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Economics of steam-assisted gravity drainage for the Nigerian Bitumen deposit

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ABSTRACT

Combining deterministic and probabilistic procedures, the economics and commerciality of steam-assisted gravity drainage (SAGD) for exploiting the Nigerian heavy-oil sands are investigated. Considering net present value (NPV) and value–investment ratio as the objective functions, the impacts of reservoir performance, costs, oil price and fiscal regime are evaluated. Within the range examined, reservoir performance, oil price, and expenditure profiles are found to be the primary determinants of project value and risks. For the case studied, SAGD has more than 75% chance of economic success ($NPV > 0$), suggesting its attractiveness for the Nigerian bitumen deposit. However, potential risks are highlighted, and mitigation measures prescribed.

1. Introduction

The International Energy Agency (IEA) predicts a global primary-energy demand rate of about 300 million barrels of oil-equivalent per day by the year 2035 (IEA, 2010). Due to production decline from conventional crude-oil sources, bitumen and heavy-oil resources are expected to play a key role in alleviating the anticipated oil-supply shortfall (IEA, 2010). Faced with this energy-supply challenge, there have been unprecedented interests in heavy-oil and other unconventional resources (Lee, 2009; Roche, 2008) which, until recently, were generally unattractive, despite their relatively low exploration costs and vast in-place volumes (IEA, 2010; Meyer et al., 2007).

The high viscosity of heavy crudes under reservoir conditions accounts for most of their exploitation challenges and prohibitive investment requirements. One method of enhancing the oil mobility is to reduce their viscosity in the reservoir. Presently, steam-assisted gravity drainage (SAGD), including its variants, is the leading in situ exploitation technology for bitumen and heavy-oil deposits (Jimenez, 2008; Roche, 2008).

In southwest Nigeria, within the Dahomey Basin, there is a tar-bearing belt (Enu, 1985; Adegoke et al., 1980), estimated to contain 70–420 billion barrels of bitumen (oil equivalent) and 1–13 Tscf of dissolved gas (Lawal, 2011a). Despite this resource volume, Nigeria still depends on heavy-oil and asphalt imports as feedstock to one of its refineries and road construction, respectively (Lawal, 2011b). This stems from the current undeveloped state of the deposit, a situation resulting from the prohibitive capital investments required for surface mining, the recovery method initially considered (Adegoke et al., 1980). However, researchers are beginning to show interests in the relatively cheaper and less environmentally sensitive in situ recovery techniques (Lawal, 2011b; Akande, 2007; Ayodele, 2006; Adewusi, 1998a).

Through core-scale laboratory experiments (Adewusi 1998a, 1998b; Adewusi and Adetona, 1998; Omole and Omolara, 1988), field pilot (Akande, 2007) and numerical-simulation studies (Lawal, 2011b), the technical feasibility of steam injection in general, and SAGD in particular, for the development of the belt has been demonstrated. However, the economics of these recovery techniques remains to be published.

To complement the large body of technical works, which include the technical feasibility of SAGD, on the Nigerian bituminous sand (Lawal, 2011a, 2011b; Akande, 2007; Adewusi 1998a, 1998b; Adewusi and Adetona, 1998; Omole and Omolara, 1988; Adegoke et al., 1980), it has become imperative to evaluate the economic potentials of in situ development of the belt. Therefore, the primary objective of this paper is to assess the economics and commerciality of SAGD technology for the Nigerian heavy-oil deposit.

2. Method of study

The study workflow comprises four main steps – parameter screening, experimental design (ED), response-surface generation and Monte-Carlo simulation (MCS) (Yang et al., 2009). As indicators

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of economics and commerciality, net present value (NPV) and value-to-investment ratio (VIR) are taken to be the objective functions.

This paper quantifies the impacts of technical and non-technical variables on the objective functions of a simulated SAGD sector model in the Nigerian tar belt. Driven by subsurface uncertainties, reservoir performance (includes oil/gas and water production as well as steam-injection forecasts) constitutes the technical variable. The non-technical variables include costs, revenues and fiscal terms (ETF, 1993; PPT, 1990; PTDF, 1990).

Unlike its conventional-oil counterpart, Nigeria is yet to have a developed heavy-oil sector, as there are neither commercial developments nor firm fiscal policies till date. For example, stakeholders are still divided on the fiscal terms for this sector (NMGS, 2012; Ayodele, 2012; PIB, 2012; MMR, 2010; NMMA, 2007). Therefore, as reference-case, we apply the current Nigerian petroleum fiscal terms (ETF, 1993; PPT, 1990; PTDF, 1990), essentially developed for the conventional-crude activities. However, for sensitivity studies and to close data gaps, reasonable assumptions are made from the fiscal policies guiding the heavy-oil sectors in Canada and elsewhere (Shin and Polikar, 2006). In the later part of this paper, we evaluate the robustness of the results to the possible outcome of the ongoing fiscal-policy debates in Nigeria.

3. Economic model

The following expression describes the annual net cash-flow, which include the operating expenditure (OPEX) and capital expenditure (CAPEX):

$$N_{CF} = R_v - C_{op} - C_{ca} - C_r - C_t, \tag{1}$$

where R_v is the gross revenue (oil and gas sales); C_{op}, C_{ca}, C_r and C_t are the OPEX (fixed and variable), CAPEX, royalty and tax, respectively. All the variables refer to the year-end. C_r and C_t are given by

$$C_r = r_r R_v, \tag{2}$$

$$C_t = r_t (R_v - C_r - C_{op} - C_d), \tag{3}$$

where r_r and r_t are royalty and tax rates, respectively. C_d is fiscal depreciation.

While providing for decommissioning costs at project abandonment, NPV is estimated from the annual net cash flow as follows:

$$N_{PV} = \sum_{i=1}^{n_t} \frac{N_{CF}}{(1+r_D)^i}, \tag{4}$$

where r_D and n_t are discount rate and number of years to abandonment, respectively. i is the year counter.

The evaluations assume a maximum 42-year project lifetime (n_t=42), comprising a 2-year pre-start and a 40-year operating lifetime, with the latter determined by the duration of the reservoir simulations. The following discusses the key input variables and the main assumptions.

3.1. CAPEX and OPEX elements

The major CAPEX items are wells, flowlines, and treatment/gas-compression facilities. Contingency and decommission costs are included (Table 1). For simplicity, we assume that 50% of the CAPEX would be incurred in each of the two years before the project (production) start-up. The main OPEX components and their assumed reference values are given in Table 2.

3.2. Revenue and penalty

Revenue is due to oil and gas sales. As a responsible operator, we assume a carbon-constrained scenario; hence carbon tax is incurred for CO_2 emissions from fossil-fuel combustion for steam generation. No provision is made for carbon capture and storage. For the reference-case analysis, the revenue and carbon-penalty rates are indicated in Table 3. It is noteworthy that a relatively low oil price is assumed, reflecting the market differentials between heavy and light crudes.

3.3. Fiscal terms

Presently, three independent tax regimes exist in the upstream sector of the Nigerian petroleum industry. These are corporate (PPT, 1990), Petroleum Technology Development Fund (PTDF, 1990) and Education Trust Fund (ETF, 1993). The reference-case fiscal terms are presented in Table 4.

At present, the royalty rate varies from one basin to the other. For the inland basins, to which the bitumen-bearing Dahomey Basin belongs, the royalty rate is 10% (PPT, 1990). As a comparison,

Table 1
CAPEX components.

Cost item	Quantity	Comments/references
Drilling and completion		
– No. of injectors	2	Based on optimised development
– No. of producers	2	Based on optimised development
Unit cost ($ mln/well)	*1.5*	Frauenfeld et al. (2006) and Shin and Polikar (2006)
Surface pipelines (flowlines)		
– No. of injection lines	2	A “pessimistic” scenario of one flowline per injector
– No. of production lines	2	A “pessimistic” scenario of one flowline per producer
Length per line (km)	*1*	
Unit cost ($ mln/km)	*0.5*	Cox et al. (2003)
Processing facilities		
Peak steam rate, CWE (Mstb/d)	2	Based on reservoir-simulation forecasts (Lawal, 2011b)
Peak gross liquid rate (Mstb/d)	8	Gross liquid is about 4 times CWE steam (Heins, 2010)
Unit cost of gross liquid facilities($ mln/Mstb liquid)	*1.9*	Birrell et al. (2005) and Edmunds and Chhina (2001)
Unit cost of steam boiler($ mln/Mstb water)	*2.2*	Birrell et al. (2005)
Others		
CAPEX contingency (%)	10	Assumption
Decommissioning costs (% CAPEX)	25	
CAPEX phasing (%/year)	50	CAPEX spending spread over the first 2 years