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Provide Suitable Water to Displacement Oil Ratio For Safsaf Oil Fields

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Abstract

During the production life of a reservoir, its natural energy may not be sufficient to meet the production targets. A significant number of these reservoirs experience considerable water cut from the production wells, leading to occasional inefficiencies and ultimately low recoveries. Two prevalent challenges faced by waterfloods are inadequate sweep efficiency and a low contact factor.

In this paper, inflow control valves will be used in order to minimize poor areal displacement. The contact factor is caused by abnormal displacement in a horizontal direction relative to the reservoir layer.

In a system with lateral diversity or when the bedding planes exhibit this phenomenon, a decrease in areal displacement efficiency is expected. This suggests that a significant portion of the reservoir retains a high oil saturation, even when the production wells maintain an economically acceptable water cut. The effectiveness of many approaches to solving this issue has been examined.

The primary scale precipitate observed through prediction models on Safsaf oil production wells, where inorganic scale precipitation has been detected, is calcium carbonate, followed by calcium sulphate, as indicated by the results obtained from mathematical models.

Keywords: Poor areal displacement, contact factor, water cut, scale precipitate, a high oil saturation, inorganic scale precipitation, mathematical model.

1. Introduction

The main purpose of water injection is to maintain the reservoir pressure above bubble point (pressure at which all gas presents are dissolved in oil), since the driving force of the oil flow from the reservoir to the surface is pressure drop (Muggeridge, 2013).

The injection is also aimed at sweeping the remaining oil toward the producers. The use and performance of waterflooding depends on several factors such as rock wettability, rock and fluid properties, formation heterogeneities, flood patterns, composition of injection water, water injection rate and fluids production rate. Rock wettability has to deal with how the surface of reservoir rock

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interacts with the fluids. The presence of connate water in the reservoir that is more wettable than the injected water can make this technique less efficient (Willhite, 1986).

Performing waterflooding efficiently requires an attentive design pattern. Waterflood patterns are based on the arrangement of injecting wells and producing wells. The arrangement is done to minimize the drilling of new wells but maximize water injection and improve oil recovery (Dake, 1978).

In designing waterflooding injection pattern, there are steps that must be followed. Those include constructing a geological model, analyze rock and fluid properties, and construct a reservoir flow model of the data gotten from those previous steps, run prediction cases, optimize waterflood design, perform sensitivity analyzes and finally start your project (Asadollahi, 2012).

While primary reservoir drive mechanisms can lead to a recovery between 30 to 35% of the oil in place, the use of water injection as one of secondary recovery methods can rise it from 5 to 50% (Shepherd, 2009). This makes it more advantageous; in addition to that, water is less expensive than other injection fluids and is available in a great amount. When the reservoir pressure falls below the bubble pressure, the gas that was dissolved in oil comes out of oil. Since the gas has much lower viscosity, the oil viscosity will increase, and the mobility of oil in the reservoir will decrease. As a result, oil production decreases due to the slow flow of oil in the reservoir.

So, the use of water injection helps to maintain the reservoir pressure higher than the bubble pressure in which the gas will still be dissolved in oil; therefore, reduces the oil viscosity and allows it flow easily (Dake, 1978).

commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits. Figure 1 illustrates the concept of the three oil recovery categories.

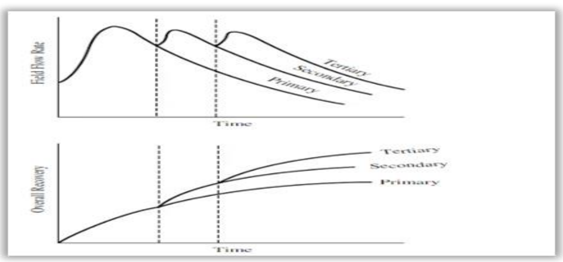

Figure 1. Oil recovery categories

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2. Factors to consider in water flooding.

Thomas, Mahoney, and Winter (1989) pointed out that in determining the suitability of a candidate reservoir for waterflooding, the following reservoir characteristics must be considered:

- Reservoir geometry
- Fluid properties
- Reservoir depth
- Lithology and rock properties
- Fluid saturations.

3. Objectives

Investigating the formation of mineral scales in oil field and looking for a suitable range of water to displace oil without making unlikely scale. To predict the potential of scale formation for separate producer wells and mixing between injection and formation waters.

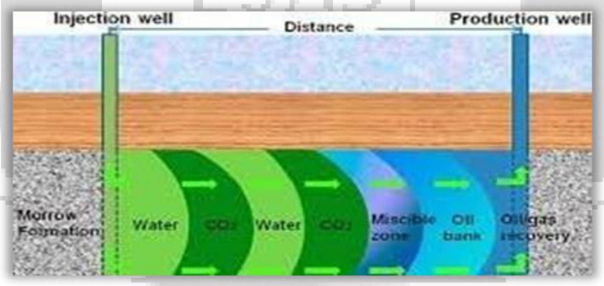

Figure 2. Water Injection (Oil production)

4. Water flooding process

Waterflooding is a process used to inject water into an oil-bearing reservoir for pressure maintenance as well as for displacing and producing incremental oil after (or sometimes before) the economic production limit has been reached figure 3. This is done through the displacement of oil and free gas by water.

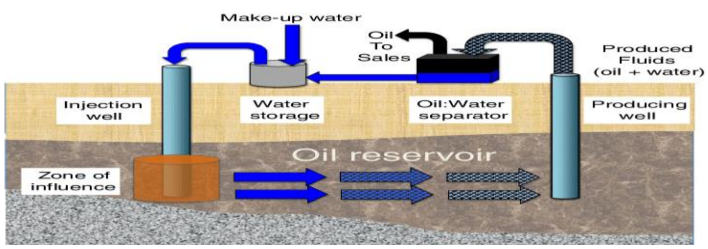

Figure 3. A water flooding system combines a process facility.

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In waterflooding, water is injected into one or more injection wells while the oil is produced from surrounding producing wells spaced according to the desired patterns.

There are many different waterflood patterns used in industry, the most common of which are illustrated in Figure 4.

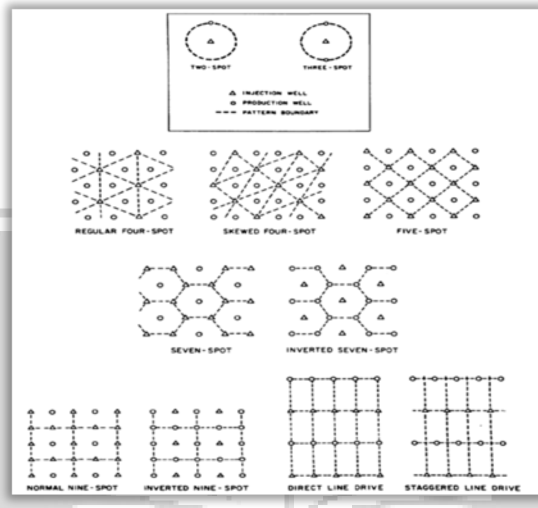

Figure 4 waterflood patterns

Measurement of the chemical and physical characteristics of injection water is the basis for both design and monitoring of any water injection system.

5. Case Study

The Safsaf field is located in the EPSA block NC74B and was discovered in 1985 through drilling wells C1 and D1. Oil was found in the Facha member of the Gir formation. Production from the Facha member commenced in 1990. To date, a total of twelve wells have been drilled into the two structures (C and D).

The C block is to the North of the D block and separated by a structural low or saddle. The saddle between C and D is believed to be a zone of low permeability.

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All wells are produced from the Carbonate Facha formation. The Safsaf field is bounded by several faults and they are assumed to have small throws so they may not be completely sealed.

The overlaying Hon evaporites provide a seal for the reservoir.

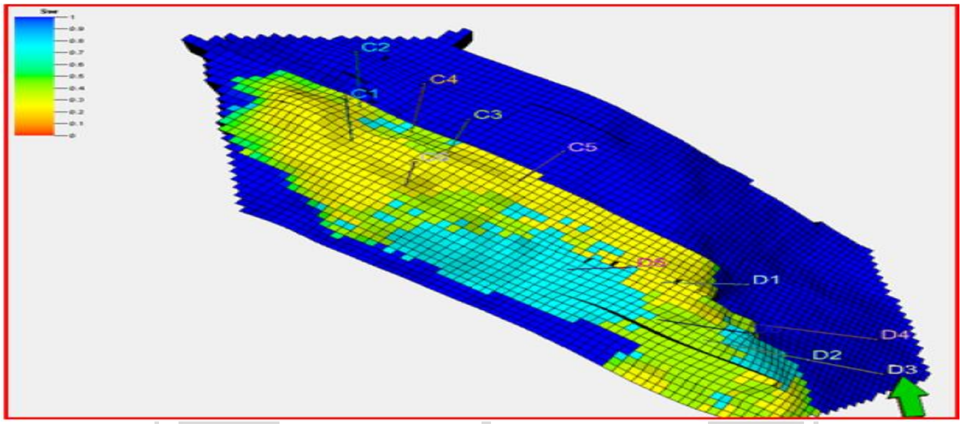

Figure 5. Safsaf field Wells Location

This section gives an overview of important production data for Safsaf field. To maintain the average reservoir pressure, a water injection project was initiated, and water was injected starting from Jan. 1991. Currently, there are 5 wells on injection with average injection water rate of 1,600 BWPD, while oil production rate is around 200 BOPD from 4 wells.

Table 1: Safsaf wells' status

Status	Wells	Sum
Production	C1, 3, 6, D2	4
Injection	C2, 4, 5, D1,4	5

Table 2: Cum. Production from Safsaf.

Start of production	May-90	
Start of Injection	Jan-91	
Cum Oil Production Till 9/2010	5.56	MMSTB
Cum Gas Production Till 9/2010	12.9	BCF
Cum Water Production Till 9/2010	6.32	MMSTB
Cum Water injection Till 9/2010	20.97	MMSTB
Intiail reservoir pressure Jul/87 D1	3,070	Psi

Production statistics were studied to summarize the available wells and their production and to provide an initial understanding of reservoir behavior.

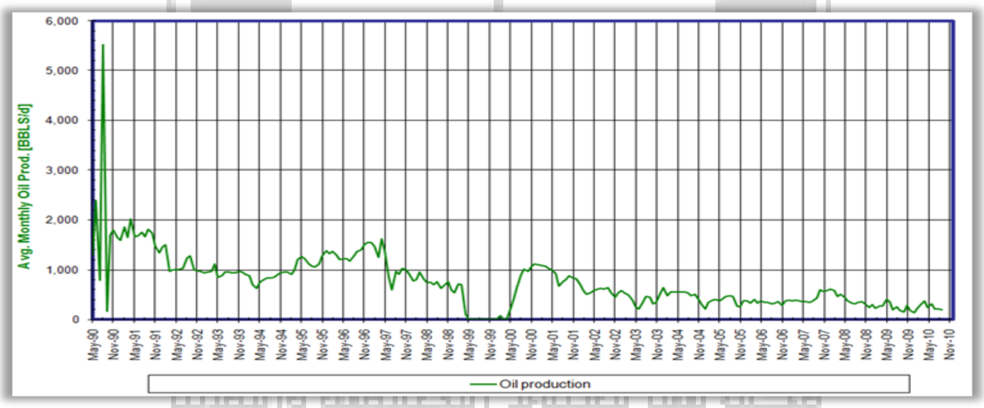

Figure 6. Production History

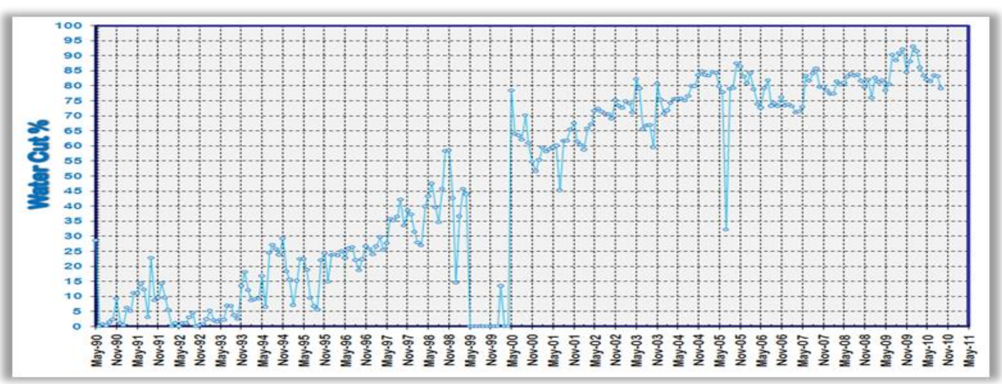

Figure 7: Safsaf Field Water Cut.

6. Measurement of the chemical and physical characteristics

Measurement of the chemical and physical characteristics of injection water is the basis for both design and monitoring of any water injection system.

The measurement and importance of many of these characteristics have been previously discussed. However, one topic remains to be addressed prior to an examination of system design and monitoring: water sensitive formations.

6.1 Water sensitive formations

Clays which exist in sandstone formation rocks are in equilibrium with the connate or natural formation water. When these clays encounter injection water or treating fluids, interaction may take place between the clays and the injected fluid which may result in decreased permeability. In water injection projects, this type of formation damage occurs most commonly when the salinity of the injection water is significantly lower than that of the connate water. Carbonate formations are seldom clay-bearing, and when clays are present, they are incorporated into the matrix.

Table 3. Minimum Salinities of Brines Required to Prevent Clay Blocking in Water-Sensitive Formation

Clay Species	Concentration (ppm)		
	NaCI	CaCl	KCI
Montmorillonite	30000	10000	10 000
Illite,Kaolinite,Chlorite	10000	1000	1000

6.2 Water Source Selection

The first step in selecting a water supply is to determine how much water will be needed. The source must be able to supply sufficient water to achieve the maximum desired injection rate for the project being considered.

A pilot flood is often instituted initially before expansion to a full-scale flood. If this is done, the water source used for the pilot should be the same as would be used for the full-scale flood.

This will give you a valid index of the behavior of the water and offer a chance to work out the major problems before expansion. Some of the common sources of water for a waterflood are:

1. Produced water.
2. Oxygen-free brine or fresh water from other subsurface zones (supply wells).
3. Surface water from oceans, lakes, ponds, streams, or rivers.
4. Water wells which draw water from shallow aquifers.

This type of water typically contains a few ppm of dissolved oxygen but is not saturated.

7. Calculation of scale indicators

7.1 Injection water

A. Calcium Carbonate

Table 4: Injection water analysis with calcium carbonate

ION	Concentration mg/L	Conversion Factor	Ioinc Sternght
Na^+	11543	2.20×10^{-5}	0.253946
K^+	50	1.28×10^{-5}	0.00064
Ca^{2+}	1623	5.00×10^{-5}	0.08115
Mg^{2+}	504	8.20×10^{-5}	0.041328
Cl^-	19464	1.40×10^{-5}	0.272496
SO_4^{2-}	3600	2.10×10^{-5}	0.0756
HCO_3^-	107	8.20×10^{-5}	0.0008774
			$\mu = 0.7260374$

B. Calcium Sulphate

Table 5: Injection water analysis with calcium sulphate

ION	Concentration Mg/l	Conversion Factor	Ionic Strength
Ca	1623	2.5×10^{-5}	0.08115
SO_4	3600	1.04×10^{-5}	0.0756

7.2 Formation water

A. Calcium Carbonate

Table 6 Formation water analysis with calcium carbonate

ION	Concentration	Conversion Factor	Ioinc Sternght
Na	56365	2.20×10^{-5}	1.24003
K	90	1.28×10^{-5}	0.001152
Ca	7014	5.00×10^{-5}	0.3507
Mg	1823	8.20×10^{-5}	0.149486
Cl	104232	1.40×10^{-5}	1.459248
SO_4	500	2.10×10^{-5}	0.0105
HCO_3	146	8.20×10^{-5}	0.0011972
			μ =3.2123132

B. Calcium Sulphate

Table 7 Formation water analysis with calcium sulphate

ION	Concentration mg/L	Conversion Factor	Ionic Strength
Ca	7014	2.5×10^{-5}	0.175
SO_4	500	1.04×10^{-5}	0.005

7.3 The mixing was between two wells from two fields.

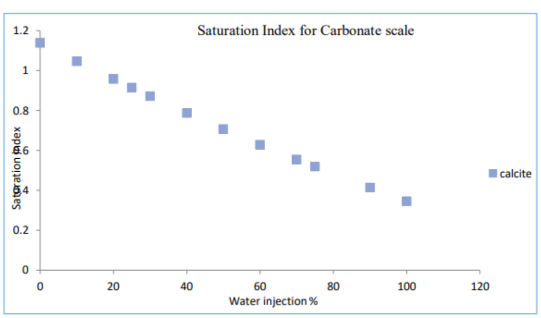

Figure 8. Carbonate scale prediction at different mixing ratios

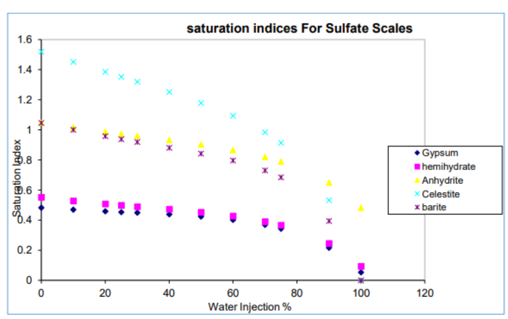

Figure 9. Sulphate scales prediction at different mixing ratios

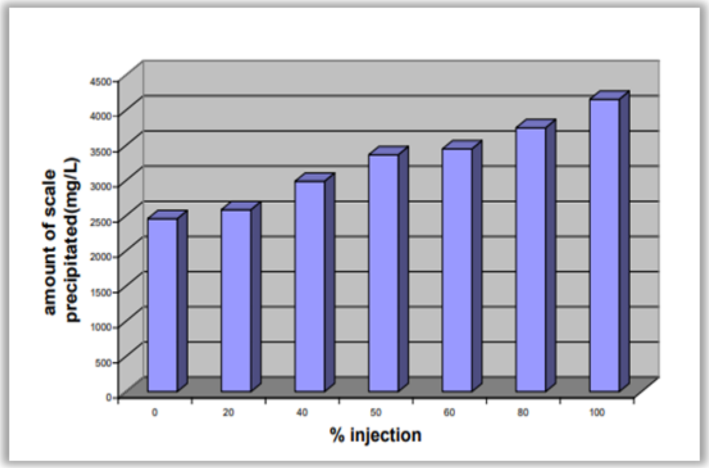

Figure 10. Amount of scale (Static test) between water injection and water A

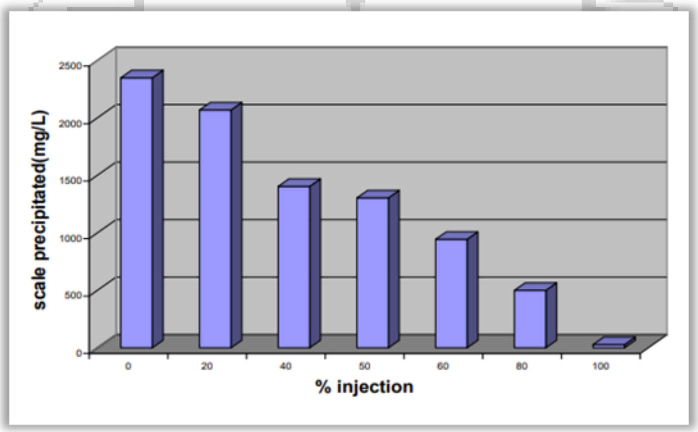

Figure 11. Amount of scale (Static test) between water injection and water

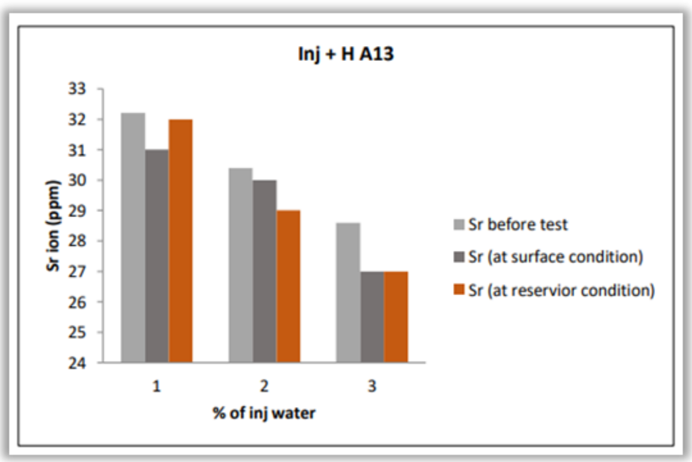

Figure 12. Reduction in strontium ion

7.4 Inhibitor performance

7.4.1 Principle of the experiment

The principle of these measurements is to inject cation-water and an anion water. The mixing of which is directly related to scale formation, into a steel capillary tube. The injections are made at a defined fixed flow rate, and the pressure drop across the capillary tube is monitored using pressure transducer and data recorded by OPA software.

Scale formation is detected by a rapid rise in the differential pressure. Inhibitor efficiency is determined by comparison of the blocking time measured on a blank with the blocking time measured with the inhibitor.

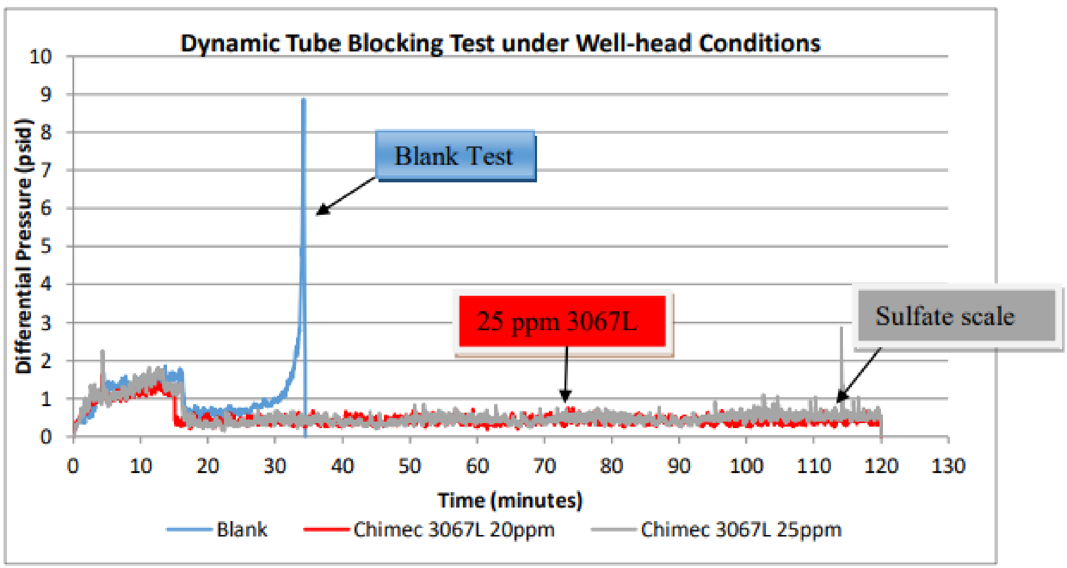

Figure 13. Inhibitor performance with and without sulphate scale

8. Results and Discussion

As injection water ratio increases (less salinity) the scale potential decreases.

Another simplified calculation method (solubility method) was compared with Oddo & Tomsom method for the major scales (i.e., calcium carbonate and calcium sulphate).

Oddo & Tomsom method is more reliable where operational parameters and dissolved gases are included in the calculations.

Figures show the amount of formed scale in a static test.

Figure 12. shows the reduction in strontium ion which is responsible for the coprecipitated scale.

The effect of the co-precipitated scale is clearly observed in Figure 13.

9. Conclusions and Recommendations

Prediction models have identified the occurrence of inorganic scale precipitation on the Safsaf field. The predominant scale precipitate is calcium carbonate, with calcium sulphate following closely behind, as indicated by the outcomes derived from mathematical models.

The performance of scale inhibitors is being impacted by the presence of co-precipitated scale, specifically Strontium sulphate.

The scale index, caused by calcium carbonate will rise with higher temperatures.

However, the potential for scale formation can be minimized by injecting low-salinity water.

This paper, highly recommends the utilization of a scale inhibitor squeeze treatment to effectively prevent the formation of intricate scale deposits ($CaCO_3$, $CaSO_4$, and $SrSO_4$), in case to ensure optimum protection.

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