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Selection of Candidates and Formation Damage Advisor with an Expert System

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ABSTRACT

In the lifecycle of an oil well, numerous factors such as pressure drop, partial perforation, turbulent flow, and formation damage can adversely affect its productivity. Identifying and addressing these issues, especially formation damage, is crucial. Acid treatment is commonly used to mitigate such formation damage, thereby enhancing well productivity. Traditionally, the selection of wells for acid treatment and the identification of formation damages have relied on extensive geological and engineering analyses. These conventional methods, while thorough, are time-consuming and involve the examination of complex geochemical, geophysical, and geological data. Accordingly, the current study introduces an expert system designed to streamline these processes. Expert systems, capable of automated and rapid data analysis, offer significant advantages by accelerating decision-making and improving efficiency. The expert system developed in this research demonstrates notable proficiency in processing intricate datasets, thus enhancing productivity and reducing the probability of errors. Its predictive capabilities also enable proactive management of wells. This research employs an expert system to analyze ten wells, identifying six as suitable candidates for acidizing. The system effectively detects potential formation damages in these wells, demonstrating its accuracy in diagnosis and decision-making. The adoption of expert systems in high-uncertainty scenarios requiring precise analysis is promising. Utilizing more routine or standard algorithms and mathematical models, these systems can significantly improve decision-making processes, predictive accuracy, and operational efficiency in oil and gas reservoirs. Improved decision-making is a key benefit as these systems, with comprehensive and analyzed data, enable more informed and effective decisions. In this study, an expert system is developed for selecting wells suitable for acid treatment and diagnosing formation damage types. Of the ten wells analyzed, six were deemed suitable for acid treatment. The system's ability to detect potential formation damages in each well highlights its effectiveness. These systems, employing algorithms and mathematical models for event modeling and prediction, aid in enhanced, faster decision-making processes. The use of expert systems in areas with high uncertainty and the need for precise modeling is valuable, contributing to improved operational efficiency and productivity in the oil and gas sector.

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1. Introduction

Improved Oil Recovery (IOR) operations are a fundamental aspect of the oil and gas industry, aimed at increasing the recovery of oil from petroleum reservoirs. Typically, only about 30-40% of the oil in a reservoir is extracted using conventional methods, either naturally or through primary recovery techniques. Consequently, IOR operations, which use methods like acidizing, water flooding, gas injection, and the application of polymers, surfactants, and nanotechnology, are crucial for increasing oil recovery rates. Acidizing, a primary and effective IOR method, is divided into matrix acidizing and acid fracturing. Matrix acidizing, common in Iran and low-permeability formations, is favored for its simplicity and cost-effectiveness. Intelligent acidizing uses reservoir modeling software, acidizing operation simulations, and production data analysis. This approach significantly enhances the efficiency and optimization of acidizing methods and additives. In the oil and gas industry, Artificial Intelligence (AI) techniques like neural networks, fuzzy logic, and evolutionary algorithms are revolutionizing key practices, especially in reservoir simulation and drilling optimization (Braswell 2013). Expert systems are increasingly used in decision-making for balanced or overbalanced drilling (Garrouch and Labbaidi 2003). Three-dimensional convolutional neural networks have demonstrated superiority over human descriptor-based models in accurately predicting catalyzed acid reaction rates (Chew, Jiang et al. 2020). Similarly, AI methods such as fuzzy logic have advanced the prediction of pore pressure during drilling and are more time-efficient in geological and engineering evaluations compared to traditional methods (Abdulmalek, Elkatatny et al. 2018). AI methods require less geological and engineering evaluation time compared to traditional methods. (Zoveidavianpoor, Samsuri and Shadizadeh 2012). Furthermore, AI's role in optimizing reservoir simulation and improving well selection for workover operations has been

notably demonstrated (Umoh 2019). This study aims to create an expert advisory system that can identify suitable wells for acidizing operations more accurately and quickly and determine the formation damage more precisely. The main goal of this study is to create and execute an expert system that uses key parameters to identify damaged wells. This study aims to develop an expert advisory system for more accurate and rapid identification of suitable wells for acidizing operations and precise determination of formation damage. The primary goal is to create and implement an expert system that uses key parameters to identify damaged wells and assess damage types. By identifying essential attributes and correlating them with observed outcomes in previous instances, this system is applied to acidizing operations, bridging the gap between manual systems and acidizing operations through sophisticated AI integration.

2. Methodology

Prior to initiating the acidizing operation, identifying wells suitable for acid treatment is crucial. A comprehensive understanding of potential formation damages is also essential before embarking on the acidizing process (Xiong, Robinson and Foh 2001). Accordingly, this research has been divided into two primary sections: 1) Selection of candidate wells for acidizing, and 2) Diagnosis of formation damage.

2.1. Selection of Candidate Wells

In the evaluation of well performance, the initial step involves assessing the skin factor, a critical parameter determined through pressure transient analysis. In scenarios lacking pressure data, the skin factor can be estimated by considering various factors such as well characteristics, flow conditions, reservoir properties, and the ratio of actual to ideal flow rate. These elements collectively contribute to the total skin factor. For potential acidizing operations, a general guideline is used: if the sandstone skin factor is greater than or equal to 0, and the carbonate skin factor is greater than or equal to -2, the well qualifies as a candidate for acidizing. It's vital to recognize

that the skin factor derived from pressure data represents the total skin factor, which is calculated as follows (Abobaker, Elsanoose et al. 2022):

$$S = S_M + D \times Q \tag{1}$$

The total skin factor is the aggregate of the mechanical skin factor and the dynamic skin factor. The latter arises from turbulent flow, a common occurrence in gas wells. To calculate the mechanical skin factor, one follows a specific formula (Furui, Zhu and Hill 2005):

$$S_M = S_{pp} + S_{\theta} + S_d + S_g + S_p + S_f \tag{2}$$

In the above equation, S_M represents the mechanical skin factor, S_{pp} represents the partial perforation skin factor, S_{θ} represents the skin factor resulting from the azimuth, S_d represents the skin factor from the damaged zone, S_g represents the gravel pack skin factor, S_p represents the skin factor from perforations, and S_f represents the frac pack (frac pack is a combination of hydraulic fracturing and sand control techniques used in oil and gas wells, especially in formations with sand issues.) skin factor. Furthermore, the dynamic skin factor is calculated as follows (Yildiz 2006):

$$D = D_d + D_r + D_g + D_c + D_f \tag{3}$$

In the above equation, D represents the total dynamic skin factor, D_d represents the dynamic skin factor from the damaged zone, D_r represents the dynamic reservoir skin factor, D_g represents the dynamic skin factor from the gravel pack, D_c represents the crushed zone, and D_f represents the frac pack. The total skin factor is the sum of the mechanical and dynamic skin factors. The dynamic skin factor, pertinent to turbulent flow conditions, is disregarded if the wellbore fluid flow is laminar. Therefore, before selecting a well for acidizing, addressing any mechanical impediments that might cause well-related issues is crucial. These include factors like perforation, partial perforation, gravel pack, turbulent flow, low reservoir pressure requiring gas lift, chokes, and artificial lift operation challenges. A key goal in sandstone formations is restoring damaged areas, aiming to remove up to 90% of the damage. Assessing the economic viability of the acidizing operation, considering costs, is also essential. Notably, for wells with permeability below 10 md in oil wells and 1 md in gas wells, hydraulic fracturing is typically advised (Figure 1) (Zhang, Guo et al. 2021).

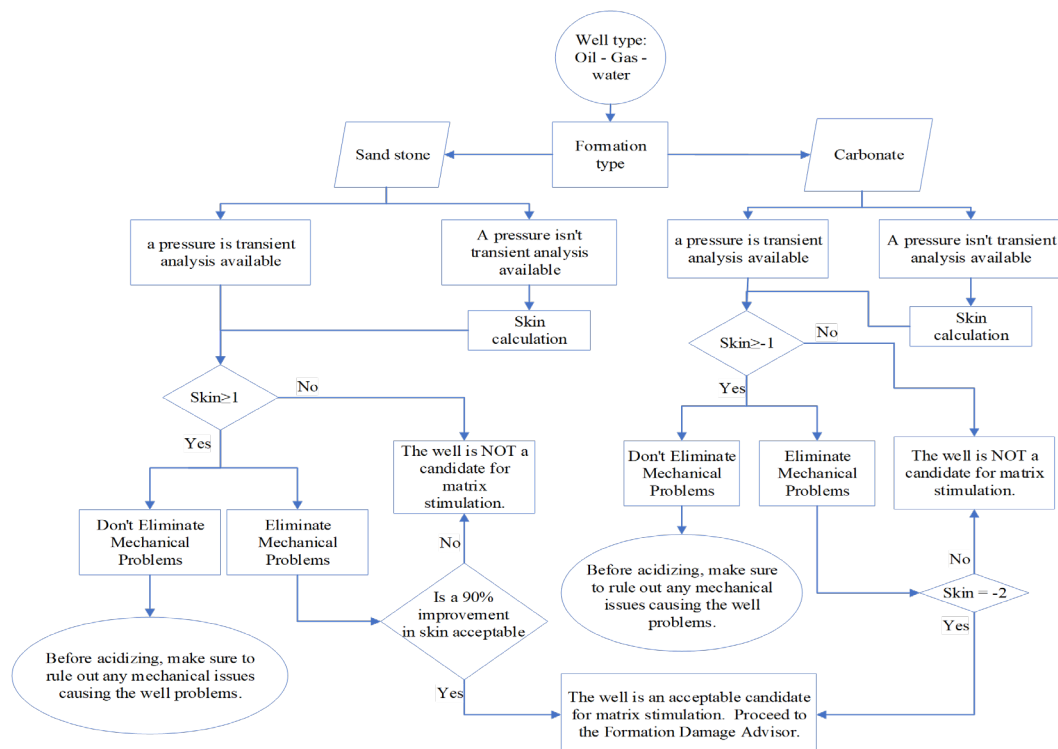


Figure 1. Candidate Selection

2.2. Diagnosis of Formation Damage

Throughout a well's lifecycle, from inception to closure, it undergoes various states such as newly completed, workover/stimulation, huff and puff, continuous operation, steam-enhanced operation, corrosion inhibition, and suspension (wells that are not currently in active production or injection service but have not been permanently abandoned). During these stages, the formation may suffer various damages, including wettability alteration, emulsion blocking, bacterial and organic deposits like asphaltene and paraffin, scale deposits, fine migration, polymer and mixed deposits (presence Scale layered with oil or paraffin), solid mud (excluding filter cake, solid mud damage from drilling mud components plugging formation pores is different from filter cake formed by reservoir fluids), solid completion-workover/stimulation fluid (damage caused by solid particles from well completion fluids, acidizing, and workover operations) residues, precipitates, clay swelling, and water blocking (Xu, Kang et al. 2016). This study leverages insights from scientific articles and existing software in reservoir damage detection to identify potential reservoir damages. The primary objective is to enhance the understanding and effectiveness of acidizing operations.

2.2.1. Wettability Alteration and Emulsion Blocking

Wettability alteration is a common occurrence in newly completed wells, particularly when using oil-based drilling mud with high losses. This phenomenon arises from the interaction between the drilling mud and the rock surface, resulting in a shift in wettability from water-wet to oil-wet. Additionally, wettability alteration may lead to unexpected gradual or sudden declines in well production rates or even total well lockup. These changes are particularly significant when the reduction

in well rates cannot be attributed to other factors such as scale deposits or tubing issues but rather to interaction between rock and fluid affinity. Emulsion formation can be diagnosed based on several factors, including the appearance of emulsion at the surface, the tendency of oil to form slugs or emulsions, minimal viscosity differences between oil and water, a high acid number of the oil, and a sudden decline in productivity index after well stimulation. These factors can alter the rock's surface properties, affecting its interaction with different fluids and the probability of particle migration. Therefore, this can lead to the formation of emulsions that obstruct flow pathways within the reservoir or production equipment. Furthermore, the manner of well completion, such as gravel pack completion with perforated casing or pre-packed screens (consisting of a gravel layer between two screens to wellbore stabilization), can also influence emulsion occurrence due to the potential for emulsions to form and obstruct flow within the completion design. During workover operations on gas and oil-producing wells, it is imperative to identify the factors contributing to emulsion formation. During stimulation operations on oil wells, especially when using HCl or HCl-HF acidizing fluids, can heighten the formation's susceptibility to emulsion occurrence. This susceptibility arises from chemical or physical alterations induced by the acidizing fluids, leading to changes in the properties of the oil and reservoir, thereby promoting emulsion formation. Additionally, in the context of sandstone reservoirs, the application of cationic surfactants and observing a sudden reduction in well rate holds the potential to cause wettability alteration damage. The use of cationic surfactants can alter the surface properties of the reservoir, impacting wettability characteristics (Figure 2) (Liew, Gholami et al. 2019).

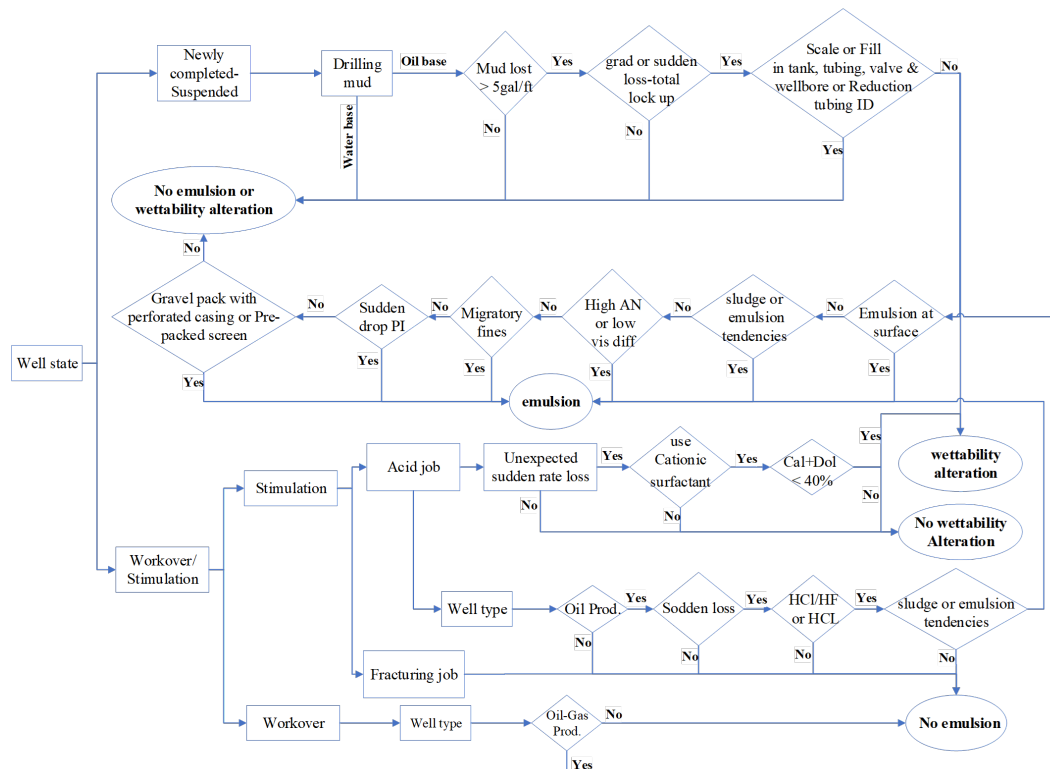


Figure 2. Diagnosis of Wettability Alteration and Emulsion Blocking

2.2.2. Bacteria, Asphaltene and Injection Carryover

Bacterial damage in injection wells can arise from various factors. Continuous operations (uninterrupted production or injection process within a well over an extended period) in these wells often create environments that promote bacterial growth, leading to bacterial damage. In wells located in H_2S -containing reservoirs, increased pressure or reduced injection rates can further exacerbate this damage. These altered conditions are conducive to bacterial proliferation, negatively affecting the well. In non-sour reservoirs, the presence of high levels of bacteria or the use of bacteria treatment operations can also lead to additional well damage. Scientific evidence indicates that these factors significantly influence the occurrence and progression of bacterial damage in oil wells. Asphaltene deposition can arise from alterations in thermodynamic conditions within the reservoir and oil and gas production wells. These changes may encompass fluctuations in temperature, pressure, shifts in the chemical composition of reservoir fluids, or variations in the pH of the

reservoir water, all contributing to the formation of asphaltene deposits. Furthermore, factors such as fluid density, the mixing of fluids with diverse compositions, and chemical reactions resulting from changes in temperature and pressure can also contribute to the formation of asphaltene deposits. Observing an unexpected gradual or sudden decrease in well rate, along with the presence of paraffin and asphaltene in reservoir fluid analysis, a resin-to-asphaltene ratio of less than one, or the floatability of solid particles on water, accompanied by solid and sooty burns (solid particles that, when burned, leave a sooty residue) that are soluble in xylene, indicate the potential for asphaltene deposition. The presence of paraffin and asphaltene in reservoir fluid analysis suggests that the reservoir fluid contains components with a tendency to form deposits. A resin-to-asphaltene ratio of less than one indicates a chemical imbalance in crude oil composition, potentially leading to asphaltene precipitation. This imbalance is critical as resins typically stabilize asphaltenes in oil. Insufficient resin levels allow asphaltenes to precipitate, forming

solid deposits that can cause operational issues. The detection of asphaltene deposits can be indicated by the floatability of solid particles on water and the observation of solid, sooty burns soluble in xylene, which are characteristic signs of asphaltene presence. When solid particles can float on water, it suggests that they have a lower density than water, which is characteristic of asphaltene deposits. Additionally, the presence of solid, sooty residues that dissolve in xylene is indicative of organic, carbonaceous materials, commonly associated with asphaltene deposits. Injection carryover damage (injection carryover damage refers to issues in injection wells caused by the injected water's quality or the conditions of injection), a concern in injection wells, is mainly related to the source of the injection water or injection conditions. It can be categorized into

three main groups: emulsion, formation solids, and oil damages. Emulsion damage arises when emulsions form due to mixing injection water with reservoir fluids, leading to stable emulsions that damage both the reservoir and the injection system. Formation solid damage is caused by the deposition of solids in the well, impeding injection water flow and affecting well performance. Oil damage occurs when oil is carried into the injection system, potentially causing plugging and reduced injectivity. Monitoring injection pressure and rate is essential, as fluctuations in these can indicate injection carryover damage. The presence of emulsion or oil on injection water filters, incompatible water additives, or oil leaks from injection equipment into the stream are signs of potential oil or emulsion damage (Figure 3).

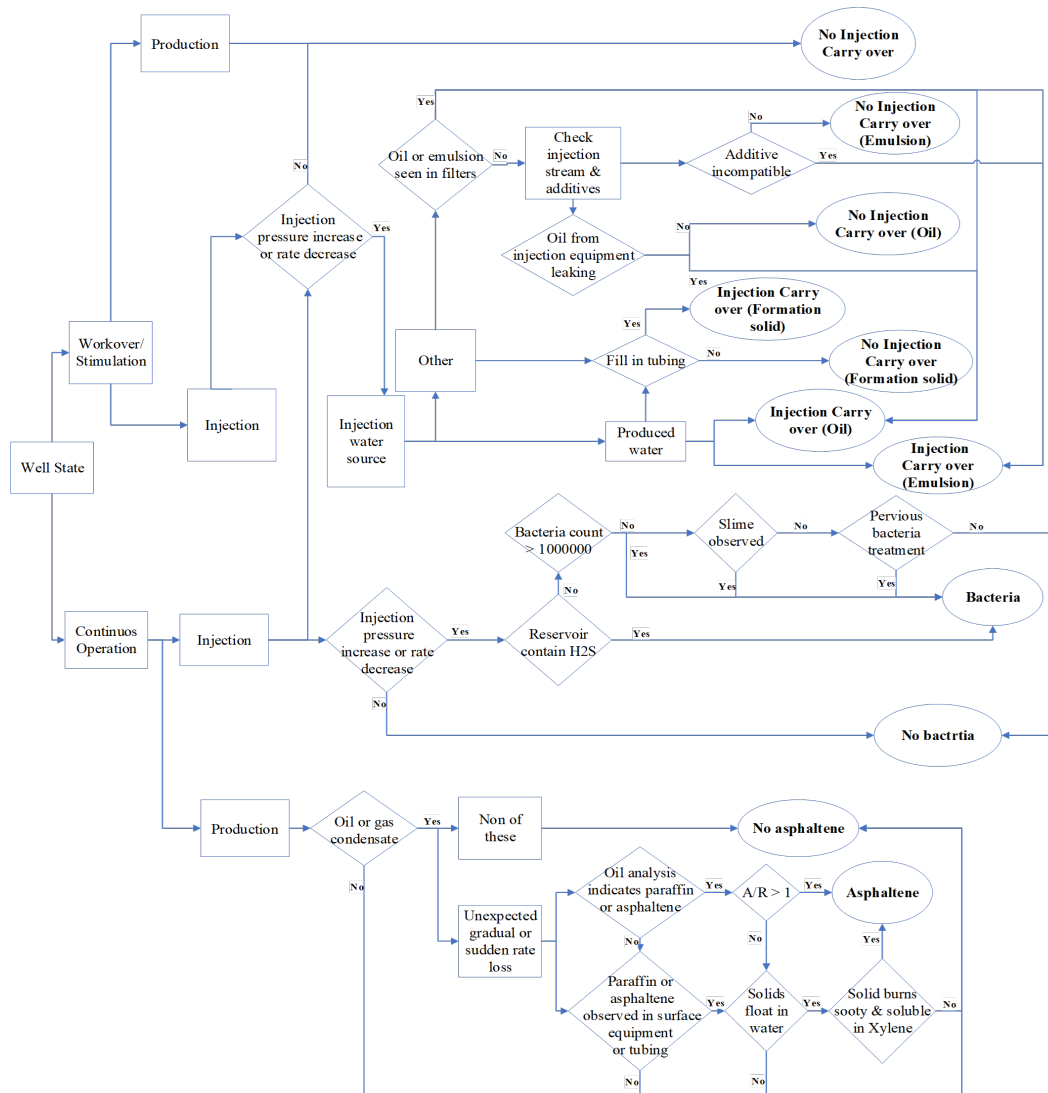


Figure 3. Diagnosis of Bacteria, Carry Over and Asphaltene

2.2.3. Scale Deposition

Scale deposition is a prevalent issue in production wells, particularly during workover, stimulation, continuous operation with steam (This method is used in heavy oil reservoirs to heat the oil with steam, making it easier to extract. It can be cyclic or part of a continuous steam flooding operation), and huff and puff processes. Analyzing produced fluids during workover and stimulation is essential for assessing potential scale damage and reviewing the field history. Even if no water is produced from the well, the potential for scale damage should not be overlooked. Field history analysis plays a crucial role in identifying scale damage in production wells, offering insights into reservoir performance, fluid composition, production rates, and previous pressure maintenance issues. This information is key to understanding reservoir dynamics and potential scale-related problems. During pressure maintenance operations in oil and gas reservoirs, the possibility of scale damage tends to be lower. This is because sustained pressure plays a crucial role in mitigating scale accumulation. Scale formation, often involving minerals like calcium carbonate or barium sulfate, is a common issue in reservoirs and production equipment. It leads to reduced flow efficiency and potential damage to equipment. Pressure maintenance, achieved through methods such as water flooding (Moghadas, Jamialahmadi et al. 2004) or gas injection, helps to maintain reservoir pressure at levels that deter the chemical conditions necessary for scale precipitation. This happens because a decrease in pressure can trigger changes in fluid

temperature and composition, which promotes mineral supersaturation and subsequent scale deposition. In assessing scale deposition in fields where pressure is maintained, factors such as wellhead pressure (WHP) are critical. Changes in WHP without operator intervention may indicate scale deposition, as scale can restrict fluid flow in the wellbore, thereby altering WHP. Monitoring and analyzing changes in WHP are vital for identifying and addressing potential scale issues. Accumulating scale can constrict the flow area, leading to an increase in pressure drop and potentially affecting production rates. Significant changes in production conditions, such as flow rates or fluid compositions, can influence the probability of scale formation. For instance, variations in temperature, pressure, or chemical composition can encourage the precipitation of scale-forming minerals. A sudden increase in water cuts could signal scale issues, as scale deposits can disrupt fluid separation processes, leading to higher water production. Water flooding in the field can alter the reservoir's chemical and physical environment, potentially promoting scale formation due to changes in water chemistry and rock-fluid interactions. Crossflow between different reservoir layers can lead to changes in pressure and fluid composition, which may influence scale deposition. Additionally, scale deposits reducing the tubing's inner diameter can result in flow restrictions and increased pressure drops. The presence of scale in production equipment is a clear indication of potential scale damage. Thus, monitoring these factors is vital

for identifying and addressing scale deposition. Regular monitoring and analysis of production well conditions are crucial for mitigating scale deposition. Implementing scale inhibition treatments and chemical squeeze programs can help in preventing and controlling scale formation. Periodic well cleanouts and scale removal operations are important to maintain optimal production rates. Continuous monitoring of WHP, fluid composition, and production conditions enables operators to proactively address potential scale issues, ensuring efficient and smooth production operations. Furthermore, the use of advanced modeling and predictive analytics can assist in forecasting and managing scale-related challenges, optimizing reservoir performance and maximizing production efficiency. After considering the above factors to identify scale deposits and meeting at least one of them in the field of pressure maintenance, the probability of scale formation is high. If any of the following factors are observed, scale deposits are present: an increase in gamma-ray levels can indicate the presence of Scale- BaSO_4 and SrSO_4 due to the natural radioactive properties of these scale-forming substances. This phenomenon allows Scale- BaSO_4 and SrSO_4 to absorb and emit gamma rays, which can be detected by specialized equipment. When the pH of produced water drops below 6, it suggests that the water is turning acidic and can cause the breakdown of carbonate minerals in the formation, like limestone (primarily composed of calcium carbonate, CaCO_3) (Qazvini, Golkari et al. 2021). This breakdown can lead to the formation of calcium carbonate scale or CaCO_3 . High CO_2 levels in produced water may also

suggest the possible existence of carbonate scales, like CaCO_3 and MgCO_3 , as carbon dioxide (CO_2) reacts with calcium and magnesium ions in the water to create carbonate scale. The detection of sour gas in a reservoir, typically containing hydrogen sulfide (H_2S), can indicate the potential for forming iron sulfide (FeS) scale. When hydrogen sulfide is present in the reservoir fluids and contacts iron compounds, like iron ions (Fe^{2+}), it can lead to the formation of an iron sulfide scale. A NaCl (sodium chloride) concentration above 50,000 ppm (parts per million) may suggest the possibility of sodium chloride (NaCl) scale formation. Elevated NaCl levels in water can result in solution saturation and the subsequent precipitation of NaCl as scale in production equipment and reservoir formations. The absence of inhibitors for tubular can indeed lead to the possibility of scale Fe_2O_3 (iron oxide) deposition. Without the use of appropriate inhibitors, tubular and other production equipment can be more susceptible to corrosion, which can result in the formation of iron oxide scale. If pressure maintenance operations are not conducted in the field, the observation of any of these indicative factors mentioned above indicates a significant risk of scale deposition damage. SiO_2 scale, commonly found in oil-producing wells during continuous operations with steam and huff and puff, is identified by a reduction in the tubing's inner diameter, which leads to decreased well productivity. This damage is associated with the accumulation of SiO_2 compounds in the wellbore, particularly during steam injection processes (Figure 4) (Khurshid, Al-Shalabi and Alameri 2020) (Moghadasi, Jamialahmadi et al. 2004).

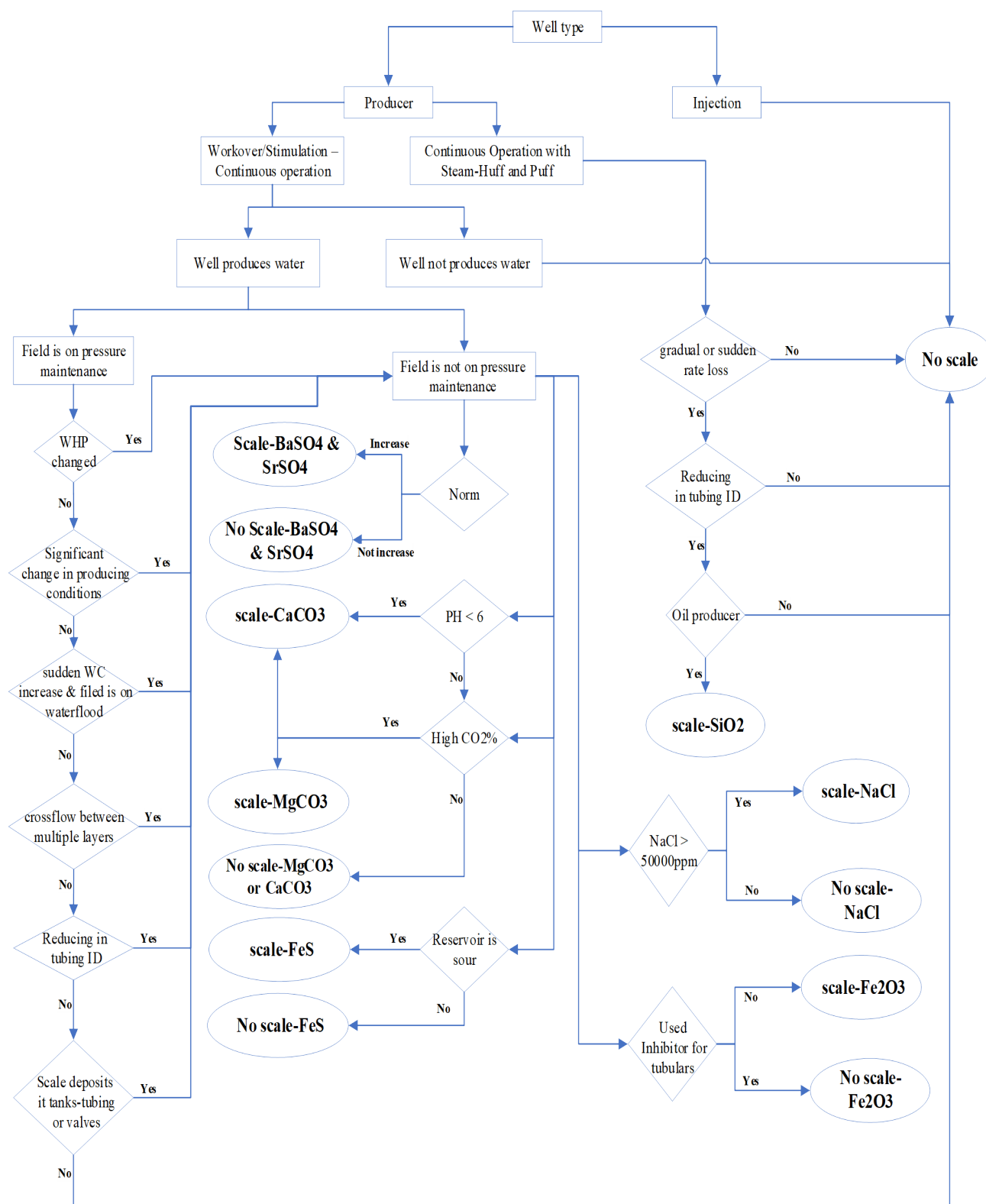


Figure 4. Diagnosis of Scale Deposition

2.2.4. Fine Migration, Polymer and Mixed Deposits

In all well states, potential issues such as polymer damage, fine migration, and mixed deposits must be considered. In a newly completed well, it is important to monitor for signs of polymer damage, particularly if a polymer-based fluid was used during the completion operation. This issue may be indicated by a gradual or sudden decrease in the well rate, in the absence of observed fill or scaling in the production equipment. If fill or scale deposits are observed in the production equipment, or if the well is not newly completed, the potential for pumping fluids into the damaged zone should be investigated. Furthermore, if the inability of fluid pumps is observed and a polymer-based fluid was used in the completion operation, polymer damage is likely to have occurred. Mixed deposit damage in oil-producing wells is characterized by a gradual or sudden decrease in the well rate, accompanied by the presence of scale layered with oil or paraffin. This type of damage suggests a mix of deposits including scale, oil, and paraffin, which can decrease well productivity and cause operational issues in all well states. The presence of Illite, chlorite, and kaolinite minerals in sandstone reservoirs makes them susceptible to fine migration damage. These clay minerals can become mobilized within the reservoir, leading to the migration of fine particles, potentially blocking pore throats, reducing permeability, and causing damage to the reservoir (Wang, Li et al. 2021). Additionally, the mineral composition of sandstone reservoirs, particularly the presence of calcite and dolomite, plays a significant role in determining susceptibility to fine migration damage. Formations with less than 40% of

calcite and dolomite are classified as sandstone (Tan, You et al. 2021). These compositions can influence the propensity for fine migration. The factors mentioned can exacerbate the risk of fine migration damage in sandstone reservoirs containing Illite, chlorite, and kaolinite minerals due to their influence on the mobilization and migration of fine particles within the reservoir. Specific well completion techniques can disrupt the formation and increase the possibility of fine particle migration. For example, the use of a gravel pack with a perforated liner or pre-packed screen can introduce stress and disturb the formation, leading to the mobilization of fine particles. Filling of the production equipment can create pressure differentials that may cause the migration of fine particles, potentially leading to blockages and reduced permeability. High production rates can induce changes in reservoir pressure and flow dynamics, potentially mobilizing fine particles and causing migration within the reservoir. Excessive drawdown rates during production can exert stress on the formation, leading to the release and migration of fine particles. Significant changes in production conditions, such as increased water cuts or unexpected shut-ins caused by surging, can alter the flow dynamics within the reservoir, potentially leading to the migration of fine particles. Lastly, the solubility of minerals such as Illite, chlorite, and kaolinite in acids like hydrochloric acid (HCl) or hydrofluoric acid (HF) can lead to the dissolution and release of fine particles, contributing to migration and potential damage within the reservoir. (Figure 5) (Radwan, Wood et al. 2022).

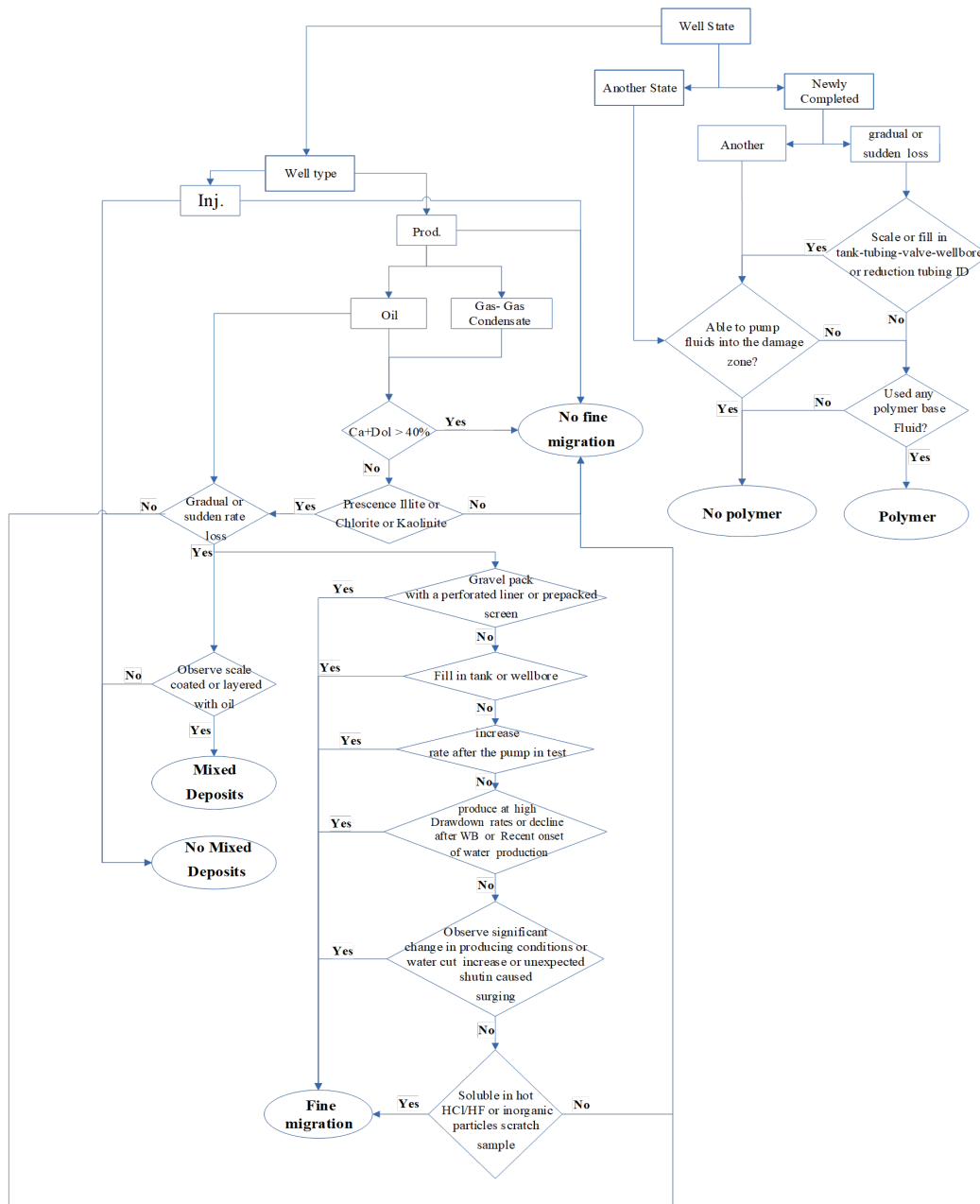


Figure 5. Diagnosis of Fine Migration, Polymer and Mixed Deposits

2.2.5. Solid Mud (Not Filter Cake)

Solid mud damage in oil and gas wells can result from various factors, including the invasion of drilling fluids into the formation, which leads to pore plugging and reduced permeability. This type of damage typically occurs in newly completed or suspended wells. High mud losses indicate an excessive intake of drilling fluid by the formation, causing decreased well productivity. A sudden or gradual decrease in well rate, or total well lock-up without observed scale or fill in the production equipment, suggests the

possibility of this damage. The presence of a horizontal or heavily deviated well can increase the risk of solid mud damage due to the potential for uneven distribution and settling of drilling fluids within the wellbore, which can lead to blockages and reduced permeability. Inadequate cleaning of drilling mud before running the casing can result in residual drilling fluid and solid particles within the wellbore, potentially causing formation damage and reduced well productivity. Perforations in the

mud system can allow the migration of solid particles into the formation, leading to pore plugging and reduced permeability, ultimately resulting in well damage. In naturally fractured reservoirs, the presence of fractures can act as pathways for drilling fluids and solid particles to enter the formation, potentially causing damage through pore plugging and reduced permeability. Inaccurate or poor cement

bonding, and variable density logs, can result in inadequate zonal isolation, allowing for the migration of drilling fluids and solid particles into the area behind the pipe, and contributing to potential damage. Lower well performance compared to open hole logs, and unproductive zones observed in production logs, may indicate potential issues such as solid mud damage (Figure 6).

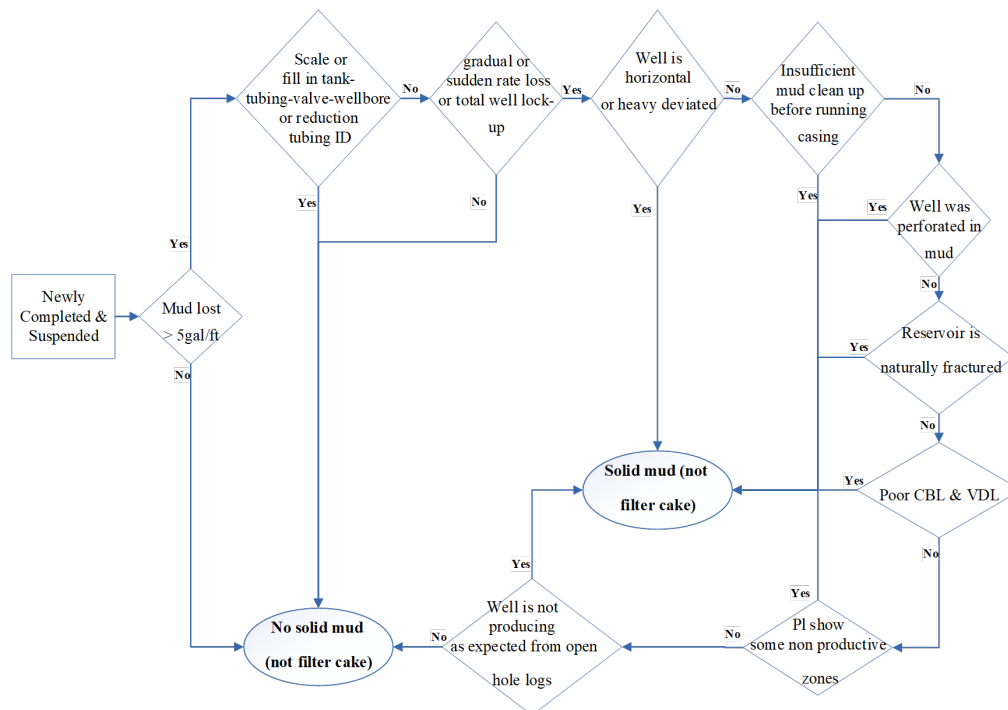


Figure 6. Diagnosis of Solid Mud (Not Filter Cake)

2.2.6. Solid-Completion-Workover/Stimulation Fluids

Damage of this kind is associated with the solid particles found in well-completion fluid and workover/stimulation fluids, warranting investigation in two distinct scenarios. In the case of solid completion fluids, in newly completed wells that are completed with a cased-hole or gravel pack (type of sand control technique in oil and gas wells to prevent the migration of formation sand into the wellbore) along with a perforated casing, insufficient underbalanced perforation can lead to the accumulation of perforation debris, solid particles, and other formation materials near the wellbore. This situation can also arise if

the well was not perforated underbalanced, or if the underbalanced pressure used during perforation is less than the minimum required, potentially resulting in incomplete cleaning of the perforation tunnels and leaving solid particles and debris (unwanted material blocking fluid flow) within the wellbore, which may cause formation damage. When it comes to workover/stimulation fluids, using a dirty water-based fluid in the killing job introduces solid particles, contaminants, and other debris into the wellbore and near the completion zone. These contaminants can accumulate in the formation, near the perforations, or within the completion equipment, leading to

linked to the creation of FeOH_3 precipitate. This reaction occurs when the acid interacts with the chlorite minerals, leading to the release of iron ions. Without sufficient chelating agents, these iron ions can react with hydroxide ions in the formation water, leading to the precipitation of FeOH_3 . Similarly, when an acid job is carried out using acid mud in sandstone reservoirs containing Illite or K-feldspar minerals and

an inadequate overflush is used, a sudden decrease in the well's rate can be attributed to the formation of K_2SiF_6 precipitate. This occurs due to the reaction between the fluoride ions from the acid and the potassium and silicon ions released from the Illite or K-feldspar minerals. The inadequate overflush fails to adequately remove the reaction by-products, leading to the formation of K_2SiF_6 precipitates (Figure 8).

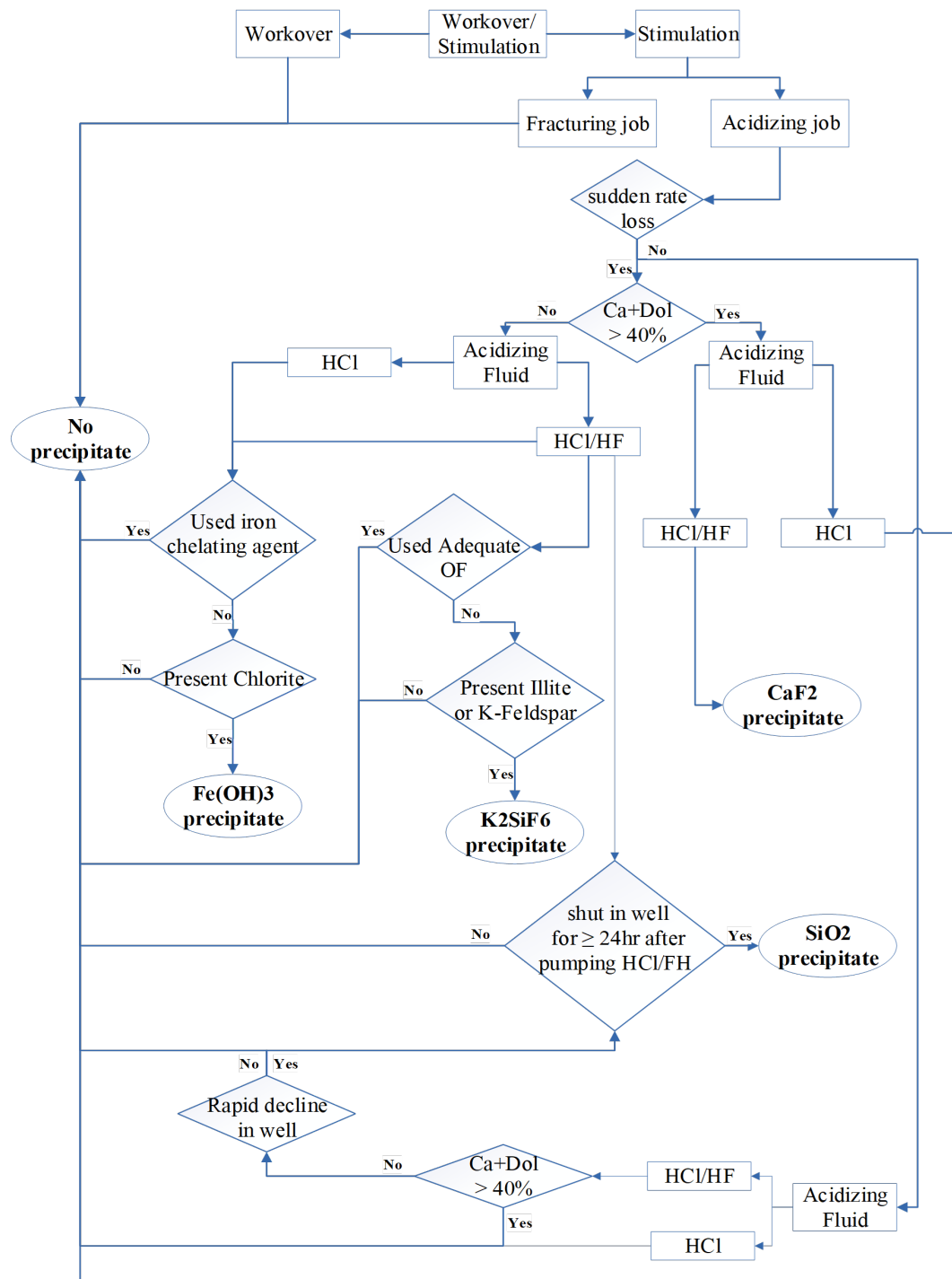


Figure 8. Diagnosis of Precipitate

2.2.8. Clay Swelling

Clay swelling in sandstone formations is primarily caused by the presence of minerals such as smectite or mixed-layers. Smectite, a type of clay mineral, tends to swell upon contact with water. Mixed-layers clays, composed of alternating layers of different clay minerals, can also contribute to swelling behavior in sandstone formations. The use of water-based drilling mud or completion fluids with lower salinity than the formation water in newly completed wells can increase the potential for clay swelling. This is due to the lower salinity creating an osmotic pressure difference between the fluids and the formation of water, leading to water absorption by the clay minerals in the sandstone formation. Clay swelling in wells utilizing oil-based fluids or water-based fluids with higher salinity than the formation water is typically the result of the interaction between the fluids and the

clay minerals in the sandstone formation. For instance, the presence of water-sensitive clay minerals like Smectite in oil-based fluids can cause swelling upon contact with water infiltrated into the formation. Similarly, the use of water-based fluids with higher salinity than the formation water can lead to clay swelling due to osmotic pressure differences and subsequent water uptake by the clay minerals. During workover or stimulation operations, a sudden rate loss can indicate clay swelling. This occurs when the introduction of fluids into the wellbore causes the clay minerals to swell, reducing permeability and impeding fluid flow. Additionally, core analysis indicating water sensitivity can be a sign of potential clay swelling issues, suggesting that the clay minerals in the formation are prone to swelling upon contact with water (Figure 9).

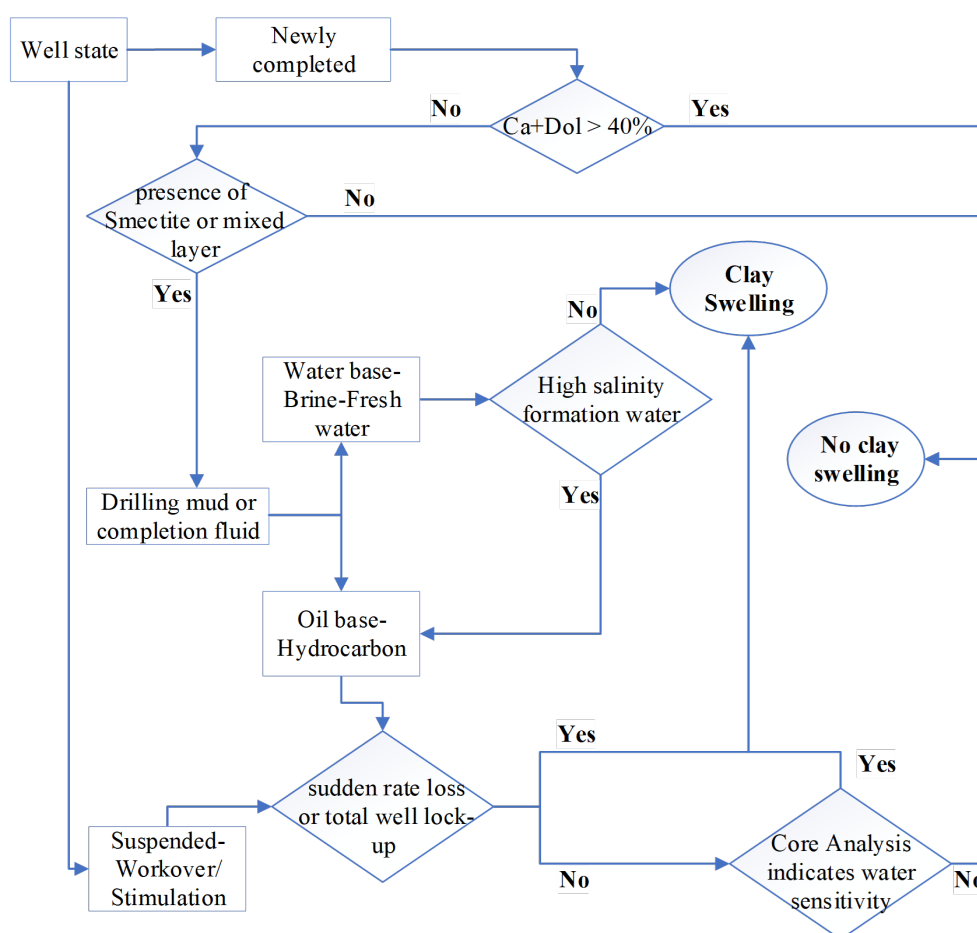


Figure 9. Diagnosis of Clay Swelling

2.2.9. Water Blocking

When a newly completed well utilizes water-based drilling mud with significant filtrate loss in low permeability reservoirs, it can result in water-blocking damage in oil and gas-producing wells. This occurs when the filtrate from the drilling mud infiltrates the formation, obstructing the flow of oil or gas through the reservoir rock. The significant filtrate loss can cause the formation to become plugged with the filtrate, reducing permeability and hindering the flow of hydrocarbons from the reservoir into the wellbore. In gas condensate and injection wells, water blocks can be identified by delayed cleanup over time, no rate increase during a pump-in test, or a positive response to methanol. These signs indicate that the well is experiencing water-blocking damage, which can lead to reduced production rates. During a well-stimulation operation on low permeability formations, failure to recover water

in the acid job operation can indicate potential formation damage. This is attributed to the acid's ability to create channels or pathways within the formation that are not effectually cleaned out, ultimately leading to reduced well productivity. Conversely, water-blocking damage can be inferred if the well fails to clean up over time, shows no rate increase during a pump-in test, or displays a positive response to methanol, even when mutual solvents are used. These observations are consistent with the presence of water blockage within the formation, which can hinder fluid flow and reduce production rates. In the case of high fluid loss during a water-based fluid kill job operation, the absence of a rate increase during a pump-in test, or a positive response to methanol indicates the possibility of water-blocking damage (Figure 10) (Shu and Yan 2008).

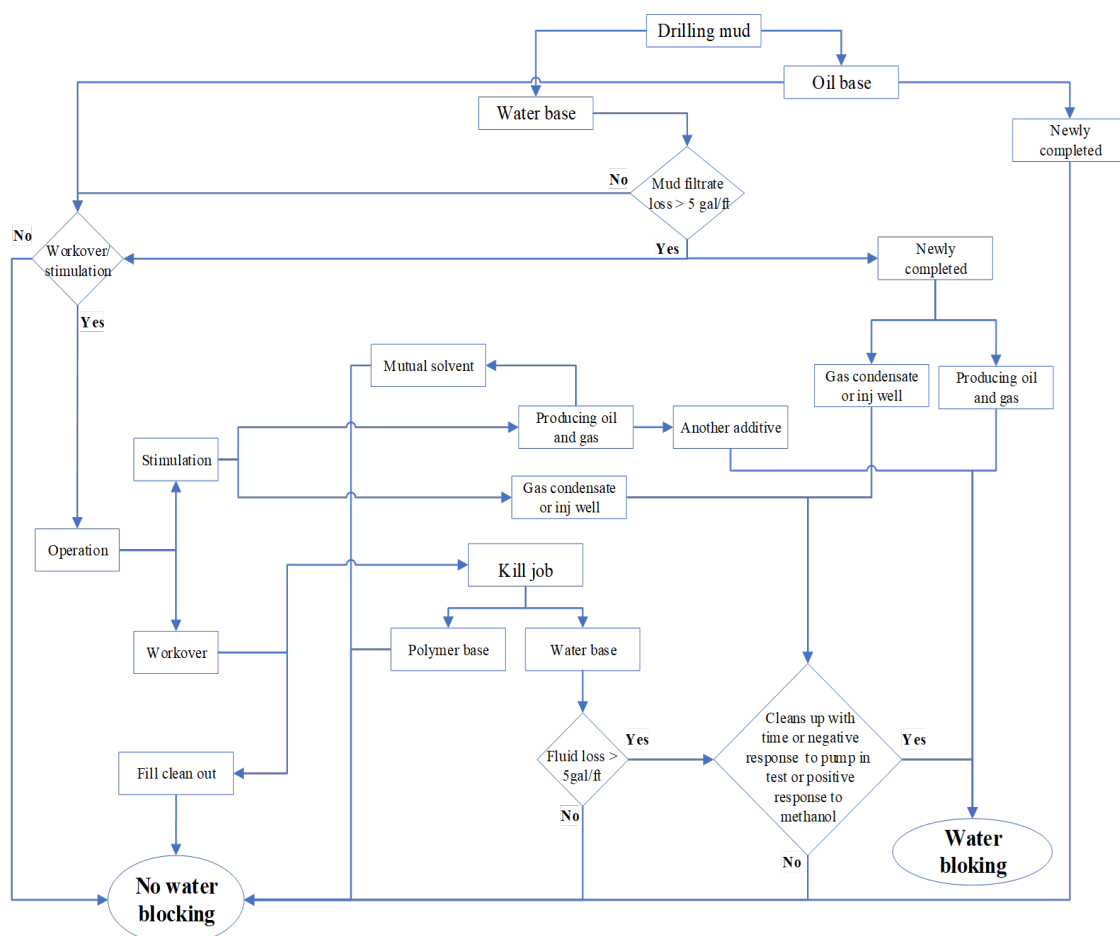


Figure 10. Diagnosis of Water Blocking

3. Results and Discussion

The operation of the expert system implemented for diagnosing formation damages in this research follows the rules obtained as illustrated in (Figures 2 to 10). The system considers all aspects, significantly reducing the number of possibilities through an elimination technique, thereby greatly enhancing the system's performance speed. For instance, clay swelling and fine migration are not common damages in carbonate formations. Therefore, if carbonate formation mineralogy is identified, these two types of damage are eliminated. The software begins by asking about the well state, initially considering only the damages likely to occur in that specific condition. It then further narrows down the number of damages by selecting the type of well (production or injection), the fluid used for production or injection in the well, and the type of drilling or completion fluid. After precisely identifying the well state, well type, type of injected or produced fluid, and the type of drilling mud or completion fluid, the system evaluates the well's history, test observations, surface equipment observations, well rate, past operations on the well, amount of lost drilling mud and its additives, and the types of these additives, among other factors, to identify potential damages. This step-by-step elimination technique reduces the number of possibilities, making the use of the expert system easier and faster, and enables the user to identify potential formation damages with minimal information and a lower error margin. The application of expert system criteria for selecting wells suitable for acid treatment was conducted on 10 wells chosen randomly. Among these, six wells are situated in a sandstone formation,

while the remaining four are in a carbonate formation. Specifically, in the sandstone formation, there are four wells dedicated to oil production, one for gas production, and another for water injection purposes. As for the carbonate formation, it comprises two oil-producing wells, one well for gas production, and one utilized for water injection. As shown in (Table 1), skin can be determined using parameters such as geometry, flow rate, BHP, viscosity, net pay, permeability, K_v/K_h , and well length (for deviated wells). It is important to address mechanical issues that reduce well performance before calculating the skin factor. Out of the ten selected wells, six were found suitable for acidizing jobs, with three in the carbonate formation and three in the sandstone formation. Identifying the specific type of formation damage accurately is crucial before initiating an acid treatment operation. This crucial step informs the selection of the most suitable acid treatment fluid, which is key to the operation's success. The expert system, detailed in the appendix section with its figures, has successfully pinpointed the types of damage in both carbonate and sandstone formations. This diagnosis is based on a thorough analysis encompassing various factors: reservoir characteristics, well type, current state of the well, fluids used in past operations, well's operational history, observations from tests and ongoing operations, and production equipment assessments.

The outcomes of this analysis are meticulously documented in (Table 1), (Table 2), and (Table 3). These tables validate the expert system's effectiveness in accurately determining the formation damage.

Table 1. Results of an Expert System for Well Candidate

Well Candidate	1	2	3	4	5	6	7	8	9	10
Formation	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone	Carbonate	Carbonate	Carbonate	Carbonate
Well Type	Oil	Oil	Oil	Oil	Gas	Water	Oil	Oil	Gas	Water
Well Geometry	Straight	Straight	Low Deviated	Horizontal	Straight	Straight	Heavy Deviated	Straight	Straight	Straight
Flow rate	300 STB/d	150 STB/d	70 STB/d	78 STB/d	7 MMscf/d	700STB/d	70 STB/d	61 STB/d	30MMscf/d	190STB/d
Pres (psi)	4710	2150	1460	2900	1430	2000	2950	2820	3500	2560
BHP (psi)	1200	1120	630	1050	560	1420	750	820	1700	1470
Viscosity (cp)	13	5	11	12	-	1.009	15	3	0.6	0.970
Net pay	20	35	30	15	40	70	30	47	51	12
Perm (md)	180	40	28	20	20	18	7	2	14	30
K_v/K_h	-	-	-	0.1	-	-	0.2	-	-	-
Lwell (ft)	-	-	-	27	-	-	100	-	-	-
Scalculated	15	6	-1	-3	3	0	-5	14	4	8
Qualification Candidate	Acceptable	Acceptable	Unacceptable	Unacceptable	Acceptable	Unacceptable	Unacceptable	Acceptable	Acceptable	Acceptable

Table 2. Results of Expert System for Formation Damage Detection in Sandstone Reservoirs

Well Candidate	1	2	5
Formation	Sand Stone	Sand stone	Sandstone
Well Type	Oil Producing	Oil producing	Gas Producing
Well State	Newly Completed	Suspended	Workover (Kill Job)
Produce Water	Yes	No	Yes - High CO ₂ - PH<6 - NaCl > 50000 ppm
Completion Fluid & Salinity	Oil base - High salinity	-	Water Base - Low Salinity
Drilling Mud & Salinity	Water base - Low salinity	Oil Base - High salinity	-
Filtrate Lost- Mud Lost	High - High	High - High	*- High
Candidate Selection	Illite - Chlorite - Smectite - Calcite - Dolomite - Zeo- lite- K Feldspar - Quartz	Siderite - Mica - Calcite - Dolomite - Glauconite - Chlorite - Illite - Quartz - Mixed layer	Na Feldspar - Calcite - Dolomite - ZeoLite - Illite
Kill Fluid	-	-	Kill Water Not Filtered-Kill Tank Cleaned-Flushed Lines (Before Kill Job)
Completion Type	Cased Hole and Straight	-	Perforated Liner
Perforation	UBD-Perforated in Mud	-	
Reservoir Information	Not sour k=30md TVD = 180ft P = 2560 psi BHT=160 deg °F	-	Sour k=12md TVD = 2500ft P = 1500 psi BHT=150 deg °F
Flow Rates Observation	Unexpected Gradual Rate loss	Total well Lock-up	Unexpected Sudden Rate Loss
Well History	-	-	-
Pump-in Test	Yes	Yes	Yes
Able Pump Fluids in to the Damage zone	Yes	No	No
Increase Rate After Pump-in Test	No	Yes	No
Lost Circulation Pill Pumped	-	Yes	Yes
Lost Circulation Pill Solids Free	-	Yes	No
Lost Circulation Pill Polymer Base	-	Yes	Yes
Production Equipment Observation	Fill Tanks-Scale layered with Oil	Scale Deposits in Tubing - Fill in Tanks and Tubing -	Fill in Tubing-Evidence of Emulsion
Test Observation	Poor CBL&VDL	-	Oil has High acid Number- Poor CBL&VDL- Increase Gama Ray-
Operation Observation	-	-	WC Increase
Formation Damage Detected	1) Clay Swelling 2) Fines Migration 3) Mixed Deposits 4) Solid Completion Fluids 5) Water Blocking	1) Clay Swelling 2) Polymer	1) Emulsion 2) Fines Migration 3) Polymer 4) Solids Workover Fluids 5) Water Blocking 6) Scale (CaCO ₃ -Fe ₂ O ₃ -FeS-MgCO ₃)

Table 3. Results of Expert System for Formation Damage Detection in Carbonate Reservoirs

Well Candidate	8	9	10
Formation	Carbonate	Carbonate	Carbonate
Well Type	Oil Producing	Gas Injection	Water Injection
Well State	Continuous Operation	Stimulations (Acidizing HCl)	Huff and Puff
Well Shut-in	-	30hr After Pumping Acid	-
Produce Water	Yes - High CO ₂	-	-
Injection Well	-	Increase Pressure Used Produced Water	-
Completion Fluid & Salinity	-	Open Hole - Straight	Cased Hole - Straight
Drilling Mud & Salinity	-	Water Base - High Salinity	-
Filtrate Lost- Mud Lost	-	Low-High	-
Mineralogy	Calcite - Dolomite - Zeolites - Chlorite - Quartz	Calcite - Dolomite - Siderite - Smectite - Illite - Quartz	-
Kill Fluid	-	-	-
Completion Type	-	-	-
Perforation	-	-	-
Reservoir Information	Not Sour k=40md TVD = 1200 ft P = 1700 psi BHT= 210 deg °F	-	-
Flow Rates Observation	Unexpected Gradual Rate Loss	Unexpected Sudden Rate Loss	-
Well History	Recent onset - Produced at High Drawdown - Sudden Drop PI	-	-
Pump-in Test	Yes	Yes	Yes
Able Pump Fluids in to the Damage Zone	Yes	Yes	No
Increase Rate After Pump-In Test	Yes	No	Yes
Lost Circulation Pill Pumped	-	Yes	Yes
Lost Circulation Pill Solids Free	-	Yes	Yes
Lost Circulation Pill Polymer Base	-	Yes	Yes
Production Equipment Observation	-	Fill in Tubing	-
Test Observation	Positive Response to Metha- Nol- Small Difference Viscosity oil-Water - High Acid Number	-	-
Operation Observation	WC Increase - WHP Changed - Fields on Pressure Maintenance	WC Increase - Field is on Water Flooding - WHP Changed	-
Formation Damage Detected	1) Scale (CaCO ₃ -Fe ₂ O ₃ -MgCO ₃)	1) Injection Carryover (Emulsion- Formation Solids-Oil) 2) Polymer 3) Solid Stimulation Fluids 4) Water Blocking	1) Polymer

4. Conclusion

Determining whether a well is suitable for acidizing is a challenging process. This complexity continues even after several potential candidate wells have been identified, as the task then becomes identifying the best candidate well among those selected. In other words, selecting the best candidate from the identified wells requires a thorough assessment of the potential damage to each well. In this study, our goal was to develop an expert system capable of selecting appropriate wells for acidizing jobs and identifying formation damages. This system aids in determining which wells are suitable for acidizing and in detecting any formation damage. Given the varied conditions of hydrocarbon reservoirs and the multitude of operations on wells, identifying formation damage necessitates analyzing tens of millions of possibilities. This research introduces an expert system that, for the first time, is capable of rapidly assessing these scenarios through fundamental rules and an elimination technique. Tested on ten well samples, it detected damages with minimal error, showcasing its efficiency and the potential to significantly advance formation damage diagnosis in the industry. Moreover, in future research, we aim to further enhance these investigations by leveraging fuzzy logic and developing a system based on this logic for more accurate detection of formation damage and identification of wells susceptible to acidizing.

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استفاده از یک سیستم خبره در انتخاب کاندیداهای مناسب برای عملیات اسیدکاری و مشاوره در زمینه آسیب‌های سازندی

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چکیده

در طول عمر یک چاه، عوامل متعددی نظیر کاهش فشار، مشبک‌کاری ناقص، جریان آشفته و آسیب سازندی، می‌توانند بهره‌وری چاه را به شدت تحت تأثیر قرار دهند. شناسایی و رسیدگی به این مشکلات، به‌ویژه آسیب‌سازندی، بسیار حیاتی است. عملیات اسیدکاری به‌طور معمول برای کاهش چنین آسیب‌هایی به کار گرفته می‌شود و معمولاً پس از انجام این عملیات، بهره‌وری چاه افزایش می‌یابد. عموماً، انتخاب چاه‌ها برای انجام اسیدکاری و شناسایی آسیب‌های سازندی بر پایه تجزیه و تحلیل‌های گسترده زمین‌شناسی و مهندسی استوار بوده است. این روش‌های سنتی، هر چند کامل، زمان‌بر هستند و شامل بررسی داده‌های پیچیده ژئوشیمیایی، ژئوفیزیکی و زمین‌شناسی می‌شوند. به همین علت، این مطالعه یک سیستم خبره را برای ساده‌سازی این فرآیندها معرفی می‌کند. سیستم‌های خبره به‌صورت خودکار و سریع به تجزیه و تحلیل داده‌ها پرداخته که موجب سرعت بخشیدن به تصمیم‌گیری و بهبود کارایی می‌شود. سیستم خبره توسعه‌یافته در این تحقیق، توانایی قابل‌توجهی در پردازش مجموعه‌های داده‌های پیچیده نشان می‌دهد و در نتیجه بهره‌وری را افزایش می‌دهد و احتمال خطاها را کاهش می‌دهد. توانایی پیش‌بینی سیستم‌های خبره همچنین امکان مدیریت پیشگیرانه چاه‌ها را فراهم می‌آورد. این تحقیق از یک سیستم خبره برای تحلیل ده چاه استفاده می‌کند و شش مورد را به‌عنوان نامزدهای مناسب برای عملیات اسیدکاری شناسایی می‌کند. این سیستم به‌طور مؤثر آسیب‌های احتمالی سازندی در این چاه‌ها را شناسایی می‌کند و دقت آن در تشخیص و تصمیم‌گیری را نشان می‌دهد. استفاده از سیستم‌های خبره در سناریوهایی با عدم قطعیت بالا که نیازمند تحلیل دقیق هستند، امیدوار کننده است. با بهره‌گیری از الگوریتم‌ها و مدل‌های ریاضی بیشتر معمول یا استاندارد، این سیستم‌ها می‌توانند فرآیندهای تصمیم‌گیری، دقت پیش‌بینی و کارایی عملیاتی در مخازن نفت و گاز را به‌طور قابل‌توجهی بهبود بخشند. بهبود تصمیم‌گیری یک مزیت کلیدی است زیرا این سیستم‌ها، با داده‌های جامع و تحلیل شده، امکان تصمیم‌گیری‌های آگاهانه‌تر و مؤثرتر را فراهم می‌آورند. در این مطالعه، یک سیستم خبره برای انتخاب چاه‌های مناسب برای عملیات اسیدکاری و تشخیص نوع آسیب‌های سازندی توسعه یافته است. از ده چاه تحلیل شده، شش مورد برای عملیات اسیدکاری مناسب شناخته شدند. توانایی این سیستم در شناسایی آسیب‌های احتمالی سازندی در هر چاه، کارایی آن را نشان می‌دهد. استفاده از این سیستم‌ها در مواردی با عدم قطعیت بالا و نیاز به مدل‌سازی دقیق، ارزشمند است و به بهبود کارایی عملیاتی و بهره‌وری در بخش نفت و گاز کمک می‌کند.

واژگان کلیدی: سیستم‌های خبره، اسیدکاری خمیره، آسیب سازند، انتخاب کاندیدای اسیدکاری، بهره‌وری چاه