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Extrication of CBM Wellbore Fire Explosion Paradox in Enugu, South Eastern, Nigeria

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Abstract

Methane dexterity and degasification in heavily stratified subsurface water aquifers sandwiched with coal seams surreptitiously expedited the recent fire explosion in Enugu State, South Eastern Nigeria. The verisimilitude is to divulge the non-availability of coal bed methane (CBM) reservoir engineering modeling technology. The aim of this study is to demonstrate the didactic, luminous and effective volubility of CBM reservoir engineering modeling techniques for extrication of the wellbore fire explosion paradox in Enugu state, Nigeria. The Schlumberger Eclipse simulated reservoir has a dimension of 8 ×8×2 with dual porosity of 0.05 and 0.15 located at depths of 1,000ft, 1,200ft and 1,400ft. Results inconceivably showed improvement in coal quality by 72.83% in the y direction indicating increased methane palpitation upsurge in that direction. Results of initial 40% CO_2 isotherm fracture gas gave a cumulative maximum field gas pressure (FPR) of 540psi for the 1,400ft model. This indicates higher gas volatility with shallow depths. It is admonished to critically evaluate aquifers in zones deeper than 700ft to forestall future petrifying devastating occurrences triggered by maladroitness.

***Keywords**: Coal bed; Methane, Gas; Simulation; Model; Gas pressure; Aquifer; Water; Reservoir; Depth.*

1. Introduction

Nigeria is ranked amongst the world's greatest deposits of proven coal reserves with over 2.5 billion tons and approximately 700 bcf of unconventional coal bed methane (CBM) gas [1]. Deviation from coal to conventional fossil fuel has unfortunately led to the monumental moribund state of this sector giving rise to a colossal decrease in its production. The production of coal is associated with coal bed methane which would have tremendously increased the gas infrastructure to an enviable economically robust state devoid of its numerous short comings [2].

The coal deposits in Enugu state, south eastern Nigeria is mostly sub-bituminous with large quantities of coal bed methane and located at minimal depths of range of 800 – 1000ft. The large-scale scarcity of portable borehole water is largely caused by the complex hydrogeology of Enugu metropolis. This has led to numerous technological incapacitated water borehole companies without clear understanding of the subsurface geology as it pertains to the occurrence of coal bed methane gas.

However, drilling beyond 800 feet in quest of portable water without proper geophysical exploration data may be devastating, resulting in the first of its type fire explosion on May 22, 2022. According to the Nigerian Petroleum Upstream Petroleum Regulatory Commission (NUPRC) [3], the fire was started by a suspected associated gas reservoir at around 200m while drilling a water well with a target depth of 400m. They said that Caritas University in Enugu, Nigeria, had hired HydroGeo Engineering Services to dig a water well, but that the operation was later subcontracted to Orange Water Wells Drilling Company. It was reported that after about 200 meters of digging, pressured seepage was detected and gases were streaming out of the drilled hole. One of the workers who felt the odors were caused by gas seepage apparently tried to prove his theory, and in the process introduced a source of ignition, resulting in the fire. This terrible move supplied more proof of the emitted fumes as related gas. Following the fire, the drilling contractor quickly withdrew the drill pipes, demobilized the rig, and alerted the Enugu state government of the event. The state and federal fire departments who were dispatched to the scene fought the fire for more than two days. "The university authority cordoned off the site and restricted access to the area; and directed that all facilities within the affected area, including a nearby hall used for examinations, be immediately discontinued usage," the statement read.

Similarly, it stated that no fatalities were reported as a result of the incident, despite the fact that drilling firm employees suffered first-degree burns. While presenting the findings of its preliminary investigation, it stated that there is no pipeline right of way in the area, and that there is a continuous supply of gas from an underground source, as evidenced by the continuous fire, which is suggestive of the presence of shallow gas, which could be associated with coal bed methane gas or gas seepage. In both circumstances, it may not be a reservoir accumulation but associated gas for which the drilling procedure supplied a flow line; a development comparable to coal mine occurrences. Caritas University is finalizing plans to conduct a Geophysical Resistivity Survey of the region in order to collect data that will provide a better understanding of the near-surface gas concentration in the area and its potential spread.

According to Vanguard newspaper [4], the Nigerian Mining and Geoscientist Society (NMGS), they suspected that the well penetrated a fracture/fault zone which served as a conduit or migration pathway for hydrocarbon (gas) generated in the deeper buried mature shales of the Nkporo/Enugu, Agwu and Eze-Aku geological formations. The initial speculation that the flare is methane gas from fracking of the mature and fractured Nkporo/Enugu formation is discountered due to the sustained flare that has maintained its intensity for over 7 days. They advised that detailed geological and geophysical studies should be carried out in the area and environs to unveil the mystery behind the subsurface structure, stratigraphy and hydrocarbon prospects of the area which is also an extension of the southern Benue Trough and Anambra Basin. They urged the Federal Government to harness the gas resources in the area. They also stated that if the gas resource in the area is found to be substantial, the federal government and Enugu State Government should develop a framework to harness the gas resources to enhance industrialization and job creation for the benefit of the state and the nation.

However, the non-availability of detailed subsurface data analogous to coal bed methane reservoir data required to decipher the possible palpitable effects of the behavior of the pressure, flow rates and cumulative production under simulated conditions is the bane of the degenerated and petrified conundrum. Interestingly, the absence of methane gas control and degasification management in heavily stratified subsurface underground water aquifers sandwiched within coal seams is perhaps the possible cause of the fire explosion. The major challenge is that the absence of detailed coal bed methane (CBM) reservoir engineering modeling technology is the missing technical link. The reason for this is that the area is largely embedded by cyclopean deposits of coal seams both within the subsurface and as out crops. Non awareness of the menace of the vulnerability of CBM gas explosion during drilling of water wells [5]. The drilling rigs currently being used do not have the capacity for manoeuvring under highly pressured CBM reservoirs if encountered while the properties of drilling mud are also not adequate to suppress and control kicks and possible blowouts.

The aim of this study is to demonstrate the effectiveness of CBM reservoir engineering modeling for effective extrication of the wellbore fire explosion paradox in Enugu State, south eastern Nigeria.

The objectives are to carry out detailed reservoir sensitivity simulation of a CBM reservoir at depths of 1000ft, 1200ft and 1400ft, to carry out comparative analysis and evaluation of three modeled case studies, to predict mathematical correlations of critical CBM reservoir properties in order to understand their behavior within the reservoir and migration through the wellbore and to predict possible methane gas flow pressure and direction critical for effective management of deep water wells in parts of Enugu Metropolitan city.

2. Geology of coal bed methane (CBM)

Coal bed methane is a non-conventional source of hydrocarbon reserve which is different in its accumulation and production techniques when compared to the conventional natural gas. Coal is a surface and subsurface sedimentary rock with organic and inorganic debris [6]. It is mostly composed of ancient plant materials such as seeds, leaves, wood, twigs, spores, pollen and other terrestrial and aquatic plants [7].

These materials are deposited and buried in a sedimentary basin forming peats separated by clay and sand facies during accumulative cyclic periods [8]. As the peat accumulates, physical (such as insects, worms and fungi) and chemical (such as water and dissolved salts in aqueous solutions) processes are activated to break it down to smaller pieces called macerals. The continual burial of the peat due to dynamic sedimentation squeezes out fluids and make it compacted. The peat is then buried deeper with time with high pressure and temperature to transform it to coal through maturation in oxygen restricted domains [9].

Furthermore, it takes around 5ft of raw biological detritus to make approximately 1ft of coal. As it evolves from peat to anthracite, coal undergoes metamorphism or coalification. As indicated in Fig. 1, coal is classified into five grades: lignite, sub-bituminous, bituminous, semi-anthracite, and anthracite. The oldest and highest-ranking coal grades are found at substantially greater pressures and temperatures, with massive volumes of carbon deposits. Carbon is left behind in the form of coal as volatile moisture evaporates during coal maturation [10].

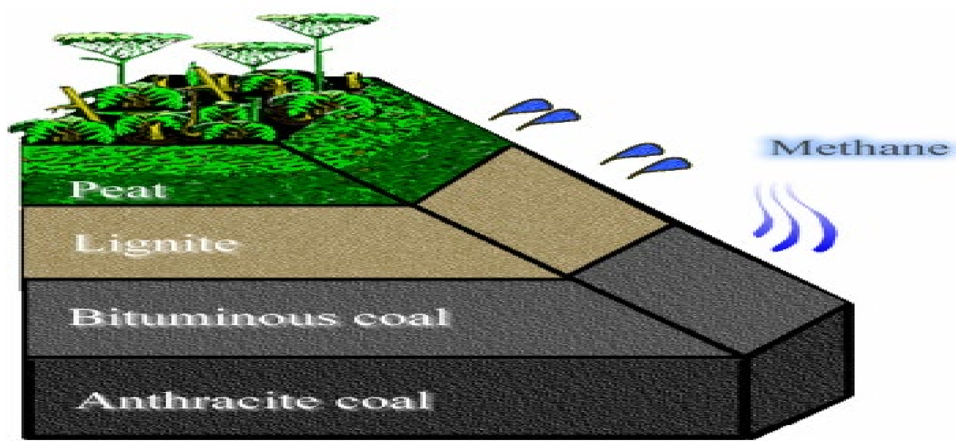

Figure 1. Sedimentation and the formation of coal (after [10]).

Coal bed methane (CBM) is described as a natural subsurface methane (CH_4) gas occurrence with minute quantities of other hydrocarbons and non-hydrocarbon gases co-existing inside coal seams owing to physical and chemical processes [11-12]. They may be created at shallow depths using a borehole that allows gas with huge amounts of water of varying quality to be produced. Shallow aquifers near CBM reservoirs must be safeguarded against pollution and other safety issues. CBM production is an essential component of coal seam mining since they serve as both reservoir and source rocks [13-14]. They occur in three forms in coal: gas adsorbed on the solid surface of the coal, gas dissolved in coal water, and free gas. The coal pulls gas molecules to its surface, but CBM is really stored inside its molecular structure, with some stored within the coal's cleats or cracks or dissolved in the water trapped in the fractures.

Methane adheres to the surface of the coal and spreads into its fissures, where it is limited or confined by water pressure [15-16]. This implies that the water is released during drilling by successively permitting the gas to flow via the linked cracks into the wellbore and to the surface. Coal, on the other hand, has the ability to create more gas than it can absorb and store. Basins with 450SCF to 650SCF of methane (CH_4) per ton are commercially feasible for production with appropriate rates of desorption and reservoir permeability [17-18]. Desorption is the process through which coal releases methane gas when hydrostatic pressure decreases. The most promising coal resources are gas-rich, permeable, and feature linked natural fracture networks [19-20].

3. Coal bed methane production

Gas migration, coal maturity, fracture, permeability, coal dispersion, geologic structures, well completion choices, hydrostatic pressure, and generated water management all influence CBM output [21–23]. By reducing the hydrostatic pressure in the coal seam, the desorption process is substantially accelerated. CBM wells initially generate water, but as gas production grows, water output decreases [24–26]. Because of the geologic features of its natural fracture system, some wells do not produce water but instantly generate gas. The commonly generated gas is devoid of high-quality pollutants and is suitable for pipeline transit and storage [27].

However, methane may not be produced in some coal seams if the hydrostatic pressure cannot be reduced while some with gas may be too deep to be economically drilled [28]. Maximum depth for CBM wells is about 5,000ft. The gas content of coal increases with depth and the rank originalty of the seam [29]. One major way of CBM development is by conventional drilling and/or horizontal drilling [30–31]. The three methods of extraction are; underground coal mining (UCM), underground gasification of coal (UGC) and pre-coal mining or coal seam gas (CSG).

4. Geology of the study area

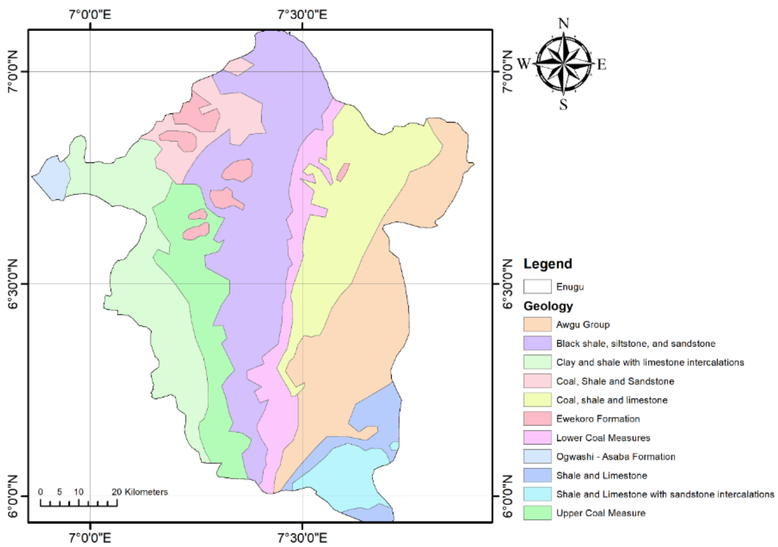

Figure 2. Geologic map of the study area.

The Enugu coal is found in two strata, the lower Mamu formation and the higher Nsukka formation, in the cretaceous Anambra and Markudi basins, Afikpo syncline [27]. They are found in three major geologic strata: the brown coals (lignite) of the Miocene to Pliocene ages of the Ogwashi-Asaba formation, the upper and lower sub-bituminous coal of Maastrichtian age, and the bituminous coal of the Awgu shales of Coniacian age (CBM). This coal may be found in the Nigerian states of Enugu, Imo, Kogi, Delta, Anambra, Bauchi, Adamawa, Edo, and Ondo (Fig. 2).

4.1. Study location

The study location is within Caritas University, Amorji-Nike, Enugu, South eastern Nigeria. It is a member of the Nkporo group and forms part of the stratigraphy of the Anambra basin. It is located within latitudes 6^0 30′N and 6^0 00′N and longitudes 7^0 25′E and 7^0 35′E (Fig. 3).

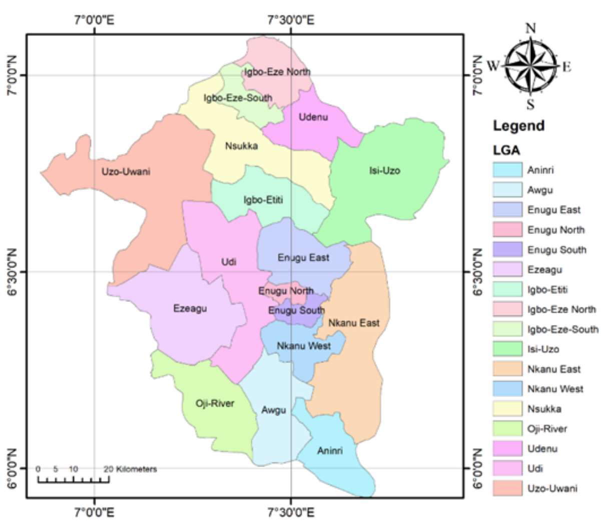

Figure 3. Map of the study area.

5. Materials and method

5.1. Materials

Materials used in this study are reservoir data analogous to water bed reservoirs in coal seams in parts of the Enugu basin. The data sets are reservoir dimensions of 8 × 8 × 2 which is equivalent to a total of 64 cells. Dual porosity data of 0.10 and 0.15, while the producing well is located at x, y, z = 1, 1, 1. Properties common to rock matrix and fractures are; D_X, D_Y, D_Z = 75 × 75 × 30; permeability = 500md; water saturation range = 0.2 – 0.9; gas saturation range = 0.1 – 1.0. Other data includes PVT data for water (PVTW) and gas (PVDG), rock properties, density, gas viscosity and gas formation volume factor (B_g).

The data was simulated with Schlumberger Eclipse E100 using the CBM window frame from January 2022 to June 2024 (or 10,000 days).

5.2. Method

The input data file for the three case scenarios at depths of 1,000ft (CBM1), 1,200ft (CBM2) and 1,400ft (CBM3) was developed, tested, validated and uploaded into the simulator and made to run with 32-bit version as provided by the software version. It took about 10.92sec, 11.87sec and 14.39sec each to complete the simulation runs.

The simulated results were uploaded in the office sectional framework to portray them collectively as borehole (B), Field (F), Group (G), Region (R), Time (T) and Well (W). The built generic model has 64 cells with the producing well located at (1, 1, 1) of (x, y, z) as shown in Fig. 4.

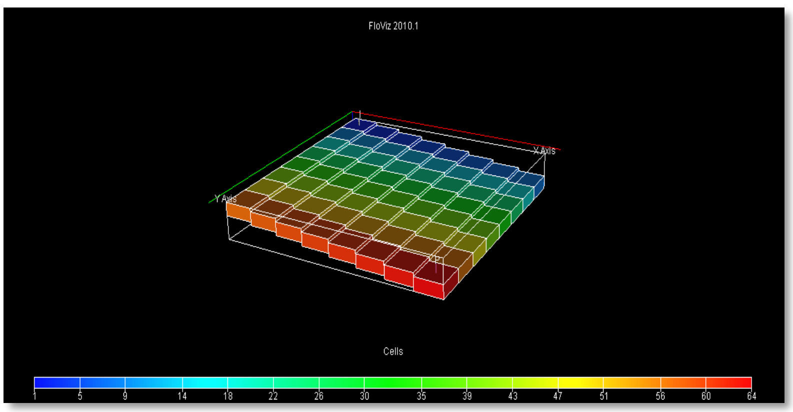

Figure 4. Flow visual image of simulation run.

6. Results and discussion

Results of block coal gas concentration (BCGC) shows that the concentration of the coal gas concentration within the reservoir block reduced exponentially with time as shown in Fig. 5.

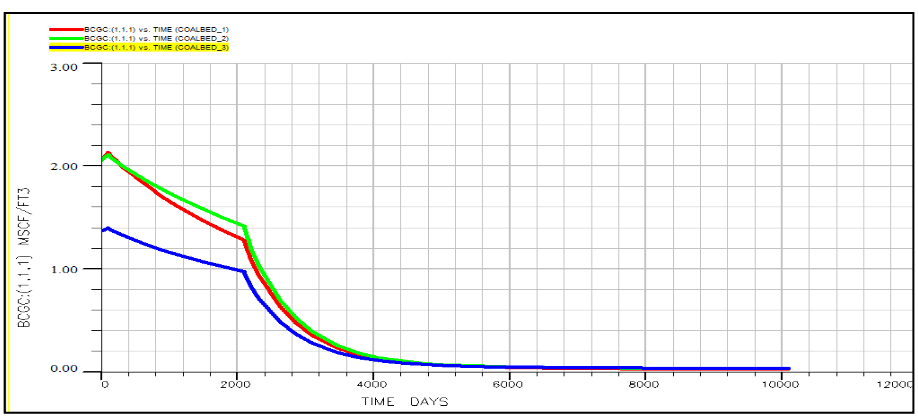

Figure 5. Results of block coal gas concentration (BCGC)

This behavior of volume reduction in mscf/ft^3 with time due to production which appears initially gentle for the first 2,000days to 10,000days. The high density CBM concentration of approximately 2 mscf/ft^3 is more for the 1,000ft (CBM1) and 1,200ft (CBM2) cases than the 1,400ft (CBM3) case of approximately 1. mscf/ft^3. Results of bulk coal solvent concentration (BCSC) tends to reduce and increase to maximum of 6.2 mscf/ft^3, 6.0 mscf/ft^3 and5.0 mscf/ft^3 for CBM3, CBM2 and CBM1 all at 6,000days. They however converged together at approximately 2.2 mscf/ft^3 at 10,000days as shown in Fig. 6. This means deeper wells have more capacity for CBM gas production with prominent dynamic bulk coal solvent concentrations.

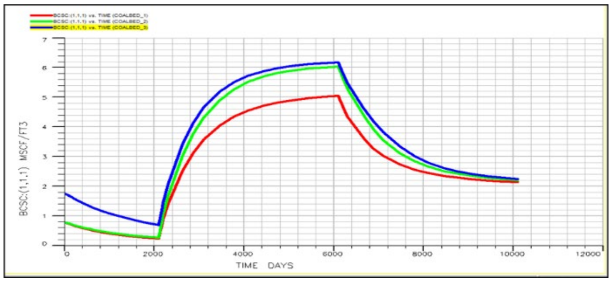

Figure 6. Results of block coal solvent concentration (BCSC).

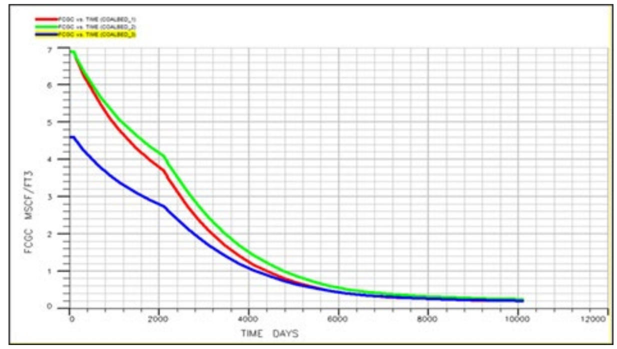

Figure 7. Results of field coal gas concentration (FCGC).

Results of field coal gas concentration (FCGC) shows exponential declining behavior of CBM with time from maximum of 7 mscf/ft^3 for CBM1 and CBM2 and 4.6 mscf/ft^3 for CBM3 as shown in Fig. 7. This means that the CBM gas concentration declines with time due to production. Result of field coal solvent concentration (FCSC) gave maximum concentration of 14.2 mscf/ft^3 for deepest CBM3, 12.6 mscf/ft^3 for CBM2 and 10.4 mscf/ft^3 for CBM1 (Fig. 8). This means that the dissolved coal solvent tends to increase with time with reduced hydrostatic pressure.

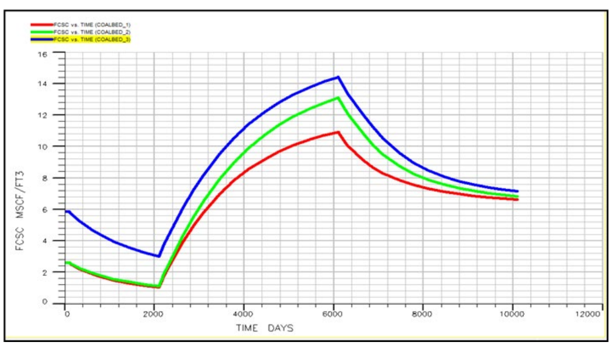

Figure 8. Results of field coal solvent concentration (FCSC).

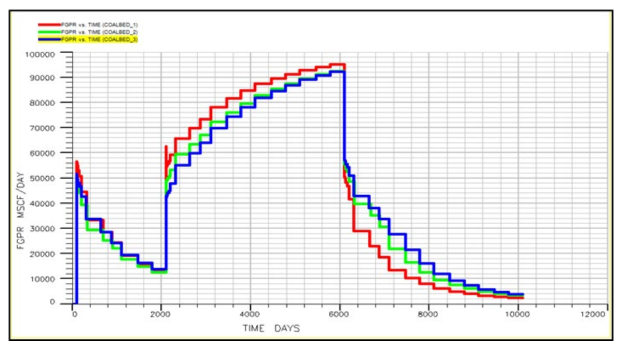

Figure 9. Results of field gas production (FGPR).

Results of field gas production rate (FGPR) shows reduction from approximately minimum of 50,200 mscf/day for CBM3 and CBM2 to a maximum of 50,800mscf/day as shown in Fig. 9. It increased collectively to approximately 90,200 mscf/ft^3 at 6,000days before declining again suggesting gas injection period to sustain gas production. Results of field gas production total (FGPT) gave increasing cumulative total gas production with time to a maximum of 4.3E8mscf at 10,000days as shown in Fig. 10. Divergence existed from 2,000 to 8,000days with higher values of CBM1 and lower values of CBM2 and CBM3.

Results of field pressure (FPR) gave minimal pressures of 160psia for CBM1, 170psia for CBM2 and 190psia for CBM3 all locate dat about 2,000days as shown in Fig. 11. They increased to maximum pressures of 560psia (CBM3), 500psia (CBM2) and 410psia (CBM1) in the y direction before declining to about 80psia at 10,000days.This behavior is due to re-injection of carbon dioxide. Results of group gas production rate (GGPR-G) shows that the maximum possible rate of 90,400 mscf/ft^3 occurred at 6,000days due to re-injection of CO_2 as shown in Fig. 12. Results of group gas production total (GGPT-G) shows increased cumulative total production of a maximum of 4.3E8mscf at 10,000days as shown in Fig. 13.

Results of group reservoir volume production rate (GVPR-G) gave maximum increased middle rates of 560,000 RB/day (CBM1), 440,000 RB/day (CBM2) and 400,000 RB/day (CBM3) all at 6,000days as shown in Fig. 14.

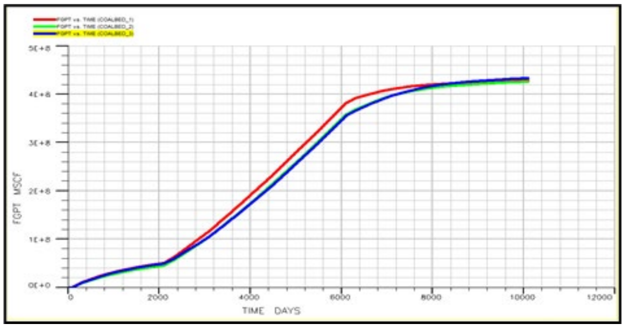

Figure 10. Results of field gas production total (FGPT).

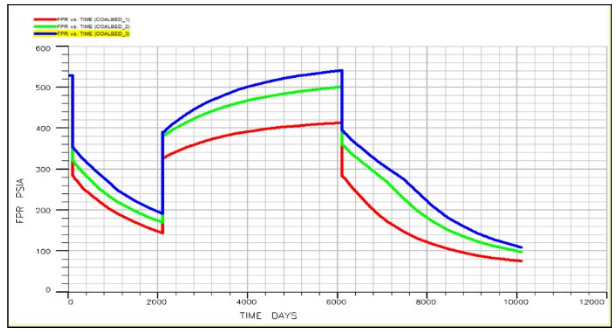

Figure 11. Results of field pressure (FPR).

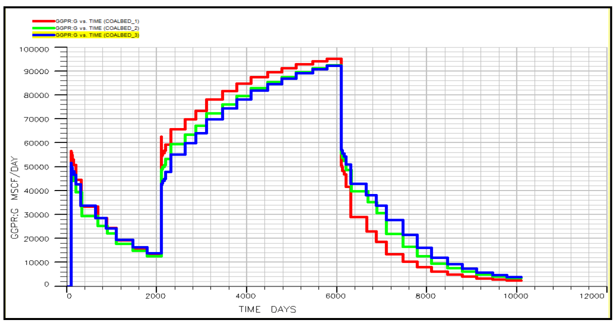

Figure 12. Results of group gas production rate (GGPR-G).

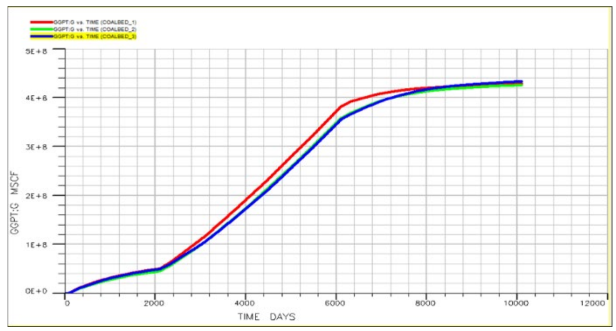

Figure 13. Results of group gas production total (GGPT-G).

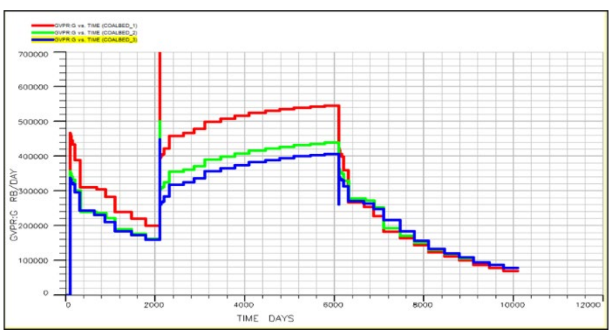

Figure 14. Results of group reservoir volume production rate (GVPR-G).

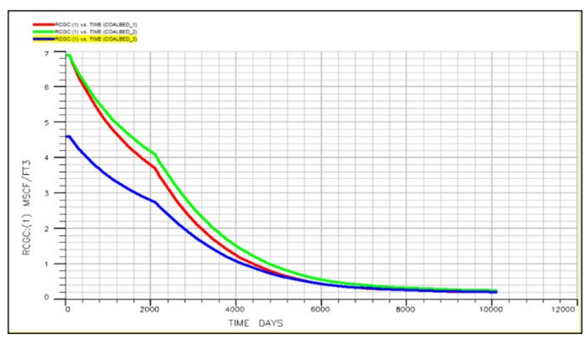

Figure 15. Results of region coal gas concentration (RCGC).

Results of region coal gas concentration (RCGC) gave exponential declining pattern from maximum coal gas concentration of 7.0 mscf/ft^3 for both CBM1 and CBM2, while the deeper CBM3 gave 4.6 mscf/ft^3 as shown in Fig. 15. Results of region coal solvent concentration (RCSC) gave minimal concentrations of 3.0 mscf/ft^3 for CBM3 and 1.0 mscf/ft^3 for CBM1 and CBM2 all at 2,000days. The maximum concentration occurred at 6,000days with 14.4 mscf/ft^3 for CBM3, 13.0 mscf/ft^3 for CBM2 and 10.8 mscf/ft^3 for CBM1 all occurring at 6,000days as shown in Fig. 16. Results of well gas production rate (WGPR) gave converged minimum rates of 10,200 mscf/day at 2,000days to slightly dispersed maximum outputs of 90,600mscf/day for CBM1 and 90,200mscf/day for CBM2 and CBM3 all at 6,000days as shown in Fig. 17.

Results of well gas production total (WGPT) gave increasing cumulative production to a maximum of 4.3E8 mscf for all cases at 10,000days as shown in Fig. 18. Results of well solvent production rate (WNPR) increased from minimum values of 4,000 mscf/day for CBM1 and CBM2 and 8,000 mscf/day for CBM3 to maximum values of 90,300 mscf/day for CBM1 and 90,000 mscf/day for CBM2 and CBM3 as shown in Fig. 19. Results of well reservoir volume production rate (WVPR) gave maximum volumetric rates of 540,000 mscf/day for CBM1, 440,000 mscf/day for CBM2 and 400,000 msf/day for CBM3 as shown in Fig. 20. Results of well reservoir volume production total (WVPT) gave increasing production with time a converged point at the origin to diverged maximum values of 3.2E9 RB for CBM1, 2.7E9 RB for CBM2 and 2.6E9 RB for CBM3 at 10,000days as shown in Fig. 21.

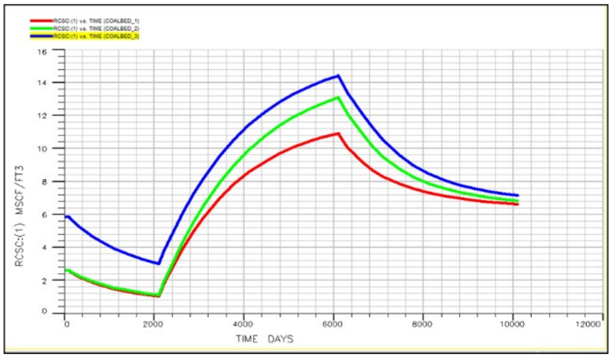

Figure. 16. Results of region coal solvent concentration (RCSC).

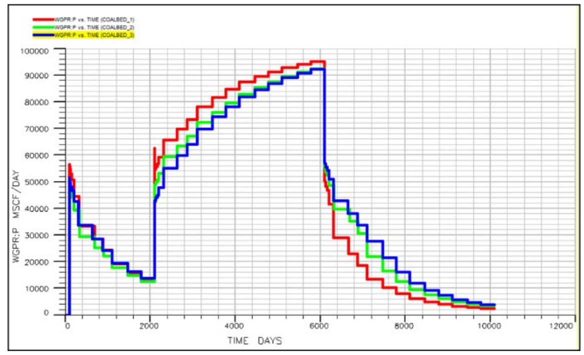

Figure 17. Results of well gas production rate (WGPR).

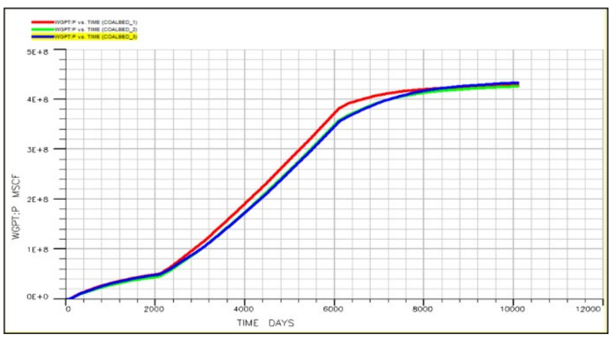

Figure 18. Results of well gas production total (WGPT).

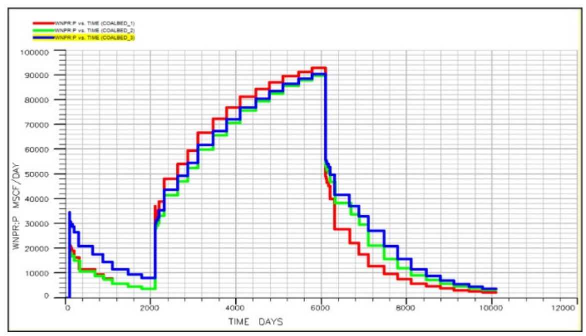

Figure 19. Results of well solvent production rate (WNPR).

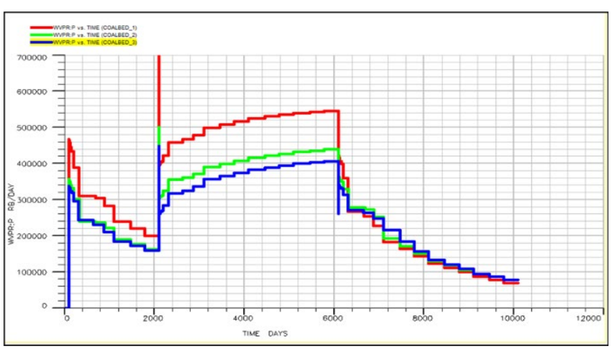

Figure 20. Results of well reservoir volume production total (WVPR).

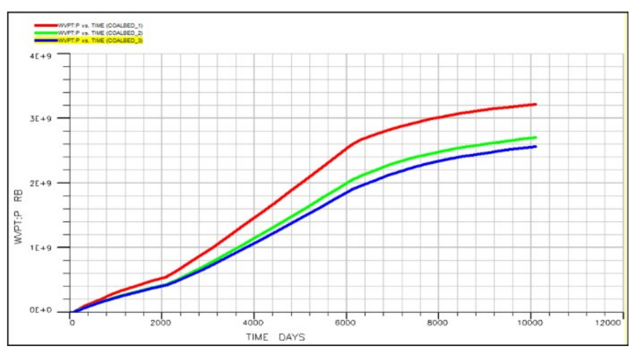

Figure 21. Results of well reservoir volume production total (WVPT).

6.1. Comparative analysis and model predictions

Average results of coal gas concentrations (CGC) for the block (BCGC), Field (FCGC), and Region (RCGC) gave similar behavioral patterns by declining exponentially with average maximum CBM gas concentrations of 5.0 mscf/ft^3 indicating the error bars along the curve with average percentage static error of 0.254% (Fig. 22). The average predicted model is $GC_{ave} = 4.9391e^{-4E-04t}$ with squared regression coefficient of $R^2 = 0.9774$.

Average results of coal gas production total (GPT) for field (FGPT), group (GGPT), well (WGPT) and well (WGPT) gave increasing polynomial curve of the 5th order with average maximum total produced gas of 40 bcf at 10,000days as shown in Fig. 23 with error bars along the curve indicating the average percentage error of approximately 0.213%. The predicted model is $PT_{ave} = 7E\text{-}11t^5 - 2E\text{-}06t^4 + 0.0134t^3 - 30.518t^2 + 45411t - 2E06$. The squared regression coefficient is $R^2 = 0.9995$.

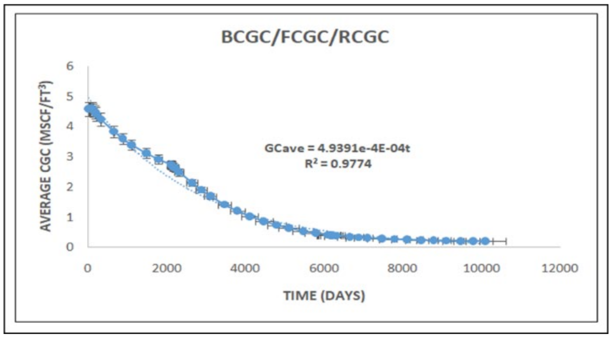

Figure 22. Results of average coal gas concentrations (BCGC/FCGC/RCGC).

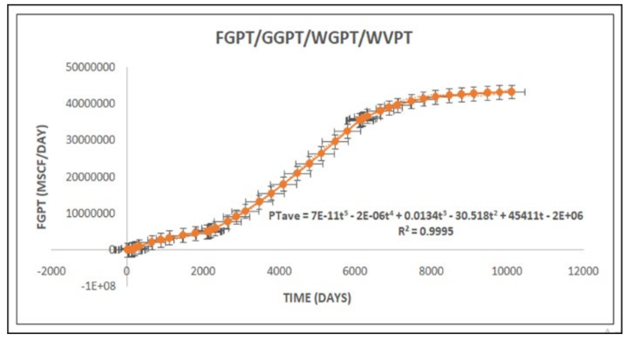

Figure 23. Results of average gas production total (FGPT/GGPT/WGPT/WVPT).

7. Conclusion

The Schlumberger Eclipse simulated reservoir has a dimension of 8 ×8×2 with dual porosity of 0.05 and 0.15 located at depths of 1,000ft, 1,200ft and 1,400ft. Results generally showed improvement in coal quality by approximately 72.83% in the y direction indicating increased methane upsurge in that direction. Results of initial 40% CO_2 isotherm fracture gas gave a cumulative maximum field gas pressure (FPR) of 540psi for the 1,400ft model (CBM3). The presence of CBM at shallow depths in the Enugu basin enclosed in the Anambra basin, southeastern Nigeria irrespective of the simulated depth range from 1,000ft to 1,400ft as illustrated in this study has the inherent capacity for storage, migration and perhaps its volatility in terms of possible kicks and blowouts if not effectively managed. With a capacity of perhaps over 40 bcf and low emissions, there is currently no form of CBM exploration and production in Nigeria to earnestly compliment conventional natural gas resources.

However, due to its vast lucrative economic potentials, the major concern is how to predict the presence and manage production both during and after drilling. Underground gasification of coal can contaminate portable unconfined aquifer systems due to their high-pressure volatility with high mobility along migration pathways. The clear understanding of the geology with possible structural relief complex of hidden CBM gas pathways will effectively prevent future occurrence of fire explosions during water well drilling.

This mercuric study has clearly shown that the compeling simplicity of the initially perceived hollowness of reservoir engineering perspective of CBM reservoir behaviors which perhaps has never been explored, exploited or even discussed by major stake holders and at any governmental level, has been carefully researched, discussed and dissected using state of the art modeling tool to understand the behavior and safety concerns of CBM as it affects its extraction during and after drilling programs. There is evidence of CBM gas and its direction of flow is largely in the y or near-vertical direction. It is technically viable due to good reservoir pressures and rates with perhaps indications of economic benefits due to the long duration of 10,000days of appreciable simulation runs. This has quenched the dappled quest for CBM gas exploration and expoitation drive in Nigeria.

This study hangs heavy with existing knowledge base of CBM modeling and extraction guides to prevent fire disasters and contribute to existing literatures on CBM in Nigeria and perhaps raises the need to have CBM engineering taught in institution of learning in the regions where coal deposits abound. Major stake holders can loosen their tongues from the parch by possibly taking a grab of this opportunity for a holistic gas asset expansion program review to compensate the current world demands in a time of its scaresness and to boost economic recovery.

There is urgent need for a comprehensive geophysical, geological and engineering re-evaluation of coal deposits for CBM potentials. There should also be a technical framework or guide to water borehole users, developers and managers developed by qualified and experienced stakeholders. Re-engineering of existing water well drilling rigs for deeper CBM wells is required. The findings of this research perhaps can act as a major source of boosting existing scarce literatures of CBM modeling of Nigerian coal seams which serves as complementary to conventional natural gas resources.

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