Experimental Study of Improving Nigerian Heavy Crude Oil (Agbabu Bitumen) Viscosity Reduction by Dilution with N-Heptane, Phenol, Toluene, Xylene, And Naphtha

[1]Adetokunbo FALADE ,[1]Temitope ONI & [2]Diran OLANIYAN
[1]Department of Mineral & Petroleum Resources Engineering, School of Engineering, Federal Polytechnic, Ado Ekiti.
[2]Oulu Mining School, University of Oulu, Finland.
Corresponding author's Email: ademola201052@yahoo.com

Abstract:

This experimental study examines the viscosity reduction of Nigerian heavy crude oil, specifically Agbabu bitumen, through dilution with selected solvents including naphtha, n-heptane, phenol, toluene, and xylene. The influence of pressure variation on solubility-driven viscosity reduction was investigated. Solubility tests of bitumen in each solvent were conducted at pressures of 20, 80, 140, 200, and 260 psia. The results indicate that bitumen solubility increases with pressure for all solvents, with xylene exhibiting the highest solubility of 13.0 mol/dm³ at 260 psia. Kinematic and dynamic viscosities were measured using a Redwood viscometer at minimum and maximum solubility conditions. Xylene achieved the highest viscosity reduction, with dynamic viscosity decreasing from 390.6 cP to 13.95 cP and kinematic viscosity reducing from 420 cSt to 15.0 cSt. The study highlights the superiority of aromatic solvents for viscosity reduction of Agbabu bitumen, providing insights useful for heavy crude oil production and transportation. The discoveries of this study contribute to the development of cost-effective and efficient approaches for enhancing the production and transportation of heavy crude oil. The results also give valuable insights into the thermodynamic and rheological behavior of heavy oil- solvent mixtures under varying pressure conditions. This study's results can be applied to optimize the design and operation of heavy oil production and transportation systems, in the end improving the economic viability of heavy oil resources.

Keywords: Viscosity, Heavy Oil, Solvent, Dynamic, Kinematic

Introduction

According to Ebii (2015), bitumen is defined as a highly viscous and dense hydrocarbon that occurs naturally within tar sands where it is typically intermingled with water, sand, and clay. Bitumen is classified as a subclass of heavy crude oil and requires viscosity modification prior to production and refining. Nigeria hosts appreciable volumes of this resource, with reserves estimated at approximately 38 billion barrels of heavy oil and bitumen combined (Milos, 2015).

Bitumen represents a subclass of heavy crude oil distinguished by extremely high viscosity and low API gravity.

Nigeria hosts appreciable volumes of heavy oil and bitumen resources, with reserves estimated at approximately 38 billion barrels (Milos, 2015). Although smaller than Canadian and Venezuelan deposits, Agbabu bitumen remains strategically important to Nigeria's energy mix.

Bitumen remains a critical unconventional hydrocarbon resource entrenched within tar sands—sedimentary deposits consisting of sand, clay, and water—rendering it naturally immobile due to its high viscosity (Ebii, 2015). Nigeria harbors significant bitumen reserves, most notably in Agbabu, estimated at around 38 billion barrels (Milos, 2015).

Physicochemical constraints dominate production challenges. Asphaltenes-high-molecular-weight aromatic compounds-combined with impurities such as CO_2 and H_2S elevate viscosity and stabilize the colloidal structure, inhibiting flow (Wei, 2013). These properties render conventional production methods used for lighter crudes ineffective.

Extracting and refining this heavy petroleum relies heavily on overcoming its intrinsic high viscosity and complex composition.

To counter these issues, enhanced recovery techniques have evolved, encompassing thermal methods, core annular flow modulation, and, importantly, solvent-based dilution (Martínez, 2011).

In tandem with such techniques, detailed geological and engineering investigations of Agbabu bitumen have provided valuable insights. Geophysical tomographic studies using electrical resistivity tomography (ERT) and ground magnetic profiling have confirmed substantial lateral continuity and thickness of bitumen layers at shallow depths (~3–23 m), though overlying clay layers may introduce groundwater vulnerability (Ogunlana et al., 2019; Iwueze, 2021; Adigun, 2020. Laboratory characterization indicates high specific gravity, low API gravity, and SARA distributions comparable to Athabasca bitumen (Ogiriki et al., 2018). This similarity suggests that solvent-based recovery strategies applied elsewhere may be transferable to Nigerian bitumen.
Solvent-assisted recovery methods have been explored. Akinsete et al. (2024) demonstrated that aromatic solvents such as toluene significantly enhance solubility and viscosity reduction, while methanol promoted asphaltene aggregation.. These findings highlight the importance of solvent chemical class and molecular interactions in viscosity reduction

Environmental considerations are critical. Bitumen-associated contaminants such as PAHs and heavy metals have been detected in groundwater near Agbabu, raising exploitation concerns (Olajire et al., 2008; Eganoosi, 2021).
Despite extensive studies on Nigerian bitumen composition, limited attention has been paid to pressure-dependent solvent dilution as a mechanism for viscosity reduction. This study addresses this gap by systematically evaluating solubility–viscosity relationships under controlled pressure conditions.
Chemical assays also revealed elevated heavy metals and polycyclic aromatic hydrocarbons (PAHs)—notably chrysene and fluorene—in some Agbabu and nearby deposits, raising environmental and health concerns during exploitation (Ademila, 2019).

Solvent-aided methods have been specifically assessed for Agbabu bitumen recovery. A study published in *Petroleum Science and Technology* (Akinsete et al., 2024) revealed that bitumen exhibits high solubility and viscosity reduction—especially with toluene at elevated pressures— while methanol increased asphaltene content and viscosity, underscoring the importance of solvent selection. Additionally, composite solvent studies (from other heavy oil fields) demonstrated that combinations like toluene-cyclohexane could recover up to 99% of bitumen via favorable SARA extraction dynamics (PubMed, 2022). Similarly, supercritical CO_2 modified by alcohols (e.g., ethanol) achieved recovery rates up to 24.5% at high pressures (60 MPa), although asphaltene rejection and fraction compositions varied (ACS Energy & Fuels, 2014).

Environmental aspects cannot be overlooked. Bitumen contaminants—such as n-alkanes, PAHs, and heavy metals—have been detected in soil and groundwater near Agbabu, indicating seepage and contamination risks from both geogenic and anthropogenic sources (Olajire et al., 2008; Eganoosi, 2021). Emulsion-based recovery approaches using biodegradable surfactants have shown promise in viscosity reduction (e.g., a 64% decrease using plant-derived surfactants) and may offer environmentally friendly pathways (Olabemiwo et al., 2024).

The rheology of heavy crude is strongly influenced by its chemical composition. Wei (2013) recognized asphaltenes with high molecular weight in addition to hydrocarbon impurities such as carbon dioxide (CO_2), nitrogen, and hydrogen sulfide (H_2S), as the major factor responsible for the elevated viscosity of heavy oils. This explains why bitumen recovery through conventional production strategies used in the production of lighter oils are often inappropriate.

In recent years, several enhanced and improved recovery and viscosity reduction techniques have been deployed to overcome these limitations. According to Martinez (2011), the following are among the commonest techniques designed to improve flow behavior and transportation efficiency, these include thermal reduction methods, dilution with lighter hydrocarbons, and core annular flow technology. Solvent dilution because of its capacity to lower viscosity, improve solubility, and alter flow properties of bitumen has gained prominence.

In this study, toluene, n-heptane and xylene solvents are introduced into the heavy oil matrix to disorient the intermolecular interactions and improve mobility. Experimental studies investigate their effects on flow behavior under controlled conditions of temperature, solvent concentration, and applied pressure. The rheological responses of solvent–bitumen mixtures are then evaluated under deformation to establish flow profiles. Moreover, diffusion studies at conditions such as 35.5 °C and pressures up to 72.5 bar (equivalent to ~1050 psi) have been proposed to understand how solvents penetrate the bitumen structure and affect its flow. Such datasets also serve as critical inputs for reservoir simulation and predictive modeling.

The knowledge gap addressed by this study stems from earlier findings by Ogiriki (2018), who noted that the recovery of bitumen requires more sophisticated approaches than those applicable to conventional crude oil. This is due largely to its exceptional viscosity and complex flow mechanics. Previous research on Nigerian tar sands has examined chemical composition and recovery techniques, but relatively little attention has been paid to the fundamental roles of dilution and diffusion in enhancing solvent-assisted recovery.

2. Agbabu heavy oil field and the Eastern dahomey basin region.

The Agbabu heavy oil field lies within the Eastern Dahomey Basin, Ondo State, Nigeria. Recent studies report API gravity values of 8–11° and high specific gravity (Akinsete et al., 2025), classifying it as very heavy crude oil. Viscosity increases sharply with decreasing temperature, exceeding 10^4 cSt at low temperatures. Aromatic solvents such as toluene and xylene exhibit superior dilution performance compared to aliphatic and polar solvents.

Materials and Methods

Basis for Solvent Selection

The solvents were selected to represent distinct chemical classes and interaction mechanisms: n-heptane and naphtha (aliphatic diluents), toluene and xylene (aromatic solvents with strong asphaltene affinity), and phenol (a polar organic solvent used as a contrast case).

. N-heptane and naphtha represent aliphatic solvents, toluene and xylene represent aromatic solvents with strong asphaltene affinity, while phenol serves as a polar organic solvent for comparative evaluation.

Solubility Tests

The solubility of Agbabu bitumen was assessed using **a fixed solvent volume of 20 mL combined with 2.0 g of bitumen,** corresponding to a **weight-to-volume ratio of 0.10 g/mL**. This ratio was maintained for all solvents to ensure comparability across tests.

Solubility experiments were conducted at pressures of 2**0, 80, 140, 200, and 260 psia.** Solubility was calculated as mol/dm³ using the measured mass of dissolved bitumen at saturation.

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Filtration Observation

During sample preparation, the bitumen–solvent mixtures were passed through a 150-mesh wire cloth filter. Noticeable asphaltene precipitation was observed on the filter during n-heptane tests, consistent with the known poor solvency of aliphatic solvents for asphaltenes. No visible precipitation was observed for aromatic solvents.

Viscosity Measurement

Kinematic viscosity was measured using a Redwood viscometer in accordance with ASTM D445. Dynamic viscosity was calculated from kinematic viscosity and density. All viscosity measurements were performed at minimum and maximum solubility conditions to assess solvent effectiveness.

All viscosity values are reported consistently in cP (dynamic viscosity) and cSt (kinematic viscosity).

The experimental study on improving Nigeria heavy crude oil viscosity reduction by dilution with N- heptane, phenol, toluene, xylene, and naphtha involved a systematic approach to evaluate the effects of pressure variations on solubility and viscosity. The methodology included

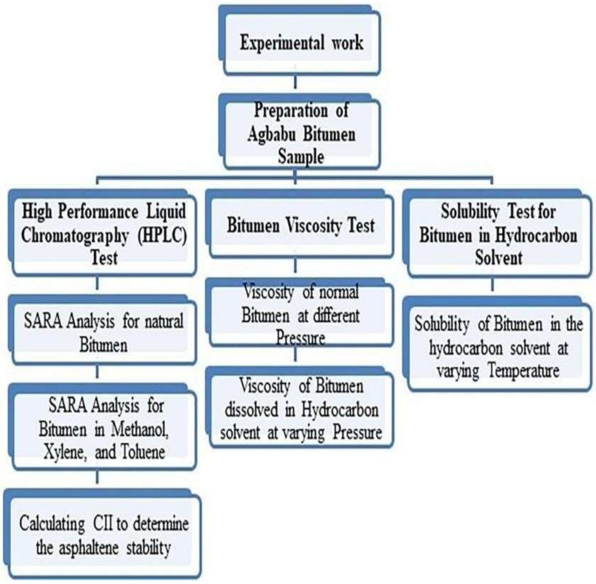
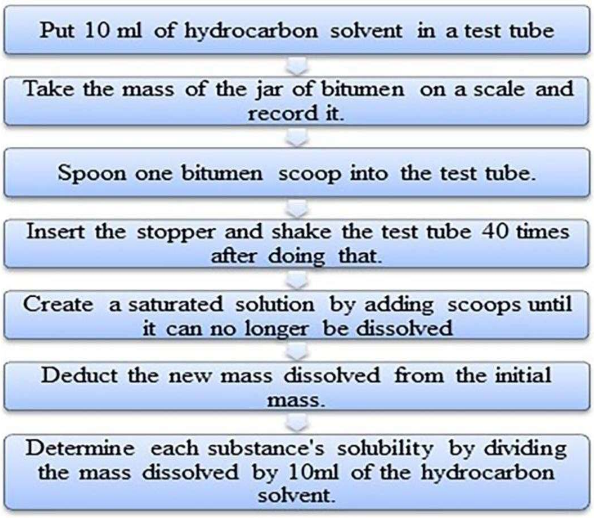


Figure 1. The flow chart showing the methodology of experimental work.



Put 10 ml of hydrocarbon solvent in a test tube

Take the mass of the jar of bitumen on a scale and record it.

Spoon one bitumen scoop into the test tube.

Insert the stopper and shake the test tube 40 times after doing that.

Create a saturated solution by adding scoops until it can no longer be dissolved

Deduct the new mass dissolved from the initial mass.

Determine each substance's solubility by dividing the mass dissolved by 10ml of the hydrocarbon solvent.

Figure 2. Flow chart of the solubility test procedure.

Solubility Tests Solubility Measurement

The solubility of the Agbabu bitumen was assessed in selected hydrocarbon solvents, namely n- heptane, naphtha, toluene, xylene, and phenol, to evaluate solvent–bitumen interactions. Equal volumes of solvent (20 mL each) were combined with measured quantities of bitumen at different temperatures. The mass of dissolved bitumen at saturation was recorded, and comparative solvent efficiency was established from the maximum solubilized fractions. A schematic outline of the procedure is provided in Figure 3.

Procedure: A 20ml test tube was used to dissolve the heavy oil sample in each of the hydrocarbon solvents (N-heptane, phenol, toluene, xylene, and naphtha).
-Solubility Calculation: The solubility was calculated as the ratio of the amount of heavy oil sample dissolved to the volume of the 10ml solvent.
Pressure Variations: Solubility evaluations were conducted at pressures of 20 psia, 80 psia, 140 psia, 200 psia, and 260 psia to assess the impact of pressure on solubility.

Viscosity Measurement

Kinematic viscosity of the bitumen sample was determined in accordance with ASTM D445 using a Redwood viscometer. The bath temperature was first stabilized at the desired test condition and verified with a calibrated thermometer. A cord-attached cork stopper was fitted at the base of the viscometer to prevent air leakage, confirmed by the absence of oil traces on the cork upon removal. For test points above ambient conditions, the sample was preheated to approximately 1.7 °C above the target temperature and maintained at least 28 °C below its flash point. The homogenized sample was then introduced into the viscometer through a 150-mesh wire cloth filter until the level reached the overflow rim.

Method: Kinematic and dynamic viscosities were determined using a Redwood viscometer.

Kinematic Viscosity: Measured using the Redwood viscometer based on the flow time of the oil sample.
Dynamic Viscosity: Calculated from kinematic viscosity data.

Experimental Conditions and Measurements

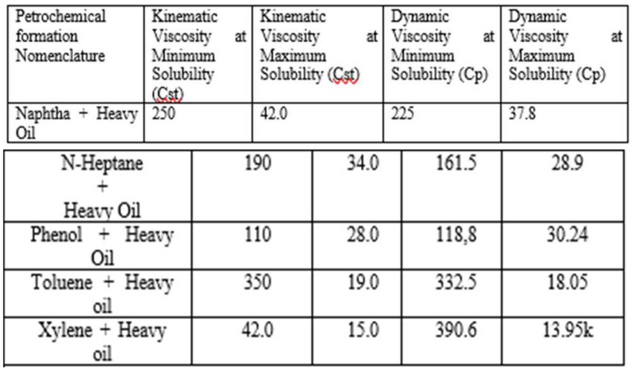
Pressure Effects: Solubility of bitumen in each solvent was measured at varying pressures. Viscosity at Maximum and Minimum Solubility: Kinematic and dynamic viscosities were estimated at maximum and minimum solubility conditions for each solvent. This approach allowed for the evaluation of the effectiveness of different solvents in reducing the viscosity of heavy crude oil under varying pressure conditions.

Results and Research Discussion

Table 1: Showing the Solubility of Heavy oil at various pressure in varying mediums

Pressure (Psia)	Solubility (Mol/dm3)				
	Bitumen in Naphtha	Bitumen in n-Heptane	Bitumen in Phenol	Bitumen in Toluene	Bitumen in xylene
20	2.20	1.80	1.00	3.70	4.40
80	4.60	3.40	2.90	5.60	6.20
120	6.80	5.20	4.60	7.50	9.10
200	8.90	7.40	6.00	9.20	10.90
260	10.90	9.80	7.80	11.40	13.0

Table 2: Kinematic viscosity and dynamic viscosity at minimum solubility and maximum solubility.



Petrochemical formation Nomenclature	Kinematic Viscosity at Minimum Solubility (Cst)	Kinematic Viscosity at Maximum Solubility (Cst)	Dynamic Viscosity at Minimum Solubility (Cp)	Dynamic Viscosity at Maximum Solubility (Cp)
Naphtha + Heavy Oil	250	42.0	225	37.8
N-Heptane + Heavy Oil	190	34.0	161.5	28.9
Phenol + Heavy Oil	110	28.0	118,8	30.24
Toluene + Heavy oil	350	19.0	332.5	18.05
Xylene + Heavy oil	42.0	15.0	390.6	13.95k

Discussion

Solubility Trends

Solubility increased consistently with pressure for all solvents. Xylene exhibited the highest solubility (13.0 mol/dm³), followed by toluene, naphtha, n-heptane, and phenol.

Figures 3–7 (high-resolution) illustrate solubility trends and viscosity behavior across solvents and pressures.

Solubility–Viscosity Correlation

Figure 7 presents a scatter plot with regression analysis showing an inverse correlation between solubility (mol/dm³) and dynamic viscosity (cP). Increased solubility corresponds directly to reduced viscosity, confirming dissolution-driven viscosity reduction.

Effects of Pressure and Solvent Type

Phenol exhibited the least sensitivity to pressure due to **hydrogen bonding interactions that favor resin fractions but do not effectively disrupt asphaltene aggregates,** unlike aromatic solvents such as xylene, which exhibit strong π–π interactions.

Comparative Efficiency and Cost Consideration

Although xylene achieved the highest viscosity reduction (~28-fold), naphtha provided a moderate ~6-fold reduction at significantly lower cost and greater availability. This suggests that naphtha may represent a more viable industrial candidate where economic constraints dominate.

Viscosity Reduction Analysis

Significant reductions in both kinematic and dynamic viscosity were observed. **Aromatic solvents demonstrated superior viscosity reduction due to π–π interactions with asphaltenes.** Xylene achieved the greatest reduction, lowering dynamic viscosity from 390.6 cP to 13.95 cP.

Comparative Implications

The effectiveness ranking was xylene > toluene > naphtha > n-heptane > phenol, consistent with previous studies on heavy oil solvent dilution.

Improved Viscosity Study of Heavy Oil in Agbabu, Ondo State: Viscosity Reduction of Heavy Oil

Heavy crude oil viscosity is a critical parameter affecting its production, processing, and transportation (Speight, 2014). This research centered on reducing the viscosity of heavy oil from Agbabu, Ondo State, Nigeria, through dilution with various solvents (phenol, toluene, N-heptane, xylene, toluene, and naphtha) under different pressures. Results revealed that increasing pressure improves bitumen solubility in all solvents which is consistent with findings by Luo et al. (2016) on the effects of pressure on heavy oil solubility. Xylene showed the highest solubility and most substantial viscosity reduction among the selected solvents that aligns with its high aromatic content and solvency power (Hart et al., 2018).

Effects of Solvents on Viscosity Reduction

The lowest kinematic of 15.0 cst and dynamic viscosities of 13.95 cp were achieved for Xylene at maximum solubility, outperforming other solvents. Phenol displayed the least effectiveness in reducing viscosity while Toluene also showed substantial viscosity reduction. These findings are align with the philosophy that aromatic solvents like toluene and xylene are more effective in dissolving and reducing the viscosity of heavy oils (Shah et al., 2010).

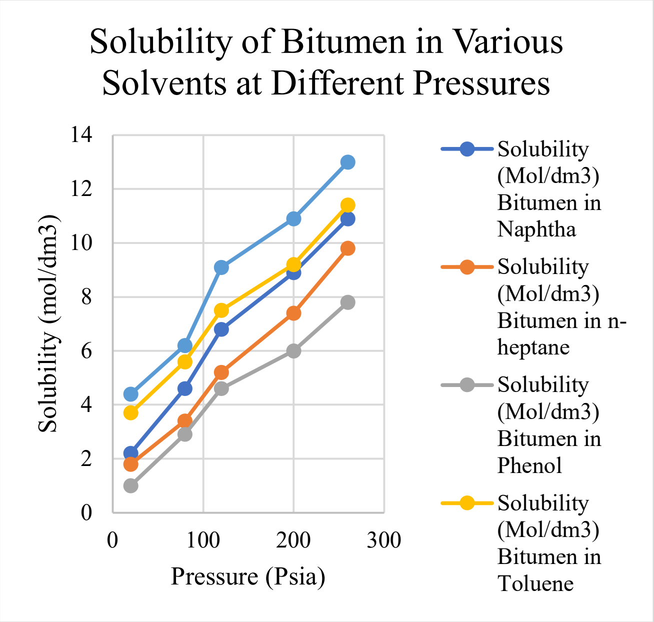


Figure 3: Solubility of bitumen in various solvents at different pressures

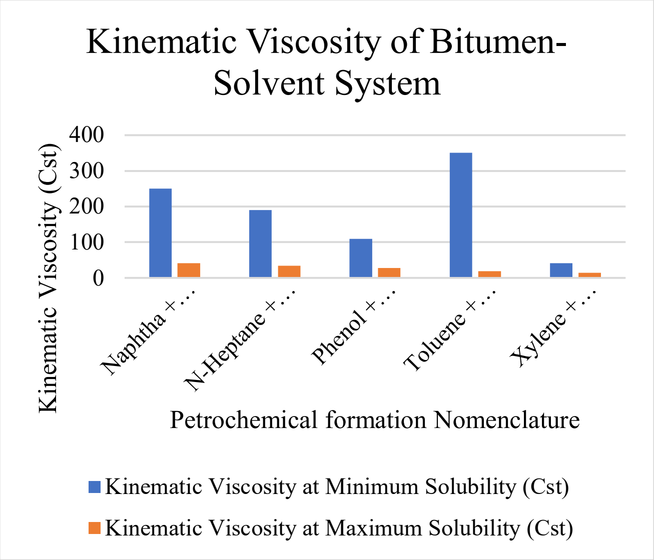


Figure 4: Kinematic viscosity of bitumen - solvent systems

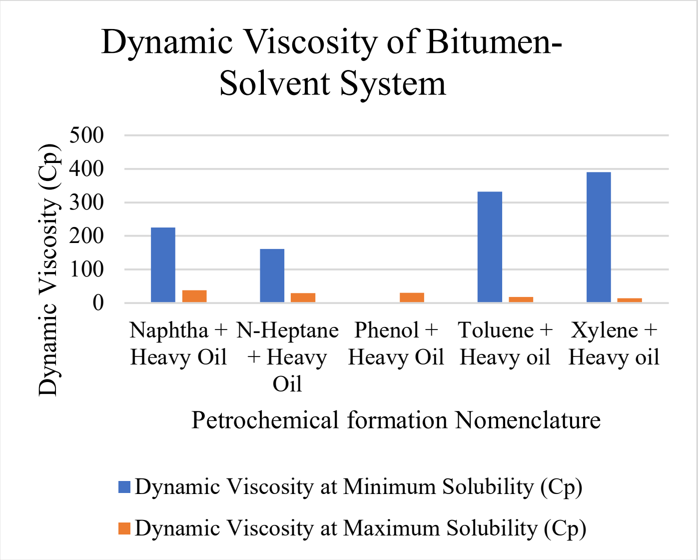


Figure 5: Dynamic viscosity of bitumen solvent systems

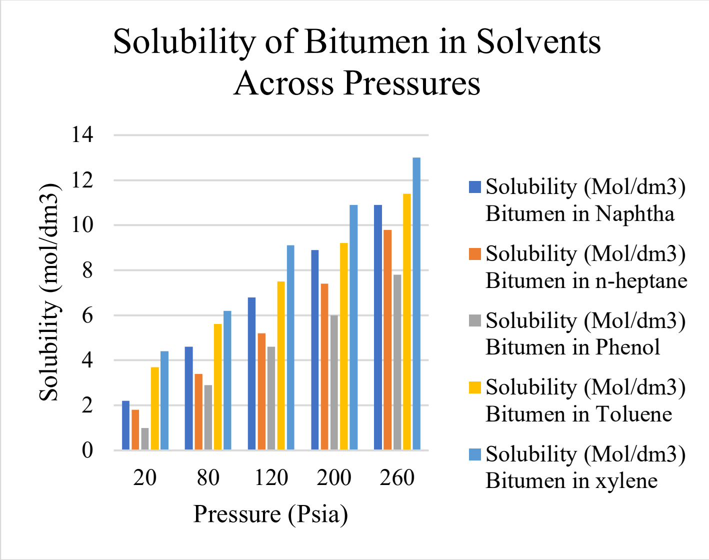


Figure 6: Solubility of bitumen in solvents across pressures

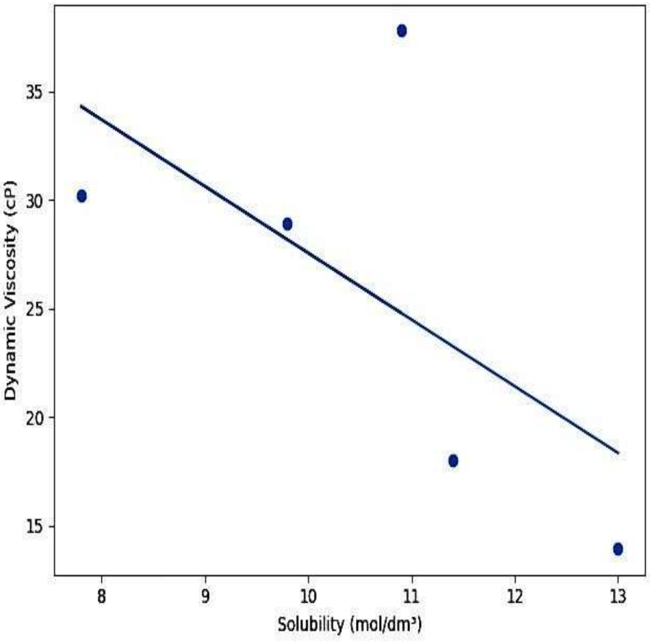


Figure 7: Inverse Correlation Between Solubility and Dynamic Viscosity at Maximum Solubility

Pressure Effects on Solubility and Viscosity

Bitumen solubility in all solvents increased significantly with increasing pressure from 20 psi to 260 psi leading to reduced viscosities. This aligns with the findings of Luo et al. (2016) studies on how pressure-enhanced solubility improves rheological properties of heavy oils. Reliable kinematic and dynamic viscosities data obtained from the Redwood viscometer measurements are essential for assessing the efficiency of viscosity reduction methods (API, 2015). Thermal stimulation (in-situ combustion, steam flooding), gas injection (CO_2, N_2, natural gas), and solvent dilution are among the several methods being studied globally for viscosity reduction (Yarranton & Masliyah, 1996; Alvarez et al., 2018). In regions like Nigeria where natural gas and refinery-derived solvents are relatively available, solvent dilution is the most attractive option. The principle is straightforward: solvents interact with the heavy oil molecules, reduce asphaltene aggregation, lower intermolecular forces, and thus decrease viscosity significantly. However, the efficiency of viscosity reduction is solvent-specific and depends on molecular interactions, solvent polarity, aromaticity, and external conditions such as pressure and temperature.

In this study, five solvents were investigated—n-heptane, phenol, toluene, xylene, and naphtha—for their ability to reduce the viscosity of Agbabu heavy crude oil. These solvents were chosen because they represent different classes of hydrocarbon chemistry: aliphatics (n-heptane, naphtha), aromatics (toluene, xylene), and a polar organic compound (phenol). Their solubility power and rheological impact were systematically tested under different pressures (20–260 psia), and viscosity was evaluated using a Redwood viscometer under minimum and maximum solubility conditions. The following discussion interprets these results within the framework of heavy oil rheology and solvent-oil interactions. Figure 7 confirms a strong inverse relationship between solubility and dynamic viscosity, indicating that increased solvent solubilization directly enhances viscosity reduction efficiency.

1.Solubility Trends at Different Pressures

The solubility experiments, carried out by dissolving bitumen in each solvent within a 10 mL test tube under incremental pressures, revealed distinct patterns in the dissolution behavior of Agbabu heavy oil. At 20 psia, solubility was lowest across the board, with values ranging from 1.00 mol/dm³ for phenol to 4.40 mol/dm³ for xylene. As pressure increased to 260 psia, solubility consistently increased for all solvents, reaching a maximum of 13.0 mol/dm³ in xylene, followed by 11.49 mol/dm³ in toluene, 10.90 mol/dm³ in naphtha, 9.80 mol/dm³ in n-heptane, and 7.80 mol/dm³ in phenol.

This trend underscores the role of pressure in enhancing the miscibility of solvents with heavy crude. Higher pressure reduces the free volume between molecules, increases contact between solvent and solute, and improves dissolution kinetics (Zhang et al., 2016). In petroleum systems, pressure has also been observed to increase solvent penetration into asphaltene aggregates, thereby destabilizing them and allowing for greater solubility.

Comparing solvents, the superior solubility performance of xylene and toluene aligns with the known affinity of aromatics for asphaltenes. Aromatic solvents interact via π–π stacking with the aromatic cores of asphaltenes, effectively dispersing them (Goual & Firoozabadi, 2004). Xylene, with three methyl substituents on the benzene ring, provides stronger solvation than toluene, which accounts for the observed higher solubility. In contrast, aliphatic solvents such as n-heptane are poor solvents for asphaltenes and typically cause precipitation rather than dissolution when used in excess. Nonetheless, the observed solubility values suggest that n-heptane can still achieve moderate dissolution at high pressures, likely due to increased disruption of non-polar van der Waals interactions at elevated pressures.

Interestingly, phenol exhibited the lowest solubility throughout the pressure range. Phenol is a polar, hydrogen-bonding solvent, and while polarity may favor interaction with certain resins, it does not align well with the largely non-polar hydrocarbon matrix of heavy crude oil. Its limited solubility performance suggests that polar interactions alone are insufficient for breaking asphaltene aggregates in Agbabu oil, and non-polar aromatic interactions are far more effective.

Overall, the solubility results confirm that pressure significantly enhances dissolution, but solvent type—particularly aromaticity—remains the dominant factor dictating solubility strength. This has direct implications for the viscosity measurements that follow.

1. **Viscosity Reduction Analysis**

Viscosity measurements under minimum and maximum solubility conditions revealed dramatic reductions in both kinematic and dynamic viscosity for all solvent systems, though the extent of reduction varied by solvent.

1.1. Naphtha

From table 2, at minimum solubility, the heavy oil–naphtha mixture had a kinematic viscosity of 250 cSt and a dynamic viscosity of 225 cP. At maximum solubility, these values dropped to 42 cSt and 37.8 cP, respectively. This indicates nearly a six-fold reduction in viscosity, demonstrating the effectiveness of naphtha in breaking down the viscous structure of Agbabu oil. Being a mixture of light hydrocarbons, naphtha dilutes the heavy fractions and reduces intermolecular interactions. However, its performance was not as strong as that of aromatics, reflecting its aliphatic-dominated composition.

1.2. N-Heptane

N-heptane reduced viscosity from 190 cSt (kinematic) and 161.5 cP (dynamic) at minimum solubility to 34 cSt and 28.9 cP, respectively, at maximum solubility. The reductions were significant, though again less pronounced than with aromatics. N-heptane's linear alkane structure offers dilution but lacks the aromatic interaction needed for efficient asphaltene dispersion. Nonetheless, its relatively strong reduction compared to phenol highlights the importance of dilution effects even without strong molecular affinity.

1.3 Phenol

Phenol yielded a reduction from 110 cSt (kinematic) and 118.8 cP (dynamic) at minimum solubility to 28.0 cSt and 30.24 cP at maximum solubility. This represents a moderate improvement, though phenol's viscosity reduction power was inferior to both aromatics and aliphatics at high solubility. The polar hydroxyl group likely introduces some hydrogen bonding with resinous fractions, but its incompatibility with the non-polar hydrocarbon matrix limits its efficacy.

1.3. Toluene

Toluene produced some of the most dramatic reductions: from 350 cSt (kinematic) and 332.5 cP (dynamic) at minimum solubility to 19.0 cSt and 18.05 cP at maximum solubility. This equates to nearly a 20-fold reduction in viscosity, underscoring toluene's effectiveness in disrupting asphaltene aggregation. Toluene is a well-established solvent for asphaltenes due to its aromatic ring and intermediate polarity, which balance solvation power with compatibility (Goual, 2012).

1.4. Xylene

Xylene was the most effective solvent tested, reducing viscosity from 420 cSt (kinematic) and 390.6 cP (dynamic) at minimum solubility to 15.0 cSt and 13.95 cP at maximum solubility. This represents a 28-fold reduction, demonstrating that xylene offers the strongest solvent-solute interaction among the tested options. Its higher methyl substitution compared to toluene enhances π–π interactions with asphaltene cores and provides steric effects that aid dispersion (Andreatta et al., 2005).

1.5. Comparative Implications

The results clearly demonstrate that aromatic solvents are superior to aliphatics and phenol for viscosity reduction in Agbabu heavy oil. The order of effectiveness was xylene > toluene > naphtha > n-heptane > phenol. These trends are consistent with the literature, which emphasizes the affinity between aromatic solvents and asphaltenes as the key to viscosity reduction (Yarranton & Alboudwarej, 2003; Orodu et al.,2019). The direct correlation between solubility and viscosity reduction further reinforces that dissolution of asphaltenes and resins is the primary mechanism of viscosity reduction.

2. Rheological Implications for Agbabu Heavy Oil

The findings have several implications for the rheology of Agbabu heavy oil and its potential exploitation.

First, the significant viscosity reductions achieved—particularly with xylene and toluene—suggest that solvent-assisted production methods could transform the mobility of Agbabu crude. Reducing viscosity from hundreds of cSt to below 20 cSt brings the oil into the range of medium crude oils, which are much easier to transport via pipelines without excessive heating or drag-reducing agents.

Second, the differences in solvent performance highlight the need for solvent selection tailored to local availability and cost. While xylene and toluene are petrochemical solvents with high effectiveness, they may be costly for large-scale use. Naphtha, being a refinery product, is more accessible in Nigeria and offers a reasonable balance of solubility and viscosity reduction, though less effective than pure aromatics.

Third, the pressure-dependent solubility trends imply that in reservoir conditions, where pressures can be high, solvent injection may achieve even greater dissolution than laboratory tests at lower pressures. This could favor in-situ recovery methods such as solvent vapor extraction (VAPEX), which relies on diffusion of solvents into heavy oil reservoirs (Das & Butler, 1998).

Finally, the rheological behavior suggests that solvent blending could provide synergistic benefits. For example, mixing naphtha with small amounts of xylene or toluene could provide both cost-effectiveness and strong viscosity reduction, a strategy supported by studies on blended solvents for Canadian bitumen (Nasr et al., 2011).

3.Comparison with Previous Studies

The results align well with global and regional studies on solvent-assisted viscosity reduction. For instance, Goual and Firoozabadi (2004) demonstrated that aromatics are superior solvents for asphaltenes compared to aliphatics, consistent with the dominance of xylene and toluene in this study. Similarly, Orodu et al. (2019), in their work on Nigerian bitumen, observed that aromatic solvents reduced viscosity significantly more than paraffinic solvents, echoing the present findings.

Other studies on Venezuelan and Canadian bitumens have also reported that toluene and xylene are among the most effective solvents for viscosity reduction (Andreatta et al., 2005; Alvarez et al., 2018). The agreement across different heavy oil types suggests that the observed trends for Agbabu oil are not isolated but part of a general principle: the aromatic content of the solvent is the strongest predictor of viscosity reduction effectiveness.

Where this study contributes uniquely is in quantifying the solubility-viscosity relationship at different pressures for Agbabu oil specifically, thereby providing localized data for Nigerian reserves. The significant impact of pressure on solubility had been suggested in earlier thermodynamic models (Zhang et al., 2016), but experimental confirmation for Nigerian heavy crude was lacking. This fills an important gap in knowledge and provides practical insight for field engineers designing solvent-based recovery schemes.

4.Limitations and Practical Applications

While the experimental results are promising, several limitations must be acknowledged. The tests were conducted under controlled laboratory conditions using small volumes (10 mL test tubes). In reservoir settings, mass transfer limitations, heterogeneity, and the presence of connate water could alter solvent efficiency. Additionally, the economic and environmental implications of large-scale solvent use must be carefully considered. Xylene and toluene, while effective, are toxic and expensive, whereas naphtha, though less effective, may be more feasible in Nigeria's refining context.

Despite these limitations, the practical potential is substantial. Solvent dilution could be integrated into enhanced oil recovery (EOR) strategies in Agbabu, either as standalone solvent injection or in combination with steam (e.g., solvent-assisted steam flooding). The significant viscosity reduction demonstrated here indicates that solvent treatment could enable pipeline transport of Agbabu crude without extensive heating, lowering operational costs.

Summary of Key Findings

a) Pressure significantly enhances bitumen solubility across all solvents.
b) Aromatic solvents (xylene, toluene) are most effective due to strong asphaltene interactions.
c) Xylene achieved the highest viscosity reduction (~28-fold).
d) Naphtha offers a practical compromise between efficiency and cost.
e) Pressure enhances solubility: Increasing pressure from 20 to 260 psia improved solubility for all solvents, with maximum values observed in xylene (13.0 mol/dm³).
f) Aromatic solvents are most effective: Xylene and toluene achieved the highest solubility and viscosity reduction, confirming their superior interaction with asphaltenes.
g) Viscosity reduction was substantial: Xylene reduced viscosity by ~28-fold, while toluene achieved a~20-fold reduction. Aliphatics (naphtha, n-heptane) were moderately effective, while phenol was least effective.
h) Relevance to Agbabu oil: The results demonstrate that solvent dilution can make Agbabu bitumen flowable, enabling potential commercial exploitation.

Conclusion

This study demonstrates that pressure-enhanced solvent dilution is an effective method for reducing the viscosity of Agbabu bitumen. **Aromatic solvents exhibit superior performance due to strong asphaltene–solvent interactions.** The findings provide practical insight for designing solvent-assisted recovery strategies for Nigerian heavy oil resources.

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