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# Feasibility Study and Technical Optimization by Implementing Steam Flooding for the Field Development Plan of A Heavy-Oil Field in Yemen

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**ABSTRACT -** Enhanced Oil Recovery (EOR) applications are highly recommended and required in Yemen to maintain stable levels of oil production. The field selected for this research is located in Yemen, where relatively-thin sandstone reservoirs are dominant at moderate depths. The reservoir is highly undersaturated with an API gravity of 14.2 and a very low solution gas-oil ratio (GOR), initial oil viscosity (μo) of 420 cP. The reservoir is naturally producing with the support of a strong water drive at the bottom, however, the increase in water cut poses a disadvantage for this reservoir. Over time, the oil production will decline and development plans will be required to improve the oil recovery. This research aims to optimize oil recovery factor and the interest in the overall project economy by evaluating the optimization of the steam flood process based on the Stochastic analysis with the highest recovery factor (RF) and the highest net present value (NPV) objective functions. Two optimization techniques have been used to perform the data analysis, deterministic and stochastic approaches. The deterministic approach is carried out by direct analysis on the results of the technical optimization method using the CMG reservoir simulator, while the stochastic approach uses the simulation results from the deterministic approach to determine the most influencing parameter in the steam flood process as well as to optimize the infill and injection wells location, number of steam injection wells and the steam injection rate with the highest oil RF and highest NPV. In this field development using deterministic approach, two producer wells are converted into injector wells. The RF for this initial scenario is 52,34%, and the NPV is 33.10 MM$/STB. For the second scenario using Stochastic approach, CMOST optimization using the maximum RF objective function resulted in RF of 61.33%, and NPV of 43.00 MM$/STB. Finally for the third scenario using CMOST optimization with the maximum NPV objective function resulted in RF of 57.29%, and an NPV of 53.86 MM$/STB. The Stochastic approach with maximum NPV objective function provides the most favorable scenario to be used in the development of Field "AR". And the optimization using the stochastic approach also produces faster, optimum, and more accurate results than the deterministic approach since it forecast a variety of probable results by running thousands of reservoir simulations using many various estimations of economic conditions.

**Keywords**: heavy-oil, enhanced oil recovery (EOR), steam flood, recovery factor (RF), net present value (NPV), CMOST.



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## INTRODUCTION

Oil and gas are non-renewable sources of natural energy that play a very important role in the growth, production, and national economy. Not only are they used to satisfy domestic energy demands, but they are also often used to provide an essential source of revenue and foreign exchange. However, this business entrails large investments, high technology, and major industry risks. Therefore, a precise field development strategy should be designed to optimally produce the hydrocarbon reserves while taking into account both technical and economic aspects (Mustapha, et al., 2012).

In the scenario of low oil prices and strict rules and regulations for the extraction of hydrocarbon, the world's market for oil and gas increased, as well as a large set of challenges for oil and gas companies that are in the period of exploration and development. The main challenges facing the oil and gas industries are mainly cost reduction, the introduction of cutting-edge innovative technology, exploring more hydrocarbons in the sector while maintaining stability between supply and demand, extending the lives of sites already discovered, and discovering new prospects for replacing the depleted oil and gas reserves (Haider, 2020).

The country of Yemen has a proven oil reserve value of 3 billion barrels and it produces oil around 127,000 barrels per day (BPD). (GeoExpro, 2016), However, oil production continues to decline as most of Yemen's oil fields have unconventional reservoirs such as high viscous oil and tight formations with low permeability. The decrease in oil production was also attributed to the low level of oil and gas exploration activities due to civil wars, lack of government participation in exploration activities (GeoExpro, 2016), and the non-existing application of advanced recovery technology in Yemeni oil fields.

Heavy oil is defined as crude oil with high specific gravity at reservoir conditions and usually having high viscosity. Due to high viscosity values, it is hard to maintain flow of heavy oil in the wellbore. Primary recoveries from these fields are lower than in the cases of light oil reservoirs. Production from heavy oil fields mostly requires techniques known as thermal enhanced oil recovery (EOR) methods. These methods are complex and require screening of the rock, fluid, and additional field characteristics for their suitability (Taber, et al., 1997).

Steam flooding (SF) as a conventional thermal EOR method has been applied in many heavy-oil fields around the world. This technique is also referred to as continuous steam injection or stream-drive. In this process, steam is constantly injected through the injection well, while oil is produced through different wells. The steam pushes oil toward the producing well by reducing its viscosity, which improves its mobility ratio and, consequently, its displacement and areal sweep efficiency (Green & Willhite, 2018).

The Field "AR" selected for this study is a newly developed field located in Eastern Yemen with an Original Oil in Place (OOIP) value of 62 million barrels. The relatively-thin sandstone reservoirs are dominant at moderate depths and the reservoir oil is highly under-saturated, API gravity of 14.2 with a very low solution gas-oil ratio, initial oil viscosity is 420 cP and initial reservoir pressure of about 1125 psi. It is naturally producing using energy from the aquifer, even though, this aquifer poses a disadvantage due to high increase in water cut. Over time, the oil production keeps decreasing and a development plan is needed to increase the oil recovery.

Before applying the steam flood EOR method, an in-depth study should be undertaken to find out the appropriate and optimum steam flood injection parameters. This study aims to optimize steam flood injection in the field by creating reservoir simulation scenarios, that include injection well's location, number of injection wells, injection pattern, injection rate, steam quality, injection pressure, and temperature needed to increase the oil recovery. And finally, economic studies are needed to play a role in determining the optimum and economic development scenario for the field (Elbaloula, et al., 2020).

However, the method that has been done so far as in Sudanese Oil Field Fula North East and many others is by trial error for all available possibilities, such as a combination of wells location, number of production and injection wells, and the required injection rates (Elbaloula, et al., 2020). This process consumes time. And in this study, the field development optimization study was carried out using the Stochastic approach method that processes simultaneous simulations with various possibilities by using the optimum simulation result from the deterministic approach to determine the most influencing parameter in the steam flood process as well as to optimize the heavy oil field development plan using steam flooding (Temizel, et al., 2016). The results of the stochastic approach are expected to be far more accurate, optimum, and faster to obtain than the deterministic approach.

## DATA AND METHODS

This research is carried out using a data processing flow as shown on Figure 1. The simulator used is the computer modeling group (CMG) Stars for the steam flooding injection scenarios, while the stochastic approach optimization using CMOST DECE.

At the initial stage, field data preparation is carried out such as geological data, fluid and rock data, available well data for making simulation models. Next, a thermal Base Case model is made for the current field conditions. And before the process development is carried out, it is necessary to evaluate whether the production rate for the available wells and the perforation zone is optimum or not. The development process begins with determining the number of infill wells. And that is done by looking for potential areas with potential intervals. Then evaluate the steam injection parameters to determine the most optimal parameters. Several optimization scenarios are made manually by adding infill and injection wells which will give cumulative value of oil production. And at the same time optimization is done by using CMOST. The optimization results obtained are compared between the two methods.

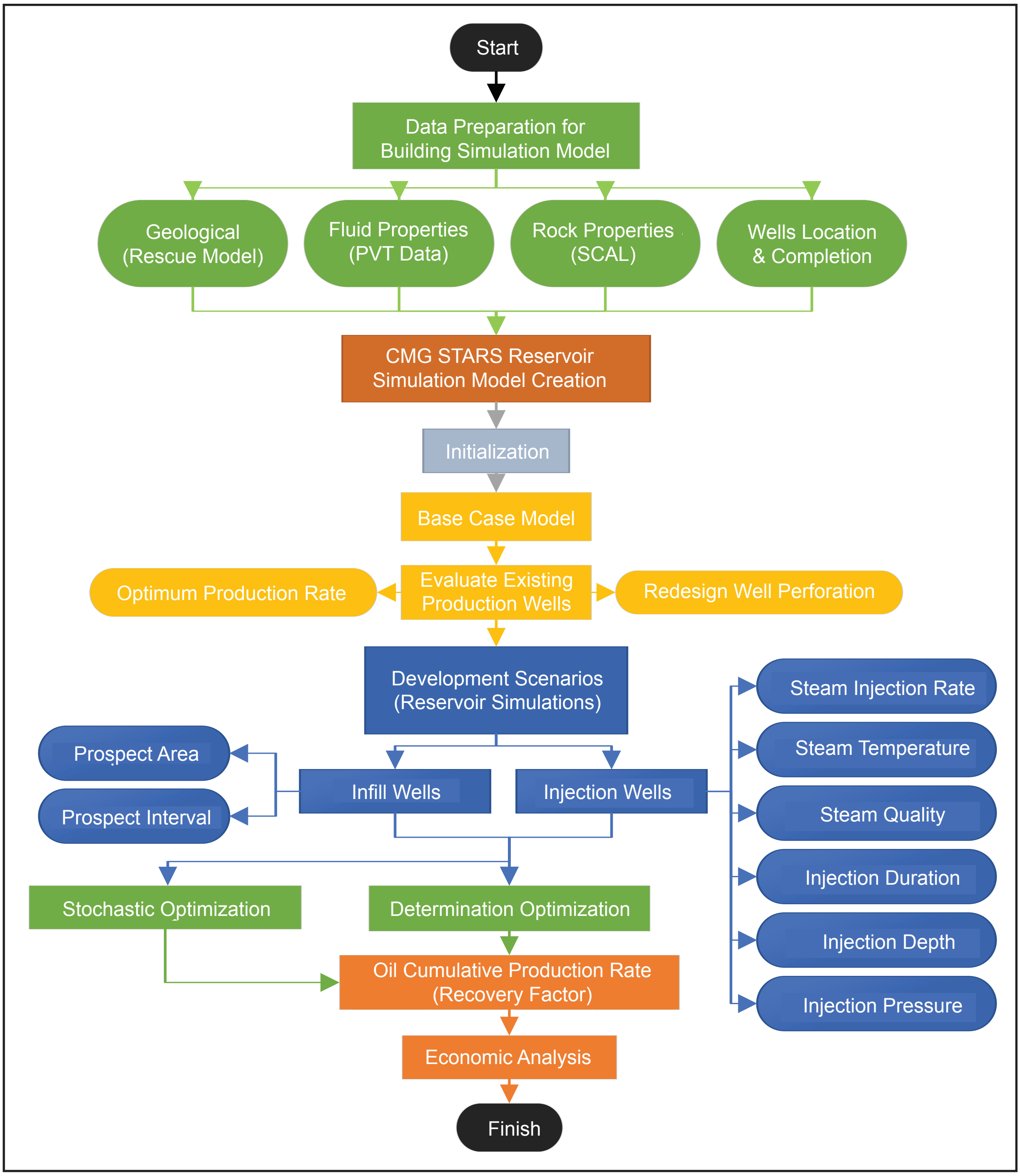


Figure 1
Workflow of the study.

In conducting the reservoir simulations, some limits for each production and injection wells have been determined, such as number of infill wells and injected steam quality and temperature. However, the total oil production rate in the field, the number of injection wells, steam injection rate, steam injection pressure are not limited and are expected to be optimized as an output from this research.

The simulation results will be evaluated whether it can increase the recovery factor and the produced cumulative oil, then economic calculations are carried out from the simulation results. Economic calculations can provide results in the form of cash flow, net present value (NPV), and will be a consideration for making decisions to invest in the field "AR" development project.

After simulations for many scenarios of cases and economic results are obtained using deterministic analysis, the optimum case is selected as the field's development plan based on the optimum results. This field development scenario case is then optimized further using the stochastic optimization method. In this study, the stochastic optimization method uses maximum recovery factor and maximum net present value as the objective functions.

This study aims to find the range of uncertainty based on the output of the stochastic method with the objective function of the maximum recovery factor (RF) and maximum net present value (NPV) value. The input parameters used in this research are the location of infill and injection wells, number of injection wells, steam injection rate, and pressure. After determining the input limits, the particles in the CMOST result chart will move at a certain speed and the objective function value will be sought at each position until it reaches the optimum condition for the objective function sought.

**A. Field Overview**

This part contains descriptions of Field "AR": which include descriptions of the existing wells in the field, reservoir model, EOR screening result, infill wells optimization, sensitivity analysis of steam injection parameters.

**1. Field Description**

Field "AR" is located in eastern Yemen. It is medium in size with a productive area of approximately 1672 acres with three sandstone reservoirs, the S1, S2, and S3. The field was discovered in March 2004 by an exploration well. The Exploration well penetrated the formation and the testing indicated high oil saturation. Current development and production activities are focused on the S1 sand reservoir, mainly due to the more favorable reservoir characteristics compared to the S2 and S3 reservoirs and to avoid excessive water production.

A total of nine wells were drilled in "AR" Field but only six of them have been producing oil as shown on Figure 2. The sandstone reservoir contains highly under-saturated, 14.2 API gravity oil with a low solution gas-oil ratio (1.7 Scf/Bbl) and reservoir

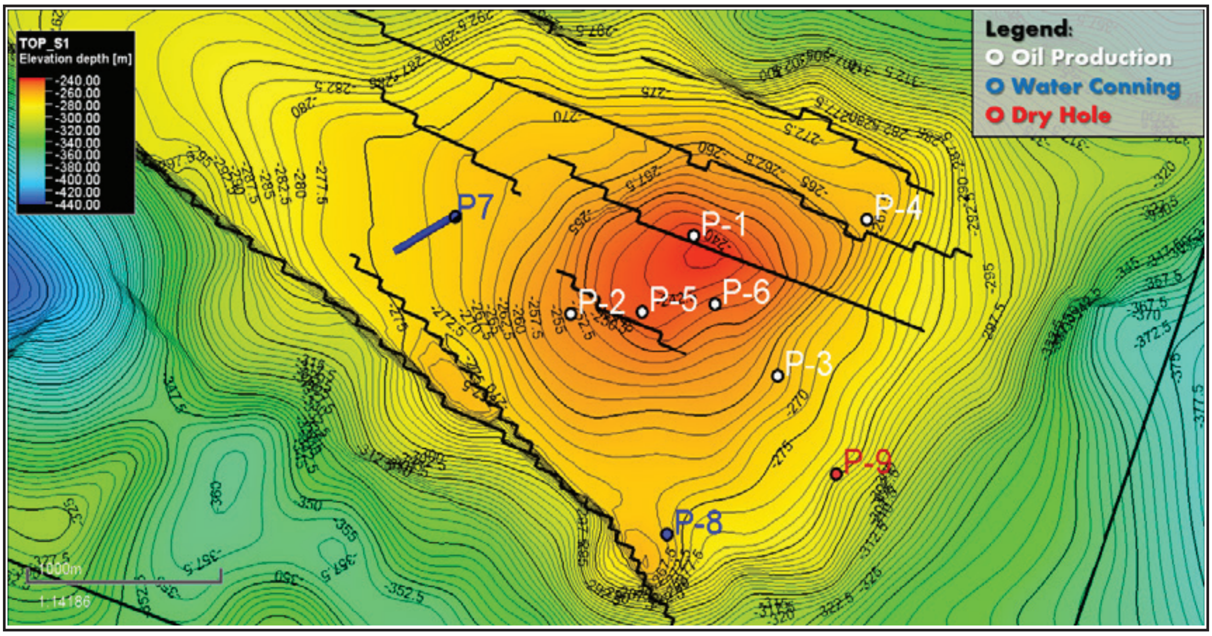


Figure 2
Depth structure map of "AR" field reservoir.

oil viscosity of 472 cP. Reservoir pressure had a slight decline due to the connection with the bottom aquifer beneath the water-oil contact (WOC).

## 2. Production History

Oil production started in December 2009 with initial production rates in the range of 250 - 400 barrels per day for each of the wells that produced oil in the field. The Producing wells showed a little water production during the initial stages but in the end, water production begins to increase after a few months. The total field production rate reached peak of production 354 MSTB during 2012 as shown on Figure 3. The initial hydrostatic reservoir pressure in the reservoir is 1125 psi at a datum of 1072 meters. The relatively small decline in reservoir pressure demonstrates the great strength of the aquifer. This field has been in production for a short period and has been closed for 8 years up until the end of the year 2020, therefore the production data cannot be used as history matching reference data.

## 3. Reservoir Simulation Model

The 3D grid for the dynamic model of the sandstone reservoir is oriented along the faults. The average value of the cell height is 0.4m. The grid dimension is 93*128*110. Total grid blocks are 1,309,440 of which 578,054 are active cells. In this study, the grid size was upscaled in the Z-axis using a CMG algorithm that cuts the grid according to its rock type. The results obtained are almost exactly as results from the original grid size. Figure 4 shows the porosity distribution in "AR" field.

All required properties distribution (including elevation, bulk volumes, net to gross, porosity, horizontal permeability, vertical permeability, and water saturation) are exported directly from the fixed static model to the simulation dynamic model. Initial reservoir pressure is calculated for all grid blocks based on fluid gradient, elevations, and datum pressure.

The data input of relative permeability tables is mandatory for reservoir modeling, and this information is one of the most important factors influencing the recovery factor and water cut dynamics obtained from the model. Unfortunately, there's no special core analysis (relative permeability, residual saturation, and capillary pressures for oil, water, and gas) for the sandstone reservoir. Core analysis of "AR" field core provided only the "porosity - permeability" relationship. Therefore, experimental data from a similar field that has similar properties to the "AR" field sandstone reservoir was used to fill the missing relative permeability data and constructs the geological model.

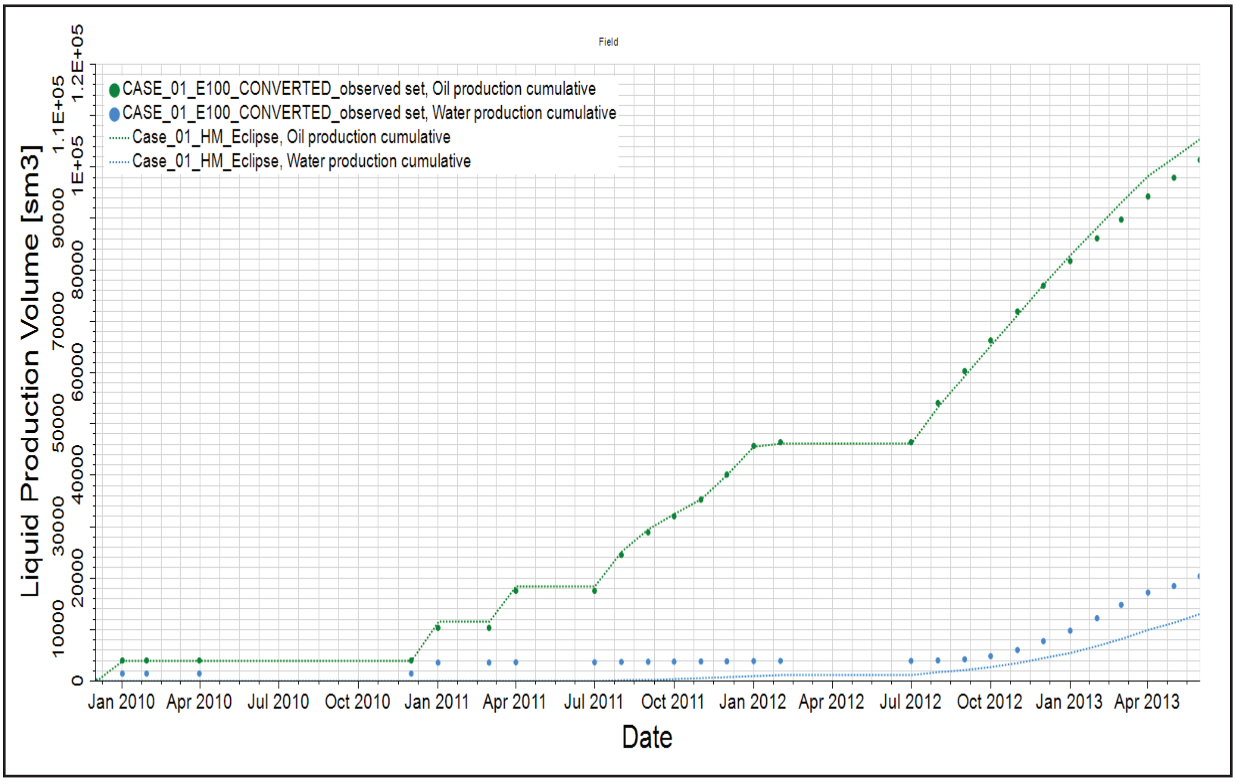


Figure 3
History of production in "AR" Field.

The common approach to reservoir modeling provides that the geological model is upscaled before the reservoir model starts to be saturated with PVT, rock fluid, and other production data.

The goal is to reduce the run times since geological models usually have quite many grid blocks and run times on such grids are long hence decreasing the validity of the models. Upscaling can resolve this issue with very little decrease in accuracy and allow running multiple scenarios within a limited time. With this idea in the background, the geological model of "AR" field was upscaled vertically only using the arithmetical averaging algorithm. This results in reducing active grid blocks from 578 thousand to 332 thousand.

## 4. Optimization Of Vertical Well Placement

Profitability of an oil field development project highly depends on selection of appropriate production well locations. The conventional method uses trial and error, is to manually determine well locations to seek the highest recovery after reservoir simulation. However, the conventional trial and error method might be more complicated in multilayer reservoirs. Therefore, in this study simulation opportunity index (SOI) was used to determine the best infill well locations.

### a. Trial and error method

A previous study was conducted for "AR" field to determine the best infill well location using the trial-and-error method ("AR" field POD 2013). For over 150 infills well location were proposed with a spacing of 250 meters between wells. The model was run separately in the base case model to determine which well produces the highest recovery factor. How this method of optimization requires time and the result may not be accurate when multiple infill wells produce at the same time that will affect the performance of one well to another. The locations of the proposed wells in this grid from the previous development plan are shown on Figure 5.

### b. Simulation Opportunity Index (SOI) Analysis

The simulation opportunity index (SOI) method is applied for "AR" field using the Petrel simulator. The result of the SOI evaluation and the proposed infill well candidates are shown on Figure 6. The red zone represents the area with the highest oil potential and is recommended for drilling in those zones. The Infill wells were selected from the previous plan of development locations and those wells are also planned to be used for future injection.

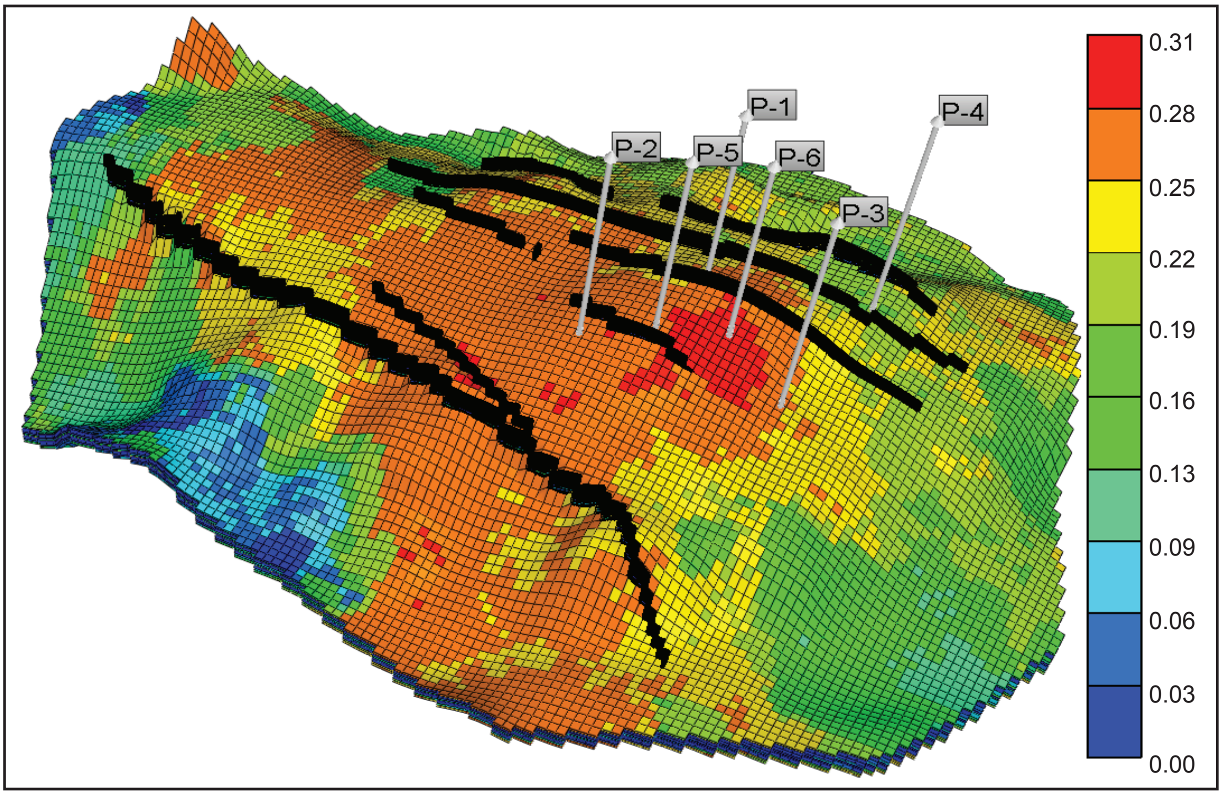


Figure 4
3D view of porosity distribution.

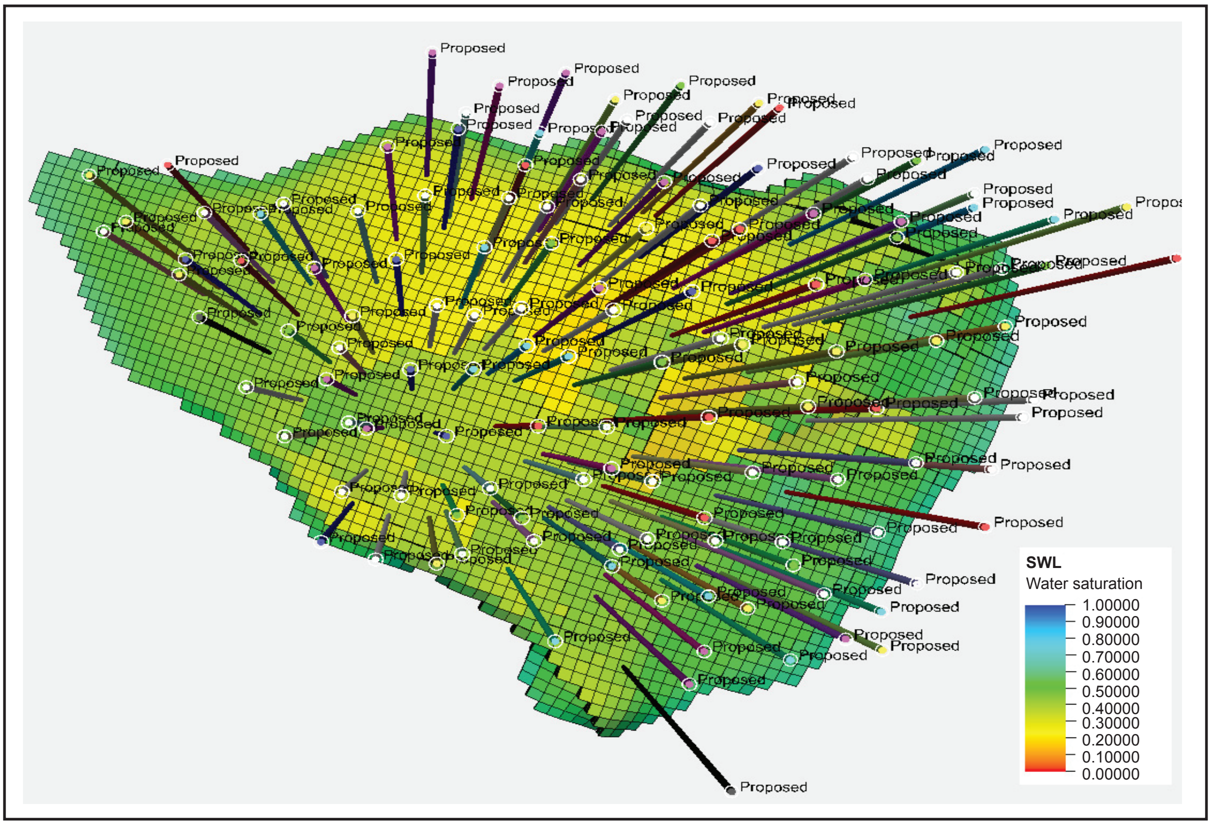


Figure 5
Trial and error simulation method.

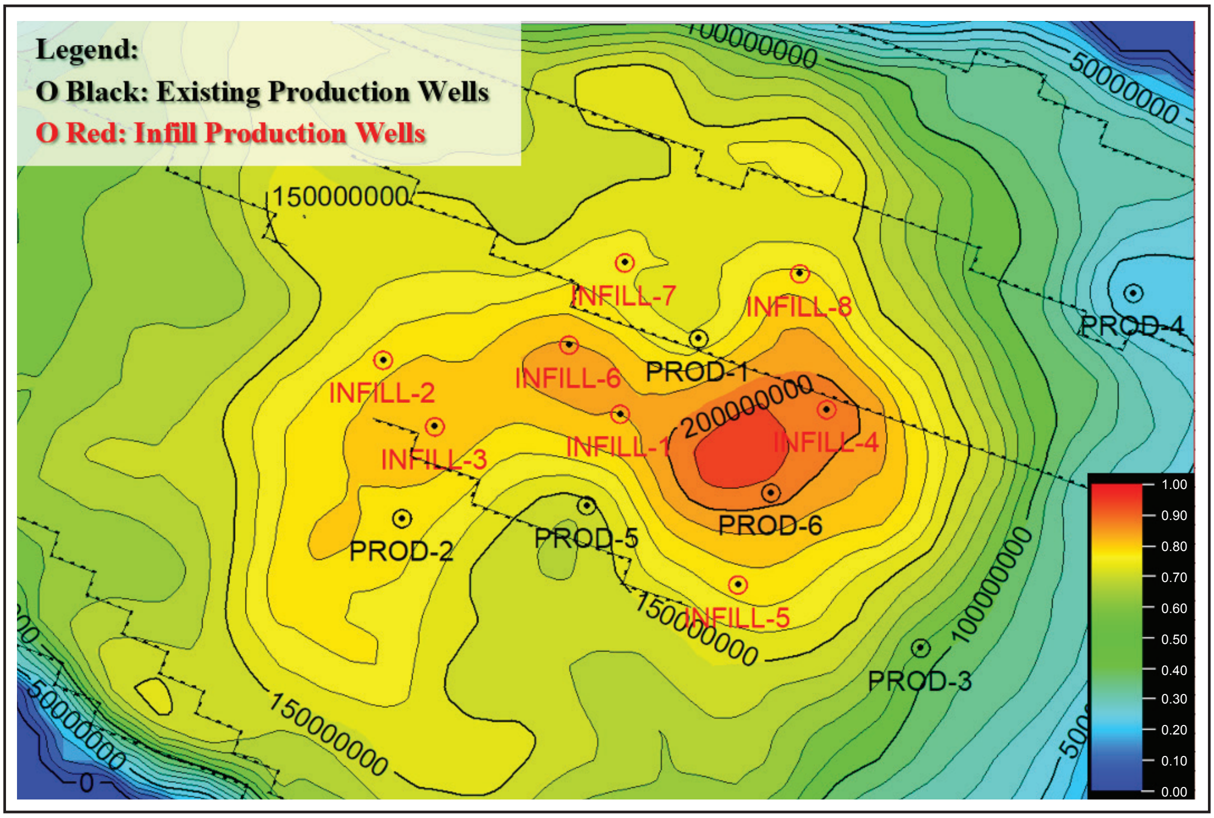


Figure 6
Infill wells location using SOI method on “AR” field top structure map.

## RESULTS AND DISCUSSION

"AR" field development plan optimization was carried out starting with the determination of the optimum number of infill wells. Afterward, steam injection scenarios were added with a different number of injection wells. Then an economic calculation is carried out that will produce the economic parameter values (NPV) of each case scenario. Once the optimum scenario had been determined using the manual method (deterministic approach), the stochastic approach is conducted to further optimize the field development plan using the objective functions.

### A. Infill Wells Optimization (Deterministic Approach)

The addition of infill wells in this study was carried out by looking at the distribution of locations in the field with the simulation opportunity index (SOI) that was calculated in the previous chapter. The addition of infill drilling wells was carried out one by one and the additional recovery factor (RF) and the cumulative oil production were observed as showed in Table 1.

After the production forecasting for 20 years, the result for the production profile of the cumulative oil, oil rate, and water production can be seen after increasing the number of infill wells as shown on the Figures 7 and 8.

The addition of every infill well resulted in an increase in cumulative production and recovery factor. Based on the results of forecasting the production of infill well cases, the optimal case was chosen to be applied in "AR" field, is the case with the addition of five infill drilling wells. This can be seen from the addition of six infill drilling wells which resulted in cumulative oil production not being too significant compared to the case of adding five infill drilling wells.

### B. Injection Wells Optimization Scenarios (Deterministic Approach)

The addition of injection wells in this study was carried out by converting the existing production wells in the field into steam injection wells and then manually analyze the obtained result. The conversion of injection wells was carried out on the existing

Table 1
The recovery factor for number of infill wells

| Scenario | Oil production rate @ 2041, (STB/D) | Cumulative production rate, (MMSTB) | Recovery factor, (%) |
|---|---|---|---|
| Base Case (6 wells) | 807 | 9.59 | 15.46% |
| Case 1 (+1 infill well) | 686 | 10.82 | 17.46% |
| Case 2 (+2 infill wells) | 662 | 12 | 19.35% |
| Case 3 (+3 infill wells) | 606 | 12.83 | 20.69% |
| Case 4 (+4 infill wells) | 546 | 13.24 | 21.36% |
| Case 5 (+5 infill wells) | 494 | 13.66 | 22.03% |
| Case 6 (+6 infill wells) | 463 | 13.97 | 22.54% |
| Case 7 (+7 infill wells) | 421 | 14.08 | 22.71% |
| Case 8 (+8 infill wells) | 397 | 14.1 | 22.74% |

wells and infill wells one by one and additional recovery factor (RF) and the cumulative oil production were observed. Results are showed in Table 2.

The results for the production profile of cumulative oil, oil rate, and water output by converting some infill wells into injection wells can be shown in Figures 9 and 10.

The addition of every injection well resulted in an increase in cumulative production and recovery factor. Based on the results of forecasting the

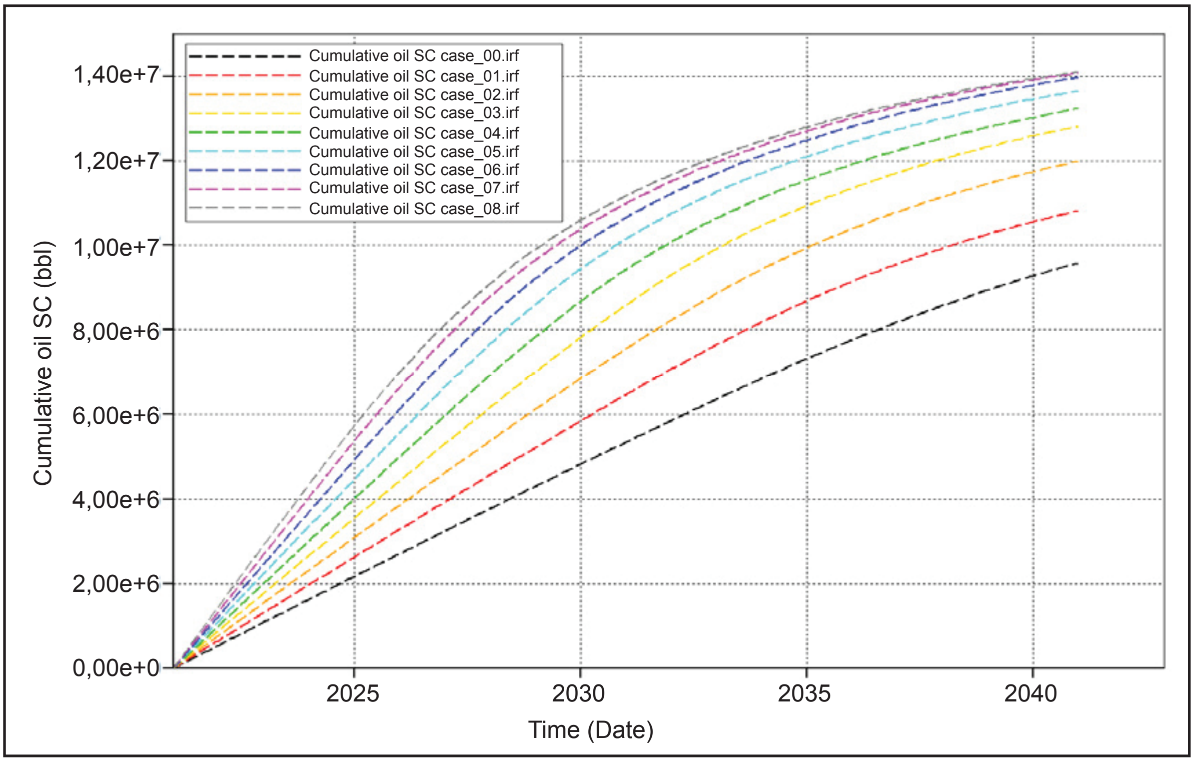


Figure 7
Cumulative oil vs time (infill wells).

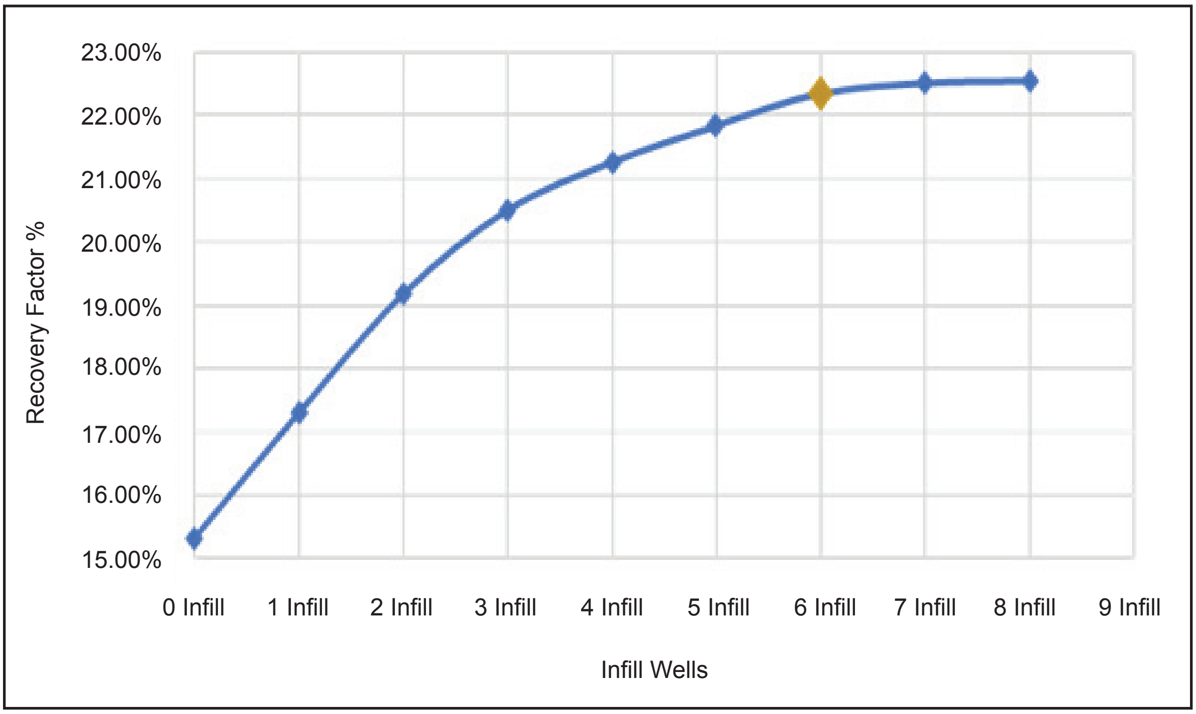


Figure 8
Oil recovery factor vs number of infill wells.

Table 2
Recovery factor for number of injection wells

| Scenario | Cumulative production rate, (MMSTB) | Recovery factor, (%) | Recovery factor inside pattern only, (%) |
|---|---|---|---|
| Do Nothing Case (6 wells) | 8.25 | 13.75% | 27.50% |
| Base Case (+ 6 infill wells) | 9.6 | 16.00% | 31.99% |
| Case 1 (+1 converted well) | 12.71 | 21.18% | 42.35% |
| Case 2 (+2 converted wells) | 15.7 | 26.17% | 52.34% |
| Case 3 (+3 converted wells) | 17.77 | 29.61% | 59.22% |
| Case 4 (+4 converted wells) | 19.17 | 31.95% | 63.89% |

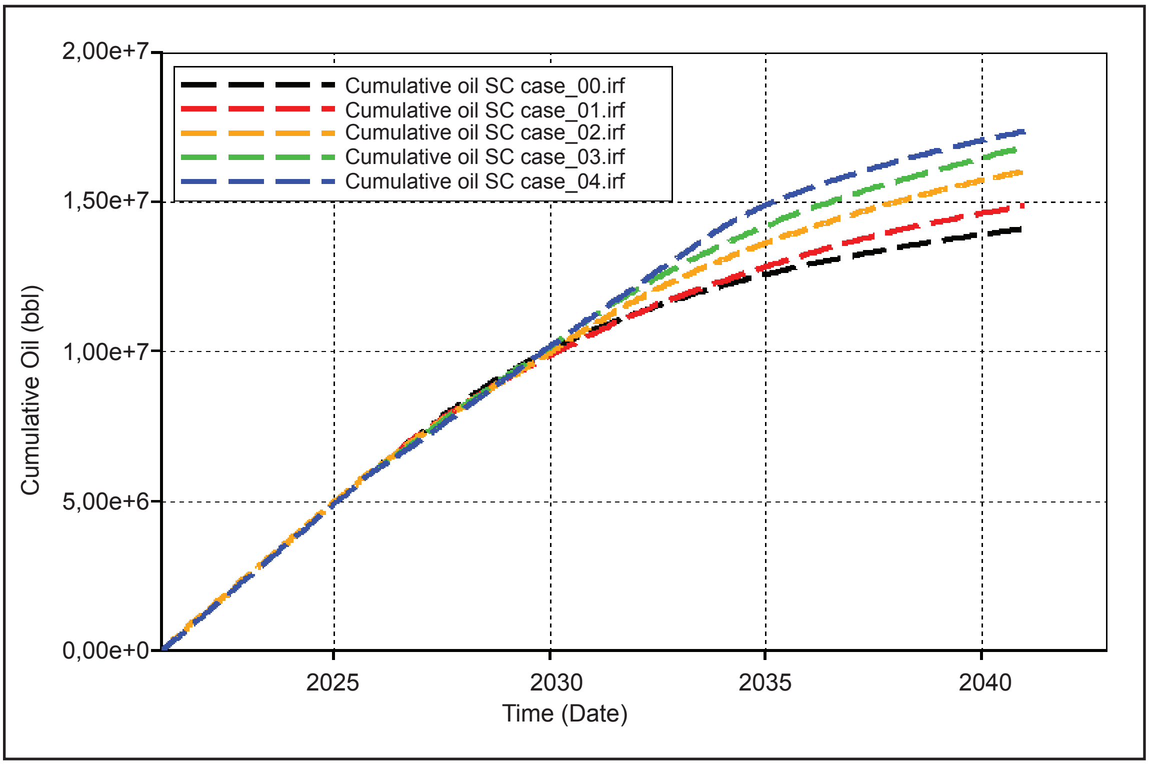


Figure 9
Cumulative oil vs time (injection wells).

production of injection well cases, the optimal case was chosen to be applied in "AR" field, is the case with the conversion of two infill wells into injection wells. This can be seen from the conversion of three infill drilling wells into injection wells which resulted in cumulative oil production not being too significant compared to the case of converting two infill wells.

## C. CMOST Using Maximum Recovery Factor (RF) Objective Function

In this study, CMOST is used with the maximum recovery factor (RF) as an objective function to perform the optimization on the optimum injection well case obtained from the deterministic approach result. CMOST is used to optimize the location of the infill and injection wells as well as optimizing the steam injection rate, steam injection pressure, oil production rate, and the well conversion. The setting used for the CMOST field optimization is shown in Table 3.

Figures 11 and 12 are obtained from the CMOST optimization for "AR" field development with maximum cumulative oil as the objective function. The experiment ID in Figure 11 showed that the CMOST optimization needed around 150 experiments to finally reach the optimization after the sampling of the parameter had been analyzed.

### D. CMOST Using Maximum Net Present Value (NPV) Objective Function

In this study, CMOST is also used with the maximum net present value (NPV) as an objective function to perform the optimization on the optimum injection well case obtained from the deterministic approach. CMOST is used to optimize the location

Table 3
CMOST engine settings and optimization parameters (max recovery factor)

| **CMOST Engine Setting** | | |
|---|---|---|
| Study Type | Optimization | |
| Sampling method | CMG DECE | |
| Optimization Engine | DECE | |
| Number of Experiments | 309 | |
| Objective Function | Oil Cumulative,<br>Oil Production Rate,<br>Net present Value | |
| Result Obtained | End of Simulation | |
| Experiment Duration | 6 Days | |
| **Parameters** | **Min** | **Max** |
| Infill Wells Location | -4 | 4 |
| Injection Wells Location | -2 | 2 |
| Well Status Conversion | INFILL | INJ |
| Steam Injection Rate, M3/D | 100 | 325 |
| Oil Production Rate M3/D | 300 | 6000 |

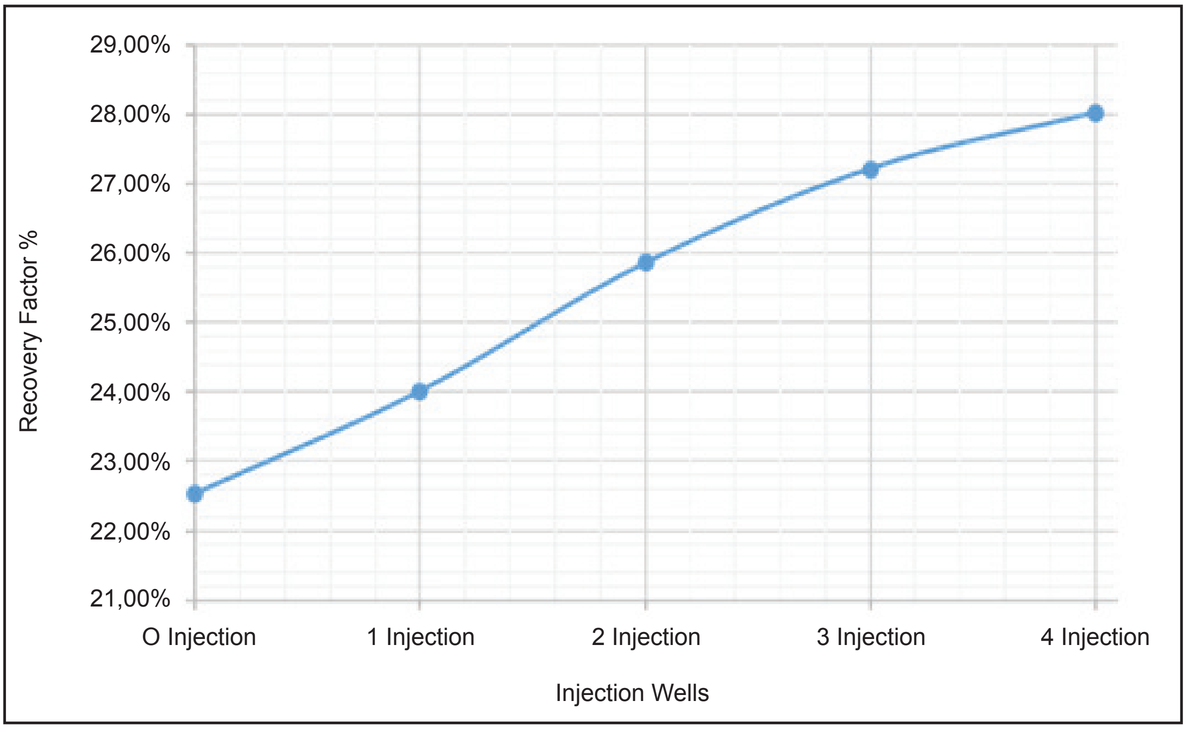


Figure 10
Oil recovery factor vs Number of injection wells.

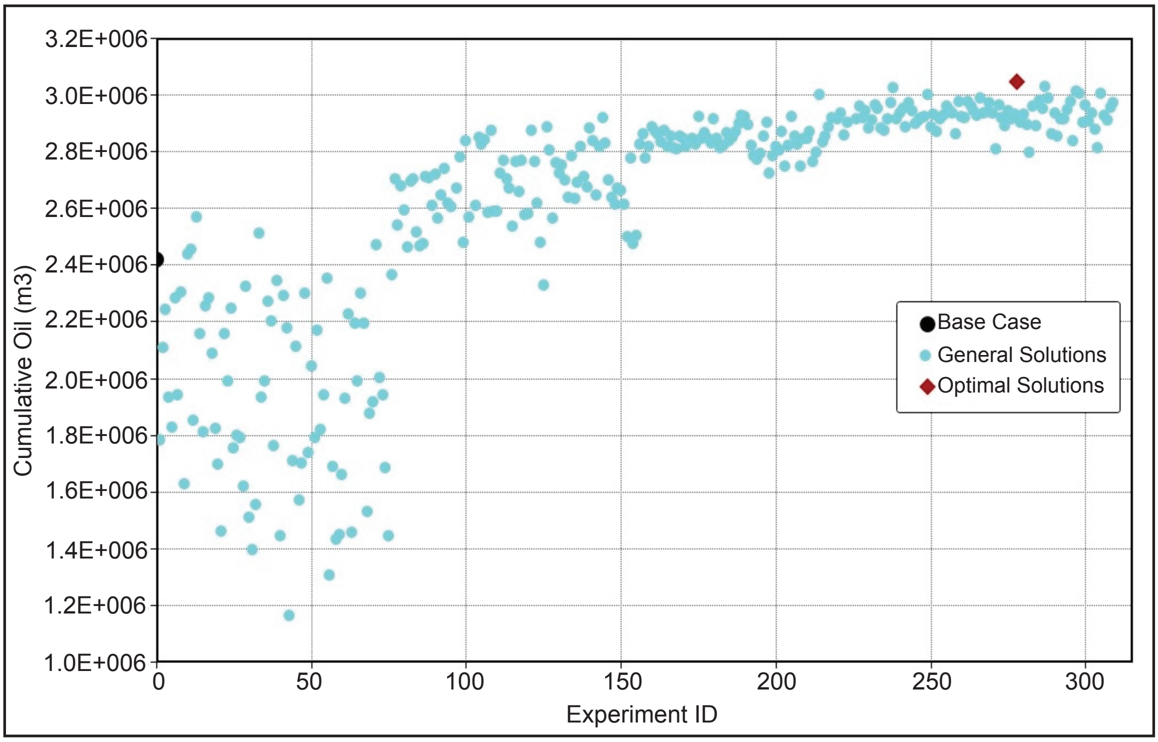


Figure 11
CMOST run progress experiment ID vs production cummulative objective function.

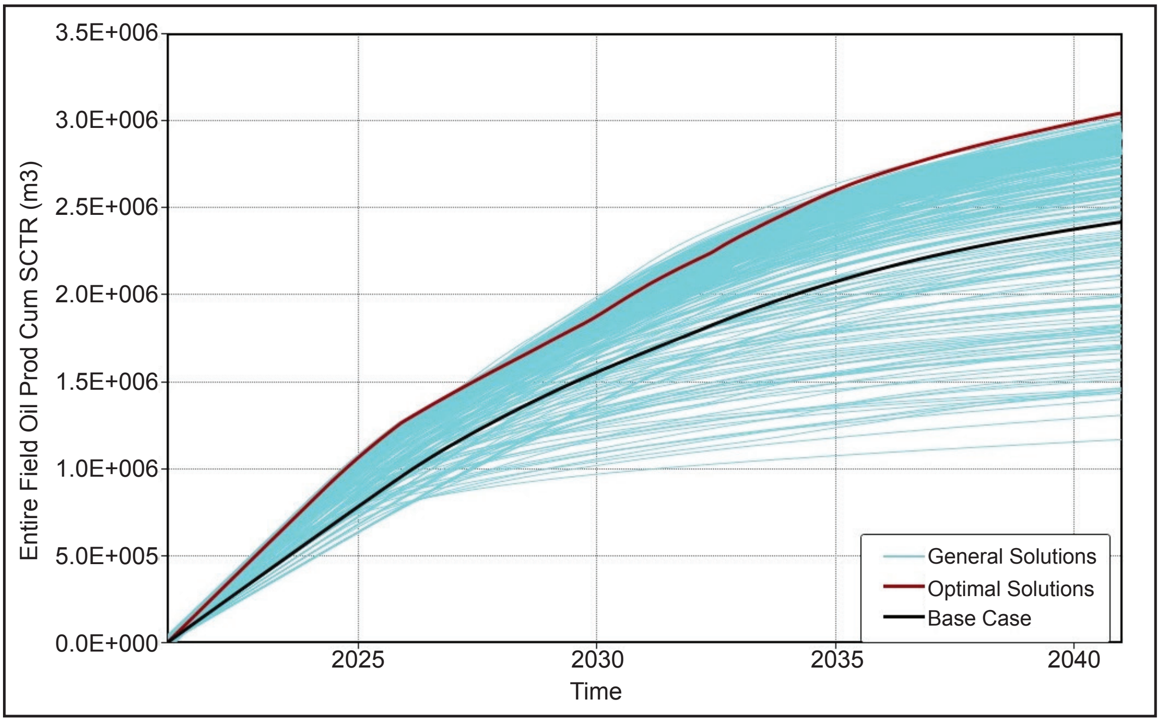


Figure 12
CMOST observed time for cummulative production objective function.

of the infill and injection wells as well as optimizing the steam injection rate, steam injection pressure, oil production rate and the well conversion. The setting used for the CMOST field optimization is shown in Table 4.

The CMOST optimization for "AR" field development with the Maximum net present value as the objective function are shown on Figures 13 and 14. After the parameter sampling was observed, the CMOST optimization required around 200

Table 4
CMOST engine settings and optimization parameters (max NPV)

| CMOST Engine SETTING | |
|---|---|
| Study Type | Optimization |
| Sampling method | CMG DECE |
| Optimization Engine | DECE |
| Number of Experiments | 306 |
| Objective Function | Net present Value<br>Oil Cumulative,<br>Oil Production Rate, |
| Result Obtained | End of Simulation |
| Experiment Duration | 5 Days |

| Parameters | Min | Max |
|---|---|---|
| Infill Wells Location | -4 | 4 |
| Injection Wells Location | -2 | 2 |
| Well Status Conversion | INFILL | INJ |
| Steam Injection Rate, M3/D | 100 | 325 |
| Oil Production Rate M3/D | 300 | 600 |

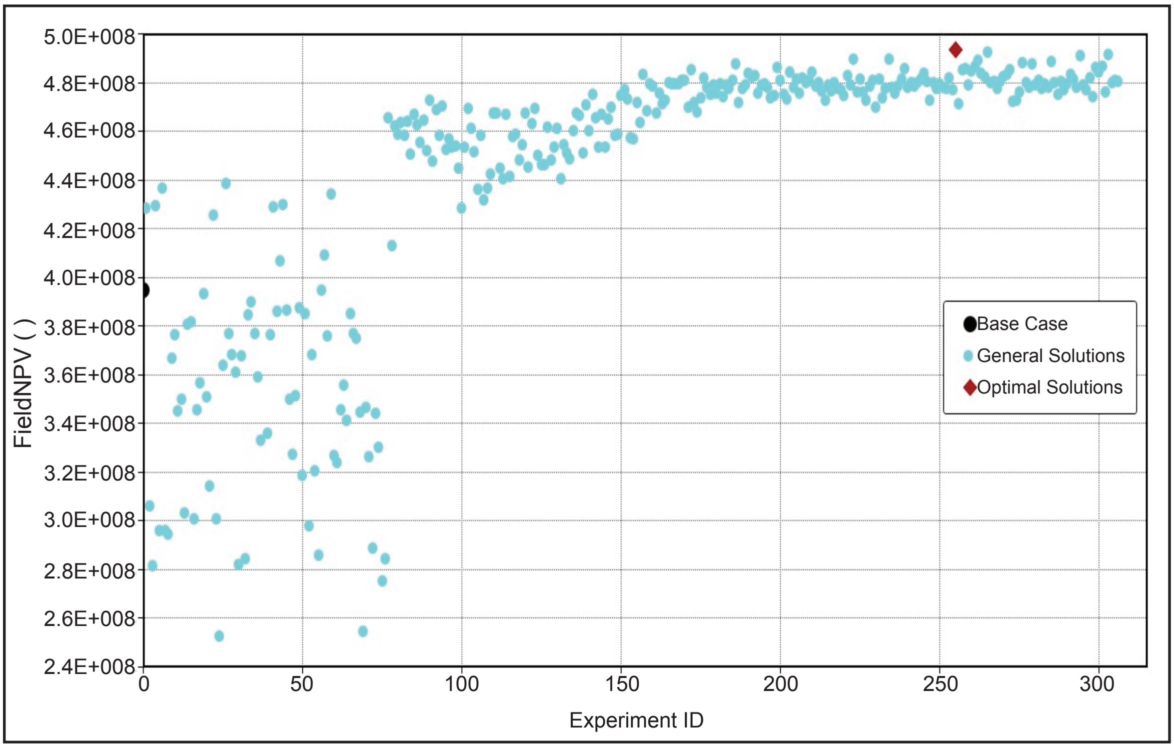


Figure 13
CMOST run progress experiment ID Vs NPV objective function.

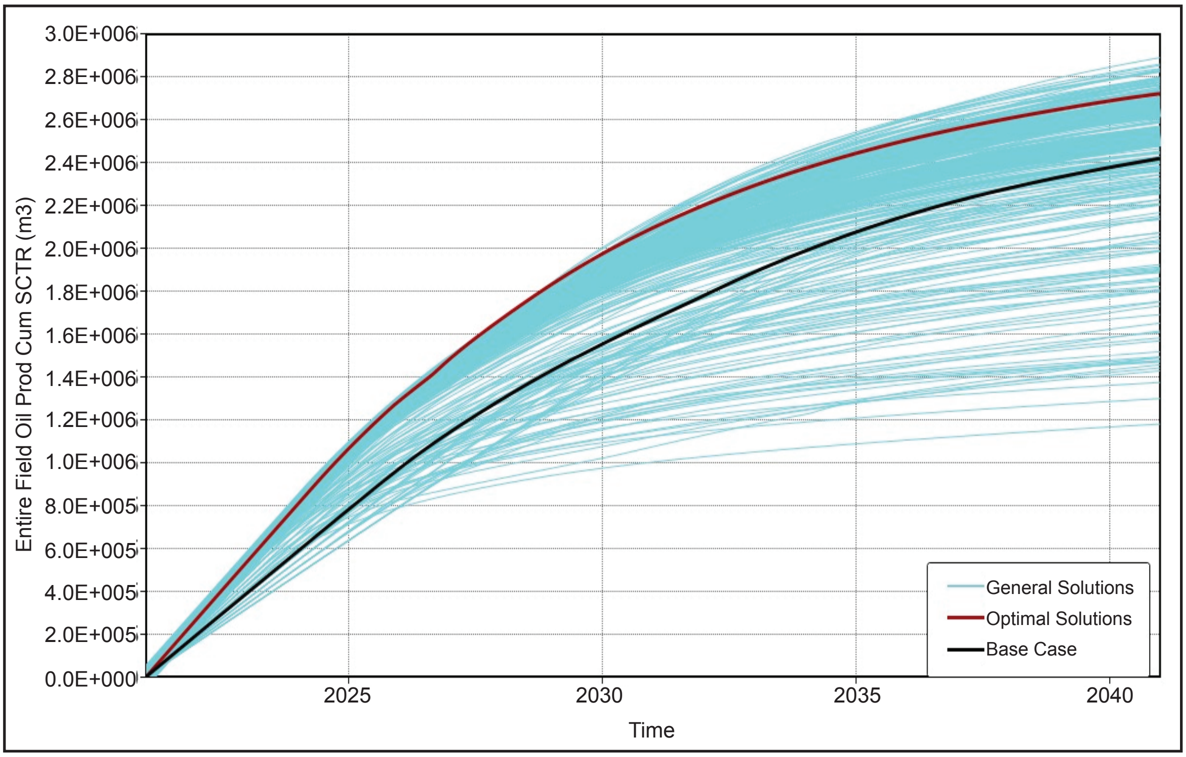


Figure 14
CMOST Observed Time for NPV objective function.

Table 5
Comparison between deterministic and stochastic optimization

| | Determini-stic Approach Result | CMOST Stochastic Optimization Result | |
|---|---|---|---|
| | | **Max RF Objective** | **Max NPV Objective** |
| Production Well Converted | 2 Wells | 2 Wells | 2 Wells |
| Injection Rate, (M3/Day) | 600 | 800 | 600 |
| Cumulative Oil Production Rate, (MMSTB) | 15.7 | 18.4 | 17.19 |
| Recovery Factor, (%) | 52.34% | 61.33% | 57.29% |
| NPV, (MM$/BBL) | $33.10 | $43.00 | $53.86 |
| IRR, (%) | 11.31% | 13.48% | 21.34% |
| Recovery Time (Year) | 1.84 | 1.85 | 1.36 |

experiments to eventually reach the optimum case, as shown by the experiment ID in Figure 13.

## E. Final Optimization Result

For the purposes of this study recovery factor was calculated only for the areas that has been places with production and injection (represented by OOIP of 30 MMSTB) to see the effect of the steam injection and its pattern. The “AR” field development optimization using CMOST as the objective function resulted in an increase in the oil recovery factor as well as the net present value. The optimum cases from each objective function are shown in Table 5.

It is shows that the comparison between the deterministic method and the stochastic method provided different results with different recovery factors and NPV values. The ammount of infill wells converted into injection wells were two wells and the steam injection rate ranged between 600 to 800 M3/Day.

The stochastic approach with maximum net present value (NPV) objective function in Tabel 5 provided the most favorable scenario to be used in the development of "AR" field as it increases oil recovery by 5% compared to deterministic apporach as well as obtaining the highest NPV.

## CONCLUSIONS

Optimization scenario for "AR" field development plan have been carried out for 20 years, namely by adding six production infill wells and converting two production wells into injection wells. The steam injection rate used was 600 M3/D and resulted in a cumulative oil production of 15.70 MMSTB, recovery factor of 52.34% and economic parameters of net present value (NPV) of 33.10 MM$/USD. This result was obtained using the deterministic approach by selecting the optimum result from the all scenarios conducted taking into account aspects in the field such as distance between wells, simulation opportunity index and steam injection parameter limit.

Optimization of field development with the stochastic method provides more accurate results in determining the field development plan compared to the deterministic method that has been carried out. In this study, a combination of full field parameters was used. By using the stochastic method, the relationship of these parameters is matched to the order of data distribution for each parameter on the plot of each data distribution, where the objective value of the NPV function is not necessarily directly proportional to the number of production wells and the injection rate.

For the stochastic approach, CMOST optimization using the maximum recovery factor (RF) objective function resulted in an Np of 18.40 MMSTB, an RF of 61.33%, and NPV of 43 MM$/STB. The maximum RF objective function resulted with the highest recovery factor scenario for "AR" field, however it does not consider the economic parameters that will result in a lower NPV and more cost spent.

CMOST optimization with the maximum net present value (NPV) objective function resulted in an Np of 17.19 MMSTB, an RF of 57.29%, and an NPV of 53.86 MM$/STB. The maximum NPV objective gave the highest NPV value for "AR" field. This result is considered the most attractive and profitable approach for developing this field technically and economically.

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