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EA Recovery Factor Geo-Cellular-Tool: A Simple Digital Testing Workflow*

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Abstract

Traditional surveillance tools are used in reservoir engineering to infer the vertical and lateral extent of reservoirs and provide indirect means to estimate the ability to flow in the reservoir. We propose a static solution using 3D geo-cellular reservoir properties that complement these traditional techniques resulting in a more robust evaluation of reservoir performance. Regardless of techniques utilized, Recovery Factor (RF) estimation is difficult. Here we present a workflow that incorporates the technical team's understanding of the reservoir and allows for the evaluation of multiple 3D development scenarios in the geologic model before running full dynamic simulation. Our purpose is to provide support to hypotheses on the effective reservoir to be drained.

While this technique is applicable to many reservoir types, it is especially useful in reservoirs with prolonged high water cuts resulting in cumulative water production beyond expected water recovery, often interpreted as higher water saturation. In this technical note we will focus on these high-water-cut reservoirs. For the case presented here, large volumes of produced water adds another tool, water recovery factor, to the traditional measure of hydrocarbon recovery factors. When comparing water production and estimated ultimate recovery (EUR) per well to the original water in-place (OWIP), and sensitivities thereof, one can place reasonable bounds on the extent of the flow unit being drained. We propose a workflow to compare outputs from a regional geo-cellular model to actual (production history) or expected production profiles. This provides a tool that the integrated multidisciplinary team can use to evaluate, produce recommendations to leaders, and make better informed business decisions. The results of applying the workflow can influence and optimize development plans based on better supported well performance predictions.

Introduction

The reservoir type for the test case presented here is a high water cut scenario where the flow ability in the effective reservoir is enhanced. In the model, the reservoir is essentially created through the artificial enhancement of the permeability around the wellbore; becoming the effective reservoir to which the well is connected. The analysis of drainage zone variations in the flow unit and basic understanding from the fundamentals of material balance, bound the effective reservoir size into reasonable outcomes as part of the identification of realistic scenarios to assess. These characteristics provide us with a unique opportunity to test the static workflow we propose. The workflow relies on available production data. Once wells in the field to be evaluated in our tool have been producing (flowing), the team can use the historic data (fluid volumes) to explore multiple geologic scenarios as different iterations are conducted to narrow possibilities to most likely solutions.

Traditional surveillance data alone, such as pressure depletion in nearby wells or build up, is very problematic for reservoirs similar to the experiment presented. However, since it produces both oil and water, the data can be leveraged to inform the completion design and improve the development plan as the field is produced. Additionally to the case study presented, other examples where the geo-cellular-tool can be used include reservoirs where SAGD (Steam-assisted gravity drainage) enhanced oil recovery techniques are applicable, fractured carbonates or other reservoirs where permeability around the well is enhanced by dissolving mechanisms (e.g. acidizing), or reservoirs where EOR methods are used to increase the ability of fluids to flow through the reservoir. In essence, our workflow is applicable to any scenario where the flow ability in the effective reservoir needs to be enhanced and there are multiple phases flowing and can be applied before conducting full blown dynamic simulation. The primary benefit of running digital tests is that it provides a technical foundation that can be implemented to improve field performance based experience (observed history) and technical forecasts (based on behaviour predictions from digital tests) as new wells are drilled. Our proposal is basically a static digital “trial and error” laboratory that can be used prior to simulation at significant lower cost than testing with the bit.

Methodology

The methodology combines input from a multi-disciplinary subsurface/surface team. A geoscience team compiles available static data into a representation that houses the volumetric distribution of individual immiscible phases into a 3-Dimensional definition of the reservoir. We focus on the detail and preservation of distributed properties (Bayer et. al., 2016) from the regional model preserving geologic trends (Figure 1; Water Saturation). When multiple phases flow in the reservoir an opportunity to use the recovery factor tool is created – here we consider a water and oil example.

Utilizing information on potential extents of the reservoir accessible by the well, two concentric boxes are constructed (Figure 2), with an inner box (Green) representing extent of enhanced permeability region and an outer box (dark blue) consisting of the expected reservoir drainage extent (without regard to no-flow or external boundaries from the system). Actual production or estimated production is distributed to both the inner and the outer box. Initially, the property is proportional to mobile in place volume of the respective phase. The production volume divided by the original in place volumes gives a 3-Dimensional representation of recovery factor.

Results

Consider the following definitions for recovery factor for each phase:

Recovery factor (oil)	$$RF_o = \frac{N_p}{N}$$	(1)
Recovery factor (gas)	$$RF_g = \frac{N_p R_p}{N R_{so1}} = RF_o \frac{R_p}{R_{so1}}$$	(2)
Recovery factor (water)	$$RF_w = \frac{N_p W_p}{N W_{o1}} = RF_o \frac{W_p}{W_{o1}}$$	(3)

OOIP: Original Oil In Place GOR: Gas Oil Ratio WOR: Water Oil Ratio.

Where Np the cumulative oil is produced, N is the OOIP, R_p and R_{so1} are the cumulative produced GOR and original solution GOR respectively, and W_p and W_{o1} are the cumulative produced WOR and original in-place WOR respectively. Examining each term in the equations above can lead one to determine the relative magnitudes of each phase's recovery factor.

Example Case

In this case we highlight how the workflow can be used to draw conclusions from oil, gas, and water production. A diagram showing how the concentric boxes are embedded in the regional geologic model to extract 3D properties is presented in Figure 3. The 3D model allows for recovery factors for different effective reservoir regions to be calculated assuming different flow unit size (Figure 4).

Integrating material balance and mobility considerations (see Hurst, 1974), and for a balance of pressures between phases during production, we postulate the recovery factor for water should be lower than the recovery factor for oil, which in turn should be lower than the recovery factor for gas.

The reason the water recovery factor declines faster than the hydrocarbon recovery factors in this particular case is due to the water-bearing zones in the shallower portions in the example reservoir. As shallower reservoir units are included in the SRV, the lower the recovery factors become. Water recovery is reduced faster due to higher Sw in the shallower zones (Figure 4; Blue bars in graph).

Figure 5 shows the recovery as multiple reservoir regions are produced in the 3-D model. This gives an initial idea of how well the reservoir is being drained, the extent of interference, and remaining infill opportunities before going into a full blown reservoir simulation evaluation. This also allowed us to identify the ideal geo-cellular grid resolution for the model. We could then make modifications if resolution was too low (cannot resolve flow behaviour) or too high (computationally expensive).

Conclusions

Dynamic modeling can be time consuming due to computational constraints and highly variable voluminous data sets that are becoming available for almost all projects. This note provides a unique approach that highlights a way to use readily available production data from an immiscible system which ultimately alleviates the computational burden associated with traditional dynamic simulation techniques. In addition, this methodology enables a novel means of evaluating the reservoir size and simultaneously the recovery factor by incorporating the interference between flow units in three dimensional space.

Running multiple scenarios in a short period of time still poses a challenge in any field development planning, however as demonstrated, our workflow offers an optimal approach in that it addresses dynamic data taking into account only the effective reservoir contributions.

Development scenarios tested in our digital laboratory ahead of the drilling bit translates into significant cost savings for the asset employing the technique. Testing by drilling actual wells is always more expensive than simulating and selecting best scenarios to implement in the oil field.

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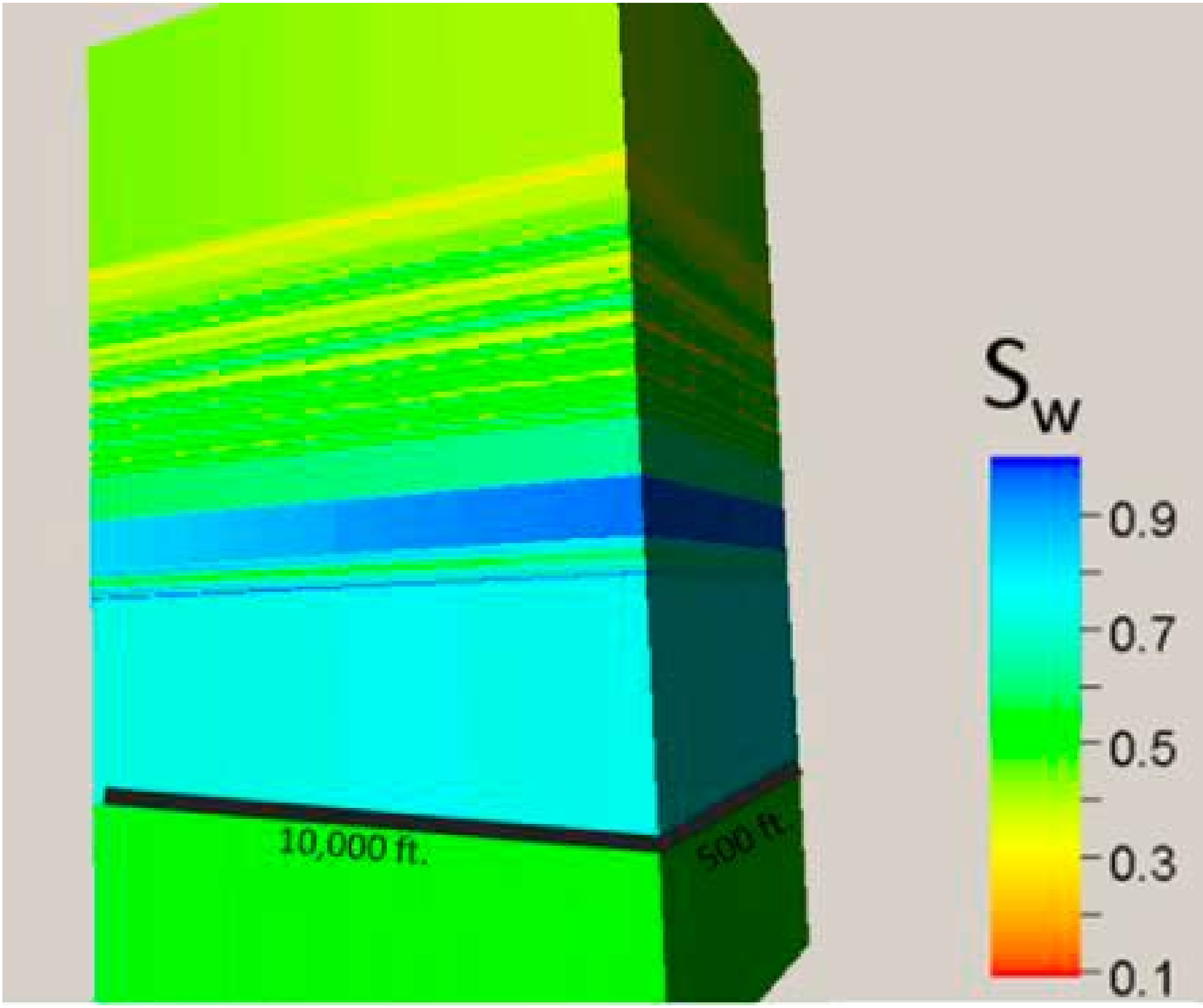

Figure 1. Water Saturation distribution. Property from cropped sector model, preserving regional geologic trends (regional reservoir properties and those used in the workflow are identical).

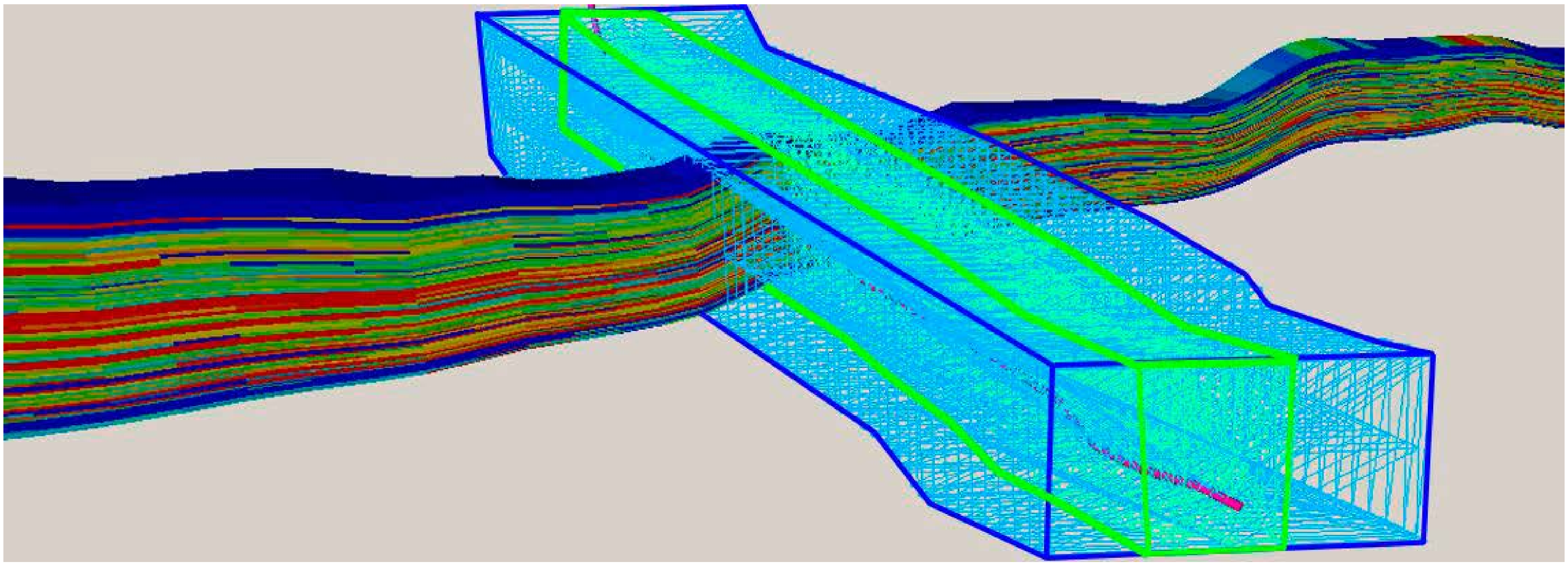

Figure 2. Concentric boxes are constructed for sector model used in workflow code. Length of reservoir boxes shown is ~5000 feet (Long axis of boxes).

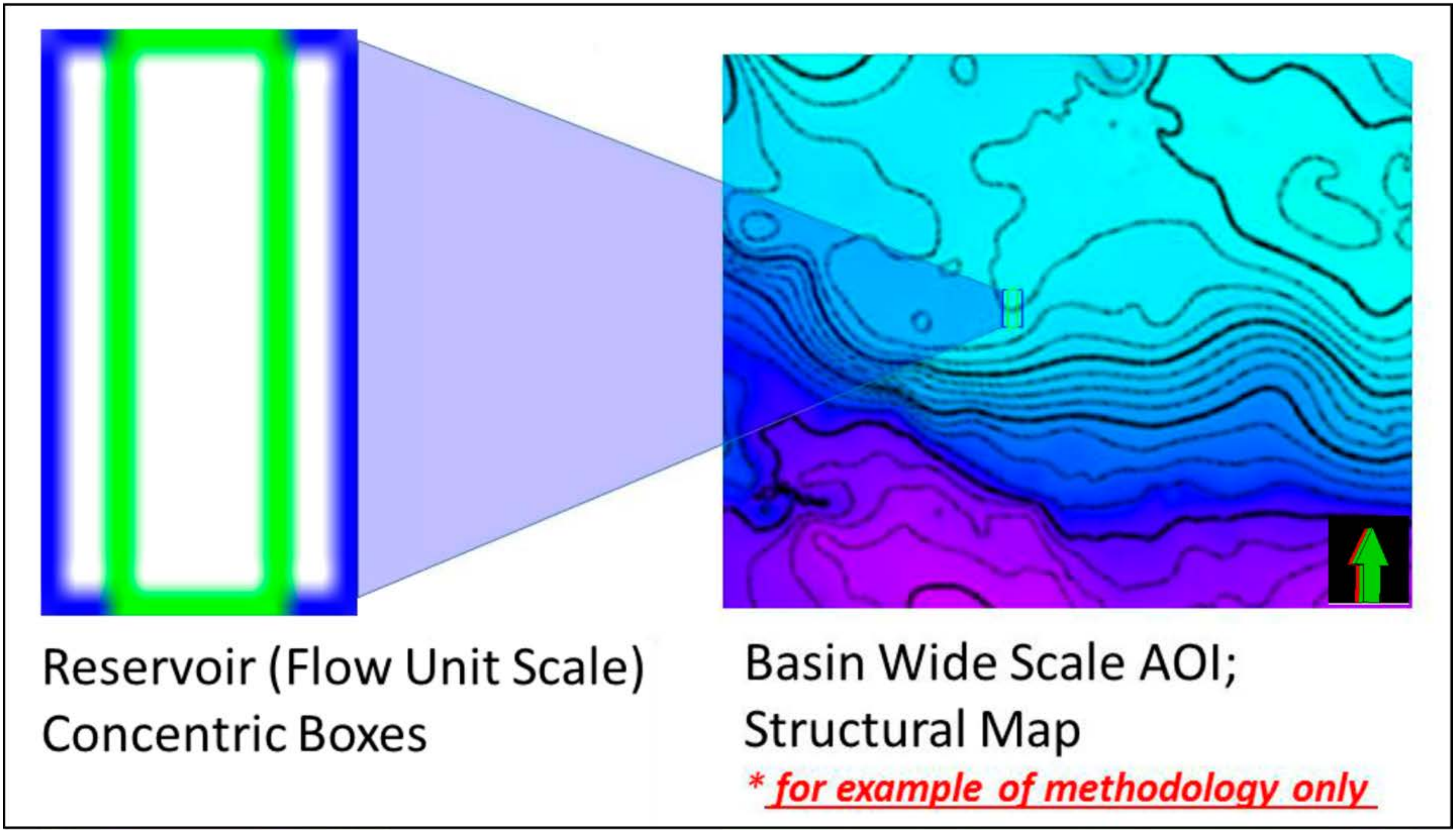

Figure 3. Example well and play.

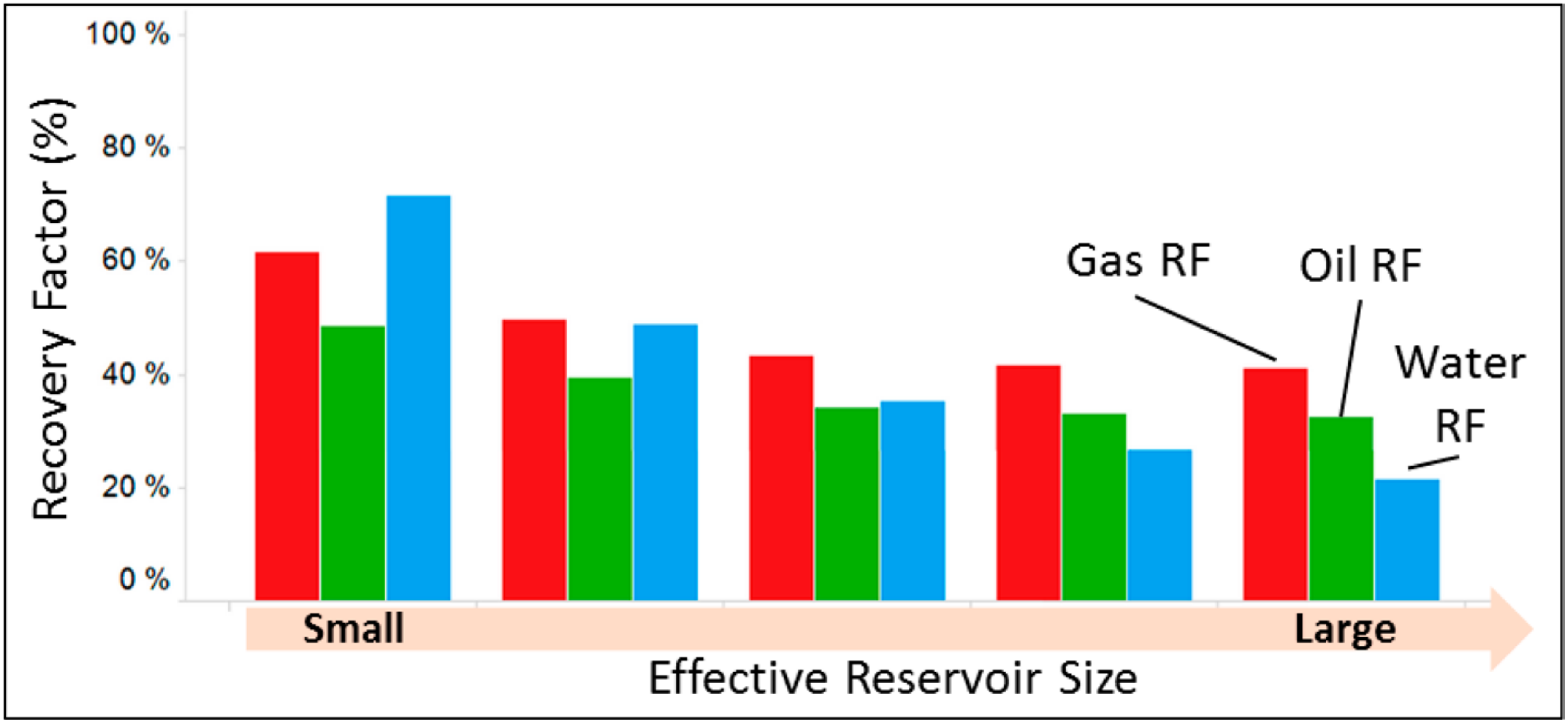

Figure 4. Recovery Factor vs. Reservoir Size.

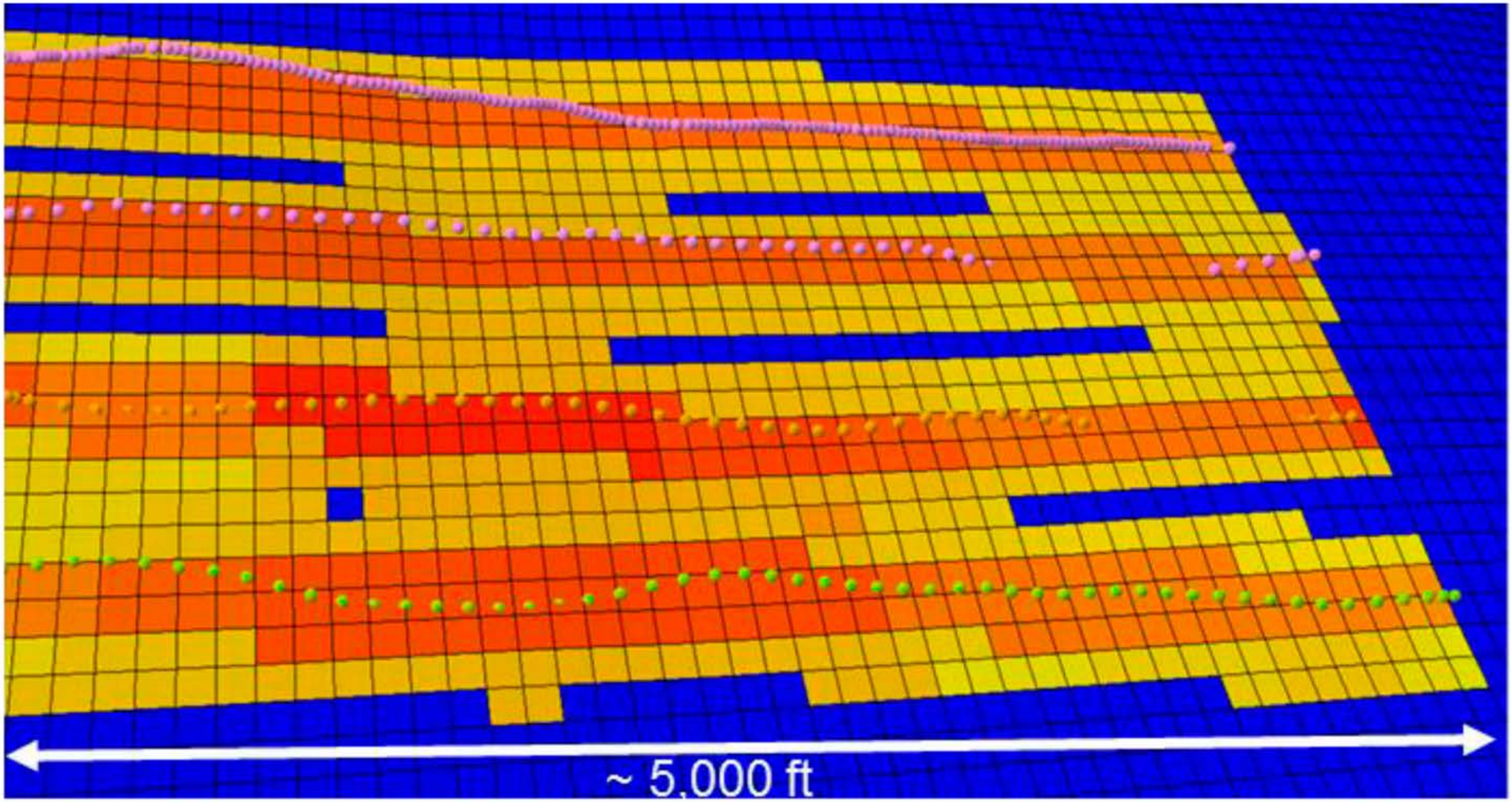

Figure 5. Visualization of drainage and interference; virgin reservoir in blue.