worse results due to earlier water encroachment in the nearby producers.

- The Well, at present is completed in layers 1-2-3, should be re-completed in the dolomitic layers 11-12-13-14 before starting the water injection.

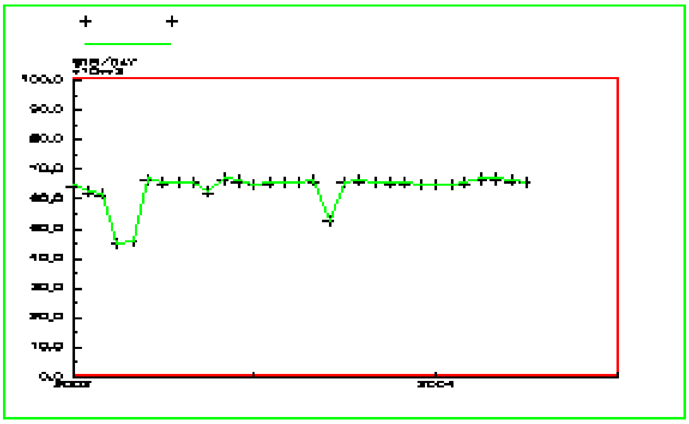


location of Water injection wells and neighboring oil wells

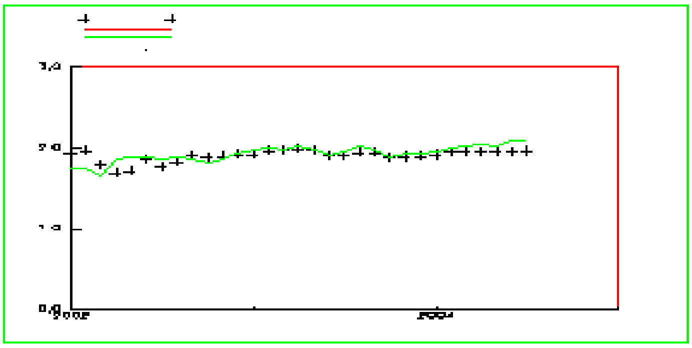
- Water re-injection in the northern flank of the field area seems to be very beneficial to sustain the pressure and is giving about 29 MMstb of additional reserves .
- Associated water production is close reaching in this period the maximum treatment capacity. It has to be highlighted that water production is steadily increasing

➢ Project Updating (Reservoir Simulation model):

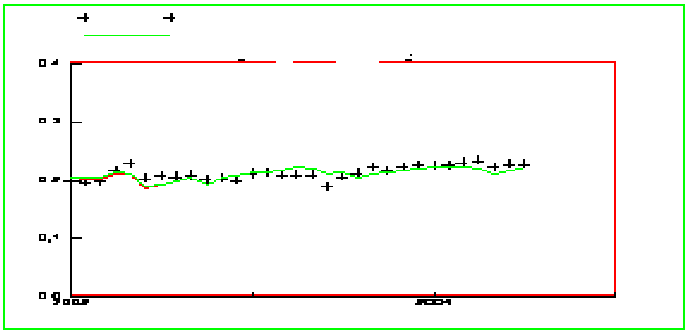
3D Dynamic reservoir model has been revised and updated. field tolerances in terms of simulated GOR and W.C. of +/- 3% during the last 3 years were met, increasing the confidence in the forecast results. figure here below shows the history matching trend.:



Oil Rate (stb/D), measured Vs. Simulated



Gas oil ratio (MSCF/STB), measured Vs. Simulated



Water Cut (%), measured Vs. Simulated

➢ Economic Evaluation:

The results of Cash Flow analysis are summarized here below:

Evaluated Period, year	Incremental oil recovery, MMstb	Gross Revenue, MM$	CAPEX MM$	OPEX MM$	Total Expend., MM$	PV (10%), MM$	ROR, %	POT, year	DPIR (10%) $/$
DEC. 2019	10	207	23	23.794	27	48	32	Mar. 2011	2.03
DEC. 2028	20	398	23	45.810	69	74	32	Mar. 2011	3.16

➢ Acid Gas Reinjection project (AGR) : the below table are shows Delta of the cumulative oil production :

Runs	Np (MMTB) at end of year 2042	Recovery %	Np (MMTB) at end of year 2052	Recovery %
D .N. CASE	**906**	**21**	**948**	**23**
Gas injection case *(GUP @2018)*	**941**	**22**	**991**	**24**
Gain	**35**		**43**	

✓ The gas re-injection @2018 has a positive effect on the final recovery giving about 35 MMSTB at 2042 with respect to the reference case.

✓ Figure below shows the comparison of field oil production rates and cumulative oil productions. It is clear that, in the case GUP-2018 it is possible to maintain a higher field oil production rate after 2026 as illustrated by solid ***green line***.

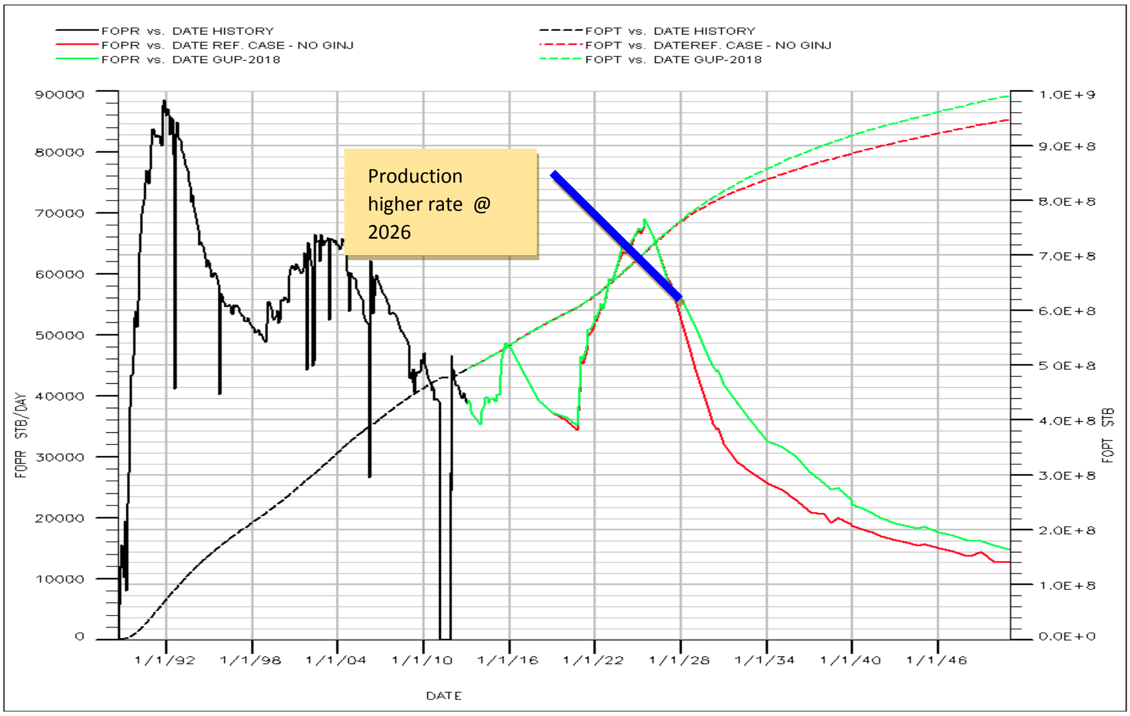


Figure of Ref. Case vs GUP-2018 (Field Oil Prod. Rate & Cum. Prod.)

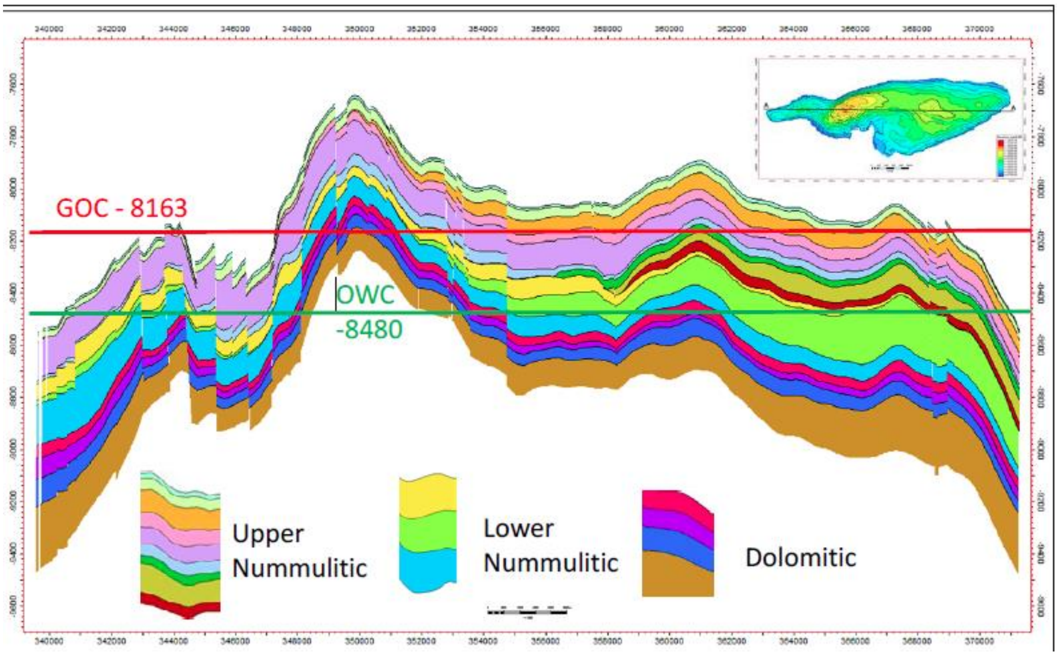
✓ Reserves: The following table summarizes the results of the main sensitivities performed on acid gas injection:

Case Description	Run/case	Gain MMstb @2052	Gas field Prod.(peak) MMSCFD	Max. gas inj. MMSCFD	CO2 (%)	Number Injectors
Ref. Case	1 (PH1)	**0**	**100**	**0**	**40**	**0**
Actions+ 1	2 (PH1)	**95**	**115**	**0**	**40**	**0**
1+2+AGR	3 (PH1)	**12**	**120**	**50**	**50**	**3**
Ref. case (No AGR)	4 (PH1+PH2)	**0**	**210**	**0**	**40**	**0**
4+AGR	5 (PH1+PH2)	**28**	**225**	**100**	**60**	**3**
5+niburing fields	6 (PH1+PH2)	**45**	**230**	**160**	**55**	**5**
Injected higher gas	7 (PH1+PH2)	**67**	**270**	**300**	**60**	**10**

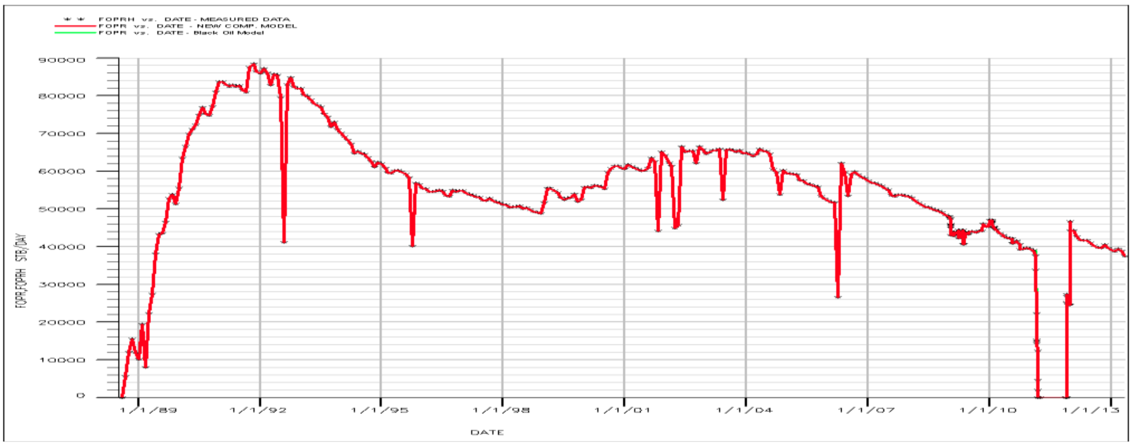
➢ **Geological information**: The average reservoir petrophysical parameters of offshore field are given below:

Main zone	Reservoir layer	NTG *(frac)*	PORO *(frac)*	Kh *mD*	Kv/Kh *(frac)*
Upper Nummulitic	U5t	0.81	0.05	2	-
	U5	0.82	0.12	21	0.74
	U4	1.00	0.15	99	0.86
	U3	1.00	0.17	10	0.81
	U2Ch	1.00	0.16	3	0.70
	U2Cl	1.00	0.15	4	0.59
	U2B	0.71	0.08	4	0.55
	U2Ah	1.00	0.15	9	0.70
	U2Al	1.00	0.11	2	0.37
Dolomitic	E3	1.00	0.23	26	0.94
	E2	1.00	0.21	19	
	E1	1.00	0.22	22	
	F2+F1	1.00	0.17	5	
Lower Nummulitic	C2	1.00	0.07	1	0.75
	C1+D2	1.00	0.04	0	
	D1	1.00	0.09	3	

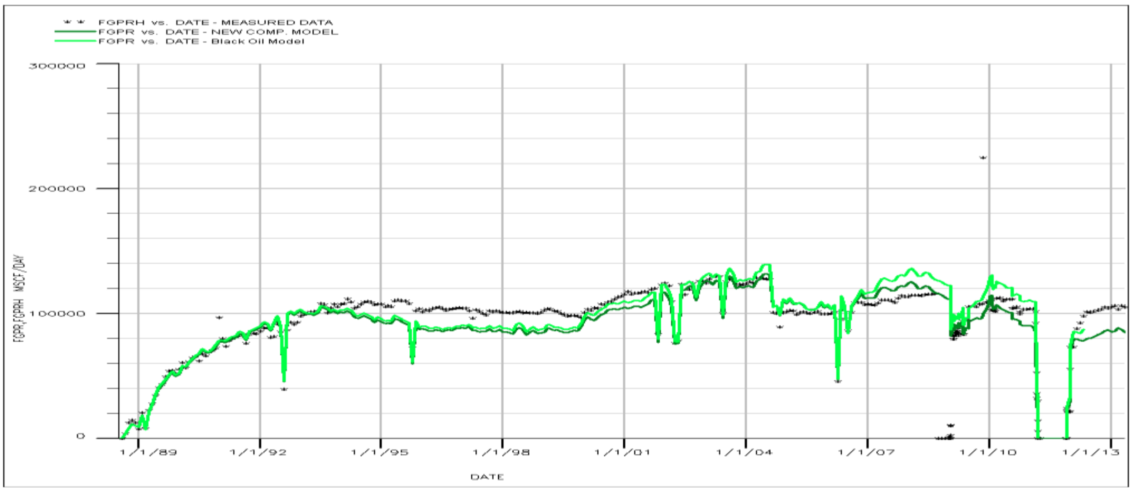
➢ The **Hydrocarbon contact** (oil water contact and gas oil cantc) are illustredd here below through The crosse section :



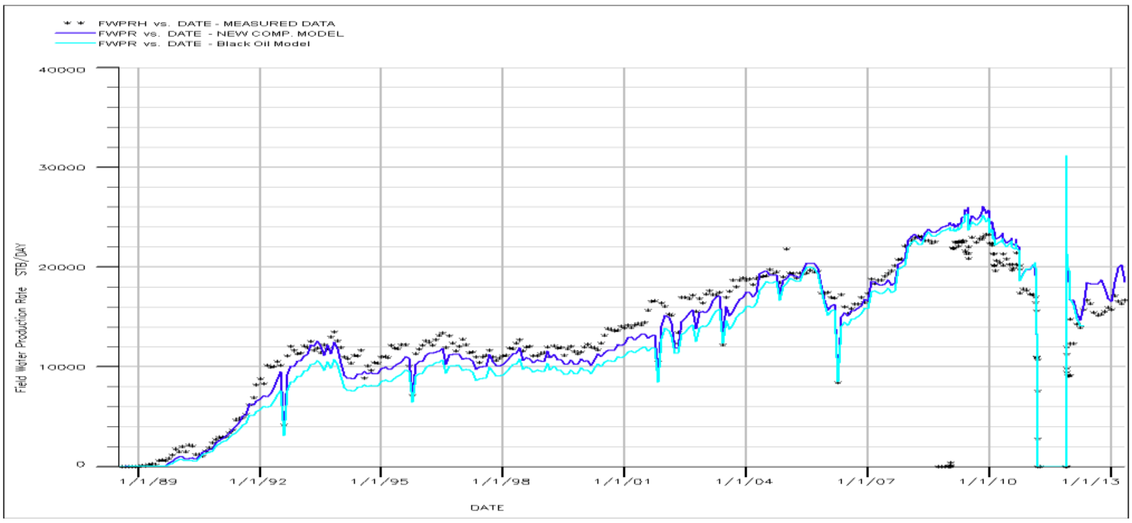
➢ **Model Healthy**: Simulation & History matching: A good history had been obtained through the following graphs:



Field Oil Production Rate: Measured versus Simulated.



Field Gas Production Rate: Measured versus Simulated



Field Water Production Rate: Measured versus Simulated.

- **Evaluation of acid gas re-injection (injectivity analysis):**

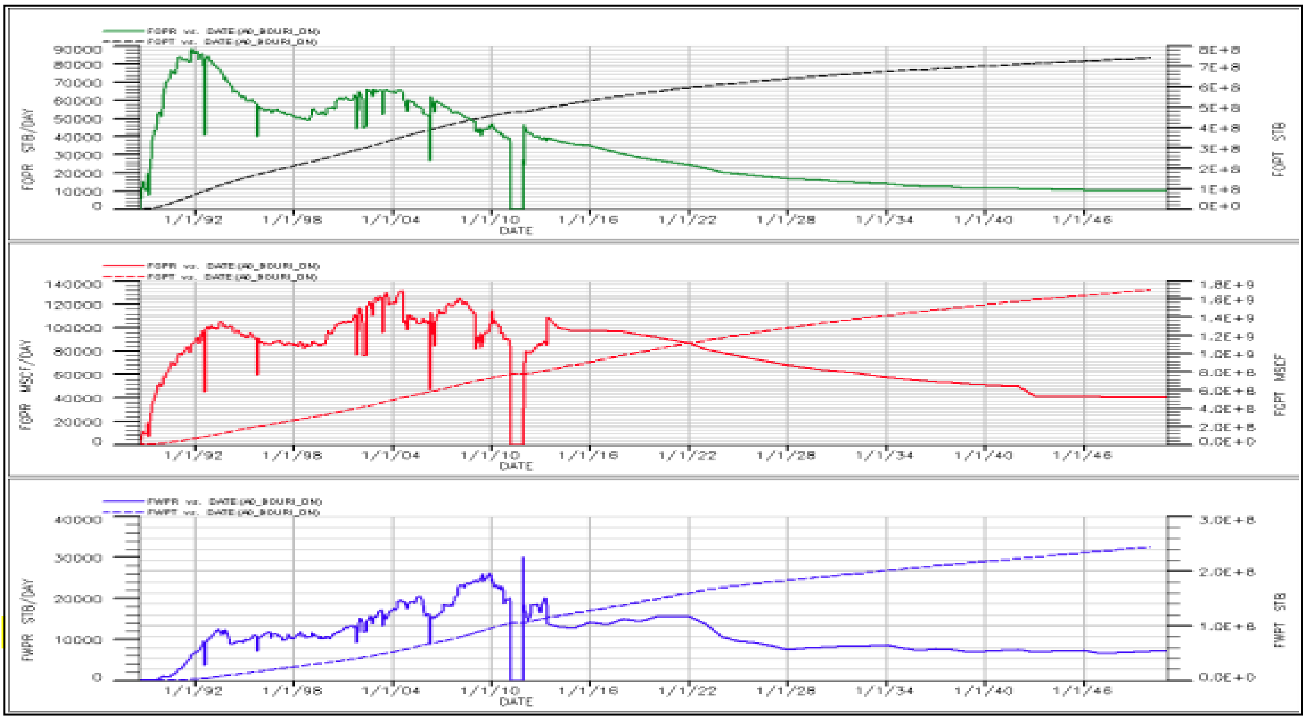
One of the vital required is the evaluation of Acid Gas Reinjection(AGR) on the reservoir performance With this target the *prosper model* has been defined as compositional model utilizing the many component Equation of State (EOS) from dynamic simulation and using for injection fluid stream that one shown in the following Table :

	% mol
CO_2	77.67
H_2O	0.01
H_2S	0.48
N_2	4.85
CH_4	15.05
C2	1.43
C3	0.34
i-Butane	0.02
n-Butane	0.09
i-Pentane	0.02
n-Pentane	0.02
n-Hexane	0.01
n-Heptane +	0.00
Total	**100.0**

Composition of injected Acid Gas

- **Reservoir Simulation and production forecast**

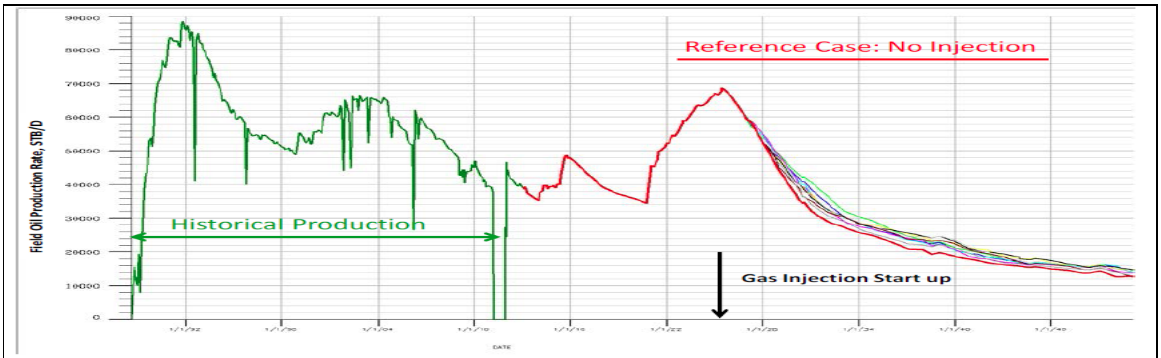
  The foreseen field oil, gas and water production profiles (**DN**) are shown in the following Figure :



➢ **Position Optimization (AGR)** : acid gas re-injection through different positions
As it can be seen from the summary in the given Table below that re-injecting acid gas in gas cap facilitates higher cumulative oil recovery with respect to cases injecting in oil rim.
The best scenario The decision to choose the gas cap re-injection:

Run/CASE	**Cum.oil prod.(MMSTB)@2042**	**Cum.oil prod.(MMSTB)@2042**
DN (Reference)	**905**	**948**
Injection into Gas Cap	**929**	**976**
Injection into Oil rim	**904**	**944**

➢ **Sensitivities runs:**
The forecasted oil production rate and cumulative oil production for the reference case in comparison with the nine sensitivity cases with acid gas reinjection are shown in the following Figure:



Field Oil Production Rate. Reference Cases versus Cases 1-9.

in the form of bar chart of next figure are summarizes the cumulative oil recovery
fore nine cases:

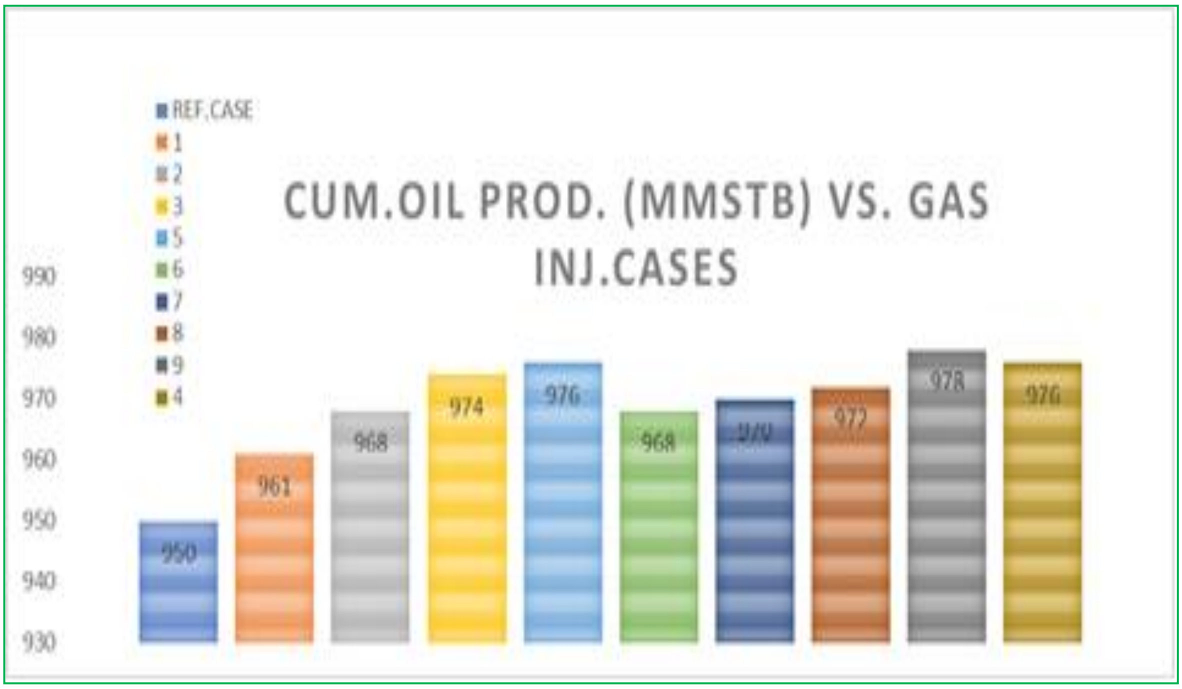
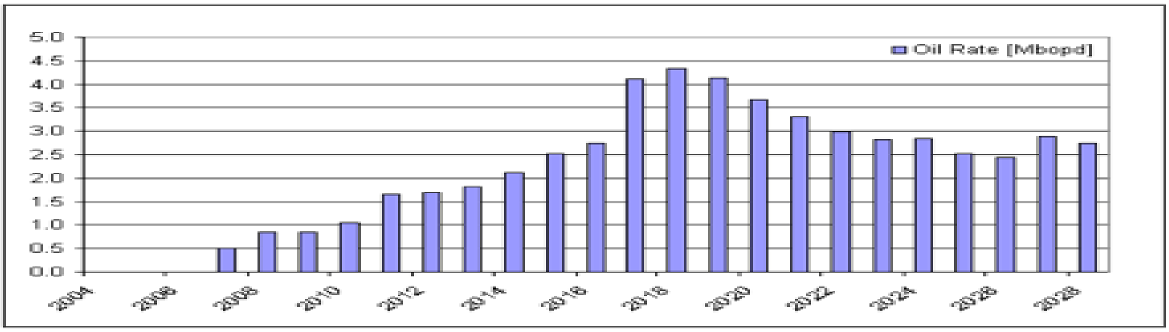


Figure Summary of Cum Oil Production @2050. Reference versus 9 ca

- **Water –re-injection: oil production profile & cash flow analysis**

Water injection project: Case description: it was clear that incremental of oil production due to WI, The peak of production due different activities such, slot recovery campaign, east area development and other intervention, injection start up in 2007 through well H4-25 , maximum water treatment unit capacity raised to 30,000 bwpd , the table below showing cash flow analysis and economic indicators of the project



No.	Time	Prod. Oil	Oil price	CAPEX	Prod. Cost	OPEX	Total Expen.	Gross Revenue	NCF	CNCF	NPV (10%)	Cum. NP
	The end of year	MMSTBY	$/STB	MM$	$/STB	MM$	MM$	MM$	MM$	MM$	MM$	MM$
0	31-Dec-04	0.00	0	0.500	2.3	0.000	0.500	0.000	-0.500	-0.500	-0.500	-0.500
1	31-Dec-05	0.00	0	7.000	2.3	0.000	7.000	0.000	-7.000	-7.500	-6.364	-6.864
2	31-Dec-06	0.00	20	10.000	2.3	0.000	10.000	0.000	-10.000	-17.500	-8.264	-15.128
3	31-Dec-07	0.18	20	5.940	2.3	0.422	6.362	3.670	-2.692	-20.192	-2.023	-17.151
4	31-Dec-08	0.31	20	0.000	2.3	0.713	0.713	6.200	5.487	-14.705	3.748	-13.403
5	31-Dec-09	0.31	20	0.000	2.3	0.713	0.713	6.200	5.487	-9.218	3.407	-9.996
6	31-Dec-10	0.38	20	0.000	2.3	0.874	0.874	7.600	6.726	-2.492	3.797	-6.199
7	31-Dec-11	0.60	20	0.000	2.3	1.380	1.380	12.000	10.620	8.128	5.450	-0.750
8	31-Dec-12	0.62	20	0.000	2.3	1.426	1.426	12.400	10.974	19.102	5.119	4.370
9	31-Dec-13	0.66	20	0.000	2.3	1.518	1.518	13.200	11.682	30.784	4.954	9.324
10	31-Dec-14	0.77	20	0.000	2.3	1.771	1.771	15.400	13.629	44.413	5.255	14.579
11	31-Dec-15	0.92	20	0.000	2.3	2.120	2.120	18.434	16.314	60.727	5.718	20.297
12	31-Dec-16	1.00	20	0.000	2.3	2.300	2.300	20.000	17.700	78.427	5.640	25.936
13	31-Dec-17	1.50	20	0.000	2.3	3.450	3.450	30.000	26.550	104.977	7.691	33.627
14	31-Dec-18	1.58	20	0.000	2.3	3.634	3.634	31.600	27.966	132.943	7.364	40.991
15	31-Dec-19	1.51	20	0.000	2.3	3.473	3.473	30.200	26.727	159.670	6.398	47.390
16	31-Dec-20	1.34	20	0.000	2.3	3.082	3.082	26.800	23.718	183.388	5.162	52.551
17	31-Dec-21	1.21	20	0.000	2.3	2.783	2.783	24.200	21.417	204.805	4.237	56.789
18	31-Dec-22	1.09	20	0.000	2.3	2.507	2.507	21.800	19.293	224.098	3.470	60.259
19	31-Dec-23	1.03	20	0.000	2.3	2.369	2.369	20.600	18.231	242.329	2.981	63.240
20	31-Dec-24	1.04	20	0.000	2.3	2.392	2.392	20.800	18.408	260.737	2.736	65.976
21	31-Dec-25	0.92	20	0.000	2.3	2.116	2.116	18.400	16.284	277.021	2.200	68.176
22	31-Dec-26	0.89	20	0.000	2.3	2.047	2.047	17.800	15.753	292.774	1.935	70.111
23	31-Dec-27	1.05	20	0.000	2.3	2.415	2.415	21.000	18.585	311.359	2.076	72.187
24	31-Dec-28	1.00	20	0.000	2.3	2.305	2.305	20.040	17.735	329.094	1.801	73.988
TOTAL		19.917		23.440		45.810	69.250	398.344	329.094	329.094	73.988	

Economic Profit Indicators

Oil Price =	20	$/bbl
Interest rate =	0.10	

Results

Gross Revenue	398	MM$
Total Cost (CAPEX + OPEX	69	MM$
Net Cash Flow	329	MM$
Net Present Value @ 10%	74	MM$
ROR	32.4	%
POT (Date, Year)	Mar-11	
PIR (CNCF / CAPEX)	14.04	$/$
DPIR (PV / CAPEX)	3.16	$/$
G.R./T.C.	5.75	$/$

➢ **Reservoir Simulation Model-2004,2005,2006**

➢ **Gas utilization Project:**

The model constrain are :.

- Field Qg_{max} after debottlenecking 136 MMscft/d
- Well THP_{min} = 300 psia (Low Pressure Wells THP min =60 psia)

The Cumulative production from 2006-2039 are given:

Ref. case @ 2040: Np about 439 MMSTB, GP ABOUT 863 Bscf

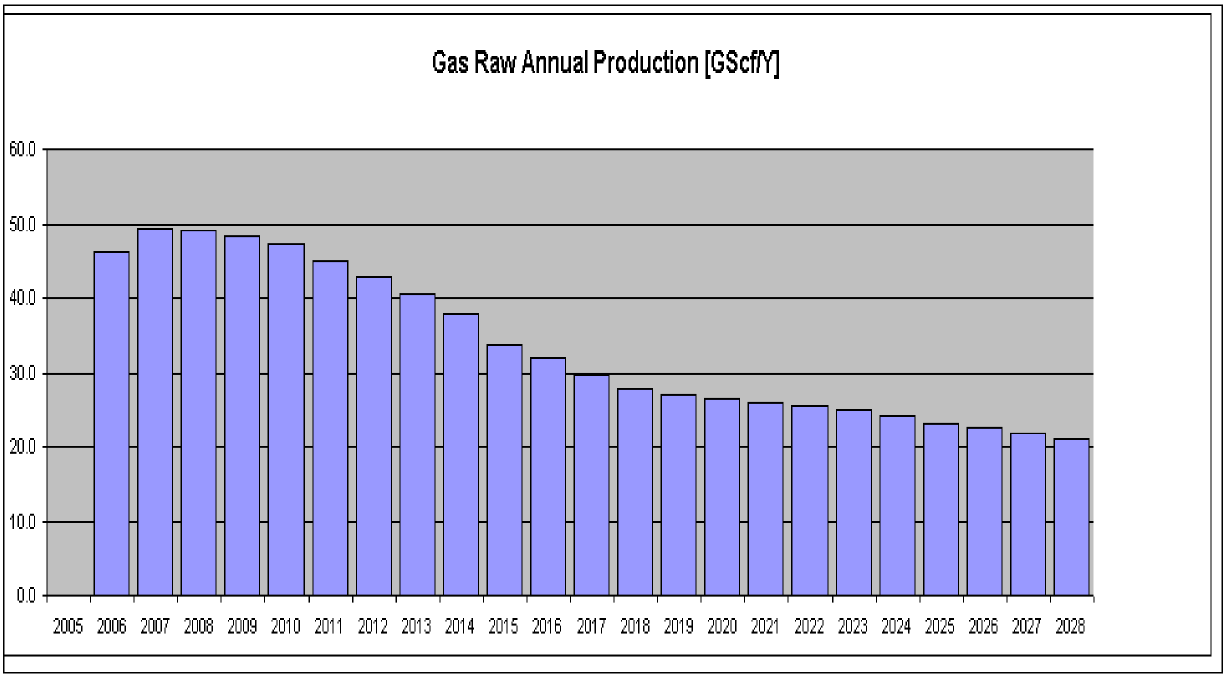
Optimized case @ 2040: Np about 483 MMSTB, GP ABOUT 965 Bscf

The acid gas re-injection is foreseen to start-up in Jan 2014. The total amount of gas impurities (Phase I + Phase II) is calculated making the following assumptions:

- Total fuel gas = 20.0 MMscf/day;
- 50% of the remaining is re-injected (impurities concentration is around 50% in the raw gas).

➢ Production and feed profile : table and figure given below raw gas production and sales gases

	Production & Feed Profiles										
DATE	Year	Gas Production (G Scf/Y)	Sales Gas (G Scf/Y)	(G Sm3/Y)	Sales Condensate (t/Y)	Sales LPG (t/Y)	Sales Gas (M BOE/Y)	Fuel Gas (MSm3/Y)	Fuel Gas (MSm3/Y)	Blend Gas (MSm3/Y)	Fuel Gas (MSm3/Y)
31-Dec-04											
31-Dec-05	2005										
31-Dec-06	2006	46.1									
31-Dec-07	2007	49.3									
31-Dec-08	2008	49.1	13.9	0.39	112118.9	30585.0	2.4	47.1	54.3	129.0	15.6
31-Dec-09	2009	48.4	13.7	0.39	110544.3	30155.4	2.4	47.1	54.3	127.2	15.4
31-Dec-10	2010	47.4	13.4	0.38	108226.6	29523.2	2.3	47.1	54.3	124.5	15.0
31-Dec-11	2011	44.9	12.7	0.36	102608.6	27990.7	2.2	47.1	54.3	118.0	14.3
31-Dec-12	2012	42.8	12.1	0.34	97688.2	26648.4	2.1	47.1	54.3	112.4	13.6
31-Dec-13	2013	40.6	11.5	0.32	92716.7	25292.2	2.0	47.1	54.3	106.6	12.9
31-Dec-14	2014	37.8	10.7	0.30	86400.3	23569.2	1.9	47.1	54.3	99.4	12.0
31-Dec-15	2015	33.9	9.6	0.27	77346.5	21099.4	1.7	47.1	54.3	89.0	10.7
31-Dec-16	2016	31.8	9.0	0.25	72710.7	19834.8	1.6	47.1	54.3	83.6	10.1
31-Dec-17	2017	29.6	8.3	0.24	67574.7	18433.7	1.5	47.1	54.3	77.7	9.4
31-Dec-18	2018	27.7	7.8	0.22	63366.7	17285.8	1.4	47.1	54.3	72.9	8.8
31-Dec-19	2019	26.9	7.6	0.21	61430.6	16757.7	1.3	47.1	54.3	70.7	8.5
31-Dec-20	2020	26.5	7.5	0.21	60637.7	16541.4	1.3	47.1	54.3	69.7	8.4
31-Dec-21	2021	25.9	7.3	0.21	59108.2	16124.2	1.3	47.1	54.3	68.0	8.2
31-Dec-22	2022	25.5	7.2	0.20	58307.1	15905.6	1.3	47.1	54.3	67.1	8.1
31-Dec-23	2023	24.8	7.0	0.20	56699.5	15467.1	1.2	47.1	54.3	65.2	7.9
31-Dec-24	2024	24.1	6.8	0.19	55045.5	15015.9	1.2	47.1	54.3	63.3	7.6
31-Dec-25	2025	23.1	6.5	0.18	52831.7	14412.0	1.1	47.1	54.3	60.8	7.3
31-Dec-26	2026	22.5	6.4	0.18	51492.4	14046.6	1.1	47.1	54.3	59.2	7.2
31-Dec-27	2027	21.7	6.1	0.17	49681.8	13552.7	1.1	47.1	54.3	57.1	6.9
31-Dec-28	2028	21.2	6.0	0.17	48328.0	13183.4	1.0	47.1	54.3	55.6	6.7
		771.7	190.9	5.4	1'544'865.2	421'424.5	33.2	989.1	1'139.4	1777.0	214.6



The recycled gas cumulative production for Phase I and Phase II wells from 2006 onwards are shown in the following table:

Cum. impurities production: Phase I @ 2030 (BSCF) =10 @ 2040 = 31 BSCF

Cum. impurities production: Phase II @ 2030 (BSCF) =7 @ 2040 = 31 BSCF

- **Cash flow analysis of GUP (with injection gas impurities @ 2014)**

No.	Time	Sales Gas (Mellitha)	Sales Gas (Mellitha)	Sales Cond (Mellitha)	Sales LPG (Mellitha)	Gas. price	Cond. Price	LPG Price	CAPEX	Main. Cost	Melitah	WorkOver	OPEX	Total Expen.	Gross Revenue	NCF	CNCF	PV @8%
	The end of year	GScf/Y	10^3 x MBTU	t	t	$/MBTU	$/t	$/t	M$	M$/Y	M$/Y	M$/Y	M$	M$	M$	M$	M$	M$
-1	31-Dec-03	0.00	0.00	0	0	2.8	205.0	222.5	4.91	0.00			0	4.91	0.00	-4.91	-4.9	-5.30
0	31-Dec-04	0.00	0.00	0	0	2.8	205.0	222.5	25	0.00			0.00	25.00	0.00	-25.00	-29.9	-25.00
1	31-Dec-05	0.00	0.00	0	0	2.8	205.0	222.5	34	0.00			0.00	34.00	0.00	-34.00	-63.9	-31.48
2	31-Dec-06	0.00	0.00	0	0	2.8	205.0	222.5	163	0.00			0.00	163.00	0.00	-163.00	-226.9	-139.75
3	31-Dec-07	0.00	0.00	0	0	2.9	205.1	222.6	93.09	0.00	0.00	0.00	0.00	93.09	0.00	-93.09	-320.0	-73.90
4	31-Dec-08	13.86	14161.20	112,119	30,585	2.9	205.1	222.6	0	3.80	3.50	0.50	7.80	7.80	70.59	62.79	-257.2	46.15
5	31-Dec-09	13.66	13962.31	110,544	30,155	2.9	205.1	222.6	0	3.80	3.50	0.50	7.80	7.80	69.88	62.08	-195.1	42.25
6	31-Dec-10	13.38	13669.58	108,227	29,523	2.9	205.1	222.6	0	7.80	3.50	0.50	11.80	11.80	68.69	56.89	-138.3	35.85
7	31-Dec-11	12.76	13041.41	103,253	28,166	2.9	205.1	222.6	0	3.80	3.50	0.50	7.80	7.80	65.79	57.99	-80.3	33.84
8	31-Dec-12	12.38	12653.93	100,185	27,330	3.0	205.2	222.7	0	3.80	3.50	0.50	7.80	7.80	64.09	56.29	-24.0	30.41
9	31-Dec-13	11.74	12000.77	95,014	25,919	3.0	205.2	222.7	0	3.80	3.50	0.50	7.80	7.80	61.03	53.23	29.3	26.63
10	31-Dec-14	12.36	12635.18	89,284	24,356	3.0	205.2	222.7	0	3.80	3.50	0.50	7.80	7.80	61.65	53.85	83.1	24.94
11	31-Dec-15	11.70	11961.24	84,521	23,057	3.0	205.2	222.7	0	7.80	3.50	0.50	11.80	11.80	58.60	46.80	129.9	20.07
12	31-Dec-16	11.46	11711.87	82,759	22,576	3.0	205.2	222.7	0	3.80	3.50	0.50	7.80	7.80	57.62	49.82	179.7	19.78
13	31-Dec-17	11.05	11293.13	79,800	21,769	3.1	205.3	222.8	0	3.80	3.50	0.50	7.80	7.80	55.79	47.99	227.7	17.64
14	31-Dec-18	10.70	10936.38	77,279	21,081	3.1	205.3	222.8	0	3.80	3.50	0.50	7.80	7.80	54.24	46.44	274.2	15.81
15	31-Dec-19	10.37	10596.51	74,878	20,426	3.1	205.3	222.8	0	7.80	3.50	0.50	11.80	11.80	52.77	40.97	315.1	12.92
16	31-Dec-20	10.36	10591.04	74,839	20,415	3.1	205.3	222.8	0	3.80	3.50	0.50	7.80	7.80	52.96	45.16	360.3	13.18
17	31-Dec-21	10.30	10529.07	74,401	20,296	3.1	205.3	222.8	0	3.80	3.50	0.50	7.80	7.80	52.86	45.06	405.4	12.18
18	31-Dec-22	10.18	10405.81	73,530	20,058	3.2	205.4	222.9	0	3.80	3.50	0.50	7.80	7.80	52.45	44.65	450.0	11.17
19	31-Dec-23	10.02	10238.68	72,349	19,736	3.2	205.4	222.9	0	7.80	3.50	0.50	11.80	11.80	51.82	40.02	490.0	9.27
20	31-Dec-24	10.00	10219.08	72,211	19,698	3.2	205.4	222.9	0	3.80	3.50	0.50	7.80	7.80	51.92	44.12	534.2	9.47
21	31-Dec-25	9.81	10027.29	70,856	19,329	3.2	205.4	222.9	0	3.80	3.50	0.50	7.80	7.80	51.15	43.35	577.5	8.61
22	31-Dec-26	9.49	9698.10	68,529	18,694	3.2	205.4	222.9	0	3.80	3.50	0.50	7.80	7.80	49.67	41.87	619.4	7.70
23	31-Dec-27	9.17	9370.70	66,216	18,063	3.3	205.5	223.0	0	7.80	3.50	0.50	11.80	11.80	48.18	36.38	655.8	6.20
24	31-Dec-28	8.89	9080.67	64,166	17,504	3.3	205.5	223.0	0	3.80	3.50	0.50	7.80	7.80	46.87	39.07	694.8	6.16
TOTAL		233.64	238,784	1,754,962	478,737				320	99.8	73.5	10.5	184	504	1199	694.8	695	135

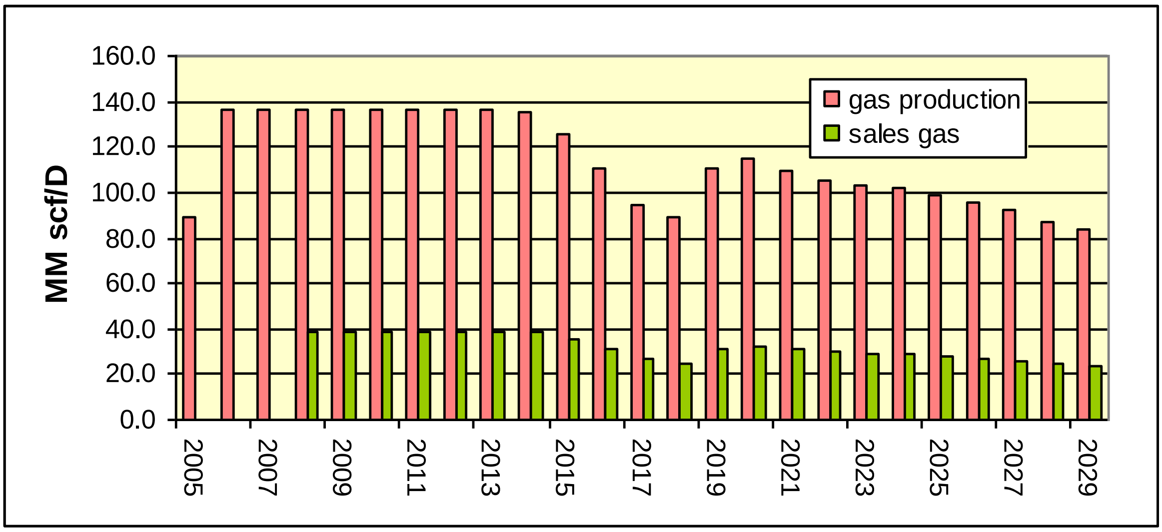
Results

Gross Revenue	1198.6	M$
Total Cost	503.8	M$
Net Profit	694.8	M$
NPV @8%	134.82	M$
IRR	13.6	%

Rate Of Return

Gas NHV =	1022	BTU/SCF
Gas Price =	2.8	$/MBTU
Cond. Price =	205	$/t
LPG. Price =	222.5	$/t
Interest rate =	8.0	%
Price Inflation Rate =	2.0	%

The results gained from 3D black oil model in terms of associated gas production profile is shown in figure 2, note that the plateau gas production of 136 Mscf/d is held for around 8 years; then rate decreases, the cumulative gas production @2029 will be 1077 B scf.



Project of Phase II development :

Based on the reservoir simulation study, the additional Gas reserves due to the phase 2 development project are given below:

	@ 2040
Scenario	(BScf)
Base Case (PH2 : standalone)	**281.6**
Base Case (PH1 Synergy)	**407.9**

<u>Cash Flow Analysis- phase I and phase II</u>

The main outcome of the Cash-Flow analysis for (Phase I & II) gas production stream ,results and economic assumptions are summarized in the following **tables :**

		Development Phase I		Development Phase II	
Gas production		Gscf/y	1035	Gscf/y	827
Gas sles		Gscf/y	255	Gscf/y	262
Gross Revenue		1348.8	M$	12201	MM$
Total Cost		511.6	M$	3298	MM$
Net Profit		837.21	M$	8904	MM$
NPV @8%		179.35	M$	2208	MM$
IRR		15	%	36	%
POT	(Date, Year)	2014		2013	
PIR		2.6163	$/$	5.8	$/$
DPIR, CPI		0.5605	$/$	2.23	$/$
G.R./T.C.		2.6364	$/$	3.7	$/$

	Development phase I		**Development phase II**	
Gas NHV	1022	BTU/SCF	1022	BTU/SCF
Gas Price	2.8	$/MMBTU	5.6	$/MMBTU
Cond. Price	205	$/t	475	$/t
LPG. Price	222.5	$/t	541	$/t
Interest rate	8.0	%	10.0	%
Price Inflation Rate	2.0	%	2.0	%
Project start up	2008		2011	

➢ <u>Acid Gas contents</u> (Gas composition):

The Graph below **displays** field gas composition. Acid gas composition ranges from 0.52% H_2S and 40.76% CO_2 (at first stage of separator train)

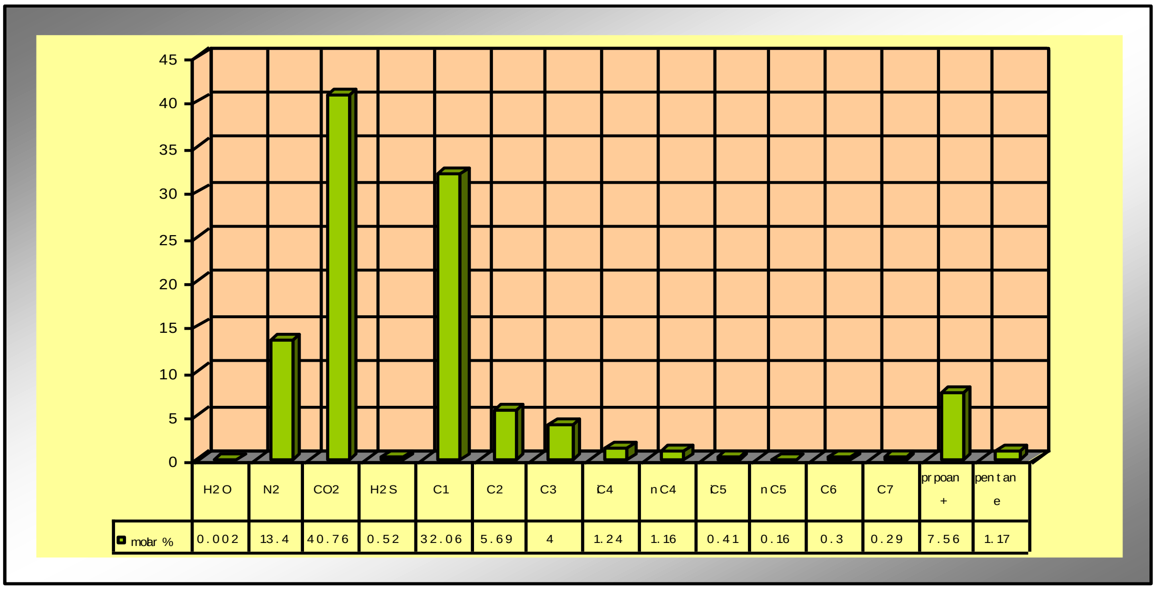
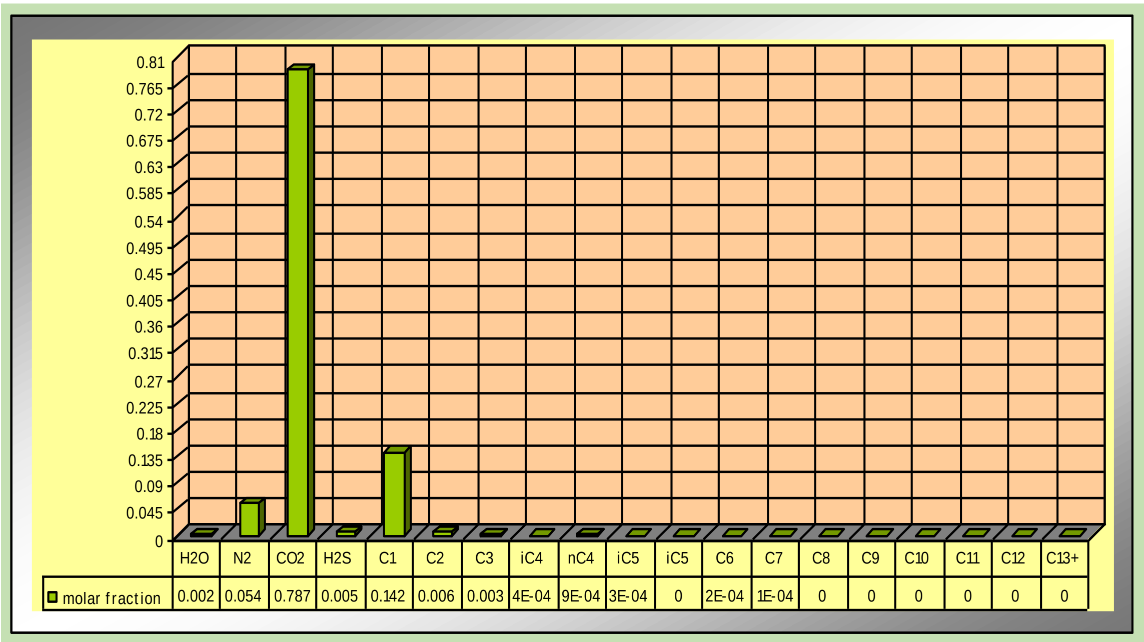
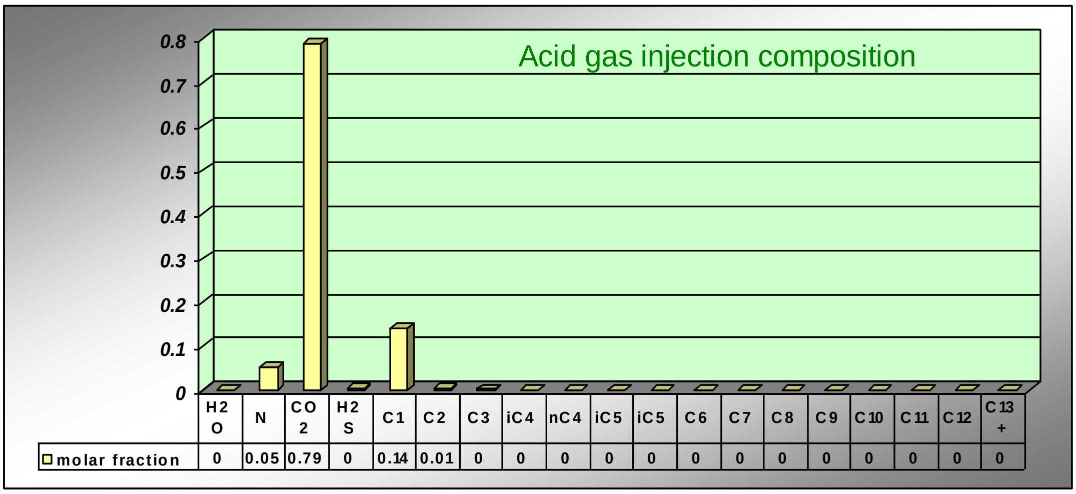


figure 6 shows gas composition that will be flared , the composition is ranging from 0.49 % H_2S and 78.70% CO_2.



The main composition of acid gas which supposed to be injected into the reservoir or nearby area are shown below :**.**


Acid gas injection composition
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
H2O
N
CO2
H2S
C1
C2
C3
iC4
nC4
iC5
iC5
C6
C7
C8
C9
C10
C11
C12
C13+
molar fraction
0
0.05
0.79
0
0.14
0.01
0
0
0
0
0
0
0
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0

Chapter

8.0

Discussion and analysis of Findings

8.1 Environmental Impact and Water Disposal

On account to present & near future activities for the increasing the production by the new low pressure Gathering System followed with the Artificial lift project, the amount of the produced oily water will increase (between 20,000-40,000 BWPD)

From the two train(1&2) to feed existing Waste Water Treatment unit 28 , where the existing treating unit is not sufficient to treat this huge quantity of the produced oily water which designed only for 21,500 BWPD, so others options becomes mandatory to overcome the accession of the produced oily water either by upgrading the treatment facilities or by re-inject a part or total of produced water into the down hole formation via a candidate disposal well in order to avoid environmental and pollution problems.

This project strategy to be done first to carry-out a pilot test to verify the availability of the reservoir's formation to absorb the target of produced oily water in range of 12,000-40,000 BWPD, and the results will ensure to be better plan:

- Necessity of other disposal wells
- Necessity to upgrade the existing treatment facilities, if the Disposal well behavior will be negative (the oily water will plug the well during the test)

Therefore, a strong need appears for a new way of dealing with this problem, represented by the suggested underground disposal of water in Melqart formation , at depth of around 1500 ft .utilizing the flooded well H4-20. Efforts were concentrated on the acquisition and analyses of data of the formation and the well to be converted for disposal, to evaluate the technical feasibility of the project

8.2 Risk analysis -HAZOP :

The technique of risk analysis assessment had been used of the available information to determine how often specific events may occur and magnitude of their consequence ,it is a systematic apply to describing and calculating risk .and to identification of undesired events and the causes and the consequences of hat events

However the mentioned task of the water disposal system and water treatment unit has been outlined for installation to be provide under OFFSHORE Field are presented through the following

8.2.1 Data acquisition:

58 values of oil in water samples (ppm) havn been collected during last 5 years of production, these data was used to build the subjected correlation .
The chemical analysis of formation water had been carried out through two sampling point, firs was before the skimmer (inlet) and the second sampling was collected from outlet of skimmer in the water treatment unit On the other hand the production data have taken from production separator.

8.3 Role of Risk Assessment

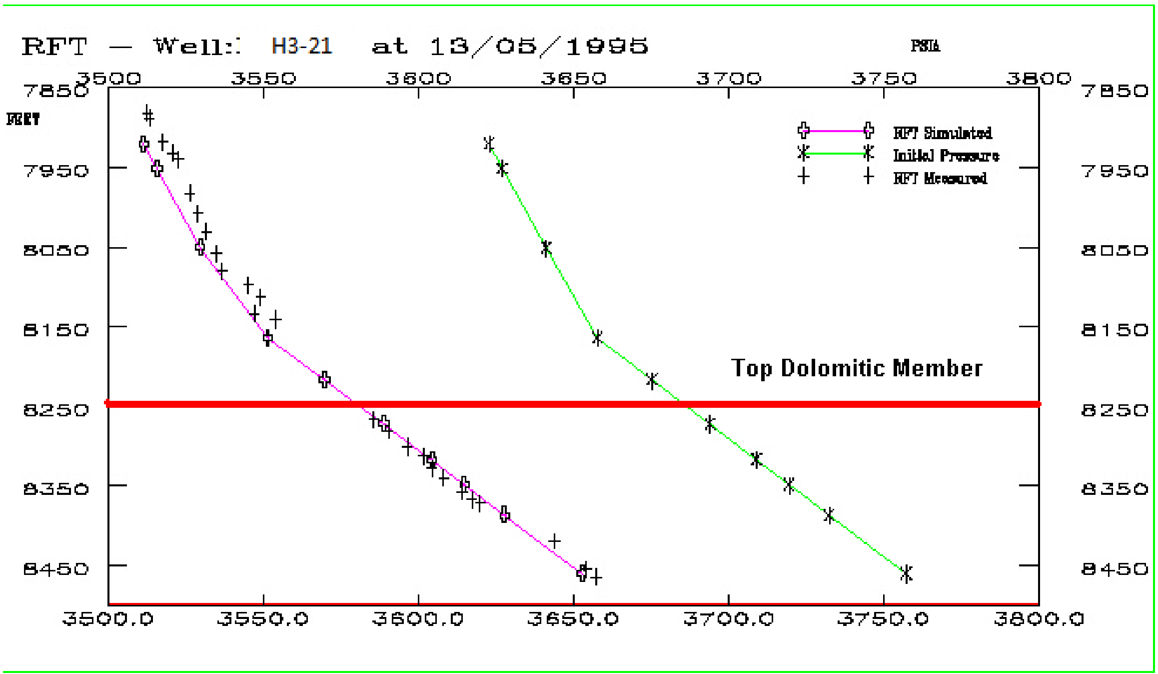
Risk assessment can:

- Facilitate communication between decision makers and technical experts by providing precise language (i-e mathematical language of probability and statistics) for describing the nature and extent of uncertainty in safety and environmental consequence

- Facilitate communication between the decision-makers and other interested parties by providing explicit data that are amenable to review by interested parties.
- Help the decision makers identifying the role and impact of policy consideration (e.g. social, political, economic and legal policy Judgment) in the assessment of scientific information.
- Help decision makers separates a complex health, safety or environmental problem into its component, and more manageable parts.
- Help decision-makers identify and understand the impact of interactions and joint dependencies between variables and components of the problem might otherwise be overlooked.
- Help decision-makers identify research needed and set research priorities that would significantly reduce the important scientific uncertainties.
- Help decision-makers by providing a framework for explicitly examining the potential adverse consequences of alternative risk management Policy or action.

8.4 Water injection into deep reservoir:

The main simulation result is that the Dolomitic member is the optimal target for water injection due to a better pressure support distribution consequent to injection in high permeability layers. Also from a practical point of view this should be the preferred option as the Dolomitic member is thought to be the main aquifer source in the northern area and is in communication with the producing layers of the Upper Numulitic Fmt as can be demonstrated by the **RFT** data on wells H3-21 and H3-26 shown here below figure 8.1:



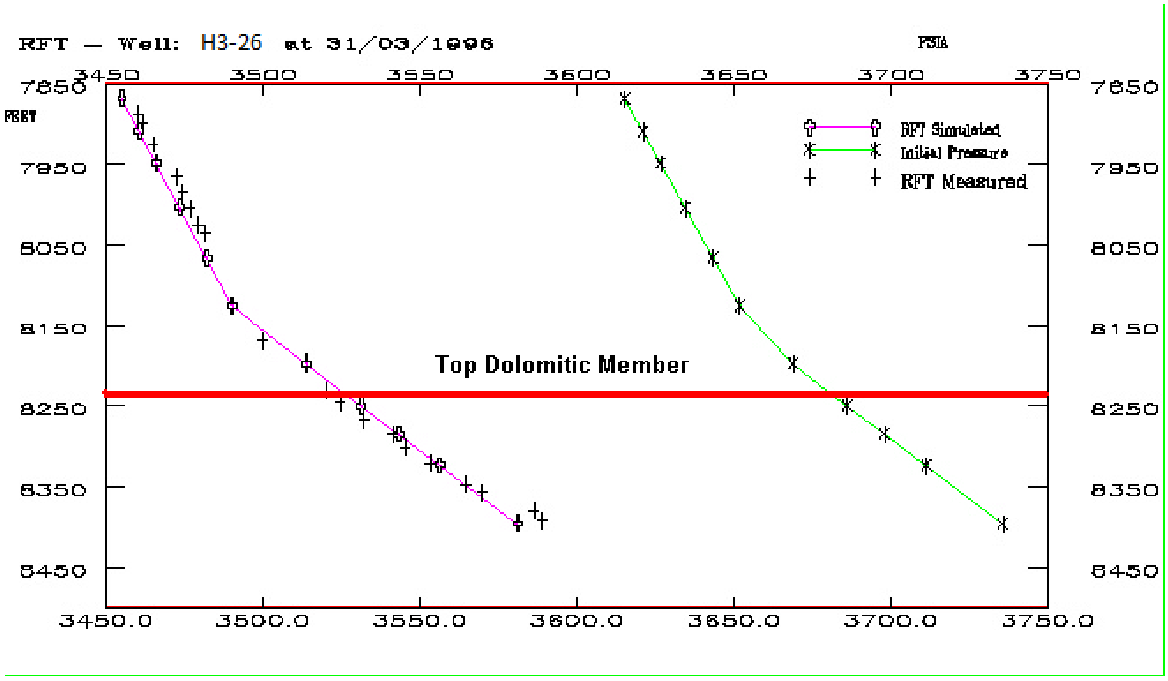


Figure 8.1: RFT measurement

8.5 Why we need water re-injection:

The project of water injection has the following objectives:

- ✓ increase recoverable reserves by
  - sustaining the reservoir pressure in the northern part of the DP4 area
  - lower the overall production GOR
  - increase field water treatment capacity to 30’000bwpd
- ✓ reduce water discharge to the sea to zero

Injecting water in DP3 area gave negative results. Well, H4-25 (shut in) was detected as best candidate to perform the injection. The 2001 study considered a pilot water injection project in order monitor GOR and watercut performance of nearby wells for 1-2 years before extending WI to an additional well also drilled in the northern flank. At the end 2001 a technical feasibility study for deepening and re-completion of the well H3-25 has been issued by D&WO. The well has to be deepened to approximately 10’850 ftMD (actual TD 10’447 ft MD) and then re-completed with a 4.5” tubing 13% Cr and a Baker Standard System for North Sea application [Ref. 2]. The feasibility study recommended a corrosion study before purchasing the equipment based on injection stream specifications.

The actual model update 2004 confirmed the possibility of increasing the recoverable reserves through water injection in the northern flank of the DP4 production area.

8.6 Why GUP is needed :

The Gas Utilisation Project for Offshore Fieldis based on the following philosophies:

- Reduction of the environmental impact by applying a suitable gas recovery system able to reduce emissions to the atmosphere
- Improvement of field economics through additional revenues from recovered gas, condensate, and LPG sales
- Increase total recoverable hydrocarbon reserves in terms of gas, condensate, and LPG

The main objectives of the gas utilization project are:

- ➢ Reduce environmental impact by diminishing emissions to the atmosphere
- ➢ Preserve natural resources
- ➢ Increase total recoverable hydrocarbon reserves in terms of gas, condensate and LPG

8.7 Prediction Scenarios of 3D reservoir simulation – Results:

Based on the 3D reservoir simulation model the gas and oil production during the period 2004 -2039, are 1331 Bscf and 546 MM stb In order to maintain a longer gas production plateau and introduce in the optimized case has been created. Optimisations of the forecast constraints *are mainly the following*:

☝ the introduction of work over on the upper layers (for 24 wells) to manage gas cap shrinkage and aquifer encroachment

☝ The high GOR wells have been allowed to continue production to keep the gas production plateau.

Automatic work over for low THP on all wells by opening higher layers.

8.8 Environmental impact assessment of gas flaring:

Even though the gas utilization project will reduce the gas flaring, the problem of acid gas is not completely solved, conversely an additional amount of acid gas production from phase II of Offshore Field will be added, this implies to think deeply of **EOR** or sequestration of acid gas (*H_2S and CO_2, with minor traces of hydrocarbons*)

As a result of implementing phase II project however the field gas production will be increased and consequently the acid gas volume will be increased.

Acid gas re injection or sequestration will have the following advantages:

- ☑ Eliminate the emission of pollutants into the atmosphere, to match the international agreement of environmental protocols.
- ☑ Preserve natural resource of LPG and gas condensate
- ☑ Increase oil recovery and Maintain reservoir pressure.

8.8 .1 The Goal of Gas Utilization Project

The main goal of gas utilization project is:

☑ Reduction of the environmental impact by applying a suitable gas recovery system able to reduce emissions to the atmosphere.

☑ Improvement of field economics through additional revenues from recovered gas, condensate, and LPG sales.

☑ Increase total recoverable hydrocarbon reserves in terms of gas, condensate, and LPG

Alternative reducing/eliminating scheme:

- To reduce CO_2 emissions, one must either reduce CO_2 production, or looking for other alternative disposal schemes.
- Several different sequestration schemes have been proposed to manage the problem of environmental pollution.
- Implementation of technologies to capture carbon dioxide (CO_2) and sequester it in geological formations will be necessary to achieve
- significant reductions in atmospheric emissions of anthropogenic greenhouse gases.
- Oil and gas reservoirs and deep saline aquifers are believed to be safe suggestion for long-term geological sequestration.

8.8.2 Possibility of application EOR

to investigate the possibility of enhanced oil recovery, meanwhile to develop methods and implement techniques for the assessment of CO_2 sequestration in oil and gas reservoirs, to investigate the potential enhanced oil recovery however, well H4-12 well had been candidate for injection purpose of CO_2 into oil reservoir .

8.9 Risk Assessment of Geological Storage

The technique of risk analysis assessment had been used of the available information to determine how often specific events may occur and magnitude of their consequence, it is a systematic apply to describing and calculating risk, and to identification of undesired events and the causes and the consequences of that events

CO_2 has less density and viscosity than formation water (brine) so the carbon dioxide will flow up wards until it is confined by barrier or non-sealing fault or law permeability of cap rocks. this can drive the a horizontal movement, as areal extent of gas sequestration, consequently the gas will eventually dissolve into pore fluid, eliminating floating forces that drive upward motion and greatly reducing transported rate to other formation, it may be trapped for couple of decades .

The classification of possible risks of geological storage or sequestration can be classified ***into two categories***:

gas surface release which will impact in atmosphere and ecosystem the second type of possible risk is related to the leak into subsurface formation due to metal mobilization or other containment mobilization raised from chemical reaction between the displaced and displacement , it may reach the fresh ground water resources or it may come in the form of fingering phenomena at hydrocarbon reservoir or early gas breakthrough, it had a negative impact on the potential and productivity of the field .

Risk assessment for sequestration projects must include predictions of sequestration zone performance.

These performance assessments will guide the selection of sequestration sites and/or operating parameters, such as injection pressure and rate, that mitigate leakage risks. If natural fractures or faults are present, then bottom-hole injection pressures higher than the minimum in-situ stress may open these fractures. Pressures higher than the fracture breakdown pressure will fracture the reservoir and/or cap rock. In both cases, CO2 or acid gas will leak from the sequestration unit. Thus, it is essential to properly estimate the minimum stress and fracture breakdown pressure and devise injection strategies that will always maintain pressures below these.

Risk analysis is an integral component of this assessment. It involves an evaluation of the types of events that may result in leakage, the likelihood of these events, and their potential consequences.

8.10 final oil recovery

• In all the gas re-injection cases the final oil recovery is above the reference case scenario that is without gas re-injection. In fact, gas re-injection helps to sustain the pressure and delay the water encroachment in most depressurized area .

• The cases considering the injectors in gas cap close to the area already developed provide the most interesting results with an increment with the Do nothing case of about 26 MM STB and 29 MMSTB at Dec-2050.

This is due to the fact that those areas are near producing wells and the pressure has been already decreased by about 500 psi from original reservoir pressure.

• Cases 3 and 4 show similar increment of final oil recovery wrt cases 5 and 9, but the location area of these clusters are in highly faulted zones with limited reservoir information and the final recovery could be overestimated.

• Case 9 has been finally selected as representative for the AGR scenarios (well locations of 9 cases are **illustrate in figure 8.2**)

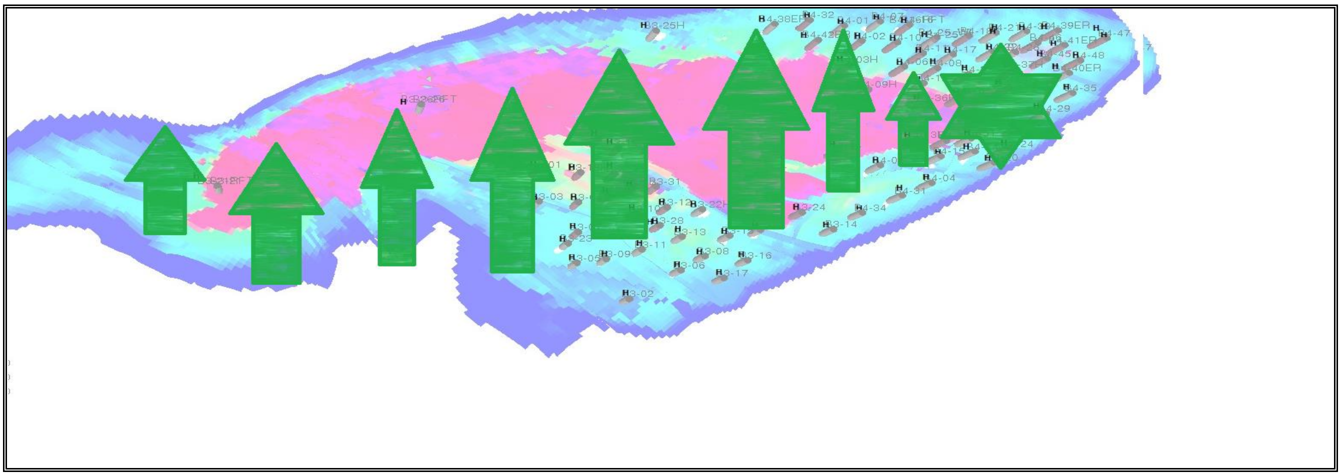


Figure 8.2: AGR Well locations

The total field cumulative oil production is very similar between case 5 and case 9 but the cumulative production by platforms varies. In case 5, where the acid gas injection is envisaged closer to DP3 platform the cumulative production is higher for DP3 wells

than in case 9. In case 9 instead, where the injection cluster location is close to DP4 wells, the cumulative oil production for DP4 wells is higher than in case 5.
Figure 8.3 shows the comparison of gas injection rates on a field level for the 9 sensitivity cases. As one of the constraints field gas injection rate has been limited at 105 MM SCF/D which is 35 MMSCF/D per well.
As it can be seen from the graph the gas injection rate for the case 1 and case 2 remains far below the maximum field gas injection rate due to the flowing bottom hole pressure limit constraint of 3700 psi. Whereas for other cases the injectivity is better. The field gas injection rate is 49% of total gas produced from the field.

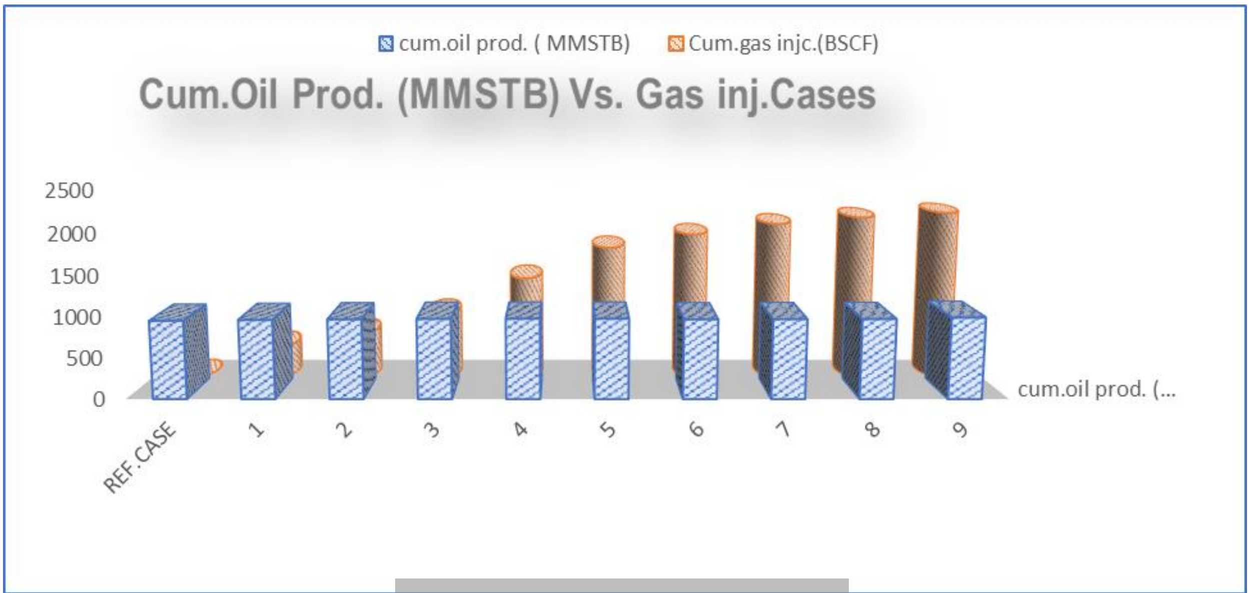


Figure 8.3: Cumulative Gas &Oil Production

The following ***Table 8.1*** summarize the obtained results:

	Num. of gas injectors	Peak gas Inj. rate [MMscfd]	Cum. Gas Injected [Bscf]	Cum. CO_2 Injected [Bscf]	Cum. CO_2 Produced [Bscf]	Sequestrated CO_2 [Bscf]	[%]
Ref. Case	-	-	-	-	-	-	-
1	3	90	473	368	49	319	87%
2	3	121	725	563	109	455	81%
3	4	157	1061	824	191	633	77%
4	5	194	1647	1279	319	961	75%
5	**6**	**231**	2145	1666	480	1186	71%
6	7	269	2358	1832	487	1345	73%
7	8	308	2527	1963	517	1447	74%
8	9	346	2633	2045	539	1507	74%
9	10	385	2706	2102	591	1511	72%

Table 8.1: Results & Summary Of injector wells

The results are indicating that increasing the gas injection volumes it is possible to increase the oil recovery, but at the same time the sequestration capacity percentage decreases. Indeed, in case1 with a cumulative gas injection volume of about 0.5 tscf the 87% of CO2 injected remain in reservoir while increasing the injected volumes sequestration capacity decrease at 72%

8.10.1 Screening sensitivities on oil rim versus gas cap re-injection

Screening sensitivities on oil rim versus gas cap re-injection Preliminary evaluation of acid gas reinjection in offshore field envisaged screening sensitivities on either injecting acid gas in oil rim or in gas cap. The target was to find optimum location for injection by analyzing the impact on final oil recovery. (*See figure 8.4*)
Initial sensitivities have been performed on Phase I development only, with further extension of analysis to full field PH1+PH2 development.

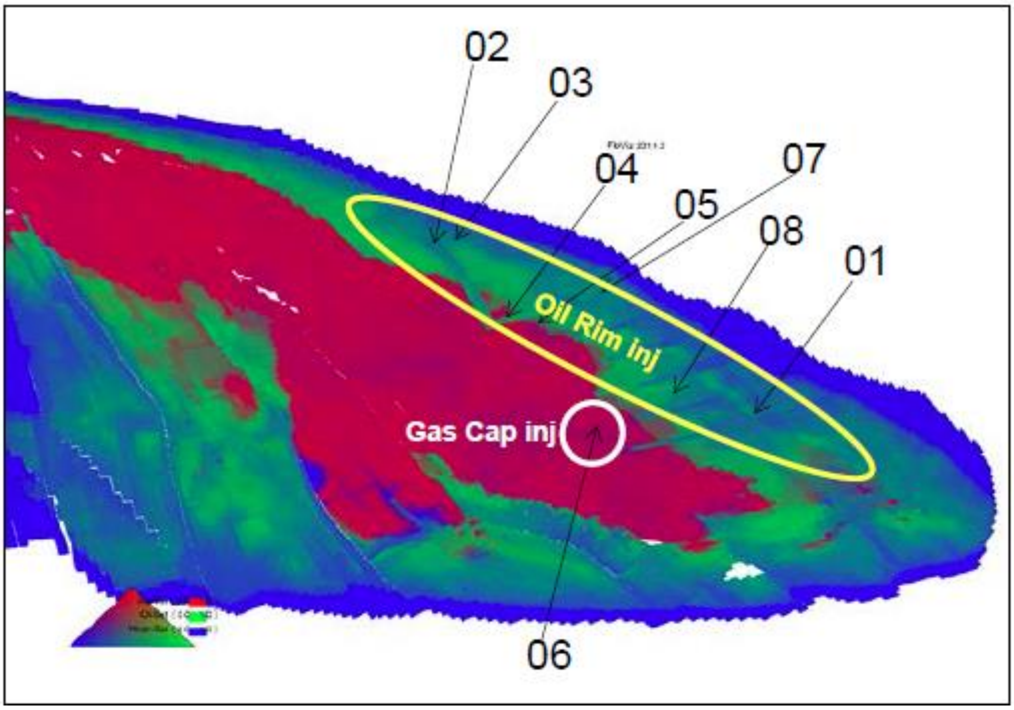


Figure 8.4: Oil Rim Vs. Gas Cap

The above figure shows the location of injectors on ternary saturation map. Case 06 is injecting acid gas in gas cap and the rest of the cases from 01 to 08 are single injection well locations in oil rim. The area has been selected mainly due to its vicinity to existing well locations and good well by well HM. The results of the simulations have shown that there is a more favorable impact on oil recovery when injecting acid gas in gas cap rather than in oil rim.
Further analysis has been performed by comparing acid gas injection scenarios in oil rim and gas cap. In each case a cluster of 3 wells has been considered. While for oil rim two cases were analyzed with different injection cluster locations as shown on Figure 8.5.

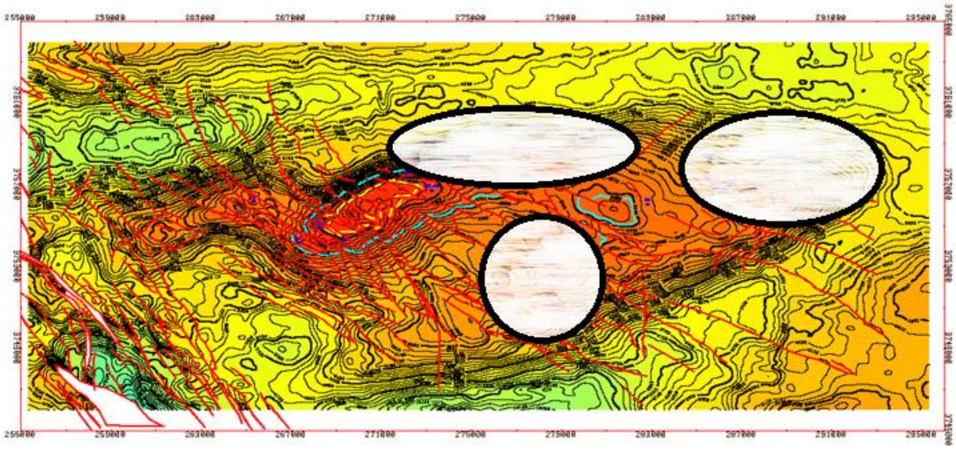


Figure 8.5: Well Cluster location

The gas re-injection sensitivities have been performed considering:

- Re-injection concentrated in the Upper Nummulitic
- Re-injection shared in Upper Nummulitic and Dolomitic members.

The following constraints and assumptions have been considered in gas injection scenarios:

- Gas re-injection start up in 2025, after the finalization of DP2 drilling and completion and full development starts up.

- Percentage of acid gas to be re-injected is 49% of the total gas produced by Offshore Field . This percentage is the acid gas remained after treatment in GRM modules planned for Gas Utilization Project (GUP). Additional 19.8 MMSCFD of fuel gas must be subtracted.

<u>For the gas injectors:</u>

- Max gas injection rate of 35 MMscfd.
- Max FBHP of 3700 psia (Initial Pressure @ datum of 8163ftssl is 3650psia)
- The max FBHP, for gas injectors, has been set as the initial pressure in order to avoid possible fracturing problems.
- The acid gas composition that has to be re-injected in reservoir has been set as the composition coming out the GRM at present the composition of injected gas has been considered constant. It is suggested, for future more detailed works, to verify the composition coming out of GRM,

Conclusions
&
Recommendations

- Produced water reinjection (PWRI) is a proven field development technology which has been widely applied to numerous fields to optimize disposal of produced fluids while meeting reservoir injection requirements. However, PWRI has not been evaluated in many of the giant carbonate reservoirs which are relatively immature in the Middle East

- In terms of **Associated water produced** to ensure to be better future field plan it is :
  - Necessity of other disposal wells
  - Necessity to upgrade the existing treatment facilities, if the Disposal well behavior will be negative (the oily water will plug the well during the test)

- In general, the separator mainly removes particulate and dispersed oil, while dissolved hydrocarbon in concentration from 20-50 mg/l go overboard as part discharged water.

- **Treatment/disposal**: a various method was available for treatment process, which need to be selected to suit the ultimate disposal location and environment and be feasible from economical, technical point of view how ever there are many methods for disposing the produced water in oil field, the main methods are
  - Re-injection to oil reservoir.
  - Re-injection in deep aquifer.
  - Down hole work separation.
  - Water treatment unit.
  - Discharged to sea.(or pits in onshore fields)
  - Re-injecting to a shallow formation.

- Currently it was observed that the produced formation water discharge into the sea present a *very law environmental risk*, due to high dilution rates this has brought that average concentration of oil in the water below 40 ppm.

- All modifications should be " hazoped " or consider in a similar way:
  - Cheap modifications as well as expensive ones
  - Modifications to procedures as well as modifications to equipment
  - Temperature modifications as wee as permanent one.

- The most effective team leaders are trained in hazan as well as hazop, because it is possible to install expensive equipment to guard against unlikely hazards . the team leader can quoting a few figures or asking a members of the team by asking for example how often do flanged joints leak ? and how far do the leaks spread ? or how often pumps leaked (check list)? etc..

- Sometimes an engineering hardware solution is impossible or too expensive, so we need to change in methods or improve the training of operators.
- Contractors in particular should choose solutions appropriate to the sophistication and experience of their client, less sophisticated solutions should be sought.
- The client should be involved in hazop studies as well as the contractor because the client will have to operate the plant.
- Identifies sensitive components in the existing environments related to the

project's location construction, operation and decommissioning, measure are then recommended to avoid or ameliorate potential negative impacts.

- Environmental impact assessment (EIA) starts with preliminary study during preplanning and continues throughout the project , allowing potential impact on the environment to be anticipated for all phase of the proposed development.
- EIA may also be used as a basis for subsequent stages of the environmental management program, including monitoring, auditing, and training.
- Routine checks detect changes in environmental and measure the extent of any disturbance and any subsequent recovery.
- A Team should periodically (2-3 years) an edit the effectiveness of environmental control personal, the adequacy of company policies and procedures, and the efficiency of laboratory services should be implemented.
- Environmental training ensure that the personal are able o deliver acceptable operating procedures, like safety, environmental awareness is an attitude that adds an extra dimension to a work forces technical completeness.
- EIA evaluate the effectiveness of incident reporting and remedy schemes and , identify current environmental problems, it is make recommendation to the management as ways of improving environmental performance.
- Hazops are only as good as the knowledge and experience of the people present. if they do not know what goes on, the hazop can not bring out the hazards
- Establishment of safe level (maximum allowable operating pressure)
- Injection of corrosion inhibiting chemicals and application of probes and coupons.
- Installation of gas detectors, (as leak alarm system for pollutants , especially for a poisonous gas such H2S hydrogen sulfide)
- Training programs for operating, maintenance and inspection personal are mandatory such operators, Formen, maintenance specially a trained in poisonous fluid (e.g. H_2S)
- A program for monitoring and maintain a pipeline integrity.
- Provisions of control and safety procedures designed to prevent the undetected continuous escape of a poisonous fluid.
- The volume of produced water could be a huge amount of contaminated water that needs an economical and environmentally friendly methods of treatment, so it can be re-used or display safely

- Field water treatment capacity should be upgraded with maximum urgency due to the cut increasing field water.

- Water re-injection in the northern flank of the DP4 area seems to be very beneficial to sustain the pressure and is giving about 20 MMstb of additional reserves @2028. The field behavior under water re-injection will be carefully monitored to confirm the very promising results evidenced by the numerical simulation.

- The economic analysis of the water re-injection shows very good results even with an oil price of 20 US$/STB, quite below the present levels. Beside of the economic importance of the project it has to be emphasized that the water presently discharged into the sea will be re-injected reducing the impact on the environment to zero.

- Start-up of the water Re-Injection project will be based on the following design figures:

- Increase water treatment capacity to 30 Mbwpd
- Deepening & completing H4-25 as a water injector
- Connect disposal well H4-20 for back-up

- **3D Reservoir Model Results:**
  - The forecast cases run with these updated models confirm essentially the reserves values of the previous integrated reservoir study
  - To evaluate the additional reserves associated to the water injection implementation, the base case for comparison purposes includes development phase projects of phase I of the field
  - The water injection case simulated can be summarised as follows:
    - Start-up of water injection is May 2007
    - The max BHIP of 5500 psia, H4-25 injects 15'000 bwpd
    - Around 176 MMbbl of water are injected till 2040
    - Additional reserves are evaluated in 30.7 MMSTB @2040 (10.4 MMSTB@2019)

- **Economic Evaluation: EOR -Water Re-injection Project**

The results of cash flow analysis due to the project is seems it is a profitable project; the most economic indicators are summarized here below:

Pay out time: March 2021, Rate of Return 32 %, present values 74 MM$ (10 %), gross revenue = 398 mm$ and total expand About 69 MM$ @ 2030.

- **Philosophies of Gas utilization Project (GUP):**

The Gas Utilisation Project is based on the following philosophies:

- Reduction of the environmental impact by applying a suitable gas recovery system able to reduce emissions to the atmosphere.
- Improvement of field economics through additional revenues from recovered gas, condensate, and LPG sales.
- Increase total recoverable hydrocarbon reserves in terms of gas, condensate, and LPG.

- **Suitability of Sequestration:**

The most common sequestration of acid gas in geological media are:

- ✓ Storage in salt caverns
- ✓ EOR
- ✓ Storage in depleted oil and gas reservoir
- ✓ Injection into deep saline aquifer

- Various ways were available for treatment process, which need to be selected to suit the ultimate disposal location and environment and be feasible from economical and technical points of view however there are many methods for disposing the produced gas in oil field, the main methods are :

- Re-injection to oil reservoir.
- Re-injection to gas cap.
- Re-injection in deep aquifer.
- Re-injection to other formation or neighboring structure.
- Down hole work separation.
- Discharged to emission. (Flaring).
- Storage to a shallow formation

- Safety and security of trapping should be examined by using a geochemical modeling and laboratory experiments.
- Develop methods and implement techniques for the assessment of acid gas sequestration in oil and gas reservoirs, deep saline aquifers are so vital, characterize specific sites selected for early implementation and monitoring of acid gas storage in geological media of offshore concession 41 are so important.
- The strategy of injecting the gases in the lower aquifer to take advantage of countercurrent flow to promote both trapping and dissolution and thus avoid contact with the top seal and potential escape of the gas is greatly aided using horizontal wells.
- Abiod Fm., although deeply buried in Offshore Field area, does not appear to be a suitable for acid sequestration, may be attributed to very low permeability, overpressure, and uncertainty of seal integrity.
- D structure has been preliminarily assessed and showed interesting opportunity for being used as acid gas disposal reservoir due to the GWC shallower than spill point toward Bouri, already existing high concentration of gas impurity (higher than 73%) and Vicinity to Offshore Field facilities (less than 15 km)
- Oil and gas reservoirs and deep saline aquifers are primary candidates for long-term geological sequestration of acid gases.
- Analysis of the porosity and permeability distributions in aquifers and hydrocarbon reservoirs. Permeability is a critical parameter in establishing acid gas injectivity, while porosity determines the potential volume available for sequestration by hydrodynamic and stratigraphic trapping
- Gas utilization project can assist to environmental protection beside that a profit indicators gained from cash flow analysis shows an encouragement figures as well as that the technical indications are feasible .
- The determination of CO2 density at in situ temperature and pressure conditions specific for various regions of Offshore Field and nearby structure for use with porosity and CO2 solubility in brines for the range of salinities encountered in the offshore basin to estimating the acid gas mass that could be sequestered by dissolution in aquifer water (solubility trapping).
- The impact of re-injecting “CO2 enriched” gas (raw gas + acid gas) on the gas treatment facilities due to the increased CO2 content of the produced gas must be studied.

- Storage of acid gas in geological media is promising as a potential option for reducing release of CO2 emission to the atmosphere, acid gas disposal is usually a less costly option than providing Sulphur recovery for small to medium sized applications.
- The gas sequestration is a means of reducing atmospheric emissions of CO_2 that is immediately available and technologically feasible.
- Biological data of sea bottom and water column, including flora, fauna and ecosystems, are strongly recommended to evaluate the environmental impact of the development phases of Offshore Field .

- **Composition of injected Acid Gas:**
  The prosper model has been defined as compositional model utilising the 10 component Equation of State from dynamic simulation and using for injection fluid stream that one shown in this table :

	% mol
CO_2	78
H_2O	0.01
H_2S	0.48
N_2	4.85
CH_4	15.05
C2	1.43
C3	0.34
i-Butane	0.02
n-Butane	0.09
i-Pentane	0.02
n-Pentane	0.02
n-Hexane	0.01
n-Heptane +	0.00
Total	**100.0**

Composition of injected Acid Gas

- **Screening sensitivities on oil rim versus gas cap re-injection**
  Preliminary evaluation of acid gas reinjection in the field envisaged screening sensitivities on either injecting acid gas in oil rim or in gas cap. The target was to find optimum location for injection by analyzing the impact on final oil recovery.

- **Comparison of sensitivity runs of AGR:**
  - The best Case is number 9 it has been finally selected as representative for the AGR scenarios.
  - The selected AGR case is case no. nine that consider 3 injectors in an area at about 4 km from both Dp3 and Dp4 nearby producers successfully history matched and consequently with low risks of unknown fault location/behavior (gas fingering).
  - The best Case is providing the best oil recovery (more than 25 MMSTB vs. DN. case), best CO_2 sequestration (about 85% of the injected volume) and consequently lower CO_2 concentration increment.

- A series of sensitivities have been run to assess the possible best location for field AGR (49% of produced gas available for reinjection after membrane module treatment).
- In all the analyzed cases there **<u>is no negative impact</u>** on oil recovery in 2050.

- The Oil Recovery is generally increasing with increased quantities of injected gas.
- The CO_2 concentration in the produced gas increases with time and its max level and increment velocity depends by the injected volumes. The expected CO_2 concentration peaks are between 45 and 65%.

- The anticipated installation of GUP and the re-injection start up at the beginning of 2018 has positive impact, not only for the recovered gas, but also in terms of additional oil production.

- NO constrains on max gas production on DP2 platform is considered in the Reservoir simulations model.

Recommendations:

- The water injection/disposal system must be designed in a flexible way permitting at any moment to choose between the re-injection through well H4-25 (reservoir) and H4-20 (Melqart) alone or in combination. As the treatment is reducing oil content below 40ppm the option of dumping the produced water into the sea will still be a back-up possibility
- Update/review all the constraints and the time schedule of the different developing actions.
- Investigate the possibility to increase the spacing between injectors optimizing their locations with the aim to reduce the acid gas re-circulation and increase the sequestration capacity.
- Define a dedicated production optimization strategy with the aim to minimize production from the higher CO2 producers and reduce the CO2 re-circulation.
- optimize the location and targets of the PH2 and North Flank
- In case of future gas cap blow-down it is recommended to verify the impact of acid gas reinjection on surface facilities and sales gas volumes
- Perform optimization on acid gas injector locations taking into consideration alternative future gas treatment and re-injection platform location.
- Define a dedicated production optimization strategy with the aim to minimize production from the higher CO2 producers and reduce the CO2 re-circulation.
  It is also recommended to optimize the location and targets of the PH2 and North Flank development wells.

- Evaluate the possibility of installing a completion with multi zone control systems in order to mitigate the gas and water increment to avoid gas and water coning .

- Effects of pilot WI should be evident after 1-2 years (GOR reducing in the nearby wells) Pilot water injection must be combined with de-bottlenecking.

Research limitations and Recommendation for Further Research

- The limitations of a thesis are its flaws or shortcomings which could be the result of unavailability of resources, small sample size, flawed methodology, lack of data or information. ..
- I presume that There is no study is completely flawless or inclusive of all possible aspects. Therefore, listing the limitations reflects honesty and transparency and shows that the student has a complete understanding of the issue/study.

- **Sample/project Size**: One of the biggest concessions was studied, in the same track all areas (neighbouring fields/structures) a regional full study must be conduct as one integrated study.

- In case of future gas cap blow-down it is recommended to verify the impact of acid gas reinjection on surface facilities and sales gas volumes.

- To define a dedicated production optimization strategy with the aim to minimize production from the higher CO_2 producers and reduce the CO_2 re-circulation.

- After couple of years an update this research is vital including any new constraints and the different developing actions according to new input information to assure the reliability of the forecast.
- It is suggested further step of the analysis to evaluate the impact of additional CO_2 injection coming from neighbouring fields.

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Yes, you do it

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