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Enhancing the Effectiveness of Vertical Water Injection Wells With Inflow Control Devices (ICDs): Design, Simulation and Economics

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Abstract

Water injector completion techniques used traditionally, such as frac packs or openhole standalone screens, were judged to be incapable of meeting all completion objectives and have been reported to loose injectivity over time coupled with the issue of long term injection conformance due to plugging. Another major challenge is to achieve even distribution of the injected water into all zones along the wellbore. Permeability contrasts, formation damage, creation of thief fractures, and changes in wellbore injectivity need to be managed to avoid early breakthrough in adjacent production wells. This study presents the application of inflow control devices (ICDs), fined tuned by reservoir simulations for balancing the water injection profile into various sand formation zones in an open–hole completed injector well in Flo-Z6, a stratified Niger Delta reservoir with communicating layers.

The solution targeted at developing a screening tool for deciding candidate layers in Flo-Z6 reservoir and installing special flow control devices, tailor-made for injection wells and with correct nozzle sizes for this particular case.

The results from this study show that, the installation of ICDs with different nozzle configuration in the injector wells tailored to equalize the water outflow (for better sweep efficiency), improved the field oil recovery by 11.9% (6.6MMstb). Economic indicators used to validate the profitability of the investment further showed that completing the injectors with different ICD nozzle configuration was more profitable, with an NPV@10% of $192.5million, profit per dollar invested of $6.6, DCF-ROR of 81% and a pay-out period of 1.2 year which is relatively short.

Key words: Profile; Sweep; ICD, Nozzle; Permeability; DCF-ROR; NPV

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INTRODUCTION

Water injection has been a successful secondary recovery technique in the oil industry for many years. In the past 10 to 15 years however, projects have been developed where high-rate water injection is a primary recovery method because completion reliability and economic constraints require early voidage replacement and pressure support. As water injection becomes integral to the economic justification for capital intensive (offshore, subsea) projects, considerable attention to the design and performance of the water injectors is required.

A major challenge facing all well architectures according to Changhong et al.[1] is premature breakthrough of water in both oil and gas production wells. Similarly, a major challenge facing all injection wells is the uneven distribution of the injected fluid. Both challenges can be caused by:

i. Reservoir productivity heterogeneity.
ii. Variations in the reservoir pressure in different regions or layers of the reservoir penetrated by the wellbore.
iii. Variation of the fluid properties in reservoir sections crossed by the wellbore.
iv. The frictional pressure in horizontal wellbores that leads to difference in the specific influx

rate between the heel and the toe of the well, especially when the reservoir is (relatively) homogeneous.

v. Variations in the distance between the wellbore and fluid contacts e.g. due to multiple fluid contacts, an inclined wellbore and a tilted oil-water contact.

vi. Variation in the distance between the wellbore and reservoir boundaries e.g. inclined reservoirs.

Advanced Well Completions employing Downhole Flow Control (DFC) technology according to Aadnoy and Hareland[2] provide a practical solution to all these challenges. DFC technologies include Inflow Control Devices (ICDs), Interval Control Valves (ICVs) and/or Autonomous Inflow Control Devices (AICDs). These valves and devices are usually in combination with Annular Flow Isolations (AFIs).

Inflow control devices (ICDs) are used to balance the flow across the entire productive section, delay early water breakthrough and enable uniform areal drainage.

Though they are called inflow control devices, ICDs are also used to manage fluid outflow in injection wells. In some cases, modeling reveals that it is more effective to place ICDs in the injector well than in the producer and in many instances installing the devices in both the injector and producer wells is the best option[2].

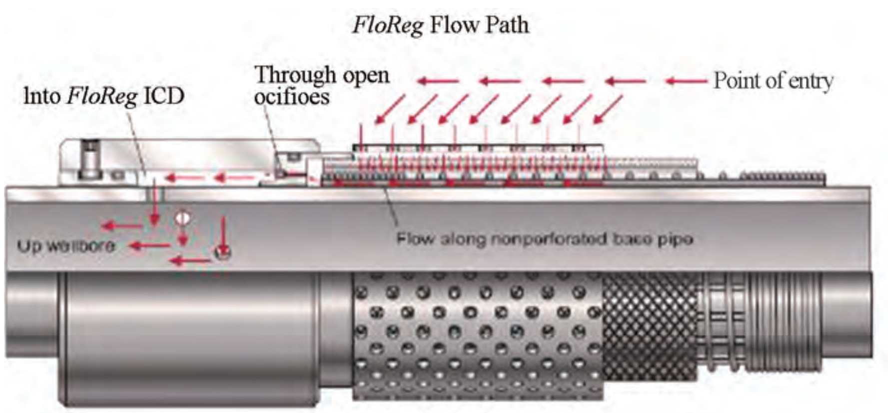

Figure 1
A typical ICD Tool (Aadnoy et al., 2009)

ICDs can also be called Passive Flow Control devices due to their inactive flow control nature. The pressure drop through the ICD will change if the type of fluid flowing through the ICD restriction changes[2]. However, the ICD restriction cannot be adjusted after the equipment is installed in the wellbore. ICDs do not have the ability to actively modify the amount of fluid being injected by it if an adjustment is required in the later time of the reservoir life. ICDs are thus considered to be a proactive FCD since they are installed early in the life of the well once the injection is to be initiated.

Available ICD designs include; Labyrinths, Helical Channels, Slots, Tubes, Nozzles and Orifices have been developed by some leading suppliers of ICD technology: Tejas, Baker Oil Tools, Easywell Solutions-Halliburton, Reslink-Schlumberger, Flotech and Weatherford respectively. All these ICD designs can either be mounted on a Stand-alone screen (SAS) for application to unconsolidated formations, or they can be combined with a debris filter (to prevent blockage of the flow restriction) when used in a consolidated formation.

The less complex nature of an ICD completion (compared to an ICV) results in the ICD being cheaper than the ICV in almost all cases[3]. Similarly the ICD will be more expensive than a wire-wrapped screen. A 51/2 inch ICD completion for 4800ft horizontal well in 2002 was reported to cost $1.8 million[4], a sum approximately 30% greater than a generic sand screen completion. Typical ICV completions would cost several million US dollars. Low cost ICD (many tens or hundreds of thousands of USD) applications have been reported[5].

ICD completion is relatively expensive in terms of installation complexity, rig time and installation risks. The last can be mitigated by proper planning and training as well as through system integration tests[3] .

Erosion or plugging of nozzle or channel in principle can cause ICD failure; however data on ICD reliability is not publicly available. There has been some field evidence of screen plugging during ICD installation[6].

An ICD is a less complex piece of equipment than other down-hole flow devices, making it potentially reliable. ICD failure is identifiable since ICD blockage is immediately apparent from the well performance. ICD reliability has been systematically studied[7-8]. Few cases of ICD failures have been identified in the field compared to other DFC. ICD thus has an advantage over other downhole flow control devices with respect to reliability.

Birchenko et al.[9] and Jeanette[3] reported that the designs of ICDs are typically based on predrilling reservoir models. They also hinted that changing the rating of channel or tube ICDs is more difficult, time consuming and not easily done on location. An ICD may be optimal initially, but not when the reservoir pressure is depleted. A long section drilled horizontally through a single reservoir presents a different set of challenges. In homogeneous formations, significant pressure drops occurs within the openhole interval as fluid flows towards the heel of the well. The result may be significantly higher drawdown pressure at the heel than at the toe; known as the heel-toe-effect, this differential causes unequal inflow along the well path and leads to water or gas coning at the heel. A possible consequence of this condition is an early end to the well's productive life and substantial reserves left unrecovered in the lower section of the well[9].

1. STUDY OBJECTIVES

The objectives of this study is to design and model ICDs on water injector wells that penetrated Flo-Z6 reservoir to visualize ICD influence on overall field performance, determine the optimum strategy for injecting water in Flo-Z6 reservoir and to evaluate the profitability of ICD deployment on water injection Projects.

2. STUDY METHODOLOGY

With limitations in obtaining a static reservoir model of Flo-Z6 reservoir, a simple box dynamic reservoir model was built utilizing rock and fluid properties obtained from Flo-Z6 reservoir. The effectiveness of inflow control devices was tested in the vertical water injection wells that penetrated this reservoir with significant permeability variation and the results in terms of efficiencies were used to perform economic analysis to understudy the profitability of deploying nozzle type ICDs in vertical water injectors.

A synthetic log of the permeability variations along the vertical section of Flo-Z6 reservoir pay section is shown below:

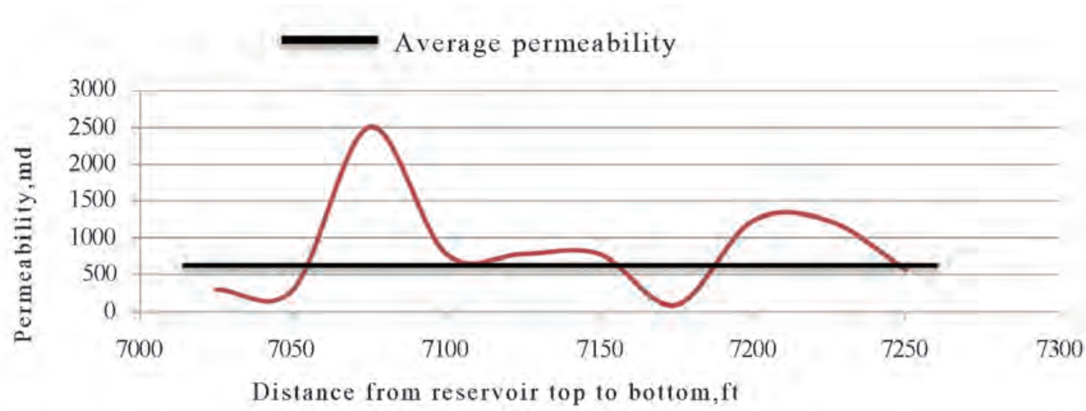

Figure 2
Permeability Variations Along the Vertical Section of the Pay Zone

During water injection Flo-Z6 reservoir, High permeability zones receive more fluid than lower permeability zones resulting in poor reservoir sweep and pressure support. A means of eliminating this imbalance was evaluated by allowing the injected water flow through the injection ICD before entering the reservoir.

The following steps where adopted for this study:

i. Building a dynamic reservoir model using rock and fluid properties obtained from Flo-Z6 reservoir and Hydrocarbon in Place (HCIP) validation.
ii. Determining the layers contribution using IPR models incorporated in Prosper simulator utilizing Flo-Z6 reservoir rock and fluid properties.
iii. Building Production and Injection well models in Prosper to generate optimum rates, bottom-hole pressures and VLP tables.
iv. Nozzle sizing sensitivity, pressure drop calculation for different ICD zones and flow profile generation.
v. ICD modeling and integration in Eclipse simulator
vi. Reservoir Simulation runs for different scenarios
vii. Profitability analysis of installing ICDs in the water injectors with results generated

3. RESERVOIR MODEL DESCRIPTION

A Black Oil model was designed with rectangular cells, with 20 cells each along the *x*-direction and y-direction and 10 cells along the thickness of the bed represented in *z*-direction as shown in Figure 3. The petro-physical properties (porosity, permeability's and Net to Gross) are included in the grid. The simplistic reservoir model used in the simulation was built using the rock and fluid data obtained from reservoir Flo-Z6, in a Niger Delta Field as shown in Table 1 below.

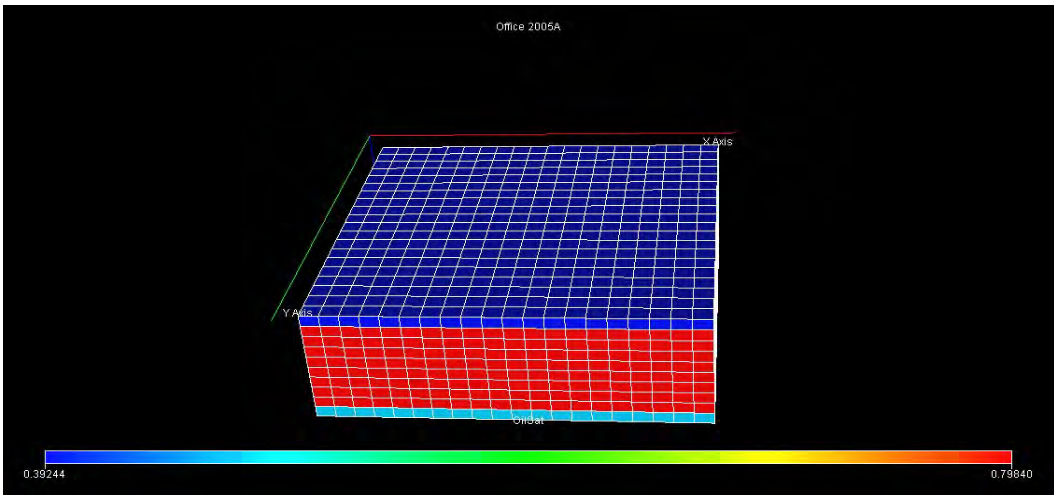

Figure 3
Reservoir Model Showing the Grids

Table 1
Flo-Z6 Reservoir Rock and Fluid Data

Model parameters	Lower pange	Higher range
Datum depth (ft)	7100	7170
Pressure at datum depth (psi)	3592	3592
Reservoir temperature, T (^{o}F)	157	157
Oil column Thickness, (ft)	100	225
Oil density, (lb/ft^3)	53	53
Gas density, (lb/ft^3)	0.0393	0.0393
Water density, (lb/ft^3)	62.4	62.4
Thickness, h (ft) / NTG	125 / 0.82	250/0.91
Porosity, Ø	0.23	0.32
Connate oil water saturation, Swc	0.18	0.23
Permeability, k	89md	2500md
GOC depth (ft)	7000	7015
OWC depth (ft)	7100	7240

4. IPR (INFLOW PERFORMANCE RELATION)

IPR describes the relationship between the pressure drop across the formation and its resulting flow rate. Appropriate flow equations coupled in PROSPER software were utilized in building an IPR model for Flo-Z6 reservoir using the rock and fluid data in Table 1 as input. This generated the outflow rates of the injected water shown in Table 2. For the injection and production well models built in the dynamic simulator (Eclipse), it utilized the optimum bottom-hole pressures and flow rates built in Prosper model, sensitized across varying reservoir, well and surface conditions.The operating point from the IPR/VLP plot shows that the vertical well which penetrated reservoir Flo-Z6 can confidently inject water around 14,585 STB/day with an expected bottom hole flowing pressure of 3629 psig.

Table 2
Model Layer Response for Water Injection Without ICD

Model layer number	Liquid rate (STB/day)	Oil rate (STB/day)	Water rate (STB/day)	Gas rate (MMscf/day)
1	163.92	0	163.92	0
2	163.92	0	163.92	0
3	1507.71	0	1507.71	0
4	452.207	0	452.207	0
5	452.207	0	452.207	0
6	452.207	0	452.207	0
7	54.56	0	54.56	0
8	714.1	0	714.1	0
9	714.19	0	714.19	0
10	325.46	0	325.46	0

5. VLP (VERTICAL LIFT PERFORMANCE) CORRELATION

The friction pressure losses calculation used in a multi segmented well model in Eclipse is based on Hagerdon-Brown correlation. It is one of the recommended methods to be used in both single-phase and multiphase vertical well. For this study, different tubing correlations were matched and compared to establish the best correlation that captures all the pressure loss in the system at a rate of 5,000STB/day and tubing head pressure of 550psig. The rate selected for this comparison is a possible rate that was injected in the reservoir for voidage replacement.

Table 3
Summary of Pressure Drop by Correlation

Index	Correlation	Total *dP* (psi)	*dP* friction (psi)	*dP* static (psi)	*dP* acceleration (psi)
1	Duns and ros (modified)	3075.08	0	3143.14	-680.615
2	Hagedorn and brown	3071.35	0	3139.51	-680.1558
3	Fancher and brown	3071.44	0	3139.51	-680.0642
4	Mukerjee and brill	3075.08	0	3143.14	-680.061
5	Beggs and brill	3075.03	0	3143.18	-680.155
6	Petroleum Expert 2	3071.35	0	3139.51	-680.1558
7	Duns and ros (original)	3075.29	0	3143.44	-680.1543
8	Petroleum Expert 3	3071.35	0	3139.51	-680.1558
9	Petroleum Expert 4	3071.34	0	3139.49	-680.1533
10	OLGA3P EXT	725	0	725	0.00067139

The above table shows that all the tubing correlations relatively matched due to single phase system (water) except OLGAS3P EXT which under predicted the pressure drop. Petroleum Expert 2 was thus selected and used in generating the lift table utilized by eclipse.

6. ICD INJECTOR COMPLETIONS DESIGN WORKFLOW

Two alternative designs were considered for the ICD injectors:

i. Design the ICD injector with different nozzle configurations tailored for different zones/layers
ii. Design the ICD injector with the same nozzle configuration along the entire well path.

The design workflow which captures the two design alternatives is as described in Figure 4. Note the "identify optimum ICD type & size".

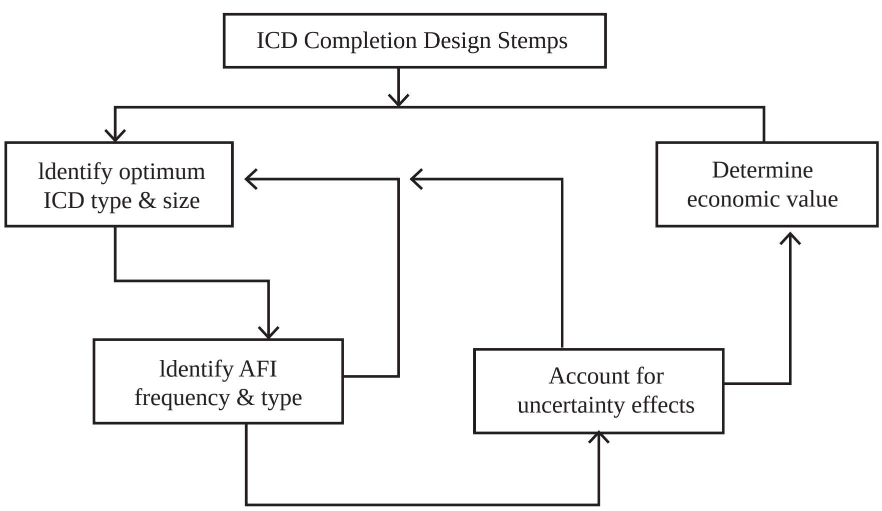

Figure 4
Completions Design Workflow

Constricting the fluid flow to a number of nozzles makes the pressure drop highly dependent on the fluid density and velocity, but less dependent on viscosity.

The pressure drop across a nozzle is calculated based on Bernoulli's Equation:

$$\frac{V_1^2}{2}+\frac{P_1}{\rho_1}+gz_1=\frac{V_2^2}{2}+\frac{P_2}{\rho_2}+gz_2 \quad , \tag{1}$$

$$dp_{\text{nozzle}}=\rho\frac{v^2}{2}\ ,\text{but } v=\frac{Q}{A} \quad . \tag{2}$$

Substituting and introducing flow coefficient:

$$dp_{\text{nozzle}}=\frac{\rho v^2}{2c^2}=\frac{\rho Q^2}{2A_{\text{nozzle}}^2c^2}=\frac{8\rho Q^2}{\pi^2 D_{\text{nozzle}}^4 c^2} \quad . \tag{3}$$

To determine the nozzle size/diameter to achieve an even outflow profile, Equation (3) above is tweaked by making the diameter of the subject; utilizing the pressure drop required to achieve the desired outflow rate.

$$D^4=\frac{8\rho q^2}{\pi^2 c^2 dp_{\text{nozzle}}} \ , \tag{4}$$

$$D=\sqrt[4]{\frac{8\rho q^2}{\pi^2 c^2 dp_{\text{nozzle}}}} \ . \tag{5}$$

Where:

dp_{nozzle}– Pressure drop across nozzle
ρ – Average fluid density
V – Fluid velocity through nozzle
q– Fluid flow through nozzle
A – Area of nozzle
D – Diameter of nozzle
c– Flow coefficient

Utilizing the layers outflow response as the rate in and the average rate as rate out across the ICD nozzle, the pressure drop across the nozzle was calculated using Equation (3). Thus the nozzle size required to achieve the outflow rate was calculated using Equation (5)

When designing a completion system, the ICD flow resistance pressure setting and the number of compartments should increase with the degree of heterogeneity along the wellbore. In this work, a 25ft screen joint with 4.5 in screen ID was deployed at each segment to enable features of the heterogeneity to be controlled through a short compartment, and injected through a fewer number of ICDs.

Table 4
ICD Selection and AFI Requirement for Layers

Layer No.	Layer thickness (ft)	Permeability (md)	Saturating fluid	ICD	No of ICD screen joint(s)	AFI requirement
1	25	300	Gas	No ICD	0	Yes
2	25	300	Gas/Oil	Yes ICD	1	No
3	25	2500	Oil	Yes ICD	1	Yes
4	25	780	Oil	Yes ICD	1	Yes
5	25	780	Oil	Yes ICD	1	No
6	25	780	Oil	Yes ICD	1	No
7	25	89	Oil	Yes ICD	1	Yes
8	25	1230	Oil	Yes ICD	1	Yes
9	25	1230	Oil/water	Yes ICD	1	No
10	25	570	Water	Yes ICD	1	Yes

The ICDs selection for each layer depends on the saturating fluid, depths and contacts. Installing ICDs at depths above GOC (7015ft) or gas saturated zone may not be beneficial unless the injector is completed across such depths. In this study, water injectors were completed at depths 7025-7250ft and not completed across the gas zone and hence no ICDs where installed above GOC. Annular flow reduces the performance of ICDs and thus was run at depths with permeability contrast to prevent layer communication at the sandface.

7. PRESSURE LOSS CALCULATION DUE TO ICD COMPLETIONS

i. Two methods can be used to calculate pressure losses due to ICD completions in ECLIPSE: The friction pressure losses based on the formulation used in the correlation of Hagerdon and Brown[10]:

$$\Delta Pf=\frac{C_f f l w^2}{A^2 D_p} \ . \tag{6}$$

The C_f here is the unit conversion constant

ii. ECLIPSE calculates the frictional and acceleration pressure losses using imported VLP (Vertical Lift Performance) tables.

8. DYNAMIC MODELING OF ICDS ON WATER INJECTORS

Before a good ICD design was achieved, a pressure/flow profile was obtained which showed unbalanced pressure losses and non-uniform outflow profile across the wellbore in the pay. This usually gives rise to cross flows, unbalanced fluid injection and inefficient sweep. Several sensitivities were run to determine the best nozzle size at different segments of the wellbore that will successfully achieve a balanced fluid injection to the target layers. After individual ICD optimum nozzle sizes for layers were selected, the design was integrated into the schedule section of the Eclipse simulation model as an input.

9. RESERVOIR SIMULATION

Model initialization for Flo-Z6 showed about 50MMstb. Two production wells (horizontal) were optimally placed in the reservoir with two water injectors at the flank to complement primary support from the weak aquifer in place.

The simulation was run and evaluated for the following cases:

Case 1: Performance simulation conducted for natural depletion.

Case 2: Performance simulation conducted for water injection without ICDs at 20% depletion.

Case 3: Performance simulation conducted for water injection with the same ICD nozzle configurations at 20% depletion.

Case 4: Performance simulation conducted for water injection with different ICD nozzle configurations at 20% depletion.

To achieve the above simulation cases the following constraints in Table 5 are placed in the model.

Table 5
Model Constraints

Initial oil production rate	4000stb/day
Maximum liquid production rate	4,000stb/day
Minimum economic rate	200stb/day
BHP Target for production wells	1500Psia
Perforation length for horizontal well	1250ft
BHP target for injection wells	3800psia
Water injection rate	5000stb/day
Maximum allowable BS&W	90%
No of horizontal producer well	2
No of vertical water injector well	2
THP for injector	550psi

10. ECONOMIC EVALUATION

To evaluate the viability and feasibility of completing water injectors with ICDs, an economic evaluation was performed.

Decision rules[11] below was adopted for the profitability indicators:

i. NPV (accept the highest and NPV greater than zero).
ii. Payout period (the shorter the better).
iii. Profit per dollar invested (the higher the better).
iv. DCF –ROR (accept if >10%).

Table 6
Parameters, Costs, Values and Assumptions for the Economic Analysis

Parameter/cost	Value	Reference
Investment cost	-	-
Well Licensing to site cleanup	$250 000	Shelf drilling, 2012
Cost of drilling and completing a well	$850/ft	Shelf drilling, 2012
Cost of drilling and completing a well to a total depth of 7250ft	$6.2million	-
Cost of installation of wellhead structures and equipment	$20 000	-
Total cost of one well	$6.22million	-
Cost of the 2 vertical water injection wells	$12.44miilion	-
Cost of drilling and completing a Horizontal wells = 1.7 * Vertical well cost	$1445/ft	Shelf drilling, 2015
Cost of 2 horizontal producer well	$23.8million	-
Cost of installation of wellhead structures for the 2 horizontal well	$40 000	-
Surface gathering and processing Facilities	$12.0million	Oil serve 2012
Cost of installation of water injection pump	$192 000	-
Cost of drilling a water well to about 1500ft	$3000	Oil serve, 2012
Cost of installing a gathering system for the water gathering	$50 000	-
Cost of installing water lines for transporting the water from about 10 miles away from the oil well	$866 000	Oil serve, 2012
Total cost of water and water lines	$1.11million	
Cost of a acquiring a 25ft Joint of ICD	$28 000	Schlumberger, 2016
Cost of at least 20 joints	$560 000	-
Miscellaneous cost	$5.0Million	
Total Investment cost	$55.6million	
Operating cost		
Labour costs per employee	$3000/month	Assumed
Annual labour costs assume 50 employees	$1.2million	-

To be continued

Continued

Parameter/cost	Value	Reference
Total maintenance costs	$1.9million	-
Management costs	$300 000	-
Annual operating cost	$3.4million	
Royalties	18% of Net Revenue	NAPIMS, 2016
Tax	30% of Net Revenue	NAPIMS, 2016
Oil price.	$30/bbl	Assumed
Gross Income (GR)	Oilprice*Cum oil production	

11. RESULTS

11.1 FLOW PROFILES FOR THE SIMULATION CASES

For water injection case without ICDs, the flow rates across layers varies due to heterogeneity, the layers with the high permeability streak receive more water and the layers with low permeability are starved. Hence an uneven water outflow/distribution is obtained, see Figure 5.

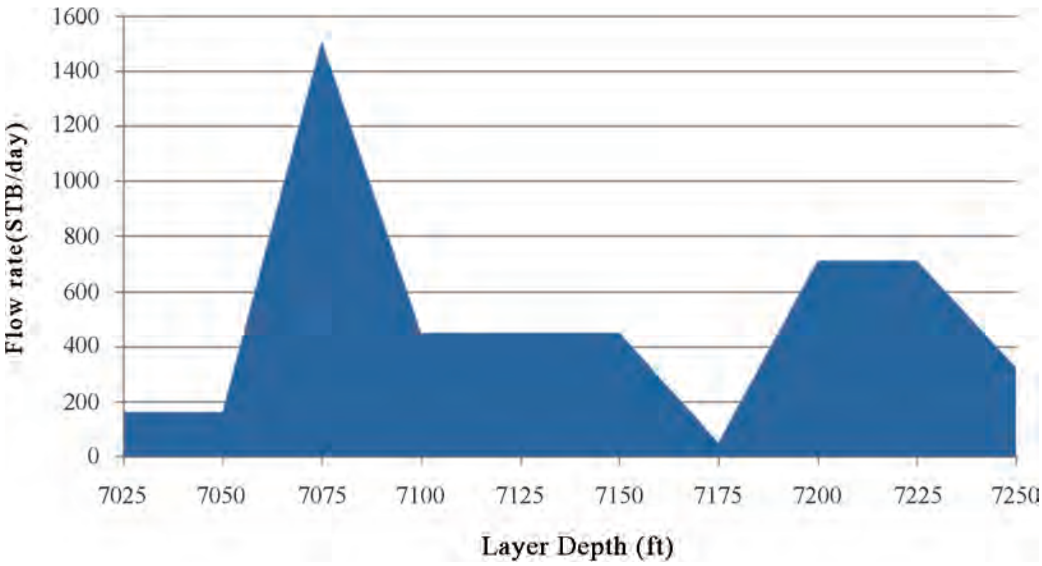

Figure 5
Flow Profile for Water Injection Without ICDs

The nozzle sensitivities gave rise to the optimum nozzle selections in Table 8, used to achieve the required pressure drop and corresponding flow rates desired in each layer. The established pressure drops are given in Appendix A.

Table 8
Layer Response for Water Injection With Same and Different ICD Configuration

Layer No.	ICD with same nozzle size in all layers	Water rate (STB/day)	ICD with different nozzle size in all layers	Water rate (STB/day)
1	13mm/joint	385.57	16mm/joint	446.42
2	13mm/joint	385.57	16mm/joint	446.42
3	13mm/joint	700.01	7mm/joint	586.33
4	13mm/joint	530.14	12mm/joint	516.81
5	13mm/joint	530.14	12mm/joint	516.81
6	13mm/joint	530.14	12mm/joint	516.81
7	13mm/joint	300.38	22mm/joint	405.60
8	13mm/joint	633.76	10mm/joint	544.24

to be continued

Continued

Layer No.	ICD with same nozzle size in all layers	Water rate (STB/day)	ICD with different nozzle size in all layers	Water rate (STB/day)
9	13mm/joint	633.76	10mm/joint	544.24
10	13mm/joint	414.48	14mm/joint	485.07

The outflow profiles for both ICD designs are given in the Figures 6 and 7 below:

When the water injectors are completed with the same ICD configuration and different configuration across the layers, a more even outflow profile was achieved. However, the choice of configuration to be used on field scale was based on the design that gave the highest recovery factor and better economics when they are simulated.

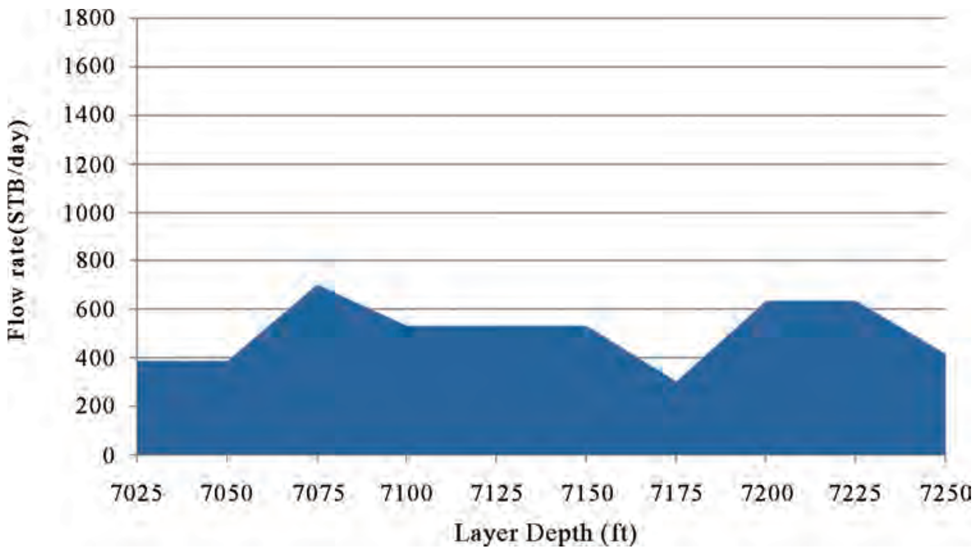

Figure 6
Flow Profile for Water Injection With the Same ICD Configuration

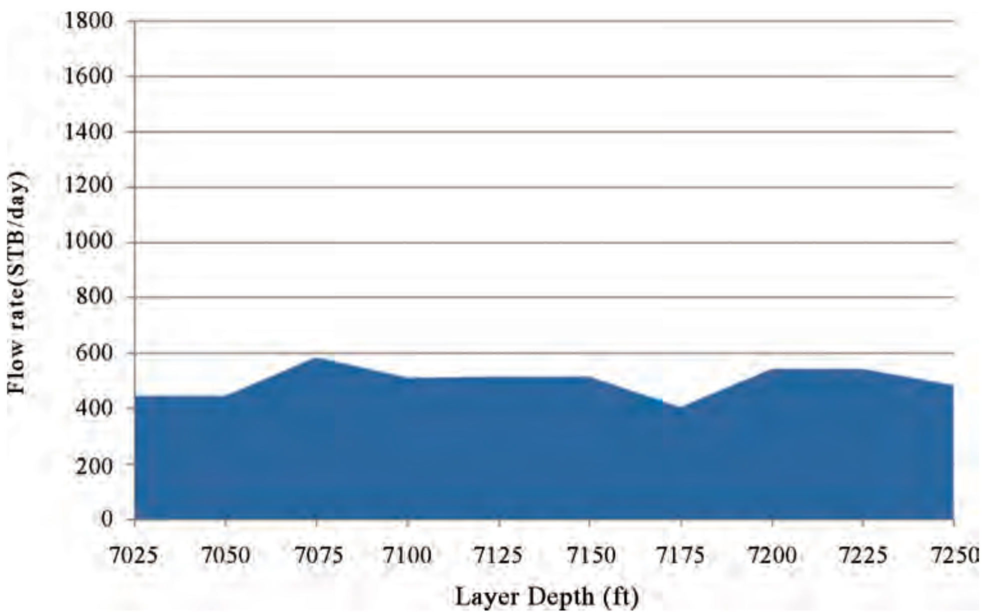

Figure 7
Flow Profile for Water Injection With Different ICD Configuration

11.2 Performance Plots of the Simulation Scenarios
The forecast of field recovery factor (FOE), cumulative oil production (FOPT), water cut (FWCT), field pressure (FPR), oil production rates (FOPR) for Flo-Z6 reservoir for the simulation scenario considered are presented in Figures 8-15.

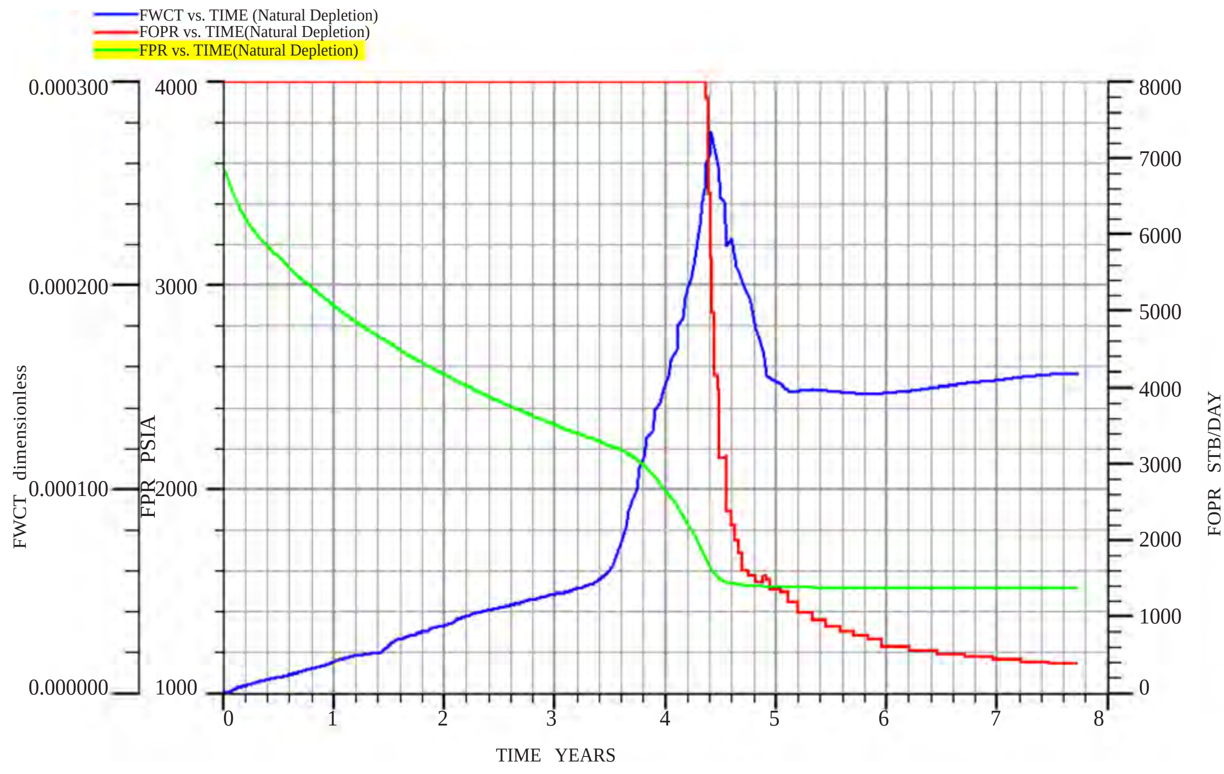

Figure 8
Plot of Field Water Cut, Pressure and Production Rate against Time, for Natural Depletion

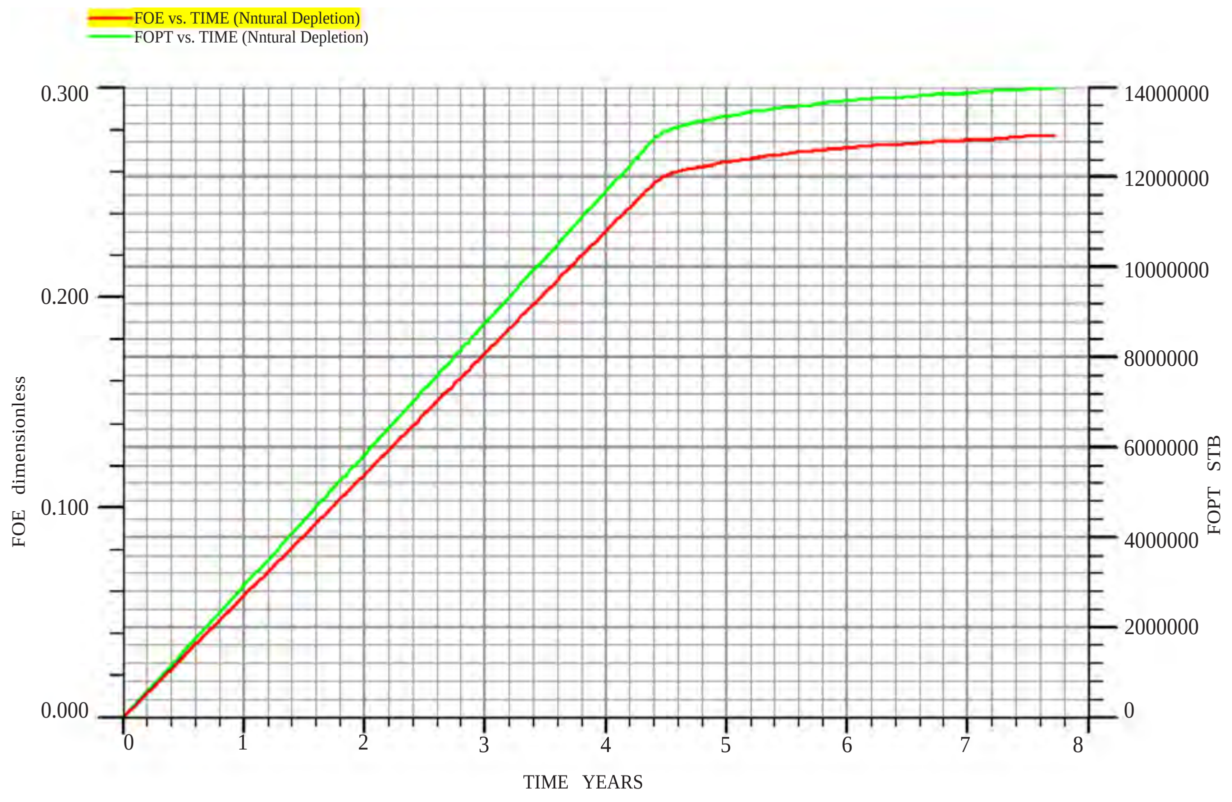

Figure 9
Plot of Cumulative Oil Production and Recovery Factor against Time for Natural Depletion

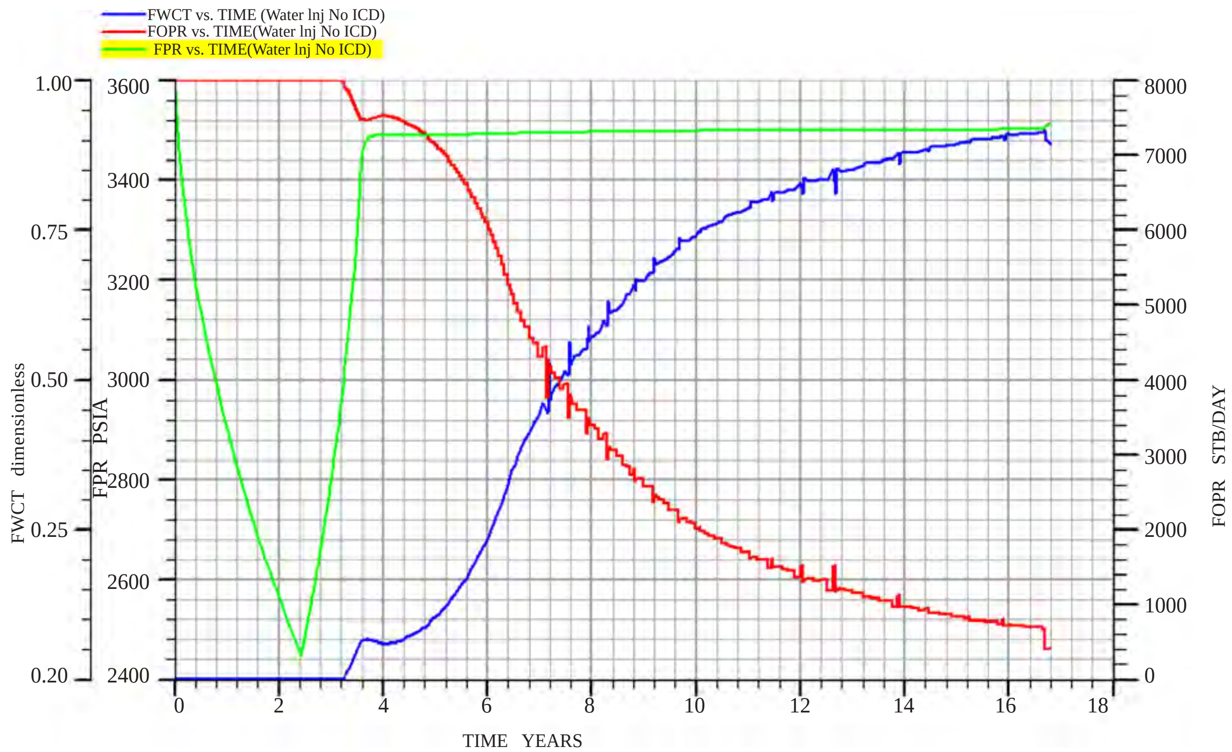

Figure 10
Plot of Field Water Cut, Pressure and Production Rate Against Time, for Water Injection Without ICDs

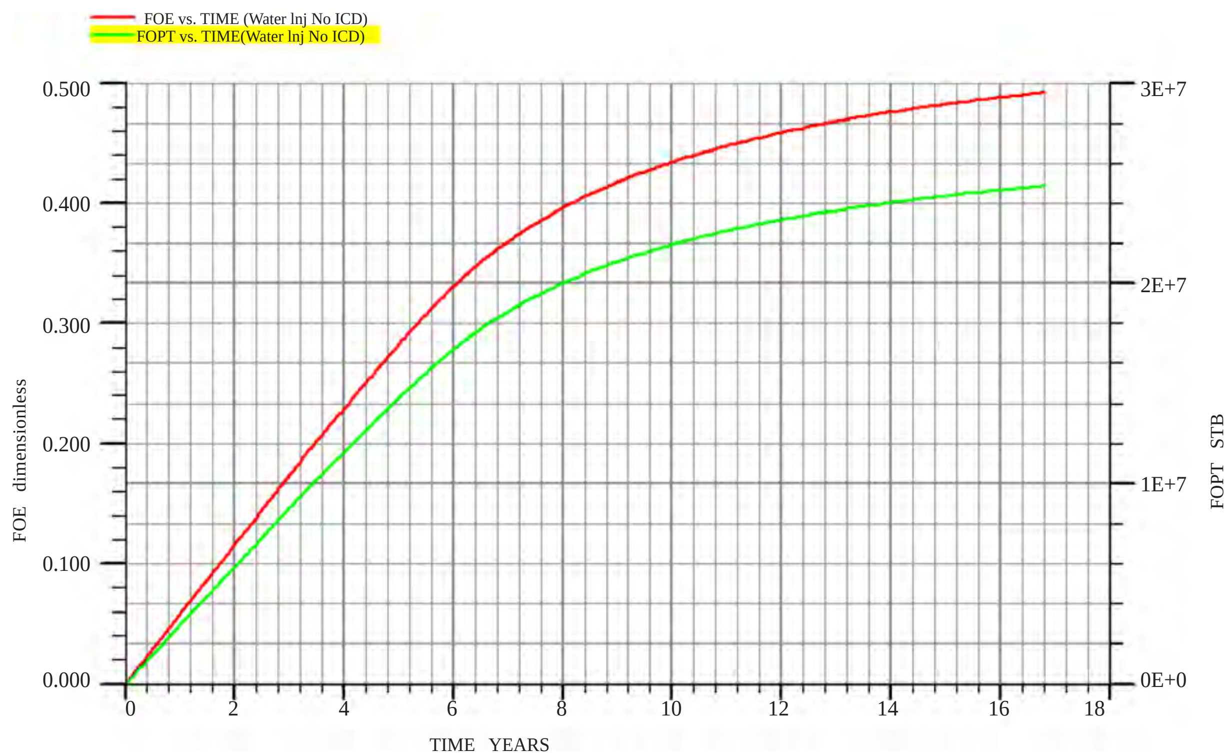

Figure 11
Plot of Cumulative Oil Production and Recovery Factor against Time for Water Injection Without ICDs

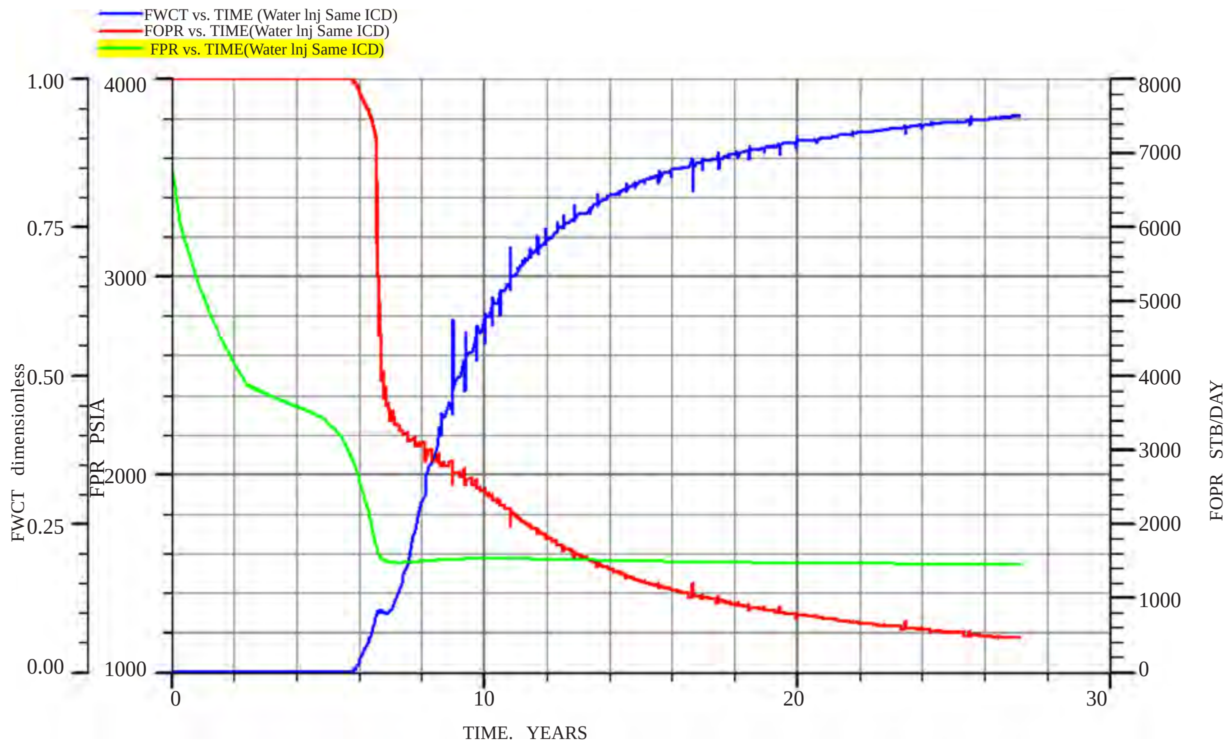

Figure 12
Plot of Field Water Cut, Pressure and Production Rate Against Time, for Water Injection With Same ICD Configuration

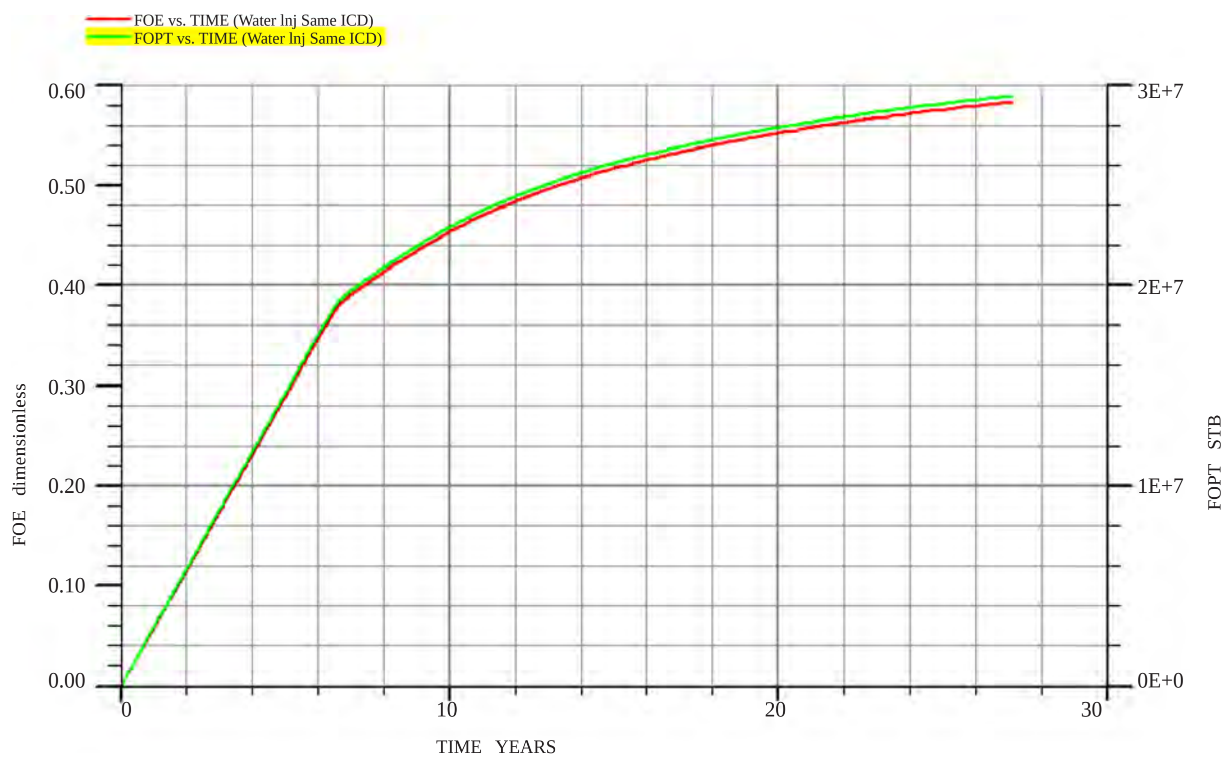

Figure 13
Plot of Cumulative Oil Production and Recovery Factor Against Time for Water Injection With Same ICD Configuration

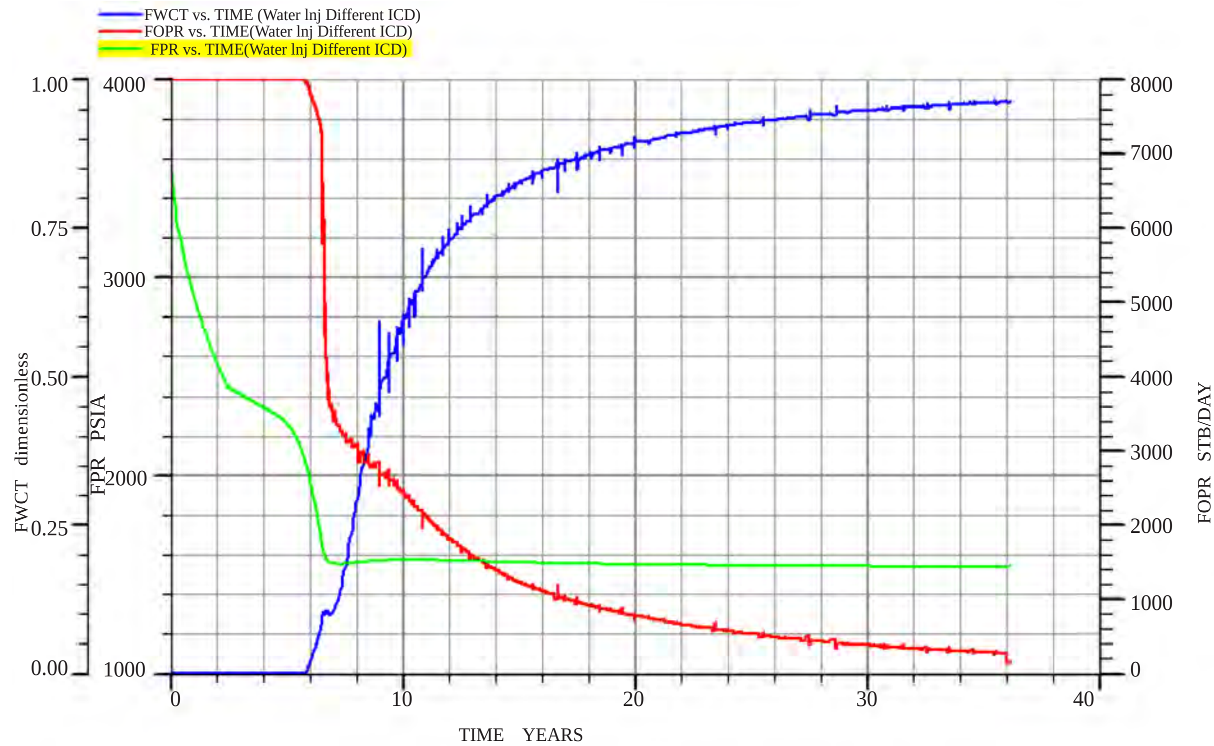

Figure 14
Plot of Field Water Cut, Pressure and Production Rate Against Time, for Water Injection With Different ICD Configuration

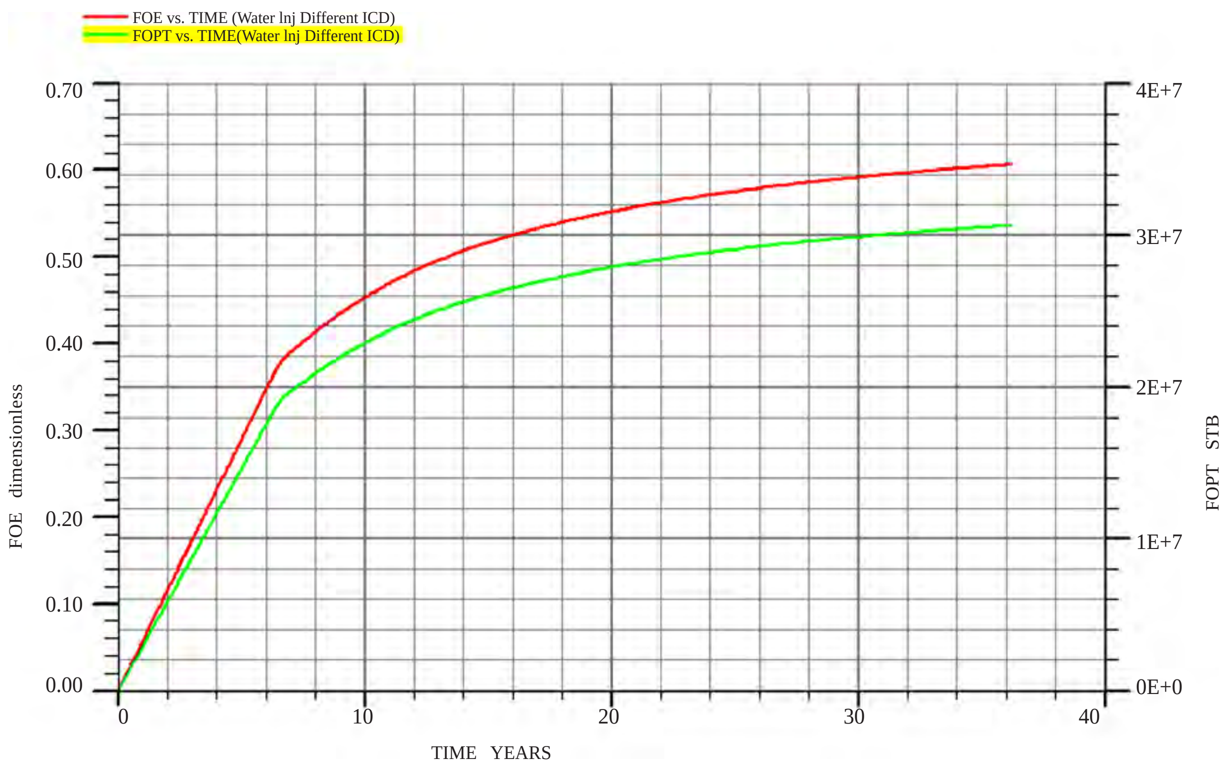

Figure 15
Plot of Cumulative Oil Production and Recovery Factor Against Time for Water Injection With Different ICD Configuration

Table 9
Summary Result of the Four Cases Considered

Case	Scenario	Foe	Cummulative production
1	Natural depletion	27.7%	13.9MMstb
2	Water Injection without ICDs	49.2%	24.6MMstb
3	Water injection with same ICD nozzle configuration	58.3%	29.4MMstb
4	Water injection with different ICD nozzle configuration	61.1%	31.2MMstb

From the result, the ICDs with the different nozzle configuration in the injector wells tailored to equalize the water outflow, improved the field oil recovery by 11.9% (6.6MMstb) which is higher than other cases.

Table 10
Summary of the Economic Analysis

Scenario(s)	NPV@ 10% ($MM)	Payout (years)	Profit per dollar invested ($)	DCF-ROR (%)
Natural depletion	112.2	0.97	3.6	98
Water injection with no ICDs	175.1	1.21	5.4	73.5
Water injection with same ICD nozzle configuration	187.1	1.25	6.4	77.5
Water injection with different ICD nozzle configuration	192.5	1.2	6.6	81

Completing the injectors with ICDs increased the investment cost. In terms of comparing the injection scenarios, water injection scenario with different ICD nozzle configuration was higher, with an NPV@10% of $192.5 million, profit per dollar invested of $6.6, DCFROR of 81% and a pay-out period of 1.2 year which is relatively short. The large DCFROR values are attributed to the assumptions used/made in the economic model which may not have captured all the uncertainties in the cash inflow and outflow. The payout period of natural depletion is the shortest (0.97yr) and has the highest DCF (98%) as the base case which is greater than the DCFROR of the injection scenarios. The DCFROR can't be used to judge the four scenarios when Natural depletion is involved because they have different project durations.

CONCLUSION

With the results from this study, the following conclusions were made:

i. Nine (9) ICD zones were optimized, covering layers with permeability contrasts where water injection was required.
ii. The application of ICD in the injector well shows a more evenly distributed outflow profile and thus risks of bye-passing reserves were minimized.
iii. Utilizing ICD design with different nozzle sizes tailored to match the layer permeability has slight gain over the same nozzle configuration for the Flo-Z6 reservoir.
iv. From the economic stand-point, water injection with different ICD nozzle configuration shows higher profit (NPV of $192.5 million, DCFROR of 81% and profit per dollar invested of $6.6) although it increases the investment cost. This is why the efficiency of the project is worthwhile.

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NOMENCLATURE

AWC(s) = Advanced Well Completions employing
DFC =Downhole Flow Control
ICD(s) = Inflow Control Devices (ICDs)
ICV(s)= Interval Control Valves
AICD(s) = Autonomous Inflow Control Devices
AFI(s) = Annular Flow Isolations
RFID = Radio Frequency Identification
DP-ICV = Discrete-positions ICV
VP-ICV = Variable-positions ICV
SCRAMS = Surface-Controlled Reservoir Analysis and Management System
AICV = Autonomous-ICV
ERA = Electrode Array Resistivity
USD = United State Dollar
AFD = Autonomous Flow control Device
AGL = Auto Gas Lift
BHP = Bottom Hole Pressure
GOR = Gas Oil Ratio
HP = High Pressure
HPe = High Permeability
LP = Low Permeability
MP = Medium Permeability
MRM = Multiple Reservoir Management
OD = Outside Diameter
GOC = Gas Oil Contact
OWC = Oil Water Contact
PI = Productivity Index
SAS = Stand Alone sand Screen
Sw =Water saturation
TVD = Total Vertical Depth
WC = Water Cut
NTG = Net to Gross
HCIP = Hydrocarbon in place
VLP = Vertical Lift Performance
IPR = Inflow Performance Relation
FOE = Field Oil Efficiency
FOPT = Field Oil Production Total
FWCT = Field Water Cut
FPR = Field Pressure
FOPR = Field Oil Production Rate

APPENDIX A: PRESSURE DROP ACROSS ICD NOZZLES FOR LAYERS

Model layers	*dp* across ICD nozzle for same configuration (psi)	*dp* across ICD nozzle for different configuration (psi)
1	11.5	8.5
2	11.5	8.5
3	84.3	102.6
4	23.4	19.9
5	23.4	19.9
6	23.4	19.9
7	4.3	2.6
8	42.7	46.5
9	42.7	46.5
10	20.1	17.6

