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Improving Acidizing Fluid Selection in Oil Production: A Comprehensive Analysis with Expert Systems

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ABSTRACT

Matrix acidizing plays an important role in improving oil recovery by decreasing reservoir damage. However, the complexity of selecting the most suitable acidizing fluid, given diverse reservoir conditions, poses a significant challenge. This article explores the utilization of expert systems in improving the acidizing fluid selection process. By examining the role, components and merits of expert systems, along with real-world case studies, the article highlights how these systems contribute to more efficient and informed decision-making. In this investigation, eight instances of damage have been selected for analysis using the proposed expert system. Following a thorough assessment, selecting a fluid for damage elimination, demonstrates the effectiveness of the expert system. The incorporation of expert systems in modeling and inference under conditions of high uncertainty and precision plays a key role in increasing productivity, declining errors, predicting events and refining decision-making processes. These systems utilize advanced algorithms and mathematical models for simulation and predicting implications across various applications, thereby aiding in expedited decision-making.

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1. Introduction

Reservoir damage is a critical major concern within the oil and gas industry that has the potential to have a significant impact on reducing reservoir productivity (Abdulmutalibov et al. 2023). In the scope of reservoir stimulation, matrix acidizing stands out as a crucial technique employed to improve the productivity of oil and gas wells (Alvarez et al. 2023). One of the key factors that considerably influences the success of acidizing matrix operations is the careful selection of treatment fluids. The choice of acidizing fluids can make the difference between a non-optimal treatment and a highly effective well stimulation. This article explores into the critical aspects of fluid selection in the matrix acidizing process, introducing the concept of an acidizing fluids selection (McLeod 1984, Mouedden et al. 2022). The acidizing fluid selection serves as a guide, enabling engineers and operators to make informed decisions about the type of acids and additives that will yield optimal results for a specific reservoir (Sumotarto 1995, Santos et al. 2022). Navigating through the complexities of matrix acidizing, one will explore the factors influencing fluid selection, the commonly used types of acids and the role of additives in tailoring the treatment to the unique characteristics of each well.

Dargi et al. (2023) demonstrated that machine learning models successfully predicted post-acidizing permeability changes in oil and gas wells, with genetic programming outperforming other models. The study underscores the potential of genetic programming and machine learning for accurate post-acidizing permeability forecasting, aiding in design and improving production rates. Sidaoui et al. (2018) used a machine learning model based on rock and HCl properties to predict optimum injection rates in matrix stimulation with 90% accuracy. This streamlined approach improves acid job design for production engineers and minimizes the demand for extensive laboratory experiments. Chavanne and Perthuis (1992) presented a novel expert system for fluid selection in matrix treatments, employing a chemistry-driven two-step reasoning process and providing multiple ranked solutions. Tested for conformity, the system offers safe recommendations, improving field practices and contributing a noteworthy addition to the literature on fluid selection advisors in well stimulation. Domelon et al. (1992) introduced the development of Acid Expert, a PC-based matrix acidizing expert system, utilized for designing damage removal treatments in sandstone formations. The system improves consistency in recommendations globally, facilitates timely technology transfer and considers technical, economic and product availability aspects for cost-saving benefits. Blackburn et al. (1990) discussed the development of acidman, an expert system for designing matrix acid treatments in oil wells, with anticipated benefits including rised treatment success rates and improved cost-effectiveness.

Chiu et al. (1993) explored the challenges of designing fluid systems for well completion, proposing expert systems as efficient tools for advising engineers on selecting base fluids and additives. It emphasized the necessity of knowledge representation, inference methods and user interface in system implementation. Using Acid Expert as an example, the study highlights the significance of knowledge acquisition and user interaction for excellent product recommendations, ultimately leading to cost savings and enhanced service quality in the oil industry. Xue et al. (2012)introduced a neural network method to predict acidizing fluid selection and dosages for oilfield applications, highlighting the complexity of conventional methods and the demand for a more efficient solution. Through successful training and testing, the study illustrates the network's ability to forecast optimal fluid systems based on diverse input parameters, aiming to foster systematization and intelligence in the oil industry.

The aim of this study is to develop an expert advisory system that accurately and quickly identifies the suitable acidizing fluid for acidizing operations, addressing well damages effectively. This system intends to utilize acidizing fluids and various acidizing stages to mitigate damages, ultimately bridging the gap between artificial intelligence and acidizing. By the end of this article, readers will gain invaluable insights into the importance of a well-informed fluid selection strategy and the tools available to make such decisions in the field of acidizing matrix.

2. Methodology

2.1. Diverting Agents

A diverter in well acidizing is a type of material or equipment used to control and prevent the uneven flow of acid or other fluids within the well. The purpose of employing a diverting agent in this process is to achieve a uniform distribution of acid in the reservoir structure and prevent pressure drop due to undesired acid diversion. Types of diverting agents include: 1) Gels: gel-forming materials are added to acid to create a gel that controls the flow of acid; 2) Polymers: polymers are additives, which added to acid for increasing viscosity and improving acid distribution in the reservoir; 3) Foams: foams are formed by adding gas to acid and can enhance the direction and distribution of acid; 4) Particulate diverters: particles such as carbonates or silica are combined with acid to act as barriers, diverting the acid flow to specific points. Diverters are typically used when the reservoir treatment interval is greater than 20 ft and the reservoir temperature is less than 300°F. As seen in (Figure 1), there are six types of diverters, which are explained below.

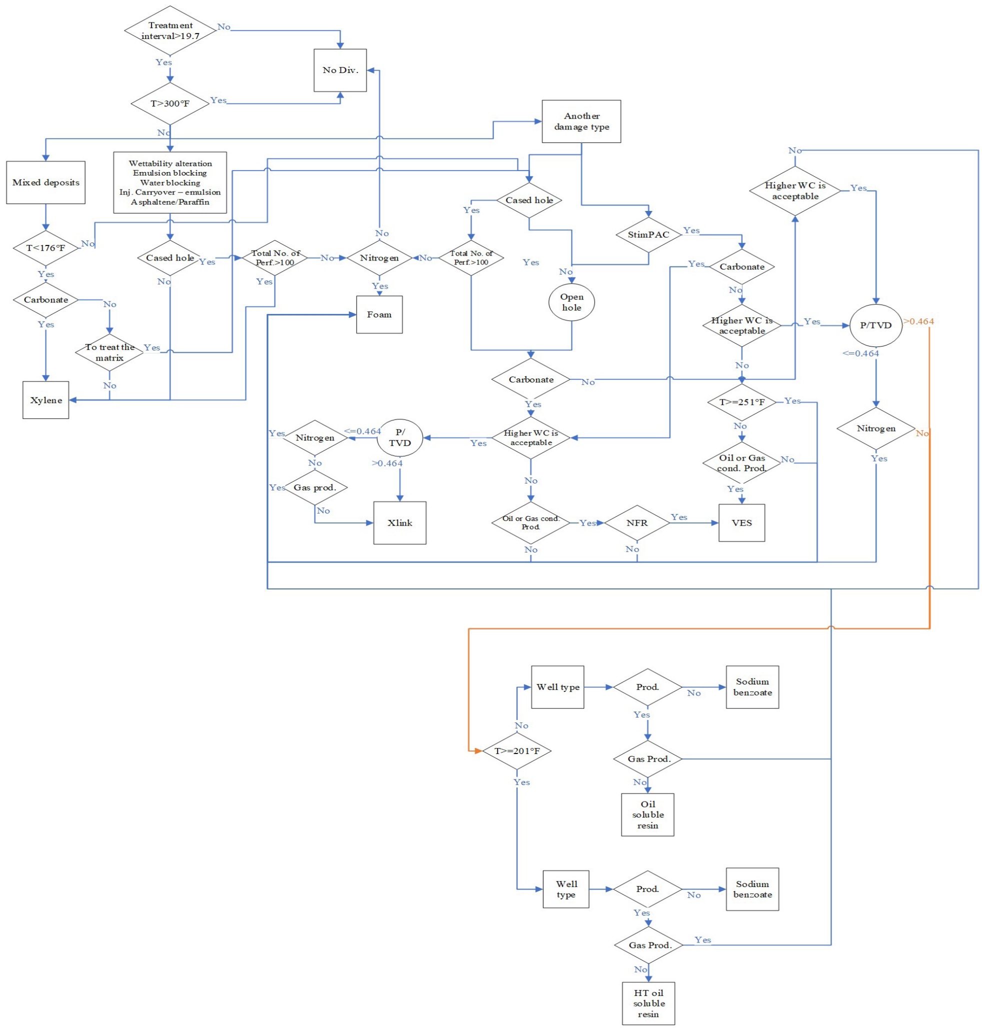

Figure 1. Detection of Diverting Agents Fluid

2.1.1. Xylene Foam Diverter

In the case of encountering damages such as mixed deposit, wettability alteration, emulsion blocking, water blocking, injection carryover-emulsion, asphaltene and paraffin in the reservoir, xylene can be used. Xylene is employed for reducing mixed deposit damage when the reservoir temperature is below 176°F and in situations where the target of acid injection is to treat the wellbore, perforation, or gravel pack solely in the sandstone reservoir. Otherwise, other diverting agents are utilized.

2.1.2. Temporary Xlink Acid Diverter

In the case of acidizing on a carbonate reservoir, if there is a need for a diverting agent, xlink should be used. The condition for using this type of diverting agent includes high water cut in the well or performing operations near the water-producing zone, along with the non-acceptance of water and avoiding the use of nitrogen. If it is not possible to use a foam diverter, xlink can be used instead.

2.1.3. Viscoelastic Surfactant (VES) Diverter

Completion type with stimPAC (stimPAC is a type of well completion method used to increase oil and gas production from oil wells) in an oil or gas condensate production well can be implemented when the reservoir temperature is below 250°F and there is a low water cut in the well. It can also be utilized when operations are conducted near the water-producing zone along with the non-acceptance of higher water cut values.

In addition, VES diverter can be utilized when the completion type is either an open hole or a cased hole in a carbonate reservoir with natural fractures and high water cut in the well, or operations are conducted near the water-producing zone along with the non-acceptance of higher water cut values.

2.1.4. High Temperature Oil Soluble in Resin/ Oil Soluble in Resin

In the reservoir, when the well produces oil or gas condensate at temperatures higher than 200 °F, high temperature oil soluble in resin diverter is utilized to address damage. This diverter is used in states with low water cut in the well and the absence of operations near the water-producing zone, along with either the non-acceptance or acceptance of higher water cut values and the avoidance of using nitrogen. Regarding reservoirs with temperatures below 200 °F, oil soluble in resin diverter is used.

2.1.5. Sodium Benzoate

In an injection well, if nitrogen is not used and there is a high water cut in the well, along with the absence of operations near the water-producing zone and either the non-acceptance or acceptance of higher water cut values, sodium benzoate diverter can be used.

2.1.6. Foam

In the case of performing various operations near the water-producing zone or observing a high water cut in the well, when using nitrogen in the wellbore treatment fluid, base foam diverters should be used. In the absence of nitrogen, only in the case of gas-producing wells, this type of diverter can be used. If a low water cut is observed in the well in sandstone formations, only base foam diverters are employed. In carbonate formations with gas-producing wells it can be used, however in other wells when there is no natural fracture in formation, foam diverters are used.

2.2. Main Fluid, Over Flush and Pre-Flush

2.2.1. Clay Swelling

For the selection of the main fluid, pre-flush and over-flush in clay swelling damage, mineralogy needs to be examined, which can be divided into two categories based on the amounts of calcite and dolomite: between 20-40% and less than 20%. If the amounts of calcite and dolomite are between 20-40% and with the absence of glauconite, chlorite and zeolite in the formation minerals, the selection of the acidizing fluid depends on the temperature. If the temperature is below 200°F, the recommended main fluid is HCl 28% and for temperatures between 200-300 °F, the suggested main fluid is HCl 15%. If the temperature is higher than 300°F, the recommended main fluid is HCl 10%.

In the next state, where the content of calcite and dolomite is less than 20%, the mineral's presence in the formation, significantly impacts the injected acidizing fluid, as illustrated in (Figure 3). In a situation where only quartz, calcite and dolomite minerals are presented in the formation and there is no cement in the formation, the selection of the fluid depends on the reservoir permeability and the injected or produced fluids. Specifically, if the permeability is less than 20 mD and the produced fluid is oil or injection fluid, the pre-flush, main fluid and over-flush will be HCl 7.5%, mud acid 6/1.5 and HCl 7.5%, respectively. For permeability between 20-100 mD, if the produced fluid is oil or injection fluid, the pre-flush and over-flush fluids will be HCl 10% and the main fluid will be mud acid 8/2. However, as long as the produced fluid is gas, the pre-flush and over-flush fluids will be gas well acid 10% and the main fluid will be gas well mud acid. For gas condensate fluids, the pre-flush and over-flush fluids will be alcoholic acid 10% and the main fluid will be alcoholic mud acid 8/2.

Finally, providing that the permeability of the formation is greater than 100 mD, for oil and injection fluids, the pre-flush and over-flush fluids will be HCl 15% and the main fluid will be mud acid 12/3. In the case of gas produced fluids, the pre-flush and over-flush fluids will be gas well acid 15% and the main fluid will be gas well mud acid. For gas condensate fluids, the pre-flush and over-flush fluids will be alcoholic acid 15% and the main fluid will be alcoholic mud acid 12/3.

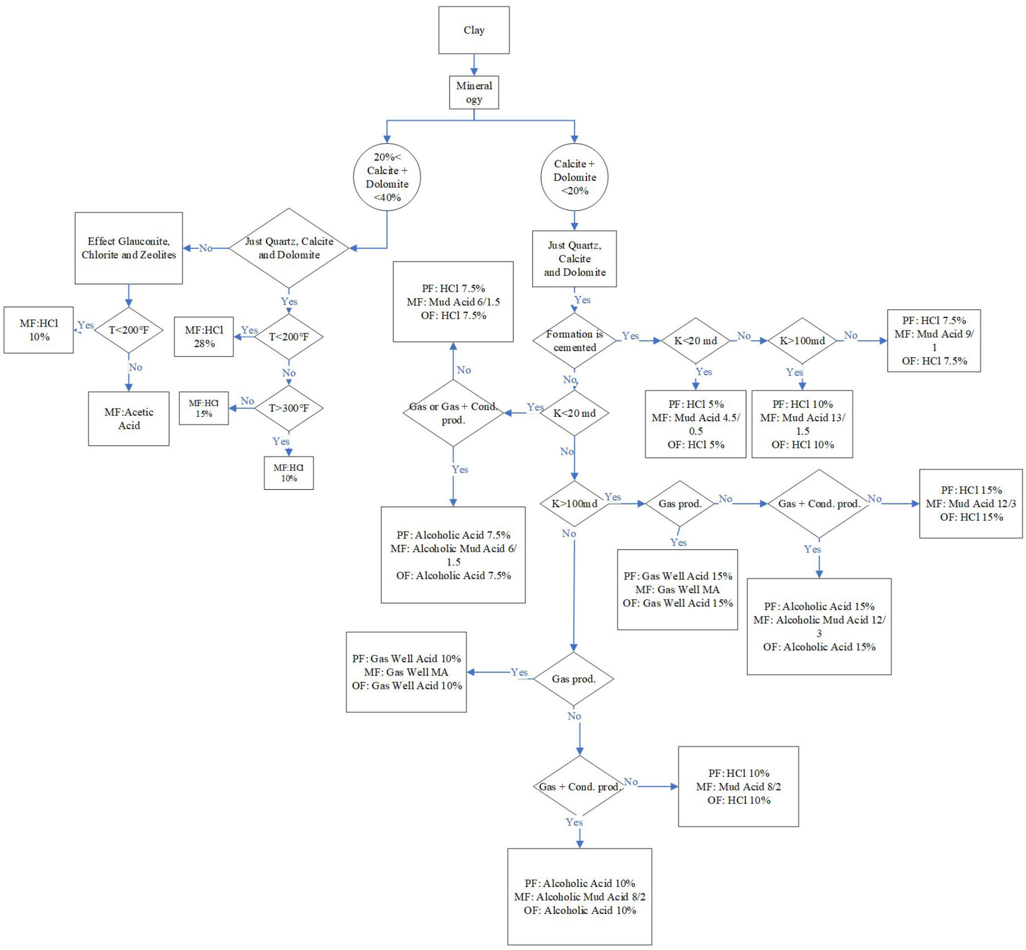

Figure 2. Detection of Main Fluid, Over-flush and Pre-flush in Clay Swelling Damage for Sandstone Reservoir

2.2.1.1. Mineralogy Effect

So long as there are other minerals except quartz, calcite and dolomite in the formation, the acid fluid injection depends on temperature, permeability and produced fluid.

If the amounts of calcite and dolomite is between 20-40% and the formation includes minerals such as glauconite, chlorite and zeolite, the acidizing fluid selection is as follows: if the temperature is lower than 200°F, the main fluid is HCl 10%, while for temperatures higher than 200 °F, main fluid is acetic acid.

In a state where the amounts of calcite and dolomite in the formation is less than 20% and with the presence of minerals such as Illite, kaolinite, smectite and mixed layer exceeds 30%, or minerals like chlorite, glauconite higher than 6.1%, or the presence of zeolite is more than 2.1%, the recommended pre-flush and over-flush fluid is acetic acid and the main fluid is organic fluoboric. If other minerals are in the formation with the percentage of 3-6% of chlorite and glauconite, also mica, K-feldspar and Na-feldspar are greater than 10%, with permeability less than 20 mD, the suggested pre-flush and over-flush are HCl/acetic 5/5 and the main fluid is mud acid/acetic 6/1/5. In formations with permeability greater than 20 mD, the pre-flush and over-flush are the same as in formations with less than 20 mD, but the main fluid is mud acid/acetic 9/1.5/5.

Another state is in addition to quartz, calcite and dolomite, the formation also contains 3-6% of the mineral's chlorite and glauconite. For formation with permeability less than 20 mD, the recommended pre-flush and over-flush are HCl/acetic 7.5/5 and the main fluid is mud acid/acetic 6/1.5/5. When formation permeability is greater than 20 mD, the pre-flush and over-flush are same as permeability in formations with less than 20 mD, but the main fluid is mud acid/acetic 8/2/5. In the next state, when the illite, kaolinite, smectite and mixed layer are between 10-30%, or mica, K-Feldspar and Na-Feldspar are greater than 10%, in formations with permeability less than 20 mD, the recommended pre-flush and over-flush for oil-producing formation is HCl 5% and the main fluid is mud acid 6/1. For gas and gas condensate producing formations, the pre-flush and over-flush are alcoholic acid 5% and the main fluid is alcoholic mud acid 6/1. In formations with permeability between 20-100 mD, for oil-producing formations, the pre-flush and over-flush is HCl 7.5% and the main fluid is mud acid 9/1.5. For gas-producing formations, the pre-flush and over-flush fluid are gas well acid 7.5% and the main fluid is gas well mud acid. If the produced fluid is gas condensate, the pre-flush and over-flush are alcoholic acid 7.5% and the main fluid is alcoholic mud acid 9/1.5.

In the final state, when the impact of zeolite content is greater than 2.1%, the effect of permeability is as follows: For formation with permeability less than 20 mD, the recommended pre-flush and over-flush are HCl/acetic 7.5/5 and the main fluid is mud acid/acetic 6/1.5/5. In formation with permeability between 20-100 mD, the suggested pre-flush and over-flush are HCl/acetic 10/5 and the main fluid is mud acid/acetic 8/2/5. For formations with permeability greater than 100 mD, the pre-flush and over-flush are HCl/acetic 15/5 and the main fluid is mud acid/acetic 12/3/5.

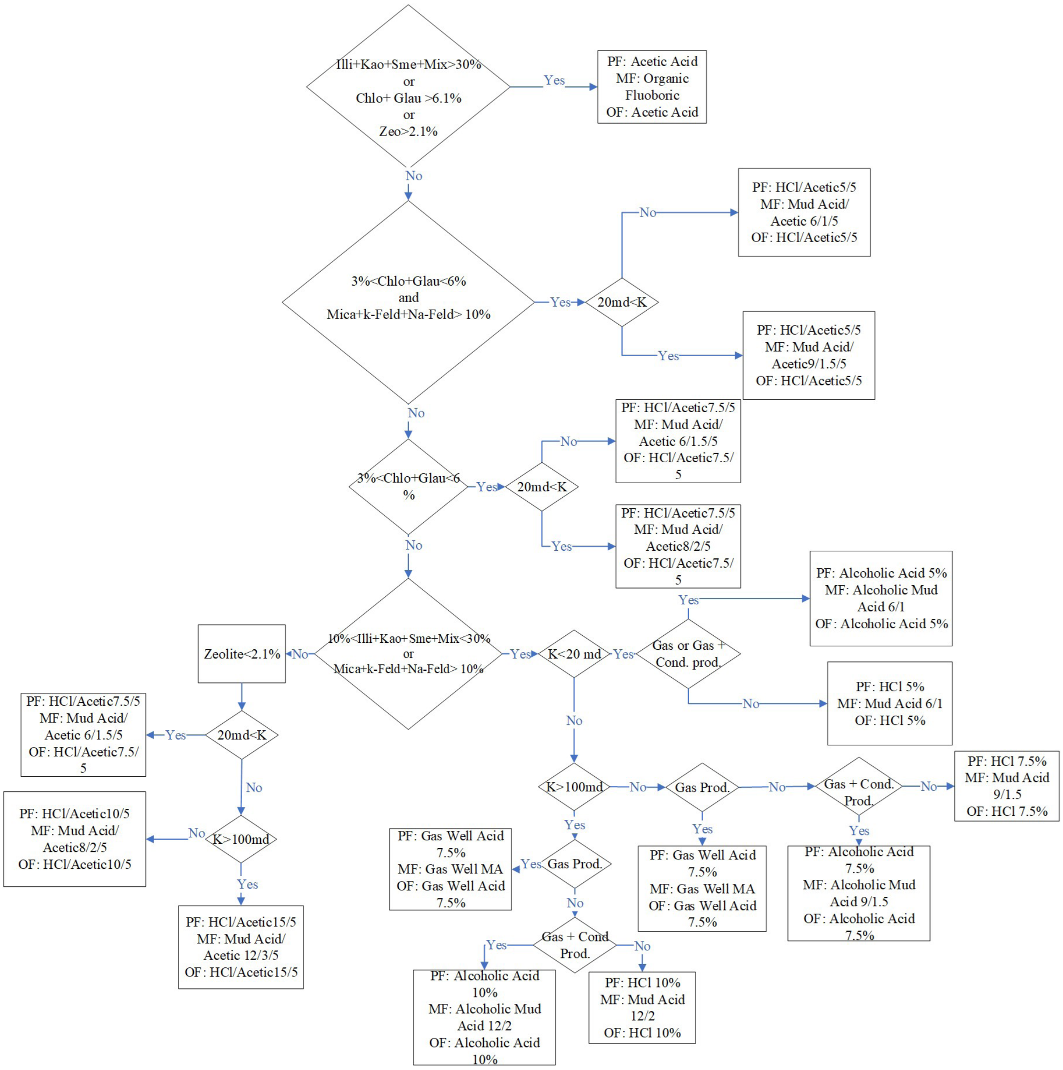

Figure 3. Mineralogy Effect in Acidizing Fluid Selection

2.2.1.2. Cement Effect

The effect of cementation is important, when the dolomite and calcite content is less than 20%. In a state that the formation includes minerals quartz, calcite, dolomite and cement, the recommended fluid is different from the situation in which cement is absent in the formation. The selection of fluid in this case depends on the permeability of the formation. For permeabilities below 20 mD, both pre-flush and over-flush are suggested to be with HCl 5%, accompanied by mud acid 4.5/0.5, as the main fluid. In cases with permeability between 20-100 mD, the recommended fluid for pre-flush and over-flush is HCl 7.5% and the main fluid is mud acid 9/1. Finally, for permeabilities greater than 100 mD, the recommended fluid for both pre-flush and over-flush is HCl 10% and the main fluid is mud acid 13/1.5.

In the formation, if the proportion of minerals such as glauconite and chlorite constituting is less than 6.1%, or zeolite is higher than 2.1%the recommended fluid for pre-flush and over-flush is acetic acid. In formations with permeability below 20 mD, the main fluid is mud acid/acetic 4.5/0.5/10, while for permeabilities higher than 20 mD, mud acid/acetic 9/1/10 is suggested. When the formation contains glauconite and chlorite in the range of 3-6%, the proposed pre-flush and over-flush are HCl/acetic 5/5. For permeability below 20 mD, the main fluid is mud acid/acetic 4.5/0.5/10 and for permeability higher than 20 mD, mud acid/

acetic 9/1/5, is recommended. However, if the zeolite content is less than 2.1%, the choice of fluid is similar to the state where the formation includes glauconite and chlorite in the range of 3-6%, while for permeabilities higher than 100 mD, a different fluid is suggested, with HCl/acetic10/5, for pre-flush and over-flush and mud acid/acetic13.5/1/5, as the main fluid. In the final state, if the formation contains glauconite and chlorite between 3-6%, along with mica, K-Feldspar and Na-Feldspar greater than10%, the injection acidizing fluid is similar to the state when glauconite and chlorite are between 3-6%, but the distinction in recommending mud acid/acetic 5/4.5/0.5, as the main fluid for permeabilities below 20 mD.

For carbonate reservoirs, if the calculated maximum pump rate is greater than zero and the anticipated pump rate is less than the maximum pump rate, then the main fluid can be selected from the available fluids (Nguyen et al. 2021, Novikov et al. 2022).

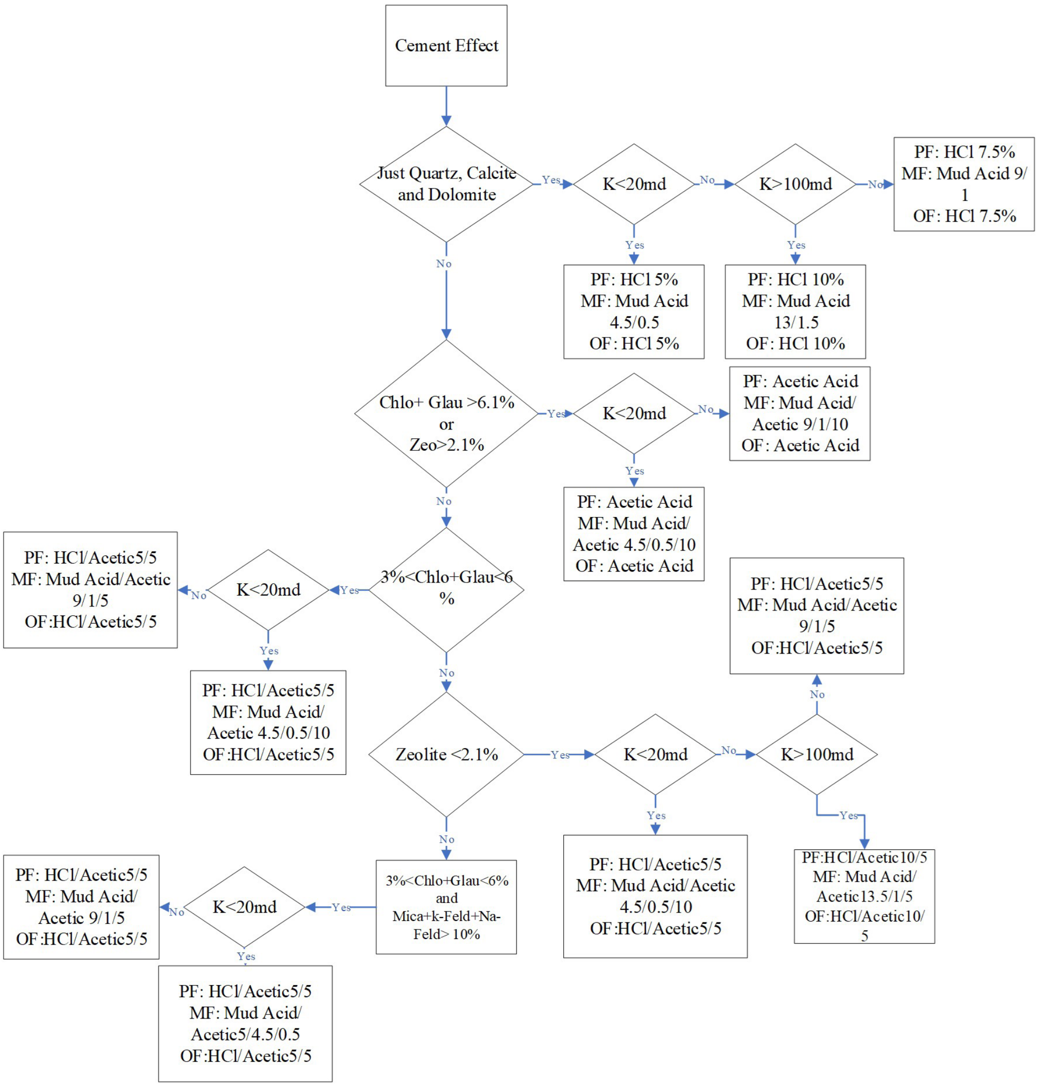

Figure 4. Cement Effect in Acidizing Fluid Selection

2.2.2. Emulsion Blocking

In this damage type, if emulsion blocking occurs without any secondary damage, the recommended fluid to eliminate this damage is a multifunctional solvent. If the emulsion phase is oil outside phase, it is type I and if it is water outside phase, it is type III.

If wettability alteration occurs along with emulsion blocking damage in the formation, priority is given to addressing the wettability alteration damage as a secondary damage. If wettability alteration is the primary damage, the fluid selection is the same Irrespective of whether the secondary damage is emulsion blocking. In the first stage, the well state should be assessed to eliminate this damage. If the well is newly completed or suspected, the recommended main fluid is the multifunctional solvent. For another well state, if drilling mud is water base, the recommended main fluid is the multifunctional solvent and for oil-based drilling mud, the recommended main fluid is the oil mud removal system.

If solids-completion, workover, stim. fluids damage occurs as a secondary damage along with emulsion blocking damage in the formation, to address these damages, in addition to the fluids mentioned in the clay swelling damage section, a multifunctional solvent pre-flush should be used.

Another secondary damage types that can occur along with emulsion blocking damage is solids - mud (not filter cake) damage. In the case of using oil-based drilling mud, to address this damage along with emulsion blocking damage, a multifunctional solvent pre-flush and an oil mud removal system main fluid should be used. If water-based drilling mud is used and the mud loss is more than 5 gal/ft and the formation consists of calcite and dolomite is between 20-40%, the recommended pre-flush and main fluids are multifunctional solvents and mud dispersant system, respectively. If the formation contains less than 20% of dolomite and calcite, the recommended fluids are similar to when dealing with clay swelling damage, with the difference that the suggested main fluid is mud dispersant. If the water-based mud with mud loss less than 5 gal/ft, is used, the recommended fluids are similar to address clay swelling damage, with the difference that the suggested main fluid is a multifunctional solvent.

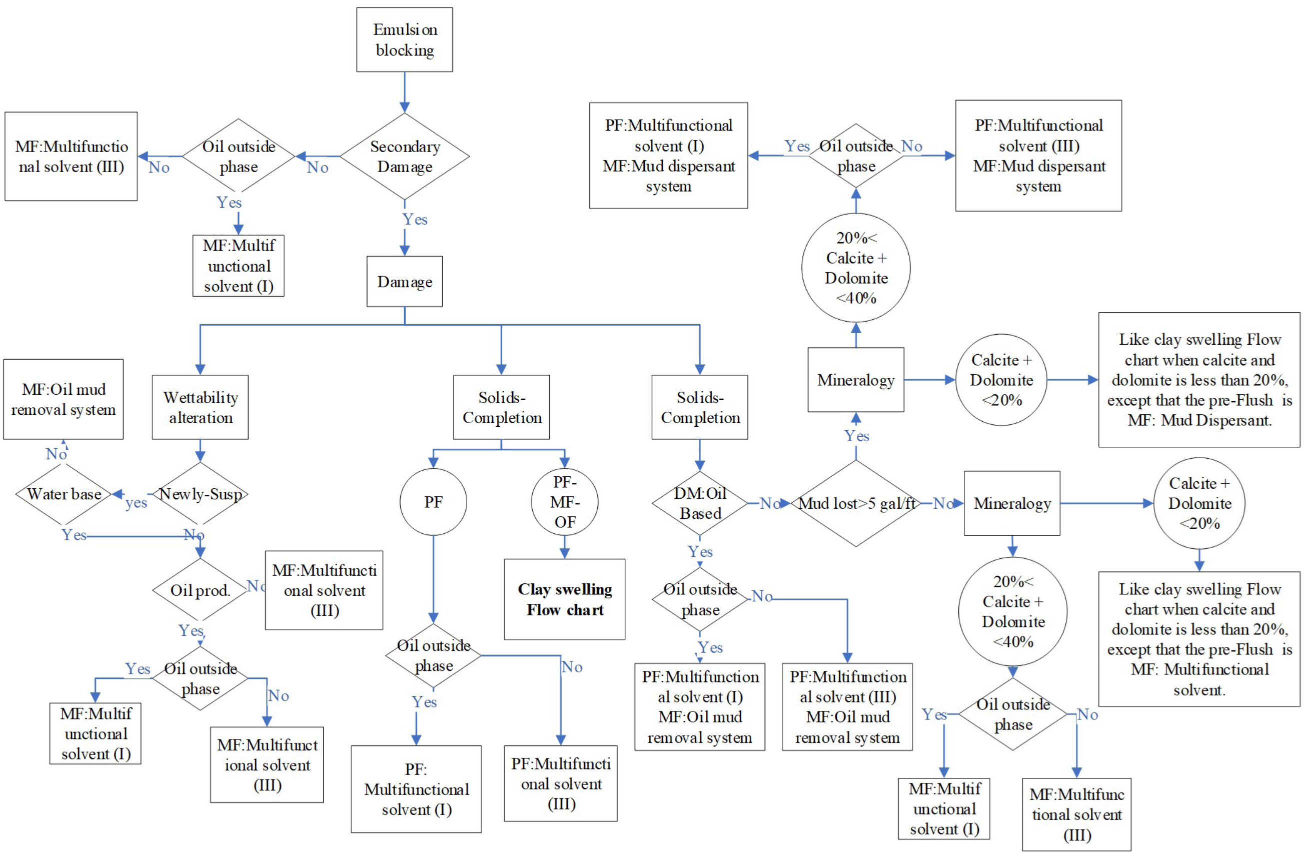

Figure 5. Detection of Main, Over Flush and Pre Flush Fluid In Emulsion Blocking Damage

2.2.3. Other Damage Types

with regard to (Figure 6), if damage other than clay swelling has occurred in the formation or well, the fluid selection is carried out as follows:

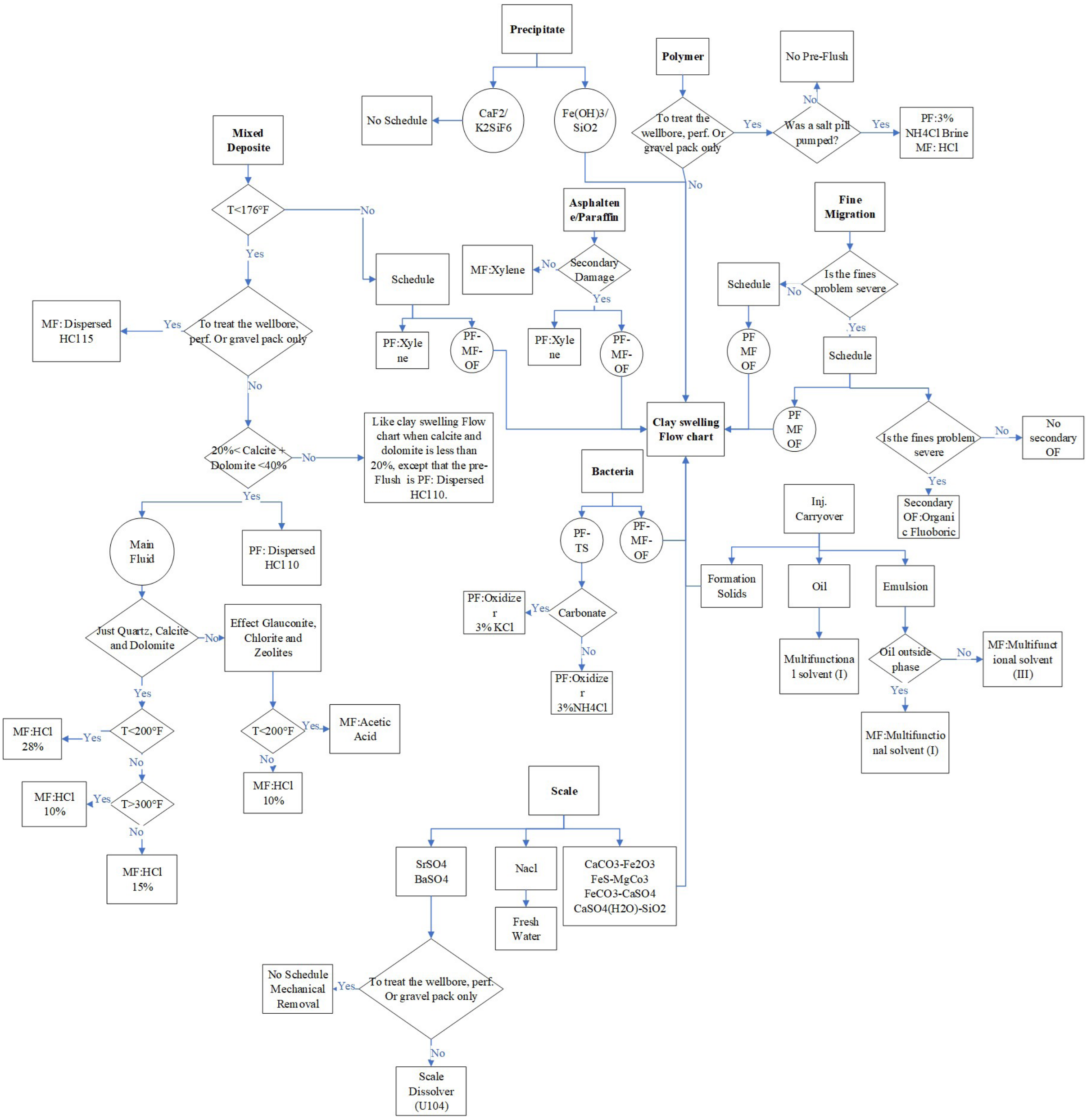

Figure 6. Detection of Main, Over Flush and Pre Flush Fluid in another Damage Types

2.2.3.1. Fine Migration

The selection of fluid for eliminating fine migration damage, such as clay swelling damage, is recommended in the previous section. However, if the fine problem is severe, it is recommended to use a secondary over-flush such as organic fluoboric to eliminate this damage completely. Fines migration is not typically observed in carbonate formation.

2.2.3.2. Polymer

If the reservoir is affected by polymer damage and the target of acidizing fluid injection is to treat the wellbore, perforation, or gravel pack, in addition to the fluids recommended for clay swelling damage recommended a pre-flush fluid of 3% NH_4Cl for sandstone reservoir and 2% KCl for carbonate reservoir are recommended. However, if the purpose of acid fluid injection is to treat the matrix, the selected fluid, as recommended for clay swelling damage, should be used.

2.2.3.3. Mixed Deposition

If the reservoir suffers from mixed deposition damage, to eliminate this damage if the formation temperature is higher than 176 °F, a pre-flush fluid of xylene is recommended in addition to the fluids mentioned for clay swelling damage. However, if the temperature is lower than 176 °F and the target of injection is to treat the wellbore, perforation and gravel pack only, the recommended pre-flush is dispersed HCl 15%, while if the target of injection is to treat the matrix, an acidizing fluid injection similar to clay swelling damage is recommended, with the difference that the pre-flush in this case is dispersed HCl 10%.

2.2.3.4. Scale and Precipitate Damage

If scale damage is $BrSO_4$ or $SrSO_4$ and the aim is to treat the wellbore, perforation, or gravel pack only, an injection schedule is not recommended. However, if the injection objective is to treat the matrix, the only recommended fluid is the main fluid scale dissolver (U104). If the scale damage is because of the NaCl, using fresh water can potentially eliminate this damage. If the scale damage is other than the states mentioned, the recommended fluids in the clay swelling damage section can be used.

The selection of fluid for eliminating precipitate damage, if caused by CaF_2 or K_2SiF_6, does not recommend any injection fluid. However, if the damage is because of the $Fe(OH)_3$ or SiO_2 the recommended fluid for addressing the damage is similar to the one suggested for clay swelling damage.

2.2.3.5. Bacteria

In oil and gas wells, bacteria can enter through the water or chemicals injected into the well. These bacteria can thrive in the well environment and on the equipment. Some of these bacteria can cause damage to the well, such as producing acid or forming deposits. Therefore, bacterial damage in oil and gas wells occurs when bacteria infiltrate the well and their activities, which leads to various problems and damage to the well structure. However, for removing the bacteria damage, the recommended fluid for pre-flush, over-flush and main fluid is similar to the fluids used for clay swelling damage. However, to eliminate this damage completely, other fluids such as oxidizer for pre-flush and tubing spacer including 3% KCl for carbonate and 3% NH_4Cl for sandstone are also recommendedi

2.2.3.6. Asphaltene/Paraffin

If asphaltene or paraffin damage occurs alone, xylene is injected into the reservoir as the main fluid to address this damage. However, if asphaltene or paraffin damage occurs along with other damage, xylene is used as the pre-flush fluid along with other selected fluids, similar to the clay swelling damage and injected into the reservoir.

2.2.3.7. Injection Carryover

If the injection carryover damage is of the emulsion type, the selection of an acidizing fluid is similar to the case where emulsion blocking damage has occurred alone. Specifically, if the emulsion phase is oil outside phase the main fluid is multifunctional solvent I and if the emulsion phase is water outside phase, the main fluid is multifunctional solvent III. However, if the damage is of the oil type, it can only be eliminated with the main fluid multifunctional solvent I. The injection carryover-formation solids damage is different from the previous two cases. In this case, the selection of the fluid is similar to the clay swelling damage.

2.2.3.8. Water Blocking

Water blocking damage is different from other damages. for mitigating this damage in any conditions, only the main fluid Multifunctional solvent III can be used.

3. Results and Discussion

An expert system criterion for selecting acidizing fluid and eliminating reservoir damage was randomly applied to eight damages that may occur in the formation. Among these eight damages, five damages are related to sandstone reservoirs and three damages in carbonate reservoirs have been identified. Damages related to sandstone formations include three damages associated with calcite and dolomite less than 20% and two damages associated with calcite and dolomite between 20-40%. As can be seen in (Table 1), for selecting acidizing fluid to eliminate the specified damages in sandstone formations, actions have been taken based on parameters such as treatment objective, treatment interval, permeability, temperature, well type, water cut, nitrogen, emulsion phase and fines problem. When bacteria damage occurs in the sandstone formation, if the treatment interval is greater than 20 ft, a diverter should be injected. Here, due to the use of nitrogen, the diverter is foam. In addition to the main fluid, a secondary pre-flush and tubing spacer should also be injected in the case of bacterial damage occurrence. When emulsion blocking occurs as the primary damage and solid-mud as secondary damage in the sandstone formation composed of cement, if the loss of water-based drilling mud is higher than five and the well type is gas-injected and nitrogen is used, the injection fluids to remedy these damages include initial pre-flush, secondary pre-flush, main fluid, over-flush and diverters. In this situation, the emulsion phase parameter also affects the initial pre-flush. The next examined sample is mixed deposition damage that occurs in the sandstone formation when the amount of calcite and dolomite is less than 20% and minerals such as smectite, illite and glauconite present in the formation. To treat the wellbore, with a permeability of 45 mD and a formation temperature of 120°F, the injection fluids are in order, the main fluid and the diverter. The next examined damage is swelling damage accompanied by paraffin, which occurs in the sandstone formation. In this case, due to a treatment interval of less than 20 ft, a diverting agent will not be used. Therefore, considering the permeability and temperature of the formation, pre-flush fluid and main injection fluid are used. The last case for investigation is fine migration damage along with asphaltene damage, which occurs during gas production in the formation. To remedy these damages, pre-flush, main fluid, diverter and over-flush are used and xylene is used in this case to eliminate asphaltene damage, while over-flush injection is performed due to fine problem. In the carbonate formation, considering the entered parameters and the calculated maximum pump rate, If the maximum pump rate is suitable, it can determine the injected fluid in the formation. The damages of polymer, bacteria, clay swelling and paraffin that have occurred in the carbonate formation have been examined. The influential parameters on the selected fluid are reservoir information, treatment interval, pump rate and treatment fluid. The injection schedule is presented in (Table 2). In the case of clay swelling and paraffin damage occurrences, the maximum pump rate is less than zero. Therefore, a fluid for injection is not recommended. Based on the compiled information in the (Tables 1) and (Tables 2), it has been confirmed by the expert system that the damage is removed in the formation.

Table 1. Results of Expert System for Sandstone Formation

Primary Damage	Bacteria	Emulsion Blocking	Mixed Deposition	Clay Swelling	Fine Migration
Secondary Damage	None	Solid-mud	None	Paraffin	Asphaltene
Well State	-	-	-	-	-
Drilling Mud	-	Water Base Mud Lost > 5gal/ft	-	-	-
Mineralogy	Quartz: 83% Calcite: 7% Dolomite: 6% Glauconite: 4% No Cement	Quartz: 67% Calcite: 4% Dolomite: 5% k-Feldspar: 12% Kaolinite: 12% Cement	Quartz: 72% Calcite: 4% Dolomite: 5% Smectite: 6% Illite: 6% Glauconite: 2%	Quartz: 67% Calcite: 16% Dolomite: 15% Zeolites: 2% No Cement	Quartz: 72% Calcite: 12% Dolomite: 14% Glauconite: 2% No Cement
Treatment Objective	-	-	To Treat the Well-bore, Perforation, ...	-	-
Treatment Interval	20 ft	20 ft	20 ft	19 ft	20 ft
Permeability	75 md	105 md	45 md	15 md	7 md
Temperature	250 degF	190 degF	120 degF	170 degF	220 degF
Well Type	Oil Producing	Gas Injection	-	-	Gas Production
Is Higher Water Cut Acceptable?	Yes	Yes	-	-	No
Nitrogen	Yes	Yes	-	-	-
Emulsion Phase	-	Oil Out Phase	-	-	
Fines Problem	-	-	-	-	Yes
Schedule	PF: Oxidizer System TS:3%NH4Cl Brine PF: HCl/Acetic7.5/5 MF: Mud Acid/Acetic8/2/5 OF: HCl/Acetic7.5/5 FO: Foam Diverter	PF: Multifunctional Solvent PF: HCl 10% MF: Mud Dispersant OF: HCl 10% FO: Foam Diverter	MF: Dispersed HCl 15 FO: Xylene Foam Diverter	PF: Xylene MF: HCl 10%	PF: Xylene MF: Acetic Acid FO: Foam Diverter OF: Fluoboric Acid System

Table 2. Result of Expert System for Carbonate Formation

Primary Damage	Polymer	Bacteria	Clay Swelling
Secondary Damage	-	-	Paraffin
Mineralogy	Quartz: 55% Calcite: 45%	Quartz: 48% Calcite: 52%	Quartz: 50% Calcite: 50%
Reservoir Information	Permeability = 50md TVD = 1000ft Pressure = 500psi Temperature = 250degF Porosity = 30% Wellbore Radius = 3in Fracture Gradient = 0.7Psi/ft	Permeability =200md TVD =1500ft Pressure =200psi Temperature =160degF Porosity= 50% Wellbore Radius = 3in Fracture Gradient = 1Psi/ft	Permeability = 20md TVD = 1500ft Pressure = 1500psi Temperature = 200degF Porosity = 7% Wellbore Radius = 3in Fracture Gradient = 0.9Psi/ft
Treatment Interval	20 ft	20 ft	20 ft
Anticipated Pump Rate Maximum Pump Rate	0.1bbl/min 0.4bbl/min	5bbl/min 7.7bbl/min	- -0.2bbl/min
Treatment Fluid Dissolution	HFc Face Dissolution	HAc Wormhole	- -
Schedule	PF: 2%KCl MF: Formic Acid SD: Temporary Xlink Acid Diverter	PF: Oxidizer System TS: 3%KCl MF: Acetic Acid FO: Foam Diverter	Maximum pump rate must be higher than zero and anticipated pump rate must be less than maximum pump rate.

4. Conclusion

Determining the appropriate fluid to eliminate existing damages in a formation is a challenging process. This complexity persists when multiple damages are identified in the formation and the task involves selecting the best fluid for mitigating formation damages. Identifying the fluid for damage remediation requires a complete understanding of the formation and the damages occurring within it. In this study, our aim was to establish an expert system capable of fluid selection for damage remediation and well improvement. The results obtained in fluid selection for eliminate formation damages have been promising. Furthermore, in future research, our objective is to enhance these investigations by developing a fuzzy logic-based system for more precise fluid selection.

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استفاده از تجزیه و تحلیل جامع سیستم‌های خبره برای بهبود انتخاب سیال اسیدکاری در تولید نفت

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چکیـــــده

اسیدکاری چاه نقش مهمی در بهبود بازیابی نفت از طریق کاهش آسیب‌های مخزن ایفا می‌کند. با این حال، پیچیدگی انتخاب مناسب‌ترین سیال اسیدکاری، با توجه به شرایط مختلف مخزن، چالش قابل توجهی را ایجاد می‌کند. این مقاله بررسی می‌کند که چگونه استفاده از سیستم‌های خبره در بهبود فرآیند انتخاب سیال اسیدکاری موثر است. با مرور اثر، اجزا و مزایای سیستم‌های خبره، همراه با مطالعات موردی، مقاله نشان می‌دهد که چگونه این سیستم به تصمیم‌گیری موثرتر و اطلاعاتی بیشتر کمک می‌کند. در این بررسی، هشت نمونه از آسیب‌ها برای تجزیه و تحلیل با استفاده از سیستم خبره انتخاب شده است. پس از ارزیابی دقیق، یک سیال برای از بین بردن آسیب انتخاب شده است که کارایی سیستم خبره را نشان می‌دهد. ترکیب سیستم‌های خبره در مدل‌سازی و استنتاج تحت شرایط عدم قطعیت و دقت بالا، نقش اساسی در افزایش بهره‌وری، کاهش خطاها، پیش‌بینی رویدادها و اصلاح فرآیندهای تصمیم‌گیری دارد. این سیستم‌ها از الگوریتم‌ها و مدل‌های ریاضی پیشرفته برای مدل‌سازی و پیش‌بینی رویدادها در انواع مختلف برنامه‌ها استفاده می‌کنند، که باعث کمک به تصمیم‌گیری بهینه و سریع می‌شود.

واژگان کلیدی: اسیدکاری خمیره، انتخاب سیال اسیدکاری، آسیب سازند، سیستم‌های خبره، بهبود تولید نفت