Marginal Oil Resources

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The term “marginal oil resource” refers to an oil reservoir that has hydrocarbon resource preservation but cannot meet the criteria of resources under the U.S Securities and Exchange Commission (SEC) standards. When oilfields step into their late life, most of their economic petroleum reserves have been well developed, and their focuses need to be switched to their intact marginal resources.

Keywords: Recovery ; Waterflooding ; Marginal Resources ; oil

1. Marginal Resources

The U.S. Securities and Exchange Commission (SEC) defines oil reserves as those that are “judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment” [1]. Based on these SEC standards, petroleum reserves are classified as either proved, proved developed, proved undeveloped, probable or possible reserves. However, because a marginal resource reservoir is not within an effective thickness laid out in these standards, marginal resources are not found among these reserve classifications. Indeed, the limited thickness of a marginal resource’s formation accounts for its classification as a resource rather than a reserve.

The concept of an oil marginal resource refers to oil formation that has resource identification but can neither meet the criteria to be evaluated as a reserve nor count as an economic reserve. Although an application of hydraulic fracturing or enhanced oil recovery (EOR) processes can result in an industrial oil flow criterion, this kind of resource still does not meet the SEC reserve evaluation standards and, therefore, effective reserve and economic evaluations cannot be carried out. Until now, as the base of their total reserves’ calculations is not established, the amounts of marginal resources have not been stated in any oilfield development plan nor formally included in the world’s reserve statistics.

Marginal resources can be divided into two types: Marginal Type I and Marginal Type II [2]. A Marginal I resource can be defined as a resource formation identified as a sandstone formation for which its thickness cannot meet the effective thickness standard of 0.2 m. This type of marginal resource has been perforated and developed, but when compared to a commercial pay zone, its development is less effective. As shown in **Table 1**, the average permeability, porosity, and initial oil saturation (*So*) are 180 mD, 25% and 45%, respectively, which are less than the ones of poor reserves. A Marginal II resource is used to indicate a resource formation that is not recognized as a sandstone formation. Compared with Marginal Type I, its permeability, porosity, and oil saturation are 60 md, 20% and 35%, respectively, indicating worser reservoir quality.

Table 1. Properties of different resource types. *So*: initial oil saturation. The arithmetic average method is applied to calculate the permeability.

Resource Classifications		Permeability (mD)	Porosity (%)	*So* (%)
Economical reserves		400+	26	80
Poor reserves		200+	25	68
Marginal resources	Type I	180	25	45
	Type II	60	20	35
	Average	21	20	40

Marginal resources can be further divided into two basic types according to their physical properties and contact relationships with other reserve layers. (1) Isolated marginal resources comprise a single layer that is composed only of a marginal resource, with a separation layer of larger than 0.5 m from a reserve layer. Based on different types of marginal reservoirs, they can be called either the Marginal Type I isolated resources or Marginal Type II isolated resources. A marginal resource with a sandstone thickness but without reaching an effective thickness criterion can be regarded as an isolated marginal resource. (2) Connected marginal resources comprise a marginal formation at the top or bottom of a reserve layer called a connected marginal resource. A junction boundary is in contact with the reserve layer or, if there is a separation layer, the thickness of the separation layer is less than 0.4 m. Based on different marginal types, they can be divided into Marginal Type I connected resources or Marginal Type II connected resources. Compared with isolated and connected marginal resources of either Type I or Type II, their reservoir quality is very similar. The contact relationships with other reserve layers do not affect their own reservoir quality.

For mature oilfields, developing marginal oil resources is usually featured as uncertain economics, possessing high risk and doubtful profitability. However, they are considered as a hot topic across major oil consumption regions where energy security is a major concern. Otombosoba (2018) studied exogenous factors affecting the development of marginal resources in emerging economies, such as China, Nigeria, India, Indonesia, Malaysia and Venezuela. Successful development depends on the principle of sustainability, with the consideration of political, social, economic, legal and technological issues [3]. Adetoba (2012) summarized the key challenges faced by developing marginal resources in Nigeria. Funding and lack of technological know-how seem to be two main concerns [4]. Economical assessment directly affects a development decision. Acheampong (2021) proposed a real option method in valuing marginal resources in UK considering various uncertainties [5]. The method shows advantages over a traditional discounted-cash-flow method in management decision. Greenhouse gas emissions have been an increasingly important factor controlling the development of marginal resources. Masnadi et al. (2021) studied greenhouse gas emissions effects on marginal resources and concluded that carbon intensity was determined by the magnitude of an oil demand decline [6].

2. Recovery Processes

Around the world, a large portion of oilfields has been developed through water flooding and has now entered a stage of high water cut [7]. In this case, it is a common desire to tap the residual potential of old oilfields with limited costs. Therefore, marginal resources, an example of a resource type that held little value in the past, is now of great research significance.

3. Waterflooding

Waterflooding processes are heavily utilized in conventional oil reservoirs and can be applied for the development of marginal resource reservoirs. The mechanisms of waterflooding have been well understood since the 1970s [8]. It has also become an important recovery process for marginal resources. Hu (2008) presented a new redevelopment concept for marginal resources by waterflooding in mature oil fields under PetroChina [9]. The expected recovery of waterflooding is about 33.6%, with average water displacement efficiency of 56%, while field performance indicated that displacement efficiency can range 60–80%. Its controlling factors were identified as layer heterogeneity, connectivity, an oil-water mobility ratio, and well patterns. Bo and Zhao (2008) leveraged a subdivision of oil layers to improve the performance of waterflooding in the Gaotaizi oil zone, Daqing Oilfield [10]. The subdivision was achieved by considering a sublayer number and sandstone thickness, layer connection and a fingering coefficient. Field performance showed that oil production was increased by 18 t/d and water cut was reduced by 0.42%. A successful reservoir management can guarantee the successful development of marginal fields. Ge et al. (2011) presented a reservoir management program in waterflooding development in the Bohai field, including water management, infill drilling and EOR. Controlling a rising rate of water was the main goal of water management [11]. They implemented water injection optimization, sand plugging and balancing reservoir energy by smart water injection to successfully reduce a water-cut increasing rate from 20% per year to 3.5% per year. Imuokhuede et al. (2020) proposed screening criteria for waterflood projects in the Niger Delta marginal reservoir by using simulations [12]. Reservoir depth, gas saturation, residual oil saturation, oil gravity, oil viscosity and the presence of an aquifer were selected as controlling parameters. Their results indicated that oil saturation of less that 33%, gas saturation of greater than 15% and oil viscosity of less than 30 cP were favorable for waterflooding. During a production and displacement process, it has been observed that isolated marginal resources can effectively provide a functional production capacity [2]. The reason is that in the development process of a connected marginal reservoir, displacement is more likely to occur in layers with high permeability, especially after water breakthrough. In this case, low permeability layers cannot be efficiently used. Wei et al. (2020) applied Nuclear Magnetic Resonance (NMR) to characterize a residual oil distribution during a core waterflooding test. Their results showed that the residual oil saturation was higher at the outlet of cores, and an improved viscous force could further reduce it [13].

4. Low Salinity Waterflooding

In recent years, increasing research has been focused on the specific types of waterflooding such as hot water injection [14], water injection in heavy oil reservoirs [15], and low salinity waterfloods [16][17]. In particular, research activities on low salinity waterflooding have sharply increased from 2 to 360 publications from 1960 to 2018 [18].

In 1997, Tang and Morrow reported that oil recovery could be improved by low salinity waterflooding (LSW) [19]. They conducted four imbibition and waterflooding tests and examined the effects that changes in salinity had on the waterflooding outcome. In their view, the possible reason for this phenomenon could be due to a change in wettability. They thought that water wetness would increase with sustained high-water saturation conditions because of a combination of the effects of oil and water interfaces [19].

Later, Zhang and Morrow performed an experimental study of LSW on cores with different permeabilities [20]. The permeabilities of their cores were 60 mD, 400 mD, 500 mD, and 110 md. For each core, two fluids (reservoir brine and low salinity brine) were used to perform 2 PV (pore volume) and 10 PV injection tests. Their results showed that, with the exception for core Berea 400, LSW produced lower residual oil saturation and better recovery efficiency. However, although the recovery of LSW and reservoir brine did not show a big difference, after the injection of distilled water, an increase in differential pressure appeared and contributed 3.8% of OOIP (original oil in place) in a 2 PV test [20].

Another study by Tang and Morrow in 1999 pointed out three conditions for a low salinity effect (LSE): a significant clay fraction, presence of connate water and exposure to crude oil to create mixed-wet conditions based on tests conducted on Berea-sandstone cores [21]. In this case, more research on not only laboratory core tests but also field experiments are needed. In 2004, BP (British Petroleum) reported that up to 60% of residual oil in an oilfield was produced by using a LSW process [22]. Within the area of a radius of about 13 to 14 ft around a wellbore, low-salinity effects can reduce the residual oil caused by HSW (high SW), which was about 13% of OOIP [23]. However, they also reported an unsuccessful example in a North Sea field in which both field pilot tests and laboratory tests failed, although the conditions were all met [24].

Such a huge difference in LSW between different fields could also be evidence of the complexity of its mechanisms. As Bartels et al. mentioned, LSW is a “cooperative process in which multiple mechanisms are acting on different length and time scales” [18]. From the literature, it has been found that the mechanisms of LSW are composed of several different effects, such as fines migration [16][21], mineral dissolution [25], variation in interface viscoelasticity [26] and a pH change effect [17][23].

As mentioned above, Tang and Morrow found that water wetness increased as water saturation increased [21]. Berg et al.’s research provided direct evidence that showed that wettability modification in a clay surface is one of the mechanisms for LSW [27]. Furthermore, Yousef et al. designed an experiment with composite rock samples from a carbonate reservoir [28]. Although the target of their study was to improve recovery by applying the injection of seawater, their dilution liquid injection test also proved that “altering the salinity and ionic content of the injection water can alter the rock wettability toward a more water-wet state” [28].

5. Enhanced Recovery

A long period of low oil prices has forced oil companies to seek lower cost reserves to develop. EOR technology can provide an effective method to effectively increase production of marginal resources, especially for reservoirs after waterflooding. Wang et al. (2019) introduced polymer injection combined with short well spacing tests in the Daqing oilfield. Both lab tests and pilot results indicated that the strategy combined with injection management can improve volumetric sweep efficiency and increase a recovery factor by around 10% with an additional cost of USD 10/bbl [29]. They examined a residual oil distribution after polymer flooding based on CT scanning. The sweep efficiency could be further increased around 11.4% than the one of waterflooding. Resnyanskiy and Babadagli (2010) studied the implementation of surfactant injection in a marginal oilfield, Sinclair field [30]. They applied numerical simulation to model this reservoir, match history and forecast surfactant injection. They indicated that its recovery factor could reach 80%, and surfactant injection was expected to possibly provide new life to the Sinclair field. Water-alternating-gas (WAG) injection was also recommended to increase oil recovery in ultra-high water-cut reservoirs. Kong et al. (2021) experimentally investigated the performance of WAG and found that WAG could further improve oil recovery by around 15% above the base of waterflooding [31]. CO_2 injection has been an increasingly important recovery process for mature oilfields, as it could trigger miscible flooding to enhance oil production and reduce greenhouse gas emissions [32]. Nanoparticles have also been tested in the laboratory to increase oil production [33]. For heavy oil marginal reservoirs, a well-designed thermal recovery process could significantly improve oil recovery [34][35][36][37][38].

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