Systematic and Facile Analysis of Deposits Composition: Implication on Effective Treatment of Oilfield Solid Deposits

Oilfield solid deposits present the major flow assurance problems in the oil and gas industry. In general, the deposits need to be accurately identified and quantified for appropriate design and successful implementation of any treatments. However, few works have been reported on the establishment of a systematic analytical procedure. This work, for the first time, presents a systematic approach that may be used to identify and quantify the composition of oilfield solid deposits, with different analytical methods being jointly used. The X-ray diffraction (XRD) and Fourier transform infrared (FT-IR) spectroscopy techniques were found very helpful in identifying the composition of the investigated oilfield solid deposit, whereas thermogravimetric analysis (TGA) and microwave induced plasma atomic emission spectroscopy (MIP-AES) were the most appropriate quantification techniques. The collected sample was found to contain mainly CaCO$_3$ and consequently, the acid treatment method that involves the use of hydrochloric acid (HCl) solution was proposed to be the most applicable and cost-effective treatment method for its remediation. The exact amount of CaCO$_3$ scale in the oilfield system, the concentration and volume of HCl solution required for the acid treatment method need to be precisely determined to ensure the effective treatment. We believe this well-established analytical procedure will be helpful and enlightening for identification and quantification of oilfield solid deposits and thus may facilitate the effective and efficient treatments on the undesirable deposits.

[DOI: 10.1115/1.4051897]

Keywords: oilfield solid deposit, qualitative analysis, quantitative analysis, flow assurance problem, treatment, petroleum engineering, petroleum transport/pipelines/multiphase flow, petroleum wells-drilling/production/construction

Introduction

Solid deposits in the oilfield systems may include wax, paraffin, gas hydrates, asphaltenes, naphthenates, and mineral scales [1–6]. Oilfield solid deposits in the oilfield systems usually occur in the reservoirs, wellbores, well casings, separators, pipelines, heat exchangers, and storage tanks [2,4,7–9]. The oilfield solid deposits are grouped mainly into organic and inorganic. Organic solid deposits are mainly due to the formation of wax, paraffin, asphaltenes, naphthenates, and gas hydrates [3,6,10]. Inorganic solid deposits are mainly due to the formation of mineral scales such as CaCO$_3$, CaSO$_4$, BaSO$_4$, SrSO$_4$, MgCO$_3$, and FeCO$_3$ [11,12].

The main driving forces for the formation of oilfield solid deposits in the oilfield systems include changes in temperature, pressure, pH, and mixing of two incompatible fluids [10,13,14]. Wax and paraffin deposition is influenced by the changes in temperature and/or pressure in the oilfield systems [15–17]. However, the formation of wax crystals is much in the downstream production systems due to changes in temperature and/or pressure [11,20]. Asphaltenene deposition usually occurs in the downstream production systems due to changes in temperature and/or pressure [21,22].

The precipitation of CaCO$_3$ is favored by a decrease in CO$_2$ partial pressure and an increase in temperature of the brine solution in the oil and gas production systems [7,25]. Apart from temperature and pressure, the formation of carbonate scales is also influenced by other factors such as carbonic acid concentration (Eq. (2)), pH (Eq. (3)), metal, and bicarbonate ions concentration (Eq. (4)) [2,4,12,14,25].

$$\text{Ca(HCO}_3\text{)(aq)} \underset{\Delta}{\overset{\text{CaCO}_3(s) + \text{H}_2\text{O(g) + CO}_2(g)}} \text{CO}_2(aq) + \text{H}_2\text{O(l)} \overset{\text{H}_2\text{CO}_3(aq)}} \overset{(\text{2})}{\text{CO}_2(aq) + \text{H}_2\text{O(l)} \overset{\text{H}_2\text{CO}_3(aq)}} \overset{(\text{3})}{\text{H}_2\text{CO}_3(aq) \overset{2\text{H}^+(aq) + \text{CO}_2^{-2}(aq)}} \overset{(\text{4})}{\text{Ca}^{2+}(aq) + \text{CO}_2^{-2}(aq) \overset{\text{CaCO}_3(s)}} $$
Sulfate scales mainly BaSO₄, SrSO₄, and CaSO₄ are formed in the oil and gas production systems due to the mixing of two incompatible brine solutions [24,26,27]. During secondary oil and gas recovery, seawater is injected into the reservoir to maintain the pressure of the reservoir, and to improve the oil and gas recovery efficiency. Seawater contains dissolved anions mainly SO₄²⁻, HCO₃⁻, and Cl⁻ while the reservoir formations are rich in cations such as Ca²⁺, Ba²⁺, Sr²⁺, Fe²⁺, Mg²⁺, and Na [7,26]. Thus, the injection of seawater with SO₄²⁻ into the reservoir formation rich in Ca²⁺, Ba²⁺, and Sr²⁺ results in precipitation of CaSO₄, BaSO₄, and SrSO₄ scales as shown in Eq. (5) [2,12,24].

\[
\text{Ba}^{2+} \text{ or } \text{Ca}^{2+} \text{ or } \text{Sr}^{2+} (aq) + \text{SO}_4^{2-} (aq) \rightarrow \text{BaSO}_4 \text{ or } \text{CaSO}_4 \text{ or } \text{SrSO}_4(s) \quad (5)
\]

Both organic and inorganic oilfield solid deposits cause flow assurance problems in the oil and gas production systems by interfering with the flow of hydrocarbon streams from the reservoir to the point of sale or processing unit [28]. Oilfield solid deposits can block the oil and gas pipelines, processing equipment, wellbore, and formation fractures in the reservoirs [7,13,21,26,29,30]. Several case studies have been reported based on the deposition of oilfield solid materials in the oil and gas production systems including the gas hydrate deposition plug in the subsea pipeline of Petrobras in Brazil [31]; wax deposition plug in the Kirkuk-Ceyhan crude oil pipeline between Iraq and Turkey, Power Play oil pipeline in the Gulf of Mexico and subsea oil pipeline of Gannet in Aberdeen (UK) [15], and CaCO₃ scale deposition in production and transportation equipment [32,33]. Figure 1 shows the flow assurance problems due to the deposition of oilfield solid materials such as wax, hydrates, and CaCO₃ scale in the oil and gas pipelines from different areas.

Generally, the deposition of oilfield solid materials in the oil and gas production systems can result in fluid flow restriction, failure of production equipment, decreased porosity and permeability of the reservoir formation, and increased maintenance and production cost [7,13,29]. Therefore, the flow assurance problems due to oilfield solid deposits need to be properly addressed to maintain a continuous flow of hydrocarbons at the required flowrates from the reservoir to the point of sale and to reduce the production and maintenance costs [23].

Various preventive methods have been used in the oil and gas industry to overcome the flow assurance problems due to oilfield solid deposits. These include thermal insulation of pipelines to control the temperature, injection of chemical inhibitors to inhibit the formation of oilfield solid deposits, and the use of reverse osmosis or adsorbent materials to remove dissolved mineral ions from seawater during water flooding in secondary oil and gas recovery [27,34]. Once the oilfield solid deposits are formed in the oil and gas production systems, some remediation methods, namely, mechanical and chemical treatment methods can be used to remove the deposits. Mechanical treatment methods include scraping, drilling, brushing, and milling while chemical treatment methods involve the use of hydrochloric acid (HCl), hydrofluoric acid (HF), acetic acid, citric acid, formic acid, and chelating agents such as ethylenediaminetetraacetic acid (EDTA) [2,13,29,34].

Chemical treatment methods are the most favorable techniques when dealing with oilfield solid deposits where other methods are infeasible [13,29]. The effectiveness of the chemical treatment method is reliant on the chemical composition and quantity of oilfield solid deposits. The chemistry and quantity of oilfield solid deposits are imperative factors in the selection of the most appropriate and cost-effective chemical treatment method. The oilfield solid deposits need to be identified and quantified first for better designing of the most appropriate and cost-effective treatment method. However, the biggest challenge when dealing with unknown oilfield solid deposits is how to go about; which analytical methods should be used to identify and quantify the unknown oilfield solid deposits. This challenge can only be handled through the application of analytical procedures that involve the use of qualitative and quantitative analysis. The qualitative analysis helps to identify what analytes are present in the given unknown oilfield samples whereas the quantitative analysis helps to determine how much analytes are present in the given unknown oilfield samples. The qualitative analysis provides an insight into the problem and helps to develop hypotheses for the quantitative analysis [35]. Quantitative analysis helps to quantify the analytes present in the given unknown oilfield samples by generating numerical data.

Since the oilfield solid deposits present the major flow assurance problems in the oil and gas industry. The results obtained from the qualitative analysis of oilfield solid deposits are very useful in designing the most appropriate and cost-effective treatment method. However, to the best of our knowledge, there are a few research works that have been done on oilfield samples and there is limited information regarding the analysis and treatment of unknown oilfield solid deposits. Therefore, there is a need for establishing analytical procedures for identifying and quantifying the unknown oilfield solid deposits, henceforth selecting the appropriate treatment method. Thus, this study briefly presents a systematic approach for the qualitative and quantitative analysis, and treatment of oilfield solid deposits using an unknown oilfield solid deposit collected from an oilfield. A well-established analytical procedure for the identification and quantification of unknown oilfield solid deposits can help to reduce the guesswork in the due course of analysis. The proper selection of the analytical methods and the most appropriate treatment method for the unknown oilfield solid deposits can save money and time for the analysis which is the ultimate goal of the oil and gas industry.

**Experimental Section**

**Materials.** An unknown oilfield solid deposit labelled sample “E” was collected from an oilfield. The chemicals used in this study include HCl (37%), nitric acid (HNO₃) (68%), calcium carbonate (CaCO₃) (99%), iron(III) nitrate nonahydrate (Fe(NO₃)₃·9H₂O) (98.8%), magnesium sulfate (MgSO₄) (98%), copper

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*Fig. 1 Solid deposits due to (a) wax plug [15], (b) hydrate plug [31], and (c) CaCO₃ scale [32]*

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*Transactions of the ASME*
sulfate pentahydrate (CuSO₄·5H₂O) (98%), barium carbonate (BaCO₃) (98%), sodium sulfate (Na₂SO₄) (99%), strontium nitrate (Sr(NO₃)₂) (99%), and double deionized water. All the chemicals used in this study were purchased from Sigma Aldrich and they were used as supplied.

Methodology. The choice of which analytical methods are suitable for the identification and quantification of an unknown oilfield solid deposit is one of the most difficult parts of the analysis. In the present study, some preliminary qualitative tests such as flame test and solubility (in water, mineral acids, and organic solvents) were carried out prior to analytical measurements to identify roughly whether the unknown oilfield solid deposit sample E is an organic or inorganic solid deposit. The selection of the appropriate analytical methods for the identification and quantification of unknown oilfield solid deposit sample E was accomplished following the approach shown in Fig. 2.

Preliminary Qualitative Test. The unknown oilfield solid deposit sample E was a hard-gray solid particle. A representative fraction of sample E was ground into fine powder by using mortar and pestle. Some preliminary qualitative tests such as flame test and solubility (in water, 15% HCl solution, toluene, and n-hexane) were conducted to identify roughly whether the unknown oilfield solid deposit sample E is an organic or inorganic solid deposit. A small amount of solid deposit sample E was ground into a sample holder and smeared uniformly with a glass slide to obtain a uniform upper surface. The sample holder was placed into a sample holder container and analyzed by X-ray Powder Diffractometer (Panalytical X-Pert) using Cu-Kr radiation in the range of 20 between 10 deg and 80 deg.

X-Ray Diffraction Analysis. This technique is commonly used in the oil and gas industry for the identification of mineral phases present in oilfield samples. In this study, a small amount of solid deposit sample E was ground into fine powder by using mortar and pestle. The finely powdered sample was then placed in a stainless-steel sample holder and smeared uniformly with a glass slide to obtain a uniform upper surface. The sample holder was placed into a sample holder container and analyzed by X-ray Powder Diffractometer (Panalytical X-Pert) using Cu-Kr radiation in the range of 20 between 10 deg and 80 deg.

Thermogravimetric Analysis. This method is commonly used for the quantitative analysis of oilfield samples, in the present study the analysis was carried out to determine the weight loss fraction of sample E as a function of temperature on heating. A small amount of solid deposit sample E was ground into fine powder by using mortar and pestle. Then, 42.230 mg of fine powdered sample E was placed in a sample holder and analyzed by Thermogravimetric Analyzer (Mettler Toledo/Balzers, TGA2/ThermoStar) at a heating rate of 10 °C/min over a range of 25–1000 °C.

Fourier Transform Infrared Analysis. This technique was used to identify whether the unknown oilfield solid deposit sample E was an organic or inorganic solid deposit. FT-IR analysis of sample E was conducted to obtain information about the functional groups of chemical constituents present in the unknown oilfield solid deposit sample E. A small amount of solid deposit sample E was ground into fine powder by using mortar and pestle. Then a small amount of finely powdered sample E was placed on the ATR diamond disc and scanned over a range of 4000–400 cm⁻¹ by FT-IR spectrometer (Perkin-Elmer, Spectrum Version10.4.00) to obtain the FT-IR spectrum.

Microwave Induced Plasma-Atomic Emission Spectrometry Analysis. This technique was used to determine the elemental composition of sample E. An aqua regia solution was prepared by mixing 75 mL and 25 mL of concentrated HCl and HNO₃, respectively, in a 250 mL beaker. The acid digestion of sample E was carried out as reported elsewhere [36]. The filtrate solution obtained from the acid digestion was analyzed by MIP-AES (MP4200 Agilent) for the general elemental scan to identify all the elements present in oilfield solid deposit sample E. From the general elemental scan by MIP-AES, the emission intensity of Ca in the filtrate solution was found to be very high as compared with other elements, this implies that its concentration in sample E is also very high as compared with other elements. Thus, its quantification was done separately by using 0.0151 g of sample E with some dilution whereas for other elements 0.2 g of sample E was used. After the general elemental scan by MIP-AES, different standard solutions were prepared to make a stock solution of multi-element from which the working solutions were prepared as reported in the “Preparation of Working Solutions” section.

Preparation of 1000 ppm Standard Solutions. Standard (Std) solutions were prepared for the quantification of each element (Ca, Na, Mg, Fe, Ba, Sr, and Cu) found in unknown solid deposit sample E based on the general elemental scan results by MIP-AES.
Fig. 3 XRD diffractogram pattern of unknown solid deposit sample E

was gray, insoluble (in water, toluene, and n-hexane) and did not burn on flame; but it was soluble in 15% HCl giving out an effervescence probably due to the evolution of CO₂ gas. This indicated that the unknown oilfield solid deposit sample E was likely to be inorganic carbonate scale deposits. Thus, based on the available instruments; XRD, TGA, FT-IR, and MIP-AES were chosen for its identification and quantification.

The following are the general observations on a preliminary qualitative test of oilfield solid deposits; color: most organic solid deposits are usually black due to the presence of carbon residues while inorganic solid deposits are either gray, off-white, brown, or greenish. Flame test: organic solid deposits burns when subjected to a flame source producing soot and leaving behind black carbon residues, while the inorganic scale deposits do not burn on flame but can only form ash when subjected to a very high temperature. Solubility test: inorganic mineral scales are insoluble in water except for NaCl; likewise, organic solid deposits are insoluble in water except those with many oxygen atoms or OH functional groups in their structures. Most of the inorganic mineral scales except BaSO₄ and SrSO₄ are soluble or slightly soluble in mineral acids such as HCl and HNO₃ whereas organic solid deposits are insoluble. On the other hand, organic solid deposits are soluble in some organic solvents; for example, asphaltenes are soluble in toluene but insoluble in n-hexane while wax and gas hydrates are soluble in n-hexane. Inorganic mineral scales are insoluble in organic solvents. These general observations are made from our research experiences in dealing with the oilfield samples and basic understanding of qualitative analysis.

X-Ray Diffraction Analysis. The XRD analysis was carried out to identify the mineral phases present in unknown oilfield solid deposit sample E. Figure 3 shows the diffractogram of unknown solid deposit sample E, the results revealed that the unknown solid deposit sample E was aragonite (CaCO₃). The diffractogram showed the presence of characteristic peaks of aragonite with a distinctive prominent inter-atomic d-spacing of 3.396 Å, 3.273 Å, 2.700 Å, and 1.977 Å at 20 value of 26 deg, 27 deg, 33 deg, and 46 deg, respectively. The obtained diffractogram of aragonite was overlaid with the diffractogram of aragonite standard reference material (International Center for Diffraction Data (ICDD) 00-024-0025) from the computer database. The two diffractograms have shown a perfect match indicating that the unknown solid deposit sample E was aragonite (CaCO₃). Similar observations were also reported by Xu and Poduska [37] on the study of crystallinity differences and temperature dependency of carbonate minerals by XRD. Sarkar and Mahapatra [38] have also reported a similar XRD diffractogram.
of aragonite from unusual polymorph transformations of calcium carbonate. Thus, based on these findings, XRD is recommended as a powerful technique for the identification of unknown oilfield solid deposits especially inorganic mineral scale deposits.

Thermogravimetric Analysis. The weight loss of unknown oilfield solid deposit sample E was recorded as a function of temperature change. From the results obtained, three weight loss fractions were observed at different temperature ranges as shown in the TGA profile of the solid deposit sample E (Fig. 4); these ranges are defined as steps I, II, and III. The weight loss fraction at each temperature range and the associated process are summarized in Table 3.

The total weight loss observed in all three steps is 42.496%; this meant that 57.504% of the solid deposit sample E was undecomposable and was presumed to be calcium oxide (CaO). The decomposition reaction of CaCO₃ produces calcium oxide (CaO) and carbon dioxide CO₂ as shown in Eq. (6). The percentage weight loss of 39.284% (presumably CO₂) obtained from the TGA curve was used to calculate the percentage composition of CaCO₃ in the unknown oilfield solid deposit sample E with the aid of Eq. (6):

\[
\text{CaCO}_3(s) \rightarrow \text{CaO}(s) + \text{CO}_2(g)
\]

The calculated percentage composition of the CaCO₃ scale in the unknown oilfield solid deposit sample E was found to be 89%. This implies that the unknown oilfield solid deposit sample E mainly composed of the CaCO₃ scale and these findings are in good agreement with the results obtained from XRD analysis. Similar results were also reported by Kodel et al. on the composition of mineral scales in oil wells by TGA [39]. Thus, this implies that TGA is a suitable method to quantify mineral scale deposits which exhibit distinctive decomposition characteristics.

Microwave Induced Plasma Atomic Emission Spectroscopy Analysis. This technique is not very famous in the oil and gas industry, it serves as an alternative technique to atomic absorption spectrometry (AAS), inductively coupled plasma optical emission spectrometry (ICP-OES), inductively coupled plasma atomic emission spectrometry (ICP-AES), and inductively coupled plasma mass spectrometry (ICP-MS) for trace elemental analysis in oilfield samples [41–43]. It offers a fast and simultaneous multi-element analysis of oilfield samples as compared with AAS which can only analyze one element at a time per sample. However, ICP-OES, ICP-AES, and ICP-MS are the best techniques for the elemental analysis in oilfield samples than MIP-AES in terms of sensitivity, accuracy and detection limit, but they are not commonly used for the routine analysis in the oil and gas industry because of their high running costs as compared with MIP-AES [41]. The experimental results for the elemental analysis of unknown oilfield solid deposit sample E by MIP-AES for the detected elements (Ca, Ba, Sr, Na, Fe, Mg, and Cu) are shown in Table 4. The concentration in weight per cent (wt%) of each element in

The results presented in Table 4 are in the mean of triplicate measurements with RSD less than 10% which is acceptable as an experimental error for the concentration reported in ppm [41]. The actual concentration in weight per cent (wt%) of each element in

**Table 3** TGA results of oilfield solid deposit sample E

<table>
<thead>
<tr>
<th>Step</th>
<th>Temperature interval (°C)</th>
<th>Weight loss fraction (%)</th>
<th>Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>100–200</td>
<td>0.506</td>
<td>Release of free or physically adsorbed water</td>
</tr>
<tr>
<td>II</td>
<td>300–600</td>
<td>2.706</td>
<td>Dehydration of hydrated crystal phases of sample E</td>
</tr>
<tr>
<td>III</td>
<td>700–900</td>
<td>39.284</td>
<td>Release of CO₂ through decomposition of sample E</td>
</tr>
</tbody>
</table>

**Fig. 4** TGA curve for the decomposition of unknown solid deposit sample E

**Fig. 5** FT-IR spectrum of unknown solid deposit sample E

Fourier Transform Infrared Analysis. Fourier transform infrared is very useful in the oil and gas industry in identifying organic and inorganic oilfield solid deposits. It gives information about the functional groups present in the oilfield solid deposits and can differentiate organic oilfield solid deposits from inorganic oilfield solid deposits. In most cases, inorganic oilfield solid deposits show their absorption bands in the fingerprint region (1500–400 cm⁻¹) while organic oilfield solid deposits are mainly characterized by the presence of a C–H bond with absorption bands at around 2800–3100 cm⁻¹. Figure 5 shows the FT-IR spectrum of unknown oilfield solid deposit sample E. The spectrum shows the absorption bands at 1455, 1082, 854, and 713 cm⁻¹ as the characteristic absorption peaks of the carbonates functional group. Since each compound produces unique absorption peaks in the fingerprint region of the FT-IR spectrum. The absorption peaks at 1082, 854, and 713 cm⁻¹ are unique to aragonite (CaCO₃), hence this indicated that aragonite was the major form of CaCO₃ in the unknown oilfield solid deposit sample E; thus, these results support the results obtained from XRD and TGA. Similar observations have also been reported by Xyla and Koutsoukos [40] on the quantitative analysis of calcium carbonate polymorphs by FT-IR.
the unknown oilfield solid deposit sample E was calculated and the results obtained are tabulated in Table 5.

The results in Table 5 show that the concentration of Ca in unknown oilfield solid deposit sample E is much higher as compared with other elements. Therefore, this implies that the unknown oilfield solid deposit sample E was likely to be CaCO3 scale as supported by the results obtained for XRD, TGA, and FT-IR. The percentage weight of the CaCO3 scale in sample E from MIP-AES results was calculated based on the average percentage weight of Ca (33.6 wt%) with the aid of Eq. (7)

\[
\text{Ca}^{2+}(aq) + 2\text{Cl}^-(aq) \rightleftharpoons \text{CaCO}_3(s) + \text{CO}_2(g) + \text{H}_2\text{O}(l) \tag{8}
\]

The calculated percentage weight of the CaCO3 scale in the unknown oilfield solid deposit sample E was found to be 83.9 wt %, this result is in good agreement with the results obtained from TGA analysis. A similar study was also done by Nelson et al. [43] on the trace elemental analysis of crude oils by using MIP-AES and reported that MIP-AES is the best technique for the trace elemental analysis in crude oil samples.

### Calcium Carbonate Scale Removal

The unknown oilfield solid deposit sample E was identified as CaCO3 scale; thus, the acid treatment method that involves the use of HCl solution is the most appropriate and cost-effective [44]. CaCO3 scale easily dissolves in hydrochloric acid solution producing water-soluble products which can be easily washed out by water (Eq. (8)) [2,45]

\[
\text{CaCO}_3(s) + 2\text{HCl}(aq) \rightarrow \text{CaCl}_2(aq) + \text{CO}_2(g) + \text{H}_2\text{O}(l) \tag{8}
\]

The removal of the CaCO3 scale by using HCl is the cheapest and easiest method to use especially when mechanical treatment methods are not applicable [13]. The disadvantage of this method is that HCl is highly corrosive, thus its application requires the addition of anti-corrosive agents to the acid solution to reduce the corrosion effects [23]. The most recommended concentration of HCl solution for the removal of the CaCO3 scale is 15% (by weight solution) [45]. The most important parameters to consider in acid treatments design include the amount of scale deposits in the oilfield system, concentration and volume of acid required, injection rate, and injection pressure [45]. The volume of HCl required to dissolve a given amount of CaCO3 scale can be determined stoichiometrically with the aid of chemical reaction (Eq. (8)) by using Eq. (9) [45]

\[
\alpha = \frac{n_c \cdot \text{MW}_c}{n_a \cdot \text{MW}_a} \tag{9}
\]

whereby \( \alpha \) = gravimetric dissolving power of HCl solution, \( n_c \) = concentration of HCl solution (15%), \( n_a \) = number of mole of CaCO3 scale (1 mol), \( n_c \) = number of mole of HCl (2 mol), \( \text{MW}_c \) = molecular weight of CaCO3 scale (100.1 g/mol), and \( \text{MW}_a \) = molecular weight of HCl (36.5 g/mol).

Since the unknown oilfield solid deposit sample E was quantified by TGA and found to contain 89% of the CaCO3 scale, the volume of 15% HCl solution required for its removal was calculated with the aid of Eq. (9). However, different volumes of 15% HCl solution were experimentally tested using a known amount of solid deposit sample E to determine the efficiency of 15% HCl solution in removing the solid deposit sample E as presented in Table 6.

The results shown in Table 6 were graphically presented as shown in Fig. 6 and it can be noted that 11 mL of 15% HCl solution was the maximum volume required to remove 3.001 g of solid deposit sample E. For the volumes of acid exceeding 11 mL, the efficiency does not change since the unknown solid deposit sample E contains only 89% as pure CaCO3 plus other impurities which do not dissolve.

### Table 5 Results for the elemental analysis of unknown solid deposit sample E by MIP-AES

<table>
<thead>
<tr>
<th>Element</th>
<th>TVOS (mL)</th>
<th>ESE</th>
<th>MCE (ppm)</th>
<th>DF</th>
<th>CESE (ppm)</th>
<th>MESE (mg)</th>
<th>wt% of ESE</th>
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<tbody>
<tr>
<td>Ca</td>
<td>12.7 ± 0.24</td>
<td>4</td>
<td>50.8 ± 1.92</td>
<td>200</td>
<td>3.2 ± 0.01</td>
<td>1.8 ± 0.05</td>
<td>33.6 ± 1.27</td>
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<tr>
<td>Ba</td>
<td>6.5 ± 0.05</td>
<td>1</td>
<td>3.2 ± 0.01</td>
<td>1</td>
<td>15.9 ± 0.05</td>
<td>1.89 ± 0.01</td>
<td>0.95 ± 0.005</td>
</tr>
<tr>
<td>Sr</td>
<td>9.5 ± 0.27</td>
<td>1</td>
<td>9.5 ± 0.27</td>
<td>1</td>
<td>15.9 ± 0.05</td>
<td>1.89 ± 0.01</td>
<td>0.95 ± 0.005</td>
</tr>
<tr>
<td>Na</td>
<td>2.6 ± 0.02</td>
<td>1</td>
<td>2.6 ± 0.02</td>
<td>1</td>
<td>15.9 ± 0.05</td>
<td>1.89 ± 0.01</td>
<td>0.95 ± 0.005</td>
</tr>
<tr>
<td>Mg</td>
<td>3.0 ± 0.01</td>
<td>1</td>
<td>3.0 ± 0.01</td>
<td>1</td>
<td>15.9 ± 0.05</td>
<td>1.89 ± 0.01</td>
<td>0.95 ± 0.005</td>
</tr>
<tr>
<td>Cu</td>
<td>11.8 ± 0.05</td>
<td>1</td>
<td>11.8 ± 0.05</td>
<td>1</td>
<td>15.9 ± 0.05</td>
<td>1.89 ± 0.01</td>
<td>0.95 ± 0.005</td>
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Table 4 Experimental results for the elemental analysis of solid deposit sample E by MIP-AES

<table>
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<tr>
<th>Solution</th>
<th>Ca643.907 nm</th>
<th>Ba614.171 nm</th>
<th>Sr650.399 nm</th>
<th>Na568.263 nm</th>
<th>Fe371.993 nm</th>
<th>Mg518.360 nm</th>
<th>Cu324.754 nm</th>
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<tr>
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<tr>
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<tr>
<td>Standard 6</td>
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</tbody>
</table>

Note: Conc: concentration (ppm), Int: intensity (unitless), SD: standard deviation, RSD: relative standard deviation, ACESE: actual concentration of element in sample E (ppm), R²: correlation coefficient, and nm: nanometer (SI unit of wavelength).
of the CaCO₃ scale. The solid deposits due to the CaCO₃ scale in the oilfield systems can be effectively removed by using acid treatment methods such as HCl. The exact amount of CaCO₃ scale in the oilfield system, the concentration and volume of HCl solution required for the acid treatment method need to be accurately determined to ensure the effective removal of the CaCO₃ scale deposit in the oilfield system.

Acknowledgment
The authors would like to thank Dr. Andrew Kindness for the technical support during the laboratory experiments and Dr. Musa Mpelwa for proofreading this research paper.

Conflict of Interest
There are no conflicts of interest.

Data Availability Statement
The datasets generated and supporting the findings of this article are obtainable from the corresponding author upon reasonable request. The authors attest that all data for this study are included in the paper. No data, models, or code were generated or used for this paper.

Nomenclature

\[ \text{Å} = \text{Angstrom} \]
\[ \text{Ba} = \text{barium} \]
\[ \text{BaSO₄} = \text{barium sulfate} \]
\[ ^{°} \text{C} = \text{degree celsius} \]
\[ \text{Ca} = \text{calcium} \]
\[ \text{CaCO₃} = \text{calcium carbonate} \]
\[ \text{cm} = \text{centimeter} \]
\[ \text{CO₂} = \text{carbon dioxide} \]
\[ \text{Cu} = \text{copper} \]
\[ \text{CuSO₄} = \text{copper(II) sulfate} \]
\[ \text{Fe} = \text{iron} \]
\[ \text{Fe(NO₃)₃} = \text{iron(III) nitrate} \]
\[ \text{FeCO₃} = \text{iron(II) carbonate} \]
\[ \text{FeS} = \text{iron(II) sulfide} \]
\[ \text{g} = \text{gram} \]
\[ \text{g/mol} = \text{gram per mole} \]
\[ \text{H₂CO₃} = \text{carbonic acid} \]
\[ \text{H₂O} = \text{water} \]
\[ \text{HCl} = \text{hydrochloric acid} \]
\[ \text{HF} = \text{hydrofluoric acid} \]
\[ \text{HNO₃} = \text{nitratic acid} \]
\[ \text{mg} = \text{milligram} \]
\[ \text{Mg} = \text{magnesium} \]
\[ \text{MgCO₃} = \text{magnesium carbonate} \]


