



Sudan University of Science & Technology
College of Petroleum Engineering & Technology
Department of Petroleum Engineering



A final year project

Optimization of Cyclic Steam Stimulation (CSS) injection parameters

a Case Study Fula North East Field well 38, Sudan

تحسين عوامل الحقن لحقل الفولة الشمالي الشرقي البئر 38 التنشيط الدوري للبخار

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الاستهلال

(اقرأ باسم ربك الذي خلق) سورة العلق الايه 1

(ان دعوت المعرفة ورفعت صوتك الي الفهم حينئذ تفهم مخافة الرب وتجد معرفة الرب لان الرب يعطي الحكمة من فمه المعرفه والفهم)

الامثال 2-3-5-6

Dedication

To our parents fathers and mothers who lighting the path for us to move forward, advising and motivating us by their wide wisdom to reach this level of life and without them we would not become the persons who we are today . To our brothers and sisters who stand with us, allow us to use their purpose when we needed to complete this research. For petroleum students who will share and upgrade the oil industry revolution in our great country Sudan. We are humble to offer this modest work and we hope that assisting to guide and understand some principle of an oil industry process. Thanks all for supporting and encouraging.

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Abstract

While searching to optimize the production rate dealing with a treatment of heavy oil crude in FNE, Fula North East “FNE” is a perfect nominee to this thermal recovery according to its high density “0.95” and high viscosity “727.33cp”. Since Cyclic Steam Stimulation (C.S.S) is one of the most proper and significant thermal recovery process. The prosperity of this technique is defined by a number of drive mechanisms like; viscosity reduction which is the most important one and the main goal of utilizing C.S.S., the expansion of gas, wettability, etc...

In this research optimization to injection parameters is performed to well-38 FNE In order to increase the recovery factor under these parameters. CMG software used with given model (FNE model well 38) and by alternating the pre-exist injection parameters and trying different scenario of production, the parameters optimized under an increment in the total recovered oil.

Then we reach for optimum parameters and they are: The optimized temperature 300 °C , The optimized steam quality 0.8 and The optimized injection rate 300 m³/d.

التجريد

اثناء البحث وجد ان افضل معدل انتاج يتناسب مع المعالجه للزيت الخام في حقل الفوله شمال شرق ؛
الطريقه المثلى للانتاج عن طريق الحراره تعتمد علي الكثافه العاليه (0.95) واللزوجه العاليه (727.33).
بما ان التحسين الدوري الحراري هو واحد من الطرق الكافيه لعمليات الانتاج بالحراره. من محاسن هذه
الطريقه انها تعرف بعدد من اليات الازاحه مثل تقليل اللزوجه و تمدد الغاز و تغير درجة التبلل.
في هذا البحث افضل المعايير للحقن اجريت علي البئر في حقل الفوله شمال شرق لزيادة معدل الانتاج
باستخدام طريقه (سي ام جي) مع التغير في المعايير الحقلية.
المعايير المثلى هي: درجة الحراره المثاليه هي 300 درجة جوده البخار المثاليه 0.8 معدل الحقن المثالي
هو 300 متر مكعب لكل يوم

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NOMENCLATURE

Symbol	Definition
FNE	Fulla North East
CSS	Cyclic Steam Stimulation
SOR	Steam Oil Ratio
EOR	Enhanced Oil Recovery
SAGD	Steam Assisted Gravity Drainage
CMG	Computer Modeling Group
GEM	Generalized Equation of State
CMOST	Computer Assisted History Matching
IMEX	Implicit-Explicit black oil simulator
STARS	Steam Thermal & Advanced Processes Reservoir Simulator
CUM OIL	Cumulative Oil
WOR	Water Oil Ratio
CUM LIQ	Cumulative Liquid
P	System Pressure (Pisa)
R_s	the gas solubility (SCF/STB) 2
γ_o	Specific gravity of the stock-tank oil

γ_g	the specific gravity of the solution (Fraction)
γ_{gs}	Gas gravity at the reference separator pressure
T	temperature, °R
	Pb^* a correlating number and is defined by: $Pb^* = 10^x$
C1, C2, C3	Coefficient values of certain magnitudes for gas solubility. equation for Vasquez Beggs
A, b, c	coefficient values of certain magnitudes for Bubble point pressure for Glose
Bob^*	is a correlating number and is defined by: $Bob^* = Rs ()^{0.526} + 0.968(T - 460)$
x -	$0.0125 \text{ API} - 0.00091(T - 460)$ “for standing”
a	$0.00091 (T - 460) - 0.0125 (\text{API})$ “for standing”
a	$-C3 \text{ API}/T$ “for Vasquez-Beggs”.
A	$-6.58511 + 2.91329 \log Bob^* - 0.27683(\log Bob^*)^2$ [11]

Chapter one

Introduction:

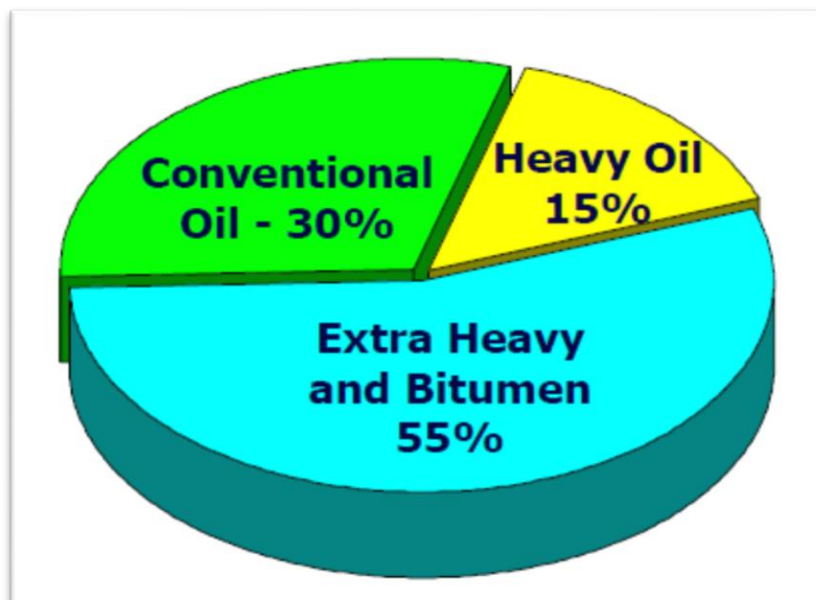
1.1. Heavy oil

Heavy oil or extra heavy crude oil is any type of crude oil which does not flow easily.

It is referred to as "heavy" because its density or specific gravity is higher than that of light crude oil. Heavy crude oil has been defined as any liquid petroleum with API gravity less than 20 API.

One of the problems associated with oil production worldwide is the heavy oil production. In Sudanese oil fields there are high productions of low API gravity crudes (conventional heavy, extra heavy and super heavy crudes). Heavy oil has many problems specially its extraction from the reservoir since it cannot flow naturally which lead us to search for solutions like EOR, which is defined as that techniques applied in certain conditions to alter the fluid properties ensuring production of oil saturations.

The crude oil is quite heavy with an API of 10 - 12. For any rod – lift system, it's quite challenging to lift such heavy oil without any operational failures. Special design considerations need to be evaluated which can overcome the challenges. Other important aspects in the development of large scale sucker rod pumping wells are to accommodate uncertainties in terms of fluid characteristics, reservoir behavior, and operational challenges to lift the heavy crude. The best method to produce heavy oil is cyclic steam stimulation (CSS) (SYED ATA ABBAS NAQVI, 2012).



Heavy Oil classification (H.K Van poolien , 2017)

Table {1.1} Oil classification (Prats, Michael., 1978)

	Viscosity (cp)	Density (kg/m	Density (API)
Conv. Oil	<100	<934	>10
Heavy oil	100-10,000	934-1,000	10-20
Bitumen	>10,000	>1,000	<10

1-2Enhanced oil recovery (EOR):

One of the important methods to deal with heavy oil is tertiary (enhanced) oil recovery is that additional recovery over and above what could be recovered by primary and secondary recovery methods. Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits.

Steam injection is an increasingly common method of extracting heavy crude oil' It is considered an enhanced oil recovery (EOR) method and is the main type of thermal stimulation of oil reservoirs. There are several different forms of the technology, with the two main ones being Cyclic Steam Stimulation and Steam Flooding. Both are most commonly applied to heavy oil reservoirs, which are relatively shallow and which contain crude oil, which are very viscous at the temperature of the native underground formation(M. F. Rdwan, 2018).

1-3Thermal Processes:

Thermal EOR processes are defined to include all processes that supply heat energy to the rocks and fluids contained in a reservoir thereby enhancing the ability of oil (including other fluids) to flow by primarily reducing its viscosity.

1-3-1 Steamflooding Methods:

Steamflooding is an established EOR technique that has been applied successfully on many heavy oil reservoirs around the world.been applied successfully on many heavy oil reservoirs around the world.

1-3-1-1 Cyclic Steam Stimulation (CSS):

Cyclic steam stimulation (CSS) is a simple and cheap method of applying thermal recovery process on a reservoir. It involves injecting steam into a well for several weeks, shutting the well in as long as necessary to allow the steam to heat the oil in the areas around the well, and putting the well back on production to recover the heated oil (Ezekwe, 2010).

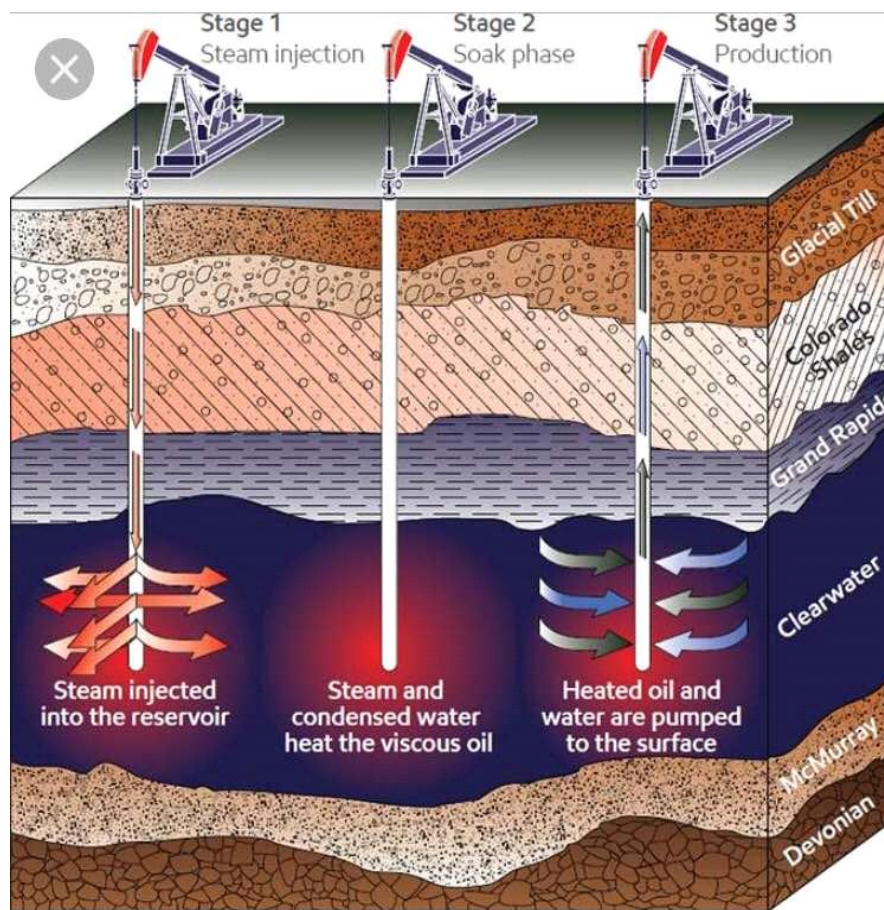


Figure { 1-1 } CSS PROCESS (Ezekwe, 2010)

1-3-1-2 Steam Drive (SD):

In steam drives, steam is injected continuously at injectors with the aim of driving oil towards producers. Typically in most projects, steam injection is organized in patterns. For instance, in a normal five-spot pattern (Ezekwe, 2010).

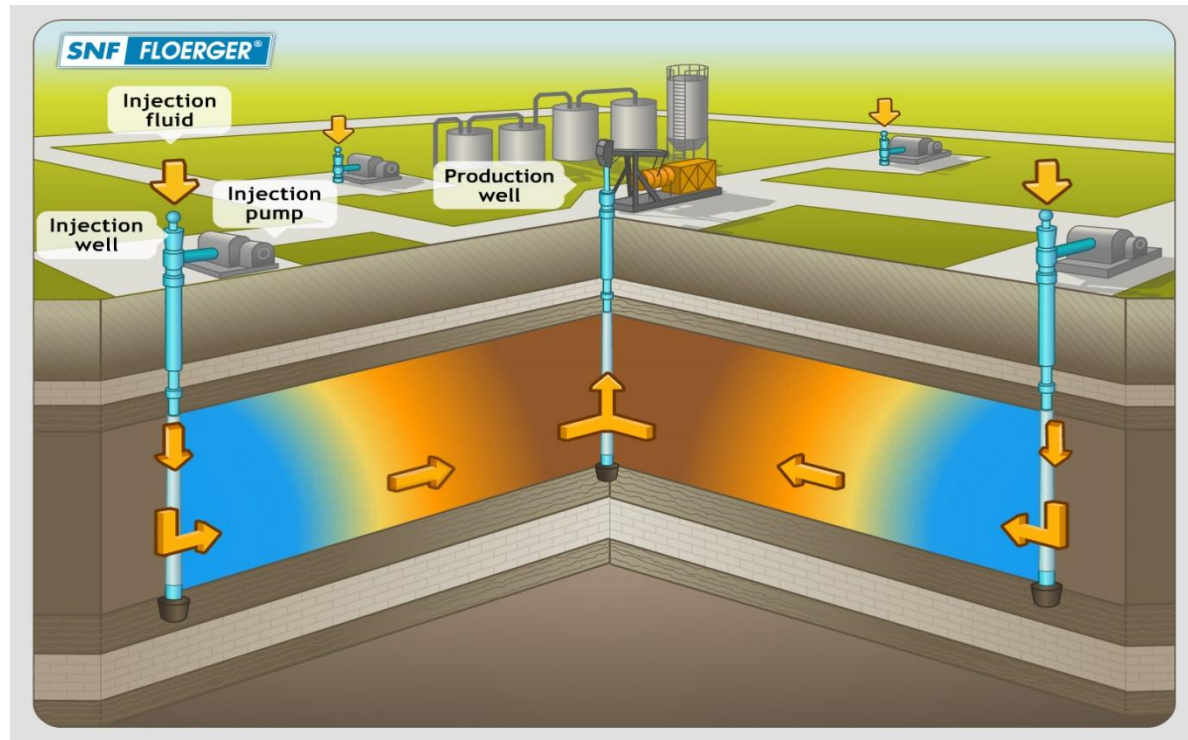


Figure (1-2) steam drive (H.K Van poolien , 2017)

- Steam drive process:

- 1-Once steam is injected into the oil reservoir with good quality.
- 2-Steam reacts with oil and reduces its viscosity, by creating an oil bank and in addition to continuous steam injected oil is pushed towards the producer.
- 3-Wettability is changed from oil to water wet due to the Reduction of oil viscosity

1-3-1-3 Steam-Assisted Gravity Drainage (SAGD):

The SAGD process consists of two horizontal wells about 15 feet apart located close to the bottom of the formation. Steam is injected into the top horizontal well, while the horizontal well below it functions as the producer. The steam creates an expanding steam chamber around the injector as more steam is injected (Ezekwe, 2010).

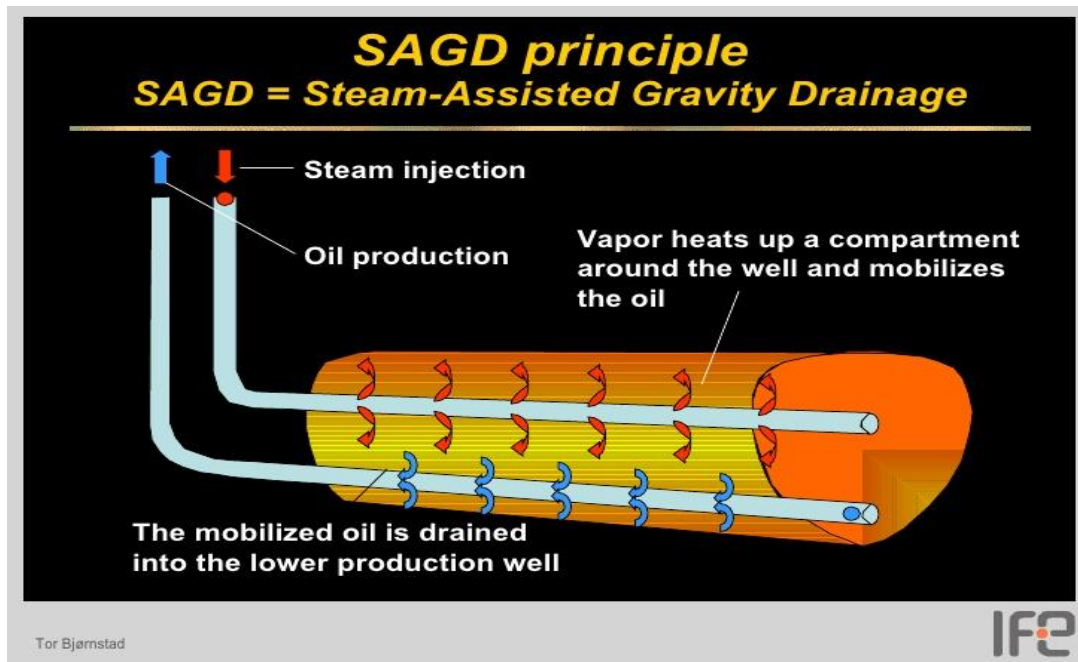


Figure { 1-3 } SAGD Process (Ezekwe, 2010)

Mechanism:

The start-up phase consists of three steps.

First, steam is circulated in both wells, and the heat transfer within the reservoir occurs mainly by conduction. Thermo-hydraulic communication

Second step, a pressure differential is imposed between the wells, adding a convection component to the heat transfer process in the reservoir.

Third step, the well pair is converted to full SAGD operation.

1-3-1-4 Water-Alternating-Steam Process (WASP):

Water-alternating-gas (WAG) is describes as an injection strategy used in gasfloods to reduce viscous fingering, improve vertical sweep, and thereby increase oil recovery.

The main benefit of WASP over continuous steam injection is elimination of premature steam breakthrough at producing wells.

breakthrough at producers wastes heat energy, and reduces productivity of the wells (Ezekwe, 2010).

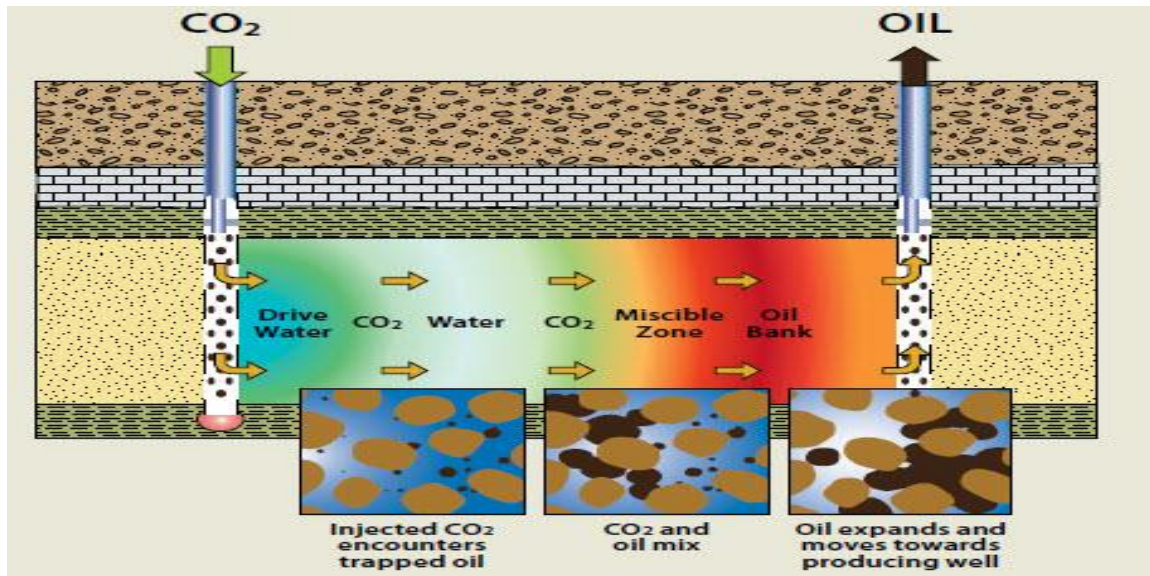


Figure { 1-4 } WAG process (Ezekwe, 2010)

Mechanism:

In this process the miscible gas (CO_2) is injected in order to extract the light component in to intermediate components from the oil and if the pressure is high enough then it develops miscibility to displace oil from the reservoir by the following :

- 1-Vaporizing Gas Drive
- 2-Viscosity Reduction
- 3-Oil Swelling.

Table (1.2) thermal recovery method (Johannes Alvarez, 2013)

Oil Recovery Factors (successful projects)	
Thermal EOR	% of OOIP
CSI	10 - 40
Steam flooding	50 - 60
SAGD	60 - 70
In-situ Combustion	70 - 80

1-4 problem statement:

One of the major problems in oil industry around the world that's large amount of the remaining oil, is heavy oil. FNE has heavy oil and causes many problems as a result to extract it in economic and beneficial way. Cyclic steam stimulation (CSS) one of the successful and suitable method to deal with heavy oil in Sudan .in this research we used some CSS parameters (injection parameters steam temperature, steam quality and injection pressure) to study the best and optimum parameters that's should be used as well as it could be used depending on the field condition and company possibility.

1-5 the objectives:

Aim objective:

To Optimize of CSS parameters of well-38 in FNE field.

Specific objective:

- a. Modeling of CSS process using CMG.
- b. Studying the sensitivity of related factors.
 - Temperature as related to boiler capacity.
 - Quality of steam.
 - Injection rate.

c. Increasing recovery factor (RF) for a given case study.

1-6 CSS Screening:

- Good reservoir characteristic with high porosity and permeability (1000-2000 mD) (0.3).
- High oil viscosity (3000-3700cp).
- High oil saturation.
- High steam quality at wellbore.
- High cold productivity index.
- Thick sand with high gross ratio.
- Low water-oil, gas-oil ratio.
- Weak aquifer support.
- Shallow depth (517-540m FNE) (Raj Deo tewari,Fahmi Abdallah,Hisham Galal, 2011).

Chapter two

2-1 Literature review:

2-1-1Case study

Fula North East (FNE) Oilfield is geographically located in the southwest of Sudan, about 700 km from the capital, Khartoum; structurally located in the northeast of Fula sub-basin of Muglad basin and in the southwest of the Moga Oilfield.

FNE Oilfield exploration began in 1989, the first well FNE-1 has been drilled In 2005, it was found one of the largest heavy oil fields in Petroenrgy (PE) block 6 Area. FNE oilfield began production test in Oct 2009, came on line in Jun 2010 (Dr. Tagwa A. Musa,Husham A. Elbaloula, 2018)

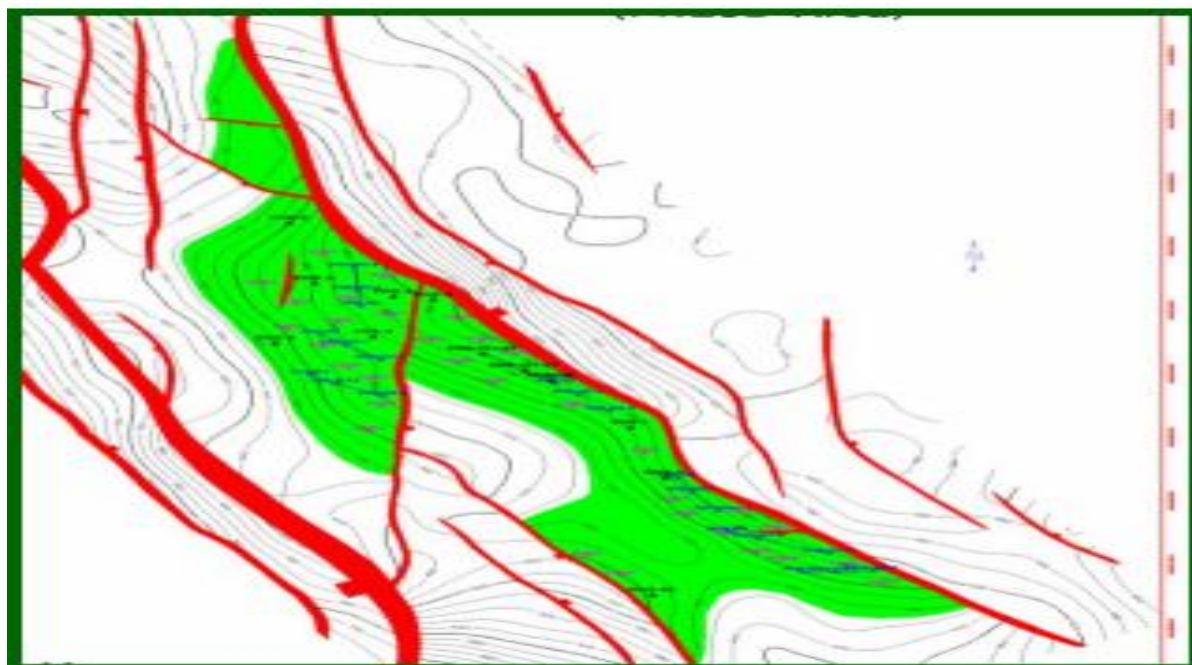


Figure (2-1) structure of fula (Tewari,R., Abdalla,F., Lutfi, H., Keqiang, Y., Faroug, A., Bakri, H., Guocheng,L.,, 2011) **north east field.**

Well FNE-38

Bentiu reservoir interval (517-524 m, 533-540 m, 2 zones) with a total net pay thickness of 10.8 m was perforated and steam injected at the end of Aug. 2009 with cumulative injected steam of 1683 t. Steam injection rate was 200 t/d with steam injection pressure being 1118 psi. Steam temperature is 285 °C. Injected steam dryness at the wellhead was higher than 70%. Soaking period for this well is 7 days (wang ruifeng, 2011).

According to FNE Oilfield FDP study, total 48 development wells include 40 vertical wells and 8 horizontal wells will be drilled to fully develop FNE Oilfield. FNE-38 is one of the vertical development wells in the FDP study.

The rig was spudded in on Dec.04, 2008, reached TD 700 m in Bentiu formation, and the rig was released on Dec.10, 2008.

Casing History Data

Casing	OD		ID (mm)	Thick (mm)	Grade	Weight		Casing depth (mKB- MD)	Casing shoe Depth (mKB-MD)
	In	mm				Kg/m	lb/ft		
Surface Casing	10 3/4"	273.05	255.27	8.89	K55	60.27	40.5	0-60.57	60.57
Production Casing	7"	177.8	157.08	10.36	N80	43.16	29.0	0-697.60	697.60

2-1-2 C.S.S. history:

In this section some of the CSS projects and applications which had been accomplished recently worldwide and in Sudanese oil fields would be introduced. First CSS or CSI "cyclic steam injection jobs were incidentally applied in South America specifically in Venezuela in Lake Maracaibo area in 1959. As a result of one steam injector had blown out and started producing oil with higher rate than other adjacent wells CSS technique has been applied in many fields all over the world such as Bolivar Coastal and Santa Barbara in Venezuela, Cold Lake oil Sands in Canada, Xinjiang and Liaohe in China, San Joaquin Valley of California in USA and in other heavy oilfields around the world. CSS started as a trial and error process without scientific researches based on experience of field workers thus many problems had evolved represented by the unknown parameters like number of cycles, well condition, water cut percentage beside other injection, soaking and production parameters. Then scientific studies and development researches had been accomplished and these problems were reduced and solved.

At the early stages of CSI application, CSI was considered as an old school oil production method in which operations are ahead of research developments (Ramey Jr., 1969)

The literature shows that many publications, explaining CSI processes, were based on field experiences rather than research work. There are a lot of unknowns about the process parameters such as the number of stimulation cycles, well orientation and number of wells, operating condition, the increase of water cut.

The number of stimulation cycles increased by time. By 1974, CSI has an average of three stimulation cycles with a maximum reported of 22. In 1990, in the Midway Sunset field, California, there was already a well with 39 cycles. Also, out of 1500 wells, there were 75 wells with more than 30 cycles, and 350 wells with more than 20 cycles (Khan, Jamaludin and Parag, Dhanpaul., 1992) (Jones et al., 1990). This increment in the number of cycles was accomplished by getting better understanding of steam properties, reservoir characteristics, and injection conditions.

The variation in the number of cycles appears from steam, reservoir properties and injection conditions. Generally, there is no optimum number of cycles. It depends on the well characteristics which vary from well to well, zone to zone.

Well orientation and number of wells were improving by time. In Trinidad and Tobago, slim hole injectors, insulated tubing and packers, and limited entry

perforations have been used to combat gravity segregation consequences (Khan, 1992).

As well, steam was injected with foam diverting agents to control water breakthrough resulting from high injectivity. In addition, in the Cold Lake oil sands, Canada, steam distribution in horizontal wells was improved by using screen sections, which facilitated contact between the well and the reservoir. Also, inside these screen sections, small flow orifices were used to control the flow between the inner pipe and the reservoir to enhance oil production and reduce steam consumption.

In China, the most up to date methods and techniques used in CSI include: high-efficient steam injection by automatic controlling steam generation, insulating surface pipeline and multizone steam injection; as well as artificial lifting, sand control, CSI with chemical additives, reentry drilling technology, and process control systems (Haiyan et al., 2005). In addition, steam distribution has been improved by using separated-zone steam injection techniques such as selected, dual and multi zone injection, either sequentially or simultaneously. This method showed, in field testing to 76 wells of the Liaohe oil field, an increase up to 70% of the steam zone (Liguo et al., 2012). Moreover, as well in horizontal well, the tubing and annulus of the same well have been applied to inject to in the toe and heel separately (Liguo et al., 2012).

Operating conditions of pressure and temperature have adjusted to each case based on reservoir properties and well design. In the Cold Lake field, CSI has been achieved by injection at pressures high enough to fracture the formation.

In California, specifically in Potter sands in the Midway Sunset field a sequential steaming process was implemented. This approach involved heating the reservoir rather than heating each well separately (Jones et al., 1990). The wells were stimulated in rows from down to up dip of the reservoir. Using this methodology, the production per well increased up to a rate of 30% per year (Jones et al., 1990). Another technique, in pilot stage and successfully simulated, is the use of Top Injection Bottom Production -(TINBOP)

whose principle is to inject steam at the top of the reservoir using the short well string and produced from the bottom of the reservoir using the long well string. (Morlot et al., 2007). Simulation studies, conducted by Morlot et al. showed TINBOP increased oil recovery by 57 to 93%, compared to conventional CSI (Morlot et al., 2007). One feature of this method is that there is no soaking period.

The increase of water cut is also addressed. In CSI, each succeeding cycle normally increases water cuts .

Consequently, in the late 70's there was a trend to convert these operations into steam drives due to the decrement in oil recovery . This trend has changed in the last years with the use of chemical additives on CSI. Recently, there have been important progresses in oil recovery using chemical addition. Although CSI increases oil recovery, chemical addition with CSI increases it even further (Ramey et al., 1967).

Nowadays, in CSI processes, coinjection of steam with gels, foams, and surfactants, among other chemicals, are used to increase oil production and reduce water production. In Russia, specifically in the Permian Carboniferous reservoirs of the Usinsk field, gels and foams have been injected with CSI from 2007 to 2011, and an increase of 20- 30 oil rate and decreased 33- 35% water cut (Taraskin et al., 2012) .

Similarly in Canada, other processes have been tested to increase CSI performance such as air injection, achieving 15% incremental in addition to the 12- 20% recovery with high pressure CSI , and biodiesel and carbamide injection , both used as surfactants to enhance the CSI efficiency. The field tests in Henan Oil Field, China, using carbamide increased oil recovery by 7% and decreased Residual Oil Saturation (SOR) almost by 1% (Zhang et al., 2009).

As well, in the Bachaquero field in Venezuela, an ionic- alkyl- aryl sulfonate surfactant (LAAS) has been used to generate foams that enhance steam distribution more evenly in the reservoir by restricting steam to the areas with higher permeability. This technique has improved the production per cycle from 15 to 40% . Moreover, solvents have been used to improve steam injectivity by removing organic deposits from the rock and changing its wettability in Costa Bolivar, Zulia, Venezuela (Mendez et al., 1992).

Wettability changes in CSI due to temperature increase have been studied by several authors with different results. On one hand, there is a line of thought which assures that as temperature increases, the system oil water rock becomes more water wet (Prats, 1985).

On the other hand, another tendency advocates that the system becomes more oil wet as temperature increases also, there is a third line of thought explaining that wettability is independent of temperature changes.

Studies with Diatomaceous rocks and Berea sandstones conducted showed that at both diatomaceous and Berea cores become more waterwet as temperature

increases (from 100 to 200°C). This behavior was attributed to fines detachment, in low salinity and high pH steam condensate fluid, which stabilizes a thin water film that covers the rock surface avoiding contact with the oil phase. This fines detachment depends on temperature and mineralogy; for example, wettability changes are reached faster in silica than that in clays (Schembre et al., 2006).

In addition, conducted similar studies using unconsolidated sands from Houston sands and MidwaySunset field, California, reaching the conclusion that increasing temperature (from 25 to 150°C) is determined in improving water wetness in the unconsolidated sands.

On the other hand, conducted CSI lab and field test in the heavy oil and bitumen Elk Point Cummings formation, Canada. Their results showed that at high temperatures (162 to 196°C), the formation, which is mainly silica (87%), became oilwet. Moreover, they also discover that salt deposition, mainly calcium carbonate (CaCO_3), in one of the core layers prevented oilwet behavior at high temperatures, changing the wettability to water-wet.

This effect was proved in core flooding and field test in which increment in oil rate and decrement in water cut were observed (from 22 BPD and 83% in the fourth cycle to 51 BPD and 77% in the five cycle) (Rao and Karyampudi, 1999).

Wettability reversal effect at high temperatures is also attributed to asphaltene precipitation. Using Athabasca bitumen and live oil sample with 5% and 3.17% asphaltene respectively, showed that from 150 to 400°C the system shifted to oilwet until asphaltene precipitation was completed and then wettability was changed to water-wet.

Moreover, in the literature, results showed that temperature do not impact wettability during CSI, tested the unconsolidated Ottawa Silica Sand and a consolidated Berea Sandstone with temperatures from 25 to 150°C, concluding that there were not changes in residual saturations that imply variance in wettability. The same results were reached in the unconsolidated silica sands at 125 to 175°C.

Consequently, when CSI is applied, there are different positions in describing wettability mechanism and their changes with temperature. However, it is important to point out that these results mainly depend on the chemical properties of fluids injected, asphaltene content and the mineralogy of the reservoir.

From its early stages until today, CSI has evolved significantly from a process discovered by chance where trial and error governed the operations with

th little number of cycles and low recovery factor to state-of-the-art applications with a great variety of chemical additives and well geometries which increase the number of cycles and the ultimate oil recovery.

2-1-3 CSS in Sudan:

CSS have been implemented in SUDAN since 2009 in FNE oil field as first field, the field contains heavy oil in multiple reservoir of Binti formation in 8 selected wells spread over the field and it led to maximize the recovery factor, the actual result is better than predicted in simulation studies with lower steam intensity of 120 m/m compared to planned 160 m/m. (Abdalla, et al, 2011)

Also Husham Elbaloula, 2016 studied the Designing and Implementation of the First Steam Flooding Pilot Test in SUDANESE Oil Field and Africa and the result showed that converting of Cyclic Steam Stimulation (CSS) to steam flooding after the third cycle could improve the recovery factor of the field up to 43 ~ 50.1%, while CSS only can increase the recovery percent of the suggested well groups by 32.5 - 34.2% of the studied sector model which makes it more attractive method as development scenario for FNE oil field. (Elbaloula, et al, 2016).

In heavy oil field of Sudan, this field contains heavy oil in multiple reservoir of Binti formation. This primary recovery around 18-20%, plan is made for thermal enhanced oil recovery application early to maximize the recovery. (Tewari, et al, 2011)

2-2 CSS cycles:

CSS technique simply using an injection and extraction process, it injects steam down hole and heated bitumen which facilitates the extraction process. This inclusive process contains a number of sub processes (injection, heating, flow and extraction) which combined together to make a cycle. Each cycle composes of three phases:

2-2-1 phase 1 Injection:

During this phase, for a short period of time steam is injected into a single horizontal or vertical well. This injection of steam will later be allowed to create a chamber for pressure build-up in the formation. The oil viscosity continues to decrease as the reservoir temperature increases which causes an increase in the initial oil rate. There is also some acceleration from increased reservoir pressure near the wellbore. As steam is injected at high pressure it creates fissures or small

fractures in the formation thereby maximizing bitumen contact and production. During the injection period, steam chamber average temperature is assumed to be the steam saturation temperature. After that, the well is closed for a short time, i.e. the soaking period to allow for the temperature profile to build-up and thus steam chamber is formed.

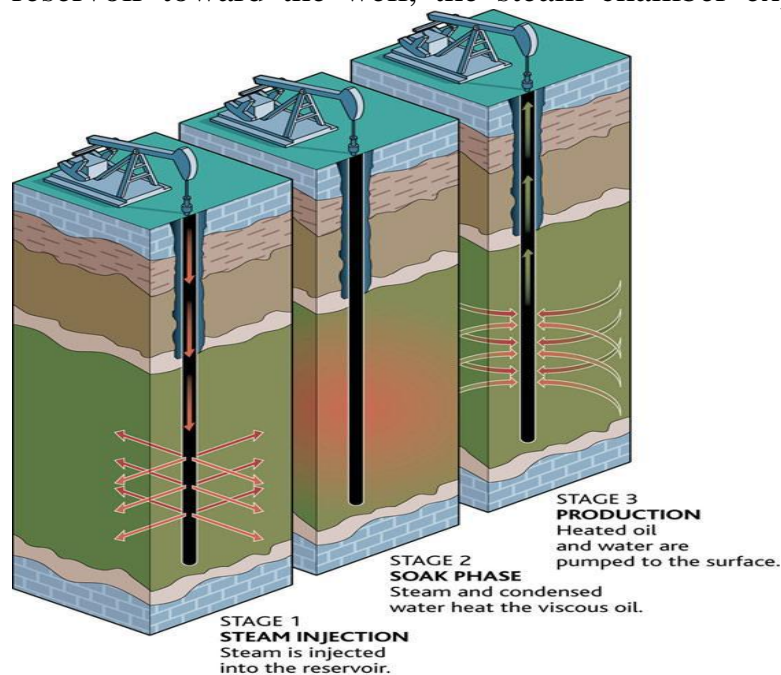
2-2-2 Phase 2 Soaking:

During the soaking phase, well is shut-in to allow injected steam to expand the chamber and heat up a larger area in the formation. Uniformity in heat distribution within the reservoir is anticipated in order to thin the heavy oil. Most of the latent heat of the steam is transferred to the formation surrounding the well, and condensation of steam occurs. The steam condensation is cooled as it moves into the reservoir and more heat is transferred by conduction. The steam chamber grows upwards as steam is the lighter phase and will float to the top of the reservoir. Oil drains downwards and steam rises upwards due to gravity effect as well as convection heat transfer. This counter-current flow helps increase the heat transfer hence improving the overall process.

2-2-3 Phase 3 Production:

This phase occurs after the well has been shut-in for a period of time (Soaking phase). Heated oil near the condensation surface is allowed to drain downwards due to gravity effect and pressure difference into the production well then produced to surface. Initially, the temperature in the heated zone is relatively high which results in high initial production rate. However, this initial rate declines with time as heat is removed with produced fluids and dissipated into non-productive formations. Steam heats the colder oil sand near the condensation surface. Production rate is greatly improved as a result of lower oil viscosity in accordance to increase in temperature. The major mechanisms of oil production in cyclic steaming are gravity drainage and pressure drawdown. As oil drains from the

reservoir toward the well, the steam chamber expands to replace produced oil.



Source: Canadian Centre for Energy Information

Figure {2-1} CSS Stages (Jones, Jeff and Cawthon, Gary J., 1990)

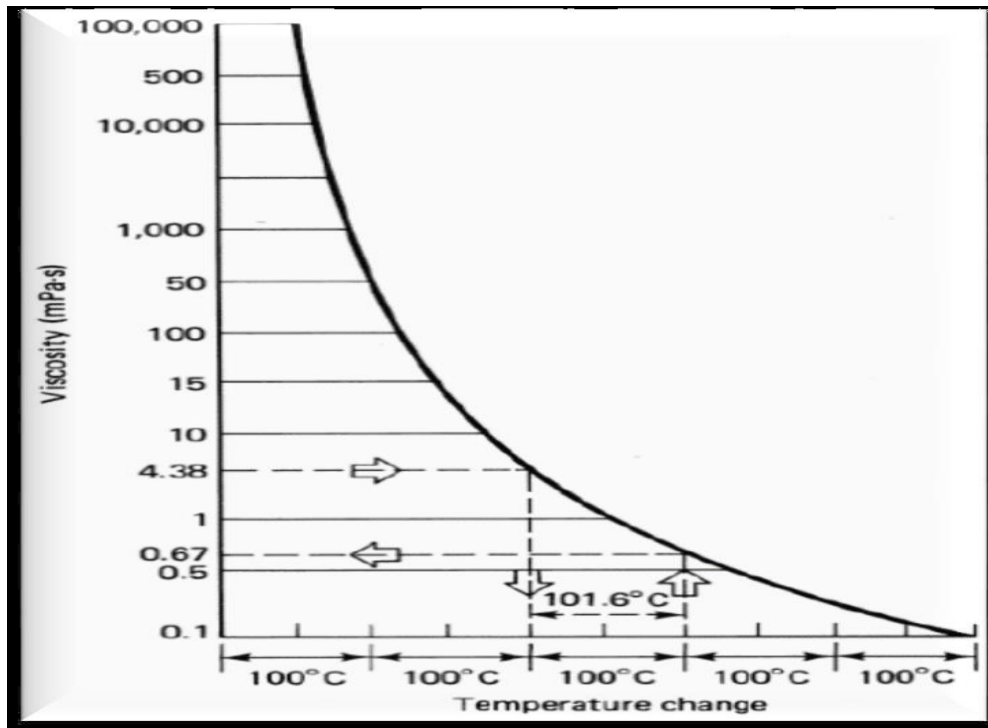
2-2-3-1 Production Mechanism:

As previously noted, by the end of soaking period the well opens to flow and the third stage (production) begins. The oil production occurs due to several mechanisms:

2-2-3-1-1 viscosity Reduction:

The most important mechanism is viscosity reduction as a result of temperature increasing. The curve below show specific changes in viscosity, It is known that the more viscous fluid, the more resistance to flow vice versa as viscosity decrease, the flow will be easier and oil flows at higher rate.

$$Q = \frac{kA(P_1 - P_2)}{\mu L} \dots \dots \dots (2-1)$$



μ :the viscosity
of the oil

Figure {2-2} Viscosity VS temperature (Ramey Jr., H. J. A., 1967)

2-2-3-1-2 Wettability changes:

associated with CSS is a secondary mechanism to enhance oil recovery, these changes in wettability with temperature had been studied by different authors and leads to different results but the more convenient approach is that the increase of temperature affect wettability to become more water-wet because of high PH number and low salinity injected steam converted into thin water layer which adhere to rock surface and prevent oil contact with rock (Erika Trigo,Eduardo,Mansarovar,Maria Jimenez, 2018).

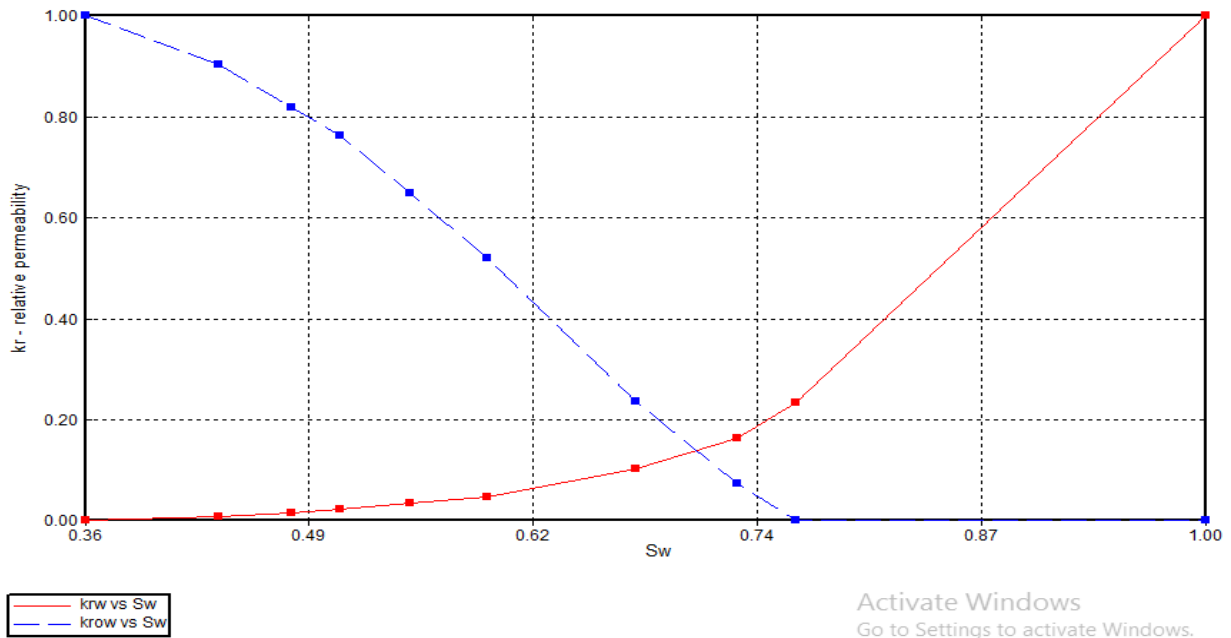


Figure {2-3] Wettability curve well -38 (Computer Modelling Group CMG,LTD, 2015)

2-3 CSS implementation facility:

1. Source of Water Tank
2. Water Storage Tank
3. Water Treatment Unit
4. Steam Generation Unit
5. Surface Flowline
6. Thermal Wellhead
7. Thermal Tubing (Tewari,R., Abdalla,F., Lutfi, H., Keqiang, Y., Faroug, A., Bakri, H., Guocheng,L.,, 2011)

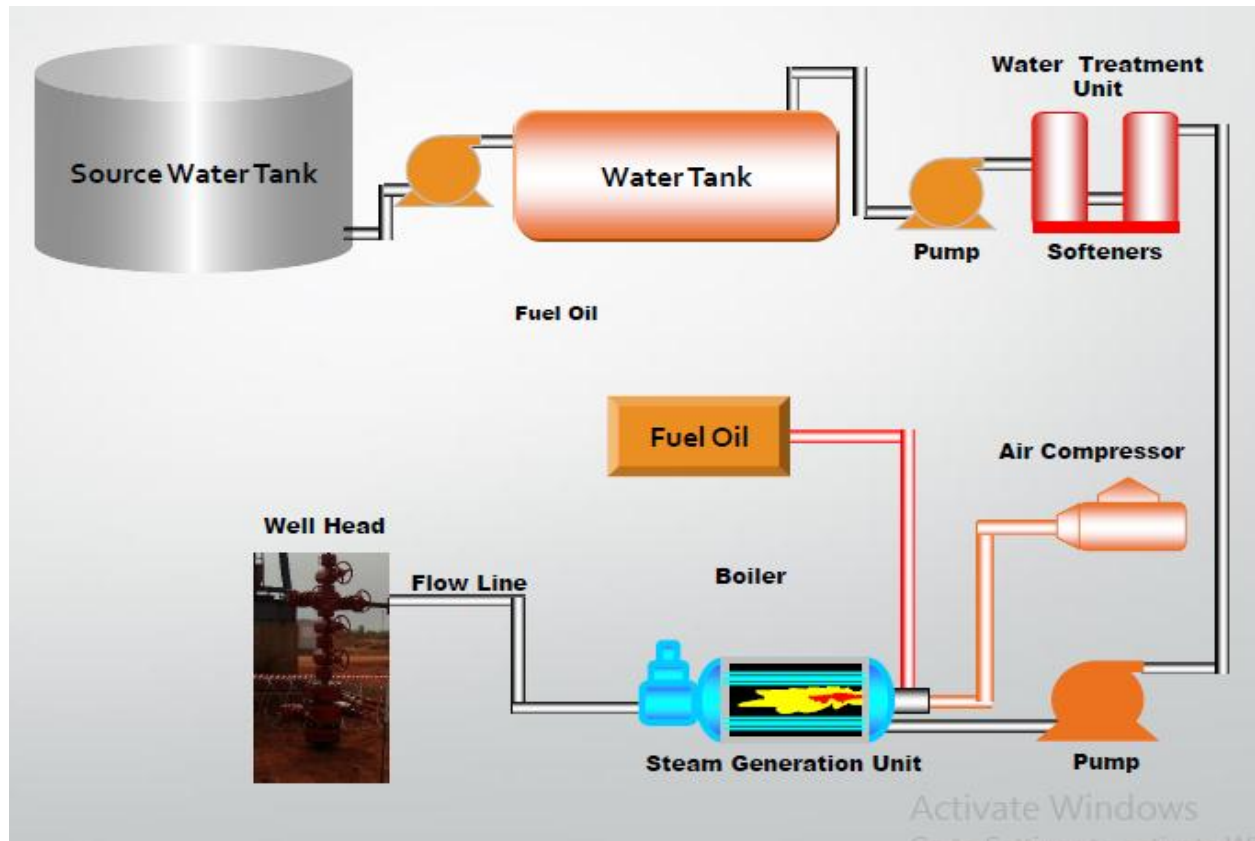


Figure {2-4} CSS Implementation facilities and Flow diagram CSS surface processes (wang ruifeng, 2011)

Chapter three

METHODOLOGY

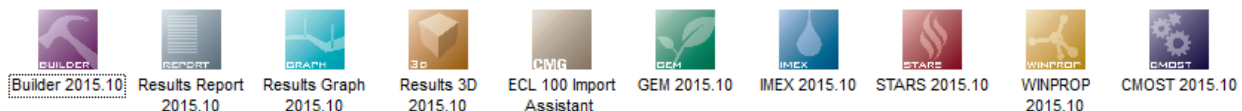
In order to achieve the objectives of this project, the upcoming methodology had been followed:

- 1- CMG software had been studied (attended CMG software course).
- 2- Data collection (CMG sector model for FNE field data had been requested from petro energy E&P company through the Sudanese oil ministry).

3-1CMG software:

CMG softwares are a group of softwares specialized in reservoir simulation it's consist of:

- .1 WinProp (model generator)
- 2 GEM (compositional simulator)
- 3 CMOST (optimization software)
- 4 CMOST (optimization software)
- 5 Builder (Preprocessor)
- 6 STARS (thermal simulator)
- 7 Results.



3-2 CMG software Correlations:

In the absence of actual PVT and core analysis data , CMG software utilize a feature to generate the fluid and rock properties using different correlations , the selection of appropriate correlation depends upon under study reservoir conditions and information available to the engineer (Computer Modelling Group CMG,LTD, 2015).

The table represents CMG correlations for oil and gas properties and relative permeability

Table {3-1 } oil properties used in CMG (Computer Modelling Group CMG,LTD, 2015)

Oil properties	Correlation Method
(Formation volume factor , solubility and bubble point pressure)	Standing
	Vazquez-Beggs
	Glaser
	Lasater
Oil compressibility	Vazquez-Beggs
	Glaser
Dead oil viscosity Correlation	Ng and Egbongah
	Beggs and Robinson
	Beal and Chew
	Glaser
Live Oil viscosity	Beggs and Robinson
Gas critical properties correlationsp	Standing Sutton
Relative permeability	Stone's first model
	Stone's second model

Table {3-2} PVT properties correlations (Computer Modelling Group CMG,LTD, 2015)

Correlation	Solubility	Bubble-Point Pressure	Oil formation volume factor
standing	$R_s = \gamma_g [(P/18.2 + 1.4)10^x]^{1.2048}$	$P_b = 18.2 [R_s \gamma_g^{0.83} 10^a - 1.4]$	$Bo = 0.9759 + 0.000120 [R_s (\gamma_g \gamma_o)^{0.5} + 1.25(T - 460)]^{1.2}$
VasquezBeggs	$R_s = C_1 \gamma_{gs} P C_2 e^{C_3 (API/T)}$	$P_b = [(C_1 R_s \gamma_{gs} /)10^a] C_2$	$Bo = 1 + C_1 R_s + (T - 520)(API \gamma_{gs})[C_2 + C_3 R_s]$
Glose	$Bo = 1 + C_1 R_s + (T - 520)(API \gamma_{gs})[C_2 + C_3 R_s]$	$P_b^* = (R_s \gamma_g /) a(t) b(API) c$	$Bo = 1 + 10A$

3-2 sensitivity analysis:

The sensitivity was studied for the following parameters:

The Injection parameters:

o Steam injection temperature.

- o Surface steam quality
- o Steam injection rate.

3-2-1 Steam injection temperature:

Steam temperature is directly proportional to produced oil, to determine the degree by which cumulative oil changes with steam temperature. In order to increase the cumulative oil .

Multiple values of steam temperature started from (150 °C till 320°C)

And fixed parameters:

- The steam quality (0.6)
- Injection rate (186 m^3)

Also the injected steam temperature values were selected based on the:

- (i.) Boiler temperature limits.
- (ii.) The formation fracturing pressure (6382Kpa) and from the steam table the minimum formation temperature without fracturing (308C).
- (iii.) Maximum allowable tubing and pump temperature, baker temperature and the thermal well head temperature.

Statements:

- 1-start by inserting $T=150$ c with constant other parameter and record the cumulative oil and water cut.
- 2- Secondly insert $T=180, 210, 240, 270, 300$ and study the effect of these values of temperature.

3-2-2 Injected Steam quality:

The quality of the injected steam must be greater than hot water quality (0.4) and less than the maximum boiler capacity (0.85).

When steam quality is high this will ensure high oil recovery, also steam is fully soaked into reservoir and will not condensate again this is why the water cut is decreased.

By using the optimized temperature in past analysis and with the same injection rate, inserting:

$Q=0.4, 0.5, 0.6, 0.7, 0.8$

3-2-3 Steam injection rate:

The optimized temperature and steam quality used in optimization the injected steam rate. Produced oil volume is directionally proportional to the injection rate, When high injection rate used (large steam volume injected) more heat carried thus more utilization of steam and increased volume of cumulative oil.

Small volumes of steam do not provide sufficient heat. This will reduce the cycle oil production, then more volumes of steam needed but further steam increment will push the oil away from well bottom hole and the cumulative oil-steam ratio drops.

Chapter four

Results and Discussion

4.1 Sensitivity to Steam temperature:

As started earlier the temperature range (150-290) selected and the other parameters (steam quality, injection volume) inserted one by one .It's noticed that cumulative increase as temperature increase for the entire model's cycles.

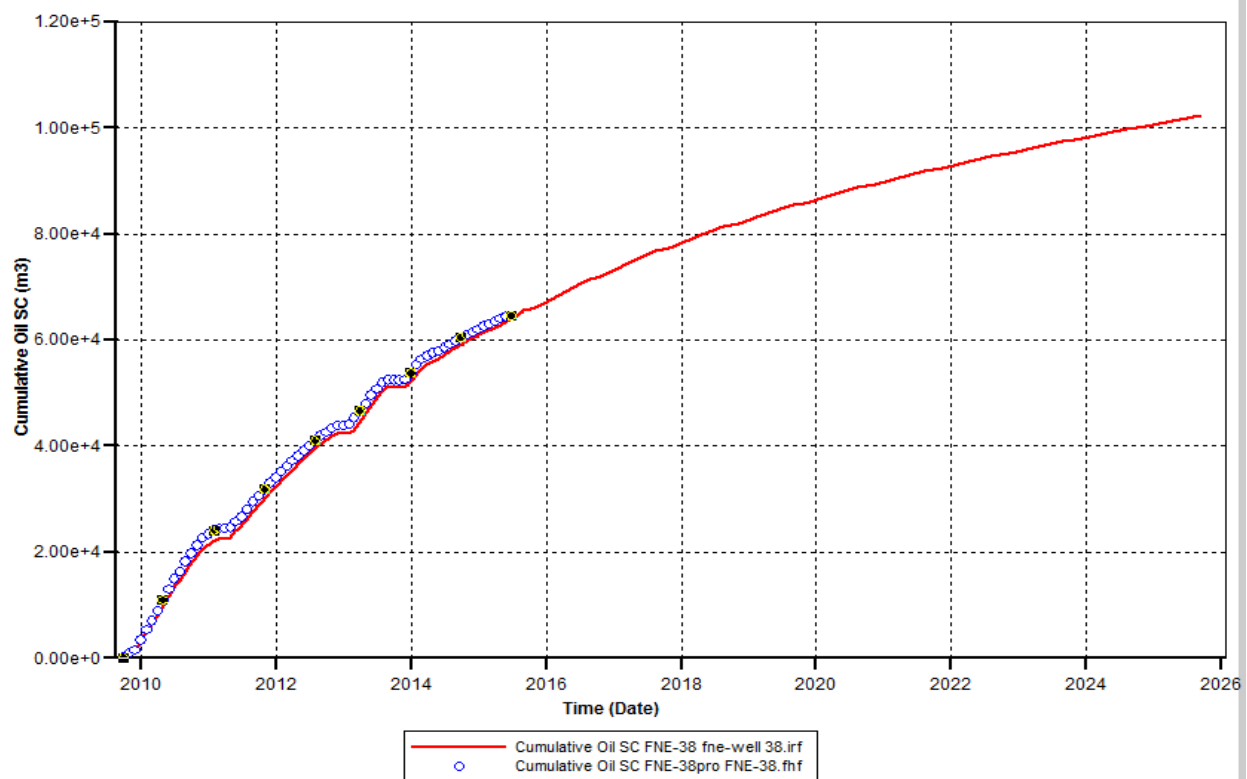


Figure {4-1} History matching between the actual data and the model and it's typically match to check whether the predicted result is in the truth path with field.

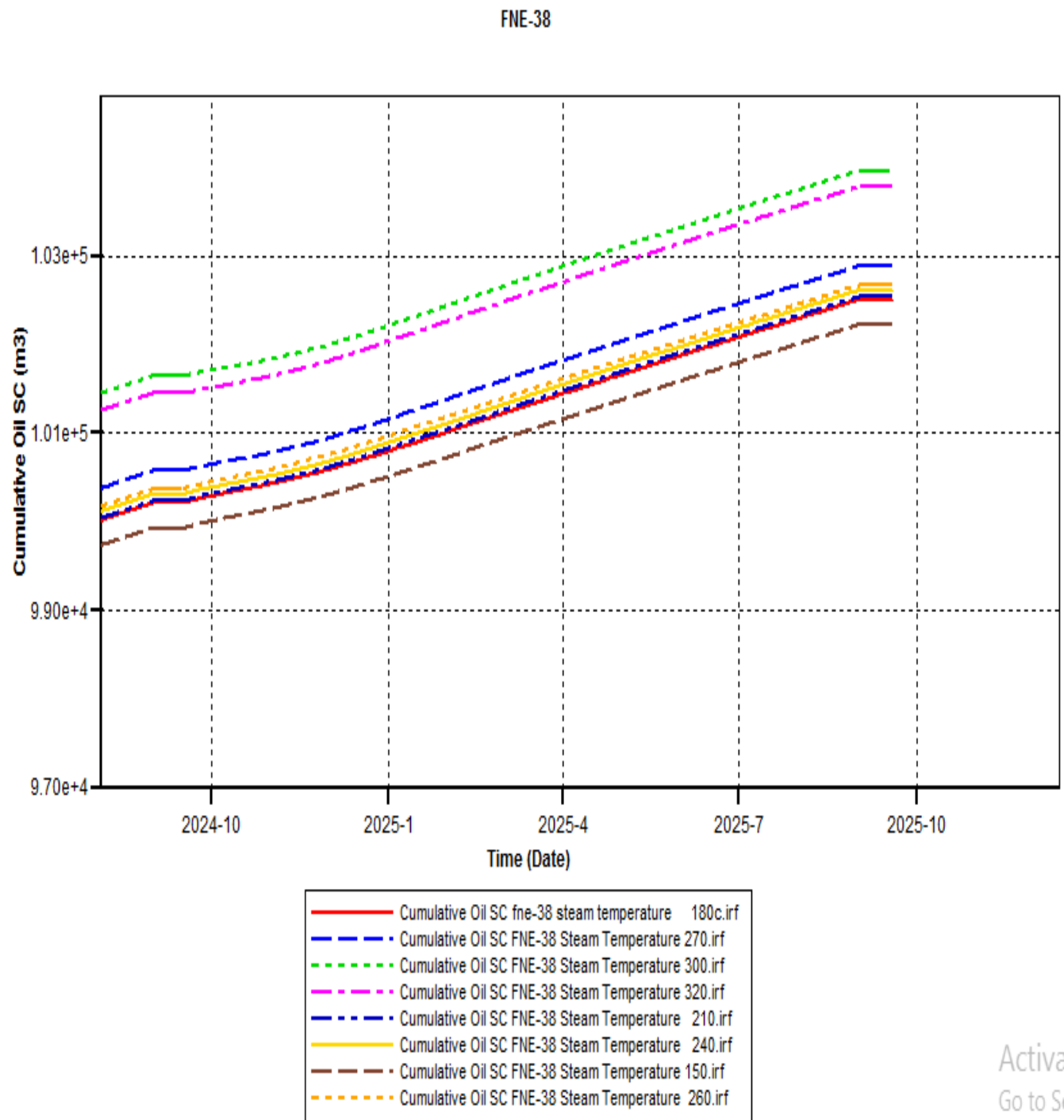
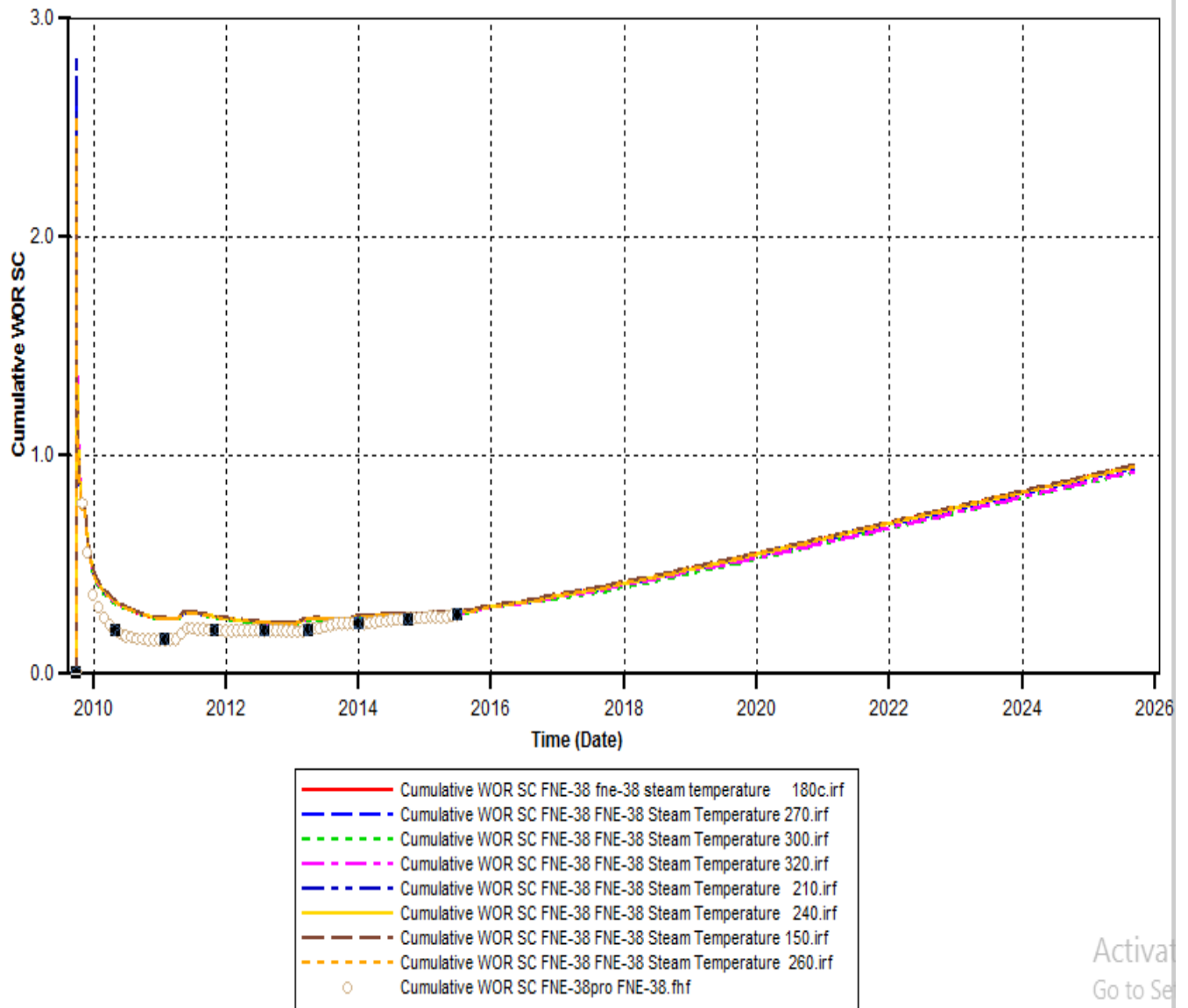


figure {4-3} cum oil at T values

With increase in temperature the cum oil increased so it's recommended to increase the temperature to maximum values as it could.

But temperature depends on boiler capacity used so 300°C chooses as an optimum value.



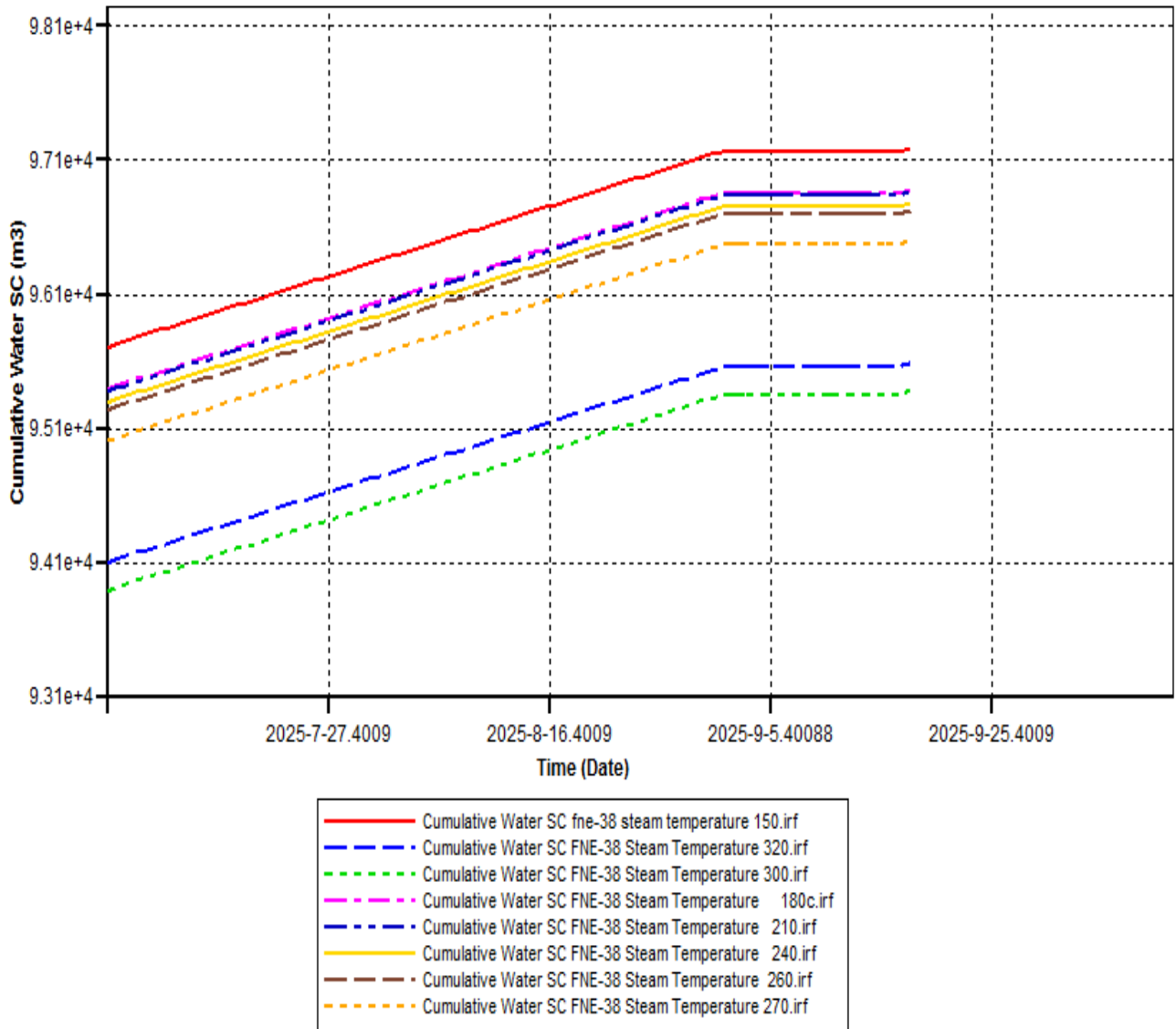


Figure {4-5} cum water at different temperature

With increas in Temperature the cum water will be decreased due to better heat distribution.

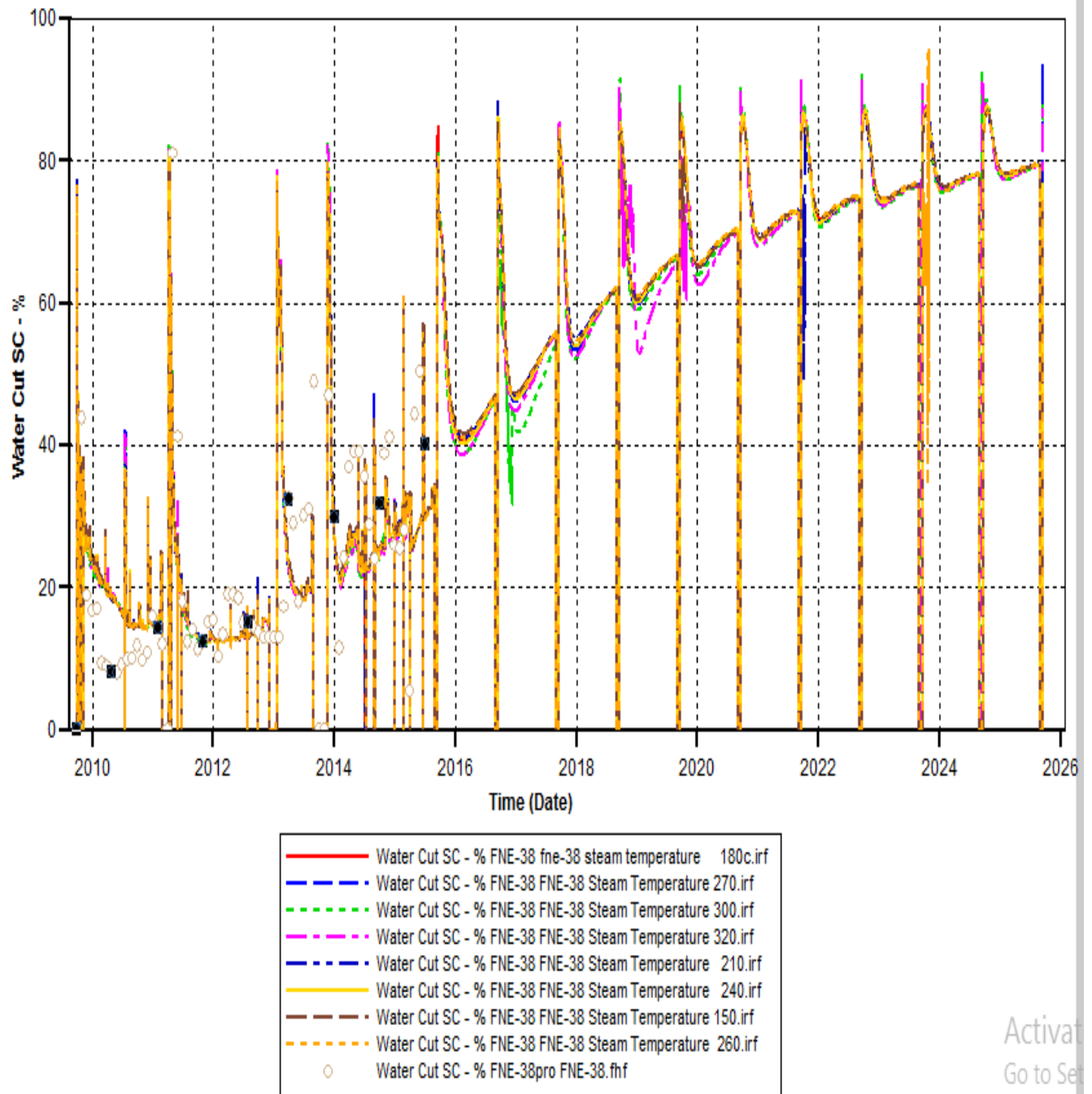


Figure {4-6} Productin history of Water cut with T° values

Water cut at different temperature there increment in water cut at the beginning of any cycle, and by repeating cycles water continuo increasing

Water increase by opening the well and allow it flow, a high production rate expected with high water cut

Water keep increasing at the beginning of any cycles for model cycles

Table {4-1} produced oil, water and liquid with Temperature

Temperature	Cum oil	Cum liquid	Cum water	SOR
320	103832	199471	95632	0.54
300	104013	199445	95427	0.52
Well 38	102938	199487	96547	0.51
260	102717	199497	96772	0.49
240	102662	199498	96828	0.46
180	102565	199493	96928	0.45
150	102281	199521	97240	0.43

4-2 Injected Steam quality

The optimized temperature is high enough to provide surface steam quality up to 60 % (maximum boiler quality can provide). The high steam quality as can be seen from plotting both water cut and cumulative oil at different steam qualities, the higher quality the higher cumulative oil and lower water cut percentage.

The problem with high steam quality is that high quality requires an additional cost required for tubing insulation to prevent heat losses. The other thing is that steam quality as injection rate is limited by boiler capacity.

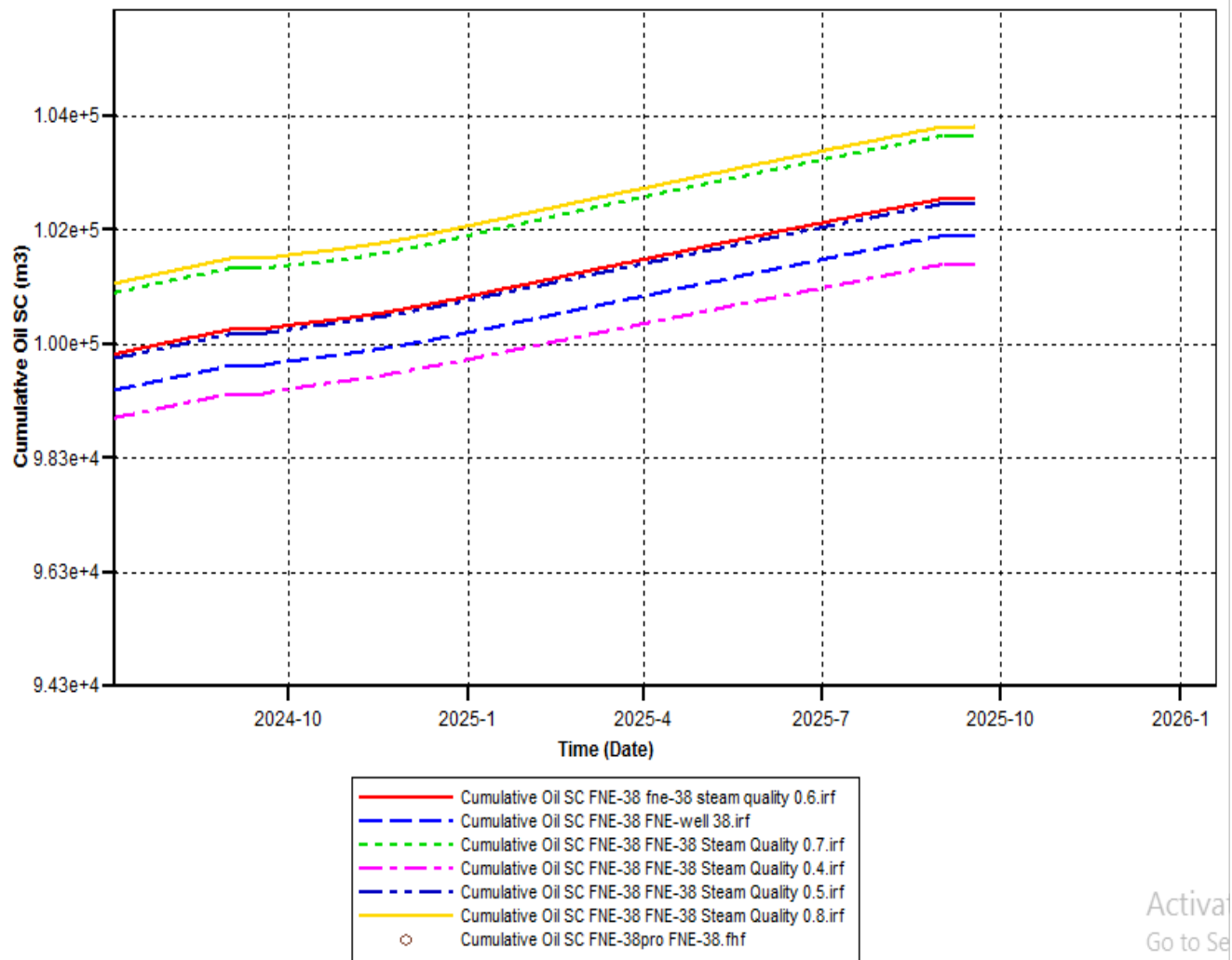


Figure {4-8} cumulative oil with quality

With increase in steam quality the cum oil will be increased, with high steam quality good heat distribution achieved and thus optimum heat developed within formation.

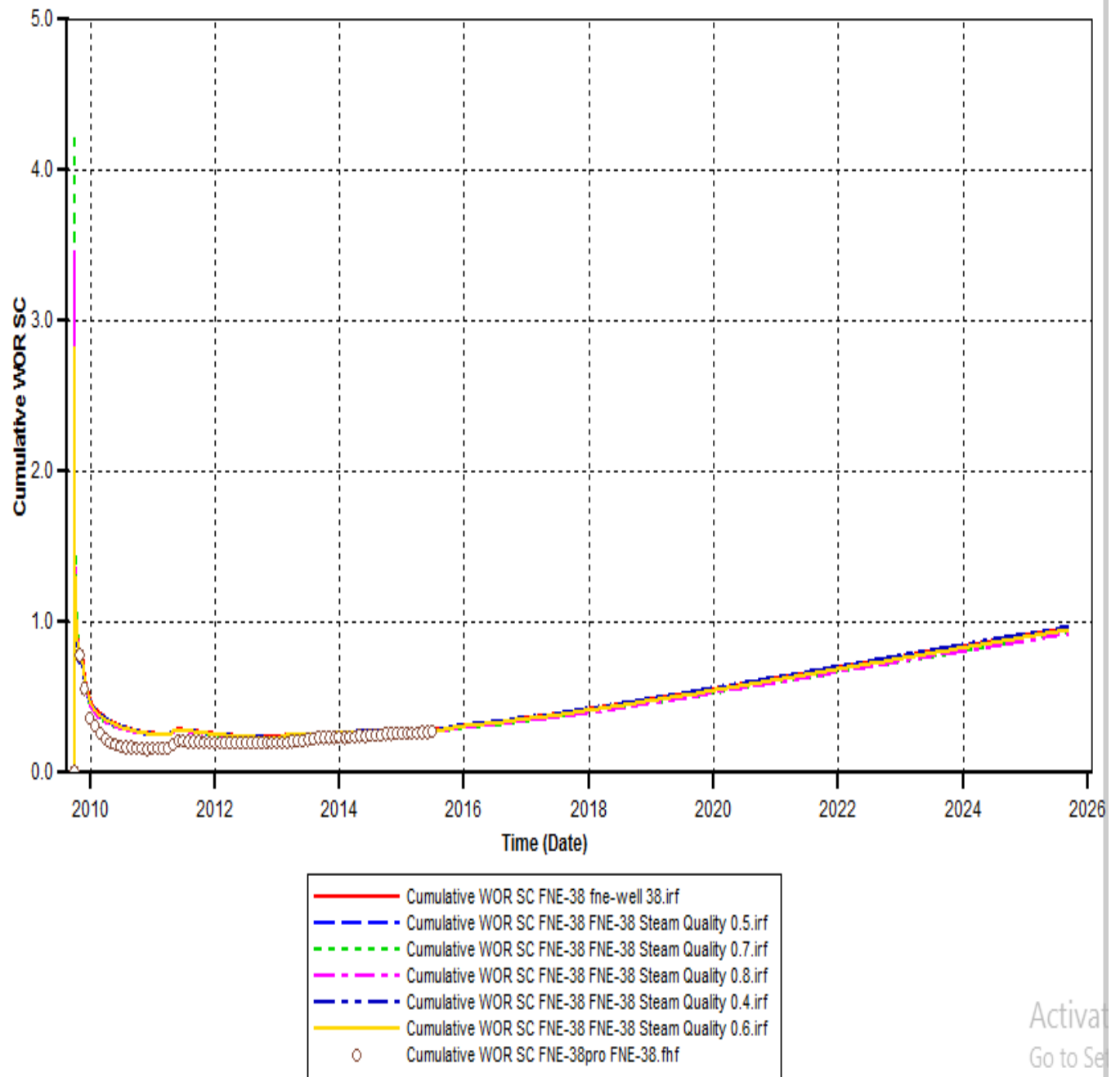


Figure {4-9} history profile of cumulative WOR

High quality has high WOR and low water quality vice versa the low quality.

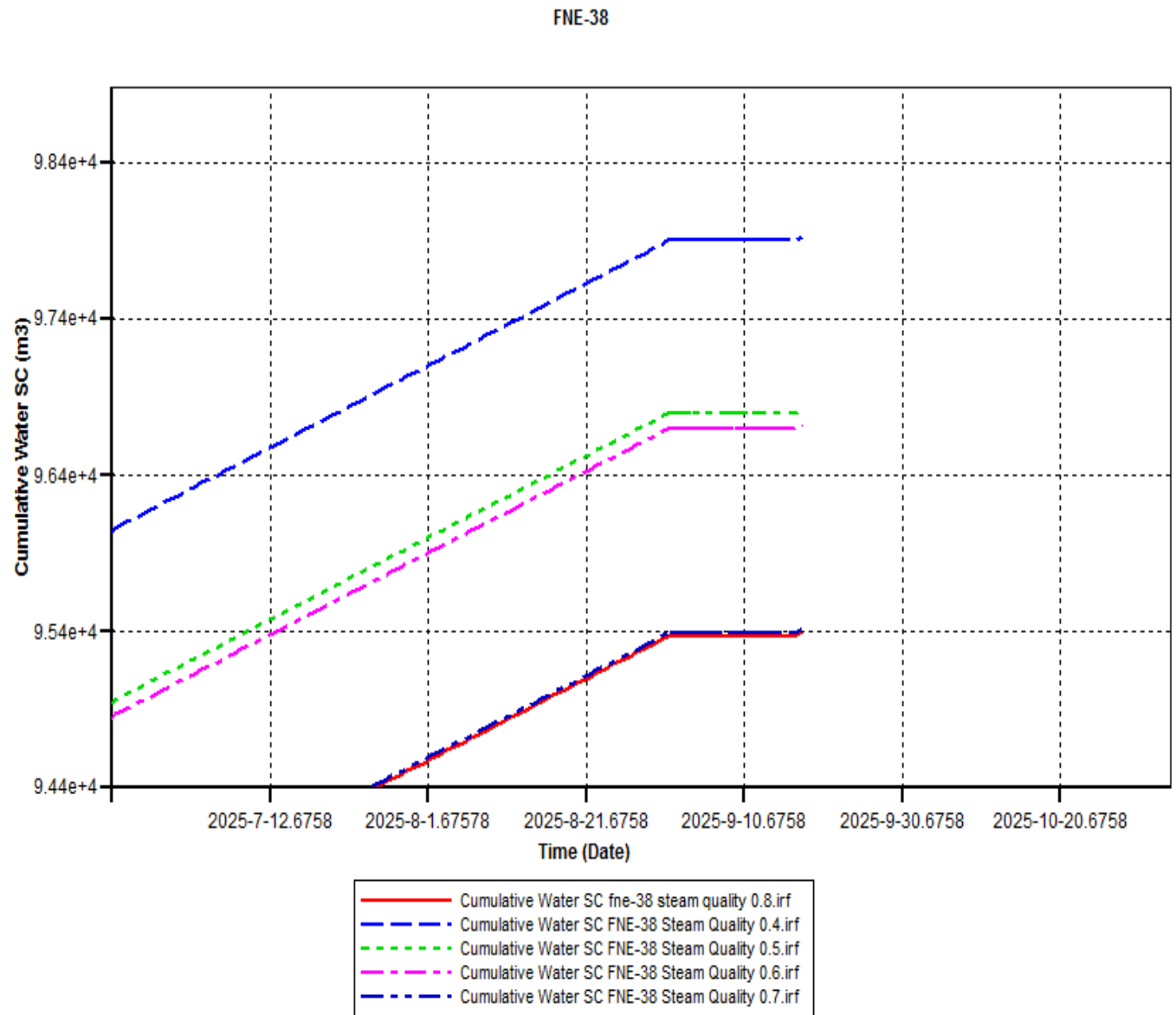


Figure {4-10} cum water

With high quality low water production predicted its take time to steam with high quality to turned into watee.

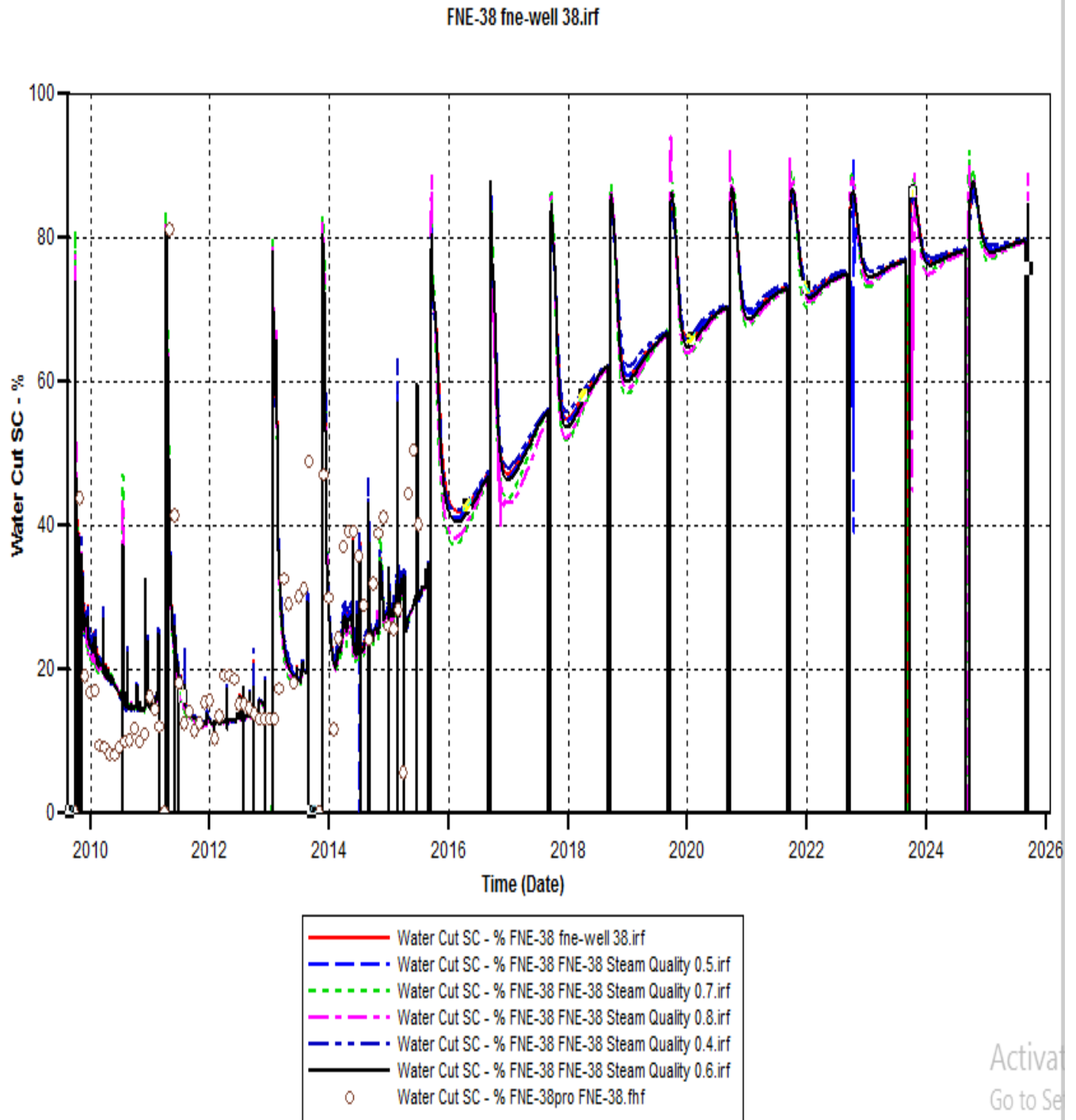


Figure {4-11} history matching of water cut

Field data with model to insure that results in same pattern with actual data. with more cycles performed water production increased.

Table {4-2} cum oil, water and liquid with steam quality

Steam quality	Cum oil	Cum liquid	Cum water	SOR
0.8	104054	194418	95345	0.535
0.7	103904	199283	95379	0.521
Well 38	102793	199492	96666	0.515
0.5	102706	199504	96765	0.5
0.4	101649	199541	97892	0.47

4-3Injection Rate:

After selection of optimized temperature (300) and steam quality (0.8) and in order to optimize the last parameter (injection rate)

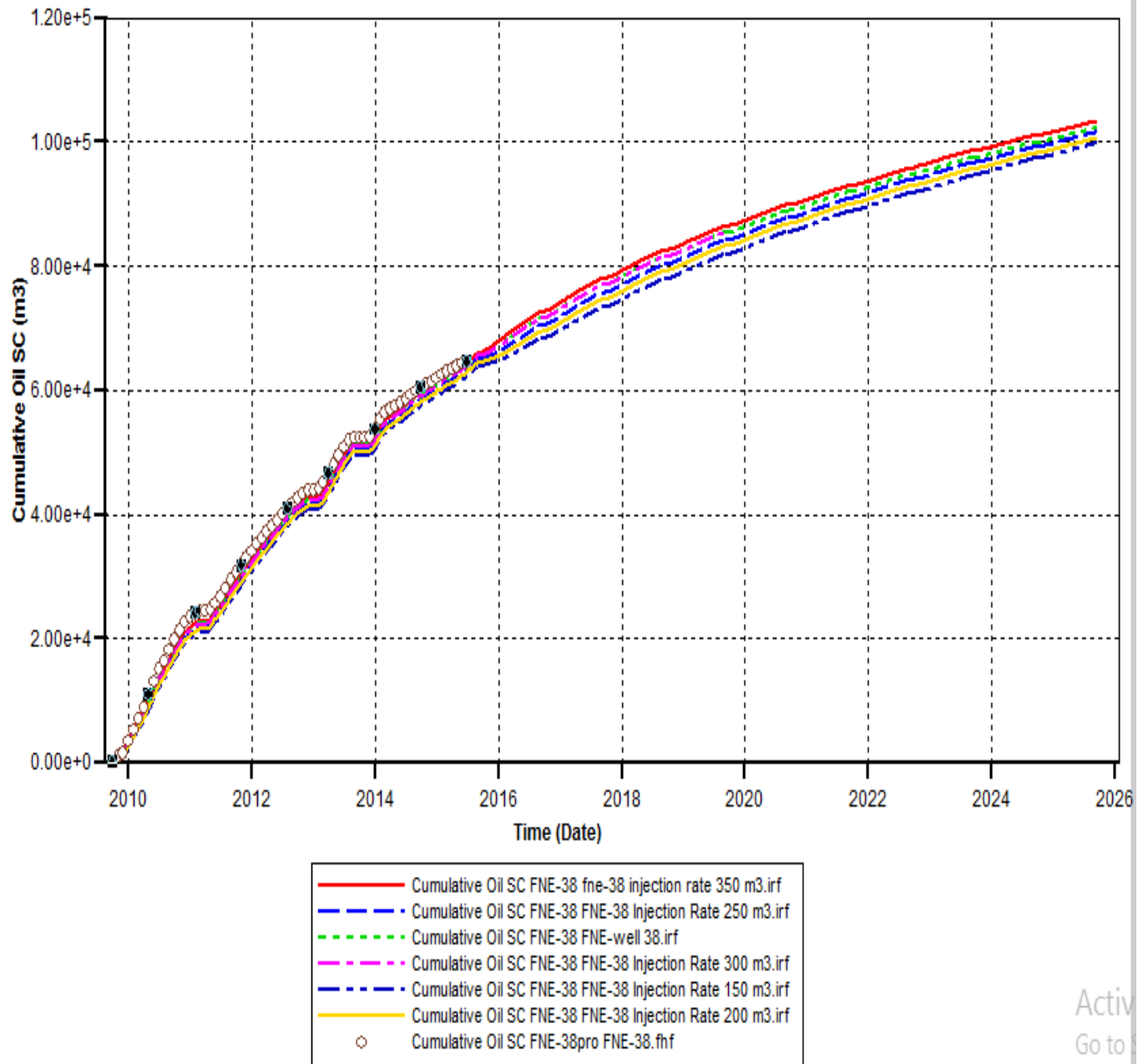


Figure {4-12} History Cumulative production at different injection rate and with same well case.

As increase in injection rate cum oil will be increased .high values of injection rate is recommend but it's costly as well as temperature and quality and depends also on boiler capacity.

So injection rate 250 m^3 is chosen due to the available boilers in FNE and if there a high capacities boiler it should be used

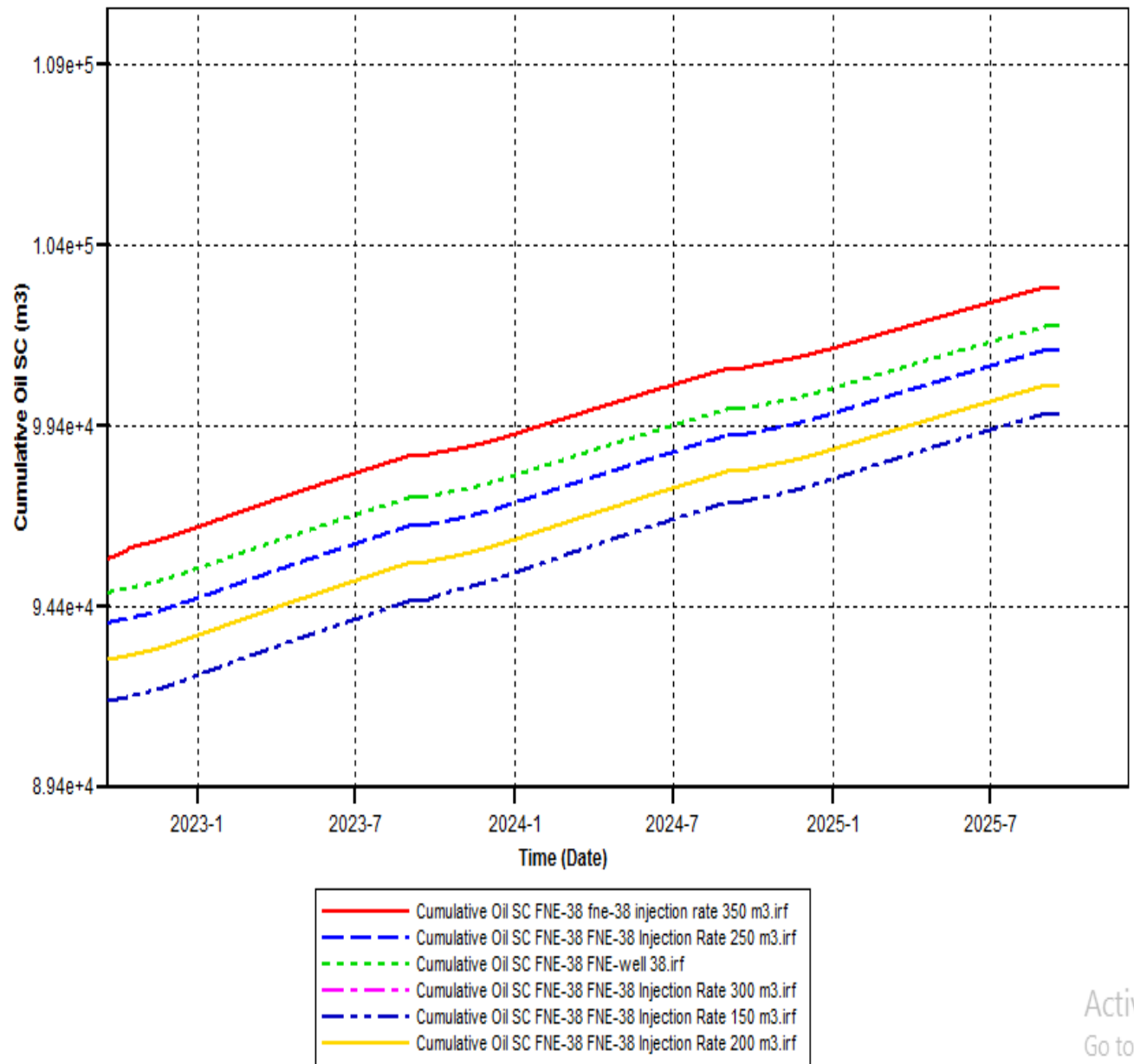


Figure {4-13} cum oil with different injection pressure As injection pressure increase cum oil increase due to high volumes of steam been injected.

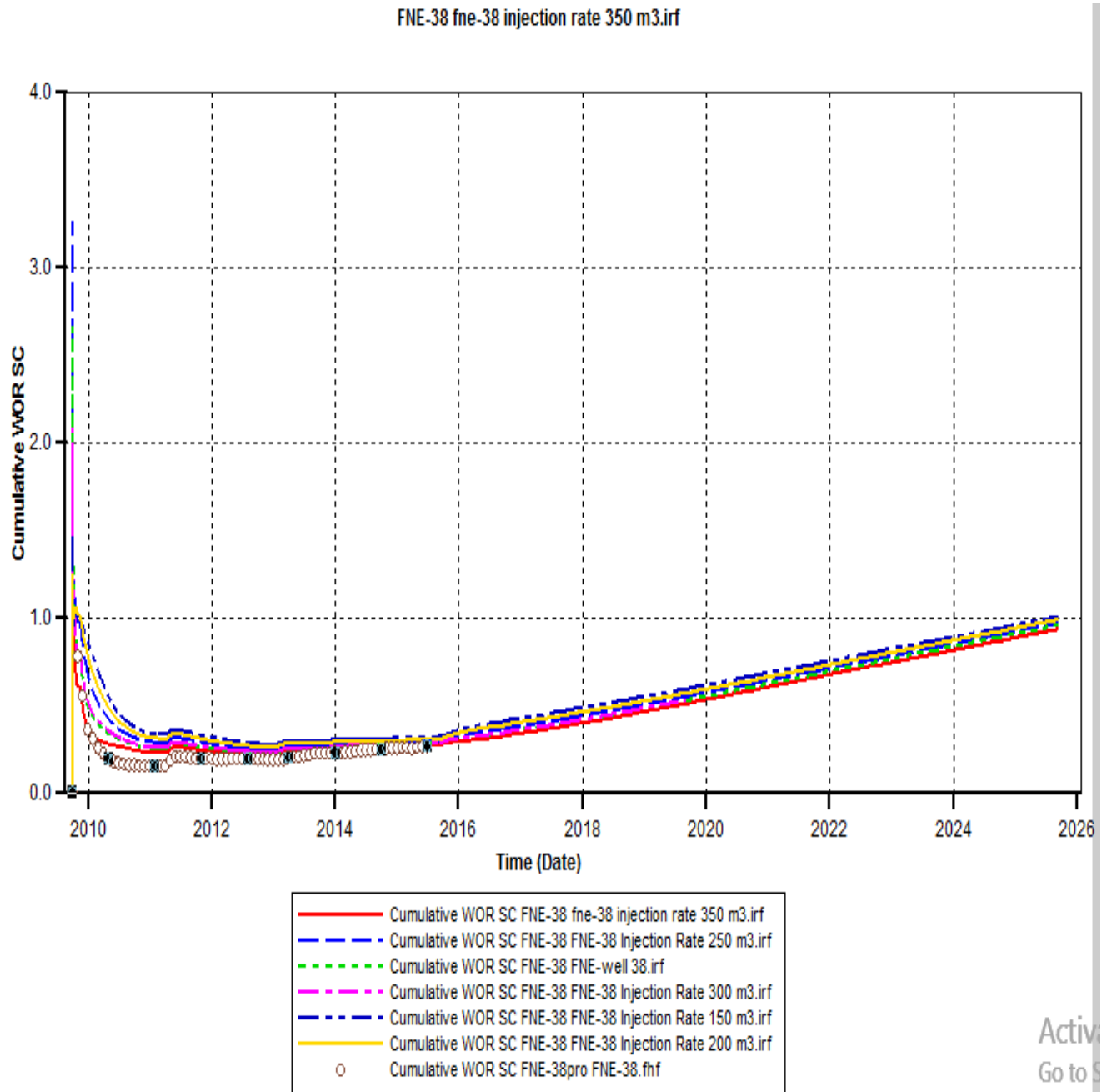


Figure {4-14}History profile WOR high injection rate has high WOR and high satem volume with large capacity boiler .

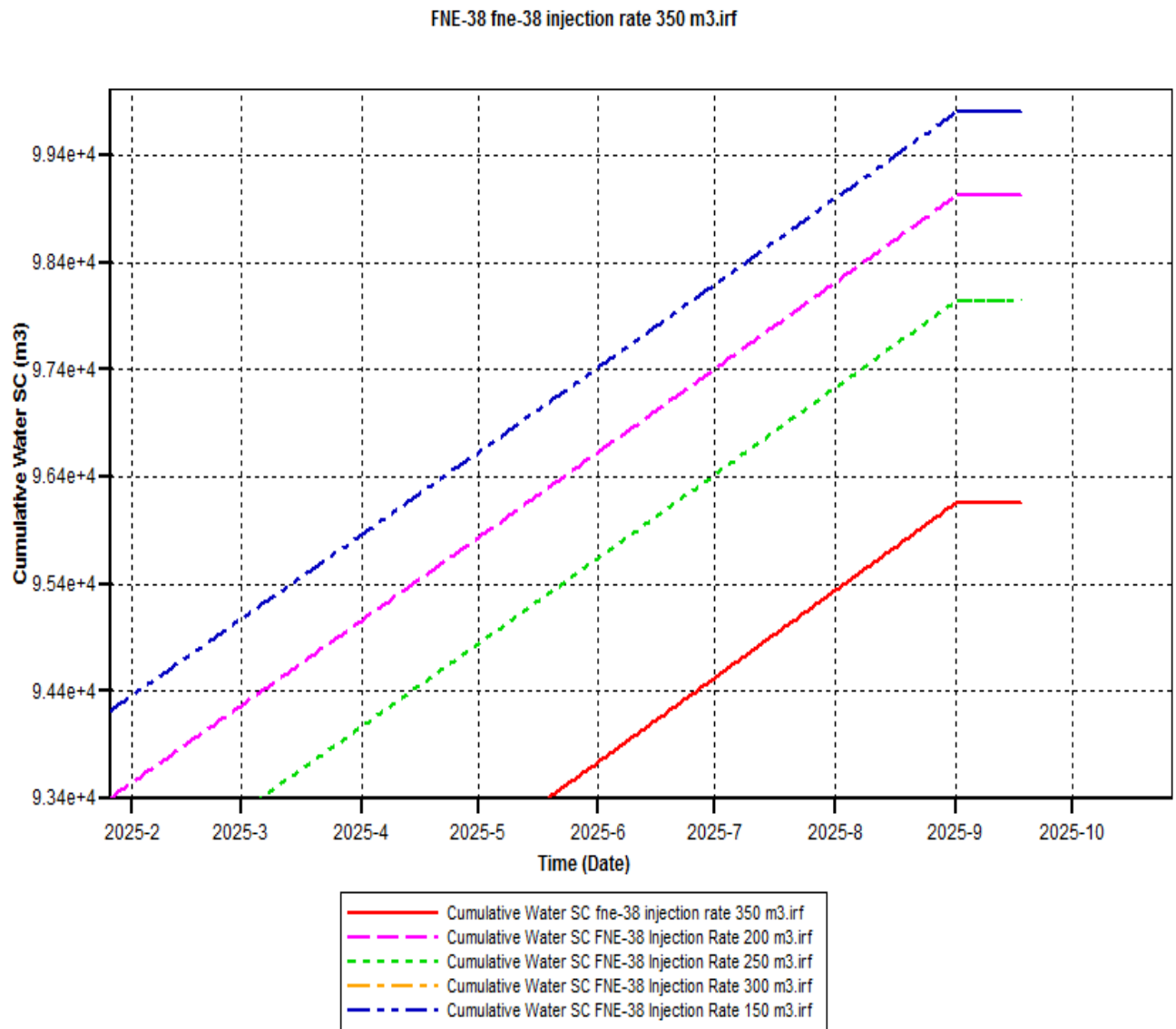


Figure {4-15} cumulative water produced

With low temperature there high water production

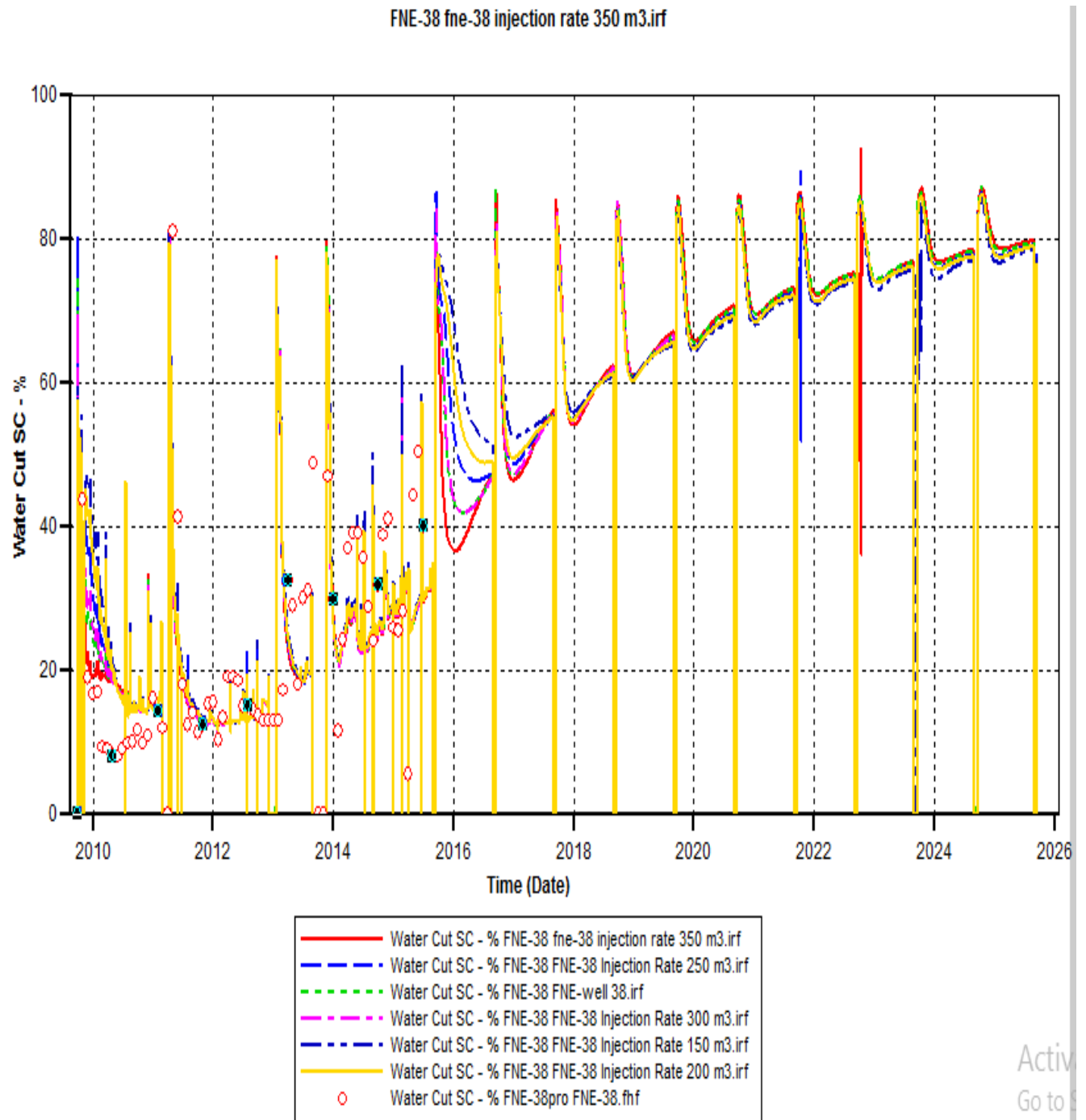


Figure {4-16} History profile water cut

An incensement in water cut noticed and it'll continuo increasing with more cycle performed.

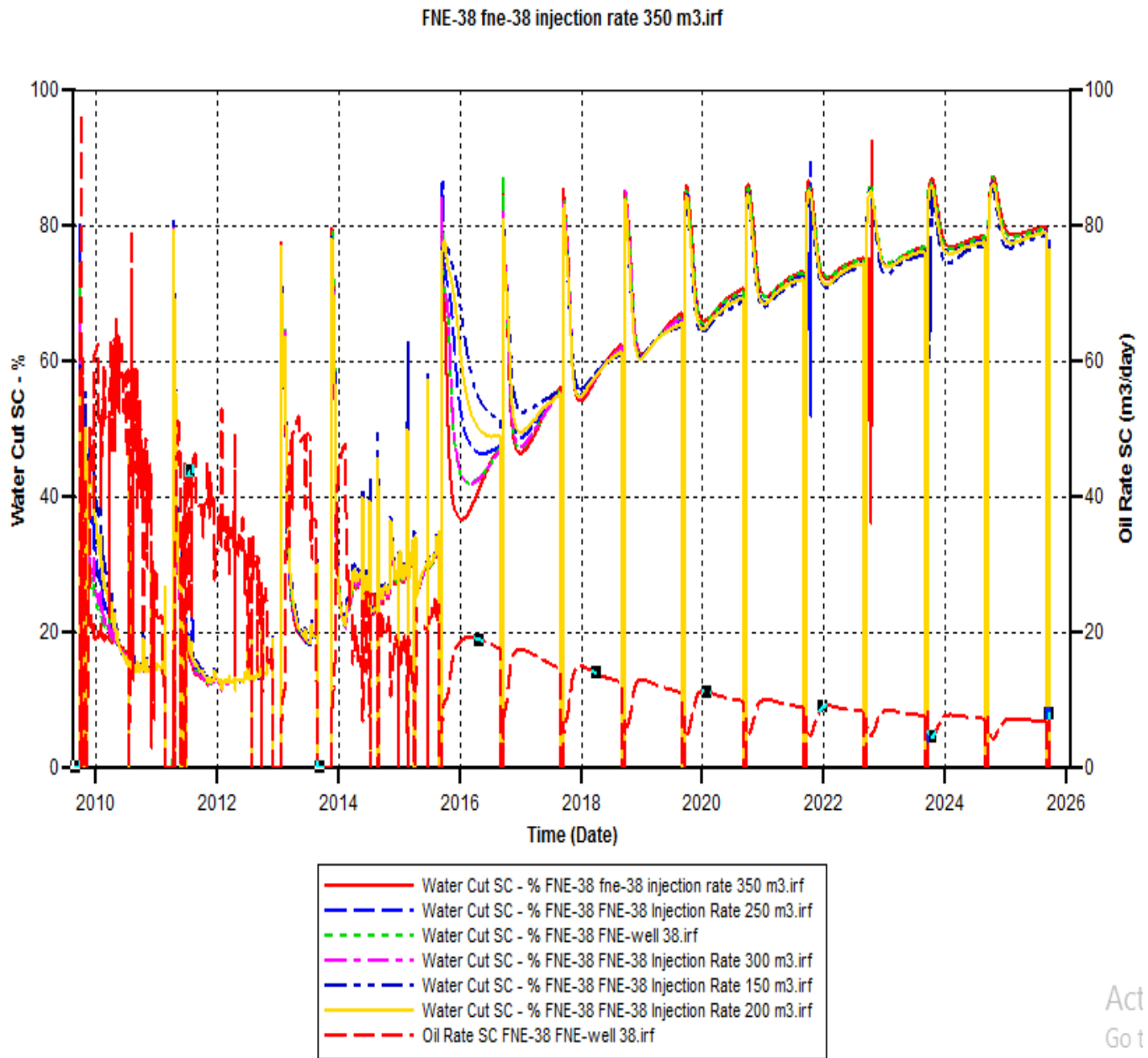


Figure {4-17} Water cut and oil rate with time

Oil rate reduces by time with more cycles until it become uneconomic, so here come the decision of turning the CSS into another thermal method

Table {4-3} cum oil, water and liquid with injection rate

Injection rate	Cum oil	Cum liquid	Cum water	SOR
350	103231	199400	96161	0.518
300	102146	199521	97424	0.512
250	101492	199544	98019	0.508
Well 38	100519	199544	99025	0.504
150	99741	199545	99803	0.4

4-4Optimized parameters:

- 1-The optimized temperature 300°C.
- 2- The optimized steam quality 0.8.
- 3- The optimized injection rate 300 m^3/d .

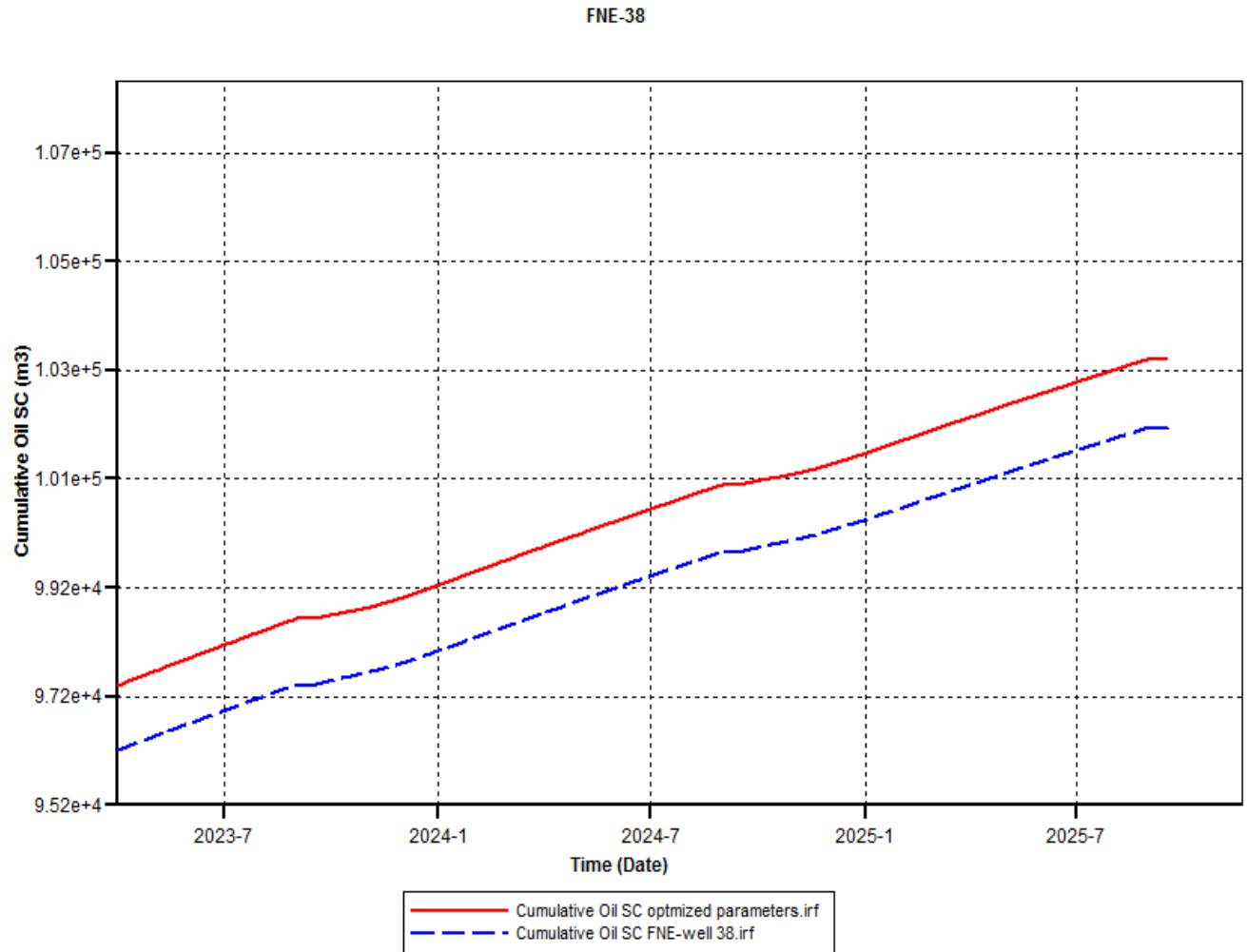
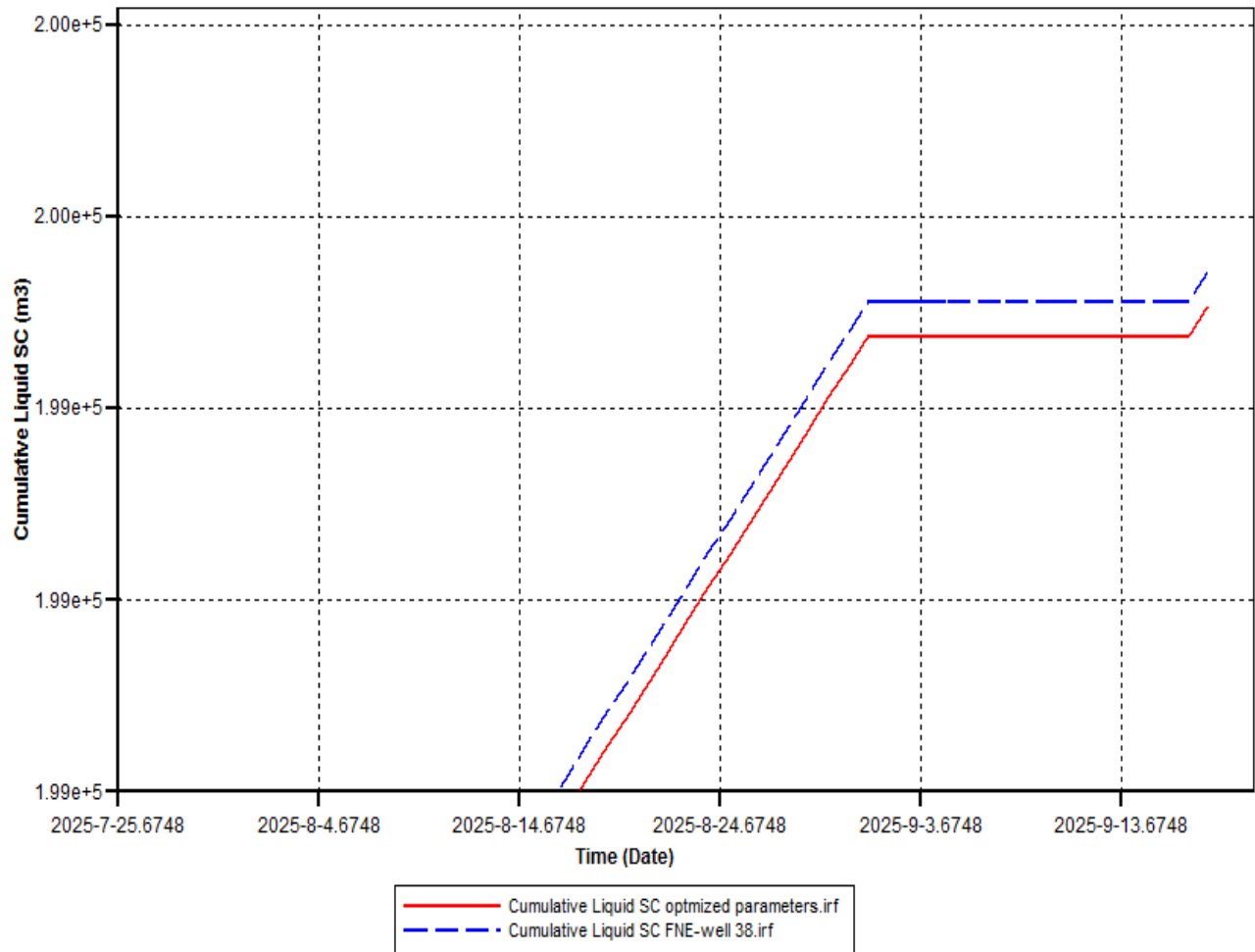


figure {4-18} cum oil of well-38 before and after optimization its noticed from the graph the optimized parameters have high cum oil than well-38



figure{4-19}cum liquid with optimized and original conditions high liquid production expected with optimized parameters.

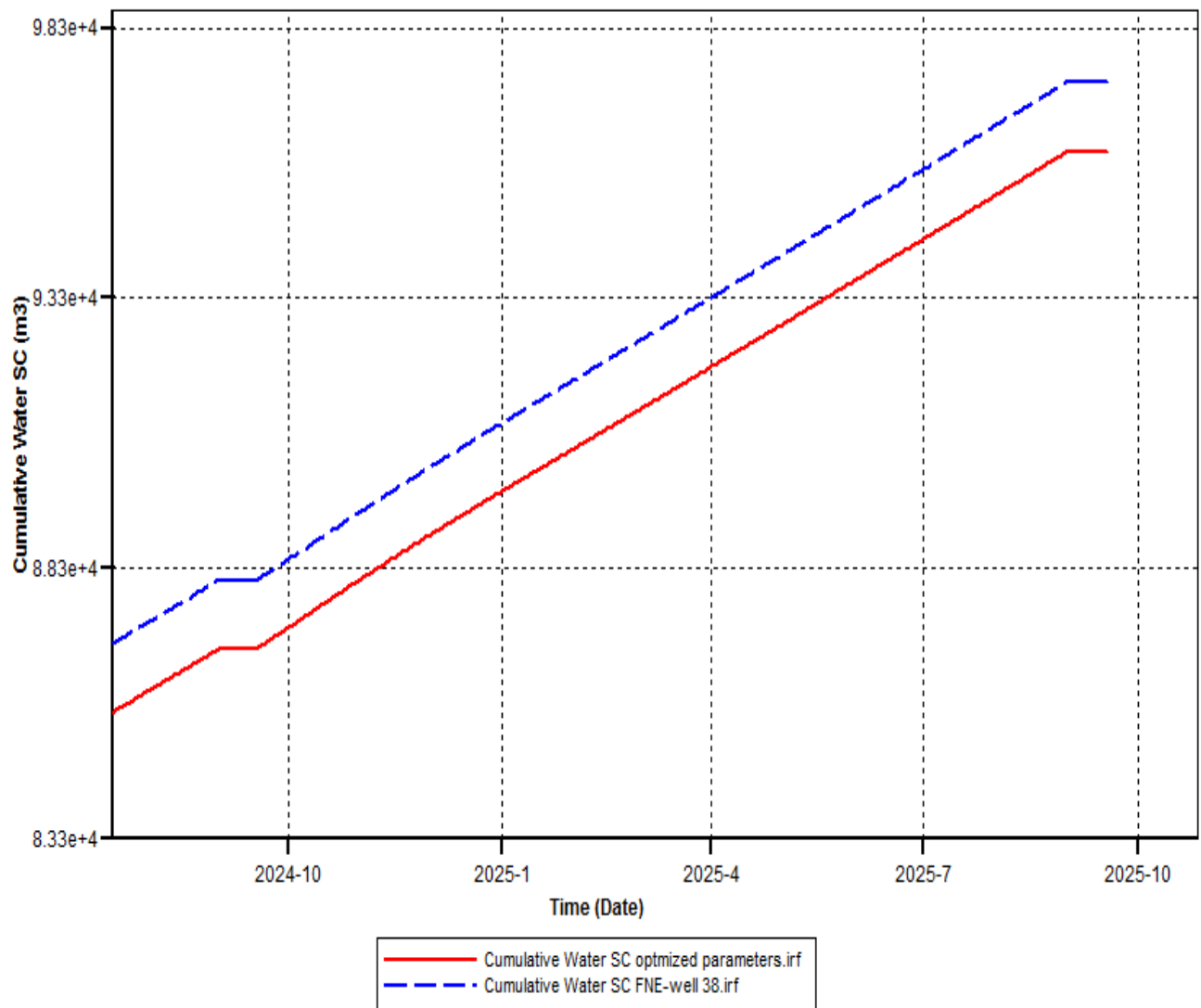


Figure {4-20} cum water for well-38 before and after optimization

high water expected due to high temperature and quality of injected parameters.

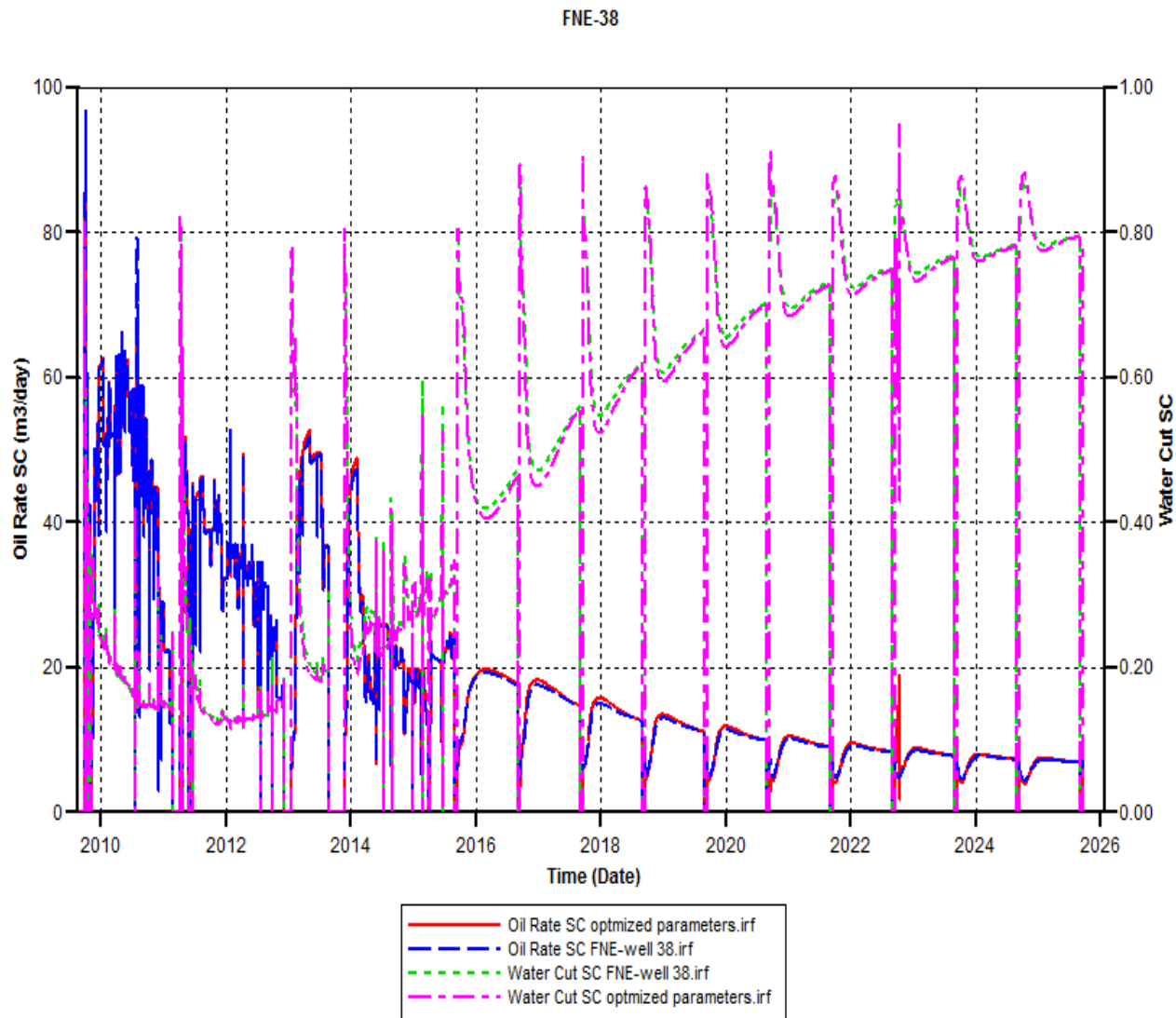


Figure {4-21} water cut and oil rate for both optimized and well-38 high oil rate and high water cut expected with more cycles but the optimized parameters

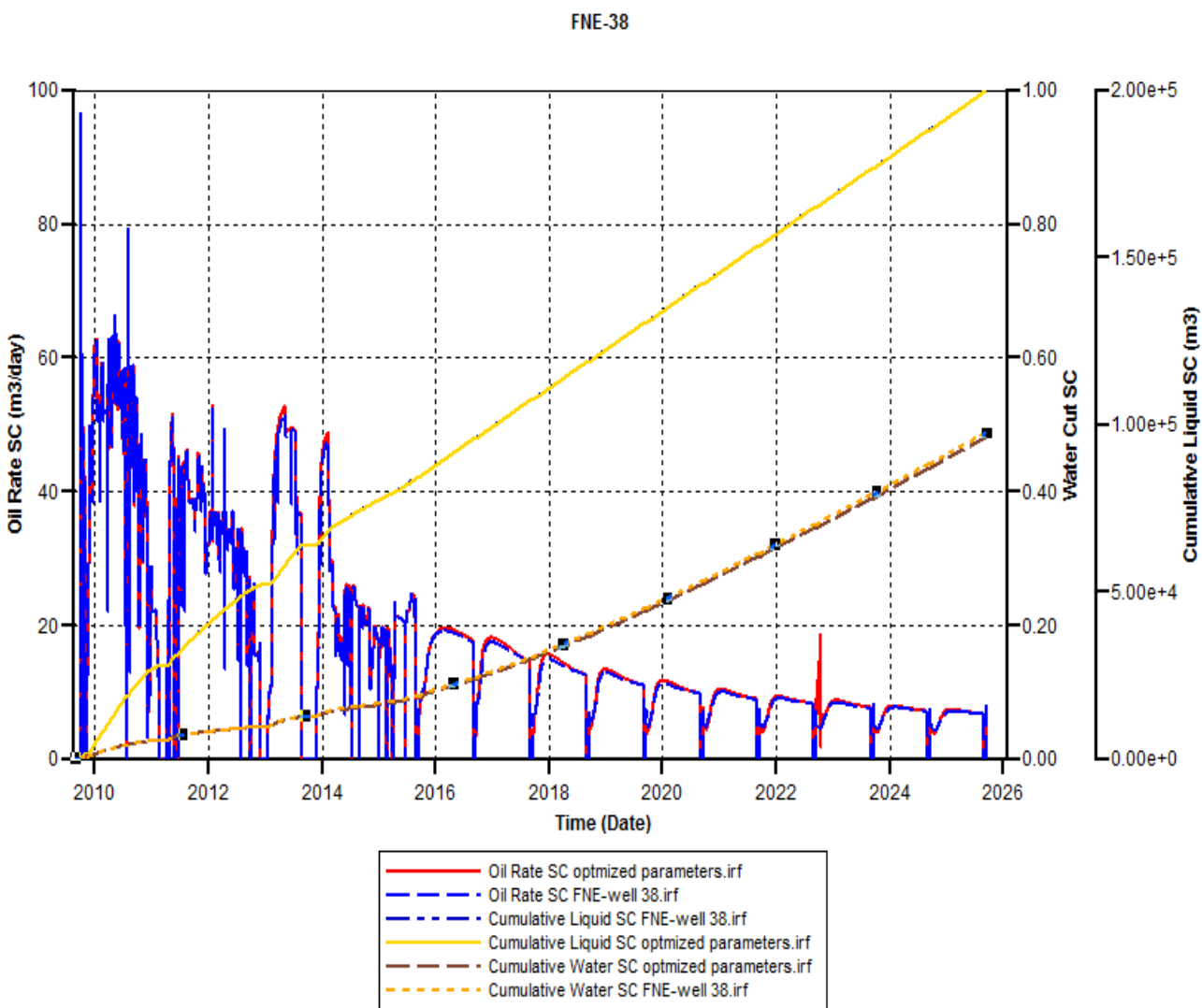


Figure {4-22} oil rate, water cut and cum liquid with high liquid production there an increase in water cut and decrease in water production.

Table {4-4} comparison between well-38 base and optimized parameters

Name	Cum oil	Cum water	Cum liquid	SOR
Well-38	102154	97342	199521	0.55
Optimized parameters	103409	9607	199485	0.6

Form the table the optimized parameters have high oil production and low water produced with high liquid produced and its have better economic indicator.

Chapter five

5-1Conclusions

1- CSS is a first stage for other thermal recovery projects. i.e.(before steam flooding and SAGD the implementation of CSS yield satisfying results.

2-CSS Injection Parameters (injection rate, injected steam temperature, injected steam quality, injected steam pressure) were all selected individually; a number of values for each parameter were introduced to the software

3-Different analyzing approaches were applied on the results to eliminate the exaggerated values and choosing the optimum parameter value (cumulative oil, WOR, water cut).

3-The optimum values obtained from the analysis are implemented to reach maximum possible recovery factor from under study well.

4-The obtained results specially steam intensity differs from one well to another, it could be noticed that for wells produce naturally before CSS the required intensity is significantly low when compared to those had been producing by CSS from the beginning of well life time.

5-2 Recommendations:

- CSS is essential for most viscous oil reservoirs.
- Adjusting and monitoring CSS injection, soaking and production periods are required for maximum oil gain.
- At the final stage to increase the recovery factor after CSS being non-effective (oil rate decrease) it is recommended to alternate to another thermal

manner using (steam flooding) where CSS played important role by heating the formation.

- It's better to increase steam quality to 0.8 and temperature 300 if it possible as field and company possibilities.
- keep injection rate at high values.

Chapter six

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