

# EVALUATION OF WATER QUALITY TO IMPROVE INJECTIVITY OF PRODUCED WATER IN A WATERFLOODING PROGRAM: A CASE STUDY FROM MELEIHA FIELDS, WESTERN DESERT, EGYPT

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**ABSTRACT:** The performance of waterflooding programs is firmly attributed to management of injection water quality, particularly scale tendency and total suspended solids. Poor injectivity not only deteriorates sweep efficiency and inconsequence reduces the overall recovery, but also results in inevitable stimulation and other costly workover jobs. In this research a detailed water quality assessment for injection water plant in Meleiha fields is discussed to determine the requirements that ensure the reliability of injection program. Two water sources and their mixtures are considered; water producers from Kharita formation and the produced water separated at API separator. Results indicates that the scale tendency (ST) analysis of various mixtures showed values less than one indicating under-saturation conditions that generally hamper scale formation. In addition, barite and calcite reported the highest ST among the feasible scales to form and the ST indices for barite and celestite tend to decrease with the decrease of formation water share in injection water mixture while increasing for calcite and gypsum. Under reservoir conditions, ST is significantly lower than the corresponding value at the surface conditions for Kharita/produced waters and their mixtures at the various mixing ratios. Compared to the water from Kharita aquifer, the produced water obtained has poor quality and shows high plugging tendency and should be thoroughly managed. In addition, bacterial activity was detected and should be suitably treated. The detailed analysis helps to formulate various water treatment stages in a preliminary conceptual design for water injection plant that could assist reducing water injection problems and maintain successful waterflooding.

**Keywords:** injection water quality, scaling tendency, injection plant design, waterflooding

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1. **INTRODUCTION:** Management of injection water quality plays the crucial role in the success of water injection programs, where measurements of water quality, compatibility, and bacterial contamination should be accurately accomplished (Patton, 1990). The quality of the produced water is influenced by total dissolved solids (TDS), the larger suspended particulates in water known as total suspended solids (TSS), scale-causing compounds (calcium, magnesium, barium, sulfate) and bacterial growth (1). Impaired water Injection and disposal wells usually acquaintances scaling due to water incompatibility and bacterial fouling, suspended solids/ dissolution products, oil/water emulsion, and formation dissolution (2). Such factors not only deteriorate the water injectivity but also jeopardize the overall reservoir quality. Thus, quality management of injection

water, based on converging financial, technical, and environmental requirements, is necessary (1). Such management is feasible particularly, on considering the guidelines of water quality accredited for injection projects in numerous publications, e.g. (3).

Due to extensive water injection, numerous reservoirs experienced scale deposition problem started with the commence water injection and continued to the break through (4). Scale problems, causing formation damage, arise when conditions favorable for deposition result in supersaturated brines with mineral scales due to deviations of pressure and other physical/chemical conditions from the original reservoir conditions (5). Therefore changes in the brine composition, could be due to water exchange between liquid and vapor phases, are the main factors that significantly deteriorate scale problems. Two main scale types are commonly found in the oilfield; carbonate and sulphate scales [(5), (6), (7), (8), (5)]. As the pressure and pH change, the production fluid is usually associating the formation of carbonate scale [(9), (10)], the formation of sulphate scale is principally due to the mixing of incompatible brines i.e. formation water and injection water [(11), (12), (9),(13)] . Classically, the deposition of calcium and strontium sulphate scales is known to form at some stage of injection with the use of sea water as the primary fluid for pressure maintenance (13).

Meleiha fields are discovered in the seventeenth of the past century and production commenced by 1978 from three heterogeneous oil bearing intervals (1.5 – 9 m thick) of low horizontal continuity. PVT data analysis indicated that the reservoir fluids are black oil with API of 41. During 2011, 24 new wells were drilled and put into operation to produce with average flow rate 37.4 tons per day (276.8 bbl/day) and the overall proved reserve reports 16.95 MMSTBO (14). In 2011, production was 987000 tons (7303800 bbl) with total 217 oil production wells and 50 injection wells in the field. The trend of reservoir pressure decline indicated depletion driving reservoir energy with no indications of aquifer support. This is augmented by well log data analysis that did not show oil water contact (15). Due to the low pressure support, natural depletion over 4 years in Meleiha NE field resulted in reservoir pressure decline from initial pressure of 2300 psi to 1000 psi, corresponding to annual pressure decline of 325 Psi/year (15). When reservoir pressure approaches the bubble point pressure (~460 Psi), the water injection, based on PVT data analysis, was recommended to support the reservoir pressure and to persue a secondary production phase of the field life. Produced water reinjection for waterflooding/disposal applications is a precious strategy for not only deriving value from waste but also preserving environmental integrity during production operations (1). Reservoir and production studies indicated a hydraulic connection among the flow systems of the different fields in Meleiha concession [(15), (16)] is connected and in consequence the Meleiha water injection systems would require additional water supplies. To mitigate repetitive problems of water source wells at Meleiha field, using produced formation separated from oil process plant became economically and environmentally viable. Thus, the injection water benefits from the reuse the produced formation water in preparing a mixture of produced water and groundwater pumped from three water production wells tapping Kharita formation. Produced formation water re-injection has many advantages including ; cost saving , provide a mean for disposal of produced water separated at API separator, and more compatible with formation water so this will minimize the risk of scale formation.

In this study a detailed compatibility analysis to the injection water mix from Bahariya (> 80%), Kharita (~10%), Alam El Buib (3-5%), and Khatatba (1% or less) formations is discussed. This includes evaluation of the compatibility of the produced water with the formation water, produced water quality, and scaling tendency to improve its injectivity. Such information is essential for injection plant conceptual design, layout, and various water treatment specifications.

**2. LOCATION AND GEOLOGICAL SETTING:** Meleiha block is located in the northern province of the Western Desert, Egypt and includes 4 main fields: Aman, Meleiha North-East, Meleiha West, and Meleiha South-East (Fig:1). It covers 700 km<sup>2</sup> area but the four fields fall between latitudes 281700 m and 293000 m and longitudes 705800 m and 718500 m (Fig:1) Meleiha Field typically follows the stratigraphic column of the Western Desert with the shallow producing intervals, around 1675 m TVDSS, fall within the Upper Cretaceous Bahariya formation (17). Bahariya Formation is composed mainly of sandstone but the various intercalations of shale and carbonates varnish a lithologically complex reservoir. It occupies a stratigraphic

position underlying the widely extended carbonate deposits of the Abu Roash Formation and overlying the clastic Kharita Fm (Fig:II) and have been subdivided into Zones; B-I to B-VI (Table:I). Within these zones, (16) identified three different lithological facies; the lower facies extends up to the top of zone III dominated by siliciclastic deposit, the intermediate facies occupies the lower part of unit II and is marked by calcareous deposits with sporadic mixed facies, and the upper facies extends up to the boundary with Abu Roash Formation and is dominated by interbedded sand-carbonate units. Core and well log data indicated average porosity of approximately 24% in the reservoir units, while moderate to relatively high permeability measurements 50 – 200 mD are measured in core data and well test [(16), (18)]. Meleiha field is covered with 3D seismic data and the prevailing structure setting is interpreted using seismic data and calibrated by well data. The geological structure at Bahariya formation is dominantly represented by multiple closures controlled to by NW-SE extensional faults (19).

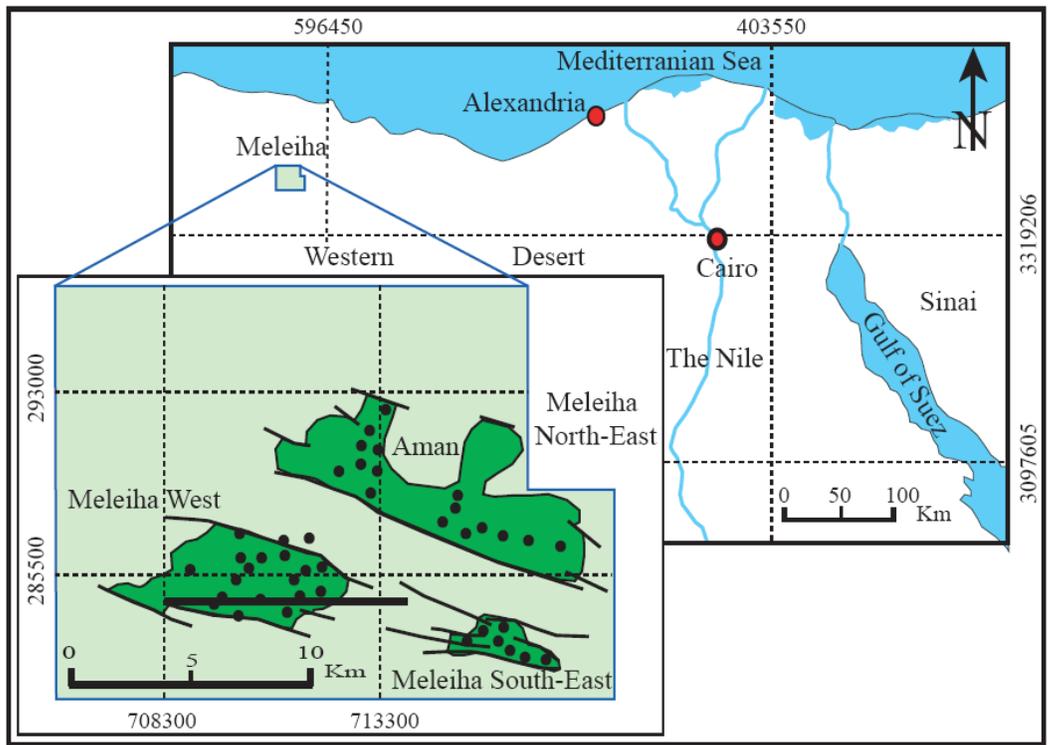


Fig I: Location map of Meleiha fields.

**3. THEORY AND METHODS**

Scaling tendency “ST” (also called the saturation level or ratio) is a measurement of a system to precipitate dissolved species. Mathematically, it can be defined as the ratio between the ionic activity product “IAP” and the solubility product “Ksp” of an equilibrium equation. Thus

$$ST = \frac{IAP}{K_{sp}} \dots\dots\dots 1$$

The IAP is the product of the activities of the chemical species (ai) in solution. For Example consider the dissociation of a compound AB according the general equation;



The ionic activity product for this reaction is calculated as

$$IAP = aA \times aB \dots\dots\dots 3$$

and

$$aA = \gamma A \times mA \dots\dots\dots 4$$

Where  $\gamma A$  and  $mA$  are respectively the ionic activity coefficient and the molal concentration for species A

The solubility product,  $K_{sp}$  is a standard thermodynamic quantity for each solid species that depend on the ambient temperature and pressure (due to the little effect for solids and for simplicity, pressure effect can be ignored).

At equilibrium the solubility product is equal to the IAP, which in case of a precipitation reaction is the solubility limit for the solid chemical species. Accordingly the system is supersaturated if the ST exceeds the unity but undersaturated if its calculated value is less than one. The logarithmic scale of the scaling tendency is known as the Langelier Saturation Index or scale index.

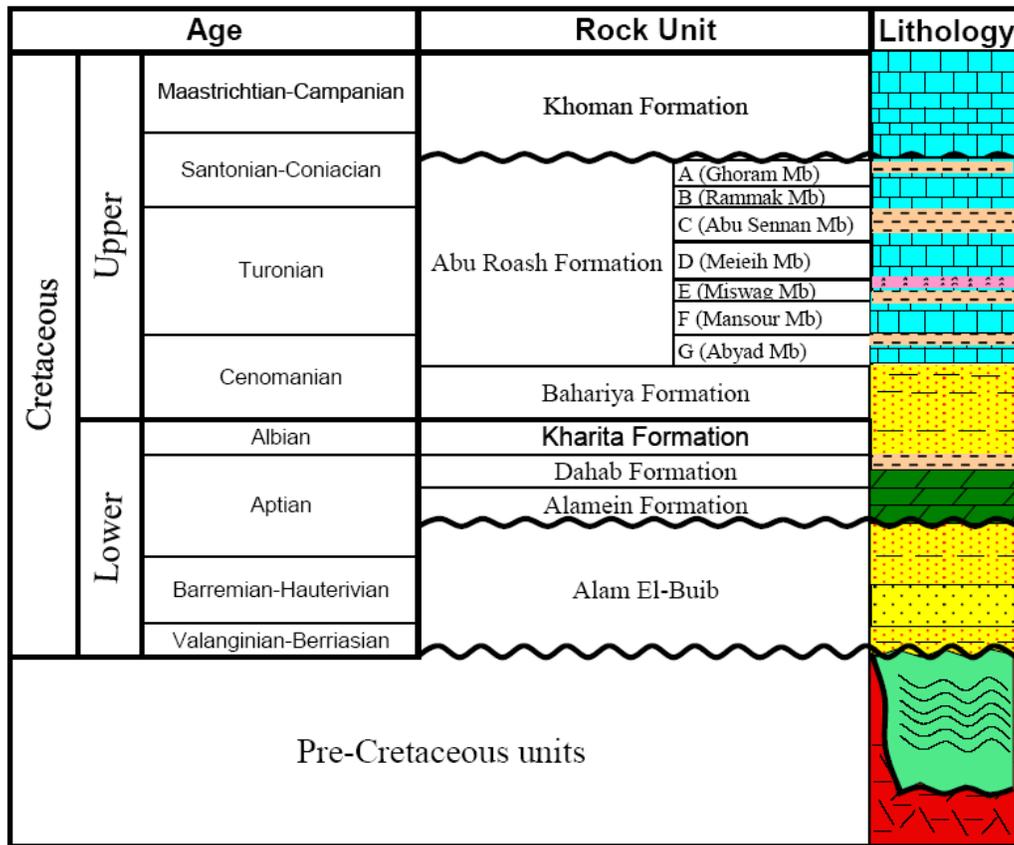


Fig II: Lithostratigraphic column of the pay zone in Meleiha fields, the northern part of the Western Desert [(20),(21)].

Two water samples were collected for analysis; one from formation water at M47 well and the other from the injection water mixture to study the compatibility analysis. The major elements, cations and anions,

are analyzed using Ion Chromatography (IC Dionex DX600). Trace elements are determined using Inductively Coupled Plasma mass spectrometry (ICP) instrument. The physical properties such as Total Suspended Solids (TSS), specific gravity, and Total Dissolved Solids (TDS) are determined using standard laboratory techniques. TSS is measured using 0.45 μm membrane filter at a constant differential pressure of 20 psi across the filter in accordance with standard TM-01-73 method (22). The solid filtrate can subsequently be analyzed to determine its origin; scale, formation, corrosion,...etc. Membrane filter test data is usually carried out to evaluate water quality and results can be displayed using both Cerini method, a plot of flow rate versus the cumulative volume (23), or Barkman and Davidson method, a plot of flow rate against square root of elapsed time (24). Being easier to construct, Barkman and Davidson plot is preferred and was applied in the present study. Particle size and count of water samples were measured using coulter particle counter (Coulter Electronics Limited) as a particle volume and subsequently expressed as a diameter of the corresponding sphere. Reliable measurements are usually taken for particle size between 1.5 and 20 microns to avoid environmental interferences to measurements.

The pH was determined in-situ at the surface temperature using HI 98128-pHep pH meter manufactured by HANNA instruments. TDS was calculated from the chemical analysis results, after performing charge balance, and confirmed by measurement using HI9835-Microprocessor conductivity / TDS meter of HANNA instruments. Dissolved carbon dioxide in water is measured on-site by titration with sodium carbonate according to the API-RP-45 method of the American Petroleum Institute. Dissolved oxygen was determined by the Indigo Carmine method using Dissolved Oxygen Test Kit, Visual Colorimetric Analysis (ASTM D 888-87). Hydrogen sulphide was determined by evolution of the gas and absorption on lead acetate paper. Bacteria analysis was undertaken on separate samples with a great care taken to prevent contamination and preserve the original biota by using aseptic techniques on pre-sterilized disposable equipment. Samples were cultured with a media adjusted to water sample salinity and bacteria were monitored according to (25). The majority of lab measurements and preliminary data processing are accomplished at the CORELAB unit at Egyptian Petroleum Research Institute (EPRI).

		Meleiha fields	Meleiha SE	Meleiha W	Aman	Meleiha NE
Bahariya formation (Lower Cenomanian)	Bahariya I					
	Bahariya II					
	Bahariya III				Upper	Upper
					Lower	Lower
	Bahariya IV					
	Bahariya V		A	A	A	A
			B	B	B	B
Bahariya VI						

Table I: Detailed subdivisions of Bahariya formation as characterized in Meleiha fields by (16).

#### 4. RESULTS AND DISCUSSION

**4.1. INJECTION WATER QUALITY:** The results of complete water analysis of both formation water and injection mixture water are presented in Table:II. These data is the typical input parameters to determine scaling tendency and saturation indices for the common scale species using Equation 1 in a computerized scale prediction model that facilitate identifying the expected compatibility between injection and formation waters. The results of scale tendency for various mixtures of the formation water and Kharita water at surface and reservoir P-T conditions are shown respectively in Tables:III and IV. Both formation water and injection water mixture are typical brine with corresponding TDS of 104940 ppm and 120290 ppm (Table:II). The chemical

analysis of these waters showed higher concentration values of all dissolved species in injection mixture except for strontium and barium that are significantly concentrated ( 69.22 Vs 0.0167 ppm for Sr and 0.646 Vs 0.117 ppm for Ba) together with slightly higher sulfate (108.5 Vs 104 ppm) in the formation (Table:II). The scale tendency analysis of various mixtures showed dramatic decrease in ST and SI values of the different scale species calculated at surface conditions (Table:III) compared to the corresponding species at reservoir conditions (Table:IV). But in all cases, barite and calcite remained the most probable scales to form. Furthermore, the ST and SI indices for barite and celestite tend to decrease with the decrease of formation water share in injection water mixture (e.g. at ambient conditions ST of barite is 0.42 @ 100% formation water but 0.06 @ 0%) while increasing for calcite and gypsum (e.g. Calcite SI index is -1.5 @ 100% formation water and increases to -0.7 @ 0%).

Scale prediction model for the Kharita water, produced water, and their mixtures at different shares were set up under the various operating conditions of temperature and pressure. Generally, calculations showed that the solution would be undersaturated for all the expected scale species in both surface and reservoir PT conditions. This indicated by the negative saturation indices and scale tendency values below the unity (Tables:III and IV). Under the API separator conditions, Kharita water has the higher tendency to deposit calcite, but the pure produced water tends to deposit barite (Table:III). Mixing the two waters also tends to deposit calcite and barite with an increase in the calcite scaling tendency on increasing of Kharita water content in the mixtures. Under the operation condition of the water injection plant, the deposition of calcite could be predicted for Kharita water, but barite scaling is envisaged for the pure produced water and their mixtures. The tendency for barite scale is significantly increasing with the increase of the formation water in the mixture (Table:III). Under reservoir conditions, only barite scale could be predicted to deposit from both pure Kharita/produced waters and their mixtures at the various mixing ratios. Therefore, a scale inhibitor could be an additive to prevent barite scaling.

To replenish the production performance, water injection started using numerous peripheral injection wells in addition to few injection wells at the middle part of the field (Fig:III). Despite the fact that total dissolved solids (TDS) in large concentrations are significant to water treatment plants because their scale tendency, but TSS is typically more significant to injection wells due to their plugging tendency. Preferably, injection water should enter the

Physical Properties	Analysis						
Total dissolved solids	104940 ppm						
Conductivity	13.45 *10 <sup>-2</sup> mohs/cm @ 77°F						
Resistivity	0.07435 ohm m @ 77°F						
Salinity as NaCl	98117.25 ppm						
PH	7.15 @ 77 F°						
Density	1.06978 gm/ml @ 77°F						
Specific gravity	1.071162						
Hardness	10534.76 ppm						
		<b>Cations</b>	<b>ppm</b>	<b>meq/l</b>	<b>Anions</b>	<b>ppm</b>	<b>meq/l</b>
		Li <sup>+1</sup>	10	1.441	Cl <sup>-1</sup>	59465	1677.29
		Na <sup>+1</sup>	33716	1466.57	OH <sup>-1</sup>	nil	nil
		Ca <sup>+2</sup>	3650	182.14	CO <sub>3</sub> <sup>-2</sup>	nil	nil
		Mg <sup>+2</sup>	345	28.39	HCO <sub>3</sub> <sup>-1</sup>	39.1	0.641
		K <sup>+1</sup>	60	1.53	SO <sub>4</sub> <sup>-2</sup>	108.5	2.259
		Al <sup>+3</sup>	nil	nil			
		Fe (total)	0.0373	0.002			
		Cu <sup>+2</sup>	nil	nil			
		Sr <sup>+2</sup>	69.22	1.58			
		Ba <sup>+2</sup>	0.646	0.009			

reservoir free from both suspended solids and oil (26).

Physical Properties	Analysis	Cations	ppm	meq/l	Anions	ppm	meq/l
Total dissolved solids	120290 ppm	Li <sup>+1</sup>	12	1.729	Cl <sup>-1</sup>	72500	2045.23
Conductivity	14.97 *10 <sup>-2</sup> mohs/cm @ 77°F	Na <sup>+1</sup>	39020.9	1697.33	OH <sup>-1</sup>	nil	nil
Resistivity	.0668 ohm m @ 77°F	Ca <sup>+2</sup>	5495	274.201	CO <sub>3</sub> <sup>-2</sup>	nil	nil
Salinity as NaCl	119625 ppm	Mg <sup>+2</sup>	780	64.186	HCO <sub>3</sub> <sup>-1</sup>	97.6	1.6
PH	6.75 @ 77 F	K <sup>+1</sup>	508	12.995	SO <sub>4</sub> <sup>-2</sup>	104	2.165
Density	1.08479 gm/ml @ 77°F	Al <sup>+3</sup>	nil	nil			
Specific gravity	1.087027	Fe					
Hardness	16933 ppm	(total)	1.296	0.069			
		Cu <sup>+2</sup>	nil	nil			
		Sr <sup>+2</sup>	0.0167	0.00038			
		Ba <sup>+2</sup>	0.117	0.002			

Table II: Physical properties and complete water analysis of formation water from well M49 (upper) and injection mixture (lower).

Compared to the water quality of the Kharita aquifer source, the produced water obtained from API separator is poor and shows high plugging tendency (Table:V). However, on filtering with 0.45 micron filter the quality of the produced water from API separator is dramatically improved showing acceptable injectivity due to the removal of entrained oil, indicating the drastic effect of oil removal on effluent water injectivity. In addition, particles  $\geq 2\mu$  reported a count up 50000 particles, corresponding to 35 mg/l of the suspended solids that should be removed by filtration to reduce the TSS to less than 1 mg/l to be suitable for injection (Table:V). In addition, the particle counts for two samples (Table:VI) showed enormous decrease from 50350 in API separator water to only 129 in the filtered sample, reflecting the successfully accomplished quality improvement by means of the 0.45 micron filter (Tables:V and VI). The membrane filtration test of the (Fig:IV) indicates that the quality of the filtered water in the water treatment plant is in agreement with particle count data (Table:V and VI) with acceptable ( $>275$  ml/sec0.5) water quality ratio (WQR) [(24), (27)]. These filtered water samples (Fig:IV) improved significantly in sample 1 with WQR of 271 ml/sec0.5 compared to sample 2 with WQR of 133 ml/sec0.5. This is typical for filtered water and in most cases attributed to the count of smaller particle size (Table:VI).

The bacterial study indicated the existence of the anaerobic sulphate reducing bacteria (SRB) in API separator water samples with average count of 100 cells/ml. Such values impose chemical treatment for bacterial control using hypochlorite and biocides. In addition, water samples produced from API separator showed CO<sub>2</sub> contents of approximately 140 ppm at about 40°C with a detectable amount of dissolved oxygen. This is usually expected due to the pressure drop and exposure to ambient atmosphere. However, these gases normally induce pH changes towards the acidic condition that associate corrosivity of this produced water. Such water is generally troublesome for injection programs, especially where iron is existed in significant amount in formation water while calcium carbonates deposition. If injection water tends to dissolve carbonate in the previously formed scale due to pH disequilibrium (28), the scale becomes porous and electrolytic corrosion takes place (29). To inhibit such corrosion Amine-type corrosion inhibitors chemical and oxygen scavengers are typically used.

Clay minerals are a common constituent in Bahariya sediments and are normally in equilibrium with interstitial formation water. However, when clay particles get in contact to different water during injection, the injection fluids could interact with clay constituents resulting in interruption to this equilibrium state. Such

interaction is a function of the type of clay minerals and the change in water chemistry/salinity. Two effects could occur due to such interaction; swelling and/or release of the clay particles. In all cases permeability reduction is always associating swollen clay due to blocking of pore-necks via swelling or trapping the loosen clay particles. Due to the high salinity of injection water of Meleiha fields, reduction in permeability induced by clay-injection water interaction is not expected.

Formation water in mixture (M49)	Type of scale				
	BaSO <sub>4</sub> (Barite)	CaCO <sub>3</sub> (Calcite)	CaSO <sub>4</sub> .2H <sub>2</sub> O (Gypsum)	SrSO <sub>4</sub> (Celestite)	SrCO <sub>3</sub>
100%	0.4172	0.0308	0.0470	0.0400	0.0015
80%	0.3306	0.0527	0.0504	0.0319	0.0011
60%	0.2531	0.0807	0.0514	0.0237	0.0052
40%	0.1834	0.1125	0.0548	0.0140	0.0079
20%	0.1167	0.1537	0.0582	0.0059	0.0028
0%	0.0593	0.1978	0.0593	0.0008	0.0008

Scale Type	Formation water in mixture (M49)					
	100%	80%	60%	40%	20%	0%
Barite	-0.38	-0.48	-0.60	-0.74	-0.93	-1.23
Calcite	-1.51	-1.28	-1.09	-0.95	-0.81	-0.70
Gypsum	-1.33	-1.30	-1.29	-1.26	-1.24	-1.23
Celestite	-1.40	-1.50	-1.63	-1.85	-2.23	-3.10
SrCO <sub>3</sub>	-2.82	-2.95	-2.28	-2.10	-2.55	-3.10

Table III: Scale tendency (upper) Saturation index (lower) for the feasible scales at ambient conditions; pressure 14.7 psi & temperature 77° F.

Formation water in mixture (M49)	Type of scale				
	Barite	Calcite	Gypsum	Celestite	SrCO <sub>3</sub>
100%	0.09091	0.01591	0.03863	0.06098	0.0004
80%	0.07227	0.02682	0.04121	0.04689	0.0007
60%	0.05553	0.04113	0.04227	0.03394	0.0010
40%	0.04068	0.05886	0.04485	0.02212	0.0009
20%	0.02621	0.07886	0.04667	0.01068	0.0005
0%	0.01288	0.01052	0.04773	0.00001	0.0001

Scale Type	Formation water in mixture (M49)					
	100%	80%	60%	40%	20%	0%
Barite	-1.04	-1.14	-1.26	-1.39	-1.58	-1.89
Calcite	-1.79	-1.57	-1.38	-1.23	-1.10	-1.98
Gypsum	-1.41	-1.39	-1.37	-1.35	-1.33	-1.32
Celestite	-1.20	-1.33	-1.46	-1.65	-1.96	-4.88
SrCO <sub>3</sub>	-3.40	-3.10	-3.09	-3.05	-3.40	-4.19

Table IV: Scale Tendency (upper) and saturation index (lower) for the expected scales at reservoir conditions (pressure: 650 psi & temperature: 195°F).

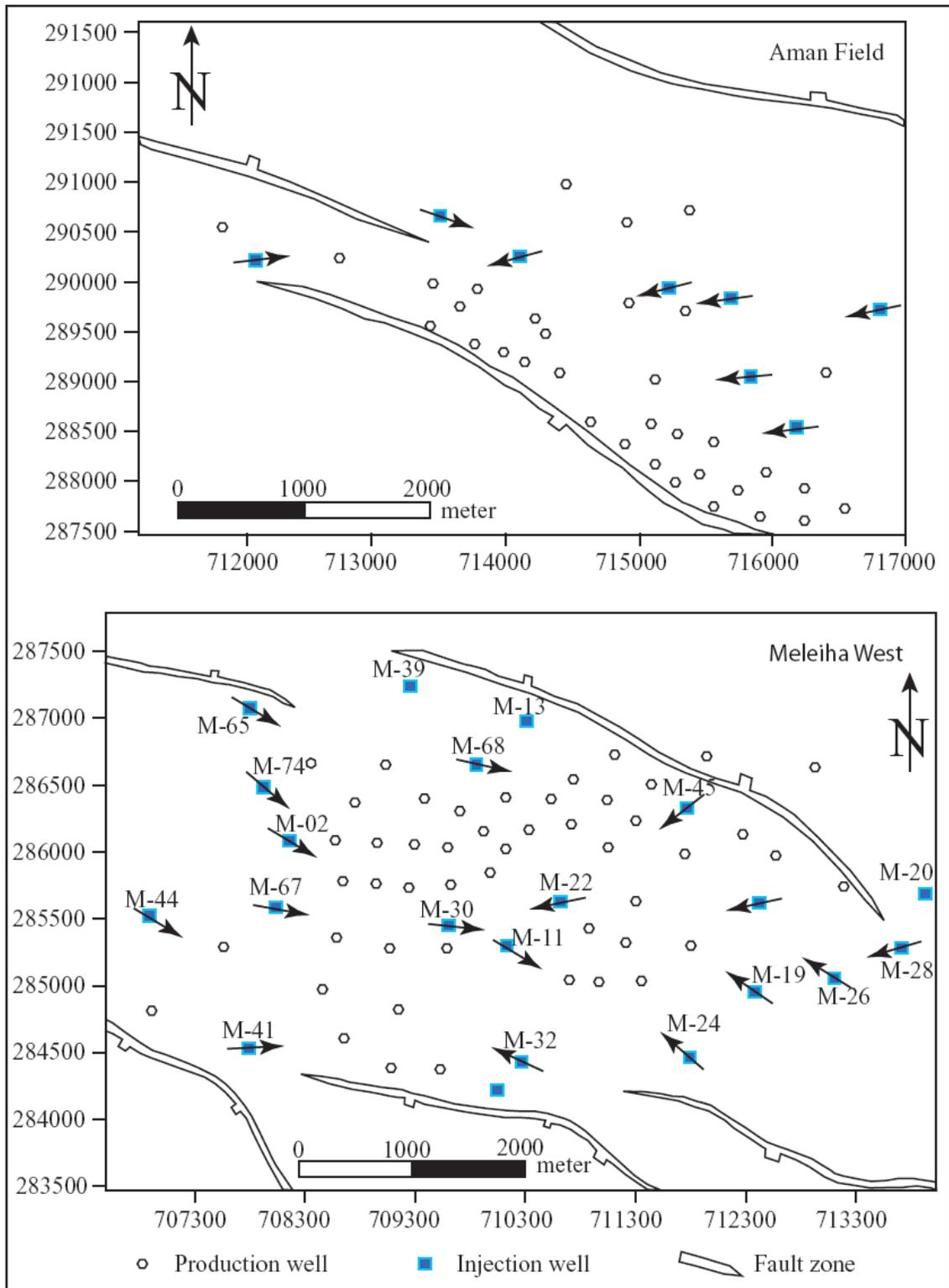


Fig III: Sketch map presenting the peripheral distribution of injection well at Aman field (Upper) and Meleiha West field (Lower). Arrows indicate the anticipated sweeping direction.

Water quality	Before filtration		After filtration
	Kharita water	API separator water	
Oil content (ppm)	nil	15-20	less than 2- nil
TSS (mg/l)	18	25-35	less than 1
$\geq 2\mu$ Particle count	10000	25000 to 50000	40-150

Table V: Water quality analysis for Kharita water and the produced water from API separator before and after treatment.

Particle diameter ( $\mu\text{m}$ )	API separator water	Filtered water
less than 2	32658	116
2	11293	3
3	3110	2
4	1728	1
5	706	1
6	447	2
7	217	1
8	81	1
9	62	0
10	25	1
11	17	1
12	6	0
15	5	0
<b>Total count</b>	<b>50355</b>	<b>129</b>

Table VI: Particle counts for two samples; one from API separator and the second for filtered water.

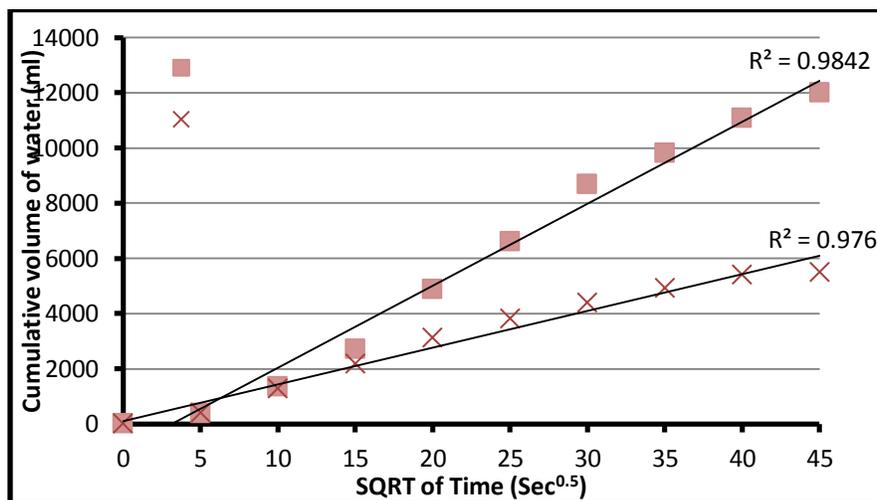


Fig IV: Membrane filter test data for treated water by the 0.45 filter.

**4.2. A CONCEPTUAL DESIGN FOR INJECTION WATER TREATMENT PLANT:** Normally, scale inhibitors should be injected into the system to control the calcite and the barite scale deposition to the skimmers, desalter, API separator and the proposed injection water Plant (Fig:V). To improve its injectivity, the produced water from the API separator should be treated through successive steps within a treatment plant (Fig:V). The treatment process typically starts with the removal of the dissolved CO<sub>2</sub> gas by liberation in a gas boot, to provide the sufficient retention time to liberate the entrained CO<sub>2</sub>. The water coming from the gas boot is mixed with a catalyzed ammonium sulphite oxygen scavenger to remove the dissolved oxygen and fed through distributors, slotted distribution pipe and spreader plates, at the bottom of a skim tank to allow uniform flow. If iron content increases or iron precipitation is detected iron sequester, chelant, is injected to keep dissolved iron in solution. After the necessary chlorination of the water upstream the skim tank biocide formulations are used for the batch wise shock treatments of the system to control the microbiological growth. To facilitate oil-water separation a reverse demulsifier is usually injected to influent water before entering the skim tank and at backwash stream clarifier as well. This allows separating the entrained oil by floatation in the skim tank that isolate the agglomerated oil to the waste oil tank by flow over a weir. The level of oil-water contact in the skim tank is controlled by an adjustable siphon leg that delivers the clean water to the surge tank. The level of oil-water contact in the skim tank is controlled by an adjustable siphon leg that delivers the clean water to the surge tank.

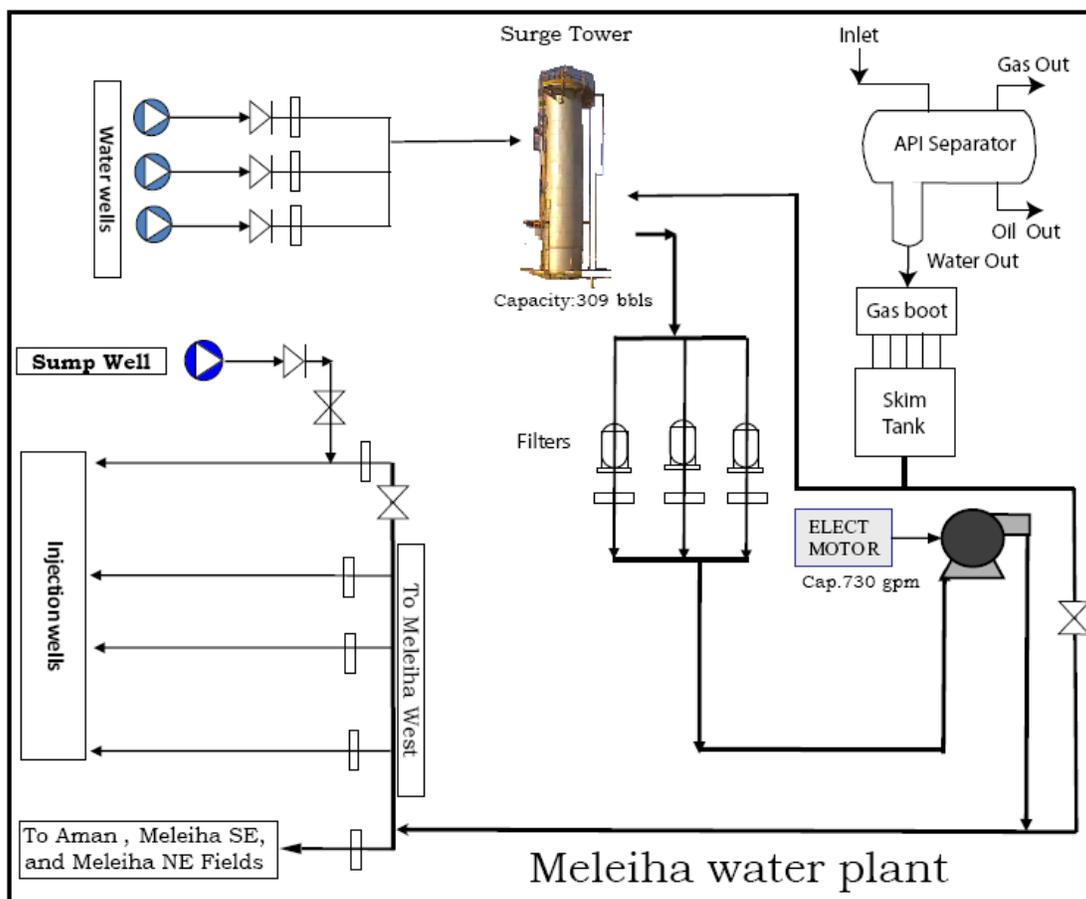


Fig V: Meleiha water injection plant.

Before delivering to surge tank the influent (Fig:V) feed water quality should be in average 20 ppm for TSS and 100 ppm oil content, while the effluent filter water should contain less than 97% of  $2\mu$  particle count and less than 2 ppm in TSS and oil content. Through a water surge tank, the separated water is pumped to multimedia filters to remove solids and the entrapped oil particulates and the filtered effluent is collected to the injection tank. Typically, 3 multi-media filters, two in-service and the third in standby or in backwash reactivation, are required for a plant of a total capacity of 20000 BWPD (Fig:V). To facilitate filtration process

and increase the filter life between backwashing, filter aids polyelectrolyte (media conditioner, flocculants and coagulants) can be applied while the efficiency of the backwashing operation can be enhanced using a surfactant (30). If required, the filtered water is pumped to a sulfate removing unit to eliminate sulfates from the effluent. Subsequently, the treated produced water is mixed with Kharita water in the source water manifold at the inlet of the existing water Injection plant or could be mixed at the surge tank (Fig:V). If produced water was to be solely injected, a corrosion inhibitor should be used to control corrosion in the injector's flow lines. For water mixture injection, corrosion inhibitor is not needed as Kharita water is treated chemically with one corrosion inhibitor. The resulting treated water is distributed for injection through a network of distribution pipes to the injection wells as shown in more details in Fig:VI.

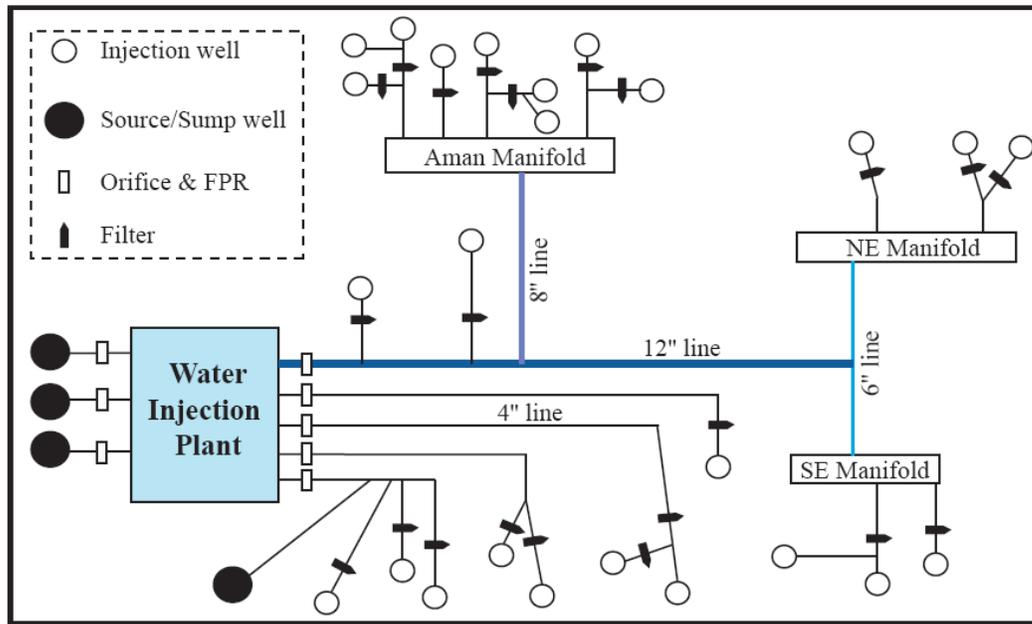


Fig VI: Simplified water distribution network proposed to handle the injection water of Meleiha treatment plant.

Naturally, the water cut increases with time and therefore the produced water is envisaged to gradually substitute the Kharita source water in the injection plant. To help providing steady state operating conditions, it is highly recommended to regularly clean multimedia filters through water backwashing. The dirty effluent containing the filter cake is ejected to a backwash clarifier, whereas the clean water is recycled through overflow to the skim tank. In the backwashing clarifier, oil is recycled to the waste oil tank and the solids at the bottom are disposed to the waste pond by a water jet.

**4.3. CONCLUSION:** Chemical analysis indicated that water mixture is generally corrosive and has low scale tendency. The water quality analysis in this study indicated that the produced water from API separator has a high plugging tendency due to presence of high levels of the suspended particulates and the entrained oil. This can be successfully treated by filtration and removal of the entrained oil in skim tank with the aid of reverse demulsifiers. The removal of the dissolved gases in a gas boot along, chemical treatment of the water with an oxygen scavenger and a corrosion inhibitor are essential treatments to inhibit water corrosion. In addition, the biocide treatment and chlorination are essential treatments to control the microbiology of the produced water. After the suitable treatment and conditioning, a mixture of the produced water and Kharita source water is prepared for injection in the currently existing water injection plant.

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