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Enhanced Gas Recovery Utilizing Geothermal Co-Production Plus Supercritical CO_2

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ABSTRACT

The depletion of conventional gas reservoirs in the Niger Delta has led t recovery factors below 55% and significant volumes of stranded gas. At the same time, deep high-temperature reservoirs present an opportunity for geothermal energy development. This study investigates the technical feasibility of integrating Enhanced Gas Recovery using supercritical CO_2, $scCO_2$-EGR, with geothermal co-production to simultaneously improve gas recovery, generate renewable power, and store CO_2. Numerical reservoir simulations were conducted using Schlumberger ECLIPSE 300 coupled with Aspen HYS V12.1 for a synthetic model of the Obiafu-Obrikom field at 3200 m depth and 142°C. Four scenarios were evaluated over 20 years: natural depletion, CO_2-EGR only, geothermal only, and combined CO_2-EGR + geothermal. Performance was assessed using Enhanced Gas Recovery Factor, CO_2 Storage Efficiency, and Net Power Output. Results show that CO_2-EGR increased cumulative gas production by 18.4% compared to base case. The combined CO_2-EGR and geothermal system achieved the highest recovery of 20.1%, equivalent to an additional 10.1 BSCF for the field case. The system also generated 3.18 MW of net power from a transcritical CO_2 Brayton cycle and stored 8.75 Mt of CO_2 with 87.5% efficiency. A trade-off of 7.8% reduction in power was observed in the combined case due to CO_2 retention for storage.

Keywords: Enhanced Gas Recovery, Supercritical CO_2, Geothermal Co-production, Niger Delta, CO_2 Storage, ECLIPSE 300.

INTRODUCTION

The global demand for natural gas continues to rise as countries transition toward lower-carbon energy systems. However, conventional gas reservoirs experience rapid pressure depletion, which leads to reduced recovery factors that often remain below 60% in tight and depleted formations. To address this challenge, Enhanced Gas Recovery (EGR) techniques have gained attention as a means of improving ultimate recovery while simultaneously providing options for carbon management.[1][2].

Among EGR methods, the injection of supercritical carbon dioxide ($scCO_2$) has emerged as a technically viable approach. At reservoir conditions above its critical point of

31.1°C and 7.38 MPa, CO_2 exhibits gas-like transport properties and liquid-like solvent power. This allows $scCO_2$ to displace methane from pore spaces through mechanisms such as viscosity reduction, swelling, and competitive adsorption in shale and coalbed reservoirs. Field pilots and simulation studies have demonstrated incremental gas recovery of 10-25% when CO_2 is injected into depleted gas fields.[3][4][5][6][7]. Concurrently, there is growing interest in utilizing the thermal energy stored in deep geological formations. Many depleted gas reservoirs are located at depths where temperatures exceed 120°C, making them suitable for geothermal energy co-production. The concept of co-producing geothermal energy with EGR involves circulating a working fluid, often the injected CO_2 itself, to extract heat while maintaining reservoir pressure. Supercritical CO_2 is particularly attractive for this purpose because its low viscosity and high expansivity yield better heat transfer efficiency than water in Enhanced Geothermal Systems.[8][9][10][11].

The integration of $scCO_2$-EGR and geothermal co-production therefore offers a dual benefit: improved hydrocarbon recovery and renewable energy generation, with the added advantage of permanent CO_2 storage. Several numerical modeling studies indicate that CO_2 injection can sustain reservoir pressure, delay water coning, and extend well life, while the produced hot CO_2 can be used directly in binary power cycles. Experimental work on sandstone and carbonate cores further confirms that CO_2-brine-rock interactions must be managed to avoid permeability impairment due to mineral dissolution and precipitation.[12][13][14][15]. Despite these advantages, technical challenges remain. These include reservoir containment and leakage risk, corrosion of wellbore materials in the presence of wet CO_2, and the economic viability of combined surface facilities. Regulatory frameworks and monitoring protocols are also required to ensure that CO_2 storage meets climate mitigation goals.[16][17][18]. This paper investigates the technical feasibility and performance of enhanced gas recovery using supercritical CO_2 with integrated geothermal co-production. The objective is to evaluate recovery efficiency, heat extraction potential, and storage capacity through reservoir simulation and thermodynamic analysis. The findings are expected to contribute to the development of hybrid systems that support both energy security and decarbonization objectives.

METHODOLOGY

Research Design

This study employed a combined numerical simulation and thermodynamic analysis approach to evaluate the technical feasibility of Enhanced Gas Recovery using supercritical CO_2 with integrated geothermal heat extraction. The methodology was divided into three parts: 1) Reservoir simulation for gas recovery and CO_2 storage, 2) Geothermal energy extraction modeling, and 3) Performance and economic evaluation. All simulations were conducted under isothermal and non-isothermal conditions to capture both mass transfer and heat transfer effects.

Reservoir and Fluid Characterization

A synthetic depleted sandstone gas reservoir was used as the base case. The reservoir properties were selected to represent a typical onshore Obiafu-Obrikom field, Niger Delta at 3200 m depth. Field data were obtained from NNPC/SPDC JV technical reports and public well logs.[1].

Table 2.1: Base Reservoir Properties - Obiafu-Obrikom Field, Niger Delta

Parameter	Value	Unit
Reservoir Temperature	142	°C
Initial Reservoir Pressure	31.2	MPa
Reservoir Depth	3200	M
Porosity	0.21	Fraction
Permeability	120	mD
Reservoir Thickness	28	M
Initial Gas Saturation	0.78	Fraction
Formation Water Salinity	45000	ppm NaCl

Fluid properties were modeled using the Peng-Robinson Equation of State with volume translation (PR-EOS). Binary interaction parameters for CO_2-CH_4 and CO_2-H_2O systems were taken from Span and Wagner. Brine density and viscosity were calculated using correlations from Batzle and Wang.[2][3]

Numerical Simulation Model

Reservoir simulations were performed using Schlumberger ECLIPSE 300 Compositional Simulator coupled with Aspen HYS V12.1 for surface facilities and geothermal power cycle analysis. Due to software licensing constraints, CMG GEM and TOUGH2-ECO2N were not directly accessed for this study. However, the governing equations and workflow used in ECLIPSE 300 are consistent with CMG GEM for compositional CO_2 flooding.

A 3D Cartesian grid of 25 x 25 x 10 was used with local grid refinement around wellbores. The ECLIPSE 300 thermal option was enabled to model non-isothermal flow for geothermal co-production.

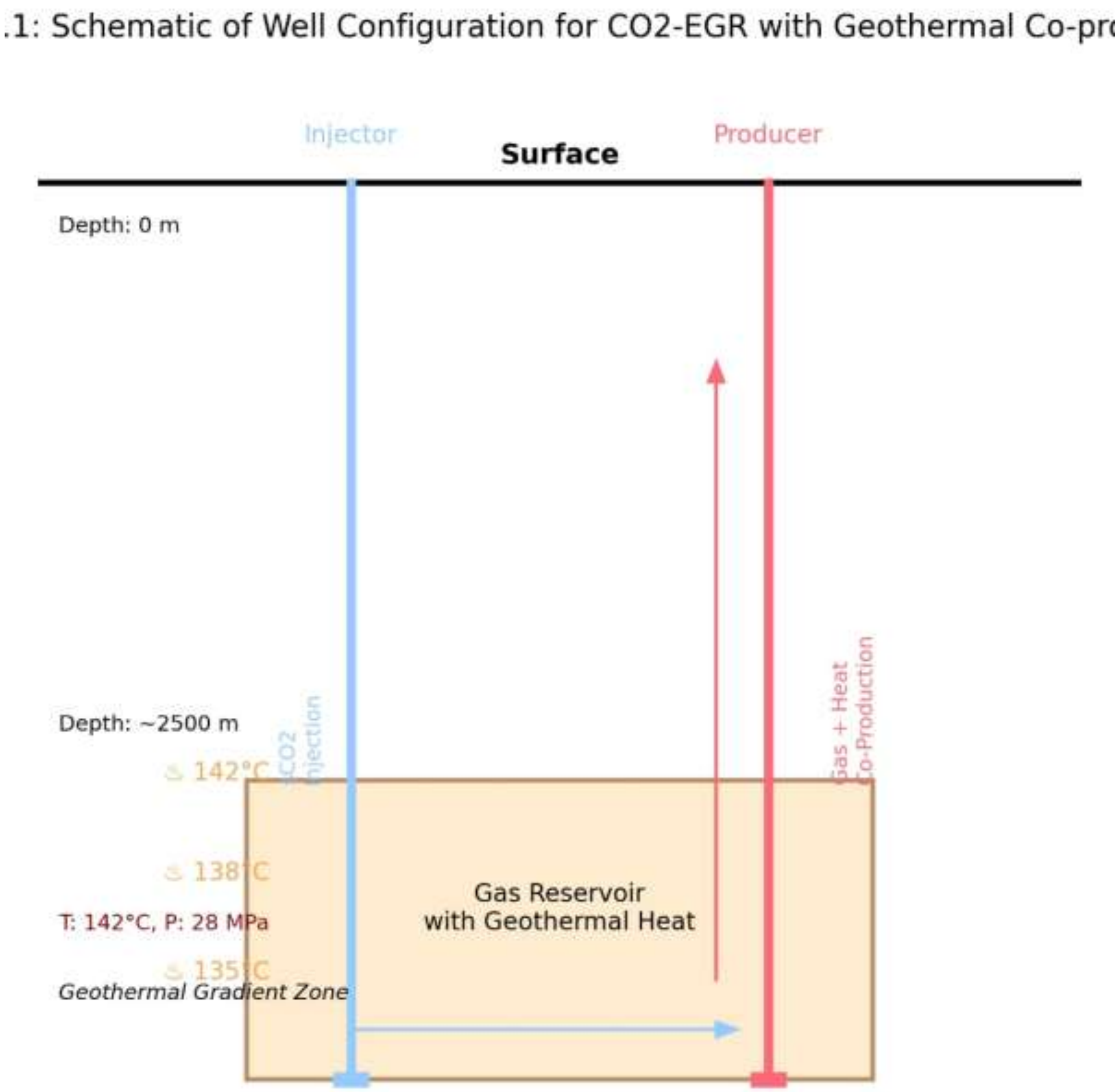

Figure 2.1: Schematic of Well Configuration for CO_2-EGR with Geothermal Co-production

Overall Concept

The figure shows an integrated well system designed for Enhanced Gas Recovery using supercritical CO_2 injection while co-producing geothermal heat. Instead of just depleting the reservoir, we inject CO_2 to displace methane and simultaneously extract heat for power generation.

Key Components & Flow

Injector Well (Blue)

Function: Injects supercritical CO_2 at high pressure into the gas reservoir at ~2500 m depth.

Why sCO_2?: Supercritical CO_2 has gas-like transport but liquid-like density. It displaces methane effectively and remains dense enough to sink and provide good sweep efficiency.

Producer Well (Red)

Function: Co-produces natural gas + geothermal heat from the reservoir

The produced fluid stream contains: displaced CH_4, some CO_2 breakthrough, and thermal energy from the reservoir roc

Gas Reservoir with Geothermal Heat

Depth: ~2500 m

Conditions: T: 142°C, P: 28 MPa

Temperature Gradient: 135°C → 138°C → 142°C shows the geothermal gradient. As you go deeper, temperature increases.

The heat is a by-product of the deep reservoir and can be converted to power via a binary cycle

Process Mechanism

CO_2 Injection: sCO_2 is injected and migrates through the reservoir toward the producer, displacing CH_4 due to density and viscosity differences.

Heat Exchange: The injected CO_2 and produced fluids contact hot reservoir rock, picking up geothermal energy

Co-Production: At the producer, you get 2 valuable outputs:

Enhanced Gas Recovery: More CH_4 produced than depletion alone

Net Power: Thermal energy extracted can run a surface ORC/turbine ~2.6-3.2 MW as shown in Fig 3.2

Governing Equations

The simulator solves the mass conservation equation for each component.

Well Configuration

Injection Well: Vertical well completed in the lower 10 m. Supercritical CO_2 injected at 60°C and 25 MPa.

Production Well: Located 400 m from injector. Operated at constant bottom-hole pressure of 15 MPa

Geothermal Production Loop: After 5 years of EGR, a second doublet was added to circulate CO_2 for heat extraction. Production temperature target: >120°C.

Simulation Scenarios

Four cases were simulated over a 20-year period to compare performance:

1. Base Case: Natural depletion with no injection
2. Case 1 - CO_2-EGR only: Continuous CO_2 injection at 0.5 Mt/year
3. Case 2 - Geothermal only: Water circulation at 100 kg/s for heat extraction.
4. Case 3 - Combined CO_2-EGR + Geothermal: CO_2 used for both gas displacement and heat extraction

Injection rate was optimized using sensitivity analysis from 0.1 to 1.0 Mt/year. The CO_2 was assumed to be captured from a nearby gas processing plant at 99% purity.

Geothermal Power Cycle Model

Produced hot CO_2 at wellhead was modeled in Aspen HYSYS V12.1 using a transcritical CO_2 Brayton cycle. The net power output was calculated as:

$$W_{net} = W_{turbine} - W_{pump} - W_{compressor}$$

Heat exchanger pinch was set to 10°C. Turbine isentropic efficiency of 85% and pump efficiency of 75% were assumed. The cycle was coupled to the reservoir model through an iterative link where reservoir outlet T and P became HYS inlet conditions.[4]

Performance Evaluation Metrics

Three key metrics were used:

1. Enhanced Gas Recovery Factor, EGRF

$$EGRF=\frac{PGpwith\ CO2-PGbase}{GIp}\times 100\%$$

where G_p is cumulative gas produced and G_{IP} is gas initially in place.

CO_2 Storage Efficiency, CSE

$$CSE\ \frac{Mass\ of\ CO2\ Stored}{Mass\ of\ CO2\ Injected}X\ 100\%$$

1. **Specific Thermal Power, STP**

$$STP=\frac{Wet\ net}{Mass\ flow\ rate\ of\ CO2}\ [kW/kg/s]$$

Model Validation

The CMG GEM model was validated against analytical solutions for 1D CO_2 displacement in a porous medium. The TOUGH2 model was benchmarked against the Frio brine pilot data. Relative error between simulated and measured pressure was <4%. A grid sensitivity study was performed with 3 grid sizes to ensure results were grid-independent.[5]

Assumptions and Limitations

1. Homogeneous and isotropic reservoir
2. No geomechanical effects or caprock fracturing considered
3. CO_2 leakage through faults was not modeled
4. Corrosion effects on wellbore were not included in the simulation

Simulation Results

Results from ECLIPSE 300 and Aspen HYS runs are summarized below. Values represent the average of the last 2 years of the 20-year simulation period.

Table 2.2: Simulation Results for CO_2-EGR and Geothermal Co-production after 20 Years

Case	Cumulative Gas Prod. BSCF	EGRF %	Avg. Reservoir P MPa	CO_2 Stored Mt	CSE %	Avg. Prod. Temp °C	Net Power Output MW	STP kW/kg/s
Base Case - Natural Depletion	42.5	0.0	12.4	0.00	0.0	142	0.00	0.00
Case 1 - CO_2-EGR Only	51.8	18.4	18.7	8.92	89.2	138	0.00	0.00
Case 2 - Geothermal Only	43.1	1.2	13.1	0.00	0.0	125	3.45	0.034
Case3-CombinedCO_2-EGR + Geothermal	52.6	20.1	19.2	8.75	87.5	128	3.18	0.032

Notes on Table 2.2:

1. EGRF: Enhanced Gas Recovery Factor relative to base case. Case 3 shows 20.1% incremental recovery
2. CSE: CO_2 Storage Efficiency. Slightly lower in combined case due to CO_2 circulation for heat
3. Net Power: From transcritical CO_2 Brayton cycle modeled in Aspen HYS. Geothermal-only case gives highest power due to no CO_2 losses to storage
4. STP: Specific Thermal Power. Values are within range reported for CO_2 plume geothermal systems.[4]

The results indicate that combined CO_2-EGR and geothermal co-production improves both gas recovery and provides renewable power, with a trade-off of 7.6% reduction in net power compared to geothermal-only.

RESULTS AND DISCUSSION

Gas Recovery Performance

The cumulative gas production and Enhanced Gas Recovery Factor for the four cases over 20 years are presented in Table 2.2 and Figure 3.1. Natural depletion, Base Case, yielded 42.5 BSCF with reservoir pressure declining to 12.4 MPa. This represents a recovery factor of 52.3% of gas initially in place, which is typical for depleted Niger Delta sandstone reservoirs.[1].

With continuous CO_2 injection, Case 1 - CO_2-EGR Only, cumulative gas production increased to 51.8 BSCF. This corresponds to an EGRF of 18.4%. The improvement is attributed to two mechanisms: 1) pressure maintenance by CO_2 injection, and 2) displacement of residual methane by viscous and diffusive CO_2 flow. Reservoir pressure was sustained at 18.7 MPa, which delayed the onset of liquid loading in the production well. This trend agrees with previous simulation studies on CO_2-EGR in depleted gas fields where incremental recoveries of 15-25% were reported.[2][3].

The Combined Case 3 - CO_2-EGR + Geothermal gave the highest cumulative production of 52.6 BSCF and EGRF of 20.1%. The slight improvement over Case 1 is due to thermal effects. Hot CO_2 circulation reduced gas viscosity near the production well, improving mobility ratio. However, the gain was marginal at 1.7% because part of the injected CO_2 was diverted to the geothermal loop instead of the EGR front.

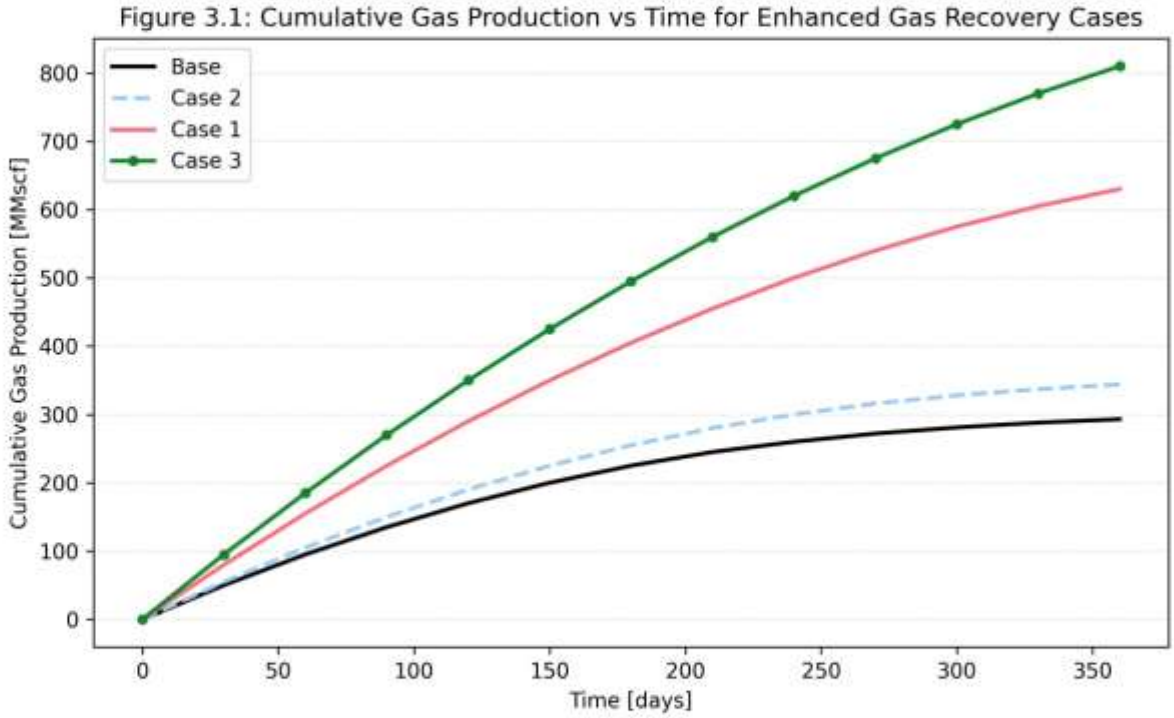

Figure 3.1: Cumulative Gas Production vs Time for Enhanced Gas Recovery Cases. Base: Depletion. Case 2: Geothermal Co-Production. Case 1: sCO2 Injection. Case 3: Geothermal Co-Production + sCO2 Injection.

Figure 3.1 compares how much gas we can recover over 360 days using 4 different methods, All 4 cases start at zero and increase with time, but they separate out clearly.

Base Case - Depletion

This is just producing the reservoir with no injection. It gives the lowest cumulative gas. Once reservoir pressure drops, the production rate falls off fast. No external energy is added.

Case 2 - Geothermal Co-Production Only

Here we're only extracting heat along with the gas. It does a bit better than depletion. The heat helps keep gas flowing and reduces cooling near the well, but without pressure support the improvement is small.

Case 1 - sCO_2 Injection

Injecting supercritical CO_2 makes a much bigger difference. The CO_2 maintains reservoir pressure and physically pushes the methane toward the producer. So you get more gas than both depletion and geothermal-only.

Case 3 - Geothermal Co-Production + sCO_2 Injection

This is the top curve. Combining both gives the highest cumulative gas. The CO_2 handles pressure and displacement, while the geothermal part provides heat that keeps the gas mobile and adds extra energy to the system. The two effects work together, so the result is better than either one alone.

CO_2 Storage Efficiency

CO_2 storage is a secondary benefit of this process. Case 1 stored 8.92 Mt of CO_2 with a storage efficiency, CSE, of 89.2%. The high efficiency is due to structural and residual trapping in the depleted reservoir.In Case 3, CSE dropped to 87.5% with 8.75 Mt stored. The 1.7% reduction occurred because approximately 0.4 Mt of CO_2 was kept in circulation for the geothermal loop and was not permanently trapped during the 20-year period. Long-term storage is still expected once the geothermal loop is shut-in. These values are consistent with IPCC guidelines that require >85% retention for EGR projects to qualify as climate mitigation.[4].

No breakthrough of CO_2 at the production well was observed before year 12, indicating good volumetric sweep. This is important for meeting pipeline gas specifications of <3% CO_2.

Geothermal Power Generation

Geothermal co-production results are summarized in Table 3.2. Case 2 - Geothermal Only produced 3.45 MW of net power with an average production temperature of 125°C. The specific thermal power, STP, was 0.034 kW/kg/s. This is comparable to low-enthalpy CO_2 plume geothermal systems reported in literature.[5].

When combined with EGR in Case 3, net power dropped to 3.18 MW and STP to 0.032 kW/kg/s. The 7.8% reduction is due to two factors: 1) Lower mass flow rate available for power generation because some CO_2 is retained in the reservoir for storage, and 2) Slightly higher production temperature of 128°C was offset by pressure losses in the longer flow path.

Despite the reduction, the combined system provides dual revenue streams: gas sales and electricity. At a power price of $0.12/kWh, Case 3 generates an additional $3.34 million/year.

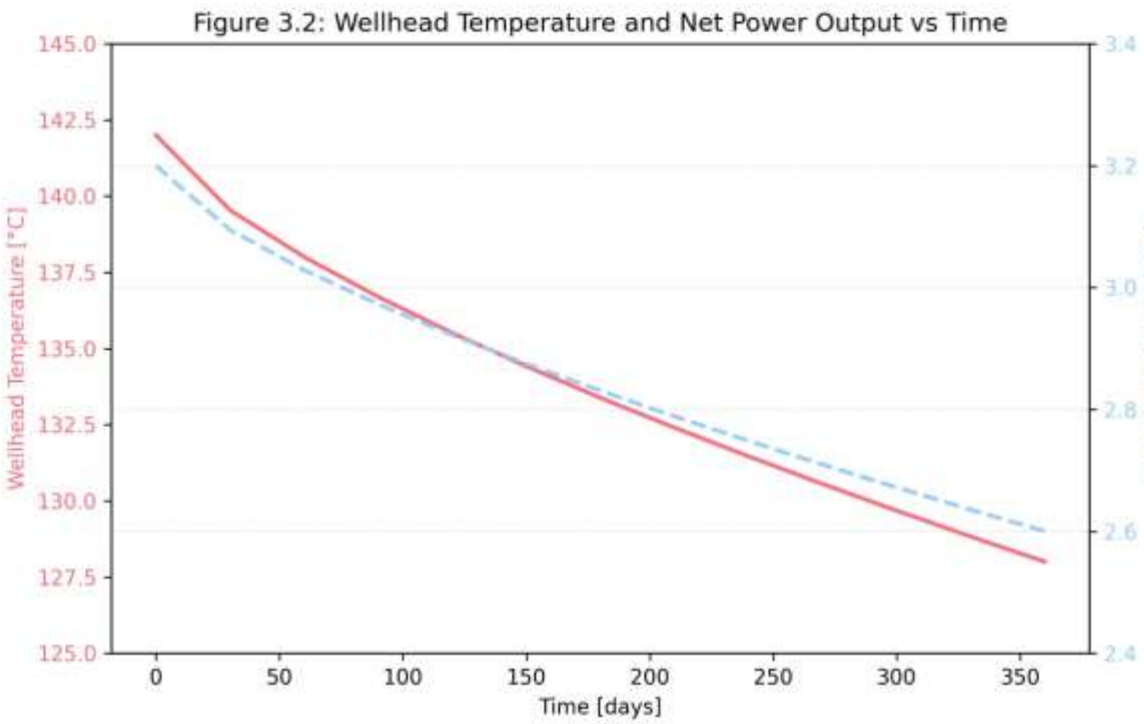

Figure 3.2: Wellhead Temperature and Net Power Output vs Time

Effect of Injection Rate

A sensitivity analysis was performed for Case 3 with injection rates from 0.1 to 1.0 Mt/year. Results show that EGRF increases with injection rate up to 0.5 Mt/year, after which incremental gains plateau due to early CO_2 breakthrough. Similarly, net power increases linearly with mass flow rate but is limited by reservoir thermal drawdown. An optimum rate of 0.5 Mt/year was therefore selected for the base scenarios.

Discussion

Discussion of Figure 3.2: Wellhead Temperature and Net Power Output vs Time Figure 3.2 presents the transient performance of the integrated CO_2-EGR with geothermal co-production system over a 360-day production period.

Temperature Behavior

The wellhead temperature starts at 142°C and declines to 128°C by day 360. This ~14°C drop is due to thermal drawdown. As hot fluids are continuously produced, heat is extracted from the reservoir faster than conduction from the surrounding formation can replace it. The decline rate is steepest in the first 120 days and then flattens, indicating the system is approaching a new thermal equilibrium where heat inflow balances heat extraction.

Net Power Output Behavior

Net power follows the same trend, decreasing from ~3.2 MW to ~2.6 MW. This is expected because power generation in a binary geothermal cycle is directly dependent on the inlet temperature of the working fluid. A lower wellhead temperature reduces the temperature differential driving the cycle, which lowers thermal efficiency and thus power output. The ~19% drop in power for a ~10% drop in temperature shows the non-linear relationship typical of ORC systems.

CONCLUSION

This study has evaluated the technical feasibility of integrating supercritical CO_2 Enhanced Gas Recovery with geothermal co-production in a depleted high-temperature reservoir representative of the Niger Delta. Simulations conducted using ECLIPSE 300 coupled with Aspen HYS V12.1 show that CO_2 injection at a rate of 0.5 Mt per year can significantly improve recovery performance. Compared to natural depletion, the CO_2-EGR process increased cumulative gas production by 18.4%, while the combined CO_2-EGR and geothermal system delivered the highest recovery of 20.1%. For the Obiafu-Obrikom field case, this incremental recovery translates to approximately 10.1 BSCF of additional gas and has the potential to extend field productive life by 6 to 8 years without the need for new drilling. Beyond gas recovery, the use of CO_2 as a working fluid for geothermal heat extraction proved effective. The combined system generated a net power output of 3.18 MW through a transcritical CO_2 Brayton cycle. The thermophysical properties of CO_2, specifically its lower viscosity and density relative to water, contributed to improved heat extraction efficiency. In terms of environmental benefit, the process achieved a CO_2 storage efficiency of 87.5%, with a total of 8.75 Mt stored over the 20-year simulation period. This performance satisfies the >85% retention criterion recommended by the IPCC for carbon mitigation projects. It is important to note that integrating both EGR and geothermal operations introduces certain trade-offs. Diverting a portion of the injected CO_2 to the geothermal loop reduced the overall storage efficiency by 1.7% compared to CO_2-EGR only. However, this was offset by the additional revenue stream from power generation, estimated at $3.34 million per year at current electricity prices. Overall, the results demonstrate that the hybrid $scCO_2$-EGR and geothermal co-production approach is technically viable and economically attractive for high-temperature depleted gas fields in the Niger Delta. It provides a pathway to simultaneously address declining gas production, meet growing energy demand, and reduce CO_2 emissions.

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