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EXCESSIVE WATER PRODUCTION DIAGNOSIS, ANALYSIS, EFFECTIVE, (ENVIRONMENT, COST), AND CONTROLING TAWILA FIELD, BLOCK-14, MASILAH BASIN YEMEN

A PROJECT SUBMITTED IN PARTIAL FULFILLMENTOF THE REQUIREMENTS FOR THE DEGREE OF BACHELOR OF SCIENCE OIL AND GAS ENGINEERING

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DECLARATION

We hereby declare that this bachelors project is the result of our own work, except for quotations and summaries which have been duly acknowledged.

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APPROVA

This is to certify that the project titled **Excessive water production diagnosis ,analysis, effect (in environment and cost), and control Tawila field block-14 Masilah basin Yemen** has been read and approved for meeting part of the requirements and regulations governing the award of the bachelor of engineering (Oil and Gas) degree of Emirates International University; Sanaa Yemen.

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ABSTRACT

Excessive water production is one of the common and challenging problems associated with hydrocarbon production in a large number of oilfields reaching maturity. Water production is also one of the technical, environmental and economic problems associated with oil and gas production. Tawila field is one of the productive and the largest and most important oilfields in the onshore of Block-14 in the Masila which produces hydrocarbons mainly from clastic deposits. The study area is within the Tawila oilfield, south of the block, and is characterized by an isolated fault-block structure.it is noted Water production in Tawila field increased rapidly throw the life of the field. This graduated project focused on understanding the mechanism of water production, the cause of water production problems, the methodology for determining the sources of water production, environmental impacts, and the cost of the impact of water disposal and treatment. The production analysis which include Chan's diagnostic was used to achieve proper diagnostic. The four T-10 ,T-22,T-70 and T-138 wells ranked according to chan plot analysis in two groups that noted according to Chan plot, all the wells in this study are diagnostic a High Conductive layer channeling ,T-22 ,T-138 and the other wells showing a conning criteria beside channeling due to the bottom water drive T-10,T-70. Mechanical shut-off was found to be not a good choice for this kind of problems due to maturated water production and the RPM materials can give a good result but its need good selection and design. The four wells economic analysis shows the value loses due to water treatment and oil loses.

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LIST OF ABBREVIATIONS

OFM	Oil Field Management
WPM	Water Production Management
API	American Petroleum Institute
TOC	Total Organic Carbon
ECP	External Casing Packer
POPD	Barrel Oil Per Day
WOR	Water Oil Ratio
WOR’ or dWOR	Derivative Water Oil Ratio
WFL	Water Flow Logs
TPHL	Three Phase Fluid
Kv	Vertical Permeability
Kh	Horizontal Permeability
OWC	Oil Water Contact
CHFR	Cased Hole Formation Resistivity
TDS	Total Dissolved Solids
PL	Production Log
ISP	Intermediate Strength Proppant
POOH	Pull Out Of Hole
DOWS	Downhole Oil Water Separation
PAM	Polyacrylamide
HPAM	Hydrolyzed Polyacrylamide
OOIP	Original Oil In Place
IFT	Interfacial Tension
EOR	Enhance Oil Recovery
EOS	Equation Of State
SP	Surfactant Polymer

CSI	Cyclic Solvent Injection
ASP	Alkaline Surfactant Polymer
LASER	Liquid Addition to Steam to Enhance Recovery
VAPEX	Vapor Extraction

CHAPTER ONE

1. INTRODUCTION

1.1. Overview

Excessive water production is one of the common and challenging problems associated with hydrocarbon production in a large number of oilfields reaching maturity. High water cut producers are a common challenge to production maintenance and platform facilities. The water produced from the oil and gas production process comes either from an aquifer, reservoir or/and from injection wells in water flooding .These aquifers can provide the natural drive for petroleum production. Once the aquifer pressure is depleted, additional water is also injected into the reservoir to provide further pressure to the hydrocarbon reserves to move towards the production wells.

Water production is also one of the technical, environmental and economic problems associated with oil and gas production. Worldwide, it is estimated that an average of three barrels of water are produced for each barrel of oil (with the ratio at 7:1 in US and 55.5:1 in North Sea). The annual cost of disposing of this water is estimated to be 40 billion dollars worldwide in the oil industry. Water production can shorten the useful life of oil and gas wells and can cause serious problems including pipe corrosion and hydrostatic loading. Excessive water production reduces net oil production and may eventually lead to premature abandonment of damaged wells. The presence of water in the wellbore increases the weight of the fluid column which leads to increased lifting requirements. Water production also promotes scale, corrosion and deterioration in field facilities from the wellbore to surface facilities. Another major problem is that the cost of separating, treating and disposing of the produced water places. A heavy burden on oil companies budgets. [1]

Many different causes of excess water production exist some of them could be related to mechanical problems, poor completion procedures, or reservoir conditions; each of these problems requires a different approach to find the optimum solution but not necessarily at the minimum cost. The nature of the problem must first be correctly identified to be able to achieve a high success rate when treating water production problems especially in carbonate reservoirs where nature of the reservoir rock with its fracture and fissure systems are perfect conduits for water to be produced.

The mechanism and volume of water produced in the well bore depends mainly on the petroophysical characteristics, pressure conditions, temperature of the reservoir and geometry of the conditions of the aquifers, the path and location of the wells drilled within the structure of the reservoir, the type of completion and stimulation methods. Depending on the reservoir characteristics, the type of problem diagnosed, and the goals of water production remediation, a variety of mechanical, chemical, and well construction techniques can be applied to stop or reduce water flow into the wellbore. However, the WPM must be properly examined and thoroughly diagnosed in order to design an appropriate and effective treatment method. [3]

Several analytical and empirical techniques have been developed using information such as production data, WOR, and logging measurements to determine the type of water production problem, determine the point of water entry into the well, and select candidate wells to perform treatment methods. [4]

In block (14) Tawila field, produced water represents the largest waste stream associated with oil production. This topic focused on understanding the mechanism of water production, the cause of water production problems, the methodology for determining the sources of water production, environmental impacts, and the cost of the impact of water disposal and treatment.

Through successful implementation of water shutoff it is possible to significantly reduce water cut whilst simultaneously increasing production of hydrocarbons. This is highly advantageous to an operator as it can boost profitability and reduce production problems such as liquid loading and save expenditure by spending less on water disposal (it is estimated that about 210 million barrels of water are produced daily accompanied with 75 million barrels of oil production worldwide).

1.2. Problem statement

One of the major problem in Tawila field is excessive water production in the most of oil wells, it is urgent to search for the main reasons of like that problem and get practical and effective solutions to control excessive water production. Tawila field, is one of the oil fields in block-14 ,Masila basin that faced increasing in water production in most of the filed wells (water cut more than 90%).

This large increase in the production of water associated with the oil production process has negative economic effects (decrease the oil recovery, equipment maintenance and cost time) as well as environmental risk effects (e.g. affecting the fresh water sources, agricultural crops and agricultural soil).

Oil wells that produce high levels of water with the oil produced usually require large costs to isolate water and treat corrosion problems. In addition, oil reservoirs with high water production have a very low oil recovery coefficient. The current work will focus on diagnoses water production, analyze and control techniques in Tawila field.

1.3. Aims and objectives

1.3.1. Aims

The main aim of this graduation project is to achieve diagnostic, analyses, and control the effect of the excessive water production (in the environment and economy) in several wells in Tawila field (Block-14) by using available data using petroleum applications. Based on the results of these analysis we able to conduct a solutions for well problems that producing oil with a higher water cut at safe and cost efficient manner

1.3.2. Objectives

To achieve the aim of the project, the following objectives are defined:

1- Collect and review any available well data that related to this graduation project
2- Analysis of the collected data like geological ,petrophysical,and well production &injection data
3- Screening for a problem and determining of water source(s)
4- Resolving the source of water production problem to prevent and reduce the excessive water from entering in production oil well
5- Developing any plan used for production system of Tawila Field to minimize the excessive water production problems
6- Carry out economic feasibility study of water treatment in the field to reduce cost of production.
7- Make recommendation how to mitigate water production and thereby optimizing well performance and oil recovery.
8- Come out with conclusion and recommendations points that add positive value to the study.

1.4. Yemen Geology

1.4.1. Petroleum geology in Yemen

Yemen is situated in the southwestern part of the Arabian Peninsula and both contains onshore and offshore sedimentary basins, all of which developed during discrete time intervals in the Paleozoic, Mesozoic, and Cenozoic. Two onshore sedimentary basins, Sab'atayn and Say'un-Masilah, where oil was discovered in 1984 and 1991 respectively, are currently the only petroleum-producing basins in Yemen. Many hydrocarbon fields have been explored and produced in Yemen since the 1990s, mostly in the Masila and Sab'atayn basins which are currently the only petroleum-producing basins in Yemen, while the other basins, including the onshore Paleozoic and offshore Cenozoic basins, and remain little-explored. [5]

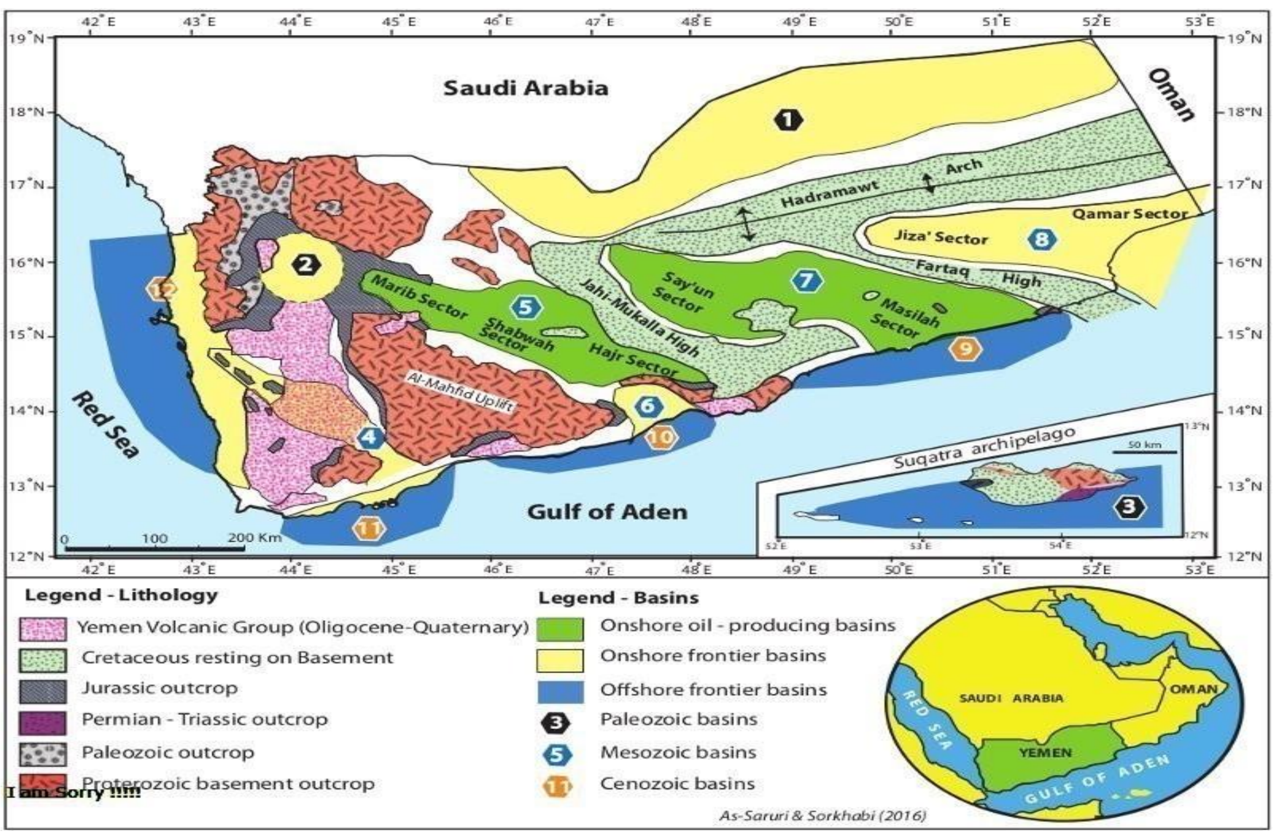


Fig1. 1: Sedmintary basins in yemen

Table below is summarizing the sedimentary basins in Yemen:

Tab 1. 1: sedimentary basins in Yemen

Geological Ear	Basin
Paleozoic Basins	- Rub' Al-Khali Basin. - San'a Basin. - Offshore Suqatra (Island) Basin.
Mesozoic Basins	- Siham–Ad-Dali Basin. - Sab'atayn Basin. - Say'un–Masilah Basin. - Balhaf Basin. - Jiza'qamar Basin.
Cenozoic Basins	- The Aden–Abyan Basin. - Hawrah–Ahwar Basin. - Mukalla–Sayhut Basin. - Tihamah Basin.

1.4.2. Sab'atayn and Say'un-Masilah Basins

These basins share many similarities including source and reservoir rocks of Late Jurassic-Early Cretaceous age. Both basins also contain fractured Precambrian granite reservoirs with 41°API oil, charged by downthrown Upper Jurassic shale. The bituminous shale members of the Kimmerdgian-Tithonian Madbi Formation are the main source rock for the discovered oil fields in the Marib and Shabwah sectors of the Sab'atayn Basin. These rocks are characterised by Type II (dominant) and Type III kerogen; the main source rock in the Say'un-Masilah Basin is also bituminous shale and carbonate within the Madbi Formation. These sediments are up to 450m thick and have TOCs as high as 18%. Immediately overlying the Madbi Formation, One significant difference between these two basins is that Tithonian-age evaporite beds are absent in the Say'un-Masilah Basin while the intra-salt sandstones and sub-salt turbidites offer significant oil accumulations in the Sab'atayn Basin. Another difference is that the Lower Cretaceous sandstone of the Qishn Formation is an important reservoir in Say'un- Masilah, but not in Sab'atayn . The initial reservoir pressures in the latter are gas-driven, while those in the Say'un-Masilah Basin are water driven. [5]

Fig 1.2: show the similarity between them.

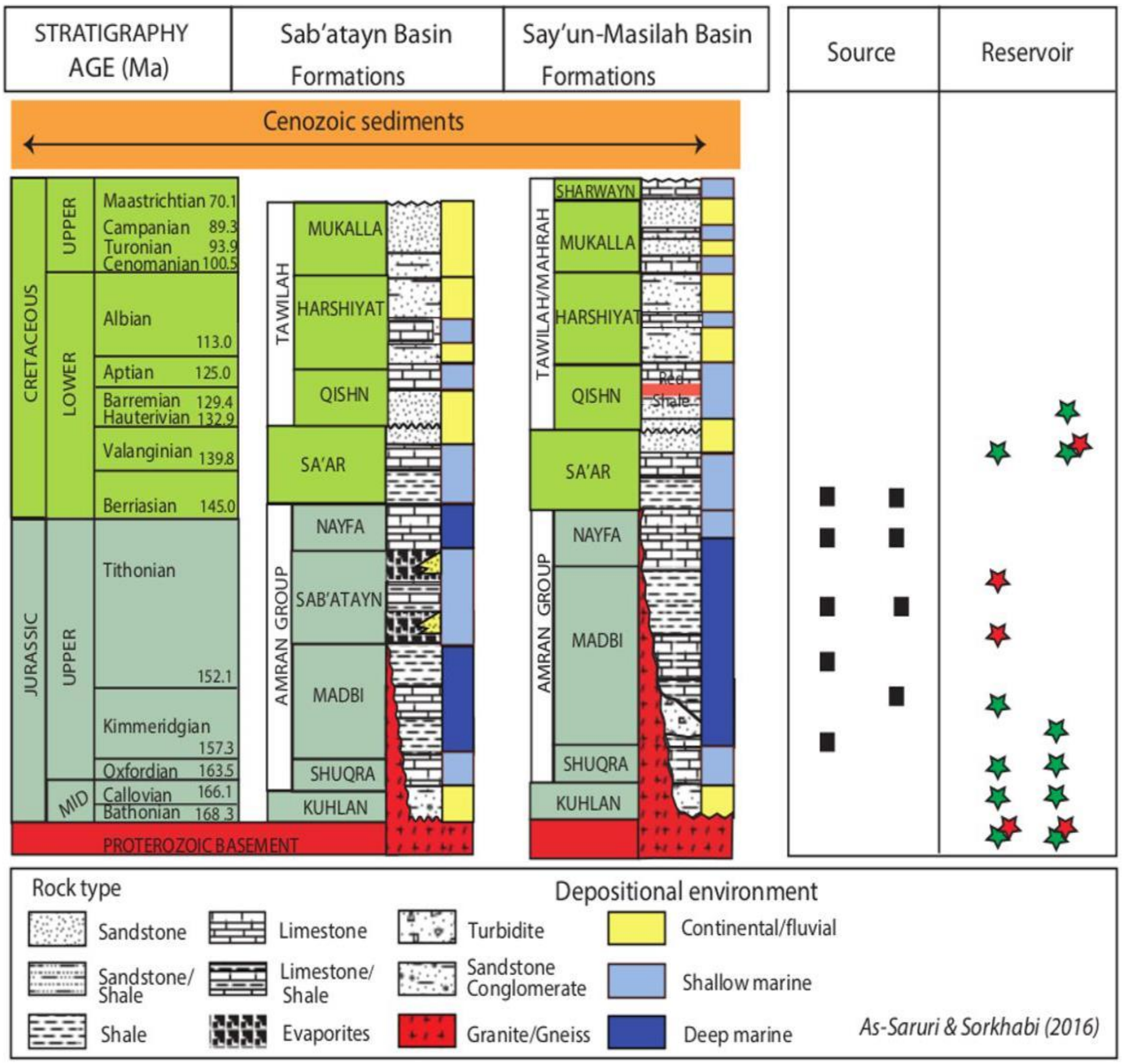


Fig1. 2: structural of sabatayn&masilah basins

1.4.2.1 Say'un-Masilah Basin

The basin is located in eastern part of Yemen. The Upper Jurassic rocks in the Sayun-Masila basin are selected due to its high hydrocarbon potentiality as source rocks. Hydrocarbon produced from the Masila region in the east central republic of Yemen was discovered in 1991, and by November 2002, 656 million bbl of oil had been produced with estimated reserves of at least 1.1 billion bbl of oil. [5]

1.4.2.2. Geological setting of Masila basin:

The Upper Jurassic rocks, in the Masila region, could be differentiated into three rock units from base to top: Shuqra Formation, Madbi Formation and Nayfa Formation . The Shuqra Formation (Oxfordian to Kimmeridgian) is composed of limestone. The Madbi Formation (Late Kimmridjean to Middle Tithonian) is generally, composed of porous lime grainstone to argillaceous lime mudstone and shale. The upper member of Madbi Formation is composed of laminated organic rich shale, mudstone and calcareous sandstone. The Nayfa Formation (Late Tithonian and Berriasian) is composed mainly of silty and dolomitic limestone and lime mudstone with wackestone. The main source rock in the Say'un-Masilah Basin is also bituminous shale and carbonate within the Madbi Formation. The reservoir rocks are found in several stratigraphic levels, but the sandstone of the Qishn clastic member of the Qishn Formation represents the main reservoir in the Masila oilfields. The fractured basement and the vuggy dolomite within the Saar Formation compose the secondary reservoir rocks in the Masila oilfields. The lower Cretaceous limestone and shales of the Qishn Formation were developed in the Masila oilfields and represent good regional seal in all fields of the Masila region. The traps are characterized by structural elements represented by dominant horst and tilted fault blocks, which initial formed during late Jurassic-early Cretaceous and development during Oligocene-Middle Miocene time. [6]

The fig 1.3: show the geological column for masila basin.

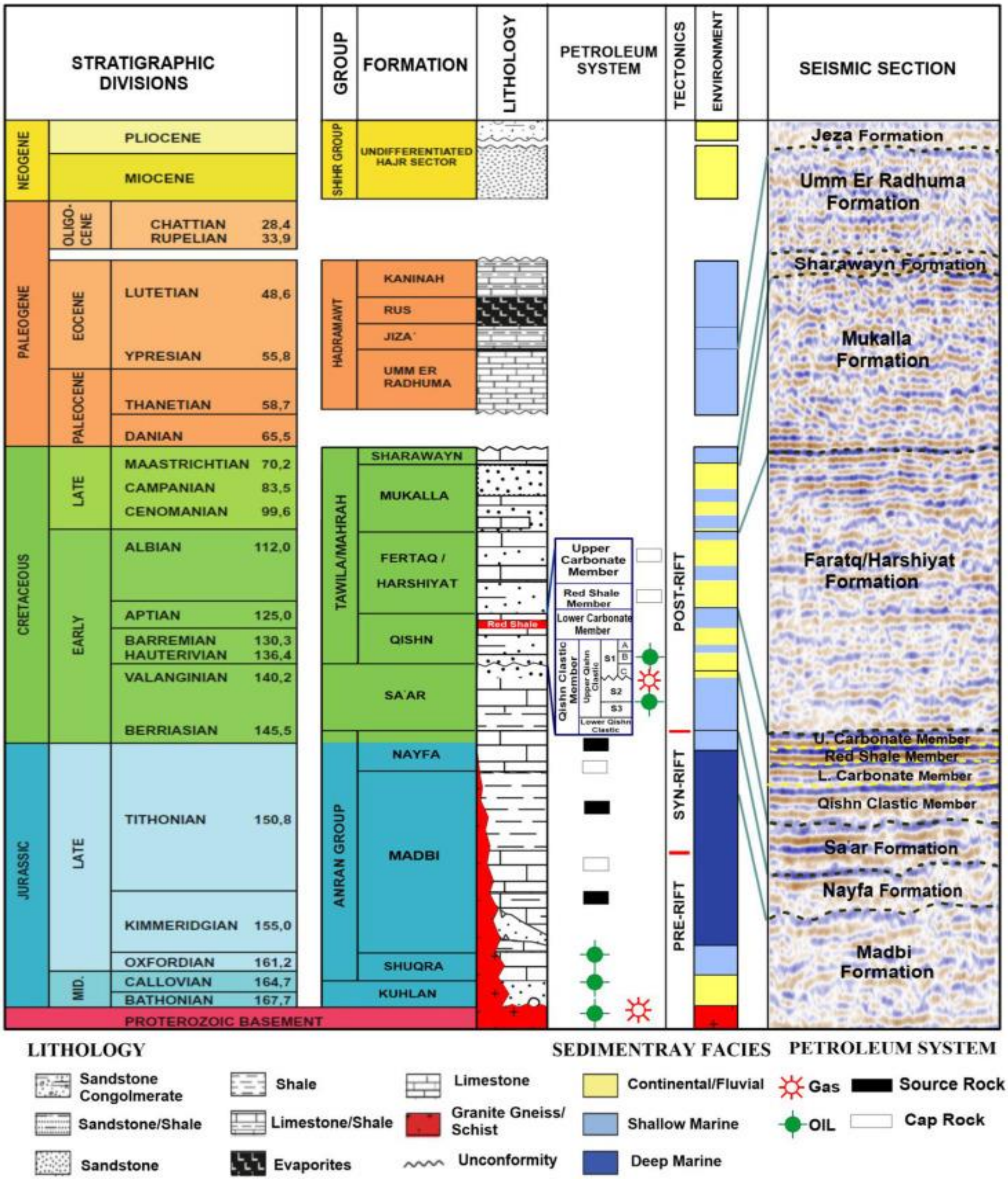


Fig1. 3:Generalized stratigraphic column of the Masila Basin-Yemen

1.5 Area of study:

1.5.1 Block (14)

Block 14 is located in the Hadramawt Region in the east-central Republic of Yemen, and is operated by Canadian Nexen Petroleum Yemen (now PetroMasila) .Oil was first discovered in late 1990, with commerciality declared in late 1991. Oil production began in July 1993. There are now 16 known fields containing 56 pools. At year-end 2000, total proven ultimate recoverable oil reserves are 891 million bbl. Proven, probable, and possible reserve estimates are approaching 1.2 billion bbl of recoverable oil. Block-14, covering an area of about 1250 km^2. Oil is found in at least seven reservoirs consisting of Lower Cretaceous and Middle to Upper Jurassic elastics and carbonates as well as fractured granitic basement. which are the informally named upper Qishn sandstones of the formal Qishn Clastics Member, Qishn Formation, Tawilah Group. The biggest production challenge is water handling. Much water is produced along with the oil because of a combination of medium-gravity (15°-33° API) moderate viscosity oil, high reservoir permeability, and a strong regional aquifer. The upper Qishn oil is undersaturated in gas (average gas-oil ratio is 3-7 scf/bbl), requiring electric submersible pumps to provide sufficient artificial lift for the large volumes of produced fluid. At the end of December 2000, the annualized daily production rate collectively for all fields was 230,000 BOPD, with 725,000 BWPD and 6.8 mmcf solution gas/day. Cumulative oil production is more than 500 million bbl. Initial average well oil-production rates vary by producing zone but range from 1500 to 20,000 BOPD, water produced in the fields were transported via pipeline to the central processing facility (CPF), where most fluid separation occurred. More recently Produced water is reinjected into the reservoirs. The clean oil is transported to the southern coast via a 140-km (85-mi)-long, 61-cm (24-in.) pipeline over a 106-km (66-mi) distance. Export oil is then loaded onto tankers via a single buoy mooring system located 3.2 km (2 mi) offshore east of the coastal village of Al Mukulla. Fig 1.4: show map for site of fields in Masila basin [6].

Block 14 include 16 fields that fields are:

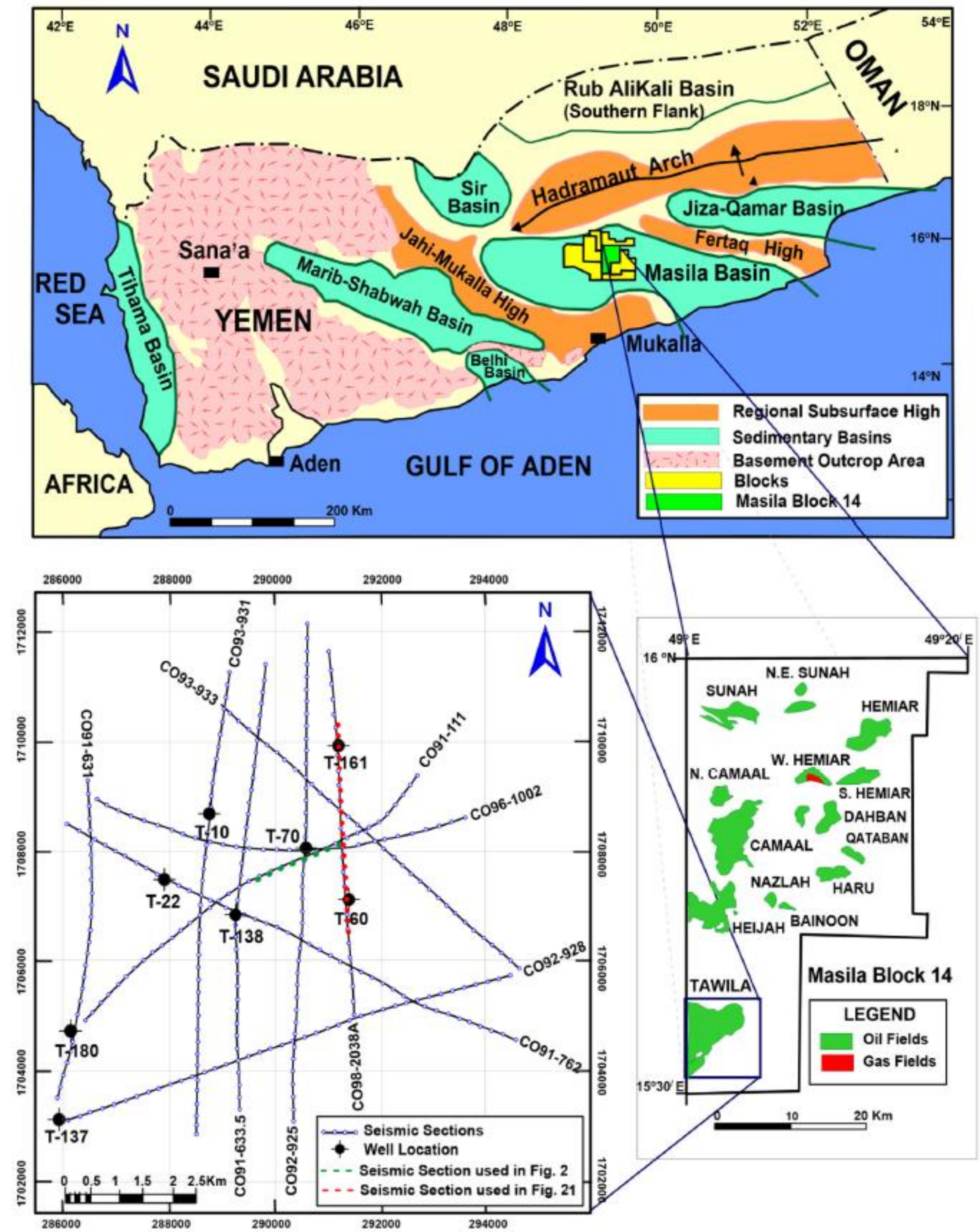


Fig1. 4: Map showing location of the Tawila oil field at block-14, Maslia basin

1.5.2 Tawila field

Tawila field is one of the productive and the largest and most important oilfields in the onshore of Block-14 in the Masila which produces hydrocarbons mainly from clastic deposits. The study area is within the Tawila oilfield, south of the block, and is characterized by an isolated fault-block structure. The information about the reservoir properties at the Tawila oil field and the major structural elements that control the whole hydrocarbon system are few. Although some studies, dealing with petroleum accumulation, generation and maturation as well as reservoir properties, are conducted for the same reservoir in nearby fields still the petroleum system in the area needs more investigations. The entrapment style and the lateral distribution of hydrocarbon in relation to the prevailing structures are not mapped till now in that specific area. Whether the reservoir consists of one compartment or of multi-zonal nature (like in nearby fields) is not clearly investigated. The post-rifting sediments are represented by the Tawilah Group that lies unconformably over the Saar syn-rift clastics. The Qishn Formation constitutes the lowest sediments of the Tawilah Group and informally is divided into the following four members, from top to bottom: the Upper Carbonate, Red Shale, Lower Carbonate, and Clastic. The Qishn Clastics are informally subdivided into two upper and lower members. The upper Clastic Member is deposited in an inner neritic to shallow marine platform and exhibits good hydrocarbon potential. The impermeable Qishn carbonates and shales act as cap rocks that offer sealing for the migrated oil from the deep-seated, thermally maturate source rocks of the Madbi Formation.[6]

Show fig 1.5: for post rifting of Tawila field .

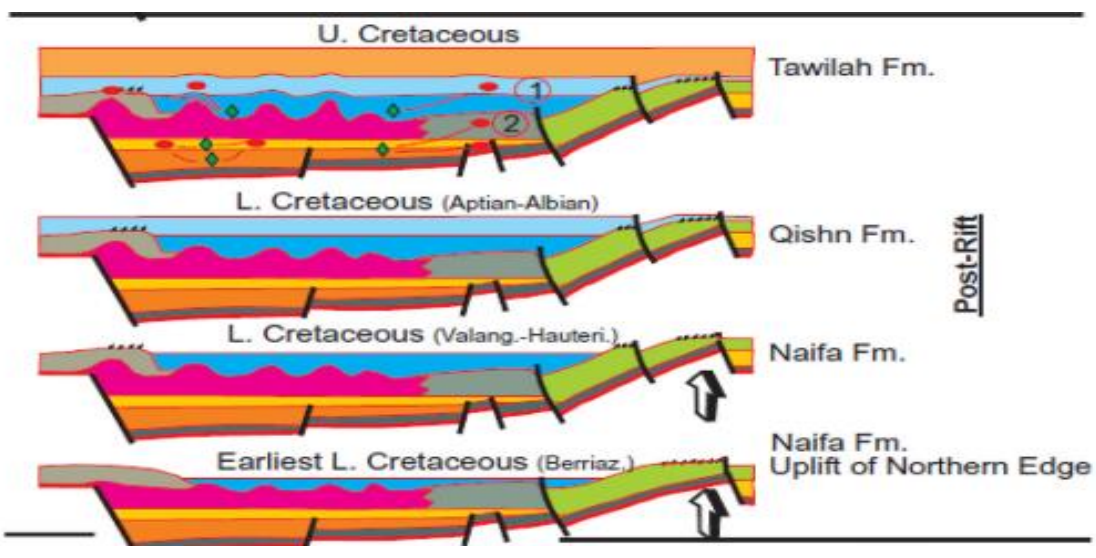


Fig1. 5: The post-rifting sediments of Tawila group

1.5.2.1. Reservoir properties

The reservoir properties of the Qishn sandstone reservoir are represented in the Qishn sandstone is divided petrophysically throughout the investigated oil fields in Masila Basin into three main units: S1, S2, and S3 .Detailed analysis showed that zone S1 can be subdivided into two subunits of S1A, and S1B. The petrophysical parameters of the three main units are represented in Table 1.2 Zones S2 and S3 have retained good hydrocarbon content.[6].

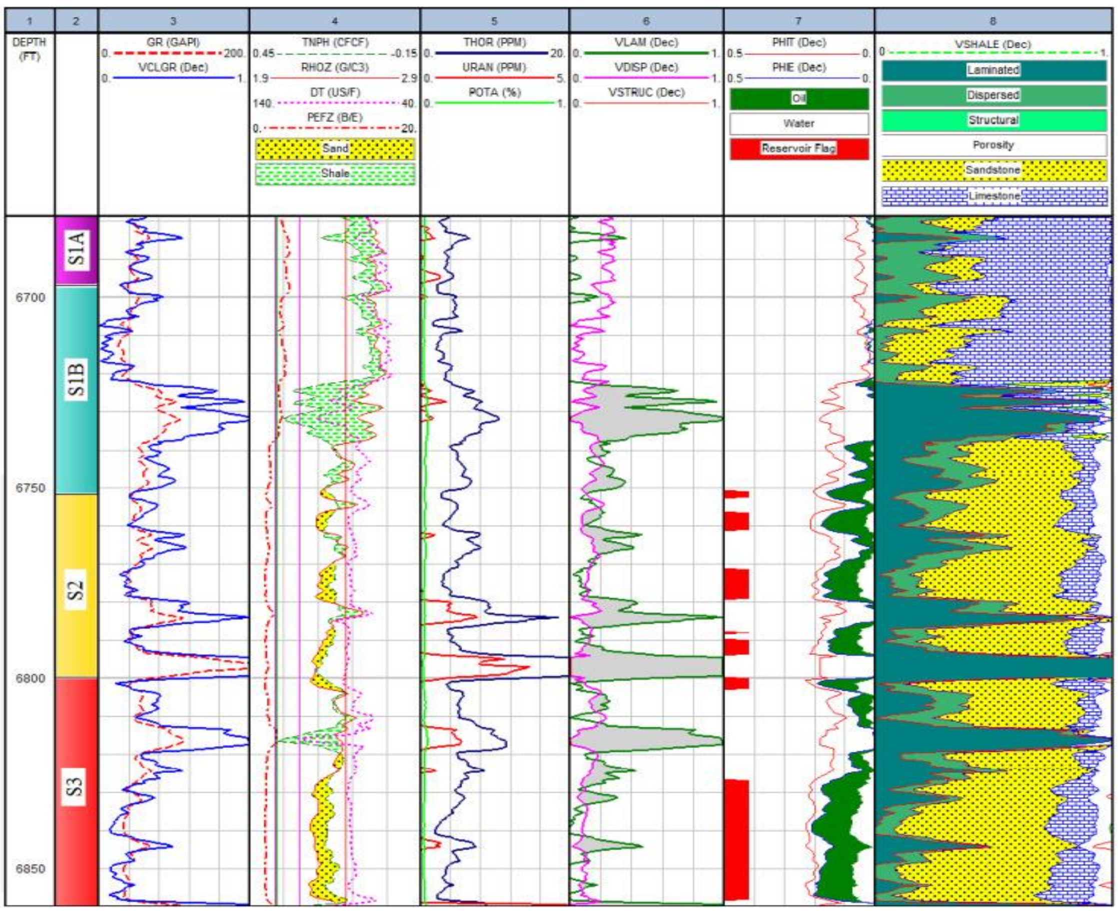
Tab 1. 2: Different deduced petrophysical parameters of the reservoir (S1 A&B, S2, and S3)

ZONE	WELL NAME	TOP	BOTTOM	CROSS THICKNESS	SHALE VOLUME	TOTAL POROSITY	EFFECTIVE POROSITY	WATER SATURATION	HYDROCARPON SATURATION
S1A	T-10	5570	5588	18	0.09	0.23	0.24	0.56	0.44
	T-22	5758	5765	7	0.21	0.13	0.09	0.93	0.07
	T-60	6679	6697	18	0.15	0.07	0.03	1	0
	T-70	5852	5865	13	0.26	0.2	0.12	0.72	0.28
	T-137	6180	6189	9	0.21	0.2	0.2	0.74	0.26
	T-138	5936	5943	7	0.32	0.14	0.08	1	0
	T-161	5686	5693	7	0.33	0.24	0.16	0.79	0.21
AVERAGE				11.29	0.22	0.17	0.13	0.82	0.18
S1B	T-10	5588	5616	28	0.11	0.12	0.11	0.96	0.04
	T-22	5765	5806	41	0.33	0.16	0.09	0.97	0.02
	T-60	6697	6751	54	0.25	0.11	0.04	0.97	0.03
	T-70	5865	5901	36	0.25	0.13	0.06	0.91	0.09
	T-137	6189	6218	29	0.13	0.06	0.04	0.97	0.03
	T-138	5943	5974	31	0.22	0.11	0.06	0.85	0.15
	T-161	5693	5742	49	0.36	0.14	0.07	0.94	0.06
AVERAGE				38.29	0.24	0.12	0.07	0.94	0.06
S2	T-10	5616	5700	84	0.5	0.24	0.12	0.93	0.07
	T-22	5906	5875	69	0.24	0.12	0.19	0.43	0.57
	T-60	6751	6800	49	0.31	0.18	0.13	0.82	0.18
	T-70	5901	5960	59	0.41	0.2	0.08	0.88	0.12
	T-137	6218	6298	80	0.24	0.2	0.17	0.59	0.41
	T-138	5974	6038	64	0.43	0.2	0.11	0.92	0.08
	T-161	5742	5829	78	0.44	0.2	0.16	0.58	0.42
AVERAGE				69.00	0.37	0.19	0.14	0.74	0.26
S3	T-10	5700	5748	48	0.13	0.18	0.12	0.38	0.61
	T-22	5875	5940	65	0.25	0.21	0.17	0.66	0.34
	T-60	6800	6860	60	0.3	0.19	0.13	0.83	0.16
	T-70	5960	6050	90	0.28	0.22	0.16	0.74	0.26
	T-137	6298	6360	63	0.18	0.22	0.2	0.62	0.38
	T-138	6038	6086	48	0.22	0.21	0.17	0.9	0.1
	T-161	5829	5878	50	0.16	0.22	0.21	0.44	0.56
AVERAGE				60.57	0.22	0.21	0.17	0.65	0.34

1.5.2.2 Lithology and fluid content

Subunit S1A and the upper part of S1B are dominantly carbonates with minor sandstone and shale, whereas the lower part of the S1B is composed of sandstone, a small amount of carbonates, and a major content of shale. Units S2 and S3 are composed of sandstone, very little carbonates and frequent interbeds of shale. Clusters of these two units are located mostly close to the quartz point .The nonhydrocarbon-bearing nature of subunits S1A and S1B is clear in the Pickett plot.(Where is the pickett plot) Most of the clusters of these subunits are located beyond the 100% water saturation line (SW) on the decreasing order of the porosity axis (**Fig 1.6 :)** On the contrary, a reasonable number of clusters of units S2 and S3 are located between water saturation lines of 40% and 80%, giving rise to a considerable hydrocarbon range of 20%–60%. However, the average hydrocarbon content of all clusters of units S2 and S3 is about 30% (Fig 1.6 :). Shown the details.[6]

Fig1. 6: Vertical petro-physical analog of the Upper Qishn reservoir at well T-60.



1.5.2.3. Shale type/distribution and petrophysical properties

Since the Qishn reservoir contains a considerable amount of shale and frequent shale interbeds, it was very important to investigate the type and distribution of its shale. There are three main types of shale: dispersed shale (DIS), laminated shale (LAM), and structural shale (STS). DIS is composed of clay minerals that form after deposition owing to chemical reactions between minerals and chemicals in the formation water these minerals occupy the pore spaces to significantly reduce the effective porosity and fluid content. A DIS volume exceeding 40% will severely disturb the reservoir quality. LAM usually occurs as thin lamina of allogeneic clay that has no impact on the reservoir properties; rather, only the vertical permeability and fluid flow of the reservoir are affected. STS occurs in the host sands as clasts or particles deposited during early depositional stages .This type sometimes has a considerable effect on the reservoir properties. [6]

1.5.2.4. Pay cut-offs

Cut-off parameters (reservoir and pay) of > 15%, < 50%, and < 20% were taken in front of units S2 and S3 for the effective porosity, water saturation and shale volume, respectively (Table 1.2). These parameters were selected on the basis of the published works on the Qishn reservoir in similar fields in the Masila and Sab'atayn basins [6]

Tab 1. 3: Standard pay cut-off parameters for the Qishn sand reservoir units S2 and S3

Porosity (PHI)	Water Saturation (Sw)	Clay volume (Vcl)
>15%	**<50%**	**<20%**

CHAPTER TOW

2. Literature Review and Theoretical Background

2.1 Previous Study

A review of the literature is presented in this chapter.the presentation will include one case study and theoretical background.

2.1.1. General information about Aswad Oilfield, Libya

The Aswad field located in Sirte Basin, Southeast Sirte Basin, South of Zella Field, owned by Zueitina oil company and NC-74B concession. Drilling started by first drilling well in October 1978 was B01, and then started water injection in June 1979. There are 19 wells authorized for drilling, and 4 Wells have been abandoned. Fig 2.1 ,and Fig 2.2.

Aswad oilfield started production in October 1978 by drilling first well B-01 and then injection started in June 1979, The Total Drilled Wells are 19 Wells, 4 Wells are dry. Last rate of water cut is 88%, GOR 1500 SCF/BBL, cumulative oil production 29 MMbbl, and cumulative gas production 32.2 BSCF.

Aswad field has been produced with high water rate, and its status as water flooded reservoir, so diagnosing reasons for producing high water. The injection rate reached to 10,000 STB/day in early period of reservoir life then stabilized in 8,500 STB/day in last period, also the water production stable in 7,500 STB/day.

Also, in production performance the cumulative of oil, water and gas, cumulative oil production was 30 MMBBL, cumulative water production was 55 MMBBL and cumulative gas production was 32 MMSCF. Channeling or coning is a serious problem that leads to excessive water production worldwide; other problems have limited propagation .[7]

2.1.2. The Method of the case study

The method of this work began with an analysis of performing Aswad oilfield by analyzing the history of production, injection and pressure history to evaluate and monitor the reservoir performance by using the Excel sheet to assess the data to optimize the research. One of the main objectives of this study was to diagnose the field problem by using water diagnostic plot (Chan plots) and by plotting WOR and WOR' to contrast them with Chan plots. In addition, the effect of water production on productivity in the field was determined.

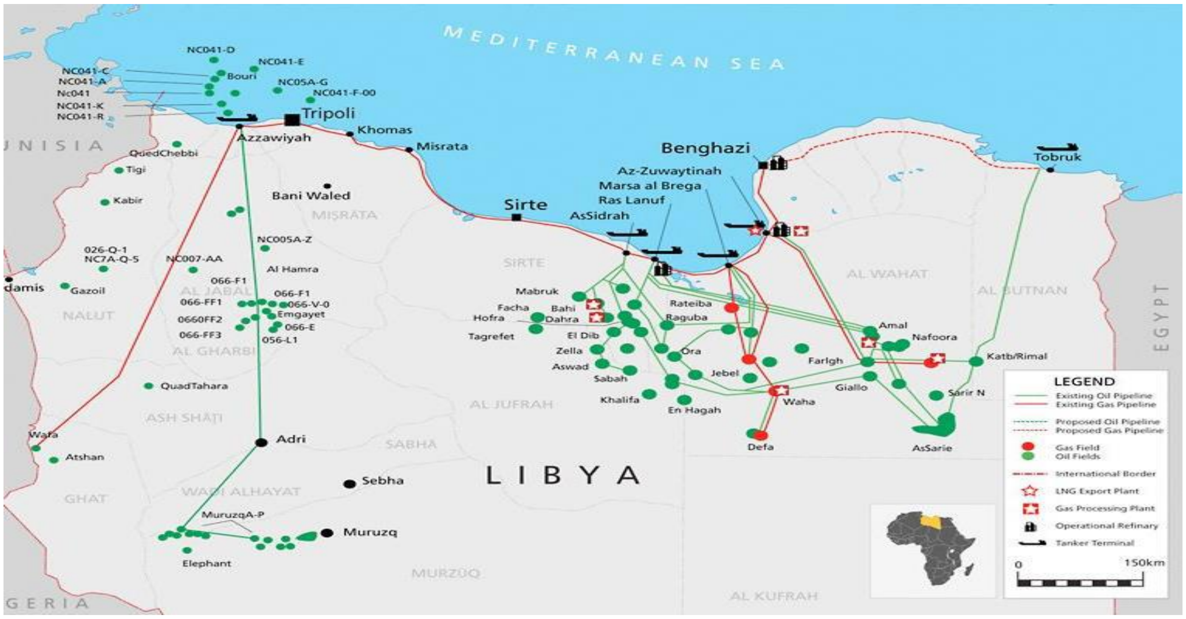


Fig2. 1:Map of Libyan oil fields.

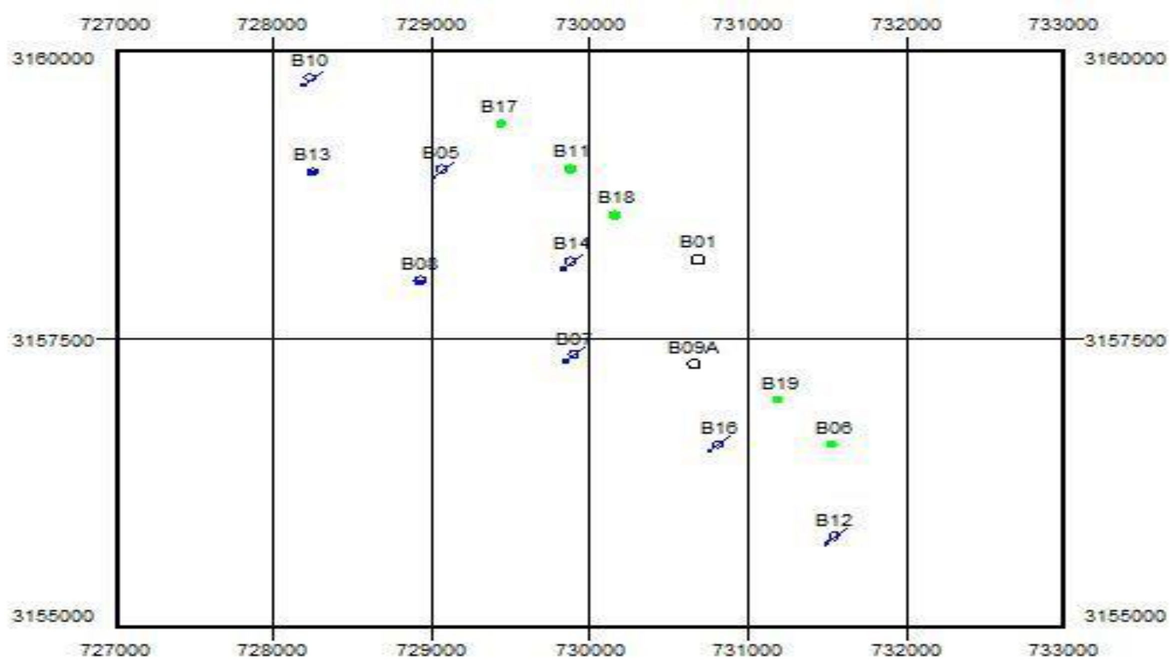


Fig2. 2:Aswad field wells Location

2.1.3 Water Problems Diagnosis in aswad oilfield

Aswad field has been produced with high water rate, and its status as water flooded reservoir, so diagnosing reasons for producing high water, is by using the most common methods such as Chan plot well by well and identifying layering method.

The first method is to investigate the water problem by plotting WOR and derivative of WOR' then compare the plot with typical Chan plots to identify the reason for water production, which was applied as a field and on three selected wells (B06 – B09A- B-11). Presents the diagnostic plot for Aswad field and as compared to the Chan plots and after this process the reason is Multiple Channels (Multilayer channeling).

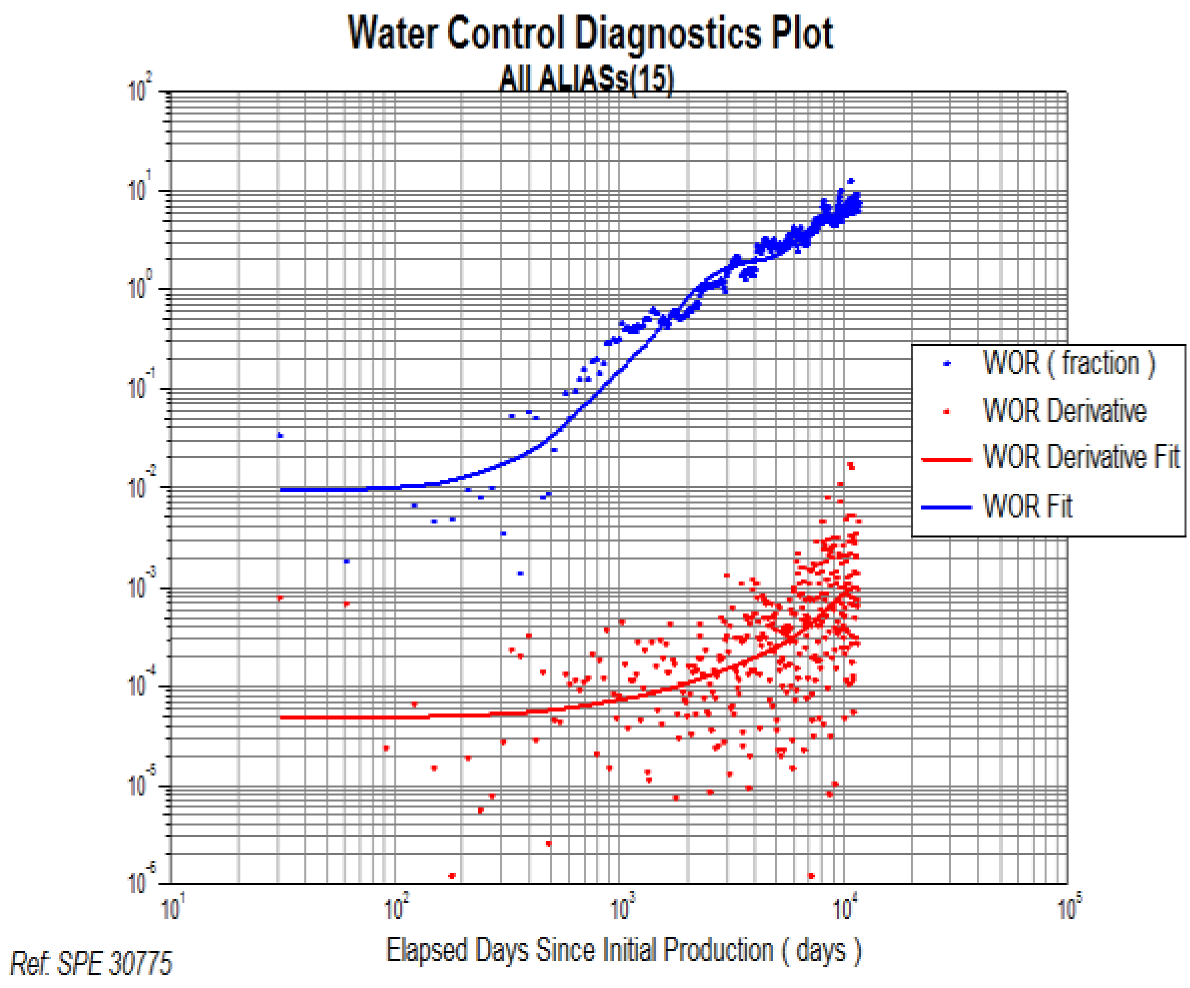


Fig2. 3: The Field Diagnostics Plot.

Figure (2.4), Presents the diagnostic plot for well B-11 and compared to Chan plots and after this process the reason is Multiple Channels (Multilayer channeling).

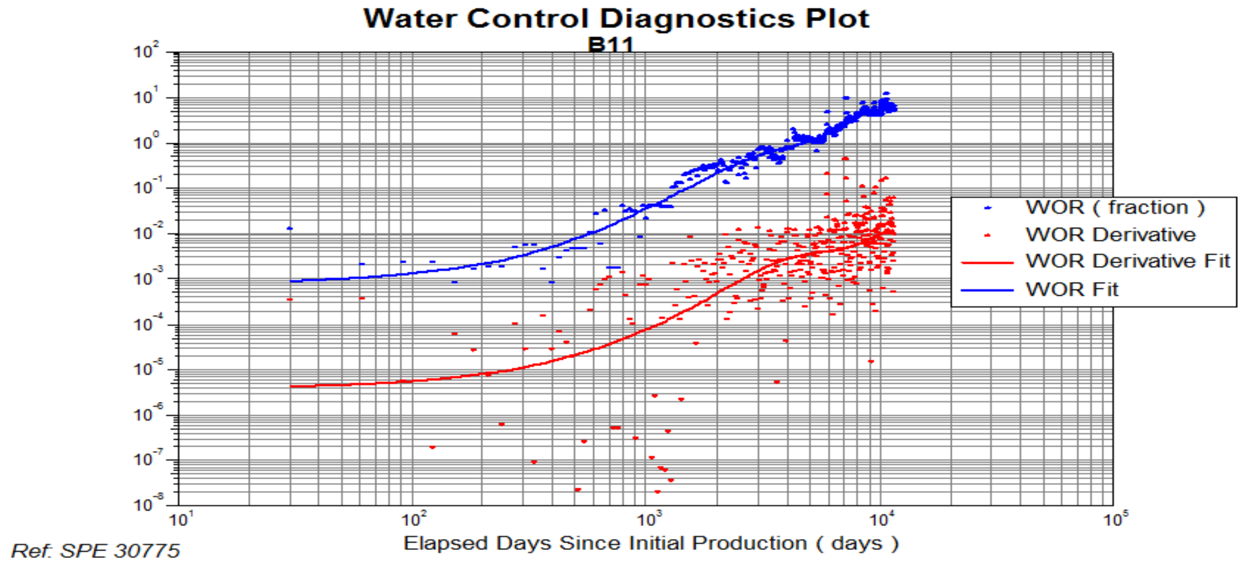


Fig2. 4: Well B-11 Diagnostics Plot.

Figure (2.5), Presents the diagnostic plot for well B-6 and compared to Chan plots and the cause is Multiple Channels (Multilayer Channeling) the same as B-11.

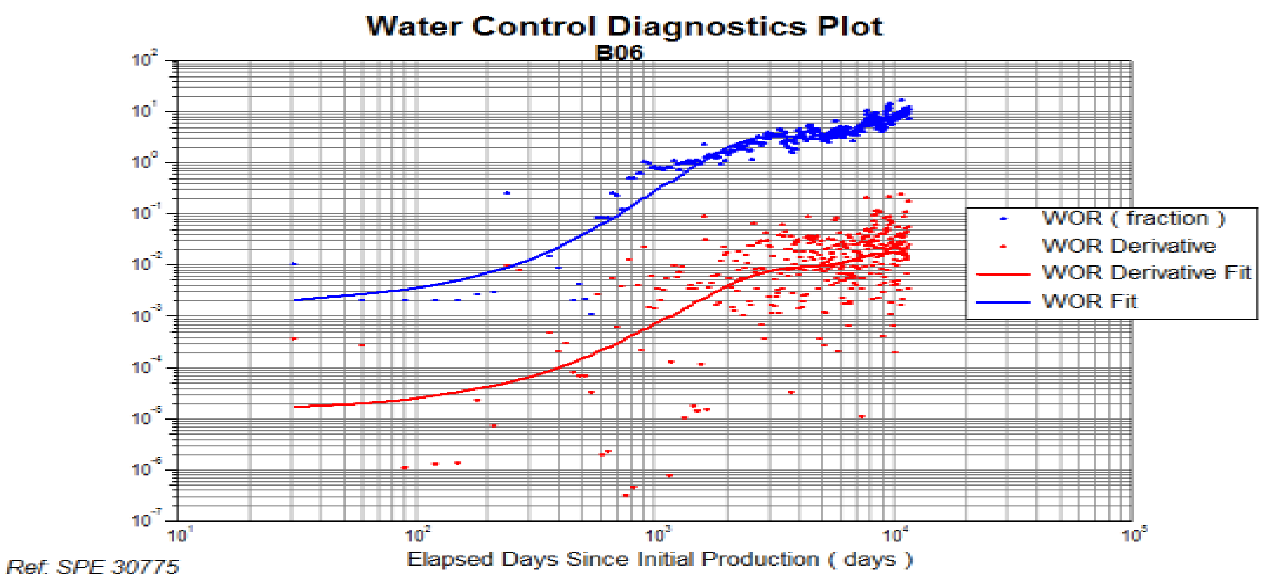


Fig2. 5: Presents the diagnostic plot for well B-6 and compared to Chan plots.

Figure (2.6), presents the diagnostic plot for well B-9A and compared to Chan plots and the reason for this method is Multiple Channels (Multilayer channeling) close to other wells.

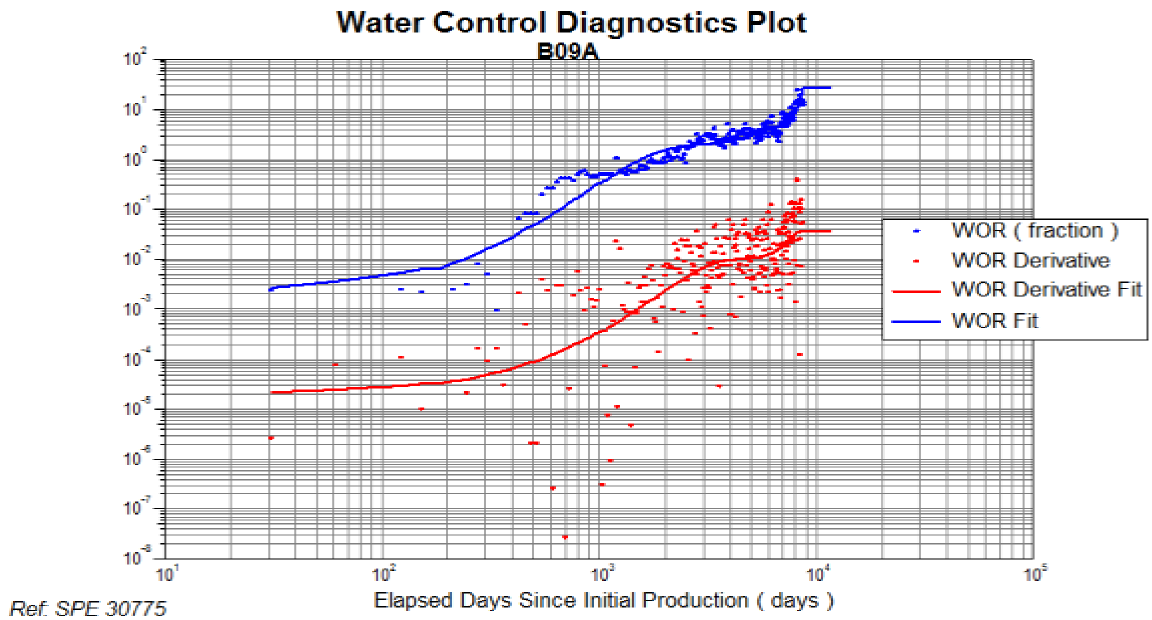


Fig2. 6: Well B-9A Diagnostics Plot.

For the field wells, a well card to summarize the wells status according to Chan's plot results, the dominated water production mechanism is the high permeability layer channeling and that is justified because of the wells strata, edge water drive and the permeability variation.[7]

2.1.4 Conclusion

Aswad field is water flooded due to high water cut that produced from reservoir that supported by water injection from early period of the field. Production performance of the field and well by well performance shows that the Aswad field produced as under-saturated reservoir due to water injection support. Aswad field has high total fluid potential but due to highly water cut.

The water problem diagnostic was applied and performed as multilayer channeling.

Diagnose the study of water production behavior is to optimize the reservoir productivity after controlling the excessive water production.[7]

2.2 Causes of excessive water production

Excessive Water production is one of the major technical, environmental, and economical problems associated with oil and gas production. Water production can limit the productive life of the oil and gas wells and can cause several problems including corrosion of tubular, fines migration, and hydrostatic loading. Water production causes can be divided into several categories including mechanical, completion related, and reservoir related problems.

2.2.1 Mechanical problems

Poor mechanical integrity of the casing such as holes from corrosion, wear and splits due to flaws, excessive pressure, or formation deformation contribute to casing leaks.

Often casing leaks occur where there is no cement behind the casing and water flows to the wellbore through the casing fissure arrives from either above or below the production zone. Casing leak results in unwanted entry of water and unexpected rise in water production. In addition, the water entry in the wellbore can cause damage to the producing formation due to fluid invasion.

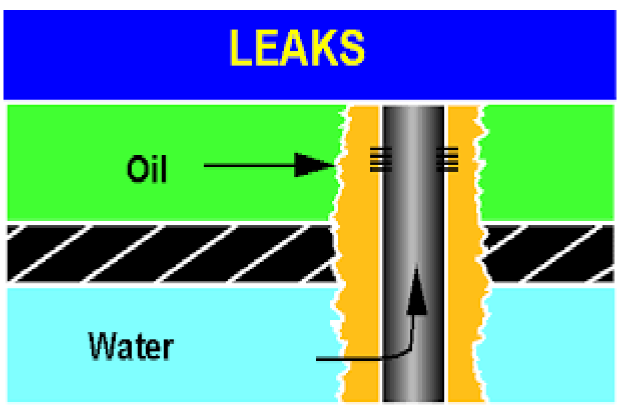


Fig2. 7: Casing leak,

Corrosion or wear holes is the main reason for casing leaks ,so the potential for corrosion must be recognized and diagnosed early in the producing life of a field. Otherwise, expensive workovers and repairs may be necessary. Corrosion within the wellbore can occur in various forms and is often accompanied by the formation of scale. [B2] Corrosion can be divided into three categories:

- Oxidation
- Electrical corrosion
- Chemical corrosion

2.2.2 Completion Related Problems

The common completion related problems are channel behind casing, completion into or close to water zone, and fracturing out of zone.

2.2.2.1. Channels behind Casing

Channels behind casing can result from poor cement-casing or cement-formation bonds. Channels behind casing can develop throughout the life of a well, but are most likely to occur immediately after the well is completed or stimulated. Channel flow behind casing failed primary cementing can contact water bearing zones to the pay zone these channel allow the water to flow behind casing in the annulus. Water produced from channels behind the casing can be identified by temperature log and using the WFL Water Flow Log (A record of the velocity and direction of water flowing in and around a borehole based on oxygen activation). Cement is an effective method for flow behind the pipe without flow restrictions.[8]

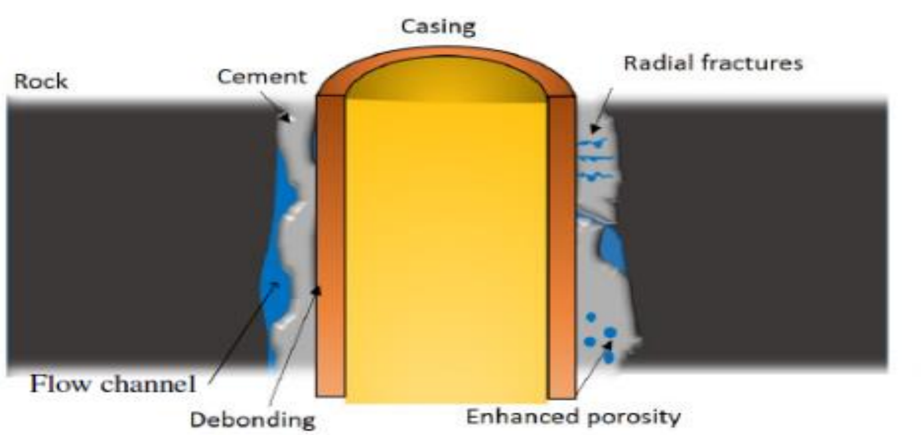


Fig2. 8: Channel flow

2.2.2.2 Completion into or Close to Water Zone

Completion into the zones where water saturation is higher than the irreducible water saturation allows the water to be produced immediately. Often, impermeable barriers (e.g., shale or anhydrite) separate hydrocarbon-bearing strata from water saturated zone that could be the source of the excess water production. However, the barriers can breakdown near the wellbore and allow fluid to migrate through the wellbore.

Even if perforations are above the original water-oil or water-gas contact, proximity allows production of the water to occur more easily and quickly through coning or cresting.[9]

2.2.2.3 Fracturing Out of Zone

When wells are hydraulic fractured, the fracture often unintentionally breaks into water zones. In such cases, coning through hydraulic fracture can result in substantial increase in water production. In addition, stimulation treatments can cause barriers breakdown near the wellbore Even if natural barriers, such as dense shale layers, separate the different fluid zones and a good cement job exists, shale's can heave and fracture near the well bore. As a result of Production, the pressure differential across this shale's allows fluid to migrate through the well bore. More often, this type of failure is associated with stimulation attempts. Fractures break through the shale layer, or acids dissolve channels through it.

2.2.3 Reservoir Related Problems

The main reservoir related problems are channeling, coning, and depletion.

2.2.3.1 Channeling

As was discussed earlier water channeling is caused by reservoir heterogeneities that lead to presence of high permeability streaks. Fractures or fracture-like features are the most common cause of the channeling. Water production could emanate via natural fractures from underlying aquifers. Induced or natural fracture fractures can cause channeling between wells. In unfractured reservoirs often stratification and associated permeability variations among various layers can result in channeling between an injector and a producer or from an edge water aquifer to the producers. Deviated and horizontal wells are prone to intersect faults or fractures. If these faults or fractures connect to an aquifer, water production can jeopardize the well.[9]

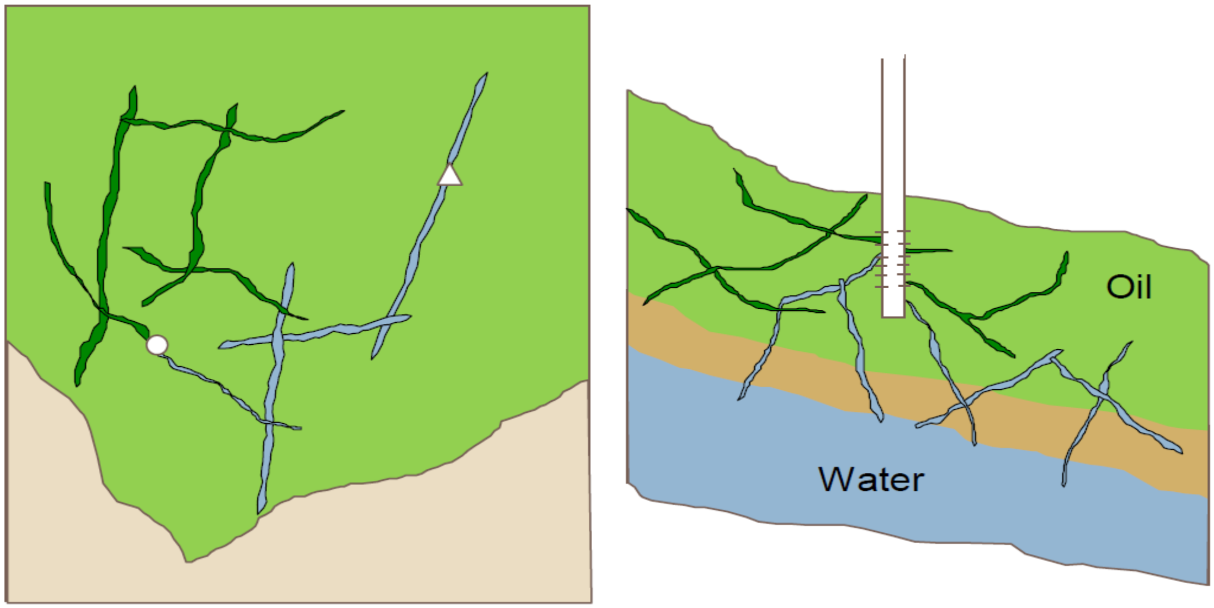


Fig2. 9: channeling

2.2.3.2 Coning

Water coning is caused by vertical pressure gradient near the well. The well is produced so rapidly that viscous forces overcome gravity forces and draw the water from a lower connected zone toward the wellbore. Eventually, the water can break through into the perforated or open-hole section, replacing all or part of the hydrocarbon production. Once breakthrough occurs, the problem tends to get worse, as higher cuts of the water are produced. Although reduced production rates can curtail the problem, they cannot cure it. Cusping, in an inclined zone up to a vertical well, and water cresting in horizontal wells are similar phenomena to water coning.

The maximum rate at which oil can be produced without producing water through a cone, called the critical coning rate, is often too low to be economic.

One approach, which is sometimes in appropriately proposed, is to place a layer of gel above the equilibrium OWC. However, this will rarely stop coning and requires a large volume of gel to significantly reduce the WOR. For example, to double the critical coning rate, an effective gel Radius of at least 50feet [15m] typically is required. However, economically placing gel this deep into the formation is difficult. Smaller volume treatments usually Result in rapid water rebreak through unless the Gel fortuitously connects with shale streaks. A good alternative to gel placement is to drill one or more lateral drain holes near the top of the Formation to take advantage of the greater distance from the OWC and decreased drawdown, both of which reduce the coning effect. In horizontal wells, this problem may be referred to as dunning or cusping. In such wells, it may be possible to at least retard cusping with near-wellbore shutoff that extends sufficiently up-and downhole as in the case of a rising OWC. [14]

The specific problems of water a coning is listed below:

1. Costly added water handling.

2. Reduced efficiency of the depletion mechanism.

3. The water is often corrosive and its disposal costly.

4. The well may be abandoned early.

5. Loss of the total field overall recovery.

Since coning can have important influence on operations, recovery, and economics, it is an important to provide the theoretical analysis of coning and outline many of the practical solutions for calculating water and coning behavior.[10]

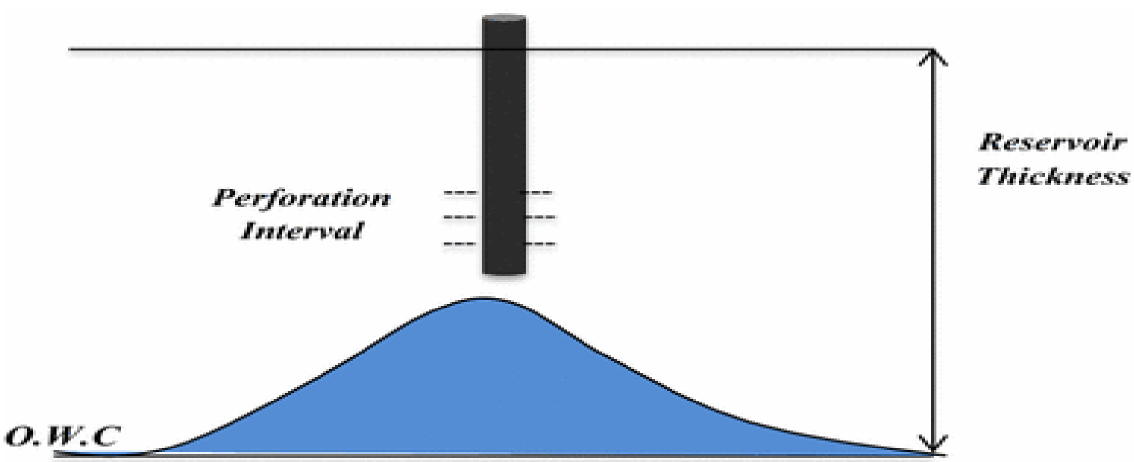


Fig2. 10: coning

2.2.3.3 Reservoir Depletion

Water production is an inevitable consequence of oil or gas production. There is very little that can be done to reduce water production in a depleted reservoir. Generally at the later stages of production the focus of water control will shift from preventing water production to reducing cost of produced water.

2.3 Diagnostic of excessive water production

The common practice for many operators is using production logging tools (PLT) to define water entries and then select the shut-off technique and design the job. It is very important to notice that the high technology PLT available in the market still have some limitations in horizontal wells due to complex fluid entry mechanisms and flow dynamics of multi-phase flow in the wellbore. To aid understanding excessive water mechanism, several methods and techniques have been developed. Majority of the techniques are specialized plots.

The main methods for diagnostic water production list below:

1. Diagnose with production data
    - Recovery plots
    - Production history plots
2. Production logging:
3. Chan's method:
4. Nodal analysis:
5. Well test:

2.3.1 Diagnose with production data

Production data analyses are the most commonly used techniques for investigating the overall performance of the reservoir as well as individual wells. The key elements of the production data are the information on the rate of the produced oil and water, collected at regular time intervals (usually on a daily basis). Usually, along with the rates of the produced oil and water, the water oil ratio (WOR) plots also used for interpretation production analysis.

Production data analyses by means of analytical and empirical techniques such as decline curve plots, and water-oil ratio (WOR) versus cumulative oil production or time is a widely explored subject in the literature. These plots described as follows:

2.3.1.1 Recovery plots

The log-log plot of WOR against the cumulative oil production called the recovery plot Figure 2.11: Cumulative oil production at any particular time during the field life cycle is the total amount of the oil produced from a reservoir at that time. The recovery plot can be extrapolated to predict the future performance and estimate the ultimate oil recovery. The point where this plot reaches the economic WOR plot shows the amount of oil production without any remedial action for water production. The economic WOR limit is the rate of WOR where the cost of handling the produced water is equal to the value of the oil produced. If the well is producing acceptable amount of water, then the extrapolated production is equal to the expected reserves. Otherwise**,** if the predicted oil production at WOR economic limit is lower than the expected oil reserve for that well, it is a sign of excess water production, which requires water control treatments are required.

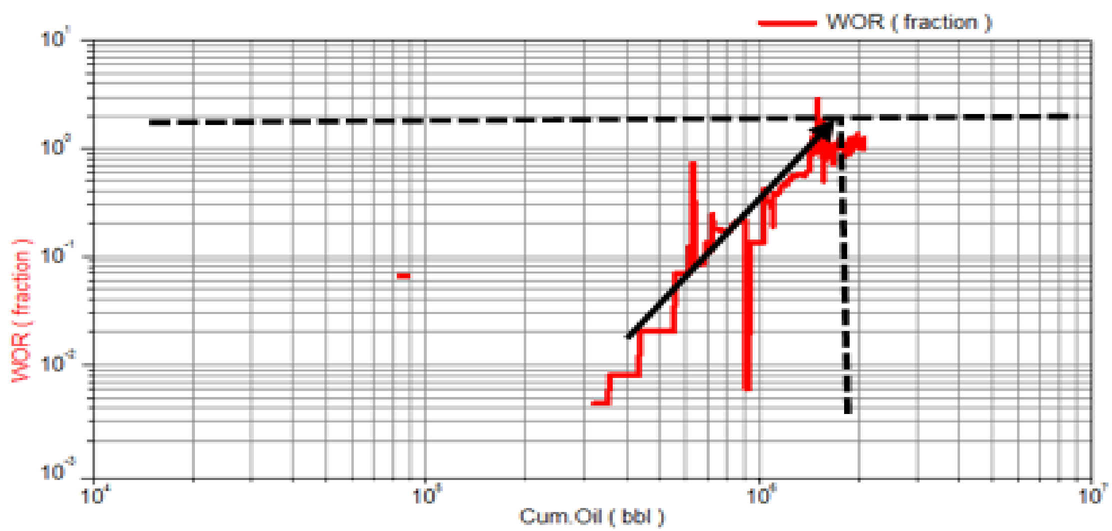


Fig2. 11: Recovery plot

2.3.1.2 Production history plots

The production history plot is a plot of oil and water rates against production time, Figure 2.12: This plot helps in visualizing rate changes during the field life cycle and assessing any "uncorrelated behaviors" such as; changes in the rate without corresponding changes in pressure. Wells with water production problem usually show a simultaneous increase in water production with a decrease in oil production

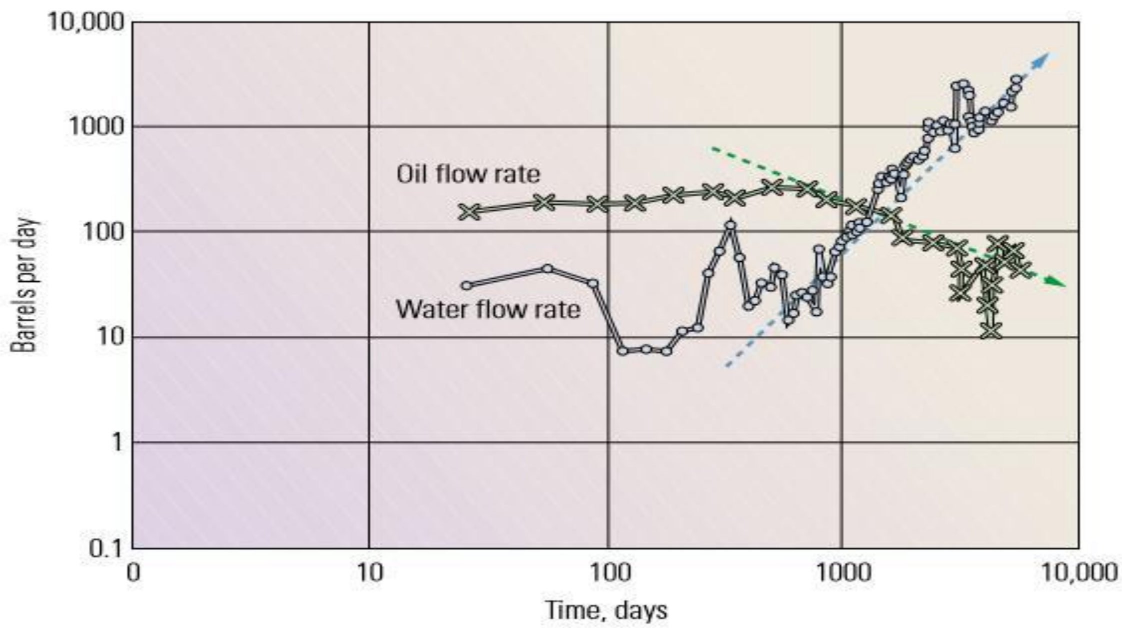


Fig2. 12: Production History

2.3.2Production logging:

The main purpose of Production Log (PL) analysis is to determine how much of which fluid is coming from where. In order to achieve this fluid velocity along with the hold-up of each phase must be known. From this information, the flow rate of each phase in the wellbore can be established and the flow profile determined. After acquisition of production logging data, an interpretation of the measurements by an analyst will reveal the composition and distribution of the wellbore fluids, Figure 2.13. One, two and three phase analyses are possible depending on the number and type of sensors run accurate production logs, can show water entry into the wellbore. This tool can determine flow and holdup for each fluid phase in vertical, deviated and horizontal wellbores. The addition of new optical and electrical sensors incorporating local probe measurements and phase-velocity measurements have resulted in major improvements in the diagnosis in both complex and simple wells with three-phase flow. Such advances in reliable and accurate production logging, particularly in deviated wells with high water cuts, represent a major step forward in identifying and understanding water-problem types

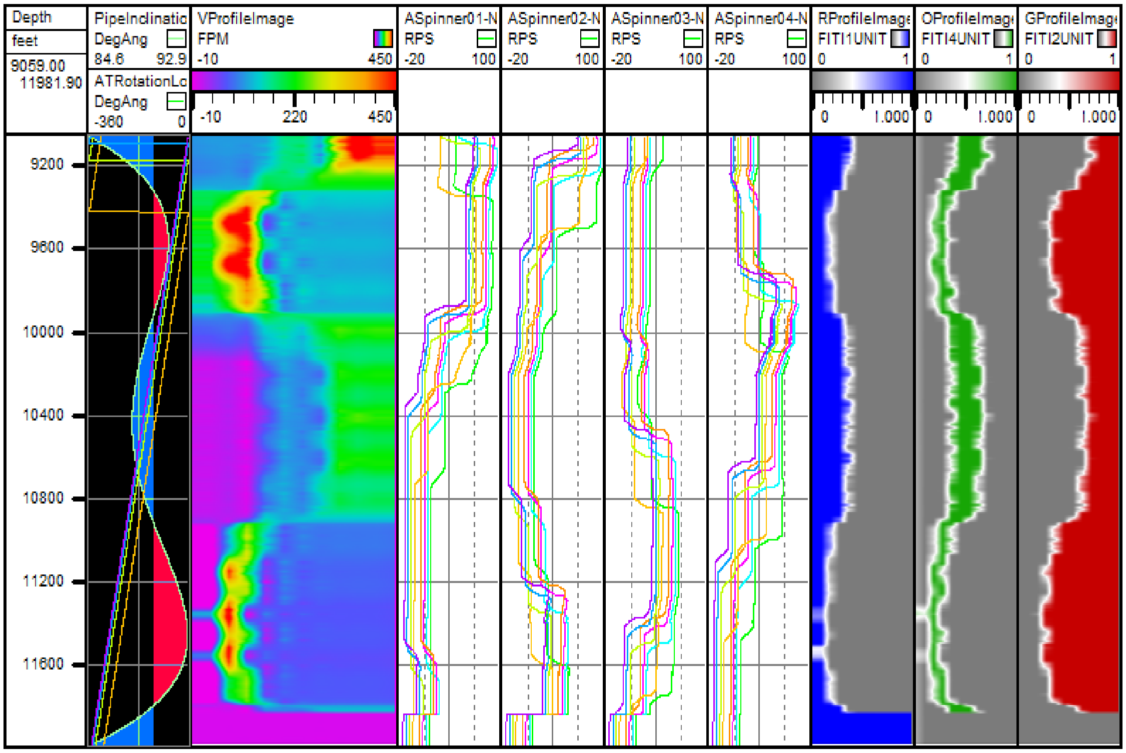


Fig2. 13: PLT Analysis

A wide choice of Production Logging sensor is employed to provide the raw data, which the analyst requires to interpret the production log. Typically, a flow meter will provide the apparent velocity of the fluid mix - this must be corrected to give the average velocity. A density sensor along with the PVT data from the well is used to allow calculation of phase hold up in a two phase system. A set of all defined equations uses these results to provide the downhole rates for the fluids present. In more complex situation where more than two phases exist in the wellbore, additional sensors can be deployed to provide direct measurement of water and gas hold-up. These sensors allow enhanced analysis and accurate results. Analysis may be further enhanced by production logging tools, which directly measure the distribution of phases across the wellbore. Such tools have many sensors deployed circumferentially across the wellbore.

Flow mechanisms are different in each well. Factors such as flow rate, bubble point and well trajectory will determine the distribution of fluids in the wellbore. In fact, well-mixed flows, traditional center measuring tools will yield good results of analyzed data. However, in wells where flows become stratified, confidence in results is increased when additional data from multi-sensor tools is available.

2.3.3 Chan's method:

Chan (1995) proposed a new methodology to analyze the log-log plot of WOR and derivative of WOR against time in order to differentiate between two common and more complicated water problems of water channeling and water coning. Chan has used various drive mechanisms and water flood scenarios using a three dimensional, three-phase black oil reservoir simulator to demonstrate the WOR plots differential mechanism. Based on Chan's report, three behavioral periods can be observed in the WOR versus time plot for both coning and channeling. During the first period from the start of the production to water breakthrough time, the WOR is constant for both mechanisms. However, this period called the departure time is usually shorter for coning than channeling.

In coning, the departure time corresponds to the time when water–oil contact (WOC) rises and reaches the bottom of the perforations. In channeling, the departure time relates to the time of water breakthrough for the highest permeable layer in a multilayer formation. After water break–through, which denotes the beginning of the second period, WOR in coning and channeling shows different trend?

In channeling, the WOR increase rate is relatively quick but it could slow down until it reaches a constant value. In coning, WOR gradually increases until it reaches a constant value thereafter, the WOR increases quite rapidly for both mechanisms during the third period.Chan also investigated the behavior of the time derivative of WOR (WOR') for channeling and coning mechanisms. Coning WOR' shows a changing negative slope while channeling WOR' exhibits an almost constant positive slope.

Stanley et al (1996) and Love et al. (1998) reported the use of WOR diagnostic plots in successful water treatment design case studies in Indonesia and New Mexico, respectively. However, it is important to notice that in both of these studies, the WOR diagnostic plots was not applied as a stand-alone technique but rather a supplementary tool with other methodologies such as production loggings and reservoir modeling.

Jassim and Subhi (2010) Applied Chan's methodology for wells in Middle East sandstone oil reservoirs using actual production history data to generate log-log plots of WOR (water oil ratio) and dWOR/dt (simple time derivative of water oil ratio) vs. time. The plots were found to be effective in differentiating whether the well is experiencing water coning (negative slope) or multilayer channeling (positive slope for the time derivative of water oil ratio curve). The diagnostic plots applied in this study provide a handy method for quick evaluation of excessive water production mechanisms in order to select wells candidates for water control treatment.

Despite the wide use of WOR diagnostic plots in wellbore and reservoir performance investigations, (Seright, 2001) challenged the view of using WOR plots as a diagnostic tool for water production management identification. He conducted a research study to determine whether Chan's proposed technique in interpreting WOR and WOR' plots is generally applicable or if there are limitations to study. Using numerical simulation and sensitivity analyses, the effects of various reservoir and fluid parameters on WOR and WOR' were investigated for both coning and channeling problems.

His study revealed that the WOR and WOR' behavior for a multilayer channeling case depends mainly on variables such as the degree of vertical communication and permeability contrast among layers, saturation distribution, and relative permeability curves. Coning WOR and WOR' behavior depends mainly on the vertical to horizontal permeability ratio, well spacing, capillary pressure, and relative permeability curves. Seright (2001) demonstrated that in many cases, multi-layer channeling problems would show negative derivative trend, which is an indication of coning mechanism according to Chan (1995).

A similar contradiction to Chan's claim was observed for a coning case where plots show a rapid WOR increase with a positive derivative slope. Seright (2001) concluded that the WOR and WOR' diagnostics plots are not general and could easily be misinterpreted and should therefore not be used alone for identifying mechanisms of excessive water production.

Equation: $\mathrm{WOR} = \frac{Water\ production}{Oil\ production}$ .... **(1)**

Equation: $\mathrm{WOR}' = \frac{WOR2 - WOR1}{Cum\ time2 - Cum\ time\ 1}$ .... **(2)**

Figures 2.14 through 2.17 (Chan, 1995) illustrate how the diagnostic plots used to differentiate among the various water production mechanisms. Fig. 2.17 shows a comparison of WOR diagnostic plots for coning and channelling.

Log-log plots of WOR and WOR time derivatives (WOR') versus time for the different excessive water production mechanisms are shown in Figures 2.15 through 2.17. Chan (1995) proposed that the WOR derivatives can distinguish between coning and channelling. Channelling WOR' curves should show an almost constant positive slope (Fig. 2.15), as opposed to coning WOR' curves, this should show a changing negative slope (Fig. 2.16). A negative slope turning positive when “channelling” occurs as shown in Figure 2.17, characterizes a combination of the two mechanisms. Chan classifies this as coning with late channelling behavior. [11]

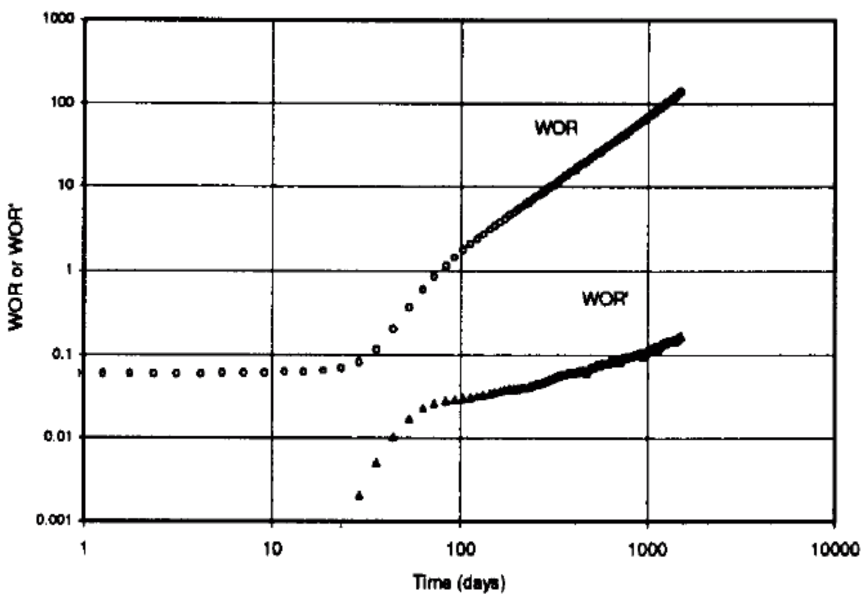


Fig2. 14: chan plot

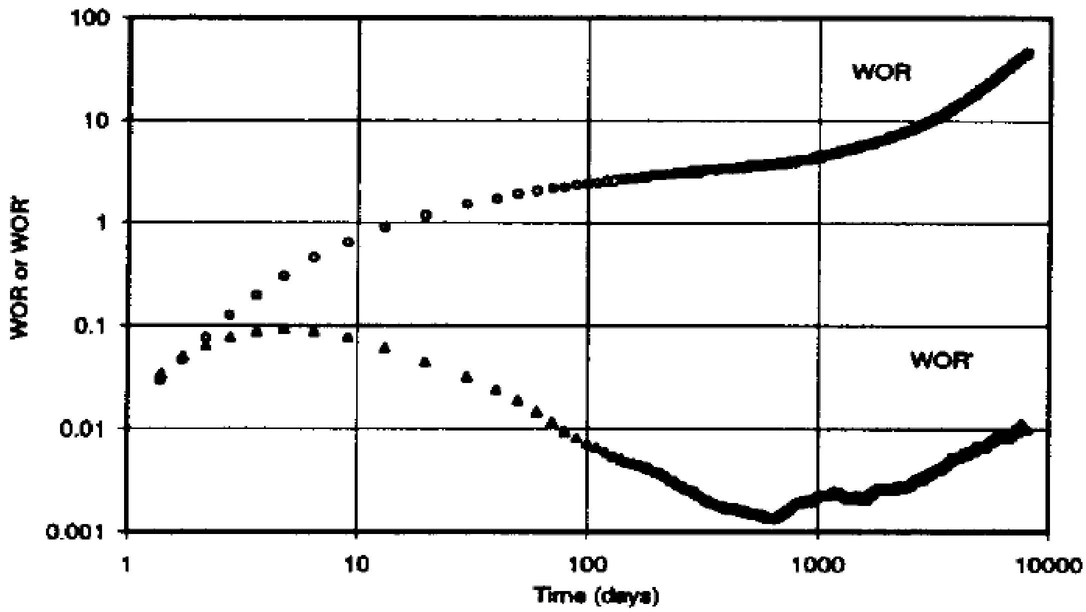


Fig2. 15: Multi-layer channeling WOR and WOR derivatives. Chan (1995)

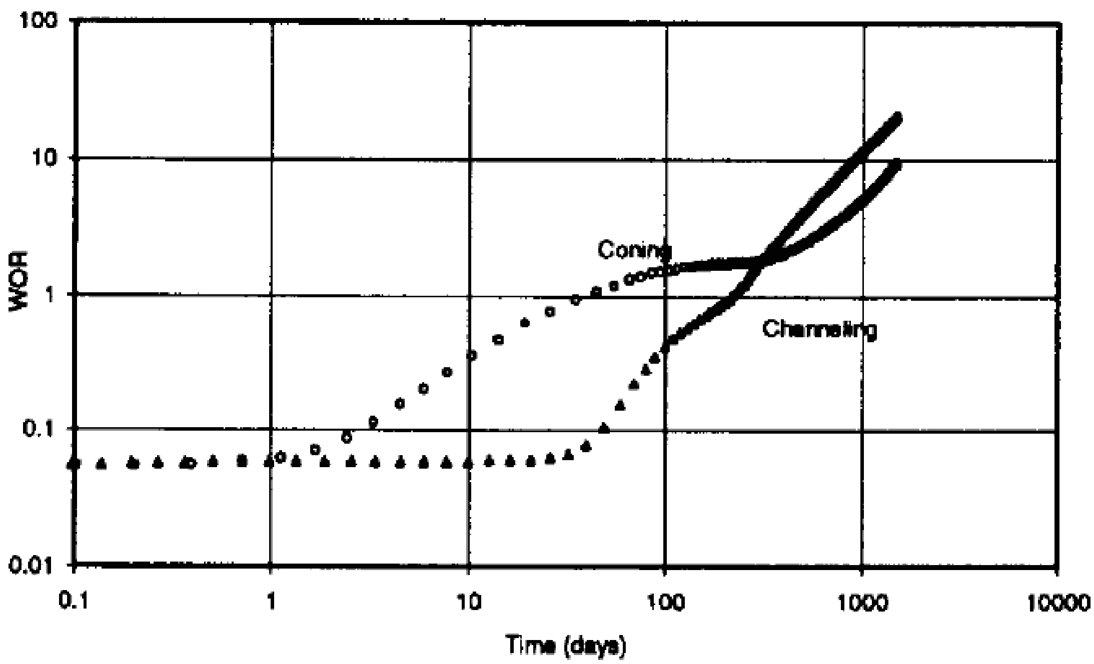


Fig2. 16: Bottom-water coning WOR and WOR derivatives. Chan (1995)

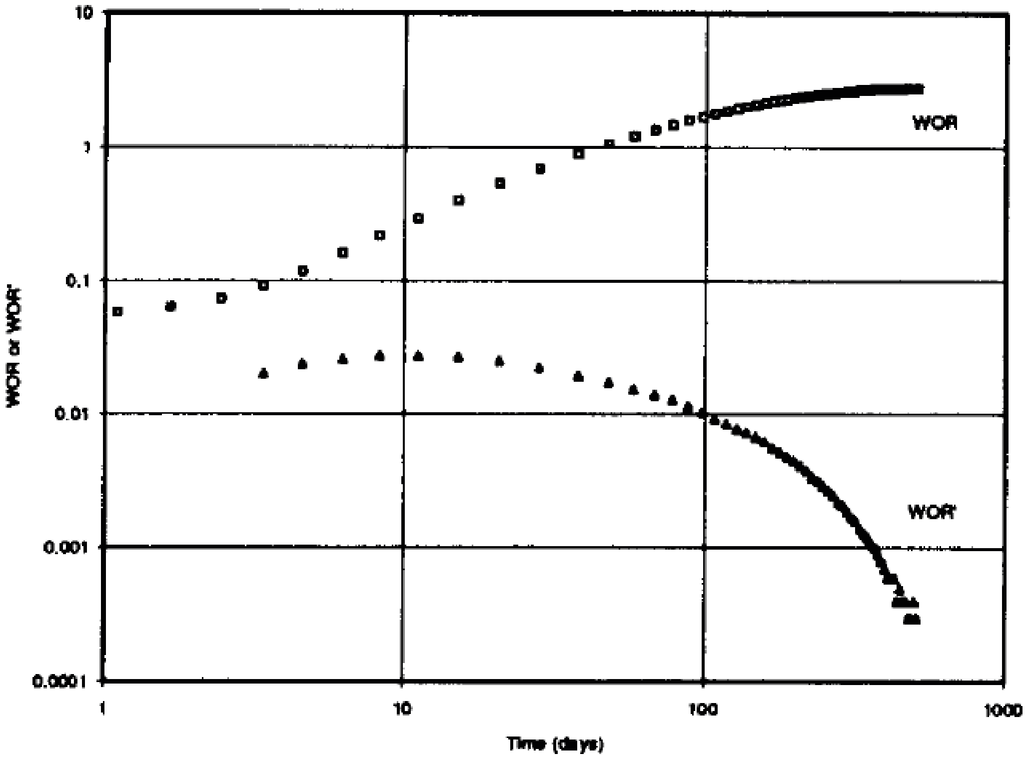


Fig2. 17: Bottom water coning with late time channeling. Chan (1995)

2.3.4 Nodal analysis:

Bailey et al. (2000) suggested techniques for water production mechanism diagnosis using nodal analysis. The total fluid pressure loss in the production system is due to the pressure loss through four subsystems from reservoir bottom to the surface equipment's. These subsystems are the porous media, well completions, tubing string and the flow line. The total fluid production from the reservoir to the surface depends on the total pressure drop in the production system. Therefore, the entire production system must be analyzed as one continuous unit, where fluid properties and pressure conditions at any point are dependent on the inflow and outflow from that particular point. The nodal analysis method views the production system as a group of nodes and fluid properties are evaluated locally at each node. The pressure drop at any particular node depends on the flow rate as well as the average pressure existing at that node. Any changes at a node in the system results in changes in pressure and/or flow rate at that specific node. For this reason, problems in the production system can be looked at by aiming at a specific node and considering the inflow and outflow subsystems of that node. Based on the concept of continuity, flow into the node is equal to the flow out of the node. Similarly, pressure in both inflow and outflow subsystems are the same. The intersection point of the plots of node pressure against production rate for inflow and outflow subsystems provides the expected production rate and pressure for the point being analyzed. Figure. 2.18 represents a nodal systems graph from for a sensitivity study of three different combinations for outflow components labeled A, B, and C. The graph explains that for outflow curve A, the well will not be expected to flow with System A, as there is no intersection with the inflow performance curve and hence, no continuity. The intersections of outflow performance curves B and C with the inflow performance curve satisfies continuity, and the well will be expected to produce at a rate and pressure indicated by the intersection points. Deviation from the expected rates could indicate a problem.[11]

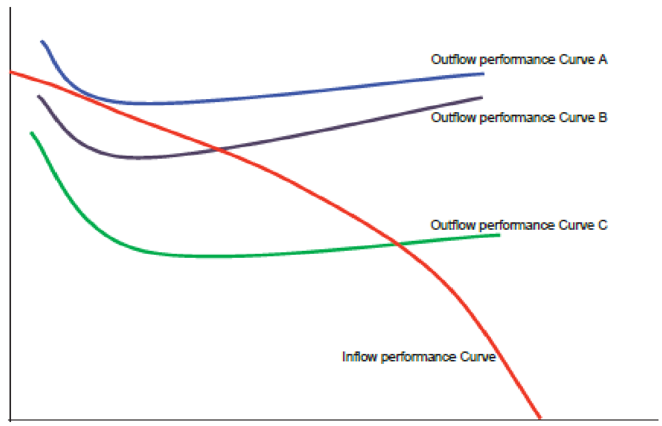


Fig2. 18: Nodal Analyses Performance

2.3.5 Well test:

Numerous well testing and logging techniques are available to observe fluids flow into the wellbore and assess the condition of the well. Radioactive tracer logs, temperature logs, spinner (flow meter) logs, cased hole formation resistivity (CHFR) tool, Figure 2.19 pulsed neutron, thermal decay time tool, reservoir saturation tool, pressure testing, casing inspection logs and chloride/total dissolved solids (TDS) test are few examples of various available well testing tools and techniques (Reynolds, 2003). The use of such tools and techniques can provide some insights into the water production mechanism encountered in the well. For example, TDS tests can determine the source of the produced water and whether it is coming from the aquifer or from the injector. Radioactive tracer logs can help in detecting leaks in the packers and plugs or fluid channels behind casing. Other production logs can also provide insights into the source of the water being produced or determine the water entry point into the wellbore. Nevertheless, while these logs are vital tools in well and reservoir surveillance, their application during production is somehow limiting. The logging instruments or application of them can be expensive.

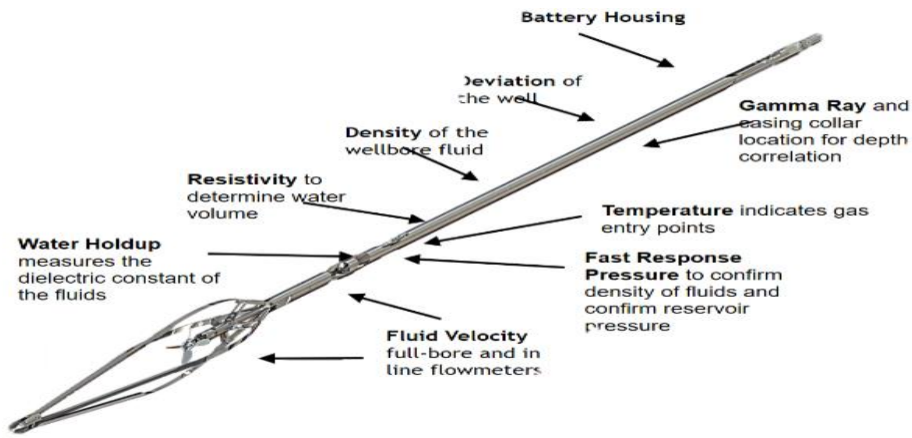


Fig2. 19: PLT

The main purpose of using CHFR is for reservoir monitoring. During the production life of a reservoir, Through-casing formation resistivity data may help understand fluid flow and recovery processes in several ways:

1) Evaluation of reservoir fluid saturation changes with time, including the identification of swept zones, potential flow barriers, and bypassed oil.

2) Monitoring of movement in oil/water contacts.

3) Identification of take-off rate-induced water coning, by repeat logging at different takeoff rates, allowing time to re-establish stable conditions.

Sometimes it is required to shut down the well during logging which consequently affects the production rate and revenue. Log data are often very complex and could entail costly and time-consuming data processing and log analysis and interpretation (Nikravesh, 2001),(Wong, 2002).

The differential temperature log measures temperature of the wellbore fluid under static (shut-in) or dynamic (flowing) conditions, Figure 2.20. Temperature logs run while a well is injecting water at stabilized rates can yield much useful information. The logging tool responds to temperature anomalies produced by fluid flow, either within the casing or in the casing annulus, and is very useful in detecting the latter. Interpretations are also used to determine flow rates and points of fluid entry or exit. In an injection well, temperature response is a function of depth, temperature of injected fluid, injection rate, time of injection, formation and fluid thermal properties, and the geothermal profile in the well. An injection well that has been taking fluid for some time can be shut in and numerous temperature logs can be run over a period of time to observe the temperature profile as it returns to geothermal values. The zones that have taken the (usually) cooler injection fluid will show a slower rate of return to the geothermal profile than the zones that have taken no fluid. (Bailey et al., 2000).

This effect can be detected in upper zones behind pipe that are taking injection water due to communication problems. The most common application is in water flooding projects where a foot-by-foot analysis of formation flooding is desired on injection wells. Advantages in tracing injected fluids with the single element differential temperature log become apparent when proper logging interpretation techniques are used. The temperature gradient log is a continuous recording of downhole absolute temperatures. Repeatability of the temperature measurement is plus or minus 0.01o F in the range of 50 to 400o F. Scales vary from fractional increments per inch to any practical limit required. The most commonly recorded scales are: 1, 2, 5, and 10o F per inch. Logging is usually performed on the downward traverse so that well fluids are encountered in their normal state without being previously disturbed by passage of the line and tool. The casing collar locator is run and recorded simultaneously, as this provides definite depth correlation with other types of logs run in the well.
(Economides, 1994). [11]

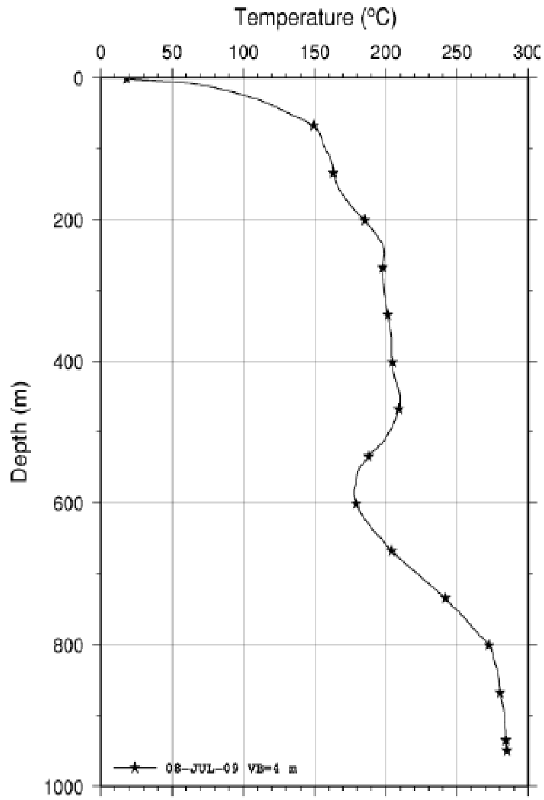


Fig2. 20: Temperature and Density log (Economides, 1994)

2.4 Water Shut-off/Reduction Methods

Water shutoff methods can be broadly be classified into two main groups: mechanical and chemical shutoff methods. The mechanical methods are known to be most suitable for wellbore related problems but can as well be used in combination with the chemical shutoff methods depending on the complexity of the reservoir problem. Of recent, the chemical methods have gained more industrial acceptability and thus have higher application than the mechanical methods.

Each problem type has solution options that range from the simple and relatively inexpensive mechanical and chemical solutions, to the more complex and expensive reworked completion solutions. Multiple water-control problems are common, and often a combination of solutions may be required. Today, in addition to the traditional solutions, there are new, innovative and cost-effective solutions for water-control problems. First we need to know how to Identifying the Problem.[8]

How to Identify Excess-water Problems?

Logically, identification of the excess water production problem should be performed before attempting a water shutoff treatment Reducing excessive water production usually starts with gathering all available reservoir and production data. Then logging tools are used to locate the water entry points. Finally, based on the results, a proper shutoff method is used .The most important part in any water shutoff operation is the accurate diagnosis of the problem. It is essential to know the water entry point, the heterogeneity of the reservoir rocks, dominant production mechanisms, and the schematics of the wellbore. In fact, all available information about the well is considered valuable, like drilling operations reports, logs, and production history. The reason behind that is that every well would have its own workflow based on it is properties, history, and reservoir heterogeneity. Accurate investigation leads to success in the water shutoff operation, increasing oil production, and saving water handling costs. Fayzullin et.al. Present an example of a case study for understanding unwanted water production. Open-hole logs are the most widely available source of information for initial water-oil-contact (WOC), fluid saturation, and permeability of the reservoir. Production logging tools in production wells using spinner, temperature, and pressure data usually are used to identify the water production zones, which is an important step in planning for an optimized water shutoff operation. For water injection wells, water flow logs are used to identify the thief zones. However, horizontal wells are challenging in identifying the problem as well as in the intervention part. That is due to the complicity of the wellbore, flow regimes, and their effects on obtaining the required information.

Luckily, advanced production logging tools can be used to identify the entry points as well as the rates. Fiber optics technologies are used nowadays along with logging tools to ensure high quality real time data that help in accurately identifying the water entry zones. Al-Zain et. al. present a case of successful usage of fiber optics to shut off unwanted water production in an oil field. In addition to that, water/oil ratio (WOR) plots can be used to identify the excessive water production problems. In fact, it can be a more effective tool than logging in many cases. For channeling behind the casings, running cement bond logs (CBL) or ultrasonic pulse-echo logs plays a vital role in ensuring the integrity of the cement job behind the casing. Those kinds of logs evaluate the bonding properties of the cement job behind the casing and point out bad cement areas. For casing leaks, production, temperature, and noise logs are all means of identifying the sources of leaking. Pulsed Neutron Logs (PNL) for reservoir saturation monitoring and remaining oil spotting provide a more in-depth assessment of hydrocarbon and water saturation behind casing even with multiple barriers. This information can indicate the source of water production as well as potential zones for further analysis development. [8]

. Table 2.1 shows logs mainly used to identify water issues

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Problems	Open-Hole Logs	Cement Evaluation Logs	Casing Evaluation Logs	Pulsed Neutron Logs	Production Logs	Spectral Noise Log
Lost circulation while drilling	X					
Lost circulation while workover	X					
Coning or cresting	X				X	
Casing leaks			X	X	X	X
High perm streak	X				X	X
Completion near water zone	X			X	X	
Fracturing job to water		X		X	X	X
Channeling behind casing	X	X		X	X	X
Channel from injector				X	X	X
Watered-out zone	X				X	

Tab2. 1: Main Diagnosis Applications of Open and Cased Logging Tools

2.4.1 Chemical method:

Far from the wellbore, in the reservoir or near the wellbore, water shutoff operations can be performed by several chemical treatments. Those chemical solutions lead to better conformance in the reservoir as well as blocking the unwanted water production zones. The idea is to be able to close the paths of least resistance in front of the water by reducing their permeability in order to prevent the water from coming to the wellbore through them. Also, they aid in forcing the water to mobilize and displace the oil in the reservoir. In other words, the aim is to block the open features and high permeability channels to force water to go toward the harder path to sweep oil from the matrix rock that results in higher overall economical returns than producing oil from fractures. In fact, induced formation damage can be used as an effective solution to control the unwanted water production.
The results of chemical solutions can be achieved in a couple of months to years, depending on

the nature of the reservoir and the properties of the injected chemicals. The main advantage that chemical water shutoff operations have over mechanical operations is that they solve the problem of the unwanted water production instead of hiding it under or behind a plug, packer, or tubing patch. Injected chemicals can reach water features in the reservoir and reduce the permeability, resulting in closing them entirely. They also have the freedom of moving between the layers and features which helps in reaching to far extents and completely closing them. Another use of chemical injection is to increase the viscosity of the injected fluid which leads to a better sweeping efficiency and eventually reduces the production of unwanted water. The success of chemical injection operations depends on the knowledge level of the reservoir and its characterizations, chemical properties, and accurate placement of the injected chemicals.

For example, the effectiveness of water shutoff agents depends highly on the properties of the reservoir and has to be compatible with the reservoir temperature and water salinity in order to achieve an effective water shutoff. In this section, common chemical solutions are discussed in detail, along with examples of the execution of the operations. [9]

2.4.1.1 Gel :

Gel injection is one of the most famous chemical solutions for water shutoff operations. It is used to reduce the water oil ratio and increase the conformance of the pattern. That happens through the ability of the gel to reduce the permeability and block the open features, fractures, and high permeability water zones. It can be applied in the wellbore, near the wellbore, and far from the production well through injection wells. It is very effective in reducing the permeability of unwanted zones and has proven its ability to improve the sweep efficiency and shutting-off the unwater water zones. The injected gel is mainly made of water, small volumes of polymers and crosslinking chemical agents . Gel treatments can completely seal off layers; therefore, they are considered aggressive and risky conformance control operation . On the other hand, polymer gel injection is considered relatively cheaper than other improved oil recovery operations.
Gel injection operations are divided into three main stages: modeling, designing, and executing. The first step is to model the gel injection operation by using simulation software, which is an important step for designing the program of gel injection operation. In this stage, all the available information about the reservoir and the well are considered valuable, such as: reservoir parameters, water entry points, drilling operations reports, logs, and production history. The second step is to design the properties of the polymer gel fluid. Injecting gel in the reservoir depends on four properties. First one is the viscosity of the gel at the time of injection which helps in directing the gel to the lager and least resistance paths. Second is the nature of the gel phase which is usually chosen to be the aqueous phase since the water is the desired phase to be shut off. Third is the density of the gel. It very important to be designed carefully and based on the density of the formation water to avoid losing the effectiveness of the gel treatment. Fourth is the setup time or injection time. Longer injection time leads to more success in allowing the gel to seal off larger features and least resistance paths. Al-Dhafeeri et. al. present a case study of using gel treatments as a chemical solution to seal the excessive water zones.[12]

2.4.1.2 Polymer Flooding

Another common technique for water shutoff operations is the usage of the polymer flooding method to increase the viscosity of the water. This technique is applied to increase the viscosity of the drive fluid (water) which helps in mobilizing and displacing the oil in the reservoir matrix rock. This technique is usually applied in the reservoir far from the production wells through water injection wells to achieve better sweeping efficiency in the reservoir. That eventually leads to preventing excessive water production. The usage of polymer flooding is very common among the oil operators and it can be prepared by dissolving the polymers in the injected water and inject it through injection wells. Polymers used in this technique are usually two types: biopolymers and synthetic polymers. Biopolymers' advantages over the synthetics are that they are not affected by the salinity of the water and they are insensitive to the mechanical degradations. However, they are more expensive than synthetic polymers. Xanthan and scleroglucan are two famous kinds of biopolymers. Synthetic polymers are more common since they are cheaper, more available, and perform well with low-salinity water. Polyacrylamide (PAM) and hydrolyzed polyacrylamide (HPAM) are two types of synthetic polymers. Polymers can also play a role in reducing the permeability if the molecular weight is increased . Finally, based on the characteristics of the reservoir and the economics of the operations, the right polymer is chosen in case of chemical injection. El-Karsani's paper includes an overall review of the polymer systems used for water shutoff operations along with their chemical compounds and properties.

There are other chemical techniques for water shutoff operation such as resins, solid particles, and foams which are also effective in obtaining better conformance and enhance the sweep efficiency. Finally, Bybee presented a case of a long horizontal well with excessive water production from southern Italy. Sealant was pumped as a solution to successfully solve the problem. [12]

2.4.1.3 Surfactant flooding

Correctly designed surfactants can create micro emulsions at the interface between oil and water phases, which cause a reduction in the interfacial tension (IFT) that consequently will mobilize the residual oil which improving the oil recovery. This method of EOR is a challenging one by many factors such as rock adsorption of the surfactant and co-surfactant, and the chromatographic separation of the surfactant during the injection in the reservoir. The designed surfactants should be resistant and active at reservoir conditions which could by at higher pressure, temperature and water salinities. In the surfactant flooding the phase behavior is the most important factor to make it successful. Currently, there is no EOS model to describe the phase behavior in these systems. Consequently, phase behavior studies should be observed experimentally which is challenging to mimic the reservoir conditions. Surfactants solutions are used to reduce the oil-water IFT, while the co-surfactants are mixed with these solutions in order to enhance the properties of the surfactant solutions. The co-surfactants added to the solutions are serving as an active agent or a promoter in the mixed solution in order to enhance the surfactant effectiveness with respect to temperature and water salinity as it is well known that surfactant flooding is sensitive to reservoir temperature and salinity .[13]

2.4.1.4 Alkaline flooding :

Alkaline flooding is one of the EOR methods in which alkaline agents are injected into the reservoir to produce in situ surfactants, so the alkaline flooding will eventually have the same effect of the surfactant flooding.

In the Alkaline flooding process, the alkaline agents such as sodium hydroxide solution is injecting into the reservoirs which react with the naturally occurring organic acids in the oil in order to produce surfactants or soaps at the oil-water interface. However, the alkaline agents are less expensive than the surfactant agents, the expected incremental oil recovery by alkaline flooding has not been confirmed by field results and still remains possibility as the process is mainly dependent on the mineral composition of the reservoir rock and its oil.[13]

2.4.1.5 Surfactant-polymer (SP) flooding:

Surfactant-polymer flooding process is injecting a chemical slug that contains water, surfactant, electrolyte (salt), usually a co-surfactant (alcohol), followed by polymer-thickened water. In this process a surfactant is added to the polymer solution that has the affinity for both water and oil. The use of the micellar solution is to reduce the interfacial tension of the water-oil system in the reservoir in order to displace the residual oil. SP flooding method was patented for Marathon oil co. by Gogarty and Tosch known as Mara-flood. The injection profile of the method consists of injecting a pre-flush (to achieve the desired salinity environment), followed by micellar slug (surfactant, co-surfactant, electrolyte), and followed by polymer solution along with drive water.

The micellar solution composition that ensures a gradual transition from the displacement water to the displaced oil without interface is as following:

- Surfactant 10–15%.
- Water 20–60%.
- Oil 25–70%.
- Co-surfactant 3–4%.

Usually, the co-surfactant is alcohol which enhances the possibility for the micellar solution to include oil or water. This surfactant-polymer flooding reduces the oil-water IFT through the surfactant portion and reduces the mobility ratio through presence of polymer.

The micellar solution is prepared using inorganic salts (water-soluble electrolytes) in order to gain better viscosity control of the solution. A polymer slug is used to drive the micellar solution slug in order to get a mobility control. The technique establishes low oil-water IFT and controls the mobility ratio which forming a considerable oil bank to be produced.[13]

2.4.1.6 Alkaline-surfactant-polymer (ASP) flooding

Individual chemical flooding processes, alkaline flooding, surfactant flooding and polymer flooding, can be combined differently. The three-component combination, alkaline surfactant-polymer (ASP). The ASP method represents a cost-effective chemical EOR method that yielding high oil recovery (mostly for sandstone reservoirs). ASP flooding is utilizing the benefits of three flooding methods, where oil recovery was enhanced, by reducing IFT, improving mobility ratio, and improving microscopic displacement efficiency. The ASP projects in China shows that the incremental oil recovery over water-flooding is 18.9% on the average.

Alkaline injection reduces surfactant adsorption and the combination of soap and synthetic surfactant results in low interfacial tension (IFT) in a wider range of salinity. Soap and surfactant make emulsions stable through reduced IFT which improve the sweep efficiency. There is a competition of adsorption sites between polymer and surfactant. Therefore, addition of polymer reduces surfactant adsorption, or vice versa and improves the sweep efficiency of ASP solution.

2.4.1.7 Solvent flooding :

Solvent flooding is quite different from the other chemical flooding fundamentally. Strictly speaking, solvent flooding works similar as the thermal injection despite several chemical solvents are applied. In these methods, solvents are either partially introduced into the steam, such as LASER (liquid addition to steam to enhance recovery) and other hybrid steam–solvent processes, or completely replacing the steam, such as VAPEX (vapor extraction) and CSI (cyclic solvent injection).

In terms of energy consumption, environmental impact, capital investment and safety issue, solvent-based recovery methods exhibit distinct advantages over the thermal injection technology. Admittedly, compatibility-induced viscosity reduction by miscible solvents is more cost-effective than heat-enhanced mode by the steam. Much less surface facilities are required for the solvent flooding than that for the steam injection, which will reduce the capital investment and operating cost. Moreover, when sufficient solvent is dissolved into the heavy oil, asphaltene precipitation could occur so that the produced heavy oil is in-situ deasphalted and upgraded. Compared to LASER and hybrid steam–solvent methods, CSI and VAPEX do not utilize steam. CSI is analogous to the CSS process, in which a solvent mixture instead of steam is injected into the reservoir and followed by a soaking period and a production period. Normally, the solvents should be mainly gaseous, exhibit good solubility in oil, and be relatively affordable. With this in mind, several blends consisting of readily available CH_4 or CO_2 as carrier gas and additional propane or butane have been experimentally tested. Before testing CSI at field scale, systematic investigations should be conducted to evaluate operational parameters such as solvent amount, soaking time and slug injection strategies. In addition, although solvents provide better performance than steam, the cost of solvents is much higher than that of steam. Thus, there will be a compromise between the production efficiency and the solvent cost. [13]

2.4.1.8 Foam flooding :

The foam flooding is an EOR method using foam as the displacement agent. The foam is composed of foamer, foam stabilizer, gas and water. The foamer selected is often a surfactant with strong foam-generating capability, the foam stabilizer is mostly a polymer (or a biopolymer), a gel, or a nanopowder, and the gas can be air, natural gas, CO_2, N_2, etc. Its oil displacement mechanism includes improving displacement efficiency and expanding sweeping volume. During the migration in the formation, the foam preferentially enters high-permeability layers or micro-fractures with low oil saturation. Seepage resistance gradually increases due to the Jiamin effect and beading effect etc. With the increase of injection pressure, the foam will gradually flow into the low-permeability layers with high oil saturation, and thus effectively improving sweeping efficiency. Besides, the foamer itself is a kind of surfactant, which can reduce the oil-water interfacial tension and residual oil saturation, and improve oil displacement efficiency. Foam has unique advantages in treating gas/water channeling during gas/water injection and sweeping remaining oil at the top of thick oil layers. Therefore, it is a promising EOR technology.

2.4.1.9 Emulsion flooding :

The study of emulsions has been of great interest in the petroleum industry. Emulsions have been used over the years as a displacing fluid for enhanced oil recovery processes (Massarweh and Abushaikha 2020). However, the application of emulsion as a blocking agent in conformance control is an emerging technique. Compared to other conformance control agents, emulsions have unique distinctions such as better injectivity, less difficult blockage removal, a wide range of channel plugging and less damage to the formation (Chen et al. 2018). Bai and Han (2000) reported that a higher oil recovery factor was obtained after an emulsion injection when compared to a polymer gel injection in their study. They attributed this to the induced formation damage caused by the polymer gel in the target areas in the reservoir and the lack of selective plugging by the gel.

Emulsions are thermodynamically unstable systems consisting of two immiscible fluids, one with a dispersed droplets phase and the other a continuous phase in the presence of surface-active agents. Hydrocarbon production from the petroleum reservoir and transportation to the surface is always in the form of a mixture containing oil, gas and water as well as inorganic and organic contaminants. These contaminants act as emulsifiers and with the continuous agitation of the mixture from the reservoirs during the flow up to surface facilities, tight emulsions can be formed. Emulsions can be intentionally formed for upstream processes such as enhanced oil recovery and acid stimulation (Maaref et al. 2017; Ahmadi et al. 2019). Depending on which phase is continuous or dispersed, emulsions can be water in oil (w/o), oil in water (o/w) (Zapateiro et al. 2018; Mandal and Bera. 2015).

The most common type of emulsion formed in oil production is the w/o emulsion with a viscosity that is greater than that of oil. Using this, it creates a large pressure drop between the injection and production well, leading to a loss of fluids. This type of emulsion is considered to be undesirable in the oil production processes (Rezaei and Firoozabadi 2014; Lim et al. 2015). On the contrary, o/w emulsion has a very low viscosity that is very similar to water. This allows for good injectivity and it flows easily, thus making it attractive for conformance control measures.[13]

2.4.2 Mechanical method:

Within the wellbore, there are available technologies which can successfully shut off the unwanted water production. The impact can be seen in hours in contrast to the chemical solutions which was discussed in the previous section. Controlling the water production mechanically is known for it is fast outcomes as well as its cheap costs. It is usually a rig less job, which means a lower cost. Mechanical water shutoff operations are preferred by operators since they are relatively cheaper than chemical solutions. Once more, an accurate diagnosis is essential before attempting to apply those solutions, since it can result in losing the oil production from the well. That can be achieved, as mentioned previously, through running logs to identify the water production zones. In the case of mechanical shutoff operations, there are some factors affecting the success of them. One of them is the setting depth of the plug or the packer can be wrong due to inaccurate readings from the coiled-tubing meter. The reservoir conditions also play a great role in affecting the operations, since a cross flow between the layers can happen and leads intervention to failure. The wellbore condition is another vital factor which needs to be considered. Scale presences in the tubing can result in failure of the operations, since it can create an obstacle while running the plug or the packer downhole. Wells with high deviation angles can be challenging to run in hole with coiled-tubing since they can get stuck a lot. In this section, common mechanical solutions are discussed in details along with examples of the execution of the operation. [9]

2.4.2.1. Plugs and Packers:

One of the most well-known mechanical solutions for water shutoff and isolation operations inside the wellbore is the installation of packers and plugs. They are successful in eliminating the production from unwanted water zones. They are commonly used by oil operators to aid the wells performance and shut off the excessive water production . This hardware is known for being economical and reliable in achieving isolation since it can be installed without pulling the production tubing and without the drilling rig. They can be installed by using coiled tubing which can run them through the wellbore. Also, the results can be achieved relatively fast, in a couple of hours to days, in contrast with chemical injection solutions. Simply, the concept of packers and plugs is a small diameter element, mainly rubber, which can expand downhole the wellbore into larger diameters, creating a seal and isolating the well from unwanted features or zones . There are different types of packers and plugs with different properties and setting techniques. Some elements expand by interacting with certain types of fluids (oil, water, or hybrid) which are known as "swellable packers". They also depend on pre-designed properties like temperature, pressure, and salinity of the formation fluid. That can be a disadvantage in some cases and leads to failure in setting the element. If those properties are not accounted for accurately, that might lead to a faster inflation of the elements or even slower inflation than expected. In the worst case scenario, the element might not inflate at all. Other packers and plugs inflate by applying pressure on the element in order to expand and seal. These types of plugs usually inflate by pumping darts, steel balls, or fluid to apply pressure on the rubber element and allow it to expand and increase its diameter. Packers and plugs can be used to isolate unwanted water production inside the wellbore in certain cases. An easy example would be an open-hole well completion and the water zone is identified to be from the bottom of the well. A bridge plug can be installed to isolate the bottom section and shut down the additional water production to aid the production performance from upper oil zones (Figure 2.21). The difficulty increases if the water source happens to be in the middle or at the top part of the production section of the tubing in the reservoir section. In that case, a blank pipe with upper and lower packers, with a pre-designed length, can be installed to isolate the water production area without compromising the lower and upper oil production zones (Figure 2.22). In the case of a multi-lateral wells, if one of the laterals is watered-out or producing extreme amounts of unnecessary water, it can be abandoned by setting a plug to isolate it from other laterals. The usage of packers is also used in early stages of the well life, specifically in the completion stages after drilling. That is a common practice for operators who have a reasonably decent knowledge of the expected features and layers of their reservoir.

Also logging while drilling tools can be an asset by identifying the open features which might be the future reason for bad water production. After drilling the well and collecting the data, a pre-perforated liners can be installed with packers to produce only the good layers and isolate the risky formations. Once more, an accurate and cautious pre-design of the job is essential for designing the elements to avoid failures.

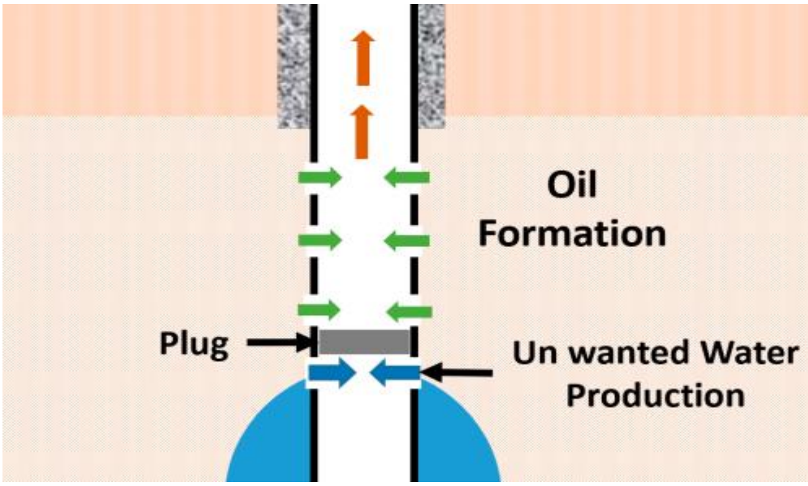


Fig2. 21: Using a plug to shut off the production of water from the bottom

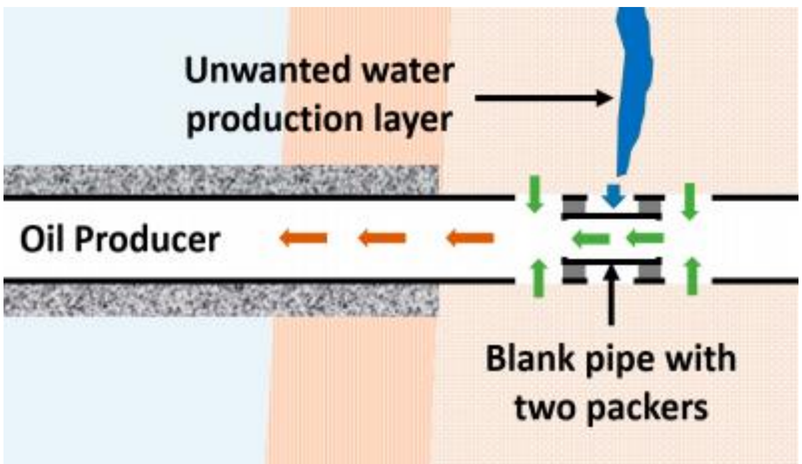


Fig2. 22: Two packers above and below a blank pipe to shut off the production of water from the

Likewise, for water injection wells, those plugs can be used to insure better conformance outcomes and to eliminate the production of bad water from the production wells through thief zones, high permeability layers, or connected open features. For example, if any of the previous features have been identified in the injection profile of water injection well, plugs can be used to isolate injected water from going into them. If there is an open feature at the bottom of a water injection well, a plug can be installed to isolate the bottom section, to avoid wasting the injected water and direct it into oil matrix rocks instead. Similarly, if the feature happens to be at the middle or the top of the injection profile, a blank pipe with upper and lower packers can be installed to isolate the thief zones from stealing the injected water without compromising the conformance and the sweeping efficiency of the field (Figure 2.23).

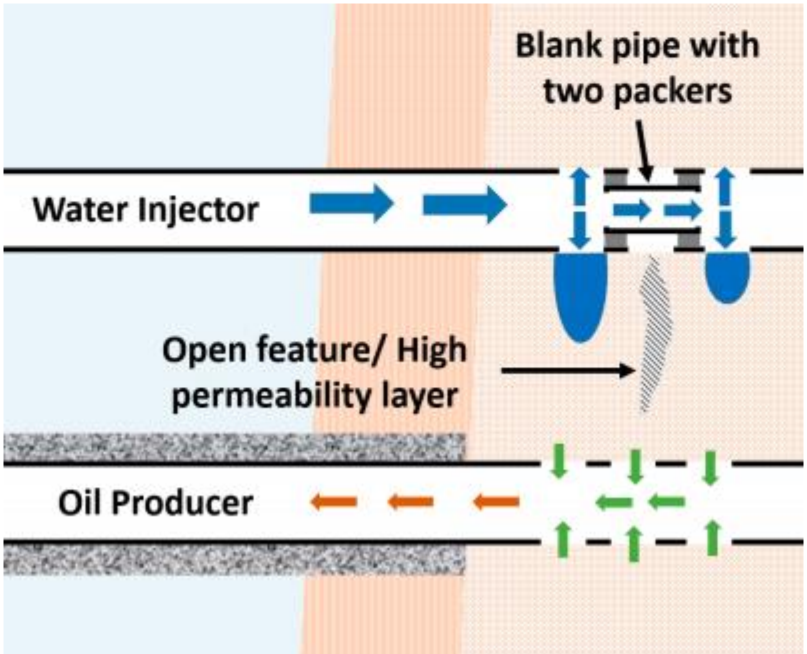


Fig2. 23: Two packers above and below a blank pipe to avoid injecting the water in open features or

Other than that, inflatable packers are also used in chemical injection for water shutoff operations. As mentioned previously, chemicals can be used in the near wellbore area to control and shut off the unwanted water production. However, this operation considered risky because of the high cost and the risk of injecting the chemicals into the oil production zones . Therefore, packers are used to direct the flow of the injected chemicals into the desired layers and prevent fluid from going into the production formation. Packers create a seal by inflating and isolating the upper and bottom intervals to make sure that chemicals do not bypass to oil zones. [14]

2.4.2.2. Tubing Patches:

This method is mainly used for fixing well integrity issues particularly casing leaks. The casing leaks problems are common in old wells and the wells which are completed in formations with corrosive gases like H_2S . If the source of the unwanted water was found to be from a leak in the casing, squeezing cement or resins patches is considered to be a suitable solution. This method can be applied only after identifying the exact location of the leak through the methods discussed earlier. Squeezing jobs can be performed by rigs or sometimes with current technologies can be a rig-less job. Usually, inflatables are used to direct the patches toward the leaking point. For small leaks, fine cement particles are squeezed to fix the well integrity issue as well as creating a seal.

2.4.2.3. Expandable packers

Expandable packers include: inflatable packer, bridge plug, swell packer, straddle packer, inflatable cement retainer, and expandable tubular. The inflatable processes are triggered by different mechanisms. The inflation of inflatable packers is achieved by the expansion of rubber blades. The expansion of bridge plugs and expandable tubular is achieved by mechanic expansion. The pressure between the base of the cone and the shoe of the clad will expand the tubular. The swelling of swell packer is caused by in contact with fluids in wells. Some expandable packers such as straddle packers with two inflatable elements and a nipple can be used as both zonal isolation tools and injection tools. The two inflatable elements provide zonal isolation, while the treatment fluid can be injected from the nipples in between. Inflatable cement retainers have similar function. It provides zonal isolation by inflatable elements for later chemical treatment and chemical injection into the target zone.

One special expandable packer is external casing packer (ECP). It is frequently used with liners or sand screens and set at intervals along the openhole. It has an inflatable section which is the rubber bladder over a section of casing. Once this section inflates, the annular will be sealed by the packers.

2.4.2.4. Non-expandable packer

Cement packer is a commonly used non-expandable packer in vertical wells. Applied in horizontal wells may face with uncompleted sealing in annulus due to the gravity effect. It is suitable for isolation of the upper zones to shut-off unwanted fluids. A novel foamed cement packer has been used in the fields. Foamed cement is created when a gas, usually nitrogen, is injected at high pressure into a base slurry that incorporates a foaming agent and foam stabilizer. It has higher mud displacement in a small annulus than conventional cement. Due to the structure of water channels. There are some other types of cement, such as expanding cement, highly-thixotropic cement, and fiber-reinforced neutral- density cement.

Tab2. 2: Common used packer characteristics and sealing mechanisms.

Name	Appearance	Expansibility	Retrievability	Sealing mechanisms
Cement plug		No	No	Cement fully plugs the annulus by forming a rigid block
Inflatable packer		Yes	Yes	The inflation of inflatable packers is achieved by expansion of rubber bladder. Inflatable elements fully occupy the annulus to provide isolation
Bridge plug		Yes	Yes	The expansion of bridge plugs is achieved by mechanic expansion. Inflatable elements fully occupy the annulus to provide isolation
Straddle packer		Yes	Yes	The inflation of straddle packer is similar to the inflatable packer. Inflatable elements fully occupy the annulus to provide isolation
Swell packer		Yes	Yes	The swelling of swell packers is caused by contact with fluids in well. Inflatable elements fully occupy the annulus to provide isolation
Cement retainer		Yes	Yes	The inflation achieved by expansion of rubber bladder. The cement is injected after the expansion.
Expandable tubular		Yes	No	The pressure between the base of the cone and the shoe of the clad will expand the tubular to provide sealing
External casing packer (ECP)		Yes	No	The inflation is achieved by expansion of rubber bladder. Inflatable elements fully occupy the annulus to provide isolation

2.4.2.5. Infill drilling:

The proposed approach consists of a stochastic evaluation of the candidate infill drill-holes that can be drilled over the deposit. Due to the large number of candidate locations, a searching algorithm is implemented to reduce the computation time, which consists of identifying potential regions in the deposit. The search algorithm is initialized by searching over a coarse drilling pattern over the deposit, and as potential regions are identified, the drilling pattern is reduced in those regions to increment the accuracy of the search. An important part of the evaluation is the definition of the metrics of performance. The infill drill-holes can be targeted based on their effect on:

The dispersion of the total revenues of the ultimate pit, the dispersion of the total amount of ore material within the ultimate pit, the geometric variability in the position of the following next sequence, the geometric variability of the ultimate pit, etc. For each location in the initial drilling pattern, the sampled values of each of the infill drill-holes are simulated conditioned to the existing data. An ultimate pit and its corresponding mining sequence is calculated for each realization of the infill drill-hole candidate and the existing data. The simulated infill drill-holes can be ranked according to the targeting criteria. For example, in the case of the reduction of the variability of the revenue criteria, the drilling location that results in the maximum variance of the ultimate pit revenues is targeted. An infill drill-hole at the targeted location will confirm the set of geologic features in the sampled region thus eliminating.

The major source of revenue variability in the deposit. To improve the accuracy in the selection of the infill drilling location, a denser drilling pattern is drilled around the more variable regions. To add more infill drill-holes to the drilling campaign, the previous simulated infill drill-holes are kept as part of the available information and the searching process is repeated again.

The proposed approach samples the different variability fields depending on the targeting criteria. The searching algorithm reduces the computation time to find the optimal targeting locations. During the evaluation of the infill locations two or more criteria can be considered by weighting the importance of the criteria in the ranking of the locations.[13]

2.4.2.6. Horizontal wells:

Horizontal well technology was originally developed for use in petroleum production and underground utility installation, but recently (since the late 1980's) has been adapted for environmental remediation applications. In the environmental remediation industry, horizontal wells provide unique characteristics and advantages that can improve the effectiveness of established soil and groundwater cleanup technologies now using traditional vertical well techniques. To date, over 300 horizontal wells are estimated to have been installed for environmental remediation purposes, with the number of installations doubling every year since 1994.

The "steering" capability associated with some horizontal well drilling techniques allows installation in areas containing underground utilities, vertical wells, and other subsurface obstructions. Horizontal wells can be installed beneath buildings and other surface structures, allowing access for treatment to areas generally inaccessible to vertical wells.

The orientation of horizontal wells compared with vertical wells may require fewer wells to achieve similar remediation goals due to the greater surface area associated with the lengthwise screened area of these wells. Horizontal screens provide greater surface area in contact with contaminated soil or groundwater, allowing more effective transfer of materials used for remedial treatment (e.g., bioremediation amendments, air for air sparging, vacuum for vapor extraction, soil flushing materials, etc.). [14]

2.4.2.7. Downhole water-oil separator:

the hydrocarbon industry developed the downhole oil–water separation (DOWS) technology in the 1990s. In spite of having such cost-efective and environment-friendly solutions.

The membrane-based separation methodology represents the coherent solution to robust the downhole separation system that does not require any moveable equipment with advance sensors and mechanical tools. If the reservoir is well characterized and a reliable simulation model is built, it is possible to predict the optimal time for the placement of a specifc length of membrane in the well depending on the layer concerned and inclination of the well.

In general the mechanical methods are known to be most suitable for wellbore related problems but can as well be used in combination with the chemical shutoff methods depending on the complexity of the reservoir problem. Of recent, the chemical methods have gained more industrial acceptability and thus have higher application than the mechanical methods.[13]

Conventional mechanical and chemical treatment methods are listed in table 2.3:

Tab2. 3: Treatment method.

Mechanical Method	**Chemical Methods**
Cement plug	Micro-matrix cement
Straddle packers	Gels and resins
Bridge packers	Gelants
Patches	Micro-particle blends
Cement	Foamed systems
Sand plugs	Relative permeability modifiers (RPM)
Expandable tubulars	Emulsions
Infill drilling	Precipitates
Horizontal well	Microorganisms
Pattern flow control	Polymers
Downhole water-oil separator	Calcium carbonates

Latest advancements in mechanical and chemical treatment methods are listed in table 2.4:

Tab2. 4: advancements treatment methods

Chemical Methods	Mechanical Methods
MARA-SEAL delayed crosslink gel	PatchFlex through-tubing casing patch
OrganoSEAL Organic crosslink gel	PosiSet plug-back tool
MARCITSM crosslink synthetic polymer gel	CoilFLATE permanent bridge plug
DGS delayed gelation system	
PERMABLOK plug	
SqueezeCRETE cementing solutions	
Co-polymer (acrylamide and t-butylacrylate) crosslinked gel	
Phenol/formaldehyde crosslinked polymer gel	
Lignosulfonate gel	
Polymer-gel Disproportionate Permeability Reduction (DPR)	

Excess Water Production Problems and Treatment Categories

There are several issues with water and excess-water production in oil and gas production wells (from newly drilled wells to wells with decades of hydrocarbon production). Four problem categories are listed in Table 2.5 in the general order of increasing treatment difficulty; within each category, the order of listing is only roughly related to the degree of treatment difficulty. The severity of excess water problems can generally be categorized depending on the difficulty to treat the problem and the relative success achieved post-treatment. However, it is more common to categorize based on the origin of the problem water, whether it being a wellbore integrity issue or a reservoir-related issue. Category A includes the application of water shutoff techniques that are generally well established, utilize materials with high mechanical strength, and function in or very near the wellbore. Examples include cement, mechanical tubing patches, bridge plugs, straddle packers, and wellbore sand plugs. [15]

Tab2 ..5: Water production problem and treatment category.

Easiest Problems	**Category A: "Conventional treatment" effective case**
	1. Casing leaks without flow restrictions 2. Flow behind pipe without flow restrictions 3. Unfractured wells with effective barriers to crossflow
Problems of Intermediate Difficulty	**Category B: Gelants treatment effective case**
	4. Casing leak with flow restrictions 5. Flow behind pipe with flow restrictions 6. Two dimensional coning through a hydraulic fracture from an aquifer 7. Natural fracture system leading to an aquifer
	Category C: Preformed gels effective case
	8. Faults or fractures crossing a deviated or horizontal well 9. Single fracture causing channeling between wells 10. Natural fracture system allowing channeling between wells
Most Difficult Problems	**Category D: Difficult problem where gel treatment should not be used**
	11. Three dimensional coning 12. Cusping 13. Channeling through strata with crossflow without fractures

Decision Matrix for Water Problem Detection and Treatment

Table 2.6 lists initial recommendation guide for typical problems, means of identification and evaluation, and chemical treatments available for correcting the problem. In this table only chemical methods are listed as treatments with chemical systems (e.g. gelants, gels) represent an economic and reliable method for water shutoff and have wider range of application than the mechanical shutoff methods thus, have gained more industrial acceptability. The chemical techniques can overcome limitations associated mechanical devices and are most suitable in mature fields. It is important to keep in mind that the appropriate final choice of a solution system should be made on a well-by-well basis, taking all the factors discussed previously into consideration in order to achieve a high success rate. [13]

Tab2. 6: Water Problem Detection and Treatment.

Casing leaks	Corrosion Improper casing and/or formation bond	Unexpected rapid increase in water or gas production	PLT PNL Tracer surveys	WBCS EASS IASS HCPMT Combination of above
Channel behind casing	Poor cement bond to casing and/or formation bond	Unexpected rapid increase in water or gas production	CBL Temperature Logs HPT-SNL PNL	WBCS EASS HBSC HBMC
Barrier breakdown	Natural fractures Breakdown during drilling Pressure differential from production	Unexpected rapid increase in water or gas production Temperature logs show deviation from geothermal gradient when the well is shut-in	Temperature Logs PNL Tracer surveys	EASS IASS HCMPT DCP
Completion into water or gas	Improper log interpretation	Immediate production of unwanted fluids	Driller's daily report Core data OH logs	WCBS EASS, IASS HCMPT HBSC HMBC
Coning and cresting	Reduced pressure near the wellbore draws water and/or gas from adjacent zones	Gradual increase in the WOR and GOR	OH logs PNL Well testing Seismic-geologic analysis	IASS HCMPT DCP SWST
Channel between injector and producer	Heterogeneous reservoir Previous stimulation operation	Production of high amount of injection water Early injection water production Majority of water producing through a small number of perforations	OH logs PNL Tracer surveys	IASS LCMPT HCMPT DCP HBMC Combination of above
High-permeability streaks	Heterogeneous reservoir Previous stimulation operation	Early produced water breakthrough in edge and bottomwater drive reservoirs	OH logs PNL Tracer surveys	IASS LCMPT HCMPT DCP SWST
Stimulation out of zone	Previous stimulation operation	Immediate water or gas production after a stimulation treatment	PLT HPT-SNL	IASS LCMPT HCMPT DCP HBMC

Wbcs = Water-based cement squeeze
EASS = Externally activated silicate solution
IASS = Internally activated silicate solution
HBSC = Hydrocarbon-based standard cement
SWST = Selective water shut-off treatment
HCMPT = Highly concentrated monomer/polymer treatment
LCMPT = Low concentration monomer/polymer treatment
HBMC = Hydrocarbon-based microfine cement

2.5 Cost effect overview

The minimum cost of treating produced water is the cost of simply disposing of the water. This is most frequently accomplished by deep well injection, ocean discharge, and/or hauling. Some pretreatment, particularly before deep well injection, is likely to be needed to maintain well inject ability and minimize well maintenance costs. Typical values given for produced water disposal range from \$0.63 to \$3.15 / m3 (Tomson, M.B,. Oddo, J.E., Kan, A.T., 1992). When more extensive pretreatment is required before disposal or when the produced water is to be used, the cost of produced water treatment includes the capital and operating costs of unit processes applied to the waste stream. Irrigation is one potential use of produced water that has been adequately treated. Various levels of treated water quality will be investigated here and the potential for the use of the treated produced water is vast. The capital and operating costs vary over time in response to changing prices for any consumable product used during the produced water treatment. Cost functions must account for these time variable aspects of cost as well as relating costs to the design and operating variables for each unit process.

2.5.1 What is cost produced water

2.5.1.1 lift cost

The cost problem in relation to lifting the produced water is considered one of the most important problems that affect the total cost of lifting the liquid and reduces the total profit of production, also we don’t forget the need for new and high –capacity lifting equipment.

2.5.1.2 Processing cost

The oil and gas water treatment faces many issue right from raw water treatment to waste water treatment. This industry consumes substantial volumes of fresh water for pressure management, drilling, fracturing, workover and other oilfield applications, that have large cost effect in processing and treatment and technical that used in it. Substituting this water with lower grade, non-potable water can greatly improve the water security in water scarce areas. The use of non-potable aquifer water is however often restricted by high concentrations of total dissolved solids (TDS) and sulfate, requiring treatment before use.

2.5.1.3 Disposal cost effect

The Oil and Gas Industry first utilized underground injection as a means of disposing of the naturally occurring brine that was often produced along with crude oil and / or natural gas in the 1930's. In 1974, the Safe Drinking Water Act required the U.S. Environmental Protection Agency (EPA) to set minimum requirements for the brine injection wells utilized by the Oil and Gas Industry along with numerous other wells used for disposal of various hazardous and nonhazardous wastes.

These requirements are generally referred to as the Underground Injection Control (UIC) program. Since inception of the UIC program, Class II wells (those wells classified for injection of oil and gas liquids including oilfield brine disposal wells) have safely injected over 33 trillion gallons of oilfield brine without endangering underground sources of drinking water (USDW).

The disposal cost effect have difficult to minimize from production to injection or disposal.

Cost of water disposal and treatment at some companies that operate disposal wells:

Texas, Louisiana, and Oklahoma are home to many companies that operate commercial disposal wells. The disposal costs range between $0.30/bbl and $10.00/bbl. In most cases, costs are less than $1.00/bbl. Evaporation of produced water is most widely reported in Wyoming (seven companies), followed by Colorado (four companies), Utah (four companies), and New Mexico (three companies). The disposal costs range between $0.40/bbl and $3.95/bbl — one company in Colorado asks $84.00/bbl. Burial in municipal landfills is potentially available for produced water across the nation. However, solidification, which is generally required, drives up the costs. Volume-based costs range between $3.00/bbl and $22.00/bbl in Texas and North Dakota, and $18.00 yd in New Mexico. Weight-based costs vary significantly by state, but generally fall into a range between $15.00/ton and $80.00/ton. Mississippi and Louisiana report higher ranges of up to $128.00/ton and $250.00/ton, respectively. Burial of produced water in commercial pits is not widely reported. Three companies — one in Oklahoma, one in Utah, and another one in Wyoming — report costs ranging between $0.35 and $4.00/bbl.Cavern disposal offers a competitive option for produced water in Texas.

Five companies at multiple facilities indicate a cost between $0.30/bbl and $10.00/bbl.

Discharge of produced water was reported by three commercial disposal companies in Pennsylvania and one company in Wyoming. The costs range between \$0.045/gal and \$0.055/gal (\$2.25/bbl and \$2.75/bbl) in Pennsylvania, and between \$2.50/bbl and \$3.50/bbl in Wyoming. All four companies conduct treatment prior to discharge operations. Two facilities in Pennsylvania discharge produced water to a municipal wastewater treatment plant for a disposal fee of \$0.015/gal to \$0.050/gal (\$0.75/bbl to \$2.50/bbl). Land application of produced water is available in Arkansas (one company), New Mexico (two companies) and Utah (one company). Costs are \$0.30/bbl to \$0.40/bbl in Arkansas, \$5.18/bbl to \$18.00/bbl in New Mexico, and \$100/ton (\$26.25/bbl) in Utah.

Treatment of produced water is offered by one company in Alabama and another in Texas. Costs range from \$5.00/bbl to \$14.00/bbl. Recycling of produced water is not widely reported. However, this method has been increasingly applied in some areas. One companyidentified in California charges \$5.00/bbl for recycling; another company in Oklahoma indicates a cost of \$25.00/load.

Thermal treatment of produced water is offered by a Texas company. Costs range from \$0.02/lb to \$0.20/lb (\$40.00/ton to \$400/ton, or \$10.5/bbl to \$105.00/bbl)

2.5.1.4 Environmental cost effect.

Oilfield water or produced water contains various organic and inorganic components. Discharging produced water can pollute surface and underground water and soil.

The produced water can be from the saline water and formation water, when formation water is leaked into groundwater layer or agricultural areas it is large effect of cost or environment cleaning or another services. [16]

CHAPER THREE

3. Methodology

3.1 Introduction

This chapter will discuss an integrated methodology for completion and production data analysis that have used to achieve the objectives of this study. Also it will be explained the data required and steps (work flow) and the output expected in addition to highlight the effect of cost/Environmental. .

3.2 Data required.

The data required to achieve project aim is summarized as the following:

1. Production data
2. Injection data
3. Drilling data
4. Well logging data
5. Petrophysical data
6. Completion data.
7. Well test data.
8. CAPEX and OPEX data

3.3 Software that will be used:

This project utilizes different software packages, described as the following:

3.3.1 Microsoft Office Package:

Microsoft Office 2016 (Excel, Word and PowerPoint) is used to handle the data, writing graduate project and making presentations for the group discussion and the final graduate project defense

3.3.2 OFM Software

The OFM well and reservoir analysis software is a powerful tool developed by schlumberger Information Solutions and designed for the day-to-day surveillance and management of oil and gas fields. OFM software provides a user-friendly interface, enabling you to view, modify, and analyze production and reservoir data. You can perform basic and complex analyses for individual or multiple completions, groups of wells, an entire field, or several fields. OFM software is suited for the occasional user yet sophisticated enough for advanced petroleum engineering analyses. Whether at the wellsite or in the office, OFM software enables you to access or load data from a local desktop, as well as corporate repositories such as Oracle and SQL Server databases.

In general OFM can be used for the following:

• Monitor and survey performance with advanced production views.

• Forecast production with powerful decline and type curve analysis.

• Analyze any asset and share results using standards.

• View, relate, and analyze reservoir and production data with comprehensive tools, including interactive base maps with production trends, bubble plots, and diagnostic plots.

• Use a library of off-the-shelf workflow templates to guide analyses from shale production to waterflooding.

OFM software enables turning data into decisions that can improve oil and gas field performance throughout the entire life cycle**.**

OFM is used in this project to achieve several types of normal analysis for oil and water production analysis to get clear overview on the water production problems. Chan's plot is used to provide essential analysis diagnosis of the produced water then select the suitable control options as well as it is used for production forecast for oil and water that will be used in economic analysis.

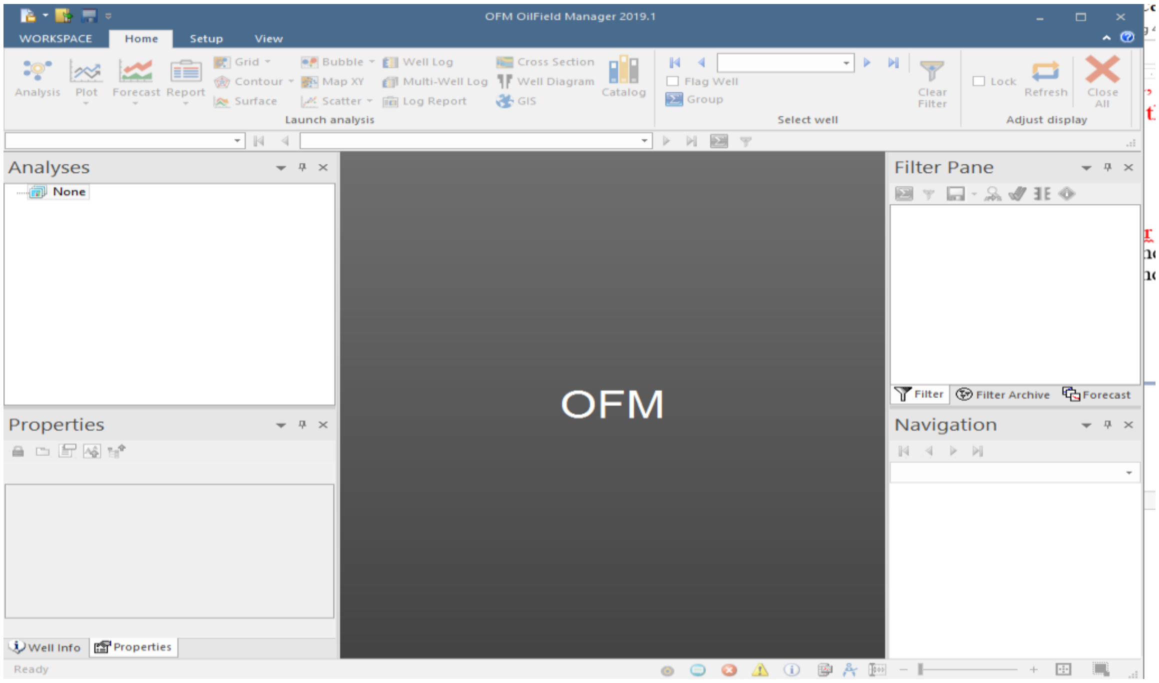


fig3. 1: ofm

3.3.3. Schlumberger Techlog Platform 2015.2

Techlog is a PC based Petrophysical analysis software made by Schlumberger company. Techlog integrates all kinds of well-bore data in an interactive, wide ranging petrophysical analyses tool with a graphical and modern user environment. Techlog software is used for most of the petrophysical analysis, to generate the cross plots , visualize, interpret, and edit all of your wellbore data.

Schlumberger Techlog is used in this project to do a petrophysical analysis, to review and visualized the well logs data, to get a plot with accurate interpretation for the wellbore data and find out what is the specific problem that yield the excessive water production, through well log correlation with well completion .

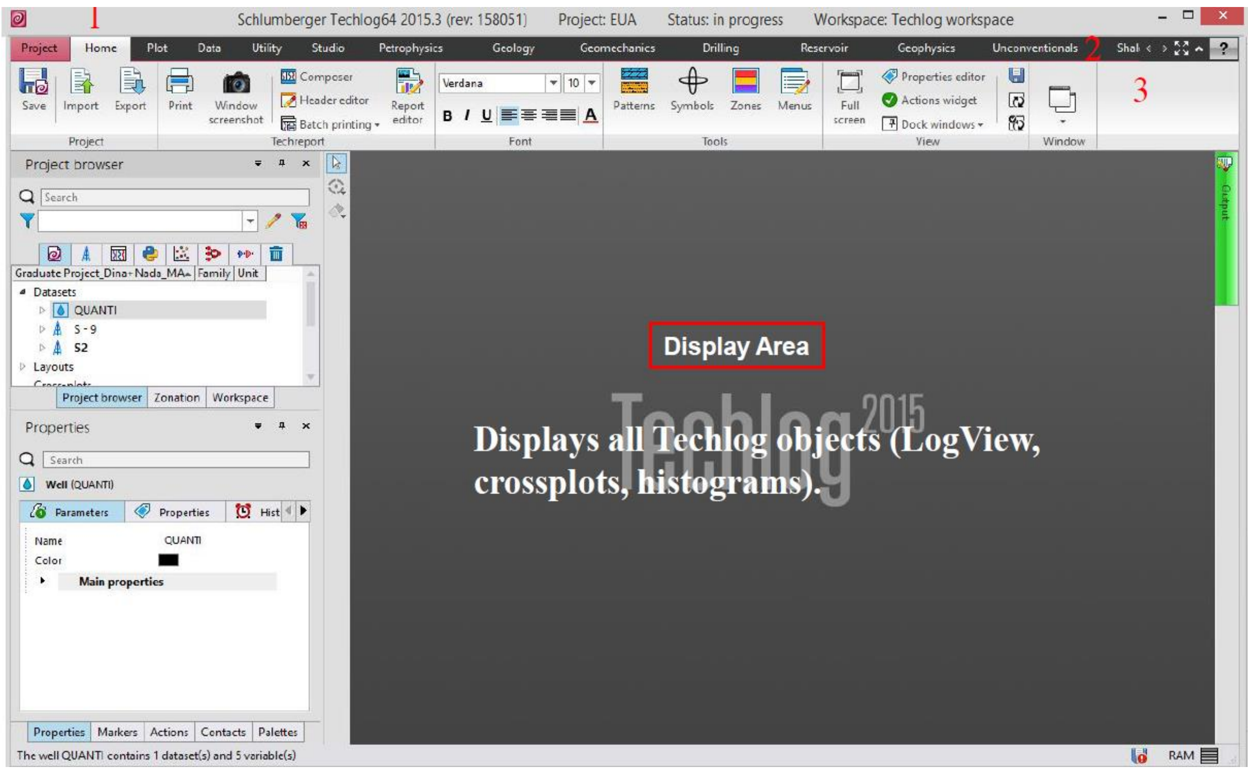


fig3. 2: Techlog

3.4. Steps of the study:

1- Collecting and gathering the required data that mentioned above.

2- Verify then order the data that was collected to be ready to assign into Excel and OFM software.

3- Investigate about any completion problems.

4- Use diagnostic plots to identify and candidate the wells that have excessive water production.

5- Select the wells that produced more excessive water for further analysis and study.

6- Use the chan plot as easy, fast and inexpensive method to find and understand the exactly reason of excessive water production in the candidate wells.

7- Use the other methods for more investigated

8- economic effect will be studied.

9- Suggests a possible treatment for shutoff excessive water production.

10-Make conclusion and recommendation of this study

3.5. Output expected:

The main output expected are:

1- Well Production performance (normal production analysis)

2- Well injection analysis

3-Well completion schematic profile

4- Present the results of performance analysis then select the candidate wells for diagnosis.

5- Diagnostic plots that will be used to identify the main problems.

6- Identify the most expected reasons of excessive water production

7- Select Optimal methods to enhance well oil production with minimal water production.

8- General overview of economic feasibility study

CHAPTER FOUR

4.ANALYSIS AND RESULTS

4.1. Introduction

Diagnosis of water production problems in most cases can be performed with information already available from routine surveillance of the reservoir and the well conditions. Methodology for identification of source of water problems and candidate selection for specific types of treatment have been discussed in a number of technical articles. Based on the extensive reservoir and completion engineering studies and analyses of many field applications, Seright et al categorized the various types of water problems and proposed a guideline for performing effective water problem diagnosis. Generally, a sudden and unexpected increase in water cut is an indicator of water production problem. Plots of water/oil or water/gas ratio versus time can provide a valuable indication of when water production problem has developed. Chan proposed using log-log plots of water-oil ratio (WOR) and time derivative of WOR versus time to differentiate types of water problem. However, WOR diagnostic plots should not be used alone to diagnose the specific cause of a water production problem. If water breakthrough is experienced early in the life of the well, completion problem should be examined first for possible reason. If water entry is experienced later in the life of the well, mechanical or reservoir problems should be considered. As was mentioned before, all oil and gas reservoir inevitably experience increase in water production when they are nearly depleted. Therefore, it is important to evaluate if sufficient amount of hydrocarbons is remaining in the vicinity of the well to economically justify any treatment. Generally, the wells that are at the final stages of production or later stages of a waterflood are not appropriate candidates for water control treatments.

This chapter presents the results and analysis of four wells in Tawila field block-14 as illustrated base map in figure (4.1) .It was noted the water cut in the selected wells were very high .well schematic & perforation data and well logs were presented to analysis using Techlog schlumberger package software .Wells production performance was analyzed using OFM Shlumberger package software combined with excel sheets. The analysis and discussion of the production data of the selected wells are presented as the following:

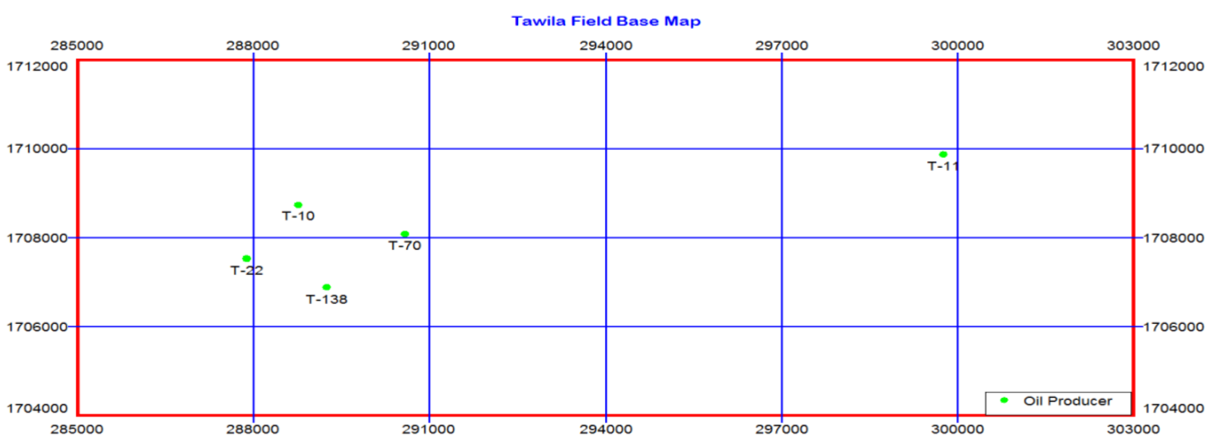


Fig 4. 1: Tawila wells base map

4.2. Tawila-10:

Tawila-10 was drilled and completed Nov / Dec 1996. The well was completed as ESP pump in the Qishn S1A, S2 and S3. As a result of a PLT log conducted, March 12, 1997 a 1 X 5/16" downhole choke was installed above the S3 perforation to restrict the water production. The last PLT conducted Feb 2002 indicated that the zone below the DHC produced water. As of 31/1/2012 the production rate is 127 BOPD and 9054.6 BWPD at a 99 % WC and the cumulative production of oil 11682177.66 bbl

4.2.1. Well Schematics and perforation data

Table below show workover events:

Perforated Date	PERFORATIONS ftKB	ZONE	STATUS
07-Sep-98	5570.0 - 5578.0	USCL S1A	OPEN
07-Sep-98	5620.0 - 5624.0	USCL S2	OPEN
07-Sep-98	5645.0 - 5658.0	USCL S2	OPEN
07-Sep-98	5662.0 - 5664.0	USCL S2	OPEN
07-Sep-98	5668.0 - 5672.0	USCL S2	OPEN
07-Sep-98	5676.0 - 5682.0	USCL S2	OPEN
07-Sep-98	5700.0 - 5708.0	USCL S3	ISOLATED
09-Sep-98	5713.0 - 5718.0	USCL S3	ISOLATED
01-Feb-98	5724.0 - 5730.0	USCL S3	ISOLATED
01-Feb-98	5736.0 - 5742.0	USCL S3	ISOLATED
03-Jan-97	5971.0 - 5979.0	LQC	ISOLATED
25-Dec-96	6049.0 - 6052.0	USCL 1	ISOLATED
26-Dec-96	6066.0 - 6077.0	USCL 1	ISOLATED

Tab4. 1: T-10 perforation data

The total depth and completion are illustrated in wellbore diagram figure (4-2)

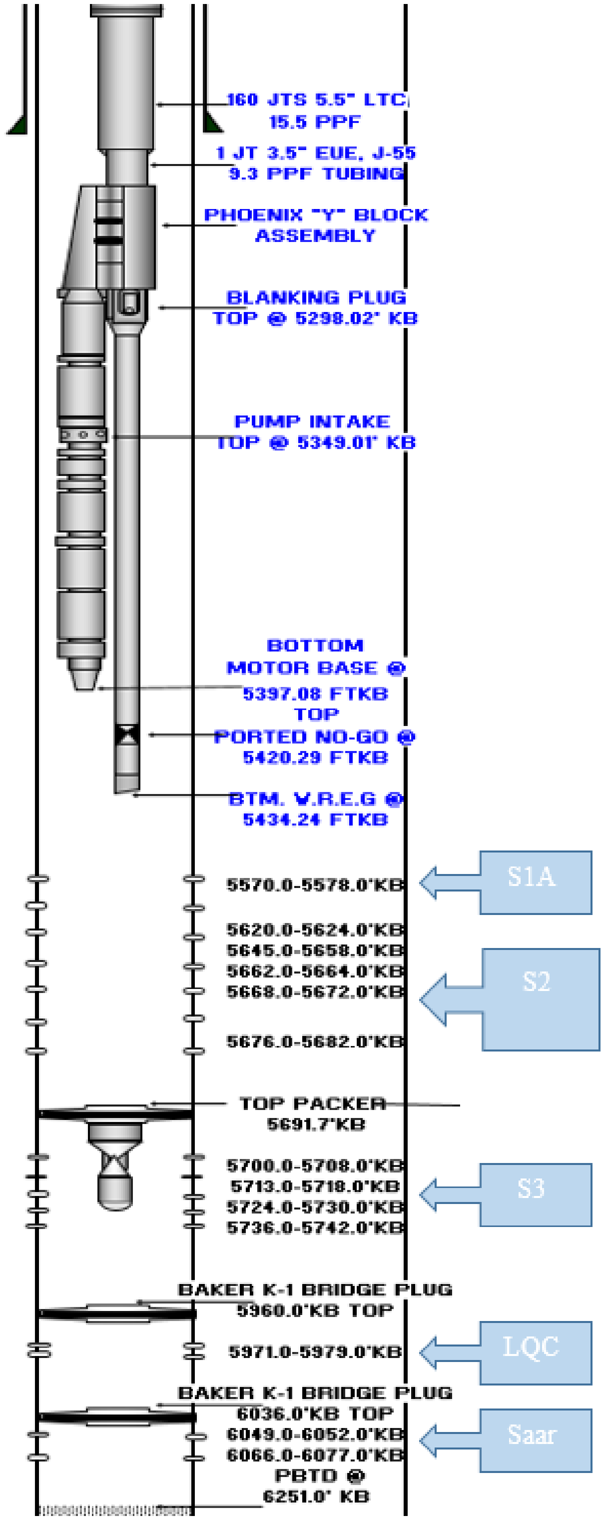


Fig 4. 2:Tawila-10 well scheme and perforation data

4.2.2. Tawila 10 well logs

These log Fig. 4.3 represent type of formation and flow rate and perforation depth and casing size

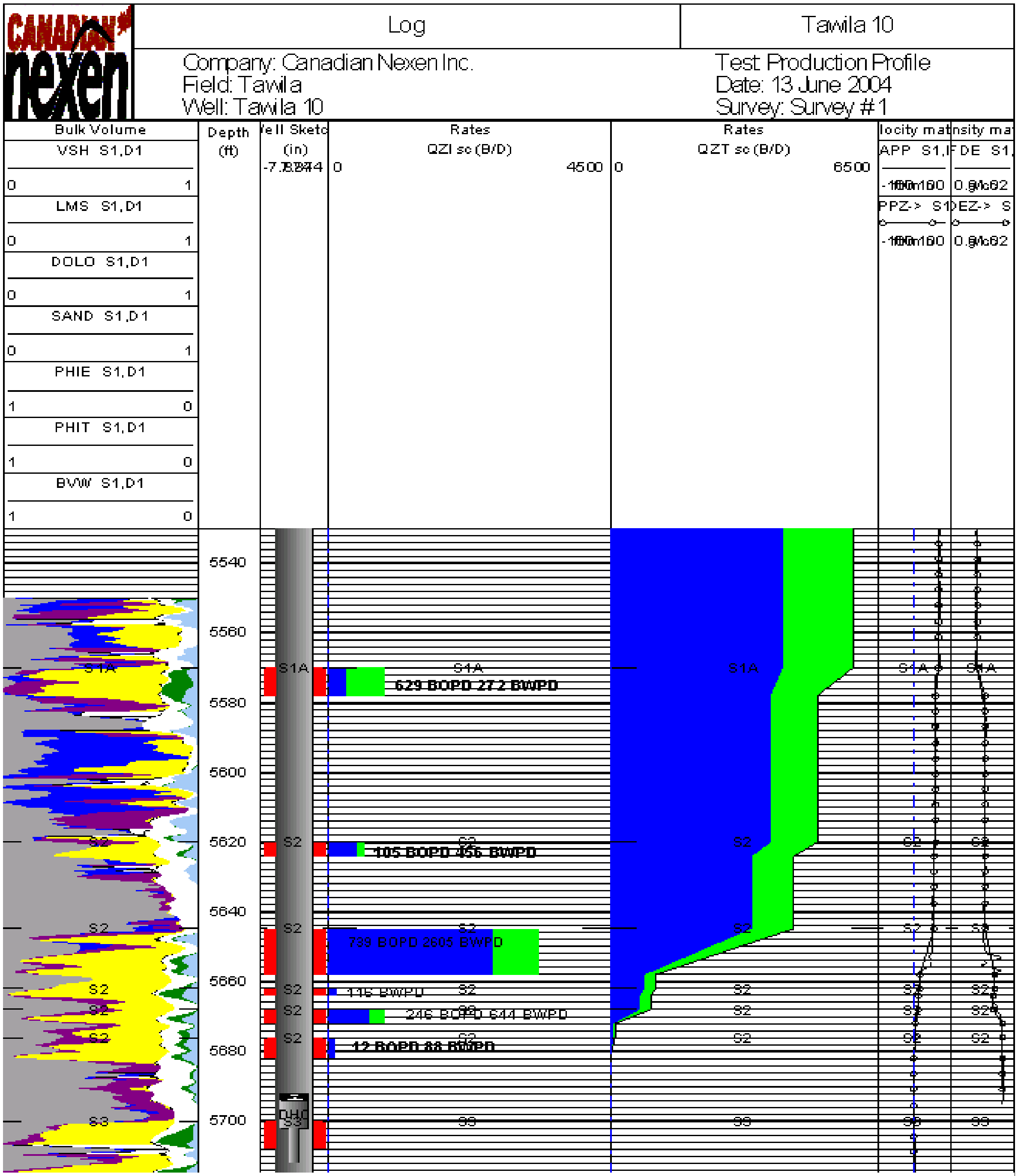


Fig 4. 3 Test Production Profiles

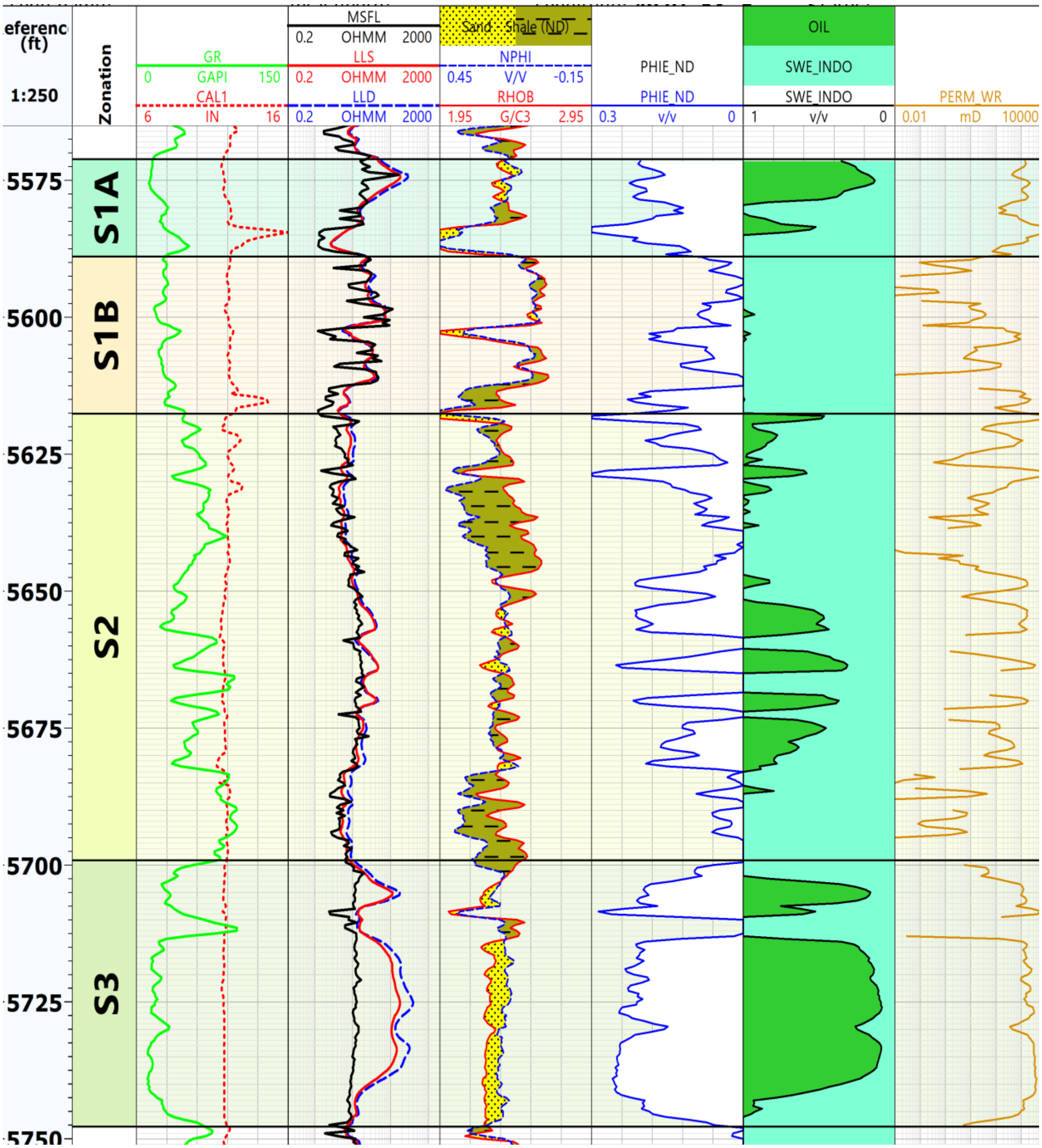


Fig 4. 4: T-10 well logs

4.2.3. Production history Analysis

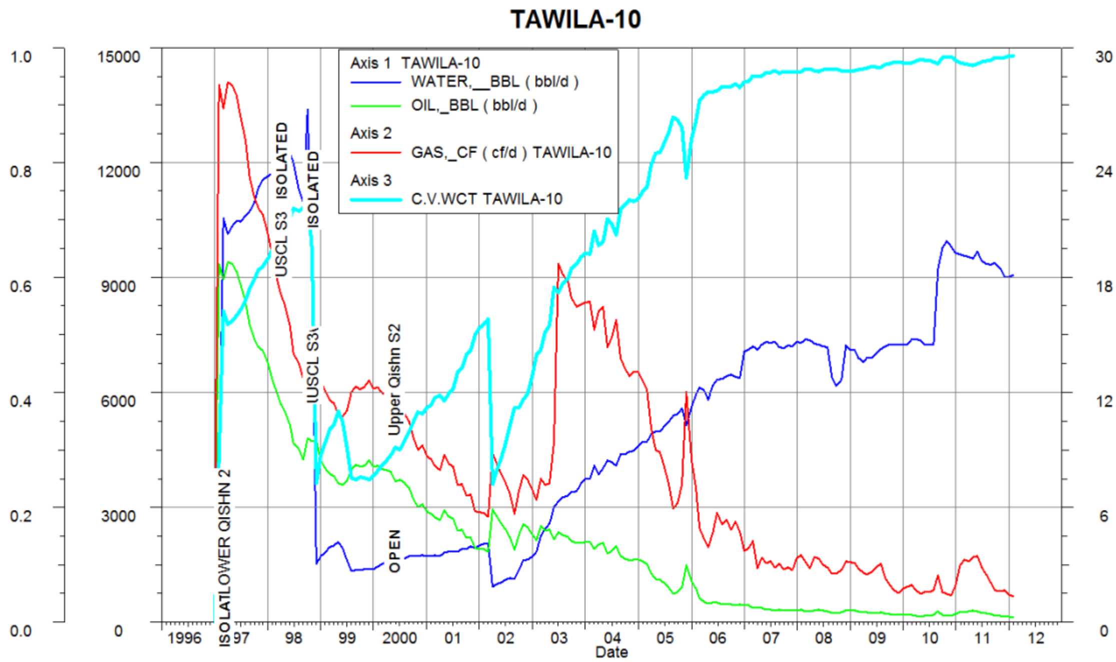


Fig 4. 5: T-10 production history plot

Fig. 4.5 plot helps in visualizing rate changes during the field life cycle and assessing any "uncorrelated behaviors" such as; changes in the rate without corresponding changes in pressure.

Water production problem usually show a simultaneous increase in water production with a decrease in oil production like at 31/3/1999 and at 28/2/2002 & at 31/7/2003 and keeping oil rate in decrease and water to increase to end. It is noted that the oil rate decrease and water rate increase at the same time that mean is not problem of skin.

The water production begin at 1997 such as plot the first oil production was 1220 bbl/d the production was increased from (31/1/1997 to 31/8/1997) from(7416 to 9363 bbl/d) and then the production begin to decrease from (31/10/1997 to 31/5/1999) from(7176 to 3577 bbl/d) then production continued to increase and decrease until at 28/2/2002 and they did a maintenance of well to increase oil production from (31/3/2002 to 31/1/2004) after that the oil production rate decreased to end.

In contrast to water production rate was rabidly increased from (31/1/1997 to 30/9/1998) from (3815 to 13380 bbl/d) and in September 1998 perforations was isolation in S3 zone to be decrease water production rate from (13380 to 1521 bbl/d) and slowly increased to 28/2/2002 in Feb./2002 the maintenance that decreased the water production rate to 931 bbl/d after that rabidly increase to end.

4.2.4. Recovery Plot Analysis

Cumulative oil production at any particular time during the field life cycle is the total amount of the oil produced from a reservoir at that time. The recovery plot can be extrapolated to predict the future performance and estimate the ultimate oil recovery. The point where this plot reaches the economic WOR plot shows the amount of oil production without any remedial action for water production. . The economic WOR limit is the rate of WOR where the cost of handling the produced water is equal to the value of the oil produced.

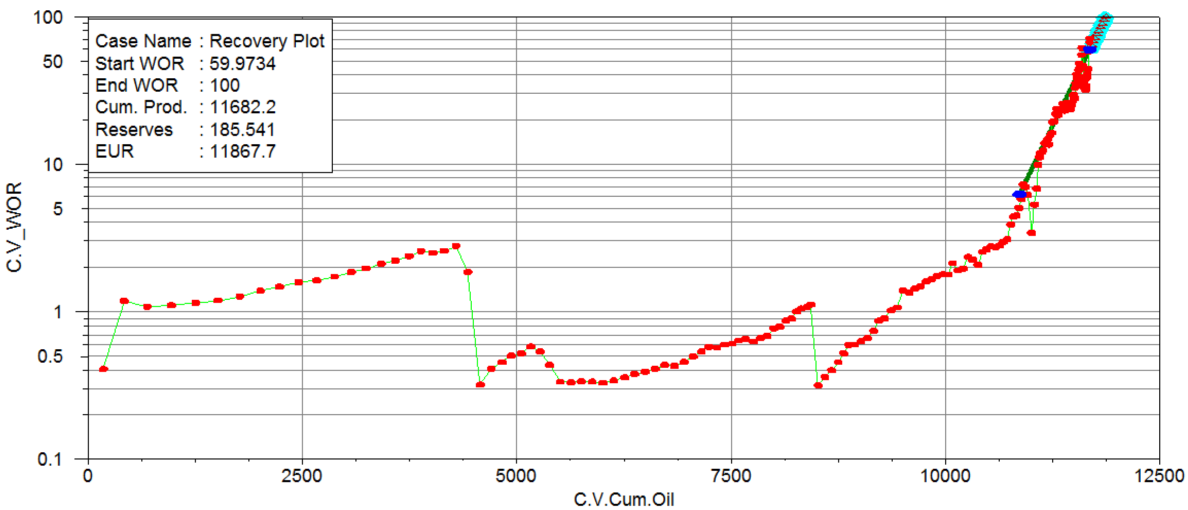


Fig 4. 6:oil recovery plot

WOR was in increase until 28/9/1998 when cum.oil 4,287,699.161 bbl and then WOR begin to reduce because isolated the perforation in S3 zone and then WOR was increase to reach 1.12 at 28/2/2002 the maintenance that decreased the water production rate and then WOR to 0.32 and still in rabidly increase to end the economic cum production 11,681,542.62 bbl and economic WOR 66.67 at economic limit of oil production rate 135 bbl/d such as notes excessive increase in water production without radical solution to these critical problem or do any procedures to reduce it.

4.2.5. Chan plot

Chan (1995) proposed a new methodology to analyze the log-log plot of WOR and derivative of WOR against time in order to differentiate between two common and more complicated water problems of water channeling and water coning.

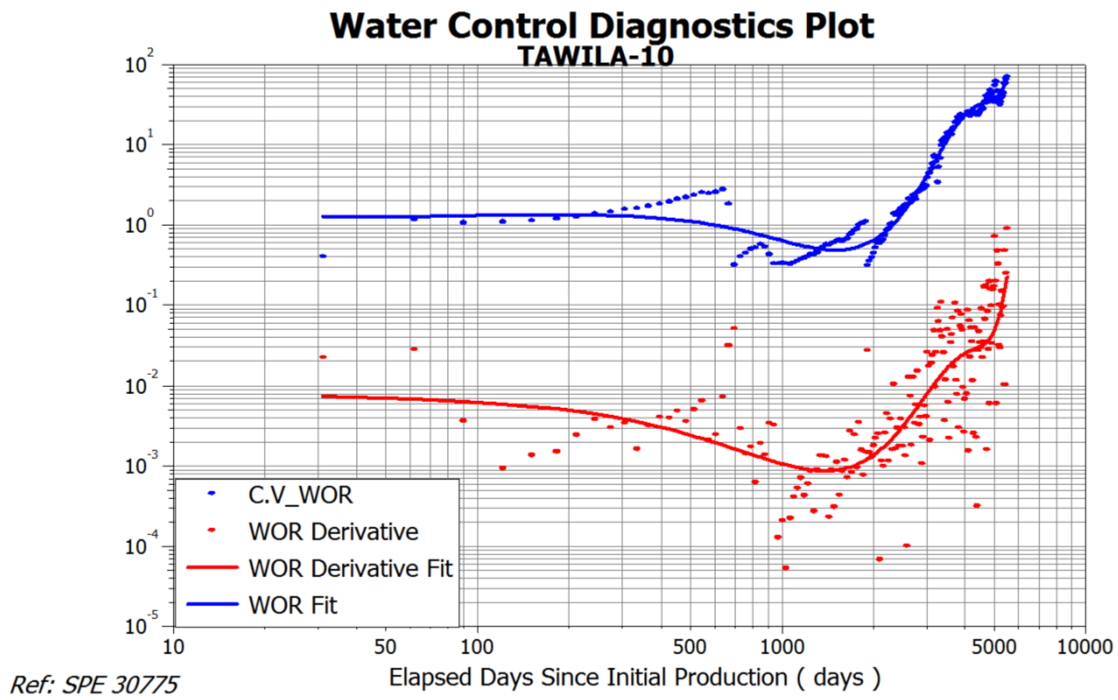


Fig 4. 7: Chan plot of T-10 well

The chan plot represent water oil ratio and derivative water oil ratio .it is in noted the WOR deccrease slowly to 1350 days and from days 1350 and above the WOR and WOR' are rabidly increase the indicator for mature conning.

When the cone is fully developed (reach the reservoir edge) the watered zone acts like high conductivity layers. Edgewater flow generally shows a rapid increase at breakthrough followed by a straight-line curve but for multiple layers , the line may have a stair-step shape depending on layer permeability contrasts after the water cone stabilizes , the WOR curve begins to look more like that for edge flow . The observed WOR response shows that the layers with higher permeabilities have watered out. The sharp increase in WOR at about 1350 days corresponding to a sudden water saturation change at the aquifer front and the less steep at above 1350 days because WOR is starting at higher value. It is needed confirmation by PLT and other methodology

4.3. Tawila-22:

Tawila-22 was proposed as a vertical well to be completed as Upper Qishn producer. The primary objective was the Upper Qishn Clastics S2 and S3 sands and Saar Carbonate being the secondary objective. By drilling this well, the geological and other information obtained will be used for reservoir management. Tawila-22 is located 0.8 km South West of Tawila-20Z and 1.7 km East of Tawila 19. Well Tawila-22 spudded on February 25, 1999.

Tawila-22 was completed in March 1999. The well was completed as ESP pump in the Qishn S2 and S3. As a result of a PLT log conducted, 27/11/2003 a 9*5/8" downhole choke was installed above the S3 perforation to restrict the water production. As of 31/1/2012 the production rate is 215.9 BOPD and 16505.38 BWPD at a 99 % WC and the cumulative production of oil 11,251,343 bbl

HYDROCARBON SHOWS

Crude oil was continuously added during drilling, has masked the actual oil shows in these formations, however individual grains were picked and examined rather than the examination of whole sample. The following is the result.

UPPER QISHN CLASTICS S2: 5800 ft – 5840 ft : SANDSTONE: Light brown oil stain, pale yellow direct fluorescence, slow to moderately fast streaming bluish white cut, no residual ring, light brown residual stain.

LOWER QISHN CLASTICS: 6137 ft **-** 6151 ft: SANDSTONE**:** Light brown oil stain, pale yellow direct fluorescence, bluish white cut, no residual ring.

6171 ft – 6194 ft: SANDSTONE: Light brown oil stain, pale yellow direct fluorescence, fast streaming bluish white cut, light brown residual ring and stain.

4.3.1. Well Schematics and perforation data

Table below show workover events:

Tab4. 2: T-22 perforation data

NAME	PERFORATED	PERFORATIONS ftKB	ZONE	STATUS
TAWILA-22	28-Mar-99	5808 - 5813	Upper Qishn S2	Open
TAWILA-22	28-Mar-99	5819 - 5824	Upper Qishn S2	Open
TAWILA-22	28-Mar-99	5830 - 5848	Upper Qishn S2	Open
TAWILA-22	28-Mar-99	5858 - 5862	Upper Qishn S3	ISOLATED

The total depth and completion are illustrated in Wellbore Diagram figure (4-8)

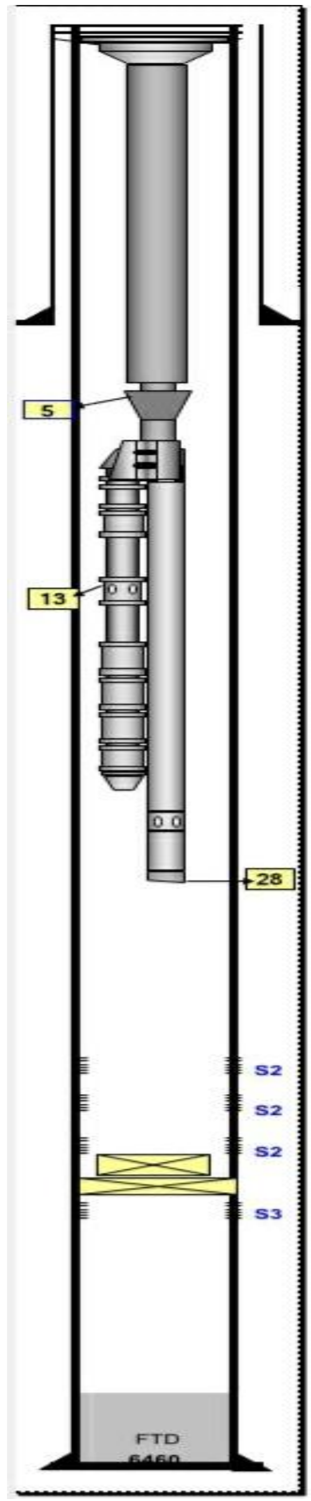


Fig 4. 8: Tawila-22 well scheme

4.3.2. Tawila 22 well logs

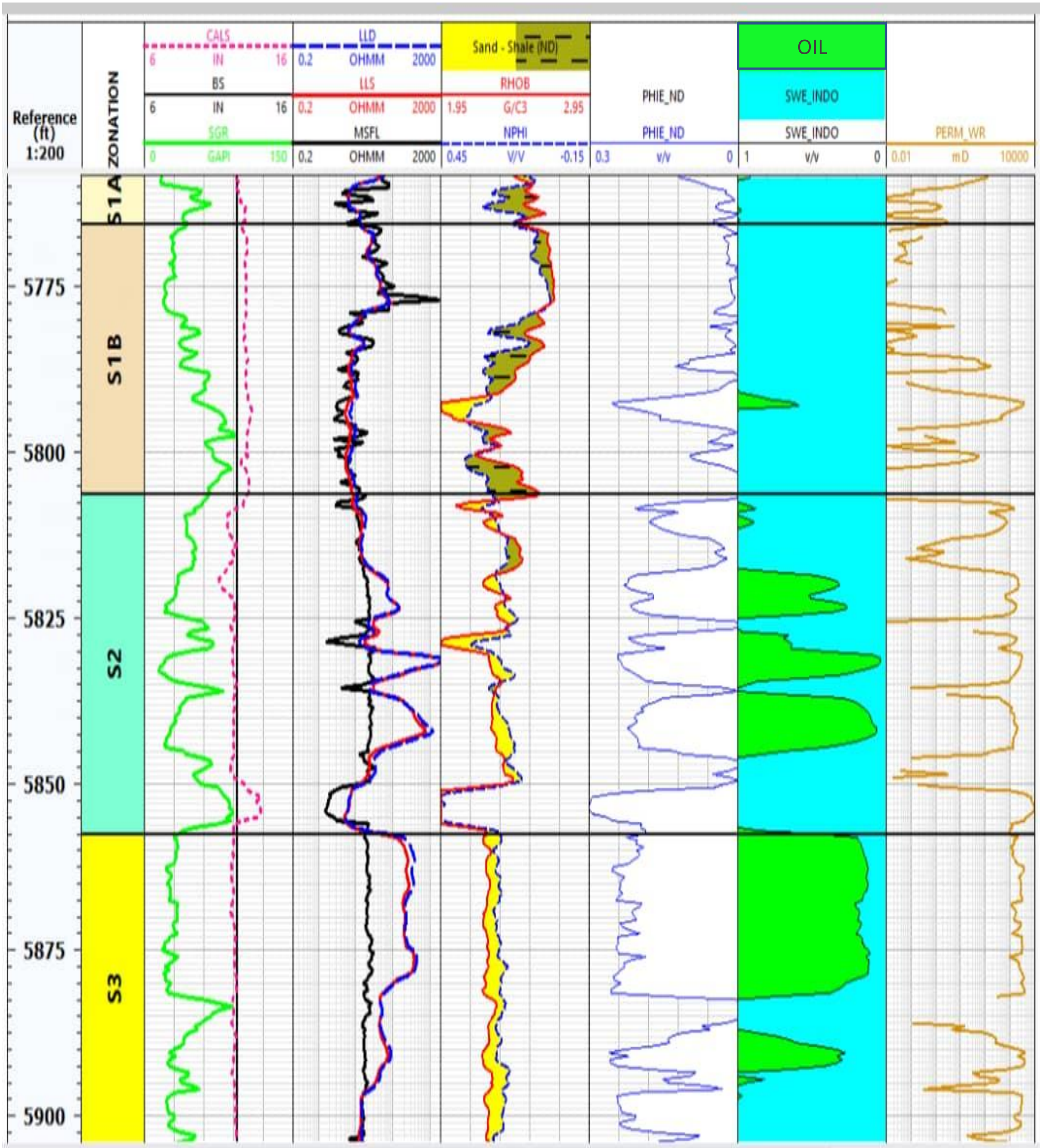


Fig 4. 9: Tawila 22 well logs

4.3.3. Production history Analysis

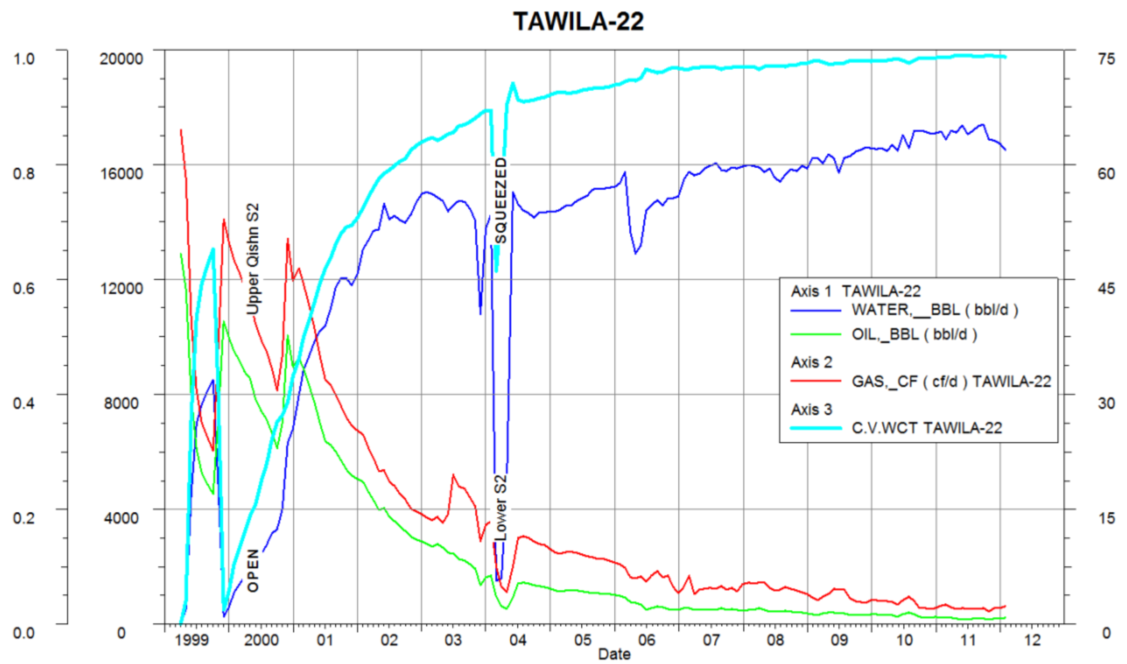


Fig 4. 10 : production history plot

Fig. 4.10 plot helps in visualizing rate changes during the field life cycle and assessing any “uncorrelated behaviors” such as; changes in the rate without corresponding changes in pressure.

Water production problem usually show a simultaneous increase in water production with a decrease in oil production like at 31/5/1999 and at 31/1/2000 and keeping oil rate in decrease and water to increase to end. It is noted that the oil rate decrease and water rate increase at the same time at 31/1/2000 that mean is not problem of skin.

The water production begin at 1999 such as plot the first oil production was 12903 bbl/d the production was decrease from (31/3/1999 to 30/9/1999) from(12903 to 4527.35 bbl/d) and then the production begin to increase from (30/9/1999 to 30/11/1999) from(4527 to 10560 bbl/d) then production continued to increase and decrease until at 28/2/2001 after that the oil production rate decreased to end.

In contrast to water production rate was rabidly increased from (30/4/1999 to 30/9/1999) from (510 to 8491 bbl/d) and in Feb-2004 perforations was isolation in lower S2 zone (5830-5848 ft) to be decrease water production rate from (14281.22 to 4772 bbl/d) and after that rabidly increase to end.

4.3.4. Recovery Plot Analysis

Cumulative oil production at any particular time during the field life cycle is the total amount of the oil produced from a reservoir at that time. The recovery plot can be extrapolated to predict the future performance and estimate the ultimate oil recovery. The point where this plot reaches the economic WOR plot shows the amount of oil production without any remedial action for water production. . The economic WOR limit is the rate of WOR where the cost of handling the produced water is equal to the value of the oil produced

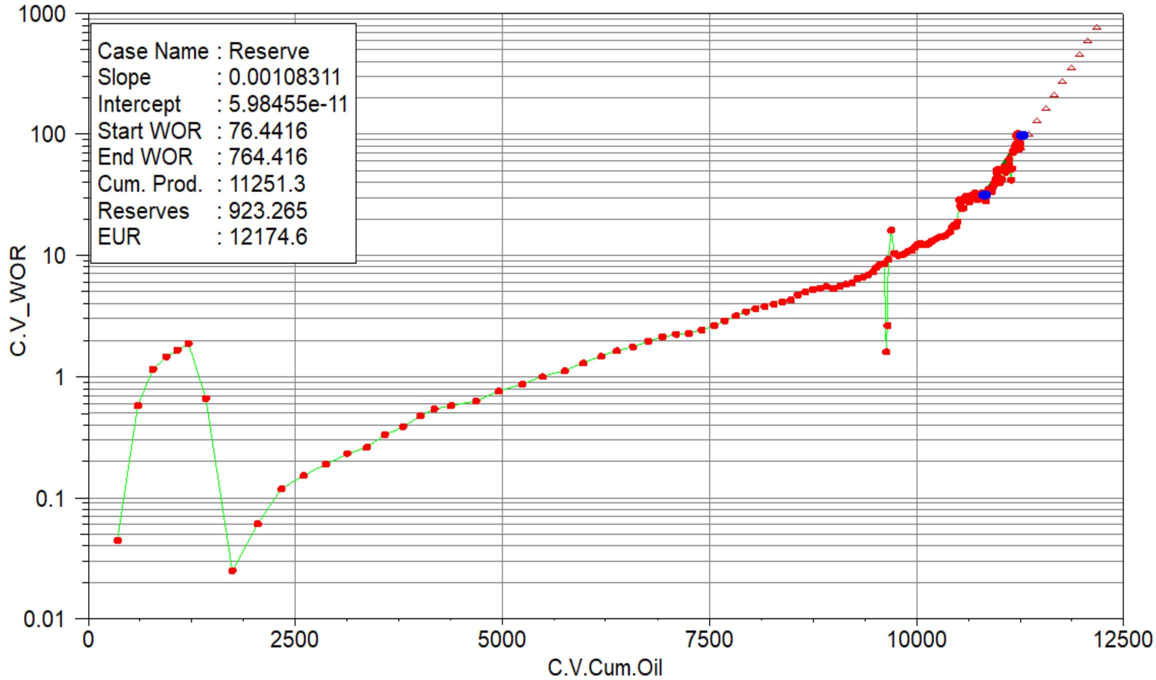
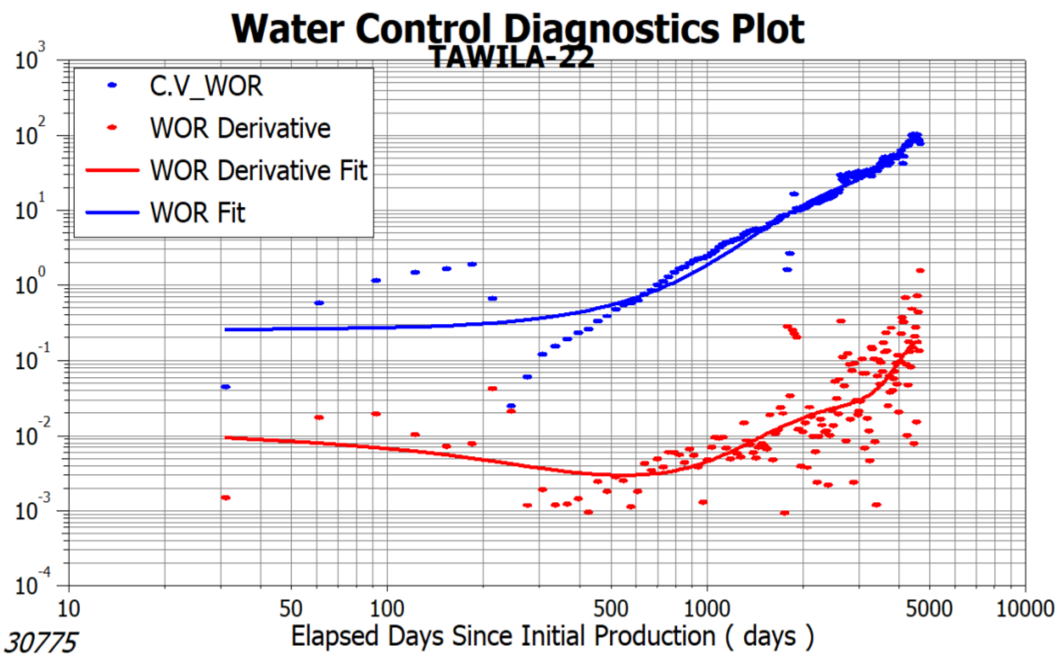


Fig 4. 11: oil recovery plot

WOR was in increase until 1/9/1999 when cum.oil 1,205,712 bbl and then WOR begin to reduce because isolated the perforation in S3 zone to reach 0.060 and then WOR was and still in rabidly increase to end the economic cum production 11,250,264 bbl and economic WOR 84.24% at economic limit of oil production rate 198.41 bbl/d such as notes excessive increase in water production without radical solution to these critical problem or do any procedures to reduce it.

4.3.5. Chan plot

Chan (1995) proposed a new methodology to analyze the log-log plot of WOR and derivative of WOR against time in order to differentiate between two common and more complicated water problems of water channeling and water coning.



Ref: SPE 30775

Fig 4. 12: Chan plot of T-22 well

The chan plot represent water oil ratio and derivative water oil ratio in notes the WOR increase slowly that is indicator of increase in WOR and then increase of water cut then the WOR and WOR' are rabidly increase the indicator for high conductivity layer(channeling). The observed WOR response shows that the layers with higher permeabilities have watered out and it is needed confirmation by PLT and other methodology

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4.4. Tawila-70

Tawila-70 was drilled and completed June 2002. The well was completed as ESP pump in the upper Qishn and lower Qishn. The first produce was on 31/7/2002 from lower Qishn channel with 1200 bbl/d oil and 449.5 bbl/d water and on 8/12/2003 there was a huge increase in water production from 5035.8-55489.6 bbl/m with decrease in oil production from 43,642 to 10,0410 bbl/m . On 27/1/2005 upper Qishn S1B, S2 and S3 was opened and isolated LQ channel. In 1/2007 the U SAAR A, C is opened with squeezed upper Qishn S1B, S2 and S3. As of 30/6/2007 the production rate is 125 BOPD and 6236 BWPD at a 98 % WC and the cumulative production of oil 1,447,730 bbl

4.4.1. Well Schematics and perforation data

Table below show workover events:

Tab4. 3: T-70 perforation data

PERFORATED	PERFORATED ftKB	ZONE	STATUS
25JUNE,05	5882 - 5888	UQS1B	SQUEEZED
25JUNE,05	5920 - 5930	UQS2	SQUEEZED
25JUNE,05	5942 - 5948	UQ-S2	SQUEEZED
25JUNE,05	5958 - 5966	UQ-S3	SQUEEZED
26 JULY,02	6275 - 6308	LQ Channel	SQUEEZED
22-JUNE,07	6345-6355	U SAAR A	OPEN
15-JUNE,07	6375 - 6392	U SAAR C	OPEN
24 JULY,07	6275 - 6308	LQ Channel	LEAKING

The total depth and completion are illustrated in Wellbore Diagram figure (4.13)

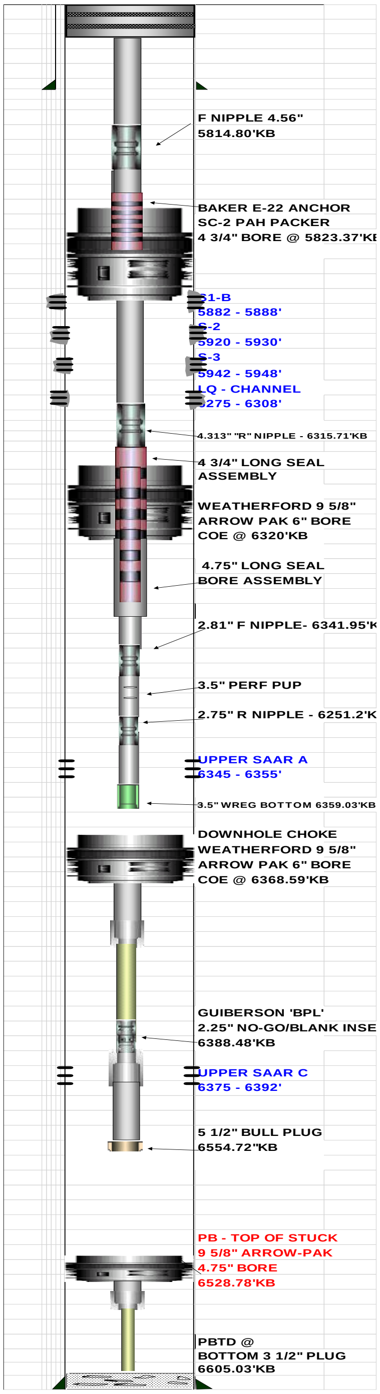

Fig 4. 13 :Tawila-70 well scheme and perforation data

4.4.2. Tawila 70 well logs

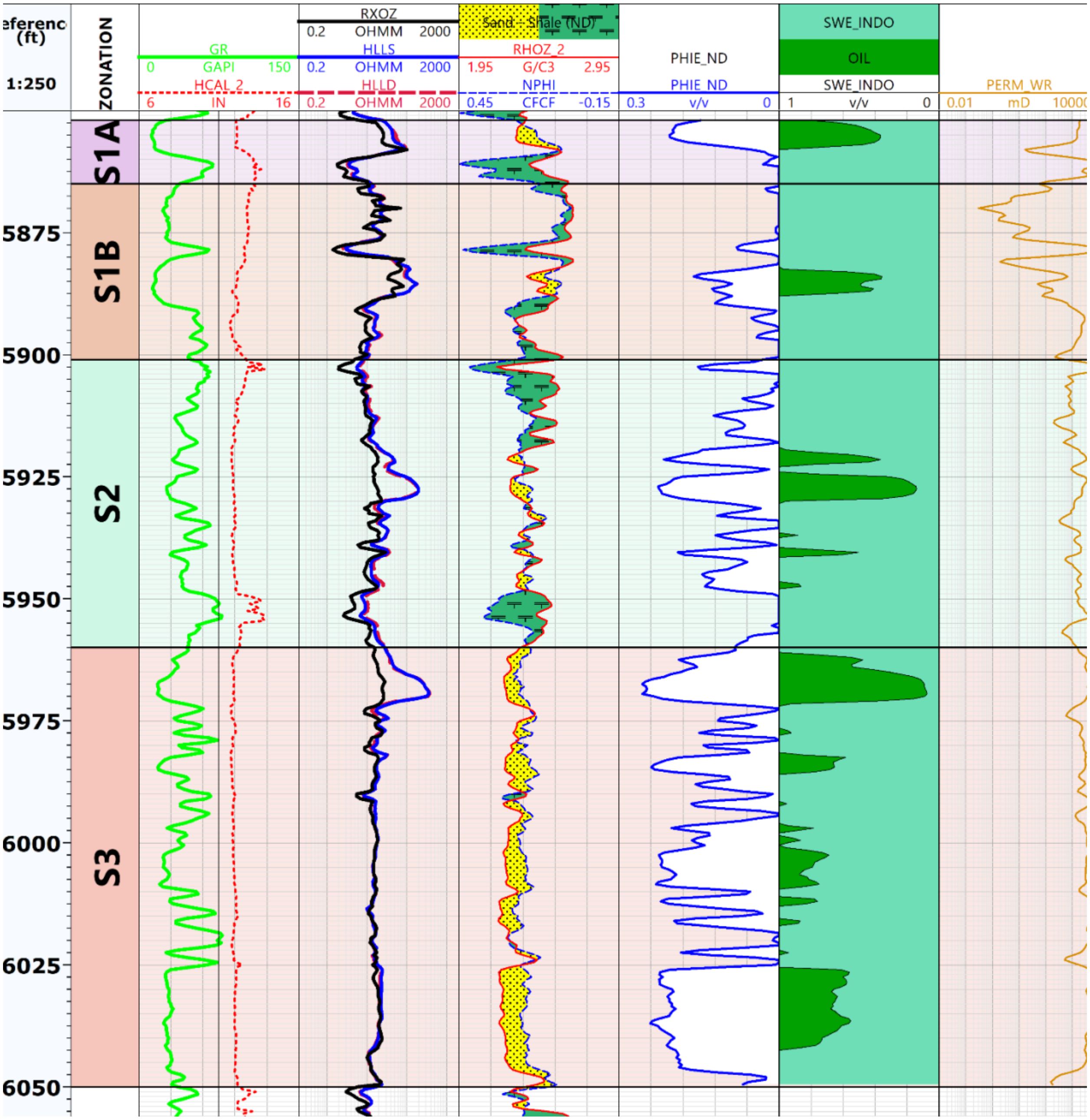

Fig 4. 14 : T-70 well log (1)

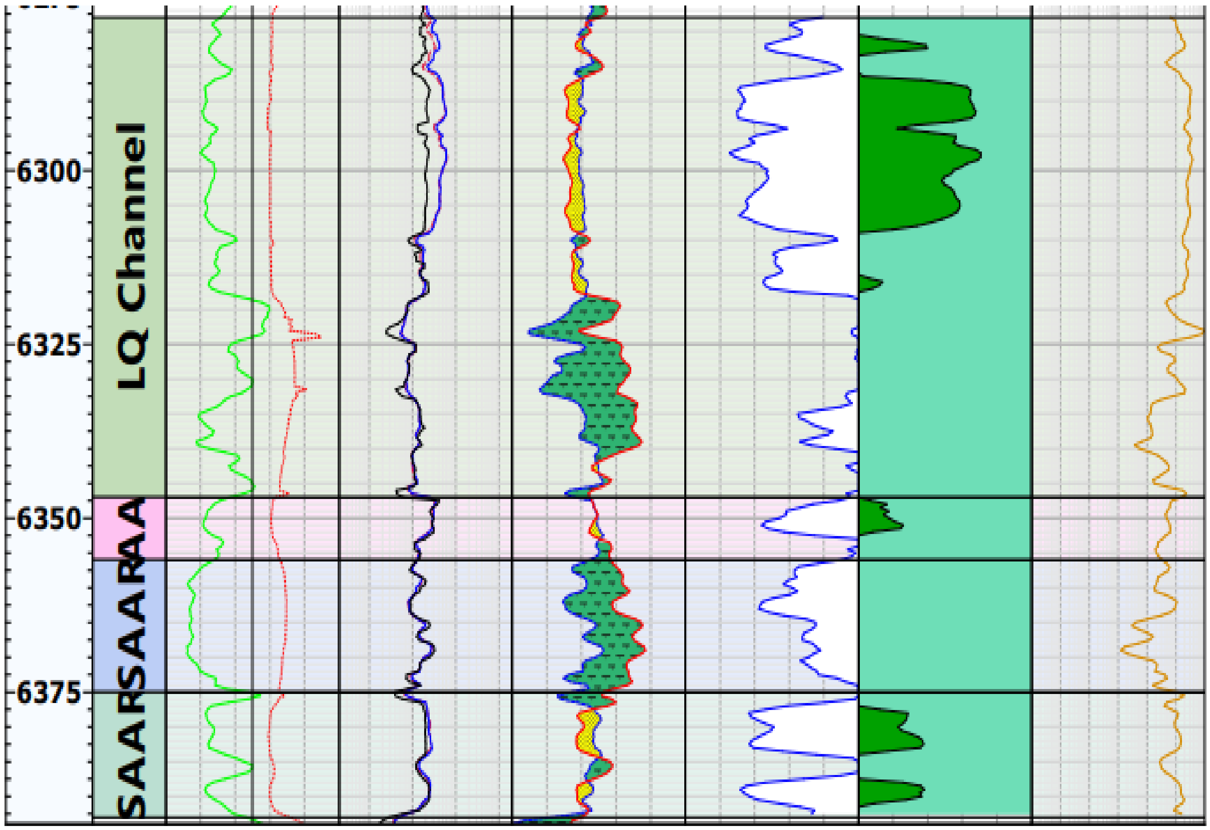

Fig 4. 15:T-70 well log (2)

4.4.3. Production history Analysis

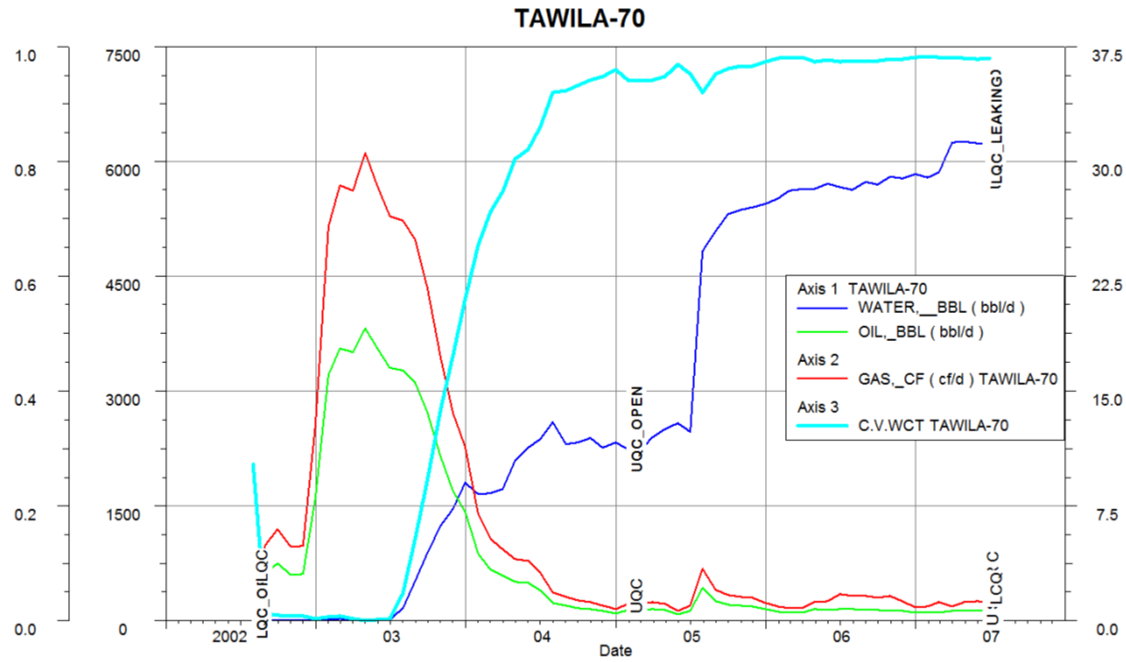

Fig 4. 16: T-70 roduction history plot

Fig. 4.16 plot helps in visualizing rate changes during the field life cycle and assessing any “uncorrelated behaviors” such as; changes in the rate without corresponding changes in pressure The first produce was at 31/7/2002 with 343 bbl/d oil and 128 bbl/d of water the production was increased from (13/7/2002 to 30/4/2003) from (343 to 3820 bbl/d) with decrease in water production from (128 to 4 bb/d) and from 30/6/2003 the water production was begin to increase with oil decrease at 6\2005 there was a huge increased in water production from 2463-4823 with increase in oil production from 124-421. After that the oil production rate decreased to end with increased in water production.

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4.4.4. Recovery Plot Analysis

Cumulative oil production at any particular time during the field life cycle is the total amount of the oil produced from a reservoir at that time. The recovery plot can be extrapolated to predict the future performance and estimate the ultimate oil recovery. The point where this plot reaches the economic WOR plot shows the amount of oil production without any remedial action for water production. . The economic WOR limit is the rate of WOR where the cost of handling the produced water is equal to the value of the oil produced.

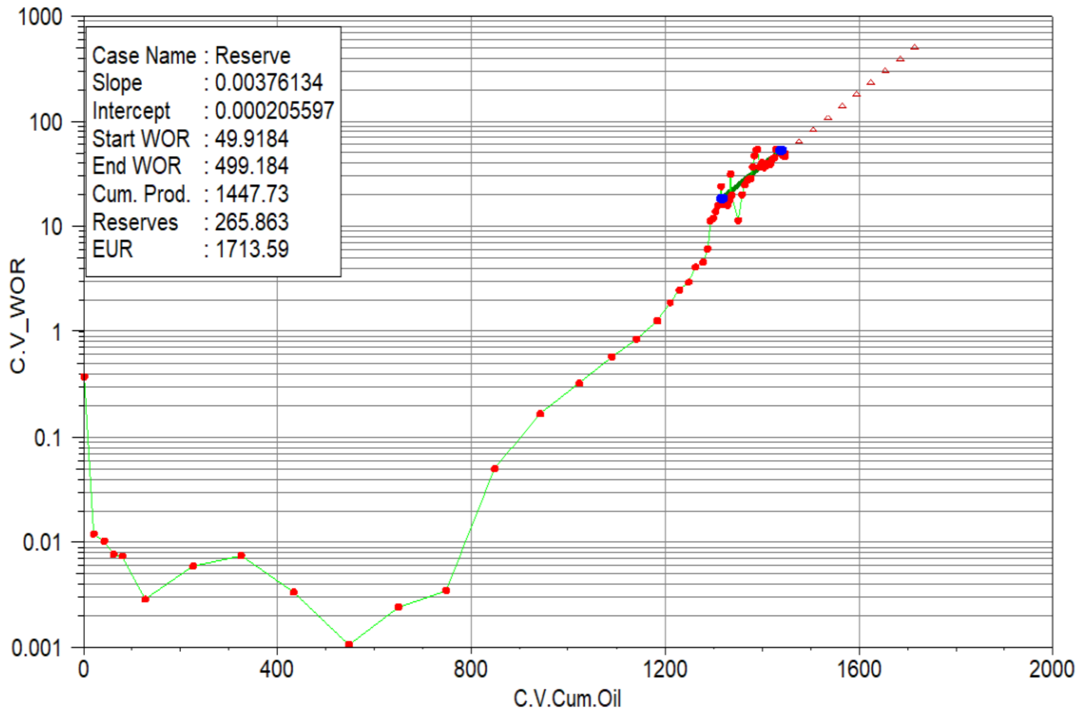

Fig 4. 17: T-10 oil recovery plot

WOR was in decrease until 31/12/2002 to the 151 day when cum.oil is 126,590 to reach 0.003 and after that days its begin to increase until 28/2/2003 to 0.007 and decrease again to 0.001 at 5/2003 and after that the WOR was in rabidly increase to end the economic cum rate 1446860 bbl and economic WOR 46 at economic limit of oil production rate 134 bbl/d such as notes excessive increase in water production without radical solution to these critical problem or do any procedures to reduce it

4.4.5. Chan plot

Chan (1995) proposed a new methodology to analyze the log-log plot of WOR and derivative of WOR against time in order to differentiate between two common and more complicated water problems of water channeling and water coning.

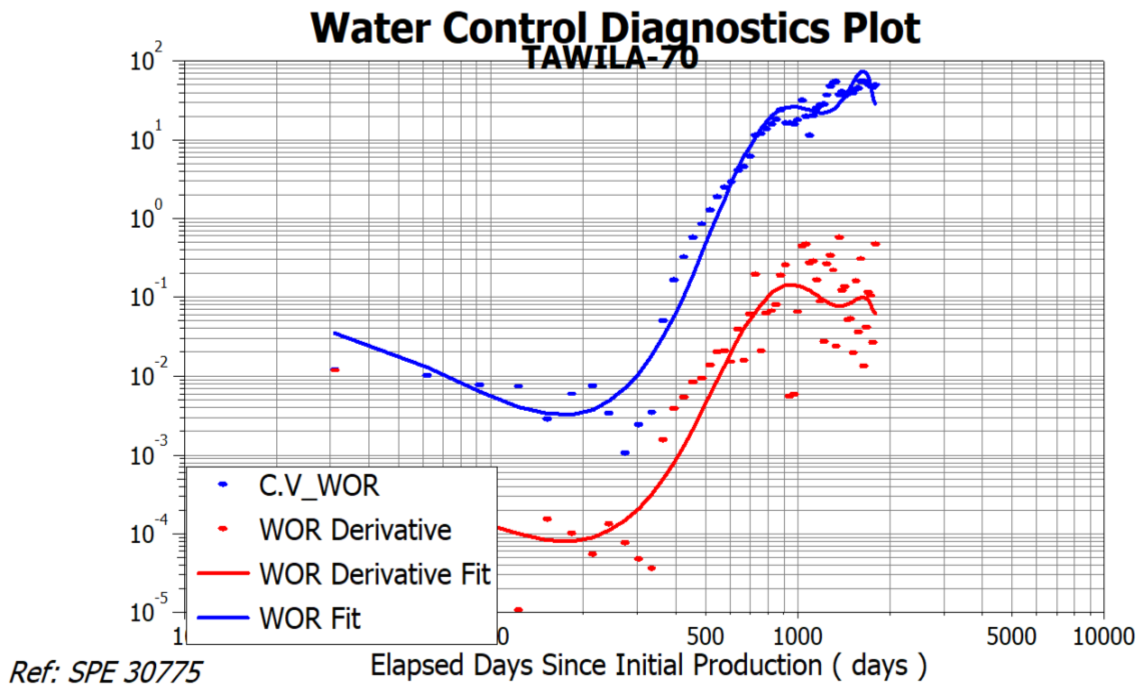

Fig 4. 18: Chan plot of T-70 well

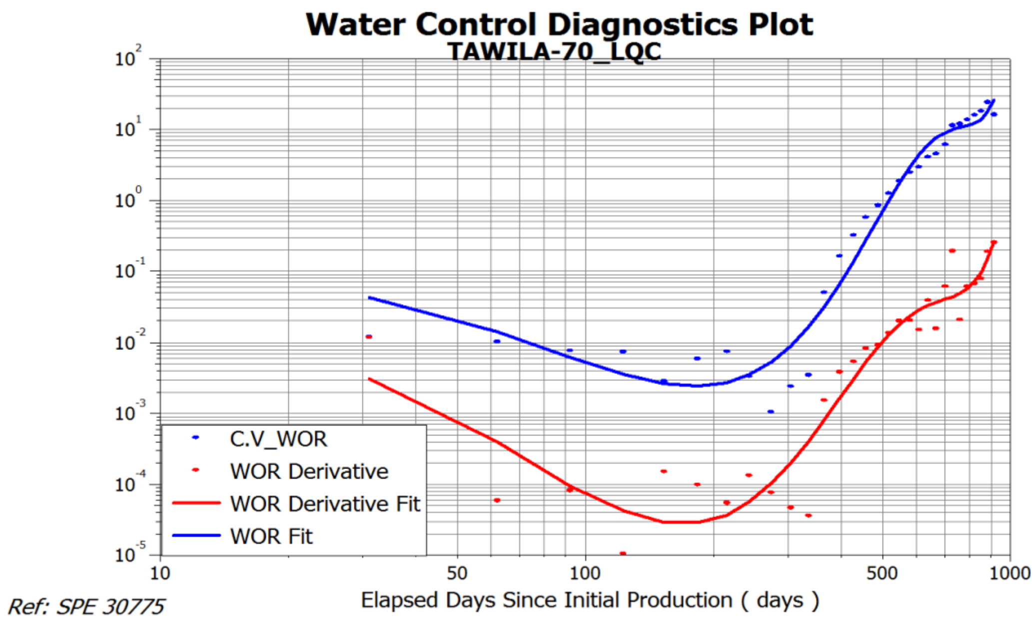

Fig 4. 19 :Chan plot of T-70 well Lower QC

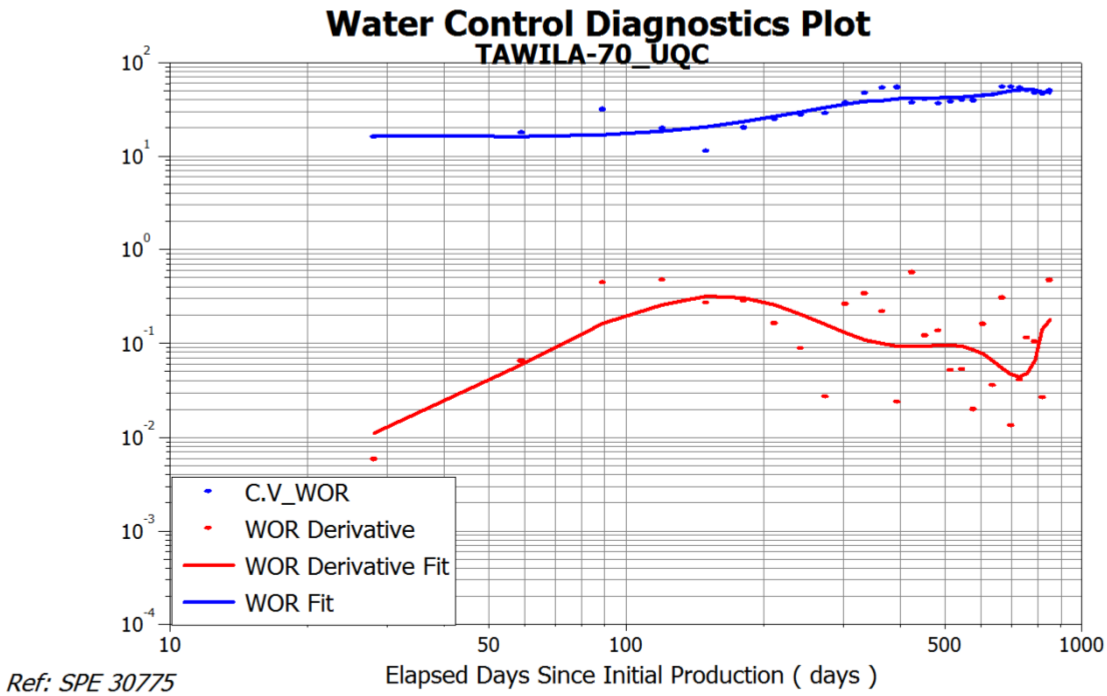

Fig 4. 20 :Chan plot of T-70 well Upper QC

The chan plot represent water oil ratio and derivative water oil ratio in notes from days 300 and above the WOR and WOR' are rabidly increase the indicator for coning and channeling for both upper and lower QC. It is needed confirmation by PLT and other methodology

4.5. Tawila-138:

Tawila-138 was drilled and completed Nov / Dec 1996. The well was completed as ESP pump in the Qishn S1B, S2. As of 31/1/2012 the production rate is 358.3 BOPD and 15,165.8 BWPD at a 98 % WC and the cumulative production of oil 432,340 bbl.

The Tawila 138 (P11-02) Upper Qishn S2 sandstone is expected to be of similar reservoir quality to the S2 encountered at Tawila 29. An estimated net pay interval of 38 feet is expected. The top of the S2 will be encountered at–2,591 ft. SS, which is 41 feet above the original OWC at –2,650 ft. SS, The top of the S3 at Tawila 138 (P11-02) is to be at –2,654 ft. SS, which is 4 ft. below the original OWC. There is no pay anticipated in the S3.

The attached Tawila Field Qishn S2 structure map is the June 2004 mapping and includes drilling results up to and including Tawila 132. The Tawila Field Qishn S2/S3 original net pay map includes drilling results up to and including Tawila 132.

Table 4.4: expected reservoir properties

Tab4. 4: T-138 Reservoir properties

Zone	Net Pay (ft)	Permeability (md)	Porosity (%)	Sw (%)	Productivity Index (b/d/psi)
S2	38	750-2000	18.0	20	4-6
S3	0	1000-2500	19.5	100	-

Proposed Location Tawila 138 (P11-02)

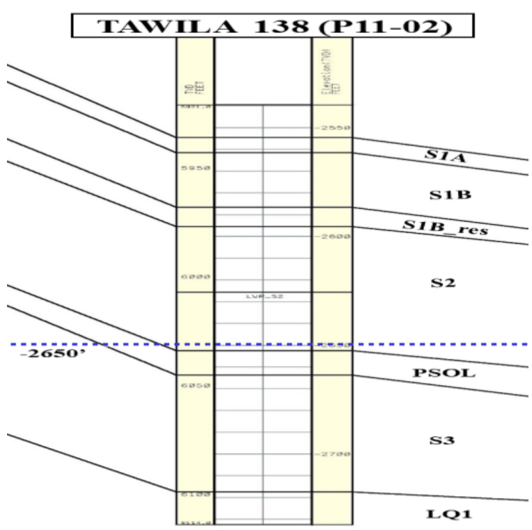

Fig 4. 21: STRUCTURAL CROSS SECTION

4.5.1. Well Schematics and perforation data

Tab4. 5: T-138 perforation data

NAME	PERFORATED	PERFORATION ftKB	ZONE	STATUS
TAWILA-138	5-Dec-04	5960-5965	S1B	OPEN
TAWILA-138	6-Dec-04	5986-5994	S2	OPEN
TAWILA-138	7-Dec-04	5999-6005	S2	OPEN

The total depth and completion are illustrated in Wellbore Diagram figure (4.22)

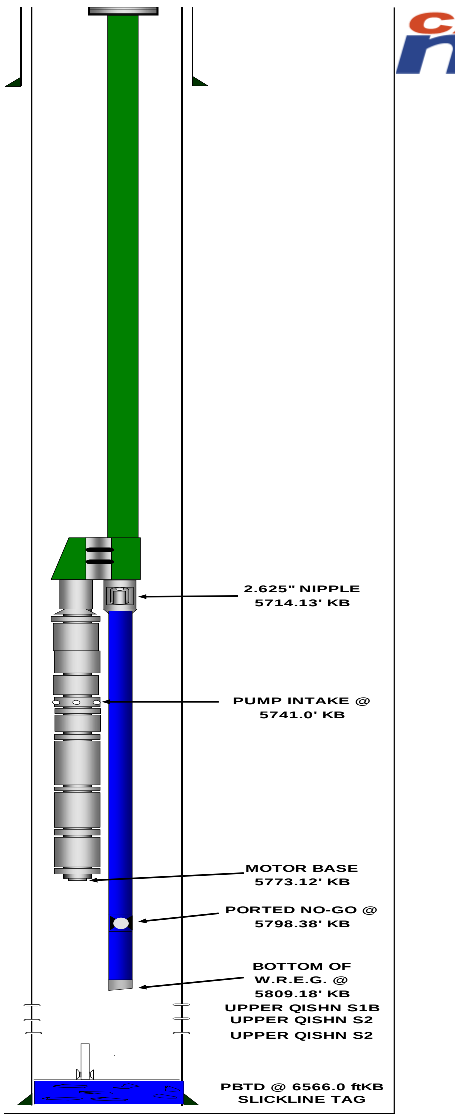

Fig 4. 22: Tawila-138 well scheme and perforation data

4.5.2. Tawila 138 well log

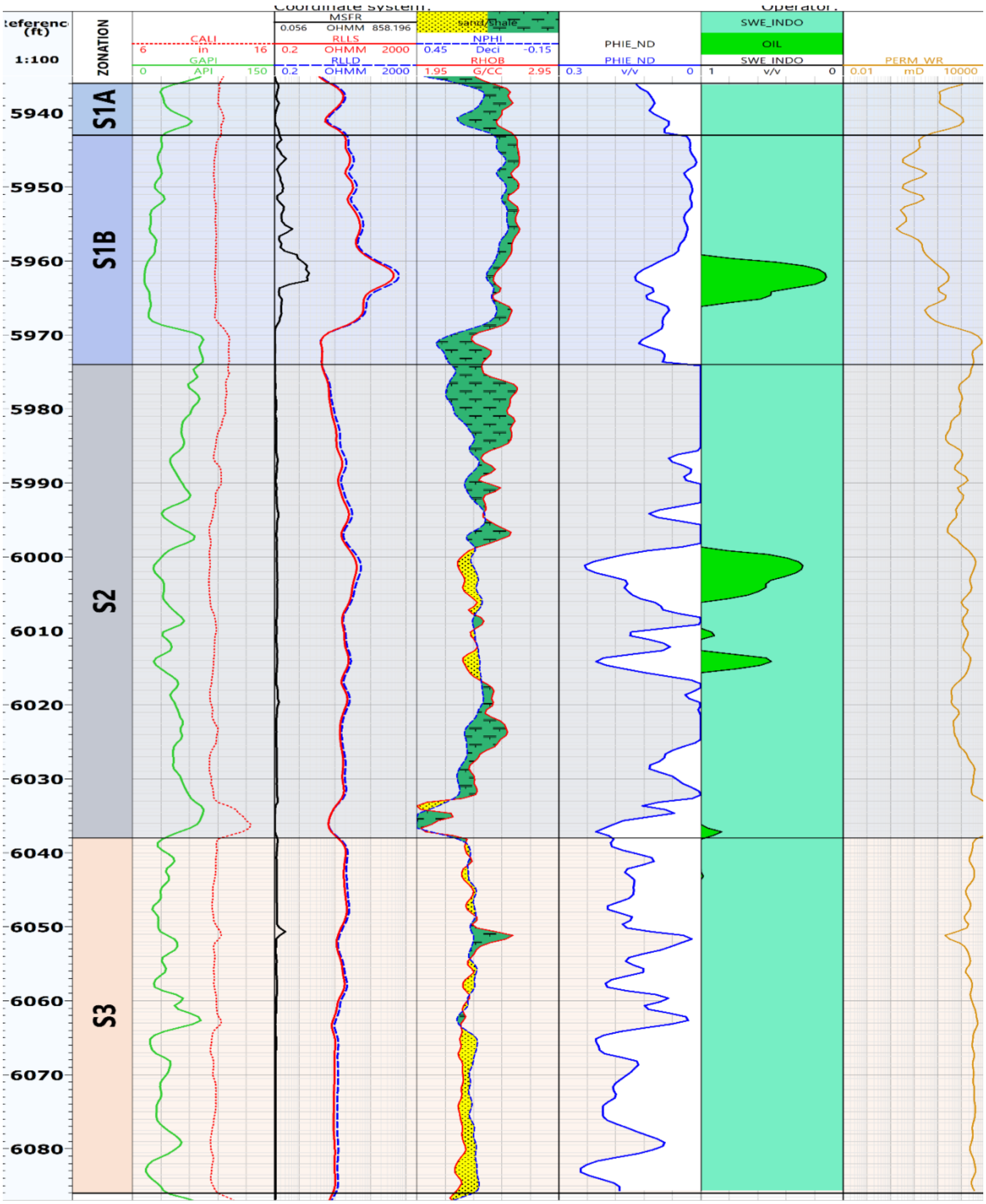

Fig 4. 23: T-138 well logs

4.5.3. Production history Analysis

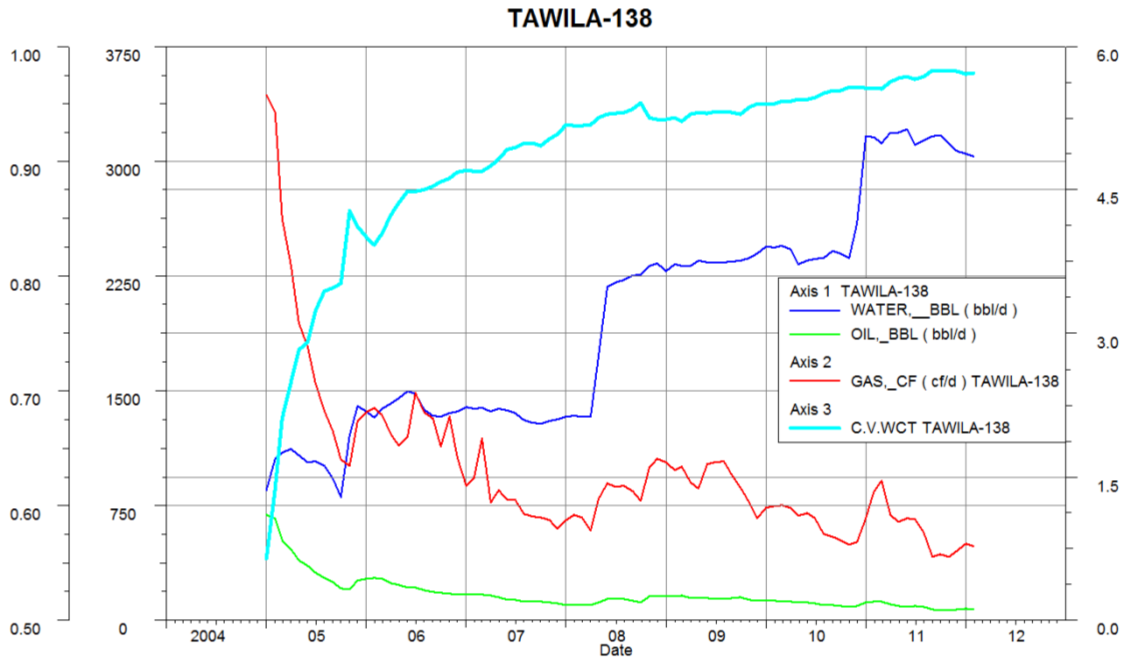

Fig 4. 24: production history plot

Water production problem usually show a simultaneous increase in water production with a decrease in oil production like at 31/12/2004 and at 28/2/2005 and keeping oil rate in decrease and water to increase to end.

The water production begin at 2004 such as plot the first oil production was 687 bbl/d the production was decrease from the beginning (31/12/2004 to 31/3/2008) from(687 to 97 bbl/d) and then the production begin to increase from (31/3/2008 to 31/2/2009) from(97 to 161 bbl/d) then the production last was at 31/12/2010 and the first there month of 2011 after that the oil production rate decreased to end.

In contrast to water production rate was rabidly increased from (31/12/2004 to 31/1/2012) from (851 to 3033 bbl/d). Workover events history for this well is unknown due to lack data.

4.5.4. Recovery Plot Analysis

Cumulative oil production at any particular time during the field life cycle is the total amount of the oil produced from a reservoir at that time. The recovery plot can be extrapolated to predict the future performance and estimate the ultimate oil recovery. The point where this plot reaches the economic WOR plot shows the amount of oil production without any remedial action for water production. . The economic WOR limit is the rate of WOR where the cost of handling the produced water is equal to the value of the oil produced.

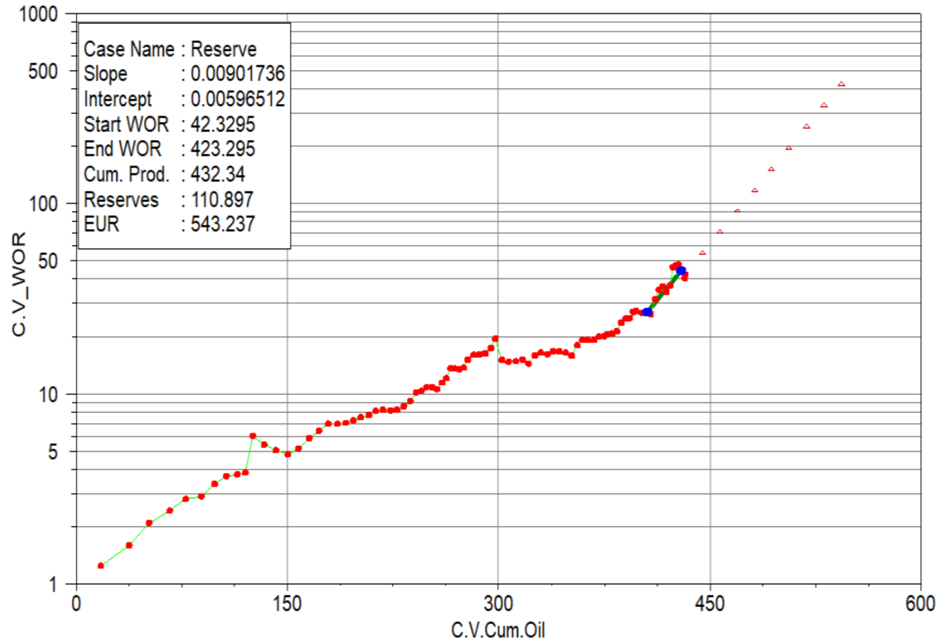

Fig 4. 25: T-138 oil recovery plot

WOR was in increase from beginning to 31/10/2008 when cum. Oil 307,094 the WOR decreased from 31/10/2008 to 28/2/2009 from 19.481 to 14.419 after that the WOR was in rabidly increase to the end the cum oil prod. 432,340 bbl and economic WOR 40.7 at economic limit of oil production rate 75 bbl/d

4.5.5. Chan plot

Chan (1995) proposed a new methodology to analyze the log-log plot of WOR and derivative of WOR against time in order to differentiate between two common and more complicated water problems of water channeling and water coning.

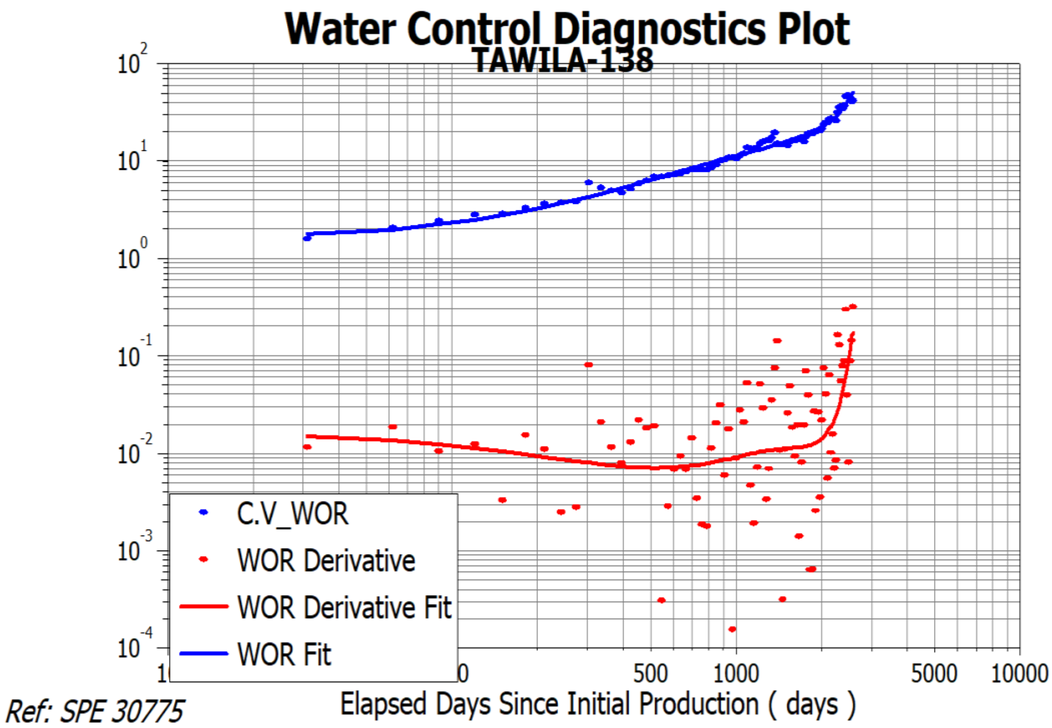

Fig 4. 26: Chan plot of T-138 well

The chan plot represent water oil ratio and the derivative of water oi ratio in this plot the WOR increase slowly at the beginning with decrease in WOR' that is indicator of coning then it is noted WOR and WOR` are rabidly increase that indicator for channeling behavior which is needed confirmation by PLT and other methodology.

Tab4. 6:summarizes the results of analysis

Well name	Well symbol	Group	Well type	Prod. Zone	The problem	High WOR	The suggests solution
Tawila - 10	T-10	Group-1	Production	S1A-S2	Coning and channeling	Yes	RPMs (relative permeability modifiers)
Tawila - 70	T-70		Production	UQC LQC U SAAR A, U SAAR C		Yes	
Tawila - 22	T-22	Group-2	Production	S2	Channeling	Yes	RPMs (relative permeability modifiers)
Tawila - 138	T-138		Production	S1B-S2		Yes	

4.6. Control of Excessive water production

The control options vary from simple to complex depending the type of the problem occurred at the well, The optimum shut off solution is depend on the problem complexity and the cost of the solution.

It is noted that the two groups cases are in channeling status so, the best shutoff solution in this case is by using RPMs (relative permeability modifiers) could be used for sealing-off the water source with a chemical treatment such as polymer gel in case of high permeability layer with bad water, there are many types of RPMs with a different chemical composition, Careful design and placement for the RPM treatment is crucial in order to get benefits from the treatment and not affecting the well performance.

4.7.Produced water cost effect in Tawila field block 14

Water production, handling, treatment, disposal or reuse is considered one of the biggest challenges facing the oil industry, and in Tawila field that it is facing the same problem, because it produces large and excessive amounts of water.

We must figure out Economic strategies for managing produced water require you to explore treatment options, treatment costs compared to disposal costs, and methods to manage risk.

These options should then be compared to the costs of any treatment solution in Tawila oil field.

Due to the lack of economic data of the field, the world wide average presents as we can see below to give a general overview:

Average water Treatment and Handling Cost:

- **Lifting cost :**0.094 $/BBL
- **Chemical cost :**0.074 $BBL
- **Disposal:** 0.01 $/BBL
- **Surface Facilities :** $0.6 $/BBL
-

In some cases, logistics or water hauling can dominate the cost equation; therefore, treatment at the source to reduce volume may make sense.

Table (4.7) show the sample for 4 wells in Tawila field during its entire productive life that represent of the total water treatment cost based on an average cost of water production above (lifting, chemical, disposal and surface facilities, …..etc.):

Tab4. 7:Produced water cost

Dates	Total prod.Water,BBL	Lifting Cost	Chemical Cost	Disposal Cost	surf.Facil cost	Total
1997	7,488,797	$703947	$554171	$74888	$4493278	**$5826284**
1998	4,210,727	$395808	$311594	$42107	$2526436	**$3275945**
1999	2,400,356	$225633	$177626	$24004	$1440214	**$1867477**
2000	2,321,612	$218231	$171799	$23216	$1392967	**$1806214**
2001	5,301,432	$498335	$392306	$53014	$3180859	**$4124514**
2002	6,123,405	$575600	$453132	$61234	$3674043	**$4764009**
2003	7,582,917	$712794	$561136	$75829	$4549750	**$5899509**
2004	8,069,666	$758549	$597155	$80697	$4841800	**$6278200**
2005	10,989,473	$1033010	$813221	$109895	$6593684	**$8549810**
2006	12,420,601	$1167536	$919124	$124206	$7452361	**$9663228**
2007	12,408,570	$1166406	$918234	$124086	$7445142	**$9653868**
2008	11,437,276	$1075104	$846358	$114373	$6862365	**$8898201**
2009	11,880,197	$1116739	$879135	$118802	$7128118	**$9242794**
2010	12,984,241	$1220519	$960834	$129842	$7790544	**$10101739**
2011	12,942,222	$1216569	$957724	$129422	$7765333	**$10069049**
						$100,020,841

Table (4.8) shows the difference in the loss in oil production due to the early non-treatment of wells:

Tab4. 8:Differential loss in EUR

Well	EUR in case there is early treatment MSTB	EUR without early treatment MSTB	Differential loss in EUR MSTB	Loss in Dollars M$
T-10	19682	12395.1	-7286.9	-582,952$
T-22	15074.3	12381.9	-2692.4	-215,392$
T-70	1775	1686.25	-88.75	-7,100$
T-138	916.82	601.638	-315.182	-25,214.6$
TOTAL	37448.12	27064.888	-10383.232	-830,659$

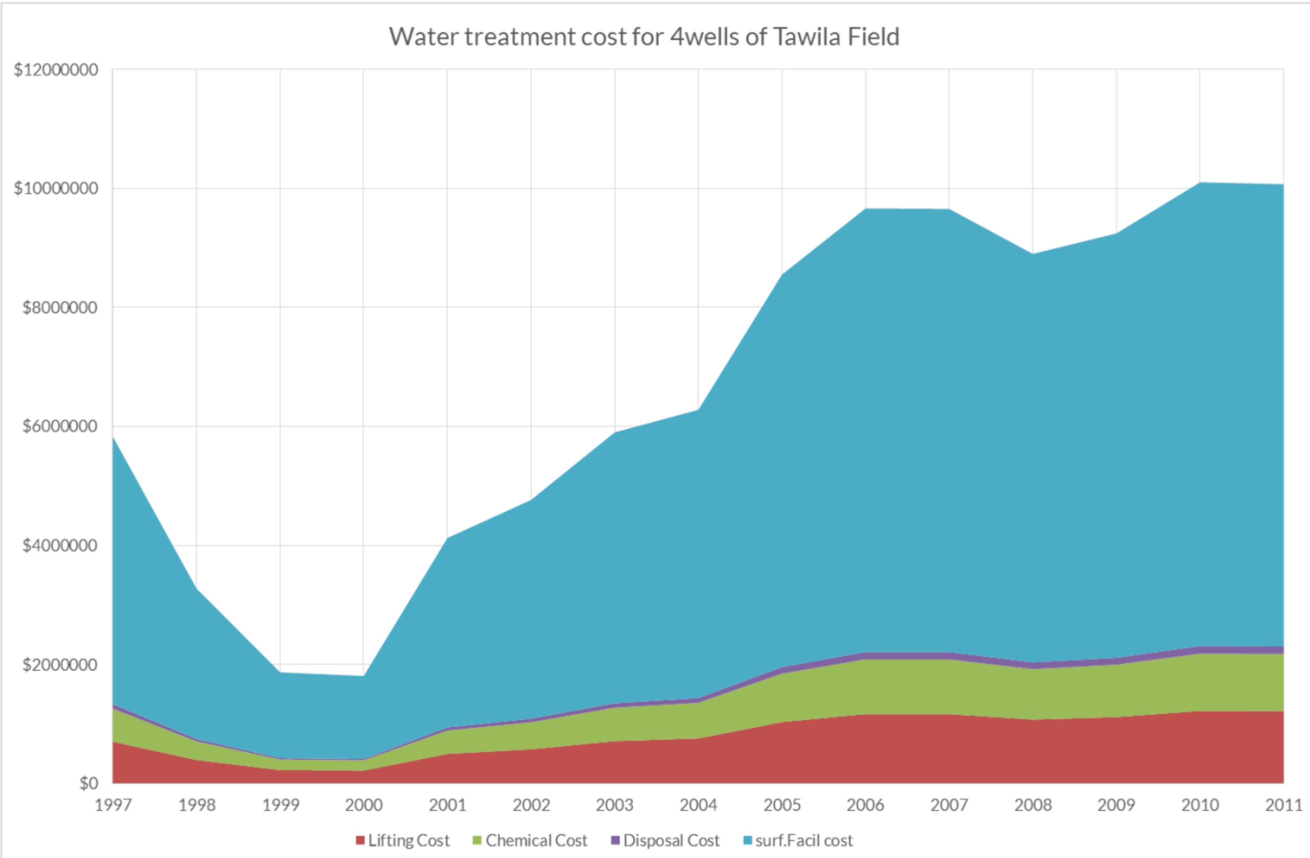

Fig 4. 27: water treatment of 4wells of tawila field

Graph (4.27) represent the comparison of the different water treatment costs. The surface facilities cost is the most cost compared to other types of cost.

In addition to the total cost of the water treatment that mentioned above we can add the cost of oil production losses due to increase water production as can be seen below:

4.8. Tawila well economic limit:

4.8.1. Tawila 10 economic limit

Figure (4.28) Tawila 10 economic limit in case there is early treatment

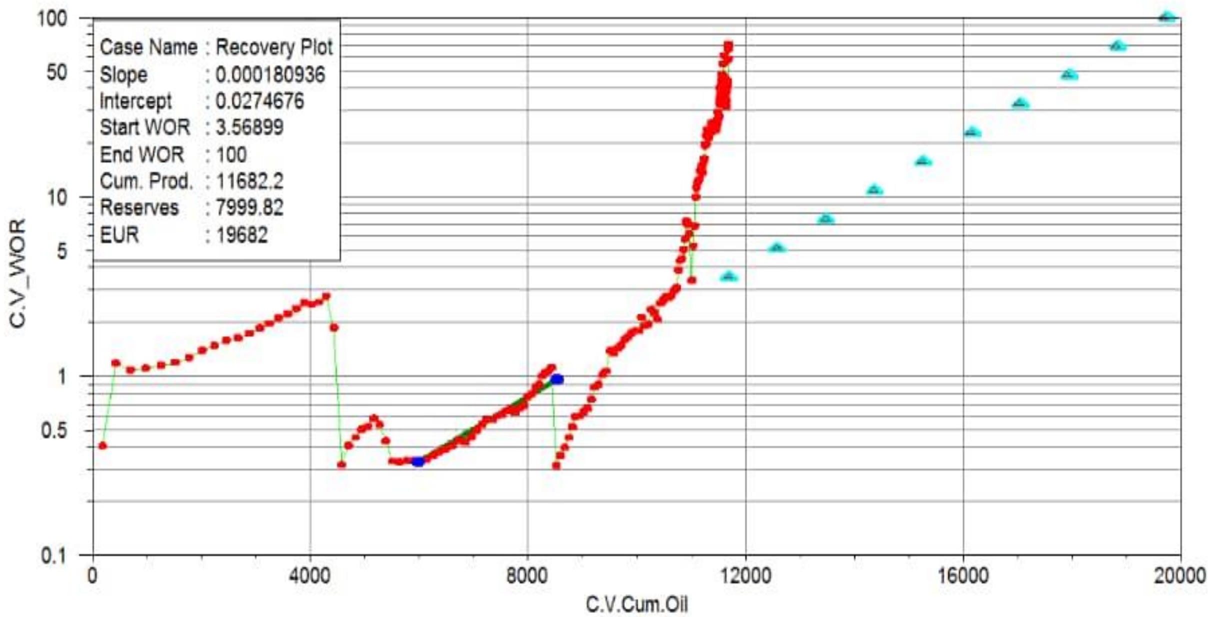

Fig 4. 28: tawail 10 economic limit

Figure (4.29) Tawila 10 well economic limit without early treatment

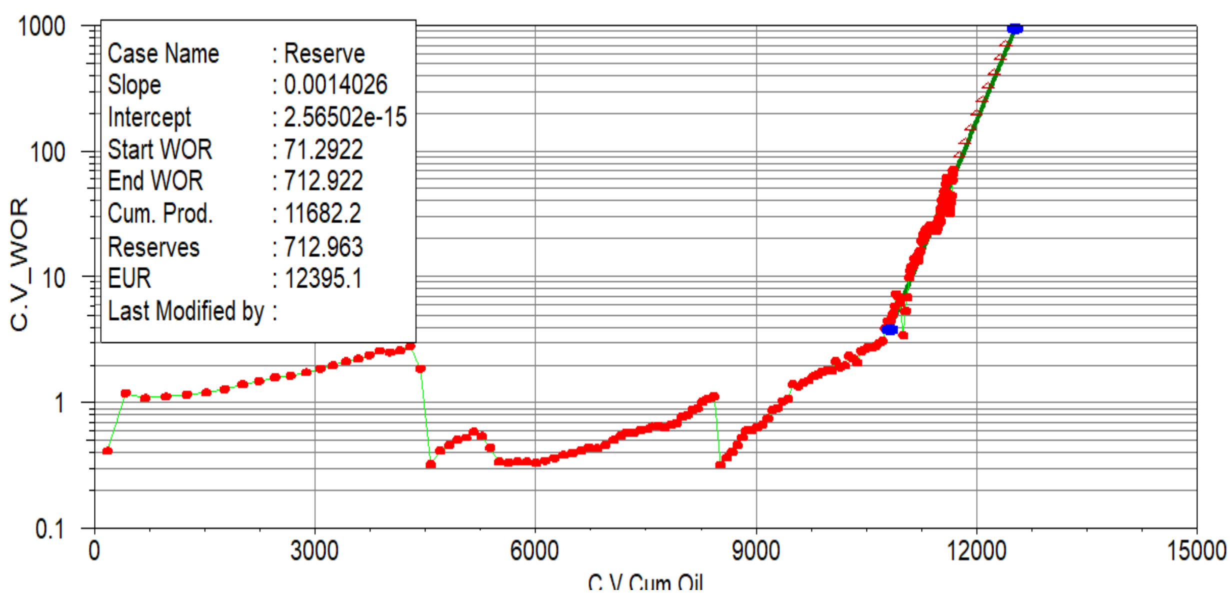

Fig 4. 29 : tawila 10 well economic limit

4.8.2. Tawila 22 economic limit

Figure (4.30) Tawila 22 economic limit in case there is early treatment

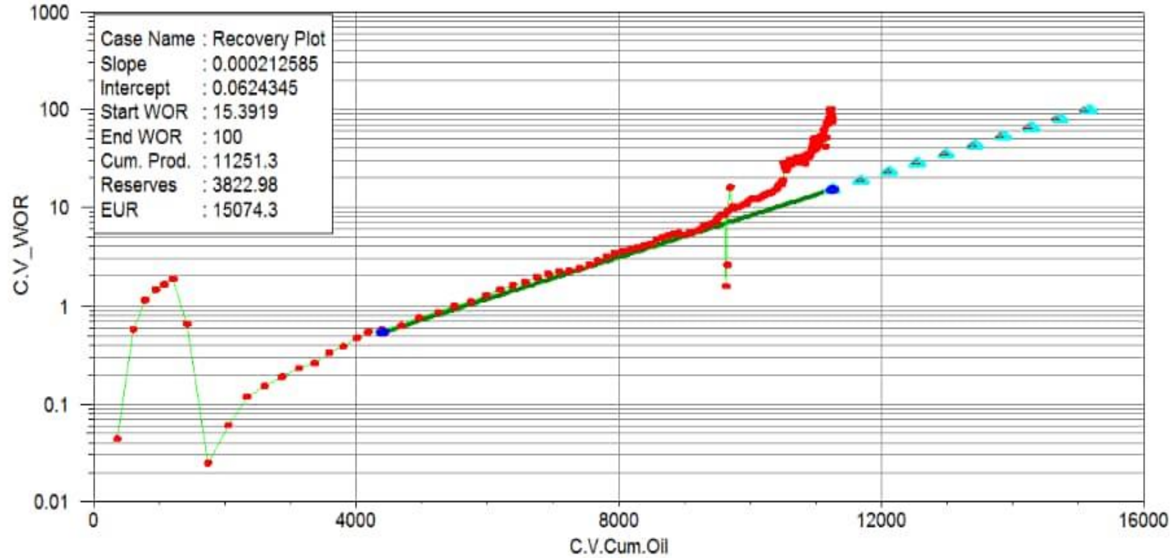

Fig 4. 30: tawail 22 economic limit

Figure (4.31) tawila 22 well economic limit without early treatment

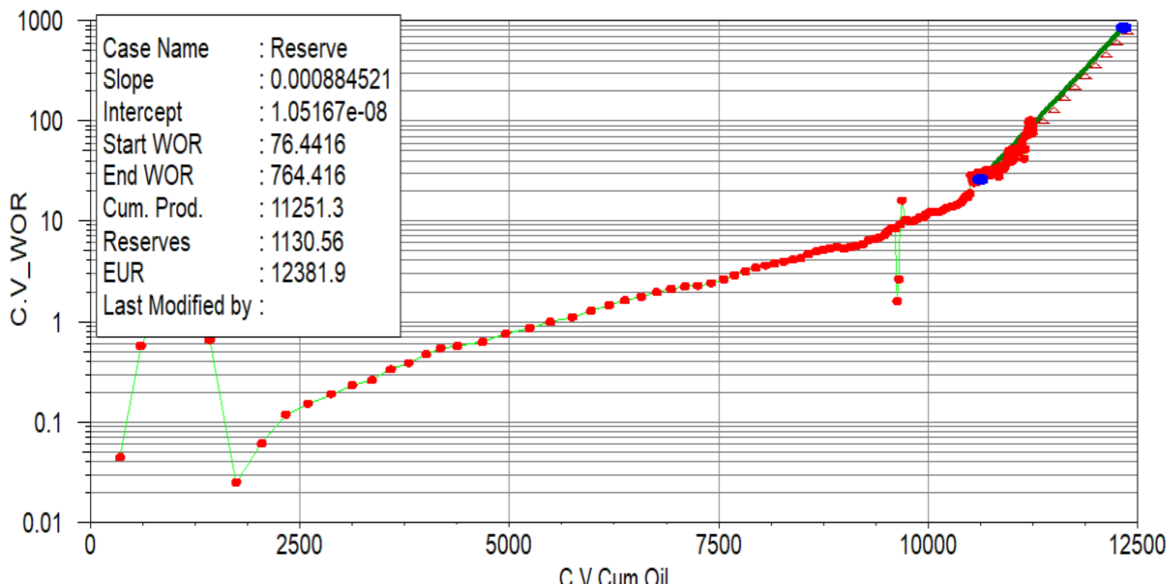

Fig 4. 31: tawail 22 economic limit

4.8.3. Tawila 70 economic limit

Figure (4.32) Tawila 70 economic limit in case there is early treatment

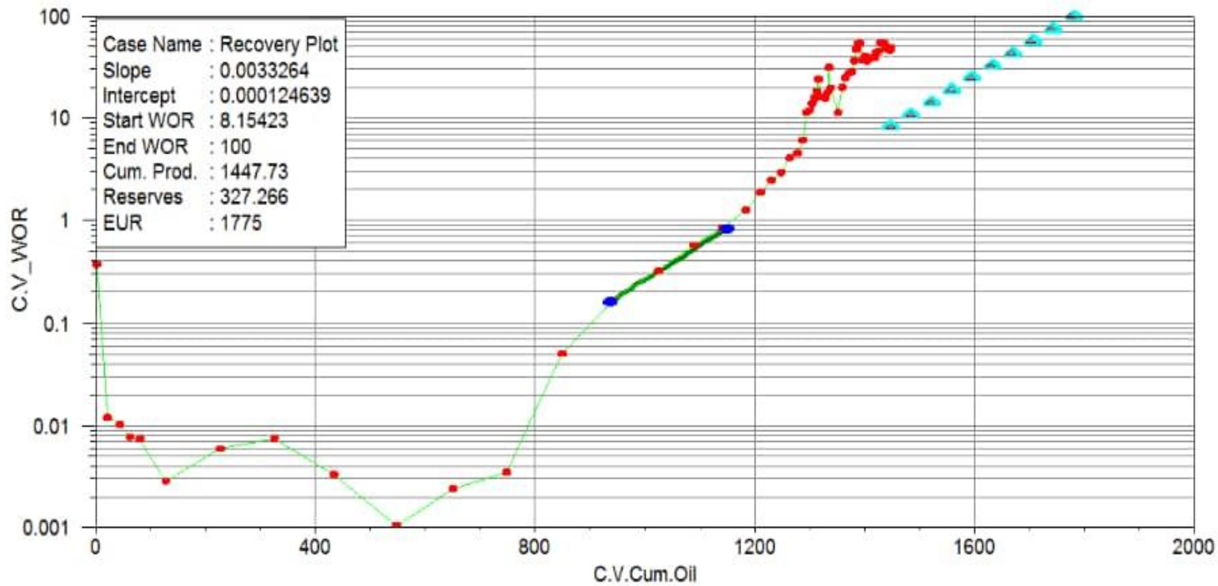

Fig 4. 32: tawail 70 economic limit

figure (4.33) tawila 70 well economic limit without early treatment

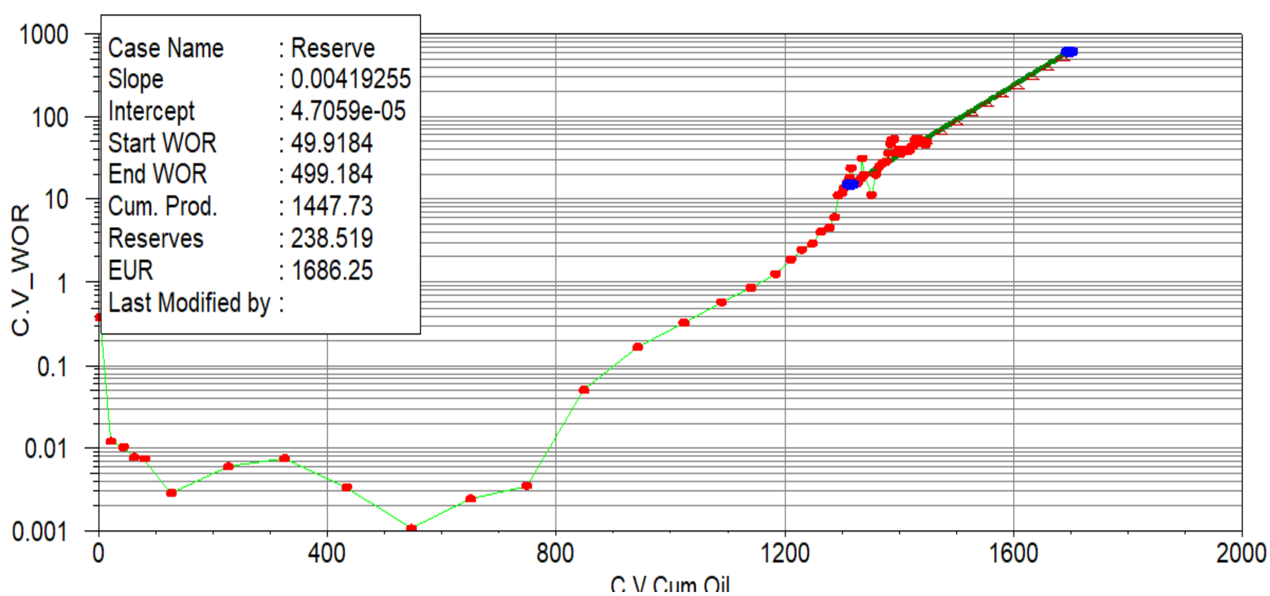

Fig 4. 33: tawail 70 economic limit

4.8.4. Tawila 138 economic limit

Figure (4.34) Tawila 138 economic limit in case there is early treatment

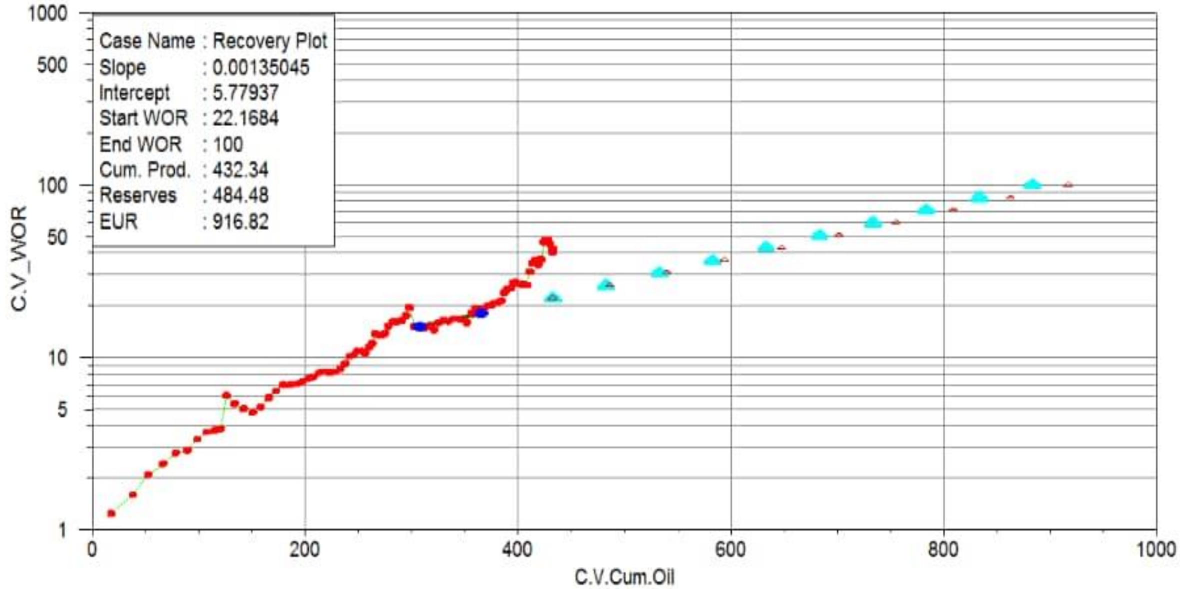

Fig 4. 34: tawail 138 economic limit

Figure (4.35) tawila 138 well economic limit without early treatment

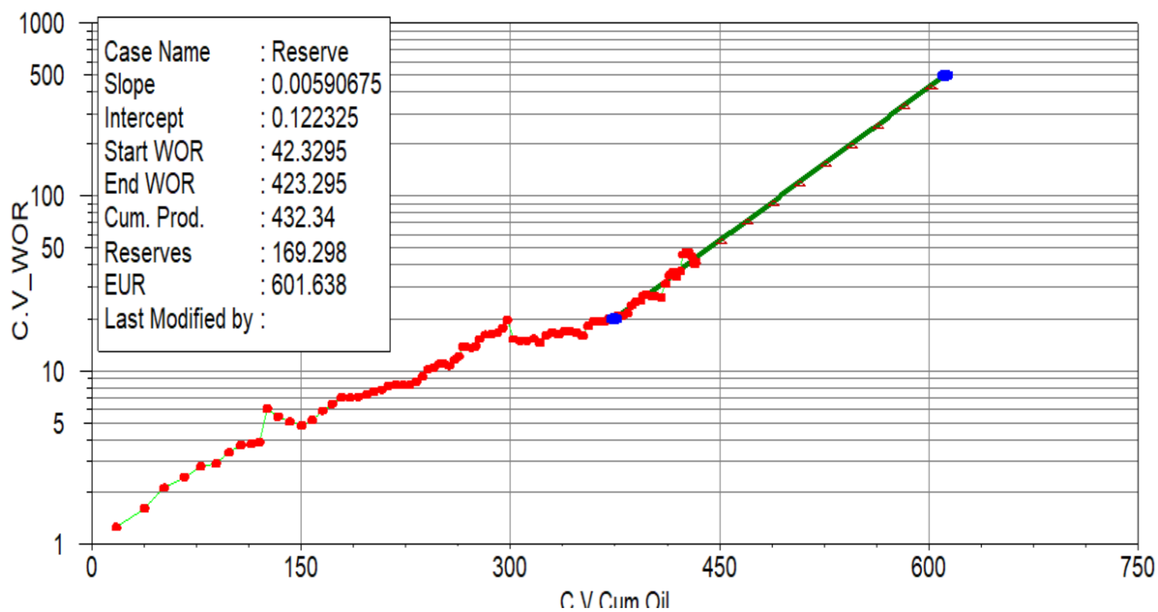

Fig 4. 35: tawail 138 economic limit

CHAPTER FIVE

5.CUNCLUSION AND RECOMMENDATION

5.1 Conclusions

According to the results analysis and observations the following conclusions:

1. Water production is one of the major technical, environmental, and economical problems associated with oil and gas production in Tawila Field like the other fields in block-14
2. Chan plot is the main and cheapest tool used for diagnosis excessive water production in Tawila field due to availability of production data only and lack the other data for more confirmed diagnosis methods
3. According to Chan plot, all the wells in this study are diagnostic a High Conductive layer channeling ,T-22 ,T-138 and the other wells showing a conning criteria beside channeling due to the bottom water drive T-10,T-70.
4. It is noted increase water production rapidly due to the completion was into or close to water zone and production without optimization.
5. It is noted decrease water production instantaneous during the production due to isolate water production zones in T-10,T-22
6. Water shutoff treatment that was used in the earlier fails to achieve desired results ,it is may be due to the exact source of the water problem is not known and it is applied at the late time of the problem
7. Mechanical shut-off was found to be not a good choice for this kind of problems due to maturated water production and the RPM materials can give a good result but its need good selection and design.
8. Tawila field is facing the bad economic effect, because it produces large and excessive amounts of water.
9. The surface facilities cost is the most cost compared to other types of water treatment costs.
10. In addition to the total cost of the water treatment that mentioned we can add the cost of oil production losses due to delay workover.

5.2 Recommendations:

Based on the results of the study, the following recommendations are provided
For future study.

1- All wells must be production at optimum flow rate to avoid early depletion in pressure that cause increasing drawdown and accelerate water production.
2- Examine core data, driller's reports and openhole logs to determine the cut-off point for moveable water. However, these are inexact and a much more accurate picture of bound and moveable water can be achieved using systems such as the CMR* Combinable Magnetic Resonance tool.This tool identifies bound fluids and allows engineers to place completions and perforations in the optimum locations.The CMR tool helps to identify productive zones that would have been ignored in the past.
3- Convert the excessive water produce wells into injection well if the well exceed the economic limit
4- Further technical and economics study is recommended when more data are available.
5- An aquifer study is recommended to determine the direction and strength the water encroachment from the reservoir boundaries
6- Due to lack of data, more investigations are needed to confirm the diagnostic results
7- PLT logs should be run in conjunction with workover to locate the source of water.
8- Well workovers to be conducted as soon as water cut increase to reduce high water production and avoid loses in oil production.
9- Water disposal was found to be less expensive and good method to eliminating the environmental effect of the produced water.
10- It should be monitored and surveillance wells in Tawila field and carry out workover maintenance as soon as possible
11- The solution which are suggested to solve the water problems for the wells in this study need further economic study to apply.

5.3 Limitation

In general, the objectives of the project have been achieved, despite some Limitations which are mainly related to unavailability of some data. These limitations can be summarized as the following:

- ❖ Difficulties to obtain all required data led to limit the project objectives. The following data are absent during conduction this project:
    - Well testing data
    - Production logging tool (PLT)
    - pressure data
    - injection data
- ❖ Data Collection took a lot of time.
- ❖ Analysis of field injection was limited due to absence of injection data to evaluate the affection of water injection on nearby wells

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