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A Novel and Sustainable Nonaqueous Insulating Packer Fluid

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Abstract

Ensuring well integrity for the life of a well is a crucial challenge faced in the industry. Heat transfer between formation and fluids in the tubing or annulus fluids can result in undesired annular pressure buildup (APB), leading to integrity problems such as collapsed tubing and casing burst. Heat transfer across the wellbore also poses environmental concerns like thawing of surrounding permafrost in arctic environments. Remediation involves costly and unsustainable intervention methods such as killing the well or performing complicated workover operations. Using vacuum-insulated tubing is a conventional practice in the industry to mitigate APB by restricting heat transfer from production flow to casing and surrounding formation, but this mechanical solution used alone has several limitations. Hence, a chemical solution should be included to increase the effectiveness of operations. A chemical solution is placing an insulating packer fluid (IPF) into the wellbore. However, conventional IPF with crosslinking agents does not always provide results that satisfy flow assurance requirements. This leads to the need for developing a more sustainable and robust IPF solution with long-term stability at wide range of temperatures.

A novel nonaqueous insulating packer fluid (NAIPF), containing base oil with a newly designed synthetic polymer forms a unique micelle structure chemistry under static conditions. The chemistry provides sufficient viscoelastic properties and yield stress without need of crosslinking agents to minimize convective heat loss in conjunction with low thermal conductivity. The NAIPF exhibits stable rheological properties at high temperatures and provides conductivity superior to water-based IPF systems. With no requirement of any additional solids, it can be recovered back on surface when needed and reused, providing additional sustainability benefit.

In this paper, we characterize the micelle structure based NAIPF with different base oils. Validation of chemistry required extensive laboratory study for a period of 2 years prior to being ready for field trials. NAIPF were formulated with different base oils, tested for key properties including thermal conductivity, yield stress, and thermal stability. Extended aging was conducted at temperatures varying from ambient up to 350°F for prolonged periods of time to test fluid stability. Field application required detailed discussion about performance expectations to identify the challenge the fluid intended to address.

The NAIPF has been successfully deployed on multiple projects globally including Arctic, South America and West Africa. Performance was further validated during a well re-entry to monitor pressures confirming the fluid maintained its properties over extended period. This paper presents the design and implementation of the NAIPF, including methods developed to optimize fluid mixing, transport, and wellbore displacement. The system's ability to limit conductive and convective heat transfer while maintaining stability makes it an economical and sustainable chemical solution to offer maximum protection against well integrity and production complications.

Introduction

The phenomenon of thermal energy transfer from a medium at higher temperature to surrounding medium at lower temperature takes place by three distinct mechanisms: conduction, convection, and radiation (Welty 1974).

Conduction is the transfer of kinetic energy through direct molecular contact. It can take place between molecules of solids, liquids, or gases. The intrinsic ability of any material to conduct heat is known as its thermal conductivity (Thermtest 2023). The rate at which a material transfers heat by conduction is through a given unit area commonly denoted by k, λ, or κ with a unit of BTU/hr•ft•°F or W/m•°K (Oluseyi et al. 2021). In solids, it takes place due to the vibrational forces of the molecules and energy transport by free electrons rather than bulk material movement. In fluids (i.e., liquids and gases), heat transfer occurs due to the collision and diffusion of molecules during their random motion. In the case of fluids, since the intermolecular spacing is much larger and the motion of the molecules is more random, thermal energy transport is less effective. Hence, the thermal conductivity of gases and liquids is generally lesser than that of solids (Nuclear Power 2023).

Convection is the bulk movement of the liquid under the driving force of density differences in the liquid. Hot liquid will expand, becoming less dense, and will rise; cool liquid will contract, becoming denser and sinking (Campbell 2015). There are two types of convection: free and forced convection. Free convection is gravity driven, where the fluid moves away from the heated body as the warm fluid rises and is replaced by a cooler parcel of fluid. In forced convection, fluid is forcibly moved across the body surface and removes heat from the body (Sokolova 2019). Convective heat transfer is determined by thermal conductivity (k value), viscosity, and configurative dimensions such wellbore casing size, where the unit of measure is denoted by BTU/hr•ft^2•°F or W/m^2•K. By increasing the viscosity, convection can be minimized or prevented.

Radiation heat transfer is the energy that is emitted by matter in the form of photons or electromagnetic waves (Shahidian et al. 2020). Heat waves which are emitted may be absorbed, reflected, or transmitted through a colder body medium. Most upstream oil and gas applications use conduction, convection, or a combination of both. Temperature conditions are usually not hot enough for radiation to be a significant mechanism (Stewart 2021). Hence, radiation is often omitted in temperature profile calculation for wellbores.

To maintain production flow and well integrity in cold temperatures, deepwater, and arctic environments, insulating packer fluids (IPFs) are used to control conduction and convection. A thermally insulating IPF is pumped into the annulus of the well as a packer fluid. It aids to control heat transfer from the production tubing to the outer annuli. To meet the heat loss reduction requirements depending on the wellbore conditions, an IPF design must exhibit low thermal conductivity value (*k*, BTU/hr•ft•°F), while also have sufficiently high yield stress to reduce convection and overall heat transfer coefficient in the wellbore. However, conventional packer fluids provide very little thermal insulation. Addition of viscosity provides improvement; however, it is not always reliable. Stable rheological behavior of the fluid in extended static conditions is critical to control convective heat loss in the wellbore, but also needs to be operationally viable. An overly viscous fluid reduces convective heat transfer but may be too thick to pump, or the opposite may occur where a fluid initially has low viscosity for placement but thickens further and sets during static periods which then may be too thick to displace.

In an oil-based environment, a crosslinked polymer system is the most common IPF used in oil and gas industry as a chemical solution. The crosslinked polymer provides a good yield stress rheological profile but lacks robustness where effectiveness may be compromised by downhole contamination. To address this issue, non-crosslinked NAIPF was developed, and stress tested to overcome the above limitations. The novel polymer is mixed in various base oils exhibiting shear thinning behavior, which provides ease of pumping and displacement, but also develops sufficient viscosity to provide the desired reduction in heat loss.

Applications

Wellbore Integrity

Subsidence. Permafrost is defined as rock or soil with ice that stays frozen for two or more years. It usually lies below an "active layer" of soil that freezes and thaws every year (Portner et al. 2019). Permafrost occurs in many different forms with various amounts of ice (continuous and discontinuous) and is mainly found in areas near the Arctic. In Alaska, about 80% of the ground has permafrost underneath it (Osterkamp et al. 2009). When heat escapes from the production or injection string of a well in a permafrost environment, the frozen soil starts to thaw, making the ground unconsolidated and mobile. As thaw subsidence adjacent to oil wells deepens, it induces large drag loads through negative skin friction and leads to strain damage and even failure of the well casing (Yang et al. 2020). This induces stress on the casing, causing wellheads to sink several feet into the ground. It can also cause the tubing to buckle or fail completely, releasing hydrocarbons into the environment. Insulating the heat from the well considerably reduces these risks.

Annular Pressure Buildup. In subsea environments, the wellhead has limitations in monitoring and bleeding off pressure from isolated annuli (Perdana et al. 2015). APB, caused by fluid thermal expansion in the confined annuli, can lead to casing failure or tubing collapse, especially during the hours of the starting period of production or injection (Liu et al. 2015). A method to mitigate APB is using an IPF. Reducing the heat transfer to the isolated annulus limits thermal expansion of annulus fluids.

Gas Migration. Gas hydrates are found in permafrost environment and in overburden sections of deepwater wells. These hydrates, when melted, release gas that can migrate outside the casing and cement, channeling to the surface. These channels act as conduits for hydrocarbons to flow to surface. An effectively designed IPF can prevent gas hydrate melting.

Thermal Cycling and Material Fatigue. The intermittent starting and stopping of production or injection leads to a change in wellbore temperature and pressure. These cyclic stresses can cause fatigue to the production tubing. An IPF helps to maintain consistent temperature for longer periods of time, reducing the rate of temperature change, and, in turn, avoids material fatigue.

Flow Assurance

Paraffin Deposits. Many crude oils contain paraffins that precipitate and adhere to the pipe walls as the temperature of the producing stream decreases. Heavy paraffin deposits reduce the effective size of the flow conduits and restricts production rate (Jorda 1966). This paraffin normally consists of high-molecular-weight hydrocarbons, both straight-chain and branched, resins and asphaltic materials, occluded oil and water, and possibly sand and silt (Noll 1999). Severe paraffin deposition can result in operational downtime and increased associated removal costs. Maintaining higher temperature of oil by using an IPF prevents or reduces the tendency for paraffin wax deposition.

Hydrate Formation. Subsea wells with high pressure and low temperature encounter formation of gas hydrates. Hydrate crystals form when produced fluid contains water and hydrocarbon gases. Hydrates can block transmission lines, plug blowout preventers, cause tubing and casing failure and foul pipes, heat exchangers, and valves (Oyeneyin, 2015). Hydrate blockages in a subsea flowline system are most likely to be found in areas where the direction of flow changes in the well, pipeline, and riser parts of a system (Bai et al., 2019). Maintaining higher temperature on the produced oil by IPF placement mitigates hydrate formation tendencies.

Scale Deposits: Scale deposition can lead to formation damage, permeability reduction, downhole equipment failure, and production loss. There are three mechanisms by which inorganic scale is formed: (1) incompatibility between injected water and formation fluid, (2) certain pressure and temperature changes that lead to dissolved salts reaching saturation point forming scale crystals, and (3) evaporation of water leaving the salts downhole (Mahmoud et al. 2022). Maintaining a suitable temperature by using an IPF can increase solubility for certain types of scale.

Salt Deposits: Salt deposits can occur when the produced fluid comes from a brine flow. The fluid cools as it exits the reservoir. As in the scaling mechanism, maintaining an appropriate temperature in the wellbore utilizing an IPF maintains the solubility of solids to prevent deposition.

Viscous Crude: Heavy oil exhibits very high viscosity at low temperature, which, in turn, significantly increases friction forces and reduced flow rate. This makes it difficult to maintain production rate.

System Additives

Base Oil

A variety of different base oils are used in the industry depending on geography, performance, and environmental impact. When using most mineral oils as base fluid, the novel NAIPF exhibits good yield at room temperatures and up to a maximum application temperature of 300°F (149°C). When using synthetic oils, the NAIPF yields at 120°F (49°C) and has a maximum application temperature of 400°F (204°C). Testing demonstrated that crude oil is not suitable for use as base fluid as it has a wide range of aromatic content resulting in inconsistent rheological properties of the NAIPF. Diesel can be used; however, it requires project-specific testing as diesel can have variations based on geography.

Novel Polymer

The newly developed polymer has superior thermal stability characteristics. The thermal stability of the polymer was tested in thermogravimetric analysis (TGA). TGA is an analytical technique used to determine a material's thermal stability and its fraction of volatile components by monitoring the weight change that occurs as a sample is heated at a constant rate. Figure 1 is a TGA thermogram of the newly developed polymer. It shows that the polymer is stable above 550°F (288°C) in the presence of air and above 700°F (371°C) in a nitrogen atmosphere.

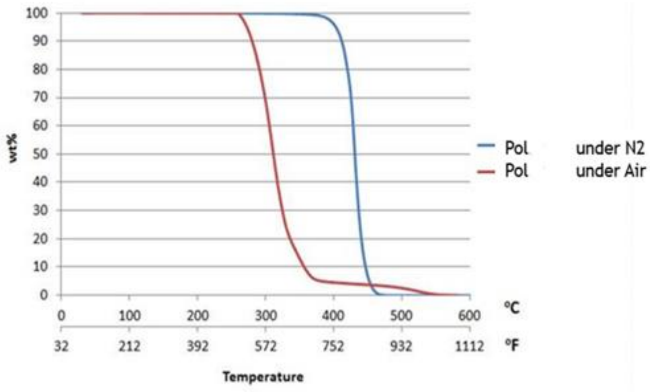

Figure 1 – Novel polymer stability by TGA thermogram.

When the polymer is mixed with the base oil, it adsorbs and swells and provides bulk viscosity, with a milky appearance. The bulk viscosity does not have good yield stress behavior. The behavior of the polymer is exceptional in that it slowly changes from bulk viscosity to yield stress fluid by forming a micelle structure. The white color nature in Figure 2 shows bulk viscosity, and the transparent color shows the micelle structure formation.

Figure 2 – Initial polymer system appearance (left) and appearance after micelle formation (right).

Temperature speeds up the kinetics of this conversion. The yield stress behavior is essential for IPF application because, at higher yield stress, the fluid behaves like a solid, and heat loss due to convection stops. The most important requirement is the need for critical polymer concentration. The critical polymer concentration varies with the base oil and temperature. The blue line in Figure 3 indicates that the system has a below-critical concentration of polymer.

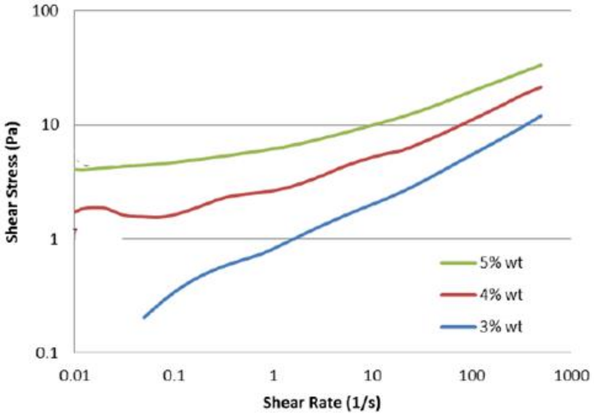

Figure 3 – Critical polymer concentration.

Once the system reached the micelle structure, then it is stable for years. The standard concentration of the novel polymer in base oil varies between 12 to 20 lbm/bbl depending on the base oil and bottomhole temperature. The reason or mechanism behind the micelle structure is the solubility and arrangement of the polymer. Figure 4 provides a graphical representation of this micelle structure.

Figure 4 - Graphic representation of a micelle formed by novel polymer in base oil.

Laboratory Evaluation

The next important requirement for an IPF is its long-term stability. Unlike a drilling fluid or fluid loss control pill, the system may remain in the wellbore for several years. Hence, studying the long-term stability of the fluid system is key to deployment as IPF. In the below example, the NAIPF was prepared in Linear Alkyl Parafin and heat aged at 150°F (66°C) for 2 years. At this aging temperature, the micelle structure forms in an hour and thereafter the rheology of the fluid was stable for years. In the lab, the stability was measured for 2 years as presented in Table 1.

Table 1 – Long-term rheology of NAIPF aged at 150°F (66°C)

Heat-aging Time	600/300 RPM Reading	200/100 RPM Reading	6/3 RPM Reading	Tau 0 (lb/100ft^2)
Initial	216/169	145/114	52/46	43
1 Month	185/156	134/110	52/45	41
2 Months	185/155	138/112	53/46	42
3 Months	185/155	138/114	53/46	42
4 Months	187/156	137/115	53/46	42
5 Months	187/156	138/116	53/46	42
7 Months	186/156	137/115	52/45	41
9 Months	186/157	138/115	52/45	41
12 Months	186/157	139/116	53/46	42
15 Months	186/157	137/115	53/46	42
18 Months	184/156	134/114	54/47	43
24 Months	186/157	137/116	53/46	42

Note: Tau 0 = 1.66 × (2R3=R6)

In aromatic base oil, the novel polymer does not form a full micelle structure, and the micelle structure dissolves at a temperature higher than 150°F (66°). In mineral oil, the micelle structure is stable to 240°F (116°C), and the temperature is extended to 280°F (138°C) in internal olefin. The new NAIPF provides long-term stability in linear alkyl paraffin, even above 300°F (149°C). This behavior is depicted in Figure 5.

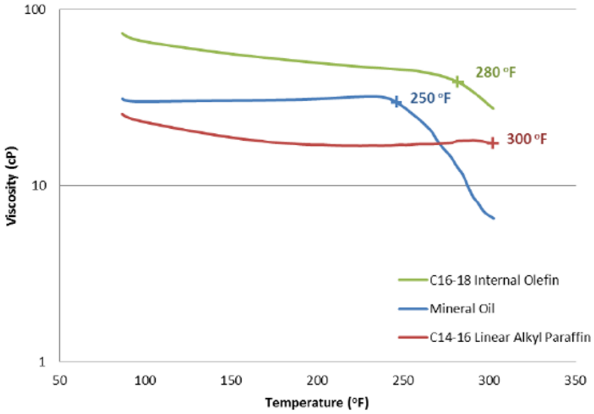

Figure 5 – NAIPF temperature stability in aromatic base oil.

The advantage of this NAIPF system is that by increasing the polymer loading, the workable temperature limit can be extended. For example, Figure 5 shows the yield stress of the system in mineral oil reduces above 250°F (121°C). This problem can be easily adjusted by increasing the polymer loading, as demonstrated by the viscosity against temperature plot in Figure 6.

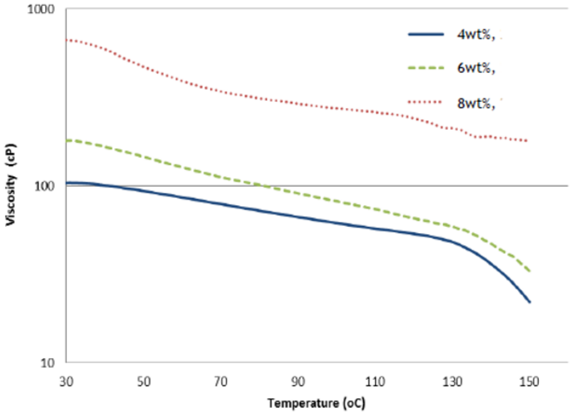

Figure 6 – NAIPF temperature stability in aromatic base oil with polymer concentration increase.

The NAIPF was heat aged at 250°F (121°C) for 2 weeks and the measured rheology is tabulated in Table 2.

Table 2 – NAIPF rheology with various base oil aged for 2 weeks at 250°F (121°C)

	Linear Alkyl Paraffin	Internal Olefin	Mineral Oil -1	Mineral Oil -2	Mineral Oil -3
600	225	189	372	393	309
300	150	123	258	258	210
200	129	102	210	207	168
100	99	78	150	144	120
6	39	33	45	36	33
3	36	30	36	27	24
Tau 0	33	27	27	18	15

The new NAIPF rheology is constant at a different temperature for the prolonged time, say years. This is important for the operations team because if the rheology decreases, that means the fluid is no longer stable. If the rheology increases with time, then it is not easy to pump the fluid back from the downhole to the surface for a workover operation. The prolonged constant rheology makes this new NAIPF unique and different from conventional IPF fluids. Conventional fluids exhibit increased rheology with time and after a certain time, they become solid.

Thermal Conductivity

Thermal conductivity was measured using the KD2 Pro Thermal Properties Analyzer shown in Figure 7. The thermal conductivity of the NAIPF depends on the base oil, and it is between 0.07 to 0.09 BTU/hr•ft•°F (0.12-0.14 W/m°K). It is 78% lower than water and 47% lower than an ethylene-glycol-based system. Hence, the new NAIPF provides superior insulation properties due to excellent yield stress properties.

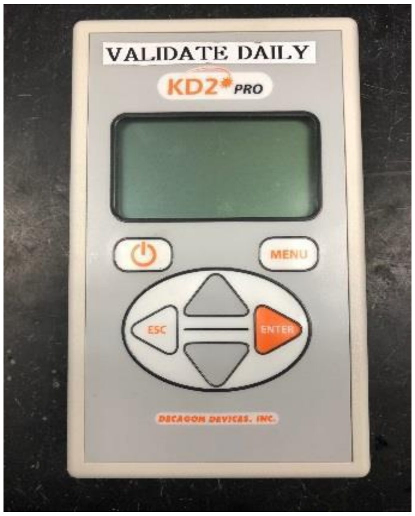

Figure 7 – KD2 Pro Thermal Properties Analyzer.

Comparison between Packer Fluid and IPF

The heat transfer due to convection is measured using the laboratory test setup shown in Figure 8. There are four sensors on each tube: two at the bottom and two at the top. In the bottom and top, one sensor is towards the outside and one sensor is towards the inside. At the center of the tube, there is a heating rod that heats the fluid. All four sensors at four different places measure the temperature. Generally, we use normal fluid in one tube and IPF in another tube. In normal fluid, the outside sensors read high temperatures compared to IPF. The reduction of heat transfer is due to the convection process of IPF.

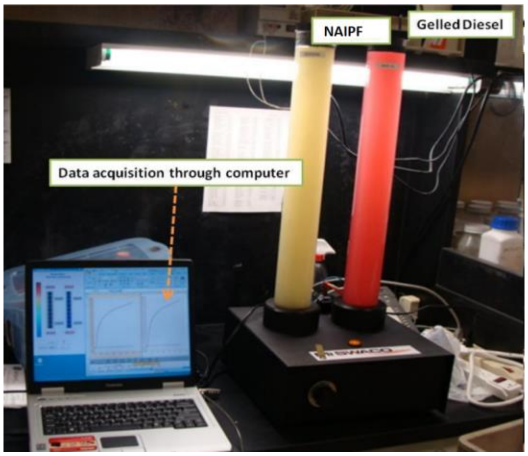

Figure 8 – Laboratory setup: Measuring convective heat transfer.

In Table 3, the conductive heat transfer coefficient for all the fluids is same because of the same thermal conductivity value. Free arctic diesel has no viscosity; because of that, heat transfer due to the convection is 90%. Gelled diesel has bulk viscosity but yield stress is low compared to both NAIPF prepared with mineral oil and arctic diesel as base fluid. Yield stress fluid provides better heat transfer reduction compared to other fluids.

Table 3 – Heat transfer properties comparison of novel NAIPF and conventional packer fluids

	NAIPF (Mineral Oil)	NAIPF (Arctic Diesel)	Gelled Diesel	Free Arctic Diesel
Conductive Heat Transfer Coefficient (BTU/hr•ft^2•°F)	0.33	0.32	0.33	0.33
Overall Heat Transfer Coefficient (BTU/hr•ft^2•°F)	0.48	0.47	0.56	3.14
Thermal Conductivity (BTU/hr•ft•°F)	0.071	0.068	0.069	0.069
Percentage of Heat Transfer due to Convection	31.3%	31.9%	41.1%	89.5%

Mixing and Preparation

The NAIPF can be mixed at both rig site and liquid mud plant. One method to transport and pump the NAIPF is utilizing a heat truck, since heat lowers the fluid rheology to assist with pumping. A heat truck is not required for all operations. For aromatic-type base oil, a heat truck is recommended because the concentration of the polymer is higher, so the rheology at room temperature makes the pumping difficult. Utilizing a heat truck solves the pumping issue. For other base oil, a heat truck is not needed unless the bottomhole temperature is higher than 300°F.

Displacement Methods

As with any fluid displacement, placing the NAIPF in the wellbore requires consideration of well geometry, operational status, pit management, available equipment, and hydraulics modelling to establish pumping parameters and resulting pump pressure limitations. Placement may be carried out either by direct annulus displacement or tubing displacement.

Direct annulus displacement where the NAIPF is pumped directly down the annulus where it is required to be placed is usually preferred over tubing displacement. This is as the fluid being displaced out is generally of higher density and the high viscosity of the NAIPF results in a large interface and increased cost. When bull heading the NAIPF into an outer annulus, it can be displaced by brine or inhibited water.

If tubing displacement is unavoidable, it can be managed by spotting the NAIPF in place followed by base oil to dissolve the residual polymer and clean the tubing string. Spacers can also be pumped ahead of the NAIPF to reduce the potential fluid interface volume.

Field Deployments

The novel NAIPF solution has been successfully implemented on several projects globally. Below is a summary of key geographic field application examples.

Alaska. To date, the NAIPF has been deployed on 17 producers and 7 injector wells in the North Slope for permafrost protection and to mitigate subsidence risk. Typical bottomhole temperature (BHT) of these wells was approximately 250°F / 121°C. Design modeling indicated a 47 to 56% reduction in heat transfer by utilizing NAIPF when compared to conventional brine-based packer fluid. The NAIPF was designed to cover up to 2,000 ft (610 m) of outer annuli on these wells. The NAIPF for these applications were bullheaded down the outer annulus at 1 to 1.5 bbl/min pump rate, with observed pressured of 1,150 to 1,250 psi at the pump truck and 650 to 750 psi at the wellhead. The representative resultant heat transfer properties of the final designed 6.9 lbm/gal (0.89 sg) NAIPF using a mineral base oil were:

Thermal conductivity (k) 0.074 BTU/hr•ft•degF
Specific heat capacity (C_p) 0.513 BTU/lbm•degF

Angola and Nigeria. The NAIPF was successfully placed on 20 wells in Nigeria and 5 wells in Angola. These deepwater development wells exhibited a BHT range of 130 to 150°F (55 to 65°C). The wells were exposed to risk associated with low seabed temperatures of 40°F (4°C) from 1,270 m to 1,700 m, wax/scale precipitation, and hydrate formation. The NAIPF designed with different mineral base oils was successfully used on these wells to mitigate the risk. The fluid was placed in the annulus in reverse through the kill line with high-viscosity brine and base oil ahead and then chased with base oil.

Argentina. The NAIPF was used on two producer wells in Argentina at BHT of 65°C. The design was similar to Angola and Nigeria applications employed using a mineral base oil as the base fluid for the formulation.

Mexico. An operator was faced with the challenge of re-entering suspended wells in offshore Mexico to recomplete. The requirement was to minimize thermal-induced stress as well as the thermal fatigue from high flowing temperatures of up to 310°F during the production life of the wells, estimated to be approximately 25 to 30 years. The NAIPF was successfully spotted in two wells: 110 & 267 bbl (2- & 6.5-hour pumping). Mixing was optimized in the LMP, saving 36hrs of mixing at rigs & eliminated contamination risk. The operator was successfully able to put both the suspended wells in production.

Conclusion

The novel NAIIPF is based on micelle structure and is compatible with several base oils. The new system is thoroughly validated in the laboratory with verification of the temperature limit, long-term stability, and compatibility. The system was successfully mixed and pumped in several wells around the world. The fluid provides superior performance by eliminating well integrity issues due to permafrost and other conditions. In a few cases where the fluid was displaced out of the wellbore after a few years, it had maintained its stability.

Acknowledgments

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Nomenclature

APB = Annular Pressure Buildup
IPF = Insulating Packer Fluid
NAIPF = Non-Aqueous Insulating Packer Fluid
TGA = Thermogravimetric Analysis

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