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Assessing Risks and Uncertainties in Chemical EOR along with Identifying Handling Options

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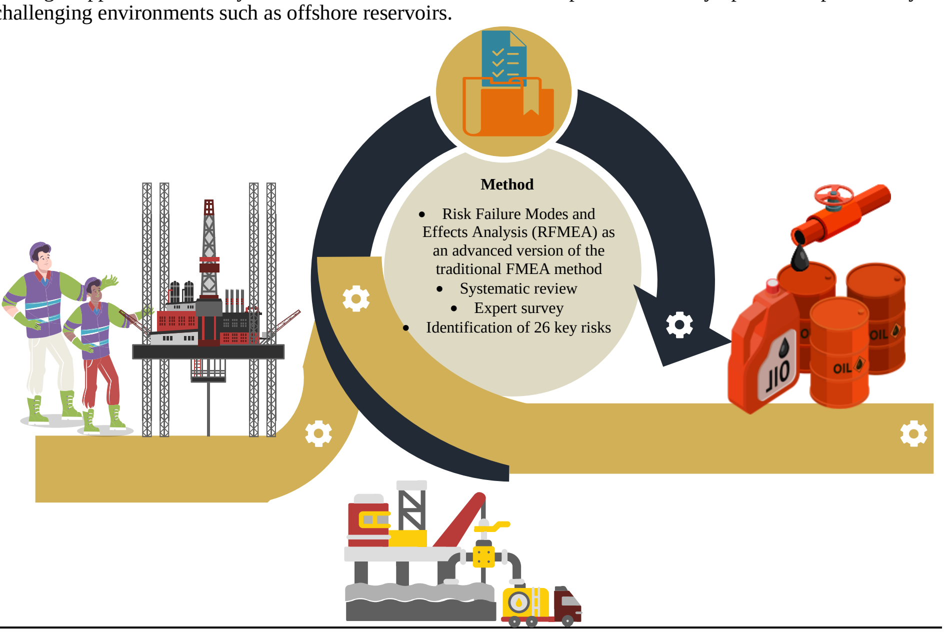
A B S T R A C T

Chemical Enhanced Oil Recovery (CEOR) is a complex, multi-phase technique that enhances hydrocarbon recovery by injecting chemicals such as polymers, surfactants, and alkalis into reservoirs. Despite its potential, CEOR faces significant technical, economic, and operational risks, especially during early project development. Effective risk management is essential to ensure success, and pilot testing plays a key role in validating reservoir response and chemical performance before full-scale deployment. This study applies the Risk Failure Modes and Effects Analysis (RFMEA), an advanced version of traditional FMEA, to systematically identify, assess, and prioritize CEOR project risks. Through a comprehensive literature review and expert surveys, 26 key risks were identified and classified into four categories: general CEOR risks, offshore-specific risks, polymer flooding risks, and risks related to chemical combinations. The analysis revealed that permeability reduction, high salinity in offshore settings, reservoir heterogeneities, polymer and chemical adsorption, and polymer yield are the most critical factors affecting CEOR efficiency. These risks can impair fluid mobility, reduce chemical effectiveness, and increase project costs. RFMEA enables a structured evaluation of these risks, helping decision-makers prioritize mitigation actions, optimize chemical formulations, and improve project outcomes. The study emphasizes the importance of integrating RFMEA into the early planning phase of CEOR projects to reduce uncertainties, enhance reliability, and maximize recovery efficiency. By proactively addressing risks, operators can increase the likelihood of successful CEOR implementation and achieve better economic returns. The findings support the use of systematic risk assessment tools in complex oil recovery operations, particularly in challenging environments such as offshore reservoirs.



1. Introduction

Enhanced Oil Recovery (EOR) has a potential to increase the recovery efficiency for most hydrocarbon fields. The average oil recovery rate for most hydrocarbon reservoirs is 33%. This shows that there is a large potential for EOR technologies [1]. Currently, the petroleum sector extensively employs diverse enhanced recovery strategies—such as water and gas injection—to maximize hydrocarbon output. Although water flooding stands as the primary technique for sustaining reservoir pressure and boosting production rates, it is typically limited to recovering between 10% and 40% of the original oil in place. Consequently, the unrecovered oil is categorized into two distinct types: oil that remains trapped after the water flooding process and oil that has been bypassed. To observers from other engineering disciplines, this low recovery factor may appear astonishing. It is difficult to comprehend that only one-third of such a precious, non-renewable resource can be extracted, while the remaining two-thirds of the geological reserve is often permanently lost. Nevertheless, for petroleum engineers, this outcome is expected due to the following restricting constraints [2]:

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• Reservoirs exhibit heterogeneity; specifically, the volumetric sweep efficiency (encompassing both horizontal and vertical dimensions) is inadequate.
• The natural oil/water/gas/rock systems possess unfavorable surface, interfacial, and capillary characteristics; that is, the microscopic displacement efficiency within the reservoirs is low.
CEOR refers to the process of enhanced oil recovery technology in which chemical solution is injected into the reservoir in order to increase sweep and/or displacement efficiency. Polymer flooding involves injecting polymer solution to decrease water mobility resulting in improved sweep efficiency. Surfactant flooding involves injecting surface-active agents (surfactants) that achieve low Interfacial Tension (IFT) with the displaced oil. The injected chemicals solubilize the displaced oil to form an oil bank that is displaced ahead of the slug. The chemical slug also has a low IFT with formation water. Polymers are usually added to surfactants for mobility control, hence the name Surfactant-Polymer (SP) flood or Micellar-Polymer flood. SP floods have advantage over other EOR methods because of its dual advantage of increasing both microscopic displacement efficiency and volumetric sweep efficiency. Microscopic displacement efficiency is increased as the oil is mobilized by the surfactant and the added polymer increases volumetric sweep efficiency. Chemical floods have been shown to have a huge potential of increasing recovery efficiency in mature water-floods with high residual oil saturation [3].
The main objectives of this thesis are:
1.Reducing damage caused by non-consideration of uncertainties and consequently the risk posed by the implementation of the CEOR operation and the models used.
2.Increasing the efficiency of CEOR in oilfields.
The Research assumptions
This research is done based on the following assumptions:
1.Static model and characteristics data are available
2.The data used in the project are reliable
3.We will focus only on technical risks, which will be considered threats (negative risks).
4.The characteristics of the CEOR projects are considered the same for Iran.
Research Inquiries
The present study aims to address the two subsequent questions:
1.What are the technical risks and uncertainties in CEOR and what are their priorities?
2. Which technical risks and uncertainties are associated with CEOR, and how are they ranked in terms of priority
Chemical flooding is a term that is used to describe the addition of chemicals to the water. In conjunction with water injection strategies, Chemical Enhanced Oil Recovery (CEOR) is implemented to facilitate and boost oil production. While CEOR initiatives saw peak popularity during the 1980s, their implementation declined in the following decade as oil prices dropped. However, there has been a recent exponential surge in the number of projects, driven by rising oil prices, advancements in program design, and falling chemical costs. Sandstone reservoirs are generally the preferred choice for CEOR applications because they offer higher permeability compared to limestone formations. Conventional primary depletion and secondary water-flooding methods typically extract only 20–50% of the original oil in place, meaning the bulk of the resource remains trapped after these standard operations. The limited recovery rates observed in secondary water-floods stem from poor macroscopic sweep efficiency due to insufficient mobility control, as well as low microscopic displacement efficiency resulting from capillary trapping of oil primarily caused by interfacial forces. By addressing these limiting barriers, CEOR methods are now recognized as viable tertiary techniques for enhancing recovery from mature oil reservoirs [3]. Field implementation of chemical flooding was a viable option until the mid-1980s, a period when crude oil values hovered near USD 30 per barrel. Nevertheless, a drastic drop in oil market values during that era led to a deceleration in CEOR field operations and the associated rise in output. In recent years, however, the combination of consistently high oil prices, rapidly decreasing production rates, and elevated water cuts—especially in offshore environments has revitalized the focus on CEOR. This renewed interest stems from the fact that the additional expenses for chemicals and equipment can now frequently be offset by the revenue generated from the more valuable incremental oil.Furthermore, CEOR processes also have a smaller CO_2 footprint because of their lower associated energy requirements when compared with other common EOR methods such as miscible gas and thermal EOR. Most fields experiencing reduced production during water-flooding are candidates for some version of CEOR [4]. Surfactant-Polymer (SP) and Alkali-Surfactant-Polymer (ASP) processes, collectively categorized under Chemical Enhanced Oil Recovery (CEOR), typically involve the injection of various chemical components such as surfactants, co-surfactants, Alkali-Co-solvent-Polymer (ACP) blends, and electrolytes. The primary function of surfactants and co-surfactants is to lower the interfacial tension (IFT) between oil and water; this reduction decreases residual oil saturation, thereby converting trapped oil into mobile oil. Meanwhile, alkalis serve to produce surfactants directly within the reservoir and minimize surfactant loss through adsorption onto rock surfaces. Polymers contribute by enhancing mobility control, which ultimately leads to improved sweep and recovery efficiency [4]. A number of researchers, including Taber and co-workers (1997a, 1997b), Al-Bahar et al. (2004), and Dickson et al. (2010), have focused on developing and evaluating screening criteria for large-scale enhanced oil recovery (EOR) techniques. This section briefly summarizes the main parameters that determine the feasibility of applying chemical enhanced oil recovery (CEOR) methods [5]. While CEOR performance can be affected by a wide range of factors, reservoir temperature, salinity of the formation water, concentration of divalent ions, clay mineral content, and crude oil viscosity are commonly identified as the most critical parameters. The initial stage involves evaluating potential reservoirs by examining their geometric characteristics along with fluid and rock properties against predefined screening requirements. Once a candidate reservoir satisfies these criteria, more detailed analyses such as numerical simulation, laboratory experimentation, and comprehensive reservoir characterization—are undertaken. These activities ultimately lead to an integrated techno-economic assessment. The subsequent step focuses on defining objectives and designing a pilot project. Following a successful pilot evaluation, an economically viable development plan is formulated and optimized, incorporating field-scale simulation and an operational framework that addresses implementation, monitoring, and production performance [6]. Project Risk Management (PRM) encompasses a set of systematic activities, including risk management planning, risk identification, qualitative and quantitative risk assessment, development of response strategies, and ongoing risk monitoring and control throughout a project. The primary aim of PRM is to enhance the probability and potential benefits of favorable events while simultaneously reducing both the chance and adverse consequences of unfavorable events within the project environment [7]. Risks that are anticipated can be addressed proactively and may therefore be covered through the allocation of management reserves, whereas an adverse risk that has already materialized is classified as a project issue [8]. The risk management framework is composed of four main components: risk identification, risk analysis, response development, and risk control. Although these stages are typically defined in a logical sequence, risk management activities are carried out in a continuous, parallel, and iterative manner throughout the entire project life cycle. The process of planning risk responses focuses on formulating strategies and measures that increase the likelihood of achieving project opportunities while mitigating potential threats to project objectives. A major advantage of this process is that it prioritizes risks and ensures that appropriate actions and resources are incorporated into the project budget, schedule, and overall management plan when necessary [9]. Risk control involves executing the planned response actions, monitoring previously identified and residual risks, detecting emerging risks, and assessing the overall effectiveness of risk management practices during the project. This process enhances the overall efficiency of risk handling by continuously refining and optimizing response strategies across the project life cycle [9]. Risk control activities may include selecting alternative approaches, activating contingency or fallback plans, implementing corrective measures, and revising elements of the project management plan. In this phase, the designated risk owner regularly communicates with the project manager regarding the performance of the response strategy, unexpected outcomes, and any required adjustments. Additionally, this process contributes to organizational learning by updating process assets such as risk management templates and lessons-learned repositories, thereby supporting improved risk management in future projects [9]. Effective project execution relies heavily on the systematic identification and mitigation of potential risks. In this context, the referenced study introduces an adapted version of the Failure Modes and Effects Analysis (FMEA) framework for the purpose of evaluating and quantifying project-related risks [10]. This adapted methodology, referred to as Risk Failure Mode and Effects Analysis for projects (RFMEA), represents an evolution of the conventional FMEA approach traditionally applied to processes, products, and services. To ensure compatibility with project-based applications, the standard detection parameter in FMEA is adjusted to better reflect the characteristics of the project environment. The applicability of the proposed RFMEA methodology is demonstrated through a practical case study within the electronics sector. Incorporating the detection factor into the risk assessment framework provides project teams with an additional dimension for risk evaluation beyond the conventional risk ranking score [10]. As a result, RFMEA enhances attention to high-priority and near-term risks, supports more effective prioritization of contingency measures, encourages stronger team involvement in risk management activities, and contributes to the design of more robust risk control mechanisms [10]. In traditional FMEA applications used for process, design, and service planning, risk evaluation is commonly performed by calculating the product of three parameters: the probability of occurrence, the severity of the potential impact, and the likelihood of detection [11]. In recent years, a significant challenge within the field of system dependability has been the modeling of systems whose complexity is continuously increasing. This challenge highlights critical issues related to parameter estimation as well as the representation, propagation, and quantification of uncertainties affecting system behavior [12]. Earlier approaches to system reliability and risk assessment often relied on simplifying assumptions, one of which was limiting the analysis to purely technical components. Such an assumption has become inadequate, as the influence of organizational structures and human factors on system performance and risk has been widely recognized [13]. Bayesian Networks (BNs) provide a graphical probabilistic modeling framework capable of capturing the dependencies among numerous random variables and supporting probabilistic inference across them [13]. Owing to their ability to decompose the joint probability distribution into conditional relationships, BNs are particularly well suited for representing complex systems. The primary purpose of a BN is to infer probability distributions of selected variables based on observed evidence and prior information about other variables. The theoretical foundations and formal principles of this modeling approach are comprehensively described in the works of Jensen and Pearl [13]. A Bayesian Network (BN) is a probabilistic modeling framework structured as a directed acyclic graph (DAG), where system variables are represented by nodes and the directed links indicate dependency or causal relationships among these variables. Each node is

associated with a set of possible states, for which probabilities are assigned. For root nodes, these probabilities are specified in advance, while for other nodes they are derived through probabilistic inference based on their parent nodes [14]. Since the early 2000s, Bayesian Networks have been increasingly applied to the assessment of risk-related scenarios. Their capability to explicitly capture probabilistic dependencies between events makes them particularly valuable for risk analysis applications [15]. Moreover, BNs are extensively employed in quantitative risk assessment because they support both forward (predictive) and backward (diagnostic) reasoning. A Bayesian Network integrates both qualitative structures and quantitative probability information within a unified model [16]. In BN, probability inference of an event is conditional on the observed evidence‖. BN tools and algorithms can implement forward or backward linear prediction analysis as well as diagnosis analysis. Considering the conditional dependencies of variables, BN represents the joint probability distribution P
(U) of variables U = {A1…An} [17]; as
P (U) = ∏))
In a Bayesian Network, Pa (Ai) denotes the collection of parent nodes associated with node Ai whereas P (U) represents the overall probabilistic characteristics of the network. Within diagnostic reasoning, Bayesian Networks employ Bayes' theorem to revise prior probabilities of occurrence or failure by incorporating newly observed information from a set of variables referred to as evidence E. The resulting posterior probability distribution for a given variable can be obtained through various inference techniques, including junction tree methods and variable elimination algorithms, all of which are grounded in Bayes' rule [18].

$$(U \mid E) = \frac{)}{)} \qquad \frac{)}{\Sigma \qquad)}$$

Treating oil–water emulsions generated during polymer flooding presents considerable challenges in offshore applications [19]. The elevated viscosity of the continuous phase, together with the fine size of dispersed droplets and solid particles, significantly reduces their settling or rising velocities, thereby necessitating longer retention times in gravity-based separation units. This issue becomes more pronounced for water-in-oil emulsions associated with heavy crude oils, where operational constraints on separation temperature—often imposed by cloud-point limitations—further hinder phase separation. Under such conditions, increased viscosity of the continuous phase and a reduced density contrast between oil and water phases lead to even longer separation times. In offshore polymer flooding projects, the substantial space and weight demands of large gravity separators can therefore render their implementation impractical [19]. To achieve low residual oil concentrations in produced water (for example, below 5 ppm), conventional filtration systems such as dual-media or nutshell filters are commonly applied. Nevertheless, the presence of polymers may negatively influence filter performance. In addition, these filtration technologies are associated with high maintenance requirements, significant operating expenditures (OPEX), and considerable footprint and weight, which collectively limit their suitability for offshore installations [20]. Offshore CEOR (polymer and ASP) faces subsurface challenges such as deep-water conditions, high temperature, pressure, and salinity, which limit the use of conventional onshore chemicals. This necessitates advanced R&D to develop salt- and temperature-stable chemistries. Improved sweep efficiency and low well density require tailored well patterns and smart-well technology. A recent study highlights early polymer breakthrough in an offshore polymer flood, causing fluid treatment issues, and the need for injection profile control to manage surface separation problems. The Angsi oil field is situated in the South China Sea at a distance of approximately 170 km from the eastern coastline of Peninsular Malaysia. It represents Malaysia's largest integrated offshore oil and gas development, comprising four drilling platforms supported by a central processing facility. The Angsi production complex includes the ANPG-A central processing platform and the ANDR-A drilling and riser platform, which are interconnected by a bridge. In addition, the complex serves as the processing hub for several satellite installations, namely ANDP-B, ANDP-C, and ANDP-E [21]. The planned CEOR implementation at Angsi is notable as it will constitute the world's first offshore application of full-field alkali–surfactant (AS) injection [21]. Angsi is also expected to become the first offshore field globally to deploy full-field AS chemical flooding, in which chemically treated injection water will be supplied from an onshore facility. This onshore plant, located approximately 170 km from the offshore platform in Peninsular Malaysia, integrates seawater treatment, chemical preparation, and power generation systems [22]. As part of a broader strategy to enhance ultimate oil recovery and prolong field production life, PETRONAS has led multiple enhanced oil recovery (EOR) initiatives across Malaysia. Among the evaluated EOR techniques, chemical EOR (CEOR) has been recognized as a particularly promising option for improving recovery factors in Malaysian reservoirs [23]. Conducting the pilot test on a normally unmanned satellite platform with limited onboard facilities introduced additional complexity and risk, necessitating careful consideration during the project planning stage. Consequently, the main emphasis at this phase was placed on thorough evaluation of pilot execution to ensure full compliance with Health, Safety, and Environment (HSE) requirements and to minimize operational risks during implementation. To support this objective, a comprehensive set of tailored procedures and guidelines was developed to facilitate the effective execution of the pilot program [24]. A multidisciplinary project team was assembled to design and carry out Malaysia's first CEOR pilot project. One of the team's initial responsibilities involved selecting suitable technical partners capable of providing specialized technical and operational support. Particular importance was given to engaging partners with demonstrated experience in SWCT applications. By involving these technical partners early in the planning process, the project team was able to incorporate their expertise into the overall strategy, leading to an optimized pilot configuration, well-defined field operating procedures, and appropriate equipment selection. Consistent with previous developments at the Angsi field, strong collaboration and effective communication among all stakeholders played a critical role in achieving successful project outcomes [24].

2. Methodology

This research aims to further expand insight into the importance of applying risk analysis within operating companies. To address the two research objectives, a qualitative research approach was adopted, with structured interviews serving as the main data collection technique. The selected approach follows an iterative nature, with repeated application and refinement throughout the entire project lifecycle.

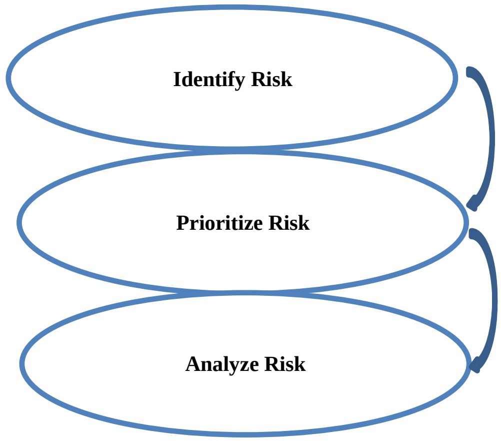

Figure 1. IS upgrade project

The key components are outlined in summary below. When applying the RFMEA methodology, several adjustments to the conventional FMEA structure are necessary. Unlike traditional FMEA, which primarily focuses on technical failure modes of products or processes, project-based RFMEA is designed to systematically recognize, measure, and mitigate risks within a project context. Furthermore, RFMEA is not applied in isolation; it complements the existing FMEA frameworks developed for product design, process engineering, and service implementation activities [25].

Table 1. Standard FMEA and the RFMEA forms

Typical FMEA	Failure ID	Failure Mode	Occurrence	Severity		Detection	RPN
Typical RFMEA	Risk ID	Risk Event	Likelihood	Impact	Risk Score	Detection	RPN

Source: See Ref [25]

In this research after interview with specialists this result achieved, the effect of cost, time and schedule in impact of risks approximately equaled together.

Table 2. Guidelines for assigning the likelihood

9 or 10	Very likely to occur
7 or 8	Will probably occur
5 or 6	Equal chance of occurring or not
3 or 4	Probably will not occur
1 or 2	Very unlikely

Source:See Ref [26]

The principal divergence from the conventional Failure Mode and Effects Analysis (FMEA) lies in the treatment of technical changes, which are considered insufficiently visible. This distinction is primarily reflected in the interpretation of the detection criterion. Under the standard FMEA framework, a high detection rating indicates the absence of any effective mechanism to identify a failure before product release, whereas a low detection score signifies that the organization can detect the failure with near-certainty prior to shipment. In contrast, the Risk Failure Mode and Effects Analysis (RFMEA) follows a structured procedure that begins with a systematic identification of potential risk events. During this initial step, team members are guided to articulate each risk in a conditional format—"if *x* occurs, then *y* will result"—where *x* denotes the risk event and *y* represents its consequences. These consequences may include significant schedule delays, increased costs, or a combination of both. When a single risk event gives rise to multiple consequences, a separate risk identification code is assigned to each identified impact. Although the nature of the impacts and the corresponding contingency strategies may vary across these cases, the probability of occurrence and the detectability of the underlying risk event generally remain constant.

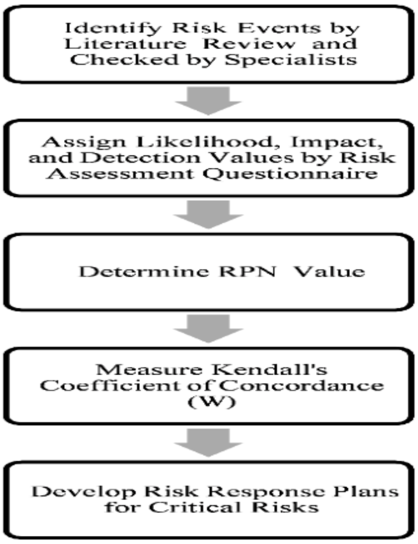

Figure 2. RFMEA procedure

In this section, the risk analysis for all of the risk groups is presented. First risks with their identification shown in Table 3. All the risks according to the experts' answers to the risk assessment questionnaire.

Table 3. Risk Identification

ID	Risk	Group	ID	Risk	Group
R1	Chemical formulation effectiveness	CEOR General Risks	R14	Polymer yield	Polymer Flooding Risks
R2	Produced fluids		R15	Polymer adsorption	
R3	Sweep efficiency		R16	Permeability Reduction	
R4	Injectivity		R17	Shear degradation	
R5	Scaling		R18	High salinity	
R6	Chemical supply and handling logistics		R19	High temperature	
R7	Logistics of handling large volumes of chemicals offshore	CEOR Offshore Risks	R20	Micro emulsion viscosity	Chemical Combination Risk
R8	Platform space limited		R21	Chemical adsorption	
R9	High salinity in offshore		R22	Chemical performance	
R10	Large well spacing		R23	Localized heterogeneities	
R11	Space and weight limitations on the deck		R24	Impact of free gas on the ASP process	
R12	Seawater as the only available injection- water source		R25	Unconstrained Fracture Growth	
R13	Limited disposal options		R26	Securing a continuous supply of chemical	

Source: Researcher's findings

The existence of gas within the pore space prior to chemical injection does not directly alter the displacement efficiency of alkaline–surfactant–polymer (ASP) flooding. However, when an ASP formulation is introduced following a gas flooding stage, a substantial portion of the gas becomes immobilized within the porous structure. This trapped gas effectively reduces the pore volume available for the flow of both the injected ASP solution and the resident oil, leading to an earlier onset of oil breakthrough. From an economic standpoint, this accelerated production can be advantageous, as it shortens the time required to realize project revenues. The influence of trapped gas on ASP performance is strongly dependent on reservoir conditions established before chemical injection. In general, increasing levels of trapped gas saturation corresponding to lower remaining oil saturation—appear to diminish the overall efficiency of the ASP process. Additionally, elevated pressure gradients or reduced injectivity may impose practical operational constraints when ASP flooding is implemented in reservoirs containing significant amounts of immobilized gas. The higher injection pressures required to place a more viscous chemical solution can increase the risk of out-of-zone injection, thereby decreasing treatment effectiveness within the intended interval and complicating the interpretation of pilot test outcomes. Furthermore, the surfactants employed in combined chemical flooding operations are typically specialty formulations rather than readily available commercial products. Consequently, ensuring a reliable and uninterrupted supply throughout the duration of the pilot program is essential. This planning must also include adequate contingency stocks to mitigate the impact of potential delays or disruptions in chemical delivery. There are two main limitations remained in ASP flooding field tests. Firstly, the strong alkali might cause scaling and erosion which shortened the pump checking cycle and increased the maintenance work. Such phenomenon. Operational problems were frequently encountered when produced fluids contained high concentrations of alkali. Although the combined application of physical and chemical scale-control techniques was able to extend the average pump inspection interval from approximately 90 days to about 160 days, the overall pump-checking cycle associated with ASP flooding remained only about half as long as that observed during polymer flooding operations.Moreover, the produced fluids exhibited an exceptionally high degree of emulsification, which made surface treatment processes complex and costly. During the industrial-scale ASP flooding tests conducted in the South-5 and North-1 East areas, strong emulsions severely hindered oil–water separation. Instability in the electric field of the electro-dehydration units resulted in exported crude oil with water contents exceeding allowable limits, while suspended solids concentrations in the produced water also surpassed standard specifications. These separation challenges were further exacerbated by elevated levels of alkali and surfactant in the produced streams. Although improvements in demulsification and dehydration performance could be achieved through measures such as modifying the electrodes of the electric dehydrators and increasing the dosages of demulsifiers and defoamers, these interventions were associated with relatively high operating costs. Risk response can be defined as the systematic process of identifying, assessing, selecting, and implementing actions intended to either reduce the probability of risk occurrence or mitigate the severity of adverse consequences. As a result, risk response serves a proactive function in limiting the negative impacts of project-related risks. Once project risks have been identified and analyzed, suitable response strategies must be developed and applied during implementation. Despite broad recognition of the importance of selecting effective risk response strategies within project risk management (PRM), this aspect remains the least developed, leading many organizations to fall short of realizing the full benefits of PRM. Many reservoir-related challenges are, in principle, amenable to relatively straightforward solutions; however, such solutions cannot be pursued if the reservoir management team fails to correctly detect and diagnose the underlying issues. Consequently, the development of a robust quality assurance program requires systematic identification of potential risk scenarios, selection of appropriate monitoring approaches, and definition of corrective actions for each credible case. In recent years, increasing emphasis has been placed on integrating risk analysis with production history matching. This integrated approach seeks to link reservoir development planning under uncertainty with ongoing reservoir management, progressively reducing geological uncertainties as production data become available. While this methodology shows significant promise, it is computationally demanding, although advances in analytical and numerical tools are helping to improve its efficiency. Once a potential chemical enhanced oil recovery (CEOR) opportunity has been screened and deemed suitable for further evaluation, a phased development strategy becomes essential for managing and reducing uncertainty. Key stages in this process typically include laboratory studies, pilot-scale implementation, and eventual full-field deployment. Each stage comprises multiple sub-steps designed to systematically de-risk the project, as discussed in the subsequent sections. Once a field has been identified as a promising candidate for chemical enhanced oil recovery (CEOR), the development process typically begins with the systematic screening of chemical formulations through a series of laboratory investigations. These experiments—such as phase behavior analysis, aqueous stability testing, and rheological measurements—are designed to evaluate the interaction of the chemical system with the reservoir crude oil and the formation and/or injection brine specific to the field under consideration. The performance of selected formulations is subsequently verified through core-flooding experiments, which address key feasibility and uncertainty-reduction aspects of the process. Results from laboratory studies and core floods are further used to calibrate chemical flood simulation models, enabling optimization of both pilot-scale and full-field development designs. Pilot testing represents a critical transitional stage between laboratory evaluation and commercial-scale deployment. These pilots function as controlled field experiments intended to confirm the technical viability of laboratory findings under actual reservoir conditions, while also providing data to refine and optimize the full-field development plan. Depending on project objectives, different pilot configurations may be employed, including single-well tests and pattern-based pilots. One or more pilot types can be selected to demonstrate feasibility with respect to parameters such as injectivity, oil desaturation, and incremental recovery. Following a positive Final Investment Decision (FID), full-field implementation is initiated. This phase encompasses the drilling and completion of wells, procurement and installation of surface and subsurface facilities, execution of the chemical injection program, and deployment of a comprehensive reservoir surveillance strategy. Although the post-FID stage is often viewed as a commitment point, opportunities for further risk reduction and performance optimization still exist. For instance, field development may be executed in phases, allowing operational experience gained in one area of the reservoir to inform subsequent expansion into other zones. While pilot projects can yield information of substantial value to a CEOR development, their effectiveness depends strongly on the clarity of their objectives and the efficiency with which those objectives are achieved. Pilots may involve either a single well or multiple wells, with each configuration offering distinct advantages and serving different evaluation goals. In general, the duration and cost of a single-well pilot are roughly an order of magnitude lower than those of a multi-well, producing pilot. Depending on whether the project is located onshore or offshore, single-well pilots may last from several weeks to a few months, with costs ranging from several hundred thousand to a few million dollars. In contrast, multi-well pilots typically extend over one to several years and require investments ranging from a few million to several tens of millions of dollars. Accordingly, CEOR projects commonly adopt a staged de-risking strategy in which a single-well pilot is conducted first to assess key feasibility indicators—such as injectivity and oil desaturation followed by a multi-well pilot prior to committing to a final commercial investment decision.

Table 4. Comparing the rank of each risk according to each expert

RANK	EXPERT 1	EXPERT 2	EXPERT 3	EXPERT 4	EXPERT 5	EXPERT 6	EXPERT 7	EXPERT 8	EXPERT 9	EXPERT 10
1	R23	R9	R9	R23	R23	R16	R15	R24	R23	R15
2	R12	R14	R10	R10	R10	R14	R14	R14	R16	R22
3	R21	R16	R21	R3	R24	R18	R1	R16	R20	R14
4	R9	R10	R11	R12	R25	R13	R22	R20	R25	R13
5	R11	R21	R17	R25	R19	R19	R16	R23	R2	R10
6	R16	R23	R12	R19	R17	R15	R17	R21	R1	R5
7	R13	R11	R16	R9	R20	R21	R21	R9	R15	R24
8	R22	R15	R23	R20	R15	R2	R19	R25	R21	R7
9	R8	R17	R13	R24	R18	R9	R18	R22	R12	R11
10	R1	R13	R22	R18	R22	R26	R24	R15	R13	R9
11	R2	R8	R8	R5	R12	R3	R25	R18	R18	R2
12	R15	R7	R25	R13	R9	R10	R23	R19	R8	R8
13	R25	R1	R14	R16	R16	R4	R9	R10	R24	R1
14	R18	R20	R15	R17	R3	R1	R6	R13	R5	R3
15	R19	R3	R1	R14	R2	R11	R4	R17	R3	R12
16	R20	R18	R19	R21	R5	R7	R5	R5	R4	R25
17	R7	R12	R20	R22	R21	R22	R10	R12	R9	R21
18	R10	R4	R24	R15	R8	R6	R20	R1	R14	R6
19	R14	R22	R3	R11	R11	R17	R8	R7	R7	R19
20	R17	R19	R6	R26	R1	R5	R11	R2	R19	R17
21	R24	R25	R7	R8	R13	R12	R3	R3	R17	R18
22	R26	R5	R4	R7	R14	R8	R7	R26	R22	R23
23	R6	R2	R18	R2	R7	R24	R26	R8	R11	R20
24	R4	R6	R5	R6	R6	R23	R12	R11	R10	R4
25	R3	R24	R26	R4	R26	R20	R2	R4	R26	R26
26	R5	R26	R2	R1	R4	R25	R13	R6	R6	R16

In order to determine rank any risk to other risks totally, the ranks of a risk in each of the columns summed together. Finally, the risks ranked according to lowest total rank and actually according to highest RPN.

Table 5. Total rank of each risk

ID	Risk	Total Rank
R16	Permeability Reduction	79
R9	High salinity in offshore	81
R23	Localized heterogeneities	81
R15	Polymer adsorption	85
R21	Chemical adsorption	89
R14	Polymer yield	98
R10	Large well spacing	99
R25	Unconstrained Fracture Growth	116
R13	Limited disposal options	117
R22	Chemical performance	118
R12	Seawater as the only available injection- water source	126
R19	high temperature	126
R18	high salinity	127
R24	Impact of free gas on the ASP process	130
R17	shear degradation	135
R20	Micro emulsion viscosity	135
R1	Chemical formulation effectiveness	138
R11	Space and weight limitations on the deck	145
R3	Sweep efficiency	158
R8	Platform space limited	158
R2	Produced fluids	166
R5	Scaling	171
R7	Logistics of handling large volumes of chemicals offshore	179
R4	Injectivity	208
R6	Chemical supply and handling logistics	217
R26	Securing a continuous supply of chemical	223

Source: Researcher's findings

3. Results and Discussion

The findings of this dissertation provide an important basis for future decision-making related to large-scale, full-field deployment of CEOR technologies, particularly in terms of minimizing technical uncertainty. These outcomes may play a decisive role in determining whether CEOR projects proceed in oilfield applications. To support this objective, the RFMEA methodology was adopted as a structured framework for identifying potential risk events, quantifying their severity through scoring, and prioritizing response actions toward those risks that pose the greatest threat to project success. Application of RFMEA to the overall project led to the identification of 26 distinct risk factors, of which six exceeded the established Risk Priority Number (RPN) threshold. Developing comprehensive mitigation strategies for these six scoring, and prioritizing response actions toward those risks that pose the greatest threat to project success. Application of RFMEA to the overall project led to the identification of 26 distinct risk factors, of which six exceeded the established Risk Priority Number (RPN) threshold. Developing comprehensive mitigation strategies for these six high-priority risks already represents a significant undertaking, while attempting to formulate detailed plans for all 26 identified risks would be impractical within the constraints of a typical project environment. In this illustration, the risks of R16, R9, R23, R15, R21 and R14 that shown in Table 6 will require that a response plan will be generate and revise RPN values calculated. Also prioritize risks shown in Table 6.

Table 6. Prioritize risks

Rank	ID	Risk
1	R16	Permeability Reduction
2	R9	High salinity in offshore
3	R23	Localized heterogeneities
4	R15	Polymer adsorption
5	R21	Chemical adsorption
6	R14	Polymer yield
7	R10	Large well spacing
8	R25	Unconstrained Fracture Growth
9	R13	Limited disposal options
10	R22	Chemical performance
11	R12	Seawater as the only available injection- water source
12	R19	high temperature
13	R18	high salinity
14	R24	Impact of free gas on the ASP process
15	R17	shear degradation
16	R20	Micro emulsion viscosity
17	R1	Chemical formulation effectiveness
18	R11	Space and weight limitations on the deck
19	R3	Sweep efficiency
20	R8	Platform space limited
21	R2	Produced fluids
22	R5	Scaling
23	R7	Logistics of handling large volumes of chemicals offshore
24	R4	Injectivity
25	R6	Chemical supply and handling logistics
26	R26	Securing a continuous supply of chemical

Source: Researcher's findings

After ranking f risks Kendall's W calculated, Suppose that object i is given the rank ri,j by judge number j, where there are in total n objects and m judges. Then the total rank given to object i is:

$R_i = \sum$

And the mean value of these total ranks is:

$\bar{} = \sum$

The sum of squared deviations, S, is defined as:

$S = \sum \quad \bar{})$

And then Kendall's W is defined as:

W =__________

Ri, ‾ and S calculated for each risk and shown in Table 7. Based on these values, Kendall's W calculated and equals to 0.5.

Table 7. Kendall's W parameter values

ID	Risk		‾	S
R16	Permeability Reduction	79.0	3.0	3114.5
R9	High salinity in offshore	81.0	3.1	2895.3
R23	Localized heterogeneities	81.0	3.1	2895.3
R15	Polymer adsorption	85.0	3.3	2480.8
R21	Chemical adsorption	89.0	3.4	2098.3
R14	Polymer yield	98.0	3.8	1354.8
R10	Large well spacing	99.0	3.8	1282.2
R25	Unconstrained Fracture Growth	116.0	4.5	353.7
R13	Limited disposal options	117.0	4.5	317.1
R22	Chemical performance	118.0	4.5	282.5
R12	Seawater as the only available injection-water source	126.0	4.8	77.6
R19	High temperature	126.0	4.8	77.6
R18	High salinity	127.0	4.9	61.0
R24	Impact of free gas on the ASP Process	130.0	5.0	23.1
R17	Shear degradation	135.0	5.2	0.0
R20	Micro emulsion Viscosity	135.0	5.2	0.0
R1	Chemical formulation effectiveness	138.0	5.3	10.2
R11	Space and weight limitations on the deck	145.0	5.6	103.9
R3	Sweep efficiency	158	6.1	537.9
R8	Platform space limited	158	6.1	537.9
R2	Produced fluids	166	6.4	973.0
R5	Scaling	171	6.6	1309.9
R7	Logistics of handling large volumes of chemicals offshore	179	6.9	1953.0
R4	Injectivity	208	8.0	5357.1
R6	Chemical supply and handling logistics	217	8.3	6755.6
R26	Securing a continuous supply of chemical	223	8.6	7777.9
Summation			134.8	42630.0

Source: Researcher's findings

4. Conclusions

The primary aim of this thesis was to mitigate the adverse impacts arising from the inadequate consideration of uncertainties, and the associated risks, in the implementation of CEOR operations and the modeling approaches applied to them, while simultaneously enhancing the overall effectiveness of CEOR in oilfield applications. To achieve this objective, the study first examined the nature of technical risks and uncertainties inherent in CEOR processes and established their relative priorities. Subsequently, the research focused on identifying appropriate and effective response strategies to address these technical risks and uncertainties during CEOR operations.

The principal conclusions derived from this research include the following:

1.Despite the presence of numerous mature onshore reservoirs that could serve as suitable candidates, chemical flooding has seen limited adoption as a tertiary oil recovery method.
2.Twenty-six risks associated with CEOR operations were identified in this research, which was classified into four groups as follows:
a.CEOR general risks
b.CEOR offshore risks
c.Polymer flooding risks
d.Chemical combination risks
3.The risk analysis in each group helped to improve the results of the analysis.
4.The prioritization of risks led to the selection of appropriate response methods..
5.Permeability Reduction, High salinity in offshore, Localized heterogeneities, Polymer adsorption, Chemical adsorption and Polymer yield are the main basis risks in CEOR.
6.Since the risk factor is high in most of the risks, it must be secured before its operation (CEOR) to guarantee its safety.
7.Due to the CEOR is complex method, it is necessary to know your experience in other areas and check your results.
8.CEOR is a very complex technology requiring a high level of expertise and experience to successfully implement in the field.
9.The pilot operation on a normally unmanned satellite platform with limited facilities requires a proper assessment of risks and additional safety measures during the pilot operation to ensure a safe operation.
10.Several factors have been investigated to find the best scenario. The RFMEA is an advanced risk tool that is simple and intuitive. It is based on the well-known FMEA technique, modified for PRM.
11.The RFMEA is based on evaluating both the risk score and the RPN value to find the critical risks that require immediate risk response planning.
12.If properly utilized, the RFMEA can greatly reduce risks on a project, create team ownership in risk planning, and act as a resource for future projects in terms of knowledge management and lessons learned.

13.The engineering manager can use this method and format as a simple and concise way to capture project and program risks. The ability to reuse the data and anything learned from the RFMEA enhances organizational learning. The project manager and engineering manager can use this information to improve project success by focusing on key risks by using the simple risk management RFMEA process.

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