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Review

Crucial Development Technologies for Volcanic Hydrocarbon Reservoirs: Lessons Learned from Asian Operations

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Abstract: Oil and gas reservoirs in volcanic rocks are a particular type of unconventional reservoir and present unique challenges for exploration and production engineers. To help the oil industry understand volcanic reservoirs and solutions to complex development problems, we reviewed their key engineering technologies as well as their geological characteristics. The distinctive geological characteristics of volcanic hydrocarbon reservoirs are strong heterogeneity, low porosity and permeability, complex fracture systems, etc. The volcanic reservoir rock types in order of hydrocarbon abundance are basalt (38.5%), andesite (15.9%), volcaniclastic (12.1%), and rhyolite (11.5%). The porosity ranges from 0.1 to 70%, and permeability ranges from 0.0007 to 762 md. In some commercially developed volcanic reservoirs of China, the average porosity is 7.7–13%; the average permeability is 0.41–3.4 md. Engineers have applied a variety of adapted technologies to produce volcanic reservoir economically. Horizontal wells can increase production and reserves by 4–6 times those of vertical wells, and longer wells are preferred. Specialized hydraulic fracturing techniques are suggested, including small or mixed proppant size, second HF treatment after proppant slugging, high-viscosity frac fluid with high-temperature resistance, special fluid loss reducer, high pump pressure, Extreme Overbalance Perforating, limited-entry fracturing, matrix acidizing, etc. Water control measures include producing below critical rates, partial perforation or penetration, controlling hydraulic fracture height, using horizontal wells, implementing complete cementing job, etc. Well productivity evaluation should be conducted to understand well performance and appropriately allocate production rates among wells, using the modified AOF method and other productivity prediction models considering breakdown fracture gradient, gas slippage effect, non-Darcy effect, etc. Well sites need to be selected based on recognizing profitable lithologies, lithofacies, high porosity and permeability, relatively developed fracture systems, thick net pay zones, etc. The critical questions for the industry are how to enhance volcanic reservoir recovery with more efficient and economic hydraulic fracturing and water control techniques. This is one of the first papers systematically summarizing the engineering technologies and unique solutions to develop volcanic reservoirs. Further and more complete reviews can be carried out in the future, and more novel and effective techniques can be explored and tested in the field.

Keywords: volcanic; unconventional reservoir; geology; engineering; development technologies

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1. Introduction

Hydrocarbon (oil and gas) reservoirs in volcanic rocks are a particular type of unconventional reservoir. Volcanic reservoirs originate from volcanic materials that were deposited as lava flows or volcanic ash (volcaniclastics) deposited in subaerial or subaqueous environments. Porosity may be poorly interconnected (low permeability) in lava flows. The minerals that comprise volcaniclastics are relatively unstable in the presence of subsurface temperatures and fluids, and they undergo diagenetic changes that reduce reservoir porosity and permeability. The distinctive geological characteristics of volcanic hydrocarbon reservoirs are strong heterogeneity, low porosity and permeability, complex fracture systems, deep burial depth, high in situ stress and Young's modulus, and high temperature.

They were first discovered accidentally in 1887 in San Joaquim Basin, California in the US by exploration in other lithologies, and they were first produced in 1923 in the granite reservoir of the La Paz field in Venezuela. Although volcanic hydrocarbon reservoirs account for only 1% of the hydrocarbon reservoirs globally (most hydrocarbon reservoirs are in sandstone, limestone, or shale), they contain huge amounts of oil and gas that could contribute to the world energy supply [1]. Figure 1 shows the global distribution of hydrocarbon occurrence associated with igneous reservoirs. The 78 largest reservoirs with more than 1000 Mbbl reserves are shown in Figure 2 [1,2]. The largest volcanic reservoirs are located in East and South Asia, the Middle East, and the Americas. In China, the Songliao and Junggar basins together hold 1 trillion m^3 of gas reserves and currently are known to have the largest igneous reservoirs in the world. Still, there are vast volcanic hydrocarbon reserves that are unexplored, and the world's resources are underestimated.

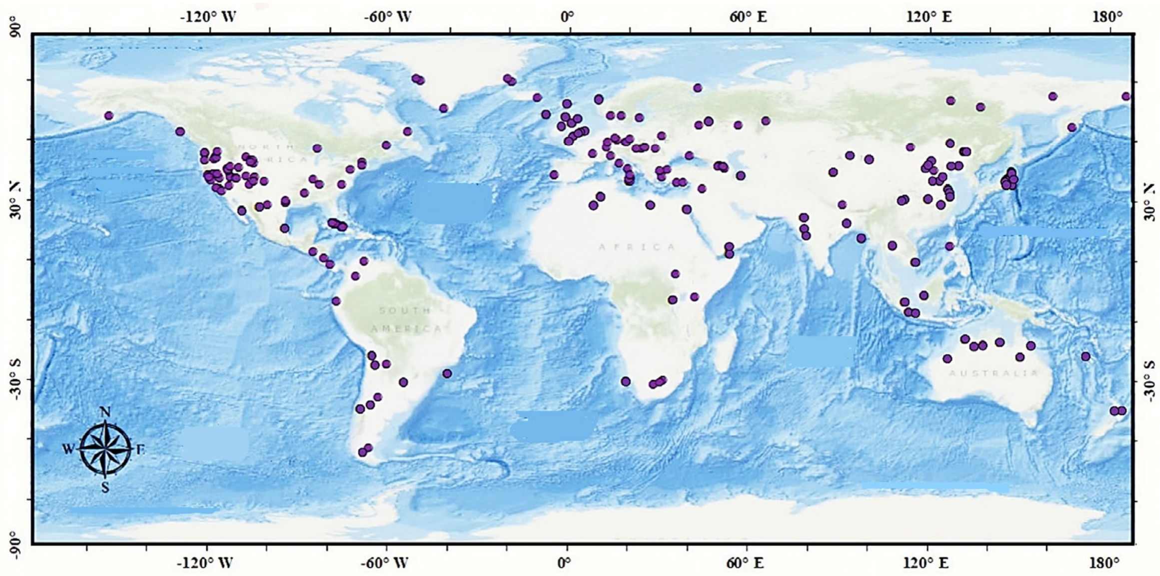

Figure 1. Global distribution of hydrocarbon occurrence associated with igneous rock (adapted from reference [2]).

The geologic complexity of volcanic reservoirs presents unique challenges for exploration and production engineers. For many years, volcanic reservoirs were regarded as coincidental and too difficult to develop, and they were not primary exploration targets [3,4]. Therefore, only 1/3 of the identified volcanic hydrocarbon reserves are commercially produced [2] due to the challenges of exploration and production. The exploration and development of these reservoirs is an ongoing learning and practicing process.

Therefore, we need to review and summarize the development experience gained from the previous commercial operations in volcanic reservoirs, especially Asia, to better produce petroleum in this type of reservoir worldwide in the future.

Since the 1950s, the exploration and production of hydrocarbons in igneous rocks has begun in a systematic way in Asia, for example, in China, Japan, Vietnam, Georgia, Azerbaijan, Indonesia, India, etc. Since the beginning of the 21st century, the worldwide volcanic petroleum reservoirs entered the fast growth stage, where systematic research and technologies are applied. China and Indonesia stand out with higher daily production, exceeding orders of 10^8 cubic meters of gas and 10^4 tons of barrels of oil [5–18]. Experience from Asia provided the global oil industry with precious expertise and solutions to complex problems.

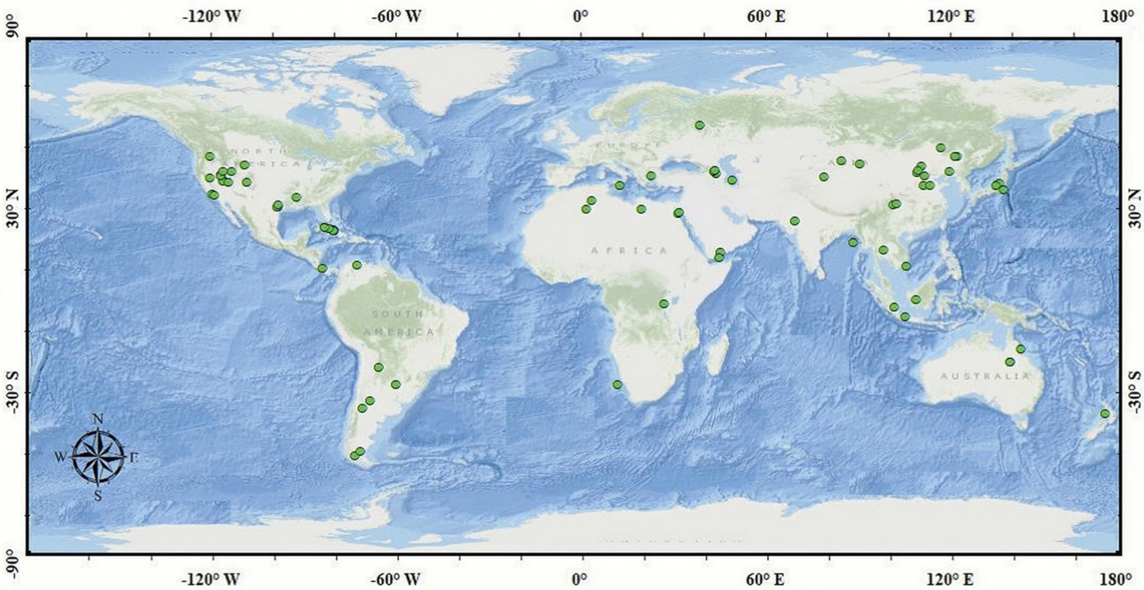

Figure 2. Global distribution of 78 largest volcanic reservoirs with reserves over 1000 Mbbl [2].

Since the 21st century, China has significantly increased its oil and gas production from volcanic reservoirs in the Songliao Basin in northeast China and the Junger Basin in northwest China [19]. Table 1 demonstrates some successful cases of developing volcanic hydrocarbon reservoirs in China. These reservoirs are located in northeast and northwest China, and they make a significant contribution to domestic hydrocarbon production. The reservoir lithology, lithofacies, porosity, permeability, key development technologies, and annual gas production rates are listed in Table 1. By and large, the lithology is primarily andesite, basalt, tuff, rhyolite, and volcaniclastic; the lithofacies are mainly flooding, explosive, and subvolcanic facies; the average porosity is 7.7–13%; the average permeability is 0.41–3.4 md; and the annual gas production rate range is 3.2–4.0 $\times$ 10^4 MMCF.

Table 1. Reservoir properties, development technologies, and annual production of some successful volcanic hydrocarbon reservoirs in China.

Basin/Field	Lithologies/Lithofacies	Porosity/Permeability	Main Development Technologies	Annual Gas Production Rate ($\times 10^4$ MMCF)
Junger Basin, Kelameili Field, China [20]	Lithologies: tuff breccia, syenite porphyry, rhyolitic tuff, and basalt. Lithofacies: falling and sputtering subfacies of the explosive facies; top and lower subfacies of flooding facies; out-belt and middle-belt subfacies of subvolcanic facies.	Average porosity: 12.3% Average permeability: 0.41 md	Geological evaluation and 3D modeling, profitable reserve prediction, fine reservoir characterization, reservoir engineering analysis, hydraulic fracturing (about 50% of wells), vertical and horizontal well combination, simulation, irregular well spacing, water drainage by lifting.	4.0

Table 1. *Cont.*

Basin/Field	Lithologies/Lithofacies	Porosity/Permeability	Main Development Technologies	Annual Gas Production Rate ($\times 10^4$ MMCF)
Songliao Basin, Changling Field, China [21,22]	Lithologies: rhyolite, rhyolite tuff lava, Anshan volcanic breccia, rhyolite tuff, rhyolite volcanic breccia; andesite, basalt, rhyolite breccia lava. Lithofacies: flooding and explosive facies.	Porosity: 3.5~22%; Permeability: 0.03~17.31 md	Geological evaluation and 3D modeling, profitable reserve prediction, fine reservoir characterization, reservoir engineering analysis and prediction, no hydraulic fracturing, vertical and horizontal wells, simulation for production.	3.2
Songliao Basin, Xushen Field, China [23,24]	Lithologies: spherulites, stomatal rhyolites, and volcanoes in volcanic lava; fused tuff and clastic tuff in clastic rocks. Lithofacies: hot debris flow subfacies in eruption facies, top subfacies in flowing facies, inner-belt subfacies in invasion facies, volcano-neck subfacies in the channel facies, etc.	Porosity: <7.75%; Permeability: <3.36 md	Geological evaluation, 3D modeling, sweet-spot and other profitable reserves identifying, well productivity assessment and effective producing techniques optimization for different reserves, horizontal wells, MWD/LWD, advanced hydraulic fracturing.	3.34

The experience of current players shows the importance of understanding geological characteristics and reservoir engineering to select the appropriate production techniques. The reservoir engineering methods may differ from those used in conventional reservoirs, owing to the unique properties of volcanic reservoirs. Therefore, adapted or improved engineering methods should be used to ensure technical and economic success. In this paper, we discuss the technical challenges and the key innovative solutions. The workflow of our review of key development technologies is shown in Figure 3.

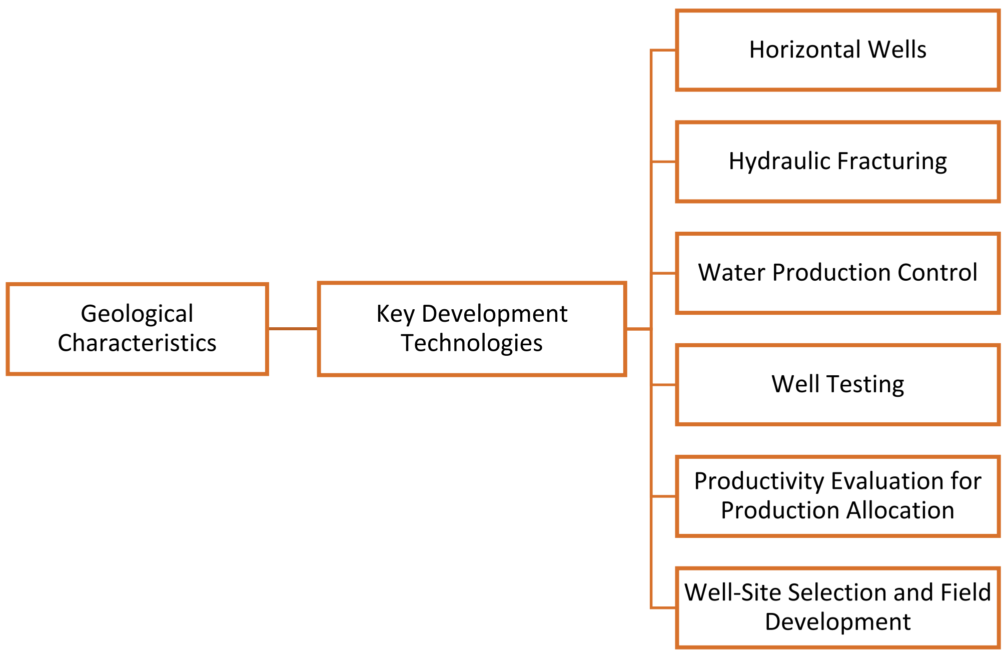

Figure 3. Workflow of this study of key development technologies.

Although there are some reviews on the geology aspects and exploration technologies in the published literature, there is little systematic review of engineering technologies. We hope to fill this gap with this paper. Since this is one of the first papers summarizing the engineering technologies to develop volcanic reservoirs, further and more complete reviews may be carried out in the future by other researchers.

2. Geological Characteristics

2.1. Reservoir Evaluation and Characterization

Geological characteristics, such as reservoir extent, lithology, lithofacies, porosity, permeability, and fluid distribution, are highly variable and unpredictable in volcanic hydrocarbon reservoirs. They are key reservoir parameters to be characterized and are the decisive factors for the development of the reservoirs.

Therefore, several procedures of geological evaluation and reservoir characterization are required before designing engineering schemes for field development: (1) Assess the reservoir layers, thickness, and extent using seismic and well log data. (2) Determine reservoir lithology and lithofacies distributions using well logs and rock/core analysis data. (3) Build a 3D geologic model with all parameters identified above. (4) Determine pore volume and reserves based on the geologic model. (5) Select a testing well site and drill an exploration well to assess the dynamic performance of the reservoir.

2.2. Heterogeneity, Formation Mechanisms, Lithology, and Lithofacies

A distinctive characteristic of volcanic reservoirs is their strong vertical and horizontal heterogeneity. A reservoir may comprise one or several layers, each having unique rock/mineral composition, lithology, lithofacies, net thickness, lateral extent, porosity, permeability, fracture systems, etc. [25]. The heterogeneity is reflected in the unique dynamical performance of each well.

This results from the complex formation mechanisms of the volcanic reservoirs. Volcanic strata form from lava flows, volcanic ash, or volcanic particles are transported by water and then deposited in subaerial and freshwater or marine environments. Next, the multiple volcanic bodies/eruptions are subject to weathering processes, burial and diagenesis, and tectonic movements over long periods of geologic time. The minerals that comprise volcaniclastics are relatively unstable in the presence of subsurface temperatures and fluids, and they undergo diagenetic changes that reduce reservoir porosity and permeability.

The lithofacies of volcanic reservoirs in China have been classified into five types: volcano channel facies, intrusive facies, explosive facies, flooding facies, and sedimentary facies, among which there are 16 sublithofacies. Experience in Chinese volcanic fields indicates that the lithofacies distribution controls the profitable zones of the reservoir [26–31]. In Table 1, some successful volcanic reservoir cases in China show that the lithofacies are mainly flooding, explosive, and subvolcanic (intrusive) facies.

Lithology in order of hydrocarbon abundance involves basalts, andesites, volcaniclastics, rhyolites, dacites, granite, dolerites, tuffs, ignimbrites, serpentinites, pyroclastics, etc., but primarily basalt (38.5%), andesite (15.9%), volcaniclastic (12.1%), and rhyolite (11.5%) [1,2,32].

2.3. Porosity and Permeability

The porosity of volcanic reservoirs may be poorly interconnected (low permeability) in lava flows. Volcanic rocks are unstable in the presence of subsurface temperatures and fluids and highly susceptible to diagenetic processes that usually reduce porosity and permeability, e.g., the movement of formation fluids may alter the original rock minerals and form clays that reduce porosity and permeability. Therefore, most reservoirs in volcanic rocks have low permeability and need hydraulic fracturing to produce economically.

Sun et al. [33] demonstrated that in the Kelaimeili oil field in the Jungar Basin, on average, the permeability of volcanic reservoirs is about 0.12 md and the porosity is 9.1%, implying low-porosity and low-permeability reservoirs. According to Zhao's research on most volcanic reservoirs in China [34], for most reservoirs in the Jungar Basin, permeability is 0.1–10 md, although the permeability of profitable zones is more than 10 md. Table 1 of some Chinese volcanic reservoirs in the Jungar and Songliao Basins shows that the average porosity is 7.7–13%; the average permeability is 0.41–3.4 md. Due to low permeability in the reservoirs in the Songliao and Jungar Basins in China, more than half of the wells needed hydraulic fracture stimulation.

In very few scenarios, porosity and permeability may increase during diagenetic process, e.g., dissolution of unstable minerals may locally enhance porosity and permeability, and natural fractures can greatly enhance them [35]. Thus, the heterogeneity of porosity and permeability is formed. Couves (2015) summarized the porosity and permeability properties data from nine countries with the largest volcanic reservoirs and found the porosity ranges from 0.1 to 70% and permeability ranges from 0.0007 to 762 md, due to the high heterogeneity [32].

3. Key Technologies of Development

Application of the appropriate engineering technologies is critical for successful economic development of volcanic reservoirs. Conventional engineering technologies should be adapted to solve the unique problems of volcanic reservoirs. Several key technologies, including the use of horizontal wells, hydraulic fracturing, water yield recognition and its control, well testing, well productivity evaluation, and well-site selection for field development, are discussed in this section.

3.1. Horizontal Wells

Horizontal wells are widely deployed for developing volcanic rock reservoirs due to their significant increase in production rates and recovery, reduced pressure differential between reservoir and wellbore, and delayed water production. However, in some thick volcanic formations, vertical wells are also used [33]. The production rates of horizontal wells are several times those of vertical wells under the same reservoir conditions. Based on a study in the Changling volcanic gas field in Songliao Basin, horizontal wells have production rates 4.7 times those of vertical wells, the drainage areas of the reservoir about 4.3 times, and the recoverable reserves about 5.8 times [21]. And the longer the horizontal wellbore and the thinner the pay zone, the higher the ratio of production rates of horizontal wells over vertical wells, or the greater the advantages of horizontal wells over vertical wells.

3.2. Hydraulic Fracturing

Hydraulic fracturing (HF) is to fracture the tight to ultratight formation rock by injecting high-pressure fracturing fluid (water, proppant, viscosifier, and other additives such as friction reducer) into a wellbore and further into the tight formation matrix. This reservoir stimulation technology is routinely implemented in low-porosity and low-permeability reservoirs, such as sandstone and shale reservoirs, as well as volcanic reservoirs, to produce the resource economically, in both vertical and horizontal wells [36]. In vertical wells, multilayer fracturing during one trip, or fracturing from the bottom layer upwards, is implemented. In horizontal wells, multistage fracturing from the farthest interval near the toe of the well to the nearest interval at the heel of the well is conducted.

Due to the depletion production and decrease in formation energy during production, or the incomplete initial fracturing operation, the production rate will decline rapidly, resulting in a low recovery factor. Thus, refracturing may be conducted, and the process includes identifying the fracturing sweet spot (unsuccessfully fractured section), refilling more perforations, injecting water-soluble diverting agents, and injecting proppant-laden fracturing fluid [37,38].

During hydraulic fracturing and oil/gas production processes, the issue of asphaltene precipitation may occur and reduce the formation porosity/permeability due to changes in thermodynamic conditions, such as the injection of hydraulic fracturing fluid. Some chemical methods (such as adding solvent, surfactant, and nanocomposite) can be used to dissolve or absorb asphaltene and improve porosity and permeability [39].

Recently, a technology called fracturing waterflooding, a combination of hydraulic fracturing and waterflooding, was proposed to effectively enhance the oil/gas production in low-permeability reservoirs [40], and it may be tried on volcanic reservoirs. Various conventional and novel chemicals can be used in the injected water, such as seawater, formation brine, surfactant, nanoparticles [41], inorganic silica gel [42], etc., by mechanisms of wettability alternation, reducing interfacial tension, increasing permeability, reducing water/oil mobility ratio, etc. This fracturing waterflooding technology has not been tested or reported in any volcanic oil fields, so it can be explored in the future.

Before, during, and after HF, fracture diagnostic tests can be carried out to understand the reservoir and HF effectiveness better, enhance HF operation efficiency, re-evaluate the potential of the reservoir, revise the future field development plan, and increase production. These tests include microseismic monitoring [43–45], diagnostic fracture injection test (DFIT), temperature logging, step rate test (SRT), step down test (SDT), production log test (PLT), etc. [46,47].

There are some unique challenges in the HF of volcanic reservoirs, and thus special solutions are needed. Some scenarios are listed below.

(1) Volcanic reservoirs usually bear deep burial depth, high Young's modulus, and high in-situ and closure stress. This poses high-pressure requirement for surface pumps, makes the proppant vulnerable to crash, impairs the hydraulic fracture conductivity, restrains the fracture opening width, and causes the proppant at the fracture tip to form a bridge plug, leading to the failure of so-called "tip-screen-out".

Solutions:

In the intervals with low clay content, a second HF treatment (refracturing) can be carried out after the first proppant slugging [48]. For high clay layers with swelling/slaking/dispersion problems, higher pump rate/pressure, certain inhibitive low-leakoff fracturing fluids, and better proppant concentration can be implemented [48]. People also use smaller-size proppant (such as 40/70 and 100 mesh) for spearhead pad and larger-size proppant (such as 20/40 mesh) for tail slurry, or small/large-size alternate sand slugs, intermediate- to high-strength proppant, shorter perforation interval [44], high-viscosity frac fluid, larger tubing size, and higher wellhead pressure, and Extreme Overbalance Perforating to overcome the high in situ stress, near wellbore tortuosity, and tip-screen-out problems [49].

(2) A volcanic reservoir is a type of naturally fractured, low-permeability reservoir. A large number of natural fractures, dissolved pores, and faults have a serious impact on the opening/propagation of hydraulic fractures. Although they would increase porosity and permeability and fracture network complexity, they would also dampen the fracturing effect, cause extra fluid leakoff and formation damage, change the stress distribution around a wellbore, and increase the near-wellbore fracture complexity and tortuosity, and thus increase fracturing initiation pressure, alter the extension direction of fracture and fracture mode, and even cause fracturing operation failure.

Solutions:

The corresponding fluid-loss control measures should be taken to control fluid leakoff, including adding fluid-loss reducer, adjusting prepad fluid ratio, using small-sized proppant, etc. Commonly used conventional fluid-loss reducer contains silica and clay, which might permanently block some pore channels. Some specially formulated fluid-loss reducers can be selected. We may reduce the amount of the prepad fluid to minimize the fluid leakoff damage to the reservoir or increase the prepad fluid ratio to meet the high-fluid-loss situation. Proppant with mixed, smaller diameters (40/70 + 100 mesh) can be used to overcome the near-wellbore tortuosity and control leakoff and maintain fracture conductivity [50].

(3) Deep volcanic reservoirs of high temperature (up to ~290 °C) render fracturing fluid and other working fluid challenges.

Solutions:

Use specially formulated fluid systems to endure high temperatures [50].

(4) Volcanic reservoirs bear substantial heterogeneity and complexity in all physical/chemical properties due to their complex forming mechanism: volcano eruption, several eruptions overlapping each other, structural activities, diagenesis, etc. This renders effective HF operation difficult.

Solutions:

Conduct comprehensive reservoir survey and rock tests to understand reservoir and rock properties so as to better design the HF treatment [48]. This includes seismic survey, (extended) leak-off test, well logging, core analysis by X-ray diffraction (XRD) mineral analysis, scanning electron microscope (SEM) analysis, electron microprobe elemental analysis, electron microscope energy spectrum analysis, etc., as well as ISRM standard rock mechanics tests such as uniaxial and triaxial tests and differential strain curve analysis, etc. The limited-entry fracturing, pin-point hydraulic fracturing techniques can be deployed to maximize net pay coverage.

(5) Rhyolite volcanic reservoirs usually have more developed fracture systems and higher permeability than tuff volcanic reservoirs, thus hydraulic fracturing will not be effective. In another case, when the fracture system of a volcanic reservoir is close to the oil–water contact, hydraulic fractures will probably extend into the aquifer below, therefore hydraulic fracturing can be risky.

Solutions:

For these volcanic reservoirs, matrix acidizing instead of hydraulic fracturing can be employed to dissolve matrices, as well as near-wellbore formation damage, and improve the reservoir transmissibility. A typical acidizing solution formula may include 15%HCl + 3%HF [51,52].

Table 2 lists some successful HF treatment cases in volcanic reservoirs in Asian countries, including the year, locations, operating companies, geologic features, problems encountered during HF, and how they solved the problems.

Table 2. Case study for HF treatments in volcanic hydrocarbon reservoirs in Asian countries.

Year, Location, Company	Geology	Problems	Solutions and Results
2001. Minami-Nagaoka Field, Japan. Teikoku Oil Company & Halliburton. [49]	Deep, hot, naturally fractured, volcanic rock. Depth = 12,500–16,000 ft, initial reservoir P = 8100 psi, temperature = 350 °F/177 °C. Repeated volcanisms of rhyolite eruptions formed a thick formation with rapid facies change: hyaloclastite, lava, and pillow breccia. Large-scale natural fractures are developed abundantly in lava and pillow breccia facies in the south but not as abundantly in the north.	The initial frac design failed for two wells. Only 20% of designed proppant placed due to premature screen-outs. Due to very narrow factures, there was a high net pressure of around 4000 psi prior to proppant pumping stage.	(1) 6 HF stages, targeting at 10 MMSCF/d. (2) Use 30/60 mesh proppant instead of 20/40, pump ~80,000 lb for each stage. (3) Select 4 target zones with maximum caliper log and kh values and high natural fracture density. (4) Decrease pad size from 50% to 25%. (5) Use CMHPG zirconate as frac fluid of 60–70 ppt; if tortuosity is excessively high, use 120 ppt high-viscosity gel pills of HPG/borate. (6) Use a short perforation interval of 6 m instead of 10 s of m to reduce fracture initiation points. (7) Test crosslink time each time on location, for it changes with pH as premixed gel ages. (8) Use a larger tubing size (4 $\frac{1}{2}$ in liner instead of 3 $\frac{1}{2}$ in) and higher wellhead pressure. (9) Apply Extreme Overbalance Perforating. The initial gas rate is 16 MMSCF/d, above the economic target of 10 MMSCF/d.

Table 2. *Cont.*

Year, Location, Company	Geology	Problems	Solutions and Results
2006. Hailaer Basin, China. Daqing Oilfield Ltd. [48]	Nonmarine extrusive sedimentary rock (basalt and tuff) and tuffaceous conglomerate. φ = 5.6–22%, k = 0.03–28 md, depth = 1655–1948 m, clay content in tuff and tuffaceous layers = 18–69%, mainly smectite–illite-type	The initial fracture design for two wells failed. Tip-screen-out after proppant concentration reached 200 kg/m^3. Petrophysics and rock mechanics research found the rock is relatively strong and stiff before HF is undertaken; some tuffaceous strata are highly plastic, so the fracture width is narrower and propagation is slower, which may cause proppant slugging and tip-screen-out; alkali tuffaceous rock is sensitive to water, swelling/slaking/dispersion occurred when exposed to aqueous frac fluid, which caused proppant slugging and then tip-screen-out.	(1) In the nonalkali intervals with low clay content, a second HF treatment was performed after the first proppant slugging. (2) For high clay layers with swelling/slaking/dispersion problems, higher pump rate/pressure, inhibitive low-leakoff cross-linked polymer fracturing fluids, and better proppant concentration were implemented. A new fracturing strategy was applied to 190 separate layers in 95 wells; a 97% success rate was achieved.
2009. Raageshwari deep gas field, Barmer Basin, West Rajasthan, India. Cairn India & BJ Services. [44]	Eroded volcanic formations (basalt, felsic, and subfelsic sublayers) underlying clastic Fatehgarh formations. High gamma-ray and density logs. Depth = ~3000 m. φ = 1.1–16.2%. k = 0.004–0.662 md. E = 1.45–4.73 × 10^6 psi. Poisson ratio ν = 0.167–0.253. Best pay lies at the top of the basalt unit.	Unsuccessful frac treatment encountered initially, wellbore tortuosity and multiple fractures were the reasons. High ISIP gradient (>overburden gradient) and high net pressure from injection tests indicate complex fracture network and small natural fractures.	They used 3.5″ monobore slim-hole strategy to eliminate the use of a rig and a separate frac string. Two-hundred barrels of crude oil crosslinked mini frac polymer gel loading at 40 ppt. Intermediate strength proppant loadings are 100 mesh for the pad stage, 20/40 for the main stages, and 16/30 for the tail end. Liquid clay stabilizer (quaternary ammonium chloride) achieved regained gas perm of ~80%. The perforation interval was reduced from 5 m to 2.5 m. Abandoned the unsuitable intervals with sand plugs to isolate them from other perforated intervals. One-hundred-mesh sand in pad treatment proved a successful means to avoid tip-screen-out. A total of 20MMSCF/D of gas production at 1000 psi drawdown. Improved the success rate of volcanic rocks fracturing
2013–2018. Raageshwari deep gas condensate reservoir, Barmer Basin, West Rajasthan, India. Cairn Oil & Gas, Vedanta Ltd., [46,47]	A poorly sorted clastic (Fatehgarh) interval on top of a stacked volcanic succession of lava flow cycles of basalt and felsic units. A total of 15–40 vertically separated pay layers. Pay depth = 2500–3500 m, low net-to-gross ratio. φ = 8–12%. k = 0.01–1 md. Sw = 50%. 80% CH_4, and low CO_2 and H_2S. Condensate gravity = 56 API. Gas calorific value = 1070 BTU/SCF.	In 2013, commercial gas sales started, allowing extensive data acquisition and well surveillance. Thirty wells were treated with 168 hydraulic fractures. Based on data acquired and four years of production history, they conducted a comprehensive re-evaluation of the resource, improved fracture design, and prepared a revised field development plan.	Limited-entry fracture technique to maximize net pay coverage and reduce cost because conventional plug and perf technique costs much more. They conducted and analyzed fracture diagnostic tests: Diagnostic Fracture Injection Test (DFIT), Step-Up Rate Test (SRT), Step-Down Tests (SDT), Temperature Surveys, and Production Log Tests (PLT). Perforation intensity was increased from 3 clusters/fracture stage to 6. Productivity was increased by 80% and Estimated Ultimate Recovery (EUR) by 20%. Screen-out rate dropped from 33% to 5%.
2016. Jinlong #2 reservoir, Junger Basin, China. PetroChina Xinjiang Oilfield Company. [50]	Depth = 3160–4400 m. Two sets of faults: three near-NS faults and seven near EW faults. φ = 10.82%. k = 0.43 md. Natural fractures mainly developed in the north, weak in the south. NF width = 0.01–0.19 mm, fracture density = 0.02–6.93 m^{-1}, NF strike = EW, dip angle > 45°. E = 30,152 MPa, ν = 0.186, azimuth of Sv = 118°, Sv = 82 MPa, Shmin = 68 MPa.	Among 12 wells, 4 did not complete the target amount of proppant, and 6 wells were dry layers or water layers after fracturing. Efficiency at the edge and bottom of the reservoir is low; The oil test results are either dry layer or water layer. The fracturing effect of gas-bearing fault block in the high part of the structure is good. The fracturing effect in the natural fracture development zone is good. Low sand ratio (<10%) or low average proppant concentration is associated with low postfrac production.	Select the high parts of the reservoir and zones with more natural fractures to conduct HF. Using mixed proppant with different diameters to fill fractures, large proppant—20/40 mesh—for fracture bridging and small proppant—100 mesh—for fluid loss control. Tests of a new fluid-loss reducer JL-1 of 1% and 2% found the wall-building filtration coefficient is reduced by over 50%, and the time to filter out was reduced by 15 and 20+ min. Formation damage by fracturing fluid with 2% JL-1 filtrate reducers is negligible, equivalent to that without JL-1. Perforation interval length is controlled in 5–10 m. Based on simulation optimization, the average sand ratio should be 15–18% to induce optimal fracture conductivity of 20 D·cm and avoid sand screen out; pumping rate should be 3.0–4.0 m^3/min considering capacity to carry 35% design sand ratio and balance between shear activation of NF and excessive fluid leakoff; Prepaid fluid volume ratio was optimized as ~40% with the presence of fluid-loss reducer.

3.3. Water Production Control

Water production often happens in volcanic reservoirs due to the presence of bottom or edge aquifers. The analysis of water production is essential for the development of the reservoir because, in the low-permeability volcanic reservoirs, oil and gas production can be inhibited dramatically by water production. The important topics on water production include water source identification, water production patterns, and water control measures.

3.3.1. Water Source Identification

There are three types of water sources: condensate water, water-bearing interbeds within the hydrocarbon formation, and bottom/edge aquifers.

The first type, condensate water, exists in the hydrocarbon formation together with oil and gas. It is produced with oil and gas and becomes liquid phase when it arrives at the surface. The study of volcanic gas wells in China shows that this type of water production is low, usually stable with water-to-gas ratio of less than 0.2 m^3/m^3. It has slight to no impact on oil and gas production and can be ignored [18].

The second type, water-bearing layers interbedded within the hydrocarbon formation, are not connected to and are independent of the hydrocarbon layers. After the well is drilled, if the cementing job is incomplete, the water from these intervals can enter the wellbore through the voids/channels in the cement. The water can go down to the well bottom and be lifted with the gas. This type of water impacts the wellbore, hydrocarbon formation, and production. The study of volcanic gas wells in China shows that the gas production rate decreases with increasing water rate until the gas/water production ratio finally stabilizes, with significant loss of wellhead pressure due to the water-lifting operation [18].

The third and most influential type of water source is the edge/bottom aquifer. Water can enter the hydrocarbon formation when the reservoir pressure declines to a specific value, driven by the pressure difference between the hydrocarbon reservoir and the aquifer and the expansion of the aquifer.

3.3.2. Water Production Patterns

Water production patterns are determined by water sources (as stated above), water-oil/gas contact, and fracture distributions.

After the well bottom-hole flowing pressure drops to a low level, a pressure differential will drive bottom/edge water up through volcanic hydrocarbon formations.

In most cases, due to natural and hydraulic fractures or faults across the volcanic reservoirs, the water breaks through fractures, causing oil and gas production rates to decline dramatically or even stop. In some cases, water coning can occur when there are not many fractures between hydrocarbon formations and the aquifers. This can be indicated by the pressure buildup test interpretation.

Many kinds of natural fractures may occur in the volcanic reservoirs, and most wells are hydraulically fractured. Field data show that [18] in the presence of natural and artificial fractures, water intrusion and breakthrough are more evident and harmful to production, because the fracture networks will be filled with water and block the oil and gas flow, leading to sharp decrease in oil and gas production, reserve loss, and cost increase.

For horizontal wells, we can use production logging to obtain the production profile and identify the location of water accumulation in the well, as well as the water depth. We can analyze the salinity and chloride content of the produced water sample, compare it with that in the formation water sample, and determine whether the well is producing formation water or connate water.

3.3.3. Water Control Measures

Besides lifting the produced water from the well, preventative and remedial measures may be taken to decrease, delay, or even avoid water production. The following are some water control measures:

(1) Produce below the critical producing rate using the wellhead choke; thus, minimize water coning by controlling bottomhole pressure. The critical rate is a function of the perforation length. As the perforation length increases, the critical producing rate decreases. If the critical rate is less than the minimum economic rate, then operators have no choice but to produce above the critical rate or abandon the well. There are some analytical solutions and empirical correlations regarding critical producing rate calculation [53–60], although the most reliable way to study coning and critical producing rate is numerical simulation.
(2) Perforate the pay zone with partial perforation or penetration. Only a limited portion of the pay thickness is perforated. The portion near bottom water contact is avoided. This approach sacrifices hydrocarbon production in the hope of avoiding coning.
(3) Control hydraulic fracture height and avoid water intrusion by creating a barrier layer at fracture bottom. This barrier layer can be a low-permeability subsidence agent, such as 40/70-mesh + 100-mesh proppant slurry [61]. Also, fracture height can be controlled by injecting an appropriate amount of fracturing fluid at the optimum pumping rate.
(4) Adopt horizontal wells to produce at higher rates while under higher bottomhole flowing pressure and smaller pressure differential between wells and reservoir so that the pressure differential is not large enough to induce the intrusion of water. Also, horizontal wells should keep a proper distance above the aquifer.
(5) Implement complete cementing jobs to avoid channels between the casing/cement/borehole. Check and ensure the cement bond integrity after cementing. This will ensure isolation of water layers from pay layers.

3.4. Well Testing

Well testing measures the production of a well for a period of time, either at the well head, or at a production facility, for the purpose of formation evaluation and field appraisal. It is used to estimate reservoir parameters such as permeability, pressure, drainage volume, boundaries, fracture characteristics, water drive, skin of the well, fluid properties, and hydraulic connectivity/transmissibility. This technique is critical to understand the original and dynamic properties of volcanic reservoirs and to take remedial actions accordingly during production. Different types of well testing include the drawdown test, buildup test, initial potential test, interference test, etc., among which the buildup test is the most used.

All interpretation models are based on assumptions of homogeneous formations of constant thickness. However, the well testing curves gained from volcanic reservoirs are different due to the complicated structures/heterogeneity of the volcanic formation, as indicated in the following scenarios.

One common scenario is the presence of radial composite reservoir characteristics due to strong horizontal heterogeneity of a formation. For example, if the outer zones of the well have higher porosity, permeability, or hydrocarbon saturation compared with the inner zones, the well production will exceed calculated volumes. In this case, the well production potential is underestimated by the productivity evaluation. On the other hand, if the near-wellbore reservoir properties exceed those of the distal reservoir, well production may be overestimated.

A second scenario develops when natural fractures are determined to be widely developed according to core analysis, FMI logging, and other measurements. However, the well test interpretations do not suggest the presence of natural fractures, which are usually indicated by the parallel curve of bilinear flow regime in the log–log plot. The reason is that natural fractures in some volcanic reservoirs are of small scale, and the bilinear flow regime in those reservoirs cannot form without artificial fractures.

The third scenario that results in complicated well test analyses involves water production from bottom or edge aquifers. In these situations, the derivative curve will decline after water yield, and the relative permeability of oil/gas may decrease to $\frac{1}{4}$ of the original value [21]. Engineers can take actions before considerable water yield according to the water-yielding feature on the curve and the presence of aquifers proven by geology studies.

3.5. Productivity Evaluation for Production Allocation

Well productivity evaluation is performed to understand well performance and confidently allocate production rates.

Well productivity is decided by the reserves controlled by the well, i.e., the resource of hydrocarbon available to the well. The main controlling factors of productivity are formation structure, reservoir properties, edge/bottom water, and well type. A field's reserve is determined by (1) geological factors, including reservoir properties (porosity, permeability, hydrocarbon saturation, pressure, structure and drainage volume, fractures/faults, etc.), fluid properties (viscosity, wettability, etc.), drive mechanisms, and the presence and dynamic of the bottom/edge aquifer (the bottom/edge aquifer is more important, especially with the presence of natural and hydraulic fractures, since water intrusion can significantly affect oil and gas production and reserve); (2) artificial factors, such as company development technology and production plans; and (3) economic factors.

For wells in conventional reservoirs, the commonly used productivity evaluation method is to obtain the Absolute Open-hole Flow rate (AOF) to determine the production capability of wells [62,63]. Conventional AOF indicates the ideal maximum flow rate based on the testing data, but it does not provide the actual production capability of a well. It reflects the hydrocarbon provision capability of the pay zone near the wellbore but not the entire accessed reservoir volume.

AOF is used in the analysis of volcanic reservoirs, with the knowledge that AOF gained by well testing in these reservoirs may be overestimated or underestimated due to substantial reservoir heterogeneity, as well as the limited time of well testing. Zhu [64] suggested a new method to evaluate the well productivity potential by considering the outer zone and thus the entire volume of the reservoir assessed by a well in the well testing interpretation [64].

For hydraulic-fractured horizontal wells, many productivity prediction models have been proposed, considering breakdown fracture gradient, gas slippage effect, stress sensitivity, non-Darcy effect, and interference coefficient among fractures. These models may apply statistical and machine learning techniques such as gray relational analysis, Laplace transform, numerical inversion, etc.

Reserve estimation methods include four basic types: volumetric method, material balance method, decline curve analysis (DCA), and reservoir simulation. The volumetric method is used early in the life of a well or field when no or limited production data are available. The other three methods are used when a sufficient amount of field production data are available. At this stage, DCA is the predominant method and is quite accurate.

When the productivity potential of wells is adequately evaluated, the production allocation among wells can be conducted. The production rates for wells should be allocated carefully based on the controlled reserve of the wells, well productivity, fractures, aquifer activities, etc.

3.6. Well-Site Selection and Field Development

Due to the strong heterogeneity and complicated distribution of profitable zones of volcanic reservoirs, well-site selection may be more complex than that for conventional reservoirs. Well-site selection for volcanic reservoirs is based on the understanding and recognition of the profitable pay zones by the integration of seismic surveys, geology, well logs, reservoir engineering, and simulation.

A field development plan is designed based on the performance of the exploration well and projected field economics. A 3D reservoir geological model is built by integrating geological, geophysical, and petrophysical studies, as well as any available engineering data.

The optimal well locations are arranged in relatively high structural positions in areas of high reservoir quality, as indicated by lithofacies, lithology, porosity, permeability, and relatively abundant natural fracture systems [65]. Well trajectory is mainly horizontal, as long as practical, so as to obtain high well productivity while avoiding the risk of water coning.

4. Conclusions

To provide the world's petroleum industry with an overview of volcanic reservoirs, we have presented the geological characteristics and challenges and technological engineering solutions in the development of volcanic oil and gas fields based on lessons learned from Asian development operation. The results of these Asian experiences may assist operators with the development of volcanic hydrocarbon reservoirs worldwide. We conclude that the following are among the most important considerations when developing volcanic reservoir fields.

(1) Geological characteristics. Volcanic oil and gas reservoirs are highly complex and heterogeneous with diverse lithofacies and lithologies, pore-fracture systems, low porosity, and low permeability. This is due to the unique origins of volcanic reservoirs. The profitable zones are usually within the flooding, explosive, and subvolcanic (intrusive) lithofacies. Lithology mainly includes basalt (38.5%), andesite (15.9%), volcaniclastic (12.1%), and rhyolite (11.5%). Porosity ranges from 0.1 to 70%, and permeability ranges from 0.0007 to 762 md. In some developed volcanic reservoirs of China, the average porosity is 7.7–13%; the average permeability is 0.41–3.4 md.

(2) In engineering technology considerations, there are several crucial technologies to be emphasized.

   A. Horizontal well drilling: Horizontal wells may improve the production rate by approximately 4.7 times, the drainage areas about 4.3 times, and the recoverable reserves about 5.8 times in comparison with vertical wells according to Chinese experience. And longer horizontal wells are preferred, especially for thin reservoirs.

   B. Hydraulic fracturing (HF): Unique reservoir characteristics (such as deep burial depth, high in situ stress, high temperature, natural fractures, substantial heterogeneity, and developed fracture systems) render unique difficulties for HF, including, tip-screen-out, high fluid leakoff, formation damage, and inefficient HF operation. Special engineering solutions are suggested accordingly, e.g., small or mixed proppant size, second HF treatment after proppant slugging, high-viscosity frac fluid with high-temperature resistance, special fluid loss reducer, high pump pressure, Extreme Overbalance Perforating, limited-entry fracturing, matrix acidizing, etc.

   C. Water production control: Water production is common in volcanic reservoirs due to widespread fractures that connect formations with edge/bottom aquifers. This can cause oil and gas production rates to decline dramatically or even stop. The water control measures include producing below critical rates, partial perforation or penetration, controlling hydraulic fracture height, using horizontal wells, implementing complete cementing jobs, etc.

   D. Well testing: Well testing is critical to understand the dynamic properties of volcanic reservoirs and take actions accordingly during production. The well testing curves for volcanic reservoirs are different due to reservoir heterogeneity and water production.

   E. Well productivity evaluation: Well productivity evaluation is necessary to understand well performance and appropriately allocate production rates among wells. The main controlling factors of productivity are formation structure, reservoir property, edge/bottom water, and well type. The modified AOF method should be used. And many productivity prediction models have been proposed considering breakdown fracture gradient, gas slippage effect, stress sensitivity, non-Darcy effect, and interference coefficient among fractures.

F. Well-site selection. For field development, well sites need to be selected based on recognizing profitable lithologies, lithofacies, high porosity and permeability, relatively developed fracture systems, thick net pay zones, etc.

(3) Advantages, limitations, and outlook of future research.

Although there have been some reviews on the geological aspects and exploration technologies for volcanic reservoirs in the literature, there is little systematic review of engineering technologies. Our goal was to fill this gap with one of the first papers to systematically summarize the engineering technologies and unique solutions used to develop volcanic reservoirs. Further and more complete reviews should be carried out as new technology and approaches are developed in the future.

Among the critical issues for volcanic reservoirs are how to enhance hydrocarbon recovery with more efficient and economic hydraulic fracturing and water control techniques. We have reviewed and summarized these unique state-of-the-art solutions in this paper. More novel and effective techniques can be explored and field-tested in the future.

Fracturing flooding technology may be explored and tested on volcanic reservoirs for enhanced oil recovery, and novel injection fluids such as nanoparticles, silica gels, etc., may be used to enhance future development.

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