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Optimization of hydrocarbon water alternating gas in the Norne field: Application of evolutionary algorithms

Erfan Mohagheghian[a], Lesley A. James[a,*], Ronald D. Haynes[b]

[a] Faculty of Engineering and Applied Science, Memorial University of Newfoundland, St. John's, NL A1B3X5, Canada
[b] Department of Mathematics and Statistics, Memorial University of Newfoundland, St. John's, NL A1C5S7, Canada

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ABSTRACT

Water alternating gas (WAG) is an enhanced oil recovery (EOR) method integrating the improved macroscopic sweep of water flooding with the increased microscopic displacement of gas injection. The optimal design of the WAG operating parameters is usually based on numerical reservoir simulation via trial and error. In this study, robust evolutionary algorithms are utilized to automatically optimize hydrocarbon WAG performance in the E-segment of the Norne field. Net present value (NPV) and two global semi-random search strategies, a genetic algorithm (GA) and particle swarm optimization (PSO), are used to optimize over an increasing number of operating parameters. The operating parameters include water and gas injection rates, bottom-hole pressures of the oil production wells, cycle ratio, cycle time, the composition of the injected hydrocarbon gas and the total WAG period. In progressive case studies, the number of decision-making variables is increased, increasing the problem complexity while potentially improving the efficacy of the WAG process. We also optimize the incremental recovery factor (IRF) within a fixed total WAG simulation time. The distinctions between the WAG parameters found by optimizing NPV and oil recovery are highlighted. This is the first known work to optimize over such a wide set of WAG variables and the first use of PSO to optimize a WAG project at the field scale. Compared to the reference cases, the best overall values of the objective functions found by GA and PSO were 13.8% and 14.2% higher, respectively, if NPV is optimized over all the above WAG operating variables, and 14.2% and 16.2% higher, respectively, if the IRF is optimized.

1. Introduction

Enhanced oil recovery (EOR) techniques are meant to decrease the residual oil saturation after primary and secondary oil production [1]. Gas injection as an EOR process is widely used for increasing oil recovery by injecting gases into the oil reservoir [1–6]. A low mobility ratio between the injected gas and the displaced oil during the immiscible displacement process leads to an unstable zone on the front as well as early breakthrough and viscous fingering [7,8]. Water alternating gas (WAG) was first proposed as a method to integrate the improved microscopic displacement efficiency of gas injection with the increased macroscopic sweep efficiency of water flooding [9].

WAG has been conducted with success in most field trials. The majority of the fields subjected to WAG are located in Canada and the United States. WAG incremental oil recovery is reported to be about 5%, however, incremental recovery has reached up to 20% in several fields. High incremental recovery is usually a result of the gas being miscible with the reservoir oil. Carbon dioxide (CO_2) and hydrocarbon gases are the two most commonly used injectants. CO_2 is expensive, not easily available, especially for offshore purposes, and it can cause corrosion issues [10,11], however, hydrocarbon gases are directly obtained from oil production or from a nearby gas field, and in almost all offshore WAG applications hydrocarbon gases are injected either as dry gas or are enriched before injection [9].

It is crucial to develop and test various WAG scenarios in order to determine the optimum operational parameters based on economics [12]. Parameters which can affect WAG are classified into reservoir characteristics (such as heterogeneity, wettability, fluid properties) and operational/well control parameters (injection pattern, injection rates, bottom-hole pressures of the oil producers, WAG or cycle ratio, cycle time, the composition of the injection gas and the total WAG duration) [9,13–17]. Reservoir characteristics are usually either uncontrollable or too costly to modify, hence locating the optimal operational point is of vital significance. Non-optimal well control parameters are likely to result in early breakthrough and high water cut and/or gas-oil ratio, thus low oil recovery and less profit. To the best of the authors' knowledge, no automatic optimization has ever been done on the whole set of control variables prepared here. As the number of controlling

* Corresponding author.
E-mail address: ljames@mun.ca (L.A. James).

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variables increases, the optimization of WAG performance in a heterogeneous reservoir becomes more complex and challenging.

Several previous simulation studies have used a limited number of runs and suggested field performance surveillance to optimize WAG parameters [12,18–21]. Ampomah et al. optimized WAG cycles using numerical reservoir simulators and proposed longer gas cycles to increase oil recovery and CO_2 storage [22]. Gharbi utilized an expert system, as a subclass of Artificial Intelligence, combined with an economic package, to optimize WAG ratio, slug size per WAG cycle and then the total slug size by changing the variables incrementally in small ranges [23]. Esmaiel and Heeremans, Ghomian et al., and Ghaderi et al. used response surfaces as a proxy for the reservoir simulator to optimize the WAG parameters by means of a polynomial expression [24–26]. Dai et al. [27,28] employed a response surface analysis and Monte Carlo simulation to optimize a CO_2-EOR process and found the optimal distance between the wells and the sequence of alternating injection cycles. Rahmawati et al. solved the mixed-integer nonlinear optimization problem for different flooding strategies and employed a heuristic simplex algorithm to find the maximum NPV and the best injection scenario. They mentioned that the NPV should be tested and maximized for the optimum field production life time (before the negative return of NPV) [29]. Jahangiri used Ensemble Kalman filter (EnKF) to optimize the net present value of a WAG process by controlling the injection rates, bottom hole pressures of the producers and injection pattern as the variables. He showed the flexibility of EnKF in the choice of simulator and economic model and its low computational cost [30].

Yang et al. used a genetic algorithm (GA) and simulated annealing to optimize the multivariate production-injection system for WAG miscible flooding using net present value as the objective function. They chose average reservoir pressure, producing GOR, water-cut and oil rate for each production well, and gas or water injection volume as the decision-making variables. They claimed that both of the techniques showed stability and efficiency for their optimization purpose [31,32]. Chen et al. used a GA to optimize the controlling variables (WAG ratio, cycle time, injection rates and bottom hole pressures of the producers) of a CO_2-miscible WAG in field scale. They hybridized the GA with an orthogonal array and Tabu search to improve the convergence speed of GA [14]. However, they limited all the optimization variables to take only a few discrete values.

The huge number of alternative WAG control schemes necessitates the employment of efficient and robust optimization algorithms to make the most profitable decision. We use a genetic algorithm (GA) and particle swarm optimization (PSO) in this study. GA has gained much popularity in the petroleum industry and both of these techniques have proven their capability in finding the optima of various oil and gas problems [33–35]. These are black-box algorithms which do not need access to the simulator code and can be efficiently parallelized. GA has already been used for the purpose of WAG optimization, however, the injection gas composition was not included and the number of variables was lower than those optimized in this paper. PSO is tested here to optimize a WAG project in the field scale for the first time.

In this study, D-optimal design, a design of experiments (DOE) approach which spans the whole search space more efficiently than a full factorial design [36], is integrated with GA and PSO to improve the initialization process of the algorithms and is also used as the reference case to monitor the success of our optimization. NPV and incremental recovery factor (IRF) are selected as objective functions and the set of controllable operating parameters include water and gas injection rates, bottom-hole pressures of the oil producers, cycle ratio, cycle time, the composition of the injected hydrocarbon gas and the total WAG period. Three case studies on NPV optimization and one on IRF optimization are designed. The case studies are carried out on the E-segment of the Norne field (See Section 3 for more information on the field). In progressive case studies, an incremental number of variables are sampled from this set to examine the practicality of the optimization algorithms and the increased efficacy of the WAG process as the problem complexity increases. We show that such optimization techniques will succeed at finding the optimal solution and increase the economic benefit.

2. Methodology

In this section, the objective functions, well control parameters (optimization variables), optimization techniques and the optimization procedure used in this study are explained and illustrated.

2.1. Objective functions

In production optimization, the ultimate recovery factor or net present value (NPV) is usually chosen as the objective (fitness) function. Although NPV, as an economic measure, is not the only influencing factor, it is a proper indication of the project's profitability and helps in decision making. NPV is defined as the sum of the present values of incoming and outgoing cash flows over a period of time [14]. NPV for a WAG process can be calculated as

$$NPV(x) = \sum_{i=1}^{n} \{Q_o^{prod}(i)c_o - [Q_g^{inj}(i) - Q_g^{prod}(i-1)]c_g - Q_g^{prod}(i-1)c_g' \ldots$$
$$-[Q_w^{inj}(i) - Q_w^{prod}(i-1)]c_w - Q_w^{prod}(i-1)c_w'\}(1+r)^{-i} \ldots$$
$$+[Q_g^{prod}(n)(c_g - c_g') + Q_w^{prod}(n)(c_w - c_w')](1+r)^{-n}, \quad (1)$$

where n is the total number of years, i is the year number, c_o is the price of produced oil, c_g and c_w are the price for purchasing gas and water for injection, c_g' and c_w' are the cost of treating and recycling the produced gas and water, $\boldsymbol{Q}$ is the total volume of the produced or injected fluid and r is the interest rate. The subscripts o,w and g refer to oil, water and gas and the superscripts inj and $prod$ represent injection and production, respectively. The volumes are obtained as outputs of the reservoir simulator and are functions of the optimization vector x.

The total oil production after the start of the WAG divided by the initial oil in place, known as incremental recovery factor (IRF), is the second objective function used in this study. IRF is defined in the following form

$$IRF = \frac{\int_0^T q_o dt}{IOIP}, \quad (2)$$

where T is the total WAG duration, q_o is the total oil production rate and $IOIP$ is the initial oil in place.

2.2. Well control parameters

The three subsystems, namely reservoir, well and surface facilities are often treated independently and the locally optimized results of each subsystem is handed off to its next downstream stage for functional analysis [37]. It is important to consider the problem of production optimization as an integrated system and optimize the subsystems' performance globally. Therefore, in this paper both the injection and production parameters are taken into account.

Due to reservoir heterogeneity, different injection rates/flowing bottom hole pressures are assigned to each injector/producer. Injection rates should be chosen according to fracturing pressure and well injectivity and the producers' bottom-hole pressures (BHPs) should vary in a range which conforms to well and surface facility constraints. It is economical to maintain the BHP at, or close to, the minimum miscibility pressure (MMP) if sufficient drawdown can be applied in the reservoir [14].

Other WAG injection parameters include the length of a period of water and gas injection. This is known as the cycle time. Another WAG injection parameter requiring investigation is the ratio of water to gas injection which can be defined by WAG ratio or cycle ratio. WAG ratio is the ratio of the volume of water to the volume of gas injected at