USER'S GUIDE

Development of a Design Tool for Planning Aqueous Amendment Injection Systems

ESTCP Project ER-0626

June 2008

Dr. Robert C. Borden
North Carolina State University

Mr. Matthew Clayton
North Carolina State University

Mr. Aaron M. Weispfenning
CDM

Dr. Thomas Simpkin
CH2M Hill

Mr. M. Tony Lieberman
Solutions-IES, Inc.

Approved for public release

ESTCP

Environmental Security Technology
Certification Program

ACKNOWLEDGEMENTS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

SECTION 1
GENERAL OVERVIEW OF EMULSIFIED OIL PROCESS

1.1 Introduction

This design tool is intended to assist with the design of injection systems for distributing emulsified edible oils to stimulate *in situ* anaerobic bioremediation (AB) of groundwater contaminants. The design tool is intended to assist users in selecting an appropriate injection well spacing and amount of emulsified oil and water to inject. Prior to beginning use of the design tool, users should have already conducted a preliminary screening to determine if AB using emulsified oils is appropriate for the conditions at their site.

Users are expected to have a good understanding of AB using emulsified oils prior to beginning use of the design tool. For information on enhanced AB using emulsified oils, users should first consult the following documents.

- "A Treatability Test for Evaluating the Potential Applicability of the Reductive Anaerobic Biological *In Situ* Treatment Technology to Remediate Chloroethenes" (search for title at http://docs.serdp-estcp.org/index.cfm)
- "Principles and Practices of Enhanced Anaerobic Bioremediation of Chlorinated Solvents" – (http://www.afcee.brooks.af.mil/products/techtrans/Bioremediation/BIOREMresources.asp)
- "Protocol for Enhanced *In Situ* Bioremediation Using Emulsified Edible Oil" – (search for title at http://docs.serdp-estcp.org/index.cfm)
- "Protocol for *In Situ* Bioremediation of Chlorinated Solvents Using Edible Oil" (http://www.afcee.brooks.af.mil/products/techtrans/Bioremediation/BIOREMresources.asp)

Emulsified oils have been applied at several hundred commercial and military sites nationwide. Although emulsified oils have been demonstrated in the laboratory and the field, this technology continues to evolve. This manual is based on the current state of practice at the time of writing.

There are a wide variety of compounds that can be anaerobically biodegraded using emulsified oils including chlorinated ethenes, chlorinated ethanes, halomethanes, perchlorate, nitrate, certain metals, and explosives (e.g., RDX, HMX). For a few of these compounds (e.g., PCE, TCE, perchlorate, and nitrate), the biodegradation pathways and microorganisms that carry out this process are relatively well understood and enhanced anaerobic biodegradation has been demonstrated in the field at multiple sites. However, there are many other compounds (e.g., chlorinated ethanes and methanes, freons) where the factors controlling contaminant biodegradation are much less well understood. In addition, substrate addition has the potential to inhibit biodegradation of petroleum hydrocarbons and related contaminants. If mixtures of chlorinated solvents, petroleum hydrocarbon, and/or solvent stabilizers (e.g., 1,4-dioxane) are present, other alternatives may need to be considered.

1.2   The Emulsified Oil Process

In the emulsified oil process, an oil-in-water emulsion is prepared using vegetable oil and distributed throughout the target treatment zone to provide a long-lasting electron donor to support anaerobic biodegradation processes. These oils are fermented to molecular hydrogen (H_2) and acetate by common subsurface microorganisms. The H_2 and acetate are then used as a carbon and energy source for anaerobic biodegradation of the target pollutants.

Oil-in-water emulsions are completely miscible with water so the emulsions easily disperse with groundwater after injection. Ideally, the emulsion should be stable (i.e., non-coalescing); have small, uniform droplets to allow transport in most aquifers; and have a negative surface charge to reduce droplet capture by the solid surfaces. The emulsified oil is injected into the aquifer with water to distribute and immobilize the oil droplets. As oil droplets migrate through the aquifer pore spaces, they collide with the aquifer material (i.e., soil) surfaces and stick. The surfaces of the aquifer material gradually become coated with a thin layer of oil droplets that provides a carbon source for long-term reductive dechlorination. Oil droplet retention on the aquifer material surfaces is proportional to the clay content with larger amounts of clay resulting in higher oil retention (Coulibaly and Borden, 2004). Soluble substrates and nutrients (e.g., lactate, yeast extract, vitamins) can be added to the mixture prior to injection to stimulate rapid growth of desired bacteria. Field and laboratory studies (Borden et al., 2004; Coulibaly and Borden, 2004, Beckwith et al., 2005) have shown that emulsified oils can be transported substantial distances (up to 50 feet) in a variety of aquifer materials with low to moderate oil retention and with little permeability loss.

1.3   Procedures for Injecting Emulsions

Projects involving injection of oil emulsions typically, but not always, involve the following steps: 1) installation of injection wells and associated equipment; 2) emulsion preparation; and 3) emulsion and water injection. Emulsions can be injected through the end of a direct push rod, through temporary 1-inch direct-push wells, or through permanent 2 or 4-inch conventionally-drilled wells. The selection of the most appropriate method for installing injection points depends on site-specific conditions including drilling costs, flow rate per well, and volume of fluid that must be injected.

Using properly prepared emulsions, it is possible to move injected emulsions 10, 20 or 50 ft away from the injection point. However, achieving effective distribution of the emulsified oil often requires injecting large volumes of water. Depending on the injection well layout and formation permeability, emulsion injection can require an hour to several days per well. As a consequence, several wells may be injected at one time using a simple injection system manifold.

The primary design variables that must be considered when planning an emulsion injection project are:

    (1) the spatial arrangement of the injection points;
    (2) the type and physical construction of the injection points or wells;
    (3) the amount of emulsified oil and water to inject;

2

(4) the timing of emulsified oil and water injection; and

(5) additional labor and equipment required for mixing and injection.

Each of these variables has an important influence on both the cost and effectiveness of the injection project.

1.3.1   *Arrangement of Injection Points*

There are two general approaches used to distribute emulsions through the subsurface: a) recirculation systems; and b) injection only systems. Recirculation systems can be effective in distributing emulsions significant distances through the subsurface in certain situations, allowing the use of fewer injection points. These systems are particularly useful where drilling costs are high or site access limitations restrict injection point installation. Recirculation systems can also be designed to minimize the physical displacement of contaminants by injection water. However, capital and operating costs of recirculation systems are can be higher due to the more complex equipment and piping requirements and higher operation and maintenance (O&M) costs. In many cases, the design of recirculation systems is more complicated and may require the use of a site-specific groundwater model.

Injection only systems are most useful when drilling and site access conditions allow installation of rows or grids of injection points. Under these conditions, capital and O&M costs are often lower for injection only systems. The design of injection only systems can also be simplified by generating a 'standard' design for a small group of injection points which is then replicated throughout the site.

The design tool described in this document has been developed to assist users in the design of injection only systems for distributing emulsions. There are two basic configurations considered: a) barriers (e.g., rows of injection points) designed to only treat contaminated groundwater as it migrates through the emulsion treated zone; and b) area treatments (e.g., grids or multiple rows of injection points) designed to treat both mobile dissolved contaminants and relatively immobile sorbed/residual contaminants.

Once a general layout has been selected (e.g., barrier or area treatment), the user must then select an injection point spacing. Selecting the best well spacing can be complicated. Increasing the separation between injection wells will reduce the number of wells, reducing drilling costs. However, a larger well spacing can also increase the time required for injection, increasing labor costs. It may also be more difficult to uniformly distribute the emulsion throughout the treatment zone using fewer, widely spaced injection points. In many cases, an intermediate well spacing results in the lowest total cost with reasonably good emulsion distribution throughout the target treatment zone. The design tool provides graphs illustrating the effect of well spacing on emulsion distribution efficiency and comparative costs allowing the designer to select a well spacing that best meets project objectives.

1.3.2 *Injection Point Construction*

Emulsions can be injected through the end of a direct push rod, through temporary 1-inch direct-push wells, or through permanent 2 or 4-inch conventionally-drilled wells. The selection of the most appropriate method for installing injection points depends on site-specific conditions including drilling costs, flow rate per well, and volume of fluid that must be injected.

When the contamination extends over a significant vertical extent, it may be desirable to install several shorter screened wells to target specific intervals. This allows a known quantity of emulsion to be injected in each interval. However, this also increases injection system cost and complexity. Additional information on injecting emulsion through wells and direct push points can be found in Solution-IES (2006) and AFCEE (2007).

1.3.3 *Amount of Water and Emulsified Oil to Inject*

Emulsions are transported in the subsurface by flowing groundwater. Consequently, sufficient water must be injected to transport the oil droplets throughout the target treatment zone. The amount of emulsified oil required is determined by the target treatment volume and the amount of oil retained per mass of aquifer material. Emulsion distribution in the aquifer can be enhanced by injecting more emulsified oil and/or more water. However, injecting additional emulsified oil increases material costs. Injecting additional water increases labor costs. Performance curves are presented in Section 2 illustrating the effect of varying the amount of emulsified oil and/or water injected on contact efficiency. Guidance on use of the design tool to calculate emulsified oil and water injection volumes is presented in Section 3.

1.3.4 *Timing of Fluid Injection*

Achieving effective distribution of the emulsion often requires injecting large volumes of water. To reduce costs, it may be desirable to manifold a group of wells together allowing simultaneous injection of multiple points. However, simultaneous injection of nearby wells can cause well inference effects, resulting in stagnation zones and poor emulsion distribution. Sections 2.2.3 and 2.3.3 provide information on the effect of simultaneous versus sequential injection on emulsified oil contact efficiency.

1.3.5 *Additional Labor and Equipment Required*

The major capital costs for emulsion injection are associated with injection point installation, substrate purchase and labor during the injection. However, there are a number of other factors that can influence the final project cost including mobilization, setup of injection equipment (e.g., pumps, meters), injection water supply, and site cleanup. These costs are not closely related to the specific injection design. However, they can have a significant impact on the final project cost. In the design tool, costs for engineering and permitting, mobilization, equipment setup, water supply and cleanup/demobilization are entered as fixed costs. Costs for equipment rental are entered on a daily basis.

SECTION 2
EFFECT OF INJECTION SYSTEM DESIGN ON CONTACT EFFICIENCY

2.1   Introduction

In situ bioremediation processes will be most effective when the emulsified oil is uniformly distributed throughout the treatment zone. Figure 2.1 shows a hypothetical injection grid for treatment of a source area. The injection system consists of five rows of injection wells. Alternating rows are offset with the objective of improving emulsified oil distribution. The shaded circles are intended to represent the target contact zone around each injection well. From this very simple illustration, it is obvious that some areas will remain uncontacted, even if emulsion could be perfectly distributed throughout the target zone. Coverage could be increased by increasing the size of the circles. However, this would result in overlap between some adjoining circles.
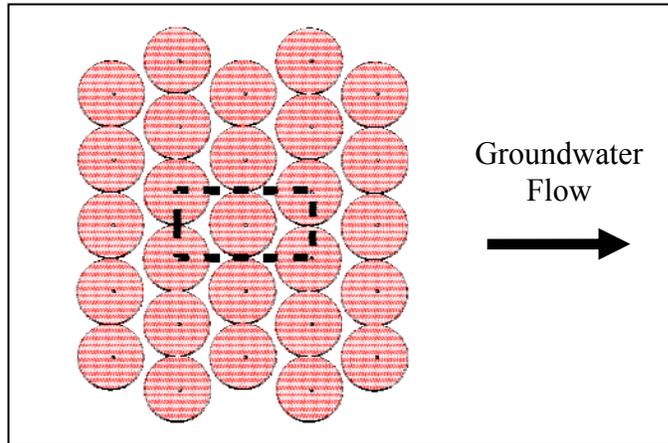
Figure 2.1. Hypothetical Injection Grid Showing Model Domain Subarea.

In real aquifers, emulsion is not uniformly distributed in a perfect circle around each injection well. Simultaneous injection of multiple wells will result in stagnation zones, diverting water and emulsion away from some areas. Aquifer heterogeneity will cause groundwater (and emulsion) to preferentially migrate through higher permeability zones, leaving lower permeability zones uncontacted.

In this project, a series of numerical model simulations were conducted to evaluate the effect of important design parameters on contact efficiency. Model simulations were performed using the numerical modeling packages MODFLOW (McDonald and Harbaugh, 1988) and RT3D (Clement, 1997). Oil droplet capture by the surfaces of the aquifer material was represented by a rate limited Langmuir isotherm. Details of the model setup and validation are presented in Borden et al. (2008). To reduce the computational burden, we have chosen to simulate a subsection of the treatment area shown by the dashed rectangle near the center of Figure 2.1. For a uniform grid, this subsection can be repeated over and over again to simulate the overall treatment area.

2.2 Model Sensitivity Analyses – Area Treatment

2.2.1 *Model Setup and Base Case Conditions*

Figure 2.2 shows an enlarged view of the model domain subsection outlined on Figure 2.1. Aquifer volume contact efficiency (E_V) will be determined for the red shaded rectangular zone between the 1st and 3rd rows of wells at 120 days after the start of emulsion injection. The 120 day period was selected to allow for downgradient transport of oil droplets by the ambient groundwater flow. For the base case, well spacing perpendicular to groundwater flow (S_W) and row spacing along the direction of groundwater flow (S_R) are both 3.0 m. The model domain is 3.25 m by 18.25 m with an effective saturated thickness (Z) of 3 m. A bulk density (ρ_B) of 2 g/cm^3 and effective porosity (n_e) of 0.2 were used in all simulations. In addition to flow induced by the injection wells, constant head boundaries located at the upgradient and downgradient limits of the model result in a background hydraulic gradient through the treatment zone. No flow boundaries are located perpendicular to groundwater flow to simulate a recurring pattern of injection wells. The hydraulic conductivity field was represented as a spatially correlated random field with low, medium and high levels of heterogeneity. Five realizations of the permeability distribution were simulated for each level of heterogeneity. The realizations were generated using the turning bands method (Tompson et al., 1989) with a horizontal correlation length of 2 m and a vertical correlation length of 0.2 m.
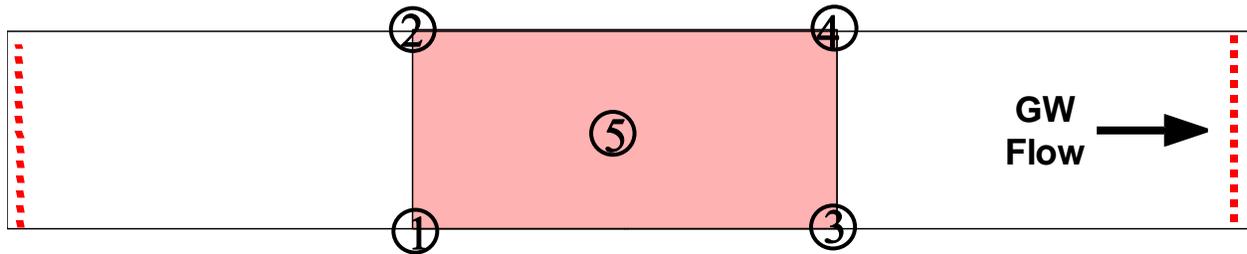
Figure 2.2. Model Domain for Base Case Condition – Area Treatment.

To allow easy comparison between different simulations, the mass of oil injected and volume of fluid injected are presented as dimensionless scaling factors. The volume scaling factor (SF_V) is the ratio of fluid (emulsified oil plus water) injected per well to the pore volume within a Base Treatment Zone around each well or

$$SF_V = \text{Volume fluid injected per well} / (n_e \, BTV)$$

where n_e is the effective porosity. For area treatment, the BTV = $S_W \, S_R \, Z$. Additional details on the model simulations and base case conditions are presented in Borden et al. (2008). The mass scaling factor (SF_M) is the ratio of oil injected per well to the oil required to fill all the attachment sites within the BTV or

$$SF_M = \text{Mass oil injected per well} / (OR_M \, \rho_B \, BTV)$$

where OR_M is the maximum oil retention per unit weight aquifer material.

2.2.2 *Typical Simulation Results – Area Treatment*

Figures 2.3 and 2.4 show the hydraulic conductivity and residual oil distributions in both plan (Fig. 2.3) and longitudinal cross-section (Fig. 2.4) for two representative simulations at 120 days after the start of emulsion injection. Higher permeability is indicated by the darker red and lower permeability is indicated by the lighter pink color. In the residual oil figures, oil treated zones are indicated by the darker red and untreated zones are white. In these simulations, the wells are injected in three steps (wells 1 and 3, wells 2 and 4, then well 5) and the aquifer was assumed to be moderately heterogeneous (permeability realization #2).
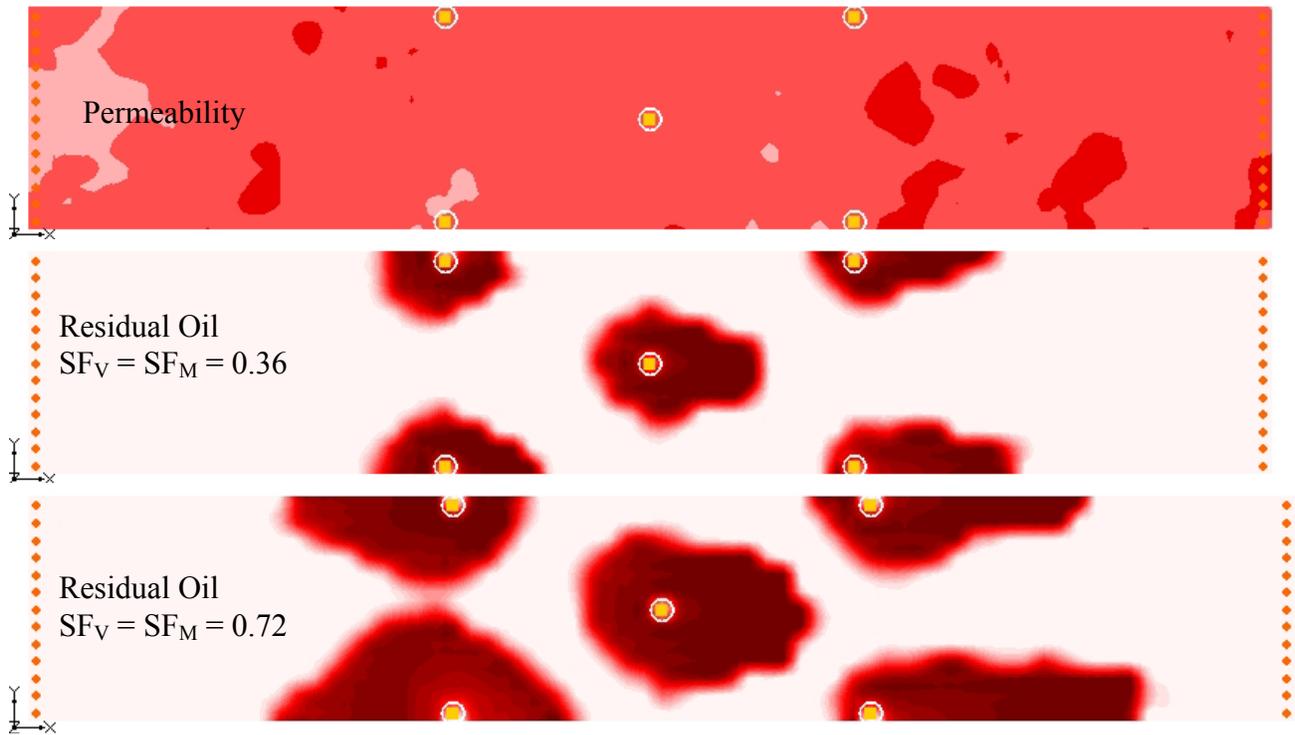
Figure 2.3. Simulated Horizontal Distribution of Hydraulic Conductivity and Residual Oil in Top Layer of Aquifer (see Figure 2.4) **for Moderately Heterogeneous Aquifer** (realization #2)**.**

In plan view (Figure 2.3), the residual oil distribution appears to be primarily controlled by the location of the injection points. As expected, residual oil concentrations are highest immediately adjoining the injection wells. However, the permeability distribution does have some secondary impacts on the residual oil distribution. Injecting additional oil and water ($SF_V = SF_M = 0.72$) enhances oil distribution.

In profile view (Figure 2.4), the residual oil distribution appears to be primarily controlled by the permeability distribution. Oil migrates farthest in the high permeability layers and is much more limited in lower permeability layers. However, the location the injection wells is also very important. Simultaneous injection of wells 2 and 4 (and wells 1 and 3) results in stagnation

zones in the middle of the injection grid between each pair of wells, driving water and oil away from adjoining injection wells. However, once injection ends, the ambient hydraulic gradient carries a portion of the oil downgradient of the injection point resulting in more extensive oil distribution downgradient of the injection wells. Again, increasing the amount of oil and water injected enhances distribution.
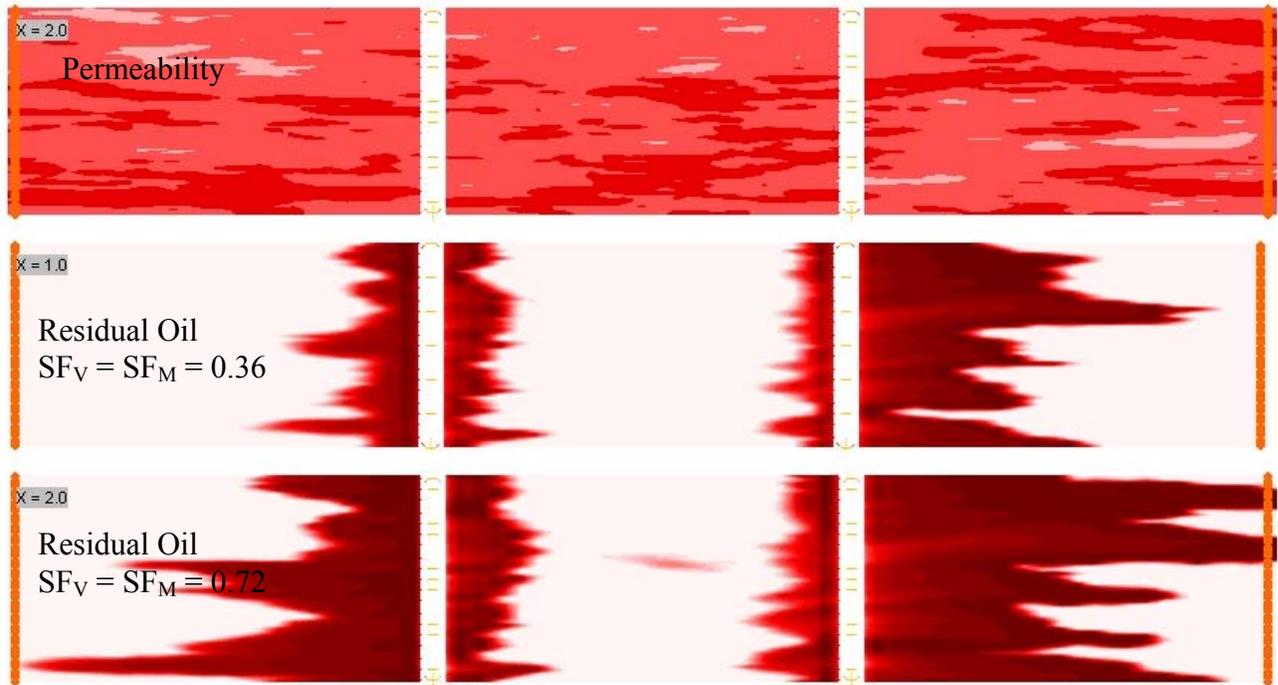
Figure 2.4. Simulated Vertical Distribution of Hydraulic Conductivity and Residual Oil in Last Row of Aquifer (bottom row of Figure 2.3) **for Moderately Heterogeneous Aquifer** (realization #1)**.**

The relatively low contact efficiency for $SF_V = SF_M = 0.36$, is due to: a) the relatively small amount of oil and water injected, and b) the heterogeneous hydraulic conductivity distribution. In subsequent sections, sensitivity analyses will be conducted to examine the effect of each of these parameters on contact efficiency. This information can then be used to generate improved designs with higher contact efficiencies.

2.2.3   *Criteria for Determining Contact Efficiency*

In this work, effective treatment is assumed to occur when the oil retention (OR) following injection is greater than a previously defined critical concentration (OR_C). Results of the model simulations are summarized as a series of performance curves relating the effect of specific design variables on contact efficiency. For area treatments, Aquifer Volume Contact Efficiency (E_V) is used as the primary performance measure where E_V = fraction of treatment zone volume where $OR > OR_C$.

Currently, there is no well established procedure to determine what oil concentration is required for effective treatment. Even very small amounts of oil will initially support anaerobic biodegradation. However, if OR is too low, the oil will be rapidly depleted and long-term performance will be limited.

Figure 2.5 shows the effect of water injection volume on E_V assuming the OR_C is equal to 1%, 5%, 10% and 25% of the maximum oil retention by the aquifer material (OR_M) for sequential injection with $SF_M = 0.36$. These curves were generated by varying the amount of water injected while keeping all other parameters constant (see Borden, 2008, for detailed description). At $SF_V = 0.18$, the volume contact efficiency is 42, 34, 31 and 26% for $OR_C/OR_M = 1, 5, 10$ and 25%, respectively. All the curves shown in Figure 2-5 follow the same general trend, where increasing the injection volume initially results in a significant improvement in contact efficiency. However, further increases in fluid injection result in progressively less benefit. Increasing the injection volume beyond $SF_V = 0.2$ results in a modest improvement in E_V whether OR_C is 1, 5, 10 or 25% of OR_M. This suggests that it may not be necessary to precisely define OR_C since the designer would draw the same general conclusions whether OR_C is 1% or 25% of OR_M.
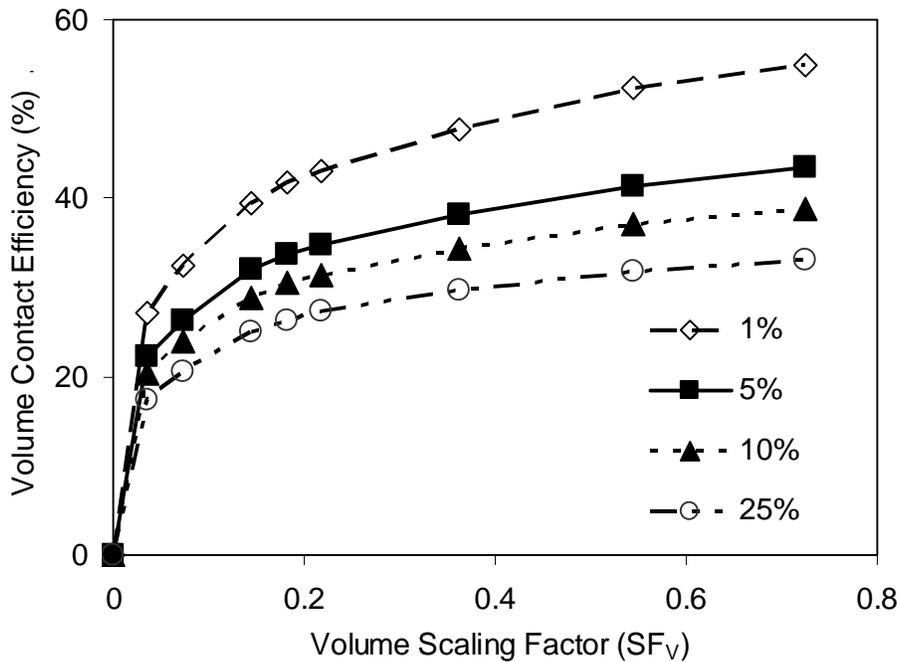
Figure 2.5. Effect of Water Injection Volume on Aquifer Volume Contact Efficiency (E_V) for $OR_C/OR_M = 1, 5, 10$ and 25% at 120 Days (sequential injection with Mass Scaling Factor = 0.36).

All remaining sensitivity analyses presented in this report have assumed $OR_C = 5\%$ of OR_M. For model conditions used in this study (Borden, 2008), $OR_M = 7.0$ mg of oil per g aquifer material. Past operating experience at emulsified oil sites indicates that 5% of this OR_M is sufficient to support anaerobic biodegradation for several years. Readers should recognize that the reported values for contact efficiency would be slightly higher if a less restrictive value of OR_C were used. However, the overall trends for contact efficiency are expected to be similar.

9

2.2.4 *Effect of Injection Sequence – Area Treatment*

A series of simulations were conducted to evaluate how important is the sequencing of the injection process (i.e., concurrent versus sequential injection) for area treatment. For these simulations, three conditions were evaluated:

Simultaneous Injection -	concurrent injection of all wells;
Three Step Injection -	concurrent inject of wells 1 and 3 followed by concurrent injection of wells 2 and 4; and then well 5; and
Sequential Injection -	inject wells well 1, followed by 2, 3, 4, and 5

For each of these conditions, the SF_V was equal to the mass scaling factor (SF_M). As shown in Figure 2.6, contact efficiency increases approximately linearly with volume and mass scaling factor for a moderately heterogeneous aquifer (permeability realization #2). Results for the three different injection sequences were similar indicating that simultaneous injection results in only a small reduction in contact efficiency.

Sequential injection results in the best contact efficiency, but also requires the most time to implement. Given the small difference in contact efficiency between the different injection approaches, the three step injection approach will be used in all subsequent simulations. The three step injection sequence provides results intermediate between simultaneous and sequential injection and should be reasonably representative of a 'typical' injection process.
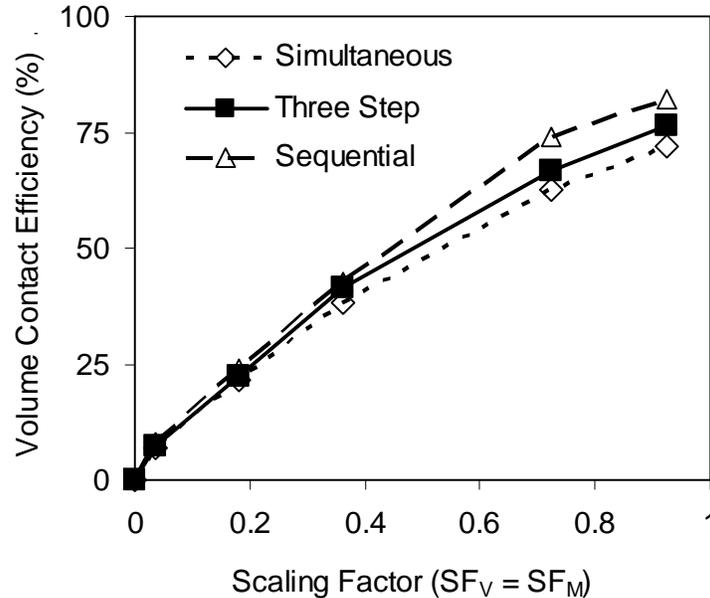
Figure 2.6. Effect of Injection Sequence and Scaling Factor on Volume Contact Efficiency (E_V for OR $\geq$ 0.05 OR_m) at 120 Days for a Moderately Heterogeneous Aquifer (permeability realization #2)**.**

2.2.5 *Effect of Aquifer Heterogeneity – Area Treatment*

Figures 2.7a and 2.7b show the simulated contact efficiency for different hydraulic conductivity realizations for $SF_V = 0.073$ and $SF_V = 0.18$. Simulation results are presented for each of the five low, moderate and high heterogeneity realizations. While there are significant variations between the different realizations, overall, the results are reasonably consistent. In all cases, injecting additional fluid (increasing SF_V from 0.073 to 0.18) improves contact efficiency. As expected, contact efficiencies are highest for the low heterogeneity simulations, and then decrease as the level of heterogeneity increases.

Based on the results presented in Figures 2.7a and 2.7b, medium heterogeneity realization #2 (MID-2) was selected as reasonably representative of contact efficiencies that might be achieved or a range of aquifer conditions. Average contact efficiencies may be slightly lower for high heterogeneity aquifers and somewhat higher for low heterogeneity aquifers.
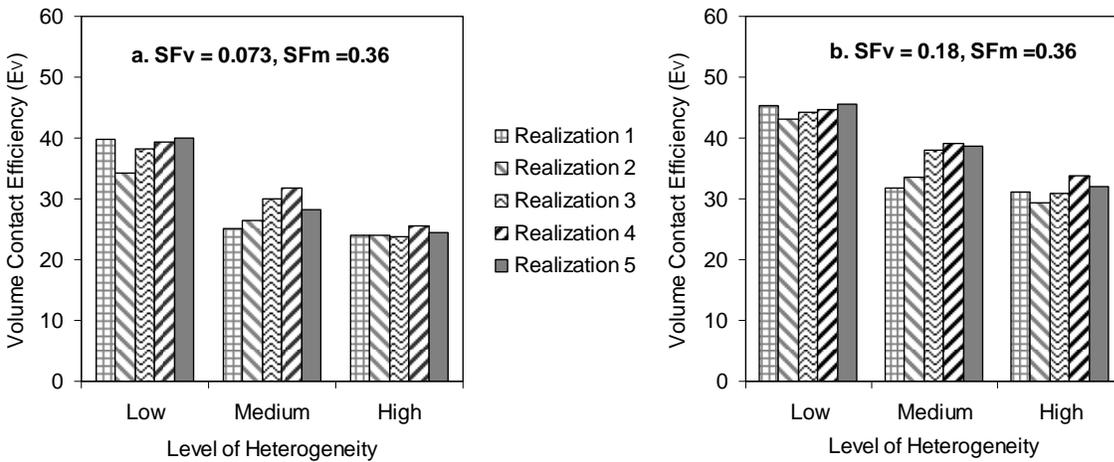
Figure 2.7. Effect of Heterogeneity Realization on Volume Contact Efficiency (E_V) for Low, Moderate and High Heterogeneity Aquifers.

2.2.6 *Effect of Oil Mass and Fluid Volume – Area Treatment*

Sensitivity analyses were also conducted to examine the effect of injection fluid volume and emulsified oil injection mass on contact efficiency. Figure 2.8 shows the effect of the SF_V (ratio of fluid injected to the target treatment zone pore volume) on volume contact efficiency (E_V) for SF_M=0.36. When mass of injected oil is held constant (SF_M=0.36), E_V increases rapidly as SF_V increases from 0 to 0.1. However, additional increases in SF_V provide progressively less benefit, with only a gradual increase in E_V as SF_V is increased from 0.2 to 0.7. Qualitatively similar results were obtained with different values of SF_M. However, the maximum achievable E_V increased with increasing values of SF_M. This indicates that as the amount of oil injected increases, there are benefits to injecting additional fluid to transport the oil.
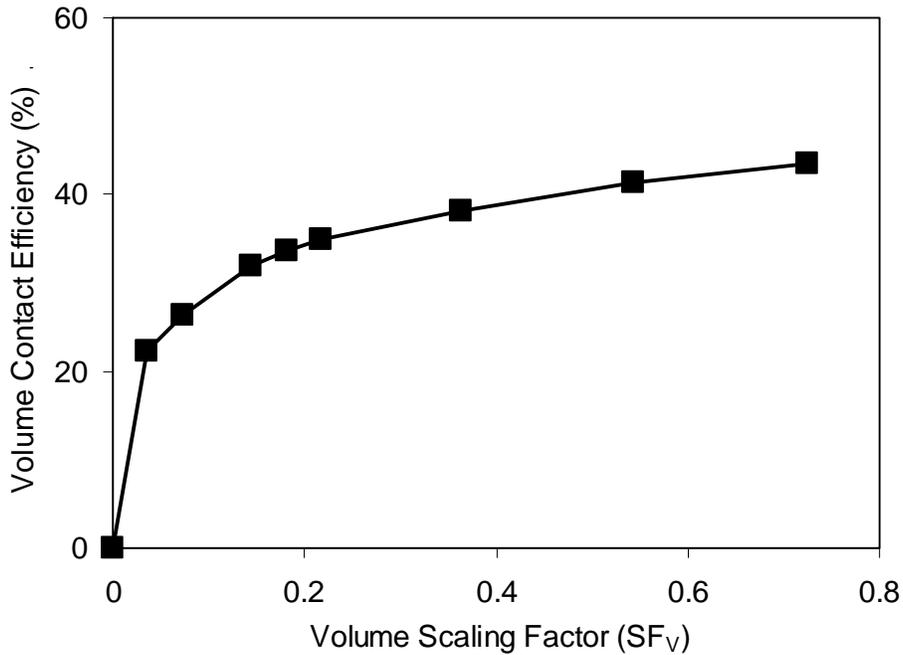
Figure 2.8. Effect of Volume Scaling Factor (SF_V) on Volume Contact Efficiency (E_V for C $\geq$ 0.05 OR$_M$) for a Moderately Heterogeneous Aquifer at 120 days (Mass Scaling Factor = 0.36)**.**

Figure 2.9 shows the effect of the SF_M (ratio of oil injected to the oil required to saturate the BTV) on E_V for $SF_V = 0.18$. When the volume of injected fluid is held constant ($SF_V = 0.18$), E_V increases rapidly as SF_V increases from 0 to 0.4. However, additional increases in SF_M provide progressively less benefit. Qualitatively similar results were obtained with different values of SF_V. However, the maximum achievable E_V increased with increasing values of SF_V. This indicates that as the amount of fluid injected increases, there are benefits to injecting additional oil.
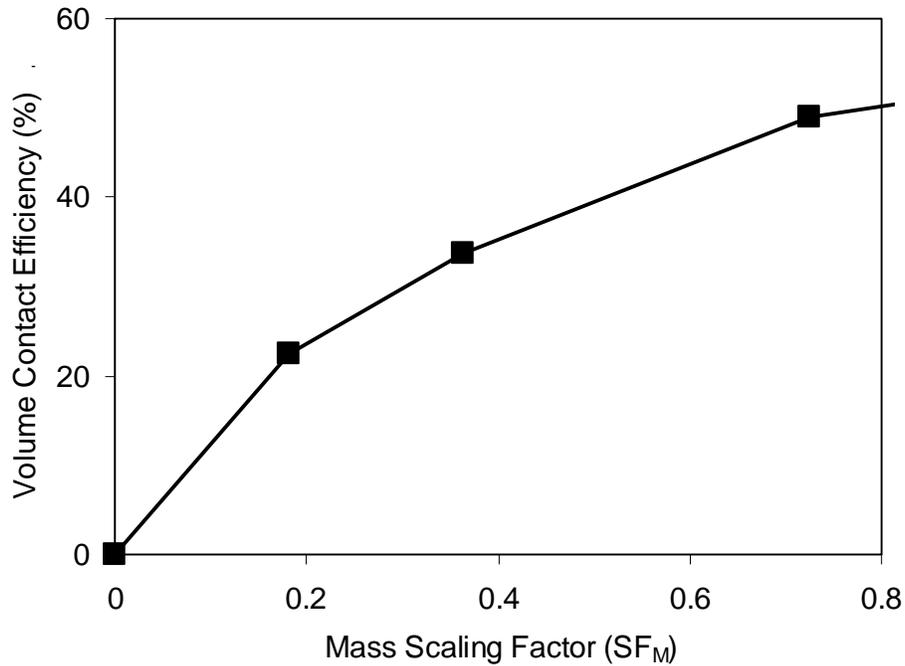
Figure 2.9. Effect of Mass Scaling Factor (SF_M) on Volume Contact Efficiency (E_V for $C \geq$ $0.05\ OR_M$) **for Sequential Injection of a Moderately Heterogeneous Aquifer at 120 Days.**

2.2.7 *Injection Row Spacing – Area Treatment*

In the simulation results presented so far, the spacing between rows of injection wells was approximately equal to the spacing of wells within a row. Figure 2.10 shows the effect of eliminating the center injection well (#5) on contact efficiency for different values of SF_V. Eliminating well 5 is equivalent to making the row spacing approximately twice the well spacing within a row, reducing the total number of wells by a factor of 2. The mass and volume injected per well were adjusted so the total mass of oil and volume of fluid injected within the target treatment zone remained constant.

When the total amount of injected fluid is small ($SF_V < 0.2$), increasing the row spacing has only a modest impact on contact efficiency. However, for larger values of SF_V, E_V is reduced by 5 to 10% by doubling the row spacing (e.g., eliminating the center injection well).

13
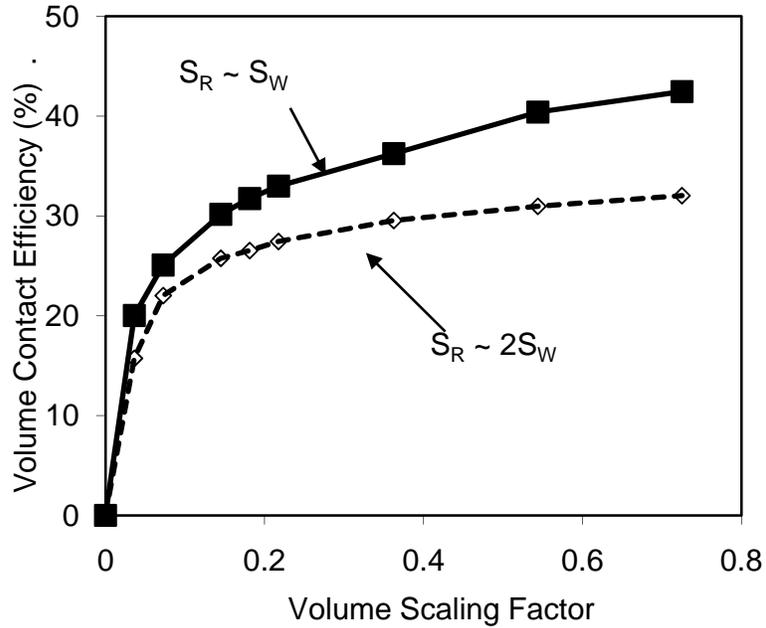
Figure 2.10. Effect of Row Spacing and Fluid Injection Volume on Volume Contact Efficiency (E_V for OR ≥ 0.05 OR$_M$) **for a Moderately Heterogeneous Aquifer.**

2.2.8   *Contact Efficiency – Area Treatment*

The results presented in previous sections indicate there is a complex relationship between SF$_M$ and SF$_V$ on E$_V$. Multiple linear regression analyses were performed to develop relationships between SF$_M$, SF$_V$ and E$_V$ for a row-to-well spacings of approximately 1:1 and 2:1. Three dimensional surfaces describing these relationships are shown in Figures 2.11 and 2.12. The highest contact efficiencies are obtained for large values of SF$_M$ and SF$_V$.

14
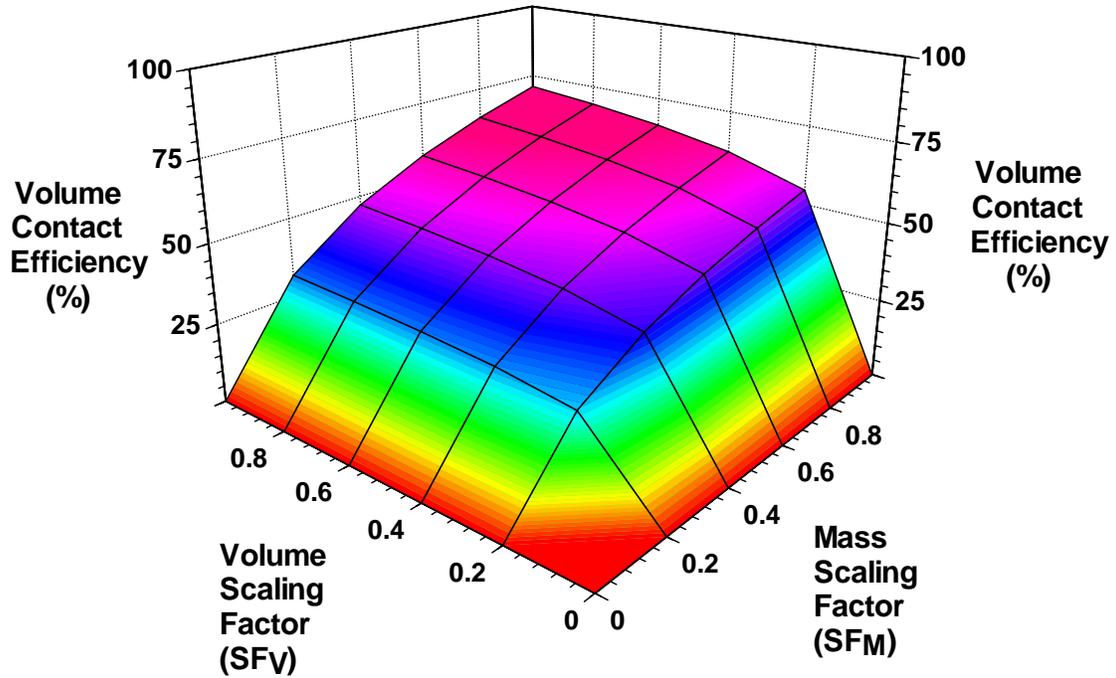
Figure 2.11. Effect of Volume Scaling Factor (SF$_V$) and Mass Scaling Factor (SF$_M$) on Volume Contact Efficiency (E_V for OR $\geq$ 0.05 OR$_M$) **for a Moderately Heterogeneous Aquifer with Well Spacing Approximately Equal to Row Spacing.**
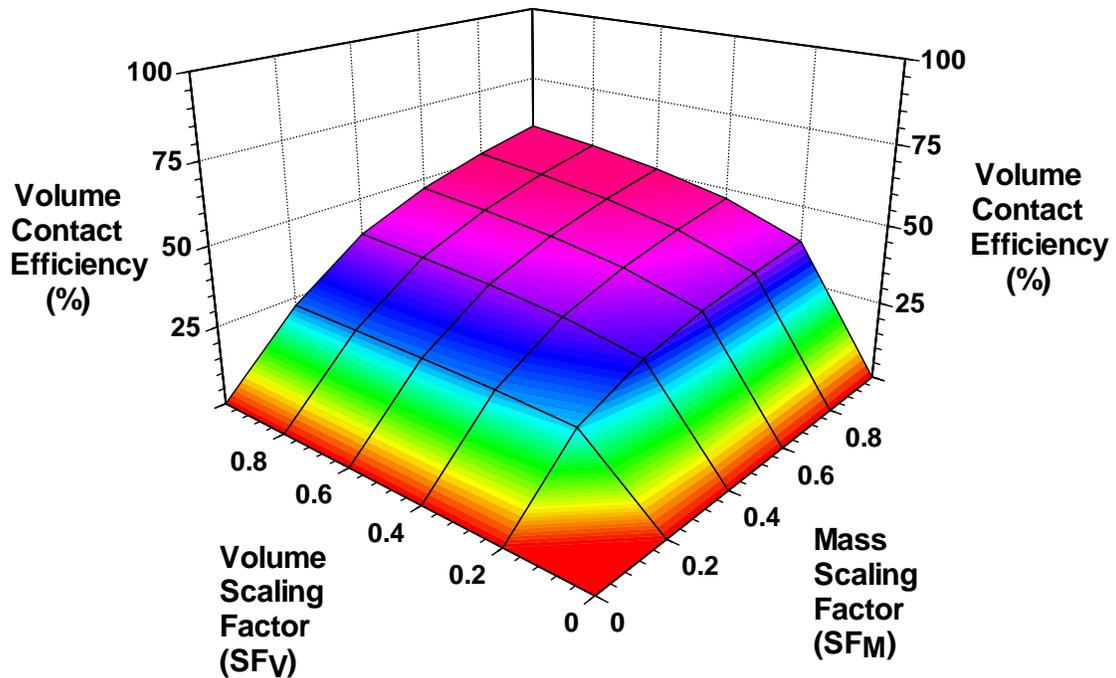
Figure 2.12 Effect of Volume Scaling Factor (SF$_V$) and Mass Scaling Factor (SF$_M$) on Volume Contact Efficiency (E_V for OR $\geq$ 0.05 OR$_M$) **for a Moderately Heterogeneous Aquifer with Row Spacing Equal to Approximately Two Times Well Spacing.**

2.2.9 *Area Treatment Contact Efficiency – Summary of Results*

The sensitivity results presented in this section examine the effect of injection sequence, SF_V, SF_M, and row spacing on E_V. Major results of this work are summarized below:
- When mass of injected oil is held constant (SF_M=0.36), E_V increases rapidly as SF_V increases from 0 to 0.1. However, additional increases in SF_V provide progressively less benefit, with only a gradual increase in E_V as SF_V is increased from 0.2 to 0.7.
- When the volume of injected fluid is held constant (SF_V =0.18), E_V increases rapidly as SF_V increases from 0 to 0.4. However, additional increases in SF_M provide progressively less benefit.
- When the $SF_V = SF_M$, E_V increases approximately linearly with scaling factor.
- The best contact efficiency is obtained for sequential injection. However, injection sequencing does not have a large impact on contact efficiency.
- Increasing the row spacing (S_R) to approximately double the well spacing (S_W) will significantly reduce contact efficiency.

Overall, the model simulation results indicate that it is relatively easy to achieve a volume contact efficiency of 50 to 60% for a moderately heterogeneous aquifer. However, it becomes progressively more difficult to achieve higher contact efficiencies and it may not be practical to achieve contact efficiencies above 75% in heterogeneous aquifers.

Readers are reminded that contact efficiency is **NOT** the same as treatment efficiency. When emulsified oil is injected into the subsurface, it primarily migrates through and contacts the higher permeability (K) zones. Contaminants present in these higher K zones will come in direct contact with the oil and should biodegrade relatively rapidly. Once contaminants in the higher K zones are degraded, contaminants will begin to slowly diffuse out of the lower K zones and will be treated. However, diffusion out of these lower K zones is a slow process, requiring years or even decades to occur. One of the major advantages of the emulsified oil process is that the edible oils biodegrade slowly, supporting biodegradation for years. As long as significant oil remains in the higher K zones, contaminant concentrations in monitor wells will remain low and the flux of contaminants transported down gradient will remain low. In addition, diffusion of contaminants out of the lower K zones will be enhanced and the rate of source area treatment will be increased. Under these conditions, a volume contact efficiency (E_V) of 30-40% may provide good treatment and increasing E_V to 50% may provide little real benefit. Unfortunately, we do not currently have any way to quantitatively relate volume contact efficiency to cleanup rate.

The time required for contaminants to diffuse out of the low K zones will be a function of the aquifer porosity and permeability, dimensions of the low K body, and sorption of contaminants to the aquifer material. At this time, there is no reliable method to estimate how long before the low K zones are 'fully' treated. Currently, the only basis for determining how long before a source area is 'fully' treated is prior experience at similar sites.

2.3   Model Sensitivity Analyses – *Barriers*

2.3.1   *Model Setup and Base Case Simulation Results -- Barriers*

Numerical model simulations where conducted to evaluate the effect of different design variables on contact efficiency in permeable reactive barriers (barriers) formed using emulsified oil. However for barriers, Flow Contact Efficiency (E_F) is used as the primary performance measure where E_F = fraction of groundwater flow through the barrier that comes in contact with aquifer material where $OR > OR_C$. As for area treatment, OR_C is assumed equal to 5% of the maximum oil retention capacity of the aquifer material. Readers should note that flow contact efficiency may be greater than volume contact efficiency because the oil preferentially flows through and contacts the high K zones. Since these high K zones also transport most of the water, flow contact efficiency is often greater than volume contact efficiency. However, E_F does not include any contact time criteria so groundwater is considered 'contacted' if it flows through a model cell where $OR > OR_C$, even if the contact time is only a few minutes.

The definition of the Base Treatment Volume is **NOT** the same as that used for area treatment. For barrier treatment, the BTV is equal to the volume of a cylinder with a diameter equal to the well spacing or $BTV = \frac{1}{4}\pi\, S_W^2\, Z$.

Figure 2.13 shows the permeability and residual oil distributions in a cross-section immediately downgradient of injection wells 1 and 2 (Figure 2.1) at 120 days after the start of emulsion injection. The injection wells are located at the left and right edges of each figure. Higher permeability is indicated by the darker red and lower permeability is indicated by the lighter pink color. In the residual oil figures, oil treated zones are indicated by the darker red and untreated zones are white. In this simulation, the wells are injected sequentially and the aquifer was assumed to be moderately heterogeneous (permeability realization #2).
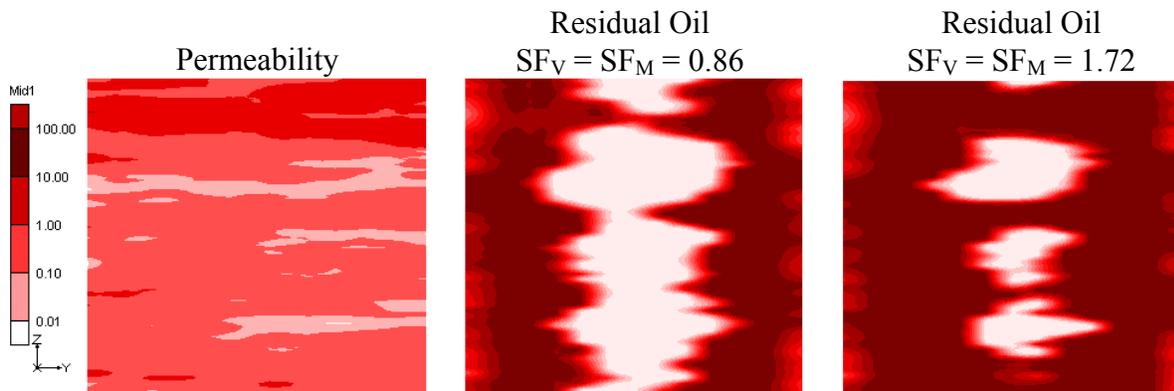
Figure 2.13. Simulated Distribution of Hydraulic Conductivity and Residual Oil in Cross-section Immediately Downgradient of Wells 1 and 2 for Moderately Heterogeneous Aquifer (realization #2)**.**

As expected, residual oil concentrations are highest near the injection wells in Figure 2.13 and decrease with distance. For $SF_V = SF_M = 0.86$, approximately two-thirds of the cross-section between the wells is contacted with oil while approximately one-third remains uncontacted.

However, the flow contact efficiency (E_F) for this simulation is 77%. E_F is somewhat higher than the fraction contacted because the oil emulsion is preferentially transported through the higher K layers. Injecting additional oil and water ($SF_V = SF_M = 1.72$) increases the E_F to over 95%. While there are some relatively large 'white' areas between the two injection wells, these zones have a lower permeability and so only transport a small fraction of the total groundwater flow.

2.3.2   *Effect of Injection Sequence – Barriers*

Results from prior simulations for area treatment were analyzed to evaluate the effect of injection sequence on flow contact efficiency. For this analysis, only two conditions were evaluated:

Simultaneous Injection -   concurrent injection of all wells;
Sequential Injection -   concurrent inject of wells 1 and 3 followed by concurrent injection of wells 2 and 4.

For each of these conditions, the amount of oil injected was held constant at the base condition ($SF_M = 1.0$) and the volume of fluid injected was varied.

Figure 2.14 shows the effect of injection sequencing and SF_V on E_F for a moderately heterogeneous aquifer (permeability realization #2). For small injection volumes, the oil emulsion does not travel far from the injection wells and injection sequencing has little effect. However, as the injection volume increases, well interference effects become more important. For $SF_V = 0.86$, sequential injection results in an 11% increase in flow contact efficiency from 77% to 88%. This is in contrast to area treatment (Figure 2.6), where sequential injection sequence had only a modest impact on volume contact efficiency.
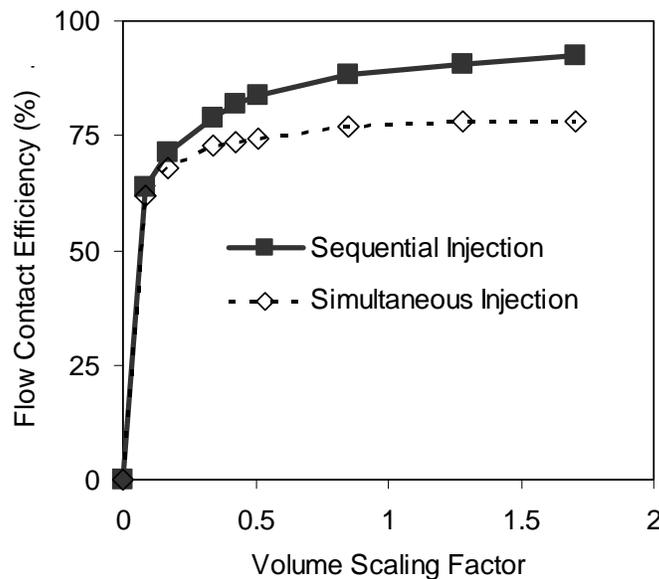
Figure 2.14. Effect of Injection Sequence and Fluid Injection Volume on Flow Contact Efficiency (E_F for OR $\geq$ 0.05 OR_M) at 120 days for a Moderately Heterogeneous Aquifer (realization #2, Mass Scaling Factor = 0.86)**.**

Sequential injection resulted in significantly improved Flow contact efficiency (E_F) compared to simultaneous injection. As a consequence, sequential injection will be used in all further simulations.

2.3.3 *Effect of Oil Mass and Fluid Volume – Barriers*

Sensitivity analyses were also conducted to examine the effect of amount of fluid volume injected and emulsified oil mass injected on flow contact efficiency. Similar to area treatment, a complex relationship was observed where increases in both SF_M and SF_V resulted in improvements in the E_F. Figure 2.15 shows the three dimensional surface describing this relationship. The highest contact efficiencies are obtained for large values of SF_M and SF_V.
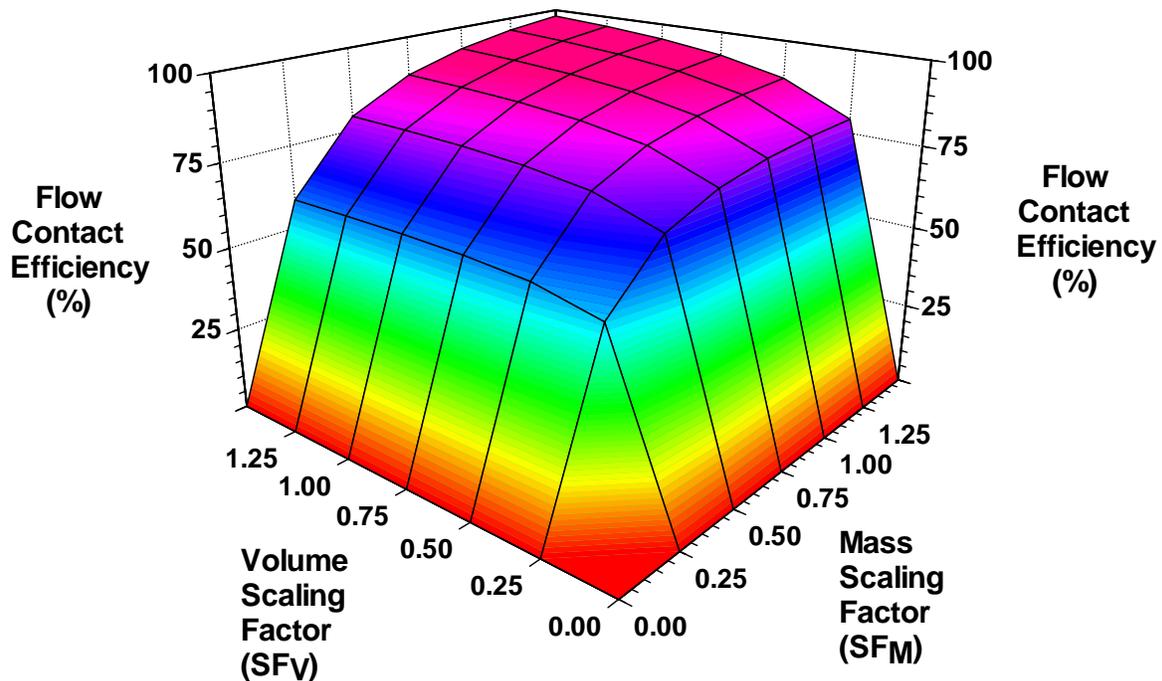
Figure 2.15. Effect of Volume Scaling Factor (SF_V) and Mass Scaling Factor (SF_M) on Flow Contact Efficiency (E_F for OR $\geq$ 0.05 OR$_M$) for a Moderately Heterogeneous Aquifer (realization #2)**.**

2.3.4 *Barrier Contact Efficiency – Summary of Results*

The sensitivity results presented in this section examine the effect of injection sequence, Volume Scaling Factor (SF_V), and Mass Scaling Factor (SF_M) on E_V. Major results of this work are summarized below:

- For small injection volumes ($SF_V < 0.2$), the oil emulsion does not travel far from the injection wells and injection sequencing has little effect. However, as the injection volume increases, well interference effects become more important. To maximize E_V when $SF_V > 0.4$, adjoining wells should not be injected simultaneously.

19

- For $SF_V = 1.0$ and $SF_M = 1.0$, it should be possible to achieve a flow contact efficiency of greater than 80%. By injecting additional water and oil, it should be possible to achieve high flow contact efficiencies in barriers. However, the amount of oil and water injected may be significantly higher than current practice.

As discussed in the previous section, flow contact efficiency is not the same as treatment efficiency. However, contact times in barriers are much shorter than in area treatments and molecular diffusion will be much less significant. Therefore, for barriers it is important to achieve a high flow contact efficiency.

SECTION 3
DESIGN PROCESS

3.1   Overview

A general conceptual design for the distribution of the emulsion should be developed after defining the remediation objectives and conceptual site model. This design will consist of determining the general layout of emulsion injection system and will take into account additional planning considerations including remediation objectives.

3.1.1   *Decide on Injection Well Layout*

Several treatment approaches are commonly considered for application of emulsified oils. The most common approaches are source area treatment and use of emulsified oil barriers. A schematic of the two approaches is shown in Figure 3.1. In choosing a treatment approach for a given site, it is important to understand the overall objectives of the project. The objectives may be to reduce contaminant concentrations below the maximum contaminant levels (MCLs), to reduce mass flux as part of an overall risk reduction approach, or to limit plume migration.
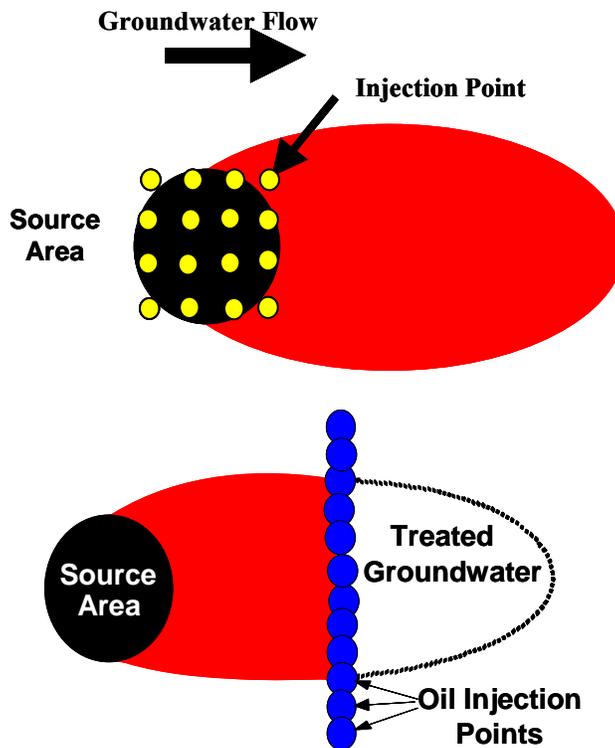
Figure 3.1. Using Emulsions to Treat Contaminated Groundwater in: (a) source areas and (b) barriers.

3.1.2 *Select Trial Well Spacing*

When planning an injection project, designers need to consider the effect of injection point spacing on cost and contact efficiency. The effect of injection point spacing on cost is primarily a trade off between well installation costs and labor costs. Wider spacing of the injection points reduces injection well installation costs, but increases the time/labor required for injection. The well installation costs are affected by the geology and depth to groundwater, while the labor costs are determined by the time required for fluid injection which is largely a function of the aquifer permeability. If the aquifer has a high permeability, fluid injection will be easier and will take less time. Often, multiple wells can be injected simultaneously to reduce the time required to complete the injections. Injection tests are often conducted to help estimate injection flow rates and pressures and the approximate time it will take to complete the injections. Well installation and labor costs associated with injection should be evaluated on a site-specific basis to determine the appropriate injection point spacing.

In real aquifers, subsurface heterogeneities will affect the final oil distribution in the subsurface. Permeability differences will cause some zones to be over-treated and some zones to remain untreated. Groundwater flow and dispersion will provide some spreading of aqueous organic carbon increasing the reactive zone.

In this design tool, SF are used to account for a variety of factors on the final oil distribution. As described in Chapter 2, injection well location, sequencing of the injection process, and subsurface heterogeneity all influence the final oil distribution and need to be considered when selecting an appropriate scaling factor for use when designing an injection system.

3.1.3 *Calculate Amount of Emulsified Oil Required*

The primary factor to consider in determining how much emulsified oil to inject is the entrapment of oil droplets by aquifer material. The amount of emulsified oil required will be a function of: a) maximum amount of oil retained per mass aquifer material; b) treatment zone dimensions; and c) Mass Scaling Factor (SF_M) required to achieve a target contact efficiency. Increasing the SF_M will increase the expected contact efficiency, but will also increase material costs. Appendix 1 describes a standard test procedure for estimating the maximum amount of oil retained per mass aquifer material.

3.1.4 *Calculate Amount of Fluid Required*

Emulsions are transported in the subsurface by flowing groundwater. Consequently, water must be injected to transport the oil droplets throughout the target treatment zone. Common procedures used include: a) injecting a concentrated emulsion followed by chase water to distribute the oil droplets; b) continuous injection of a more dilute emulsion; and c) recirculation of emulsion through the treatment zone. The total amount of fluid (oil and water combined) required will be a function of: a) effective porosity (n_e) of the aquifer material; b) treatment zone dimensions; and c) Volume Scaling Factor (SF_V) required to achieve a target contact efficiency. Increasing the SF_V will increase the expected contact efficiency, but will also increase the time and labor associated with fluid injection.

3.1.5 *Estimate the Effective Treatment Life*

The theoretical life of a single emulsion injection (T) will be determined by the mass of oil injected and the oil consumption rate where

$$T = \text{mass oil injected (g) / oil consumption rate (g/yr)}$$

The oil consumption rate is calculated as the mass of oil biodegraded per liter of groundwater times the groundwater flow rate through the barrier. The amount of oil biodegraded is primarily controlled by the concentration of pollutants and background electron acceptors (e.g., oxygen, nitrate, sulfate) entering the barrier and the amount of dissolved organic carbon and methane released by the barrier. Appendix 2 provides detailed background on the procedure used to calculate oil consumption. Additional information on calculating oil consumption is presented in Solutions-IES (2006) and AFCEE (2007).

Figure 3.2 illustrates a typical relationship between substrate consumption and pollutant treatment efficiency in an emulsified oil barrier. Field monitoring data indicate that treatment efficiency is fairly constant when excess oil is present. However, as the oil begins to be depleted, treatment efficiency will gradually decline. In the design tool, the decline in barrier treatment efficiency is accounted for using a substrate scaling factor (SF_S) where SF_S is equal to the fraction of oil consumed when treatment declines below acceptable levels. Past experience suggests that treatment efficiency will drop significantly once 30 to 60% of the injected oil has been consumed (Borden, 2007b; Solutions-IES, 2008).
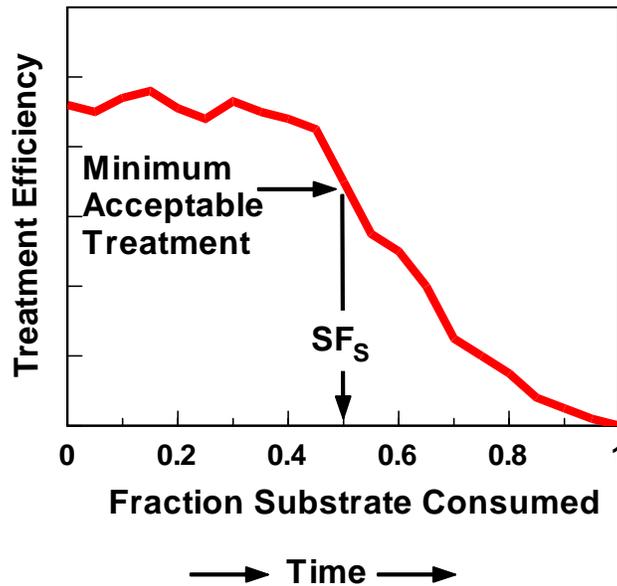
Figure 3.2. Relationship Between Fraction of Substrate Consumed and Treatment Efficiency for an Emulsified Oil Barrier.

Reinjection Interval (RI) is calculated as:

$$RI = T * SF_S$$

Little is known about the decline in area treatment performance over time. When treating source areas, the contaminant biodegradation rate is often limited by slow mass transfer rates. In these cases, maintaining a high biodegradation rate may be less critical and higher values of SF_S maybe acceptable. However, designers should never use a SF_S value greater than the theoretical maximum of 1.

In some cases, the estimation procedure presented above results in an unreasonably large RI. In these cases, designers may wish to specify a maximum allowable RI.

3.1.6 *Repeat Process for Alternate Well Spacings*

The previous steps are repeated for incremental increases in well spacing. Once this is accomplished, a graph can be generated showing the optimal well spacing. Figure 3.3 demonstrates how the well installation, injection labor, and substrate costs vary with different well spacings.
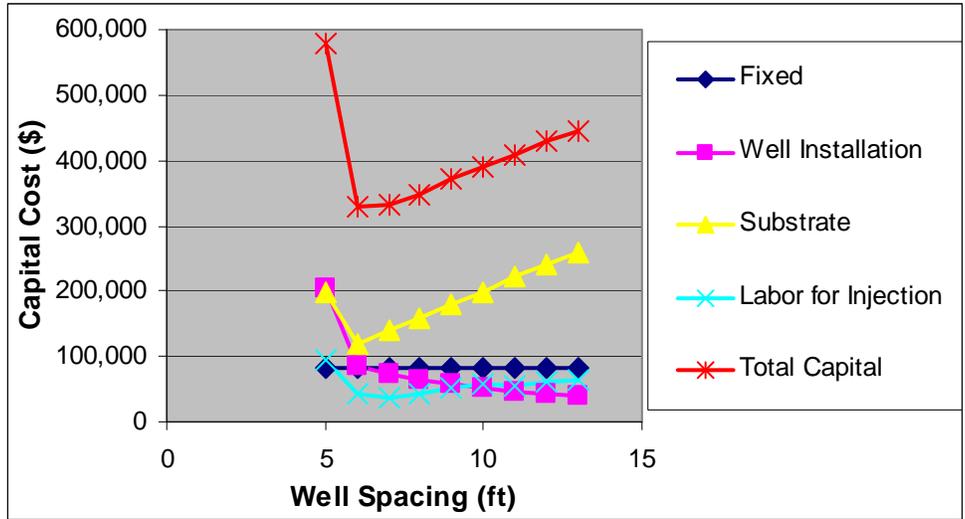
Figure 3.3. Example Cost Analysis for a Barrier with Various Injection Well Spacings.

In this example, a well spacing of 5 ft provides the lowest total installation and injection costs. However, designers may wish to use an alternative well spacing based on site specific constraints and/or personal experience.

3.1.7 Life Cycle Cost Analysis

After looking at the capital cost analysis it is necessary to determine if multiple reinjections over the life of the design changes the optimum well spacing from the capital cost analysis. Figure 3.4 shows how well spacing affects the design life net present value (NPV).
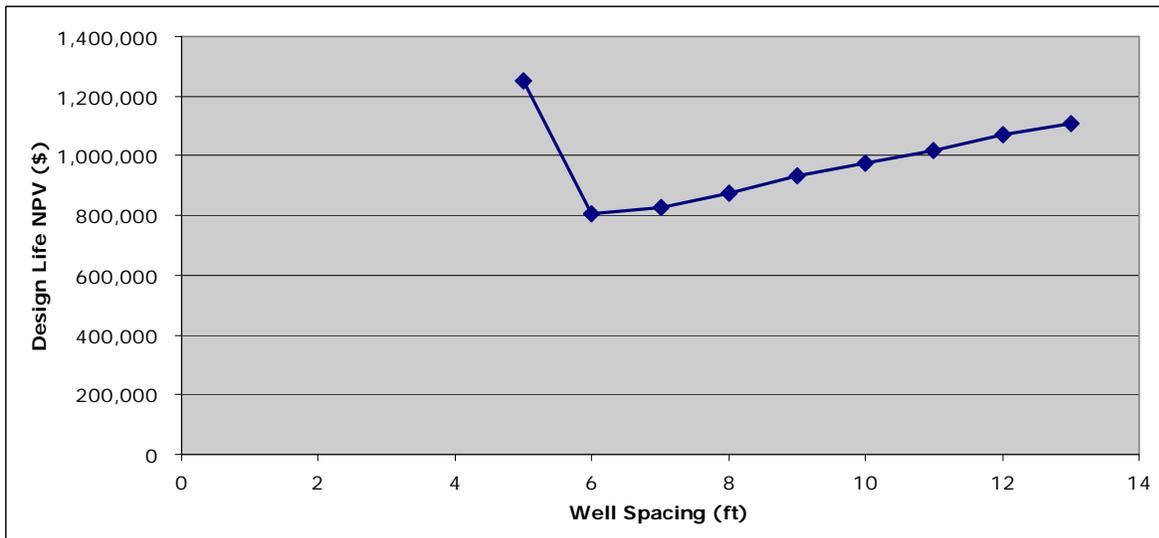
Figure 3.4. Example Life Cycle Analysis for a Barrier with Various Injection Well Spacings.

This example shows that a well spacing of 6 ft has the lowest design life net present value, but a well spacing of 7 is very similar. However, when comparing Figures 3.2 and 3.3 it is evident that the optimum well spacing for this design is 6 ft as it provides the lowest capital and life cycle cost.

3.2 Design Tool Flow Chart

A flow chart of the design process is shown in Figure 3.5.
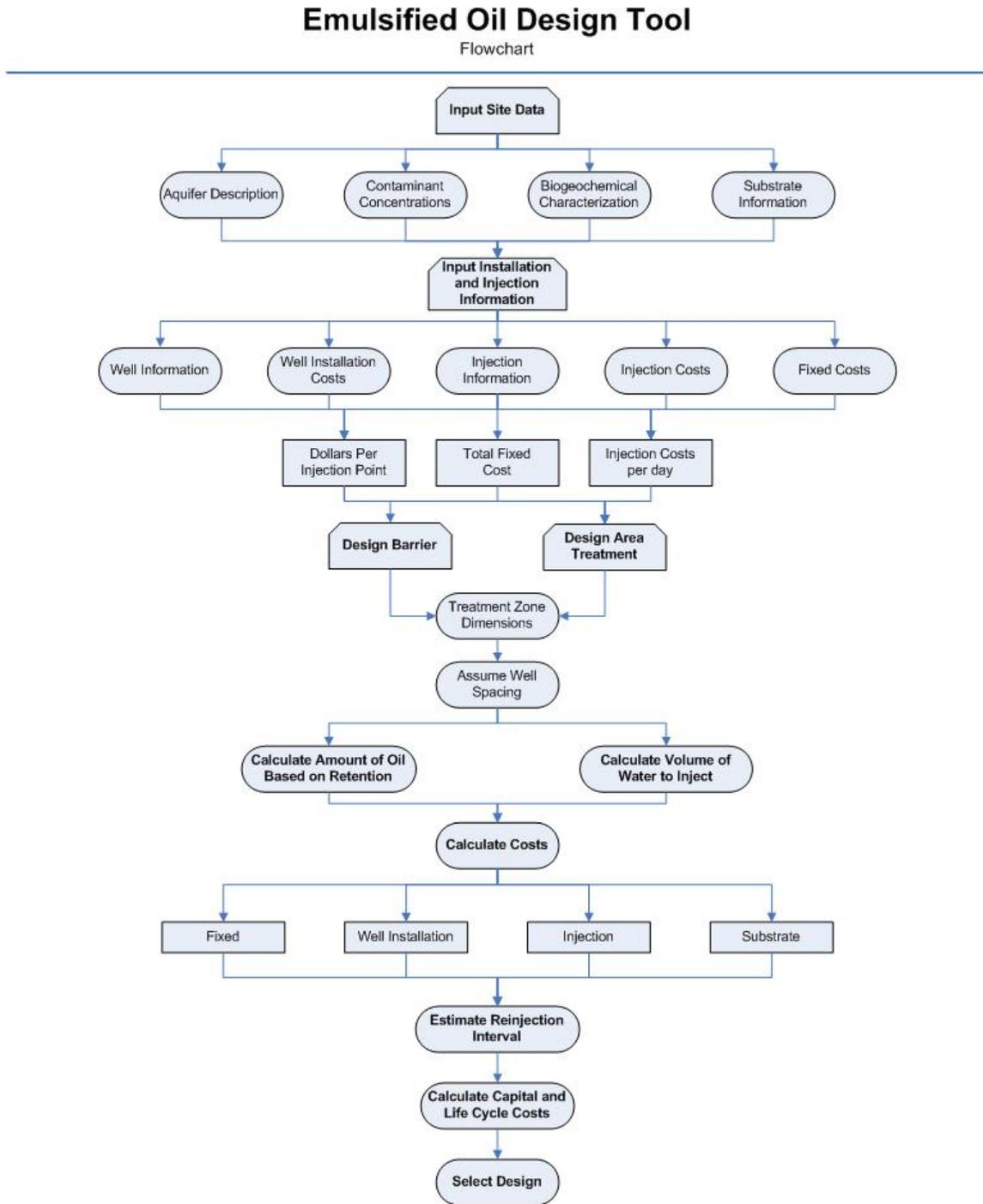
Figure 3.5. Flow Chart of the Design Process for Distributing Emulsified Oil.

SECTION 4
DETAILED DESCRIPTION OF THE DESIGN TOOL

4.1   Overview

This tool is intended to assist engineers with the design of systems for distributing emulsified oil for *in situ* enhanced AB of groundwater contaminants in barrier and area treatments. The design tool consists of several worksheets broken into four sections entitled: Site Data, Installation and Injection, Barrier Treatment, and Area Treatment. Within each section, there are several worksheets for data entry and design calculations. Using the Design Tool Table of Contents, users may easily move between worksheets.

For the design tool to work properly all worksheets within the *Site Data* section and at least one of the three methods in the *Installation and Injection* section must be filled out. Input cells are white and outlined in red, and non-input cells are shaded light gray. There are a few pages that have light yellow cells. These cells are not used in any calculations, but are provided for the user to include additional information for future reference. Yellow cells may be left blank.

4.2   Site Data – Aquifer Description

4.2.1   *General Description*

Information about hydraulic and soil characteristics is entered on this page. The characteristics are used in determining the theoretical injection rate as well as calculating injection volumes of water and substrate.

4.2.2   *Definitions*

  1. Site Information
  a, b, c. Name, description, and location: These are used to identify and describe the project. The titles show up again in the *Summary of Design* page.

  2. Hydraulic Characteristics
  a, b, c. Depth to water table and depth to top and bottom of injection zone: The depth to water table is used in calculating the theoretical estimate of injection rate per well. The depth to top and bottom of injection zone are used to determine the interval of the injection well screens (i.e., the screened thickness). The screened thickness is used to determine the thickness of the treatment zone and the volume of water to be treated.
  d, e, f, g. Hydraulic gradient, hydraulic conductivity, and porosity (total and effective): These data are used to calculate the seepage velocity (h) and groundwater flux through the treatment zone. Typical values of effective porosity are presented in Table 4.1.

3. Soil Characteristics

a. Description of soil lithology (optional): Space is provided to enter additional information for future reference.

b. Bulk density: Used to determine the amount of emulsified oil required based on maximum oil retention.

c. Maximum oil retention by aquifer material: Used to determine the amount of emulsified oil required. This value has a critical impact on cost and treatment performance. Some example values are provided in Table 4.2.

4.2.3 *Additional Information*

Effective Porosity:

Table 4.1. Typical Values for Dry Bulk Density, Total Porosity and Effective Porosity of Aquifer Materials.

Aquifer Matrix	Dry Bulk Density (g/cm^3)	Total Porosity	Effective Porosity
Clay	1.00-2.40	0.34-0.60	0.01-0.2
Peat	--	--	0.3-0.5
Glacial Sediments	1.15-2.10	--	0.05-0.2
Sandy Clay	--	--	0.03-0.2
Silt	--	0.34-0.61	0.01-0.3
Loess	0.75-1.60	--	0.15-0.35
Fine Sand	1.37-1.81	0.26-0.53	0.1-0.3
Medium Sand	1.37-1.81	--	0.15-0.3
Coarse Sand	1.37-1.81	0.31-0.46	0.2-0.35
Gravely Sand	1.37-1.81	--	0.2-0.35
Fine Gravel	1.36-2.19	0.25-0.38	0.2-0.35
Medium Gravel	1.36-2.19	--	0.15-0.25
Coarse Gravel	1.36-2.19	0.24-0.36	0.1-0.25
Sandstone	1.60-2.68	0.05-0.30	0.1-0.4
Siltstone	--	0.21-0.41	0.01-0.35
Shale	1.54-3.17	0.0-0.10	--
Limestone	1.74-2.79	0.0-50.0	0.01-0.24
Granite	2.24-2.46	--	--
Basalt	2.00-2.70	0.03-0.35	--
Volcanic Tuff	--	--	0.02-0.35

From: AFCEE, 1995.

Maximum Oil Retention by Aquifer Material:

For effective treatment, oil emulsions must be distributed throughout the treatment zone. However, as emulsions migrate through the aquifer pore spaces, a significant amount is retained. The small oil droplets coat the surfaces of the aquifer material, typically retaining a maximum of

between 0.0001 and 0.01 g of oil per g of aquifer material. Appendix 1 describes a standard test procedure for estimating the maximum amount of oil retained per mass aquifer material. Some observed values of Maximum Oil Retention are presented in Appendix 1 – Table A1.1.

4.3   Site Data – Contaminant Concentrations

Enhanced AB is applicable to a wide variety of contaminants. Some of these contaminants (e.g., chlorinated solvents, perchlorate, hexavalent chromium) are listed on the spreadsheet. There are also empty spaces for user-entered contaminants (lines **m, n and o**). If the user adds contaminants, the molecular weight and electron equivalents per mole **must** be entered for these contaminants to be included in the calculations. The contaminant data are used to calculate the total electron equivalent demand which is used to estimate the annual substrate consumption rate.

4.4   Site Data – Biogeochemical Characterization

The biogeochemical data are used to determine the electron equivalent demand from background electron acceptors. The total electron equivalent demand is the sum of the electron equivalent demand from contaminants and background electron acceptors and is shown on the bottom of the spreadsheet. This value is an important component of the substrate demand. The soil manganese content (**e**), soil iron content (**g**), pH (**i**), and alkalinity (**j**) are **NOT** used in **ANY** calculations and may be left blank.

4.5   Site Data – Substrates and Reagents

4.5.1   *General Description*

Information on the substrate to be used in the design is entered on this page. The properties of the substrate are used to calculate the electrons released per mole and ultimately the electron equivalents per Kg of raw product. This value is used to determine how much substrate is needed per year.

4.5.2   *Definitions*

  1. Substrate Used in Design:
  a, b. Brand and product ID, and chemical formula (optional): These are used to document what substrate is used in the design.
  h. Percent vegetable oil: This property is used to calculate the electron equivalents per Kg raw product (**i**) and the annual substrate demand. Typical values range from 50% to 70%.
  j. Cost per pound of product including shipping: Bulk costs typically range from $1.30 to $3.00, but a distributor should be contacted to determine actual costs including delivery.
  k. Cost per pound of oil: This is the cost per pound of oil based on the cost per pound of product and the percent vegetable oil in the product. This is the cost that is used in calculating the total substrate cost.

**4.6	Installation and Injection – Injection Through Direct Push Rods**

**4.6.1	*General Description***

Information on the labor and materials required for injection of emulsified oil by direct push technology (DPT) is entered on this page. In this approach, the injection points are installed and emulsion is injected in a single operation where the DPT equipment drives the rod to the desired depth immediately followed by emulsion/water injection. Once injection is complete, the rod is moved to a different depth and the operation is repeated. Once injection is complete, the rod is removed, the borehole grouted, and the DPT equipment is shifted to a new location.

**4.6.2	*Definitions***

1. Injection Information
a, b. Top and bottom of injection screen: These values are carried over from the Aquifer Description page and used to compute the number of injection intervals (**d**).
c. Length of injection screen: The injection screen length specifies the vertical injection point spacing.
e, f. Injection pressure and injection rate: The injection flow rate is used when calculating the injection time for a point. The injection pressure is not used in the calculations. The space for injection pressure is provided for future reference by the user and may be left blank.
g, h. Gallons injected per foot of injection interval and total gallons per injection point: The number of gallons injected per foot of injection value is a user-controlled value and is dependent upon site conditions and personal experience with an average value of 10 gal/ft. This value is used to determine the injection well spacing as explained in the barrier and area treatment capital cost analysis sections. The total gallons per injection point is the product of the gallons injected per foot of injection interval and the saturated thickness.

2. Fixed Costs: The total fixed cost (**h**) is made up of costs that are independent of the duration of the well installation and fluid injection.

3. Prime Contractor Information and Daily Costs: Information about the prime contractor including the number of personnel on site, average labor rate, and per diem are entered. These values make up the total daily cost for prime contractor (**j**) and factor into the total cost per boring (**4-h**) and the injection cost per gallon (**5-d**). An additional cost can be entered in (**i**).

4. Subcontractor Information and Daily Costs: Information about the daily cost for direct push equipment is entered along with additional material and IDW costs per boring (**g**) to compute the total cost per boring (**h**).

5. Costs for Injection Using DPT Equipment: The injection costs per day (**a**) is the sum of the daily costs for the DPT equipment and operator and the daily cost for the prime contractor.

4.7   Installation and Injection – DPT Well Installation

4.7.1   *General Description*

Information on the labor and materials required for injection point installation and emulsion injection is entered on this page. This approach assumes that temporary or permanent wells are installed first using direct push equipment. Well installation is assumed to be by a subcontract driller with supervision by the prime contractor. Once the wells are installed, multiple wells are manifolded together for emulsion injection.

4.7.2   *Definitions*

1. Well Information
a, b. Top and bottom of injection screen: These values are carried over from the Aquifer Description page and are used later in the design to determine the effective treatment zone thickness.
c, d. Well screen diameter and effective diameter of sand pack: The well screen diameter is not used in the design, but the effective diameter of sand pack is used to determine the theoretical estimate of injection rate per well (**3-e**). The effective diameter of sand pack is typically 0.75 to 2 inches depending on the installation method.

2. Well Installation Costs for Direct Push Installation: Daily costs for equipment, material costs, and personnel costs are entered to compute the total cost per well (**k**). Per diem, vehicle rental, and lodging costs from (**5-d, e, f**) are also included in the total cost per well. In addition, the subcontractor mobilization (**f**) is only included in the total fixed cost (**4-g**).

3. Injection Information

a, b. Injection pressure and well loss coefficient: These values along with hydraulic conductivity, depth to top and bottom of injection zone, and effective diameter of sand pack are used to calculate the theoretical estimate of injection rate per well (**c**). The well loss coefficient is a factor ranging from 5 to 20 to account for: (1) pressure buildup associated with simultaneous injection of multiple wells; (2) entrance losses through the well screen; and (3) clogging around the well screen and/or sand pack. The equation used in the design is based on specific capacity of injection and pumping wells (from Todd, 1980).

$$
Rate_{theo} = \frac{\dfrac{2*\pi*k*Z}{1+Ln\left(\dfrac{Z}{D_{eff}}\right)} * \dfrac{7.48\dfrac{gal}{ft^3}}{1440\dfrac{min}{day}} * \left(\dfrac{P*144\dfrac{in^2}{ft^2}}{62.4\dfrac{lbs}{ft^3_{H2O}}}+d_{wt}\right)}{Well_{loss}}
$$

k = hydraulic conductivity (ft/day)
Z = effective treatment zone thickness (ft)
D_{eff} = effective diameter of sand pack (ft)
P = injection pressure (psi)
d_{wt} = depth to water table (ft)
$Well_{loss}$ = well loss coefficient
$Rate_{theo}$ = theoretical estimate of injection rate per well (gpm/well)

d. Injection rate to be used in design: This is the value used in the design and should not exceed the theoretical estimate of injection rate per well. Users may wish to use a lower injection rate in the design based on personal experience.

4. Fixed Costs: The total fixed cost (**h**) is made up of costs that are independent of the duration of the well installation and fluid injection.

5. Injection Costs: Information about personnel, labor rates, and injection daily costs are entered to determine the injection costs per day (**l**). Additional daily costs can be entered in **i, j and k**.

4.8   Installation and Injection – Well Installation by Conventional Drilling

4.8.1 *General Description*

Information on the labor and materials required for conventional well installation and emulsion injection is entered on this page. This approach assumes that temporary or permanent wells are installed first using conventional drilling equipment. Well installation is assumed to be by a subcontract driller with supervision by the prime contractor. Once the wells are installed, multiple wells are manifolded together for emulsion injection.

4.8.2 *Definitions*

1. Well Information
a, b. Top and bottom of injection screen: These values are carried over from the Aquifer Description page and are used later in the design to determine the effective treatment zone thickness.

c, d. Well screen diameter and effective diameter of sand pack: The well screen diameter is not used in the design, but the effective diameter of sand pack is used to determine the theoretical estimate of injection rate per well (**3-e**). The effective diameter of sand pack is typically 1 to 3 inches depending on the installation method.

2. Well Installation Costs for Conventional Drilling:
The cost for well installation ($/ft), material costs, and personnel costs are entered to compute the total cost per well (**k**). Per diem, vehicle rental, and lodging costs from (**5-d, e and f**) are also included in the total cost per well. In addition, the subcontractor mobilization (**f**) is only included in the total fixed cost (**4-g**).

3. Injection Information
a, b. Injection pressure and well loss coefficient: These values along with hydraulic conductivity, depth to top and bottom of injection zone, and effective diameter of sand pack are used to calculate the theoretical estimate of injection rate per well (**c**). The well loss coefficient is a factor ranging from 5 to 20 to account for: (1) pressure buildup associated with simultaneous injection of multiple wells; (2) entrance losses through the well screen; and (3) clogging around well screen and/or sand pack. The equation used in the design is based on specific capacity of injection and pumping wells (from Todd, 1980).

$$Rate_{theo} = \frac{\dfrac{2*\pi*k*Z}{1+Ln\left(\dfrac{Z}{D_{eff}}\right)} * \dfrac{7.48\dfrac{gal}{ft^3}}{1440\dfrac{min}{day}} * \left(\dfrac{P*144\dfrac{in^2}{ft^2}}{62.4\dfrac{lbs}{ft^3_{H2O}}} + d_{wt}\right)}{Well_{loss}}$$

k = hydraulic conductivity (ft/day)
Z = effective treatment zone thickness (ft)
D_{eff} = effective diameter of sand pack (ft)
P = injection pressure (psi)
d_{wt} = depth to water table (ft)
$Well_{loss}$ = well loss coefficient
$Rate_{theo}$ = theoretical estimate of injection rate per well (gpm/well)

d. Injection rate to be used in design: This is the value used in the design and should not exceed the theoretical estimate of injection rate per well. Users may wish to use a lower injection rate in the design based on personal experience.

4. Fixed Costs: The total fixed cost (**g**) is made up of costs that are independent of the duration of the well installation and fluid injection.

5. Injection Costs: Information about personnel, labor rates, and injection daily costs are entered to determine the injection costs per day (**l**). Additional daily costs can be entered in **i, j and k**.

4.9   Installation and Injection – Installation and Injection Summary

This worksheet has a button to select the method to be used in the design. The five parameters for each method that factor into the design are:

a. **Total fixed cost**
b. **Dollars per injection point**
c. **Injection rate per well to be used in design**
d. **Injection costs per day**

4.10   Barrier Treatment – Design Information

4.10.1 *General Description*

Barrier configurations are often used for plume containment. Barriers are typically installed across the plume perpendicular to groundwater flow. Design information is entered on this page which is used to determine material quantities and estimate costs for different well spacings through capital and life cycle cost analyses.

4.10.2 *Definitions*

   1. Treatment Zone Dimensions: A schematic of the barrier design is provided in Figure 4.1 and in the design tool.
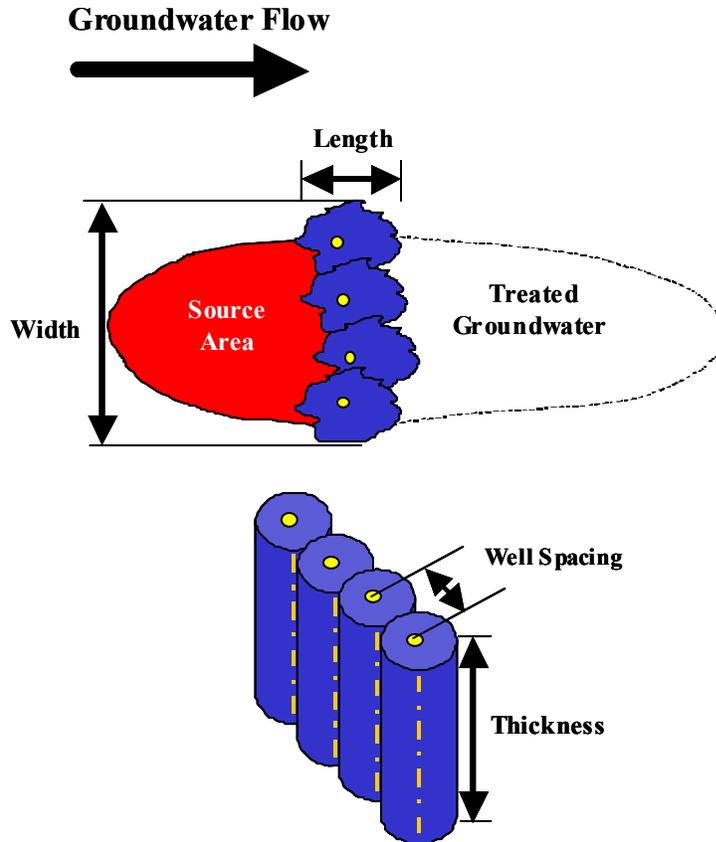
Groundwater Flow

Figure 4.1. Emulsified Oil Barrier Design Schematic.

   a. Width (Y): The user should enter the width of the barrier perpendicular to groundwater flow. Typically, the barrier should be 10% to 30% wider than the plume to account for changes/uncertainty in groundwater flow direction and hydraulic conductivity.
   c. Percentage of injection zone that transmits most flow: This user entered value is used to account for the fact that the treatment zone may contain substantial layers of impermeable layers. The effective treatment zone thickness (**d**) should exclude the impermeable layers. If impermeable layers are unaccounted for then the design may be over designed resulting in much higher costs.
   e. Seepage velocity: This value is copied over from the Aquifer Description page and is used along with the minimum allowable contact time to determine the number of rows necessary.

2. Treatment Zone Contact Time
    a. Minimum allowable contact time: The user enters an estimated contact time within the barrier reactive zone to achieve degradation of the target contaminants. The contact time is then used to calculate the number of rows needed (**see Capital Cost Analysis – Well Layout**).

$$r = \frac{C_t * v}{S_w}$$

r = number of rows
C_t = contact time (days)
v = non-reactive transport velocity (ft/day)
S_w = well spacing ft

If C_t * v is less than the well spacing then the number of rows needed is determined by taking (C_t * v)/S_w and rounding up to the next whole number where S_w is the desired well spacing in feet. If C_t * v is greater than S_w then only one row is needed to achieve the desired contact time.

The required contact time will be dependent on the target contaminants. Laboratory column experiments and limited field studies suggest a 2 to 4-month contact time when treating moderate to high concentrations of chlorinated solvents. The contact time for perchlorate may be substantially less. Longer contact times should be considered if there is high sulfate loading, very high contaminant concentrations, and a high removal efficiency is desired.

3. Targeted Carbon Released
    a. Average amount of DOC released: Dissolved organic carbon (DOC) will be released from the barrier as the emulsified oil slowly degrades. This DOC released is in excess of that required for contaminant biodegradation and consumption of competing electron donors. Field monitoring data indicate that DOC released from barriers declines from hundreds of mg/L shortly after emulsion injection to tens of mg/L near the end of the operating life. Long-term average DOC concentrations are typically in the range of 40 to 100 mg/L. This value is an important component of the substrate consumption rate.

4. Design Life
    a. Total project life: In this section, the user enters the project design life with a maximum of 30 years. For barriers, the design life is typically based on the expected life of the contaminant source.
    b. Substrate scaling factor (SF$_S$): Typically, contaminant treatment efficiency for emulsified oil barriers begins to decrease when 30 to 60% of the oil has been consumed by bacteria. While treatment efficiency does not go to zero, it may decline to unacceptable levels and reinjection may be needed to maintain performance. To account for this, the design tool includes a substrate scaling factor (SF$_S$). For example, if the theoretical life of a single injection (T) is 20 years and treatment

performance declines to unacceptable levels once 40% of the oil is consumed (e.g., $SF_S = 0.4$), the model will calculate a required reinjection interval (RI) as:

$$RI = T * SF_S = 20 \text{ yr} * 0.4 = 8 \text{ yr}$$

c. Maximum time between reinjections: This allows the user to specify a maximum reinjection interval to override the calculated reinjection interval. For example, if the model calculates a reinjection interval (RI) of 8 years, the user may decide to specify a maximum RI of 5 years based on personal experience. The design tool will then use an RI of 5 years in the life cycle cost analysis.

5. Contact Efficiency

a, b. Mass and Volume Scaling Factors: For the most effective treatment, emulsified oil should be uniformly distributed throughout the treatment zone. However in real aquifers, a variety of factors (e.g., injection well location, injection sequencing, subsurface heterogeneity) lead to a non-uniform oil distribution. A SF_M and a SF_V are used to account for these effects in the design tool.

Effects of SF_M and SF_V on flow contact efficiency are shown in Figure 4.2. Upper and lower limits of the expected contact efficiency are printed on the spreadsheet as a function of the SF_M and SF_V to be used in the design. Higher values of SF_M and SF_V will result in improved contact efficiency while increasing cost.

Users should note that flow contact efficiency does not include any contact time criteria so groundwater is considered 'contacted' if it flows through a zone with greater than 5% of the maximum oil retention, even if the contact time is only a few minutes. Consequently, pollutant removal efficiency will likely be less than the contact efficiency.

The following equations are used to determine the amount of oil and water to inject in each well.

$$\text{Mass of oil injected per well} = SF_M \, OR_M \, \rho_B \, BTV$$

$$\text{Volume of fluid per well} = SF_V \, n_e \, BTV$$

OR_M = maximum oil retention by aquifer material (lb/lb)
ρ_B = bulk density (lb/ft^3)
n_e = effective porosity
BTV = base treatment volume (ft^3)

For barrier treatment, the BTV is defined as the volume of a cylinder with a diameter equal to the well spacing (S_W) and an effective treatment zone thickness, Z, where $BTV = \frac{1}{4} \pi S_W^2 Z$.
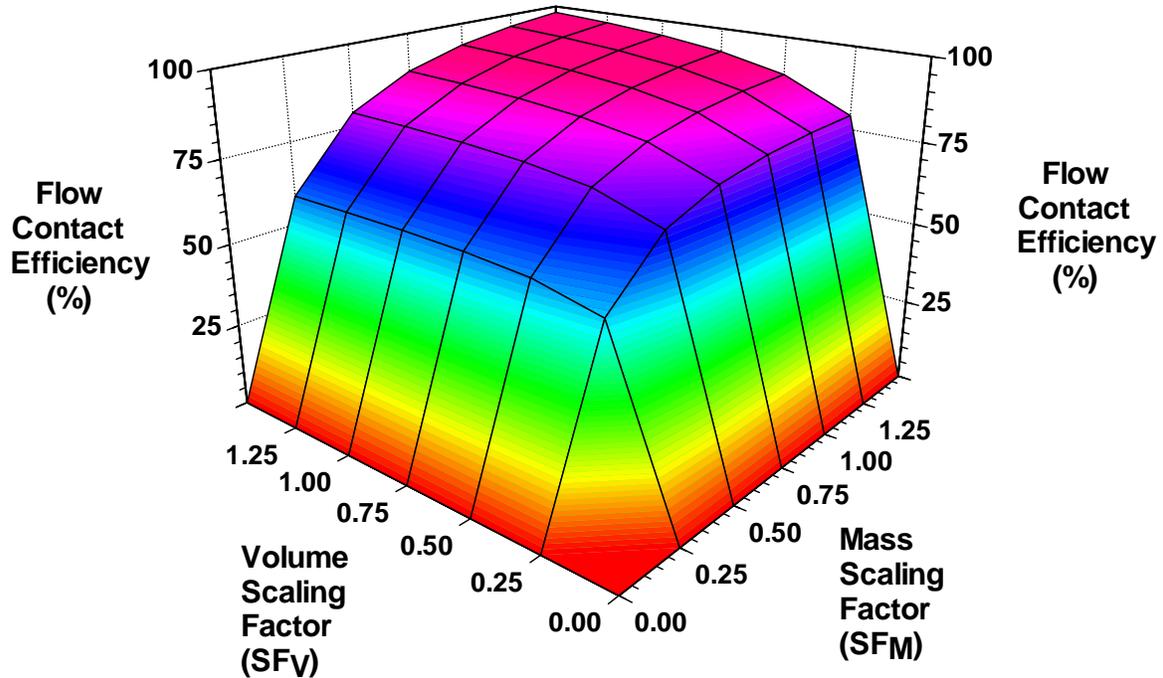
Figure 4.2. Contact Efficiency for Barrier Treatment.

4.11   Barrier Treatment – Capital Cost Analysis

4.11.1 *General Description*

This section evaluates the capital costs associated with various well spacing configurations based on the design information. A graph of well spacing versus capital cost is displayed at the bottom of the page.

4.11.2 *Definitions*

Calculation of Well Spacing for Injection through Direct Push Rods
For direct push injection, the design tool calculates the well spacing required to deliver the necessary injection volumes based upon the gallons injected per foot of injection interval as specified on the *Injection through Direct Push Rods* page. The well spacing is determined as follows:

$$S_W = \sqrt{\dfrac{IV_{pt}}{SF_V * \dfrac{1}{4} * \pi * Z * n_e * 7.48 \dfrac{gal}{ft^3}}}$$

S_W = calculated well spacing (ft)
IV_{pt} = gallons injected per injection point (gal)
SF_V = volume scaling factor
Z = effective vertical thickness of injection zone (ft)

n_e = effective porosity

The well spacing is a function of the amount of fluid that can be injected per foot by direct push as well as the desired contact efficiency. Higher contact efficiencies require larger volumes to be injected which require more closely spaced injection points. This in turn increases cost. Once the well spacing is calculated, all subsequent calculations follow those outlined below.

1. Well Layout: The tool determines the number of wells needed for each well spacing by dividing the barrier width by the well spacing.
    a. Minimum well spacing: This is the minimum well spacing to be evaluated.
    b. Incremental increase in well spacing: A total of nine different well spacings are evaluated. Changing the minimum and incremental values allows one to optimize the design by looking for the minimum capital cost.
    e. Number of rows: See the section on contact time in section **4.10** for additional information.

2. Fixed Costs
    a. Planning, engineering, and permitting: This is an estimate for the planning, engineering, and permitting costs that goes into the initial design. It is summed with the fixed cost from the selected installation and injection method to make up the total fixed cost (**c**). If post-remediation costs are significant they should be included here.

3. Well Installation: This cost is calculated by multiplying the number of wells for a given well spacing by the dollars per injection point for the selected installation and injection method.

4. Injection Information
    a. Hours of injection per day: The number of hours per day that injection will occur. This includes both attended and unattended injection and is used to calculate the time required to inject a well. This value will default to the value entered on the Injection through Direct Push Rods if this method is selected.
    b. Maximum number of wells to inject at one time: Injecting multiple wells together reduces the total time it takes to complete injection resulting in a lower total cost. However, the number of wells to inject at once is usually limited to 10 wells to limit the chance that injecting too much emulsion and water at once will displace contaminants downgradient. When using Injection through Direct Push Rods only one well can be injected at a time.
    c. Percentage of total wells to inject at one time: This value controls how many wells are injected at one time and is usually set to 50% to allow for enhanced contact throughout the aquifer. For example, if a barrier has 16 wells, and up to 50% of the wells may be injected at one time, then only 8 wells would be injected one day followed by the second 8 wells the next day. When using Injection through Direct Push Rods, this value will automatically go to 100% since only one well will be injected at a time.
    d. Required total water supply rate: The amount of water needed for injection is the product of injection rate to be used in the design and the actual number of wells

injected simultaneously. If the required amount of water at a site is not available then either a lower injection rate or injecting fewer wells at a time will need to be used.

5. Injection Costs: For each well spacing, the total volume of injection fluid (water plus emulsified oil) is calculated based on the well spacing (S_W), vertical thickness of injection zone (Z), effective porosity (n_e) and the Volume Scaling Factor (SF_V) where:

$$\text{Volume of fluid per well} = SF_V \; n_e \; \tfrac{1}{4} \; \pi \; S_W^2 \; Z$$

The total injection volume, expected injection rates, number of wells injected simultaneously, and daily injection costs are then used to determine the amount of injection time required for each well and the total injection costs. When using either well installation by direct push or conventional drilling, the time to complete a set of wells is rounded up to the next nearest day. This allows time for the emulsion to spread throughout the aquifer and minimizes the risk of displacing the contaminant. If injection through direct push rods is selected, then multiple wells can be injected in a day since only one well is injected at a time.

6. Substrate: For each well spacing, the amount of oil required is determined based on the well spacing (S_W), effective vertical thickness of injection zone (Z), maximum oil retention by the aquifer material (OR_M), aquifer material bulk density (ρ_B) and the mass scaling factor (SF_M) where:

$$\text{Mass of oil per well} = SF_M * OR_M * -_B * BTV$$

The effective life of a single emulsion injection and the reinjection interval are calculated by using the following equations:

$$T = \frac{Oil_{total}}{D * Q}$$

$$Q = Y * Z * K * i * 28.3\frac{L}{ft^3} * 365\frac{day}{yr}$$

$$RI = T * SF_S$$

T = effective life of single injection (yrs)
Oil_{total} = total mass of oil injected (lbs)
D = oil demand (lbs/L)
Q = water flux (L/yr)
Y = treatment zone width (ft)
Z = effective treatment zone thickness (ft)
K = hydraulic conductivity (ft/day)
i = hydraulic gradient (ft/ft)
RI = reinjection interval (yrs)

SF_S = substrate scaling factor

7. Total Installation and Injection Costs: The fixed well installation, injection, and substrate costs are summed to provide the user with the total capital costs for each well spacing. The cost data are also displayed graphically. Based on the cost data, the user can see the effect of well spacing on capital cost. It is important to keep in mind that these costs are only for the initial installation and injection event.

4.12   Barrier Treatment – Life Cycle Analysis

4.12.1 *General Description*

This section calculates estimated re-injection costs which can be used to estimate life-cycle costs. Information related to future injections is entered and then costs are calculated for future injections as well as the net present value of the design. A graph displays well spacing vs. NPV to aid in selecting a design. Selecting a design lets one see a breakdown of the costs for that design.

4.12.2 *Definitions*

1. First Event Costs: These values are the capital costs for the initial installation and injection event carried over from the capital cost analysis.

2. Life Cycle Analysis
  a. Annual interest rate: This is the annual interest rate used to compute NPV. Typically, a rate between 3.5% and 5% is used.
  b. Engineering, planning, and permitting costs: The estimated cost to engineer, plan, and permit future installation and injection events. This value will typically be less than the value for the initial design entered in the Capital Cost Analysis page.
  c. Fixed costs: This value is carried over from the selected installation and injection method.
  d. Annual monitoring and reporting costs: The cost each year for monitoring and reporting. Depending on the number of wells and how often samples are taken, this can range from $5,000 per year upwards to $20,000 per year.
  e. Well rehabilitation and/or installation cost: The percentage of the first event cost for well installation that will be used for future events. This covers any costs necessary to prepare the wells for injection. If injection through direct push rods is selected then this value will always be 100% as the points are temporary.

3. Life-Cycle Cost Analysis
  a. Injection costs per future event: Based on the information supplied in section 2 above, this is the capital cost for each future installation and injection event. Once again, the reinjection interval is determined by taking the lesser of the calculated reinjection interval (RI = $T * SF_S$) and the user entered maximum time between reinjections.

b. Net present value for design life: This section shows the reinjection frequency (**b**), the NPV for monitoring and reporting (**c**), and the NPV for the total injection costs (**d**). The project life NPV (**e**) is the sum of the NPV for monitoring and reporting and the NPV for the total injection costs.

4.13   Barrier Treatment – Net Present Value For Selected Design

This section breaks down the net present values for the design selected on the Life Cycle Analysis page. The NPV cost is shown for each item pertaining to a year. The event total is the sum of fixed costs, well installation, labor for injection, and substrate. Total is the sum of monitoring and the injection event. The cumulative cost is the total NPV up to and including that year. The total cost (**b**) shows the sum of each component: monitoring, fixed costs, well installation, labor for injection, substrate, event, and total. The graph on the bottom left shows the annual costs for the different components to see what is contributing most to the cost of the design. The graph to the right shows the cumulative NPV versus the year.

4.14   Barrier Treatment – Selected Design

This is a summary of the selected design and shows information on the design layout, costs for initial and future installation and injection events, and the total life cycle costs. Design parameters, which directly affect the design, are also shown as well as section to include additional notes about the design. The summary should be printed or saved before modifying the design.

4.15   Area Treatment – Design Information

4.15.1 *General Description*

Area treatments are often used to treat source areas or entire plumes. The area treatment design assumes several rows of injection wells are installed across the plume or source area perpendicular to groundwater flow. Design information is entered on this page and used to determine material quantities and estimate costs for different well spacings through capital and life cycle cost analyses.

4.15.2 *Definitions*

1. Treatment Zone Dimensions: A schematic of the barrier design is provided in Figure 4.3 and in the design tool.
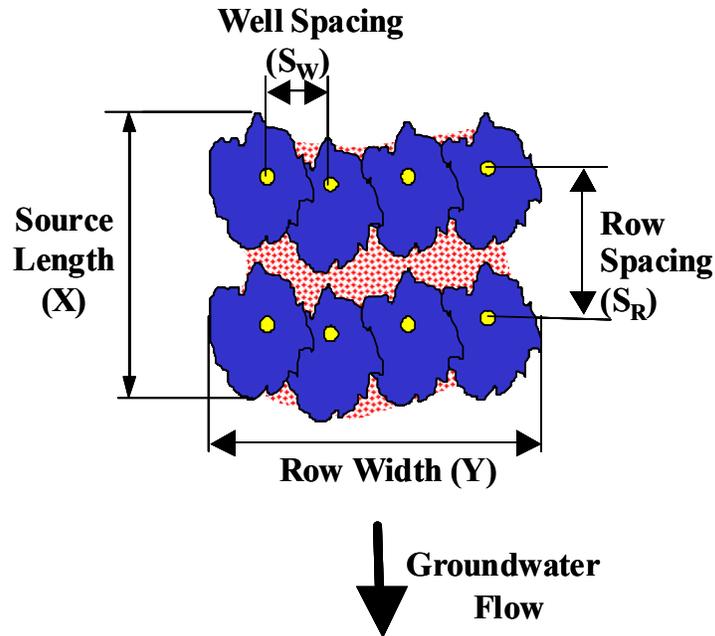
Figure 4.3. Emulsified Oil Area Treatment Design Schematic.

a. Width (Y): The user should enter the width of the treatment zone perpendicular to groundwater flow.

b. Length (X): The user enters the length of the treatment zone parallel to groundwater flow.

c. Row spacing: This is a ratio of well spacing to row spacing to determine how far apart the barriers will be spaced. For example, a ratio of 2 to 1 and a well spacing of 5 ft the rows will be spaced 10 feet apart for the length of the treatment zone. Depending on which ratio is selected the graph of contact efficiency will change.

d. Percentage of injection zone that transmits most flow: This user entered value is used to account for the fact that the treatment zone may contain substantial layers of impermeable layers. The effective treatment zone thickness (**f**) should exclude the impermeable layers. If impermeable layers are unaccounted for then the design may be over designed resulting in much higher costs.

2. Design Life

a. Reinjection interval: The reinjection interval is a fixed value specified by the user. The value entered will carry over to the life-cycle cost analysis. Personal experience or other studies should be consulted when determining this value.

b. Total project life: In this section, the user enters the project design life with a maximum of 30 years. Accurate estimation of the actual time to remediate a source area is extremely difficult and is beyond the scope of this design tool. Laboratory studies and field pilot tests have demonstrated that oil addition can stimulate rapid biodegradation of contaminants in the higher permeability zones with contaminants degraded to low levels in 6 to 12 months. However, mass transfer limitations may greatly reduce the rate that DNAPLs and contaminants in low permeability zones are

degraded. If residual oils are present, aqueous phase contaminants will be degraded as they diffuse out into the more mobile portions of the aquifer. However, once the oil is depleted, aqueous phase contaminants may be released to the downgradient aquifer. For most source areas, a five-year project life should be provided as a minimum with the expectation that additional oil may need to be injected at some time in the future.

3. Contact Efficiency

a, b. Mass and Volume Scaling Factors: In an ideal, homogeneous aquifer, emulsified oil should be uniformly distributed between throughout the treatment zone. However, in real aquifers, a variety of factors such as injection well location, injection sequencing, subsurface heterogeneity lead to a non-uniform oil distribution. A Mass Scaling Factor (SF_M) and Volume Scaling Factor (SF_V) are used to account for these effects in the design tool.

Effects of SF_M and SF_V on the volume contact efficiency are shown in Figure 4.4 and 4.5 depending on which row spacing ratio is used. Upper and lower limits of the expected contact efficiency are printed on the spreadsheet as a function of the SF_M and SF_V to be used in the design. Higher values of SF_M and SF_V will result in improved contact efficiency, while increasing cost. The following equations are used to determine the amount of oil and water to inject in each well.

$$\text{Mass of oil injected per well} = \frac{SF_M * OR_M * n_e * BTV}{w}$$

$$\text{Volume of fluid per well} = \frac{SF_V * n_e * BTV}{w}$$

OR_M = maximum oil retention by aquifer material (lb/lb)
ρ_B = bulk density (lb/ft^3)
n_e = effective porosity
BTV = base treatment volume (ft^3)
w = total number of wells

The BTV is defined as the volume of the target treatment zone where BTV = X*Y*Z.
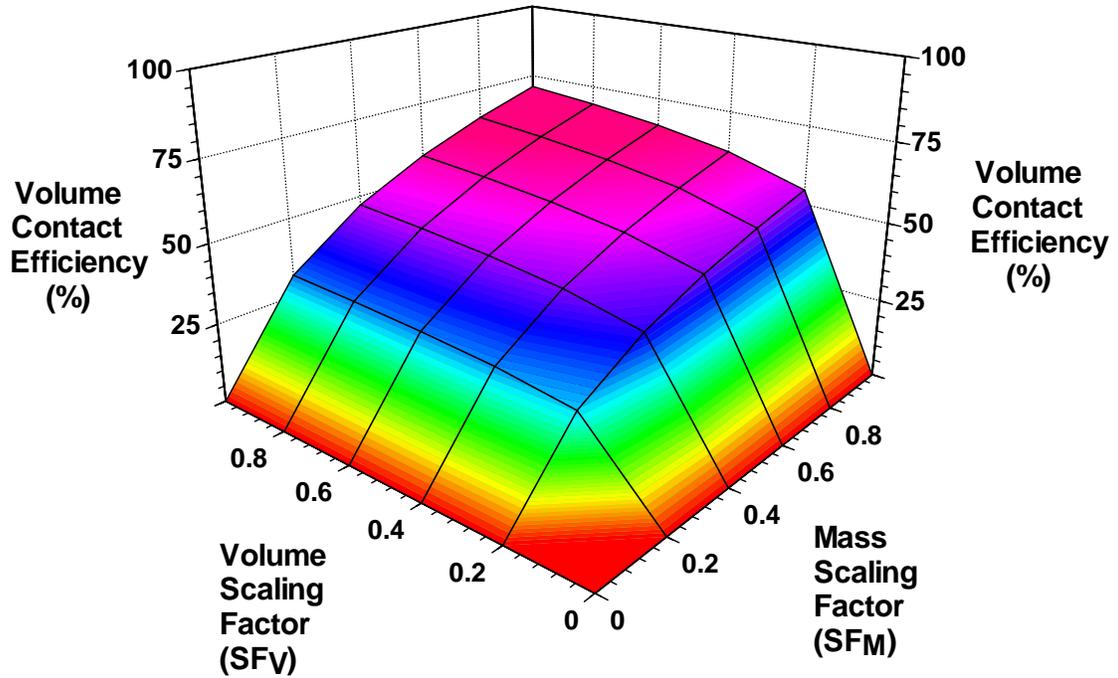
Figure 4.4. Contact Efficiency for Area Treatment when Row Spacing = Well Spacing.
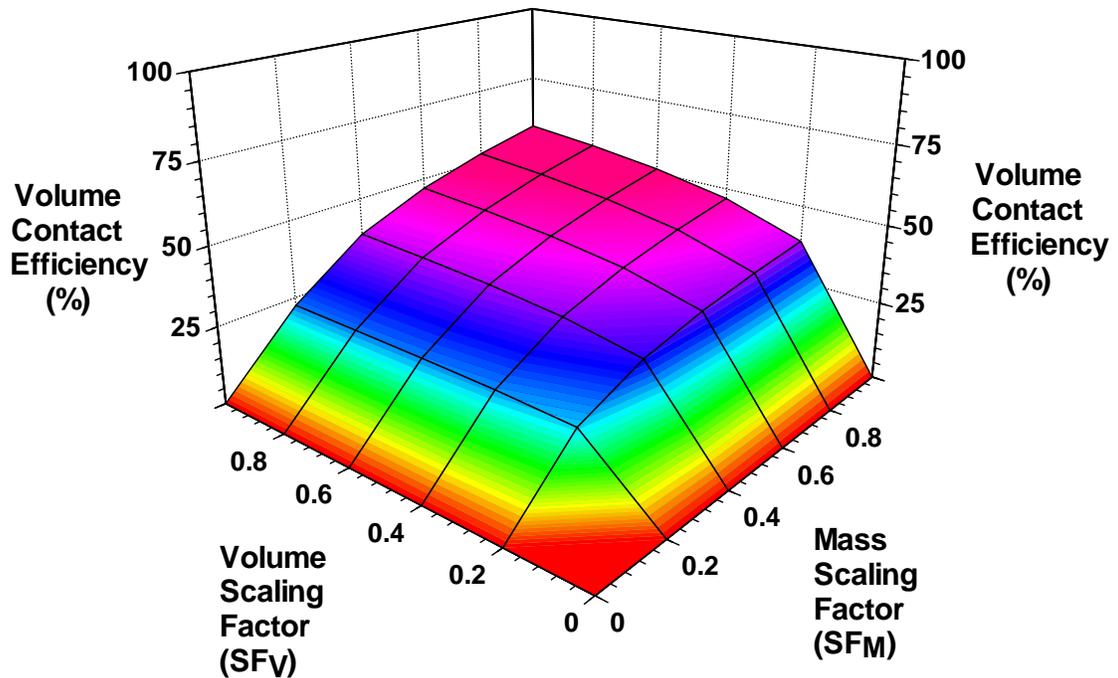
Figure 4.5. Contact Efficiency for Area Treatment when Row Spacing = 2 * Well Spacing.

4.16 Area Treatment– Capital Cost Analysis

4.16.1 *General Description*

This section evaluates the capital costs associated with various well spacing configurations based on the design information. A graph of well spacing versus capital cost is displayed at the bottom of the page.

4.16.2 *Definitions*

Calculation of Well Spacing for Injection through Direct Push Rods
For direct push injection, the design tool calculates the well spacing required to deliver the necessary injection volumes based upon the gallons injected per foot of injection interval as specified on the *Injection through Direct Push Rods* page. First the total injection volume is calculated then the well spacing is determined. The equations are as follows:

$$IV_{total} = SF_V * X * Y * Z * n_e$$

$$S_W = \sqrt{\frac{X * Y}{\frac{IV_{total}}{IV_{pt}} * 7.48 \frac{gal}{ft^3}}}$$

IV_{total} = total injection volume (ft^3)
SF_V = volume scaling factor
X = treatment zone width (ft)
Y = treatment zone length (ft)
Z = effective vertical thickness of injection zone (ft)
n_e = effective porosity
S_W = calculated well spacing (ft)
IV_{pt} = gallons injected per injection point (gal)

The well spacing is a function of the volume of fluid that that can be injected per direct push point and the desired contact efficiency. Higher contact efficiencies require larger injection volumes and more injection points. This in turn increases cost. Once the well spacing is calculated, all subsequent calculations follow those outlined below.

> **1. Well Layout:** The tool determines the number of wells for each row of wells by dividing the width by the well spacing. The number of rows is the treatment zone length divided by the row spacing.
> **a. Minimum well spacing:** This is the minimum well spacing to be evaluated.
> **b. Incremental increase in well spacing:** A total of nine different well spacings are evaluated. Changing the minimum and incremental values allows one to optimize the design by looking for the minimum capital cost.

2. Fixed Costs
   a. Planning, engineering, and permitting: This is an estimate for the planning, engineering, and permitting costs that goes into the initial design. It is summed with the fixed cost from the selected installation and injection method to make up the total fixed cost (**c**). If post-remediation costs are significant then they should be included here.

3. Well Installation: This cost is calculated by multiplying the number of wells for a given well spacing by the dollars per injection point for the selected installation and injection method.

4. Injection Information
   a. Hours of injection per day: The number of hours per day that injection will occur. This includes both attended and unattended injection and is used to calculate the time required to inject a well. This value will default to the value entered on the *Injection through Direct Push Rods* page if that method is selected.
   b. Maximum number of wells to inject at one time: Injecting multiple wells together reduces the total time it takes to complete injection resulting in a lower total cost. However, the number of wells to inject at once is usually limited to 10 wells to limit the chance that injecting too much emulsion and water at once will displace contaminants downgradient. When using Injection through Direct Push Rods only, one well can be injected at a time.
   c. Percentage of total wells to inject at one time: This value controls how many wells can be injected at one time and is usually set at 50% to allow for enhanced contact throughout the treatment zone. For example, if an area treatment has 16 wells and up to 50% of the wells may be injected at one time, then only 8 wells will be injected one day followed by the second set of 8 wells the next day. When using injection through direct push rods, this value will automatically go to 100% since only one well will be injected at a time.
   d. Required total water supply rate: The amount of water needed for injection is the product of injection rate to be used in the design and the actual number of wells injected simultaneously. If the required amount of water at a site is not available, then either a lower injection rate needs to be used or fewer wells can be injected at a time.

5. Injection: For each well spacing, the total volume of injection fluid (water plus emulsified oil) is calculated based on the well spacing (S_W), vertical thickness of injection zone (Z), effective porosity (n_e) and the Volume Scaling Factor (SF_V) where:

$$\text{Volume of fluid per well} = \frac{SF_M * n_e * BTV}{w}$$

The total injection volume, expected injection rates, number of wells injected simultaneously, and daily injection costs are then used to determine the amount of injection time required for each well and the total injection costs. When using either well installation by direct push or conventional drilling the time to complete a set of wells is

rounded up to the next nearest day. This allows time for the emulsion to spread throughout the aquifer and minimizes the risk of displacing the contaminant. If injection through direct push rods is selected then multiple wells can be injected in a day since only one well is injected at a time.

6. Substrate: For each well spacing, the amount of oil required is determined based on the based on the well spacing (S_W), vertical thickness of injection zone (Z), maximum oil retention by the aquifer material (OR_M), aquifer material bulk density (ρ_B) and the mass scaling factor (SF_M) where:

$$\text{Mass of oil per well} = \frac{SF_M * OR_M * -_B * BTV}{w}$$

7. Total Installation and Injection Costs: The fixed, well installation, injection, and substrate costs are summed to provide the user with the total capital costs for each well spacing. The cost data are also displayed graphically. Based on the cost data, the user can see the effect of well spacing on capital cost. It is important to keep in mind that these costs are only for the initial installation and injection event.

4.17   Area Treatment – Life Cycle Analysis

4.17.1 *General Description*

This section calculates estimated re-injection costs which can be used to estimate life-cycle costs. Information related to future injections is entered and then costs are calculated for future injections as well as the net present value of the design. A graph displays well spacing vs. NPV to aid in selecting a design. Selecting a design lets one see a breakdown of the costs for that design.

4.17.2 *Definitions*

1. First Event Costs: These values are the capital costs for the initial installation and injection event carried over from the capital cost analysis.

2. Life Cycle Analysis
   a. Annual interest rate: This is the annual interest rate used to compute net present values. Typically, a rate between 3.5% to 4.5% is used.
   b. Planning, engineering, and permitting costs: The estimated cost to engineer, plan, and permit future installation and injection events. This value will typically be less than the value for the initial design entered in the Capital Cost Analysis page.
   c. Fixed costs: This value is carried over from the selected installation and injection method.
   d. Annual monitoring and reporting costs: The cost each year for monitoring and reporting. Depending on the number of wells and how often samples are taken this can range from $5,000 per year upwards to $20,000 per year.

e. Well rehabilitation and/or installation cost: The percentage of the first event cost for well installation that will be used for future events. This covers any costs necessary to get the wells ready for injection. If injection through direct push rods is selected, then this will always be 100%.

2. Life-Cycle Cost Analysis
   a. Injection Costs per Future Event: Based on the information supplied in section B this is the capital cost for each future installation and injection event.
   b. Net Present Value for Design Life: This section shows the reinjection frequency (**b**), the NPV for monitoring and reporting (**c**), and the NPV for the total injection costs (**d**). The project life NPV (**e**) is the sum of the NPV for monitoring and reporting and the NPV for the total injection costs.

4.18 Area Treatment – Net Present Value for Selected Design

This section breaks down the net present values for the design selected on the Life Cycle Analysis page. The NPV cost is shown for each item pertaining to a year. The event total is the sum of fixed costs, well installation, labor for injection, and substrate. Total is the sum of monitoring and the injection event. The cumulative cost is the total NPV up to and including that year. The total cost (**b**) shows the sum of each component: monitoring, fixed costs, well installation, labor for injection, substrate, event, and total. The graph on the bottom left shows the annual costs for the different components to see what is contributing most to the cost of the design. The graph to the right shows the cumulative NPV versus the year.

4.19 Area Treatment – Selected Design

This is a summary of the selected design and shows information on the design layout, costs for initial and future installation and injection events, and the total life cycle costs. Design parameters, which directly affect the design, are also shown as well as section to include additional notes about the design. The summary should be printed and saved before modifying the design.

SECTION 5
REFERENCES

AFCEE, 1995. Technical Protocol for Implementing Intrinsic Remediation with Long-Term Monitoring for Natural Attenuation of Fuel Contamination Dissolved in Groundwater, Air Force Center for Environmental Excellence, San Antonio, Texas.

AFCEE, 2004. Principles and Practices of Enhanced Anaerobic Bioremediation of Chlorinated Solvents, Air Force Center for Environmental Excellence, San Antonio, Texas.

AFCEE, 2007. Protocol for *In Situ* Bioremediation of Chlorinated Solvents Using Edible Oil, Air Force Center for Environmental Excellence, San Antonio, Texas.

Beckwith, W.J., R.C. Borden, C. Zawtocki, M.T. Lieberman, D. Koch, and I. May, 2005. Anaerobic Bioremediation of a Piedmont Saprolite Source Area with EOS[®]. Submitted to ITRC BioDNAPL Team for Inclusion with Tech-Reg Document.

Borden, R.C. and B.X. Rodriguez, 2006. Evaluation of Slow Release Substrates for Anaerobic Bioremediation. *Bioremediation Journal*, 10(1–2):59–69.

Borden, R.C., 2007. Effective Distribution of Emulsified Edible Oil for Enhanced Anaerobic Bioremediation. *Journal of Contaminant Hydrology*, 94: 1-12.

Borden, R.C., 2007. Anaerobic Bioremediation of Perchlorate and 1,1,1-Trichloroethane in an Emulsfied Oil Barrier. *Journal of Contaminant Hydrology*, 94: 13- 33.

Borden, R.C., M. Clayton, A. M. Weispfenning, T. Simpkin, and M. T. Lieberman, 2008. DRAFT Technical Report - Design Tool for Planning Emulsified Oil Injection Systems, Environmental Security Technology Certification Program, Arlington, Virginia. (www.estcp.org).

Borden R.C., W.J. Beckwith, M.T. Lieberman, N. Akladiss, and S.R . Hill, 2007. Enhanced Anaerobic Bioremediation of a TCE Source Area at the Tarheel Army Missile Plant using EOS[®]. *Remediation* (Summer 2007): 5-19.

Coulibaly, K.M. and R.C. Borden, 2004. Impact of Edible Oil Injection on the Permeability of Aquifer Sands. *Journal of Contaminant Hydrology*, 71(1-4): 219-237.

Jung, Y., K.M. Coulibaly and R.C. Borden, 2006. Transport of Edible Oil Emulsions in Clayey-Sands: 3-D Sandbox Results and Model Validation. *Journal of Hydrologic Engineering*, 11(3): 238-244.

Lindow, N.L. and R.C. Borden, 2005. Anaerobic Bioremediation of Acid Mine Drainage Using Emulsified Soybean Oil. *Mine Water and the Environment*, 24: 199–208.

Long, C.M. and R.C. Borden, 2006. Enhanced Reductive Dechlorination in Columns Treated with Edible Oil Emulsion, *Journal of Contaminant Hydrology*, 87: 54–72.

Konzuk, J., P. Nicholson and J. Roberts, 2006. Improving the Understanding of Oil Emulsion Behavior in the Subsurface, *In*: B.M. Sass (Conference Chair), Proceedings of the Fifth International Conference on Remediation of Chlorinated and Recalcitrant Compounds Monterey, California, May 22-25.

Kovacich M.S., D.Beck, T. Rabideau, . Pettypiece, K. Smith, M. Noel, M.J. Zack, M.T. Cannaert. 2007. Full-Scale Bioaugmentation to Create a Passive Biobarrier to Remediate a TCE Groundwater Plume. Proceedings: Ninth International *In Situ* and On-Site Bioremediation Symposium, Baltimore, Maryland, USA, May 7-10, 2007, Paper I-18

Morse, J.J., B.C. Alleman, J.M. Gossett, S.H. Zinder, D.E. Fennell, G.W. Sewell, and C.M. Vogel, 1998. A Treatability Test for Evaluating the Potential Applicability of the Reductive Anaerobic Biological In Situ Treatment Technology (RABITT) to Remediate Chloroethenes. Environmental Security Technology Certification Program, Arlington, Virginia. (www.estcp.org).

Regenesis, 2008. TECHNICAL BULLETIN 3.0: Micelle Distribution Column Experiment. http://www.regenesis.com/library/Technical%20Bulletins/HRCADV/HRC_Adv_Tech_Bulletin_3_0_Micelles.pdf, downloaded on January 13, 2008.

Solutions-IES, 2006. Protocol for Enhanced *In Situ* Bioremediation Using Emulsified Edible Oil Barriers for Treatment of Perchlorate Contaminated Groundwater. Environmental Security Technology Certification Program, Arlington, Virginia. (www.estcp.org).

Todd, K.T., 1980. Groundwater Hydrology, 2nd Edition. ISBN 0-471-87616-X, John Wiley & Sons, New York, New York.

Tompson, A.F.B., R. Aboudu and L.W. Gelhar, 1989. Implementation of the Three-Dimensional Turning Bands Random Field Generator. *Water Resources Research,* 25(10): 2227-2243.

APPENDIX 1
MEASUREMENT OF MAXIMUM OIL RETENTION ON DISTURBED SAMPLES OF AQUIFER MATERIAL

Objective:

The objective of this procedure is to determine the maximum potential retention of emulsified oil by aquifer material.

Procedure:

1. Homogenize sample of aquifer material. Determine the organic content of untreated samples by Total Organic Carbon (TOC) analysis. Collect three subsamples and measure TOC on each sample following standard analytical methods (EPA 9060A or equivalent).
2. Pack a 2.5 cm diameter laboratory column with 15 cm of aquifer material and saturate with water. Larger columns may be used but will require collection and eventual disposal of more aquifer material. In many cases, the easiest approach to saturating the aquifer material is to partially filling the column with water, adding 1-2 cm of aquifer material, and repeatedly tamping the material with a small rod to compact the soil and remove any entrained air bubbles. Once the material is adequately compacted, add more aquifer material and repeat the process until the column is filled with soil. During packing, visually observe the soil to ensure there are no visible layers or entrapped air bubbles.
3. Prepare dilute emulsion containing 12% by weight oil.
4. Pump 3 pore volumes (PV) of 12% emulsion through the column packed with aquifer material followed by 3 PV of water. Flowrate should be adjusted so that approximately one pore volume of water is flushed through the column per hour. Lower flowrates may be used if pressure buildup is excessive. One PV equals the column volume times sample porosity.
5. Remove the treated aquifer material from the column, homogenize, collect three subsamples, and analyze each subsample for TOC.

Oil Retention Calculation

Carbon content of oil (g/g) = CCO   (Note: CCO of soybean oil = 0.77 g carbon per g oil)
Average initial organic content (g/g) = TOC_I
Average final organic content (g/g) = TOC_F
Maximum oil retention by aquifer material (g/g) = $OR_M = (TOC_F - TOC_I) * CCO$

Table A1.1. Observed Emulsified Oil Retention by Aquifer Material.

Site-Specific Aquifer Material	Mean Grain Size (mm)	finer than 200 sieve (75 μm)	Hydraulic Conductivity (m/d)	Emulsion	Test Condition	Maximum Retention (g/g)	Reference
Fine clayey-sand	0.38	6.9%	2	Homemade	Lab Column	0.0054	Coulibaly and Borden, 2004
Fine clayey sand amended with kaolinite	0.36	9.2%	1.3	Homemade	Lab Column	0.0061	Coulibaly and Borden, 2004
Fine clayey sand amended with kaolinite	0.37	11.5%	0.7	Homemade	Lab Column	0.0095	Coulibaly and Borden, 2004
Clayey sand alluvium	1.0 - 0.4	15% - 23%	10.7	EOS® 598B42	Lab Column	0.0037	ESTCP, 2006b; Borden, 2007a
Low K, weathered rock (sandy clay with remnant fractures)	NA	NA	0.4	EOS® 598B42	Field (estimated)	0.0030	Borden et al., 2007
Coarse grained sand and gravel	NA	NA	64	EOS® 598B42	Field (estimate)	0.0004	Kovacich et al., 2007
Medium grain sand	0.35	0.8%	6.5	Emulsified Vegetable Oil	Lab Column	0.0024	Konzuk et al., 2006
White, fine-grained sand	NA	NA	NA	HRC-A (3DMe™)	Lab Column	0.0500	Regenesis, 2008

APPENDIX 2
OIL CONSUMPTION RATE FOR BARRIERS

This appendix describes the approach used to calculate the oil consumption rate for barriers. This approach has been tested at a limited number of emulsified oil barrier sites and shown to be reasonably accurate. However, as the science and engineering behind the emulsified oil technology evolves, new and improved procedures will likely become available.

A2.1   Annual Groundwater Flow through Barrier

For a barrier design, the volume of water to be treated per year is calculated by multiplying the width of the barrier perpendicular to flow (Y), effective vertical height of the treated zone (Z), effective porosity of the treatment area (n_e), and groundwater flow velocity. Barriers are typically placed across a plume perpendicular to the direction of groundwater flow with a width (Y) that is somewhat greater than the plume to minimize the potential for contaminated groundwater to flow around the barrier without passing through the treatment zone.

When determining the effective vertical height (Z), designers should consult boring logs from the site to estimate the vertical thickness of the aquifer that transmits most of the groundwater. For example, at a typical site, the chlorinated solvent plume may extend from 20 to 40 ft below grade. However, this contaminated interval consists of sand and clay layers. Essentially all of the groundwater flow will be through the sand layers, so these layers should be targeted for treatment. While it might be desirable to treat the entire vertical extent of contamination, experience has shown that most of the emulsion is distributed in the higher permeability layers.

A2.2   Hydrogen Demand

Edible oils ferment in the subsurface generating hydrogen and acetate. The hydrogen and acetate are then used to support reductive dechlorination. However, hydrogen and acetate may also be consumed during biodegradation of naturally occurring electron acceptors including oxygen, nitrate, sulfate, ferric iron, and manganese. As a consequence, designers must consider both the amount of contaminant to be degraded and the background electron acceptor load.

The amount of substrate required to reduce the mass of dissolved contaminants and/or electron acceptors can be determined by calculating the stoichiometric hydrogen demand of the dissolved contaminants and electron acceptors. First, the contaminant and electron acceptor mass to be degraded is calculated by multiplying the average concentrations by the total groundwater treatment volume. The stoichiometric hydrogen demand required to reduce the contaminant mass can then be calculated by determining the amount of molecular hydrogen (H_2) required for complete reduction of each contaminant or background electron acceptor. The stoichiometric demand is the mass ratio of the contaminant to hydrogen (weight contaminant/weight H_2) and is based upon balanced chemical reduction equations. For example, TCE (C_2HCl_3) can be completely reduced to ethene according to the following equation:

$$C_2HCl_3 + 3H_2 \rightarrow C_2H_4 + 3H^+ + 3Cl^-$$

Since it takes 3 moles of hydrogen (molecular weight = 2.016) to reduce 1 mole of TCE (molecular weight = 131.389) to ethene, the stoichiometric hydrogen demand is 131.389 divided by 6.048 (3 x 2.016) or 21.72 (wt/wt H_2). Therefore, 21.72 grams of TCE is degraded per gram of hydrogen. Similar calculations can be done for each contaminant and electron acceptor to determine the stoichiometric hydrogen demand. For each contaminant or electron acceptor, the mass is divided by the stoichiometric hydrogen demand to determine the mass of hydrogen required to reduce the contaminant mass. **Table A2.1** provides the chemical reduction equations and stoichiometric hydrogen demand for typical chlorinated solvents and electron acceptors.

Table A2.1. Stoichiometric Hydrogen Demand for Different Contaminants and Electron Acceptors.

Chlorinated Solvents and Electron Acceptors	Chemical Reduction Equation	Stoichiometric Hydrogen Demand (wt/wt H_2)
PCE	$C_2Cl_4 + 4H_2 \rightarrow C_2H_4 + 4H^+ + 4Cl^-$	20.57
TCE	$C_2HCl_3 + 3H_2 \rightarrow C_2H_4 + 3H^+ + 3Cl^-$	21.73
cis-DCE	$C_2H_2Cl_2 + 2H_2 \rightarrow C_2H_4 + 2H^+ + 2Cl^-$	24.05
Vinyl Chloride	$C_2H_3Cl + H_2 \rightarrow C_2H_4 + H^+ + Cl^-$	31.00
Carbon Tetrachloride	$CCl_4 + 4H_2 \rightarrow CH_4 + 4H^+ + 4Cl^-$	19.08
Chloroform	$CHCl_3 + 3H_2 \rightarrow CH_4 + 3H^+ + 3Cl^-$	19.74
1,1,1-TCA	$C_2H_3Cl_3 + 3H_2 \rightarrow C_2H_6 + 3H^+ + 3Cl^-$	22.06
1,1-DCA	$C_2H_4Cl_2 + 2H_2 \rightarrow C_2H_6 + 2H^+ + 2Cl^-$	24.55
Chloroethane	$C_2H_5Cl + H_2 \rightarrow C_2H_6 + H^+ + Cl^-$	32.18
Oxygen	$O_2 + 2H_2 \rightarrow 2H_2O$	7.94
Nitrate	$2NO_3^- + 2H^+ + 5H_2 \rightarrow N_2 + 6H_2O$	12.30
Sulfate	$2SO_4^{-2} + 3H^+ + 8H_2 \rightarrow H_2S + HS^- + 8H_2O$	11.91
Ferric Iron	$2Fe^{+3} + H_2 \rightarrow 2Fe^{+2} + 2H^+$	55.41
Manganese	$MnO_2 + 2H^+ + H_2 \rightarrow Mn^{+2} + 2H_2O$	27.25

The hydrogen released from different edible oils is approximately 0.18 moles of H_2 per gram of oil (0.36 to 0.365 g H_2/g oil) depending on the oil composition. The substrate demand is determined by dividing the calculated hydrogen demand for degradation of contaminants and electron acceptors by the amount of hydrogen produced from oil.

In addition to the contaminants and electron acceptors entering the treatment zone, hydrogen can be consumed during reduction of iron oxides and manganese oxides present in the aquifer

material, production of methane, and release of dissolved organic carbon (DOC). The ideal approach for estimating the iron and manganese demand is to directly measure the amount of bioavailable iron and manganese oxides in the aquifer material and determine the fraction of these oxides that will be reduced per year. Unfortunately, these data are not commonly available. An alternative approach is to calculate the iron and manganese demand based on the amount of dissolved iron and manganese released to the downgradient aquifer. This approach may somewhat under estimate the iron and manganese demand, but should be a reasonable approximation in most cases. In previous field studies, dissolved iron concentrations released from emulsified oil barriers typical varied between 10 and 100 mg/L with somewhat lower levels of dissolved manganese.

Hydrogen and acetate that is not consumed by reductive dechlorination or electron acceptor reduction will be fermented to methane or released to the downgradient aquifer. As a consequence, additional substrate must be injected to account for any methane production and dissolved organic carbon (DOC) released. In previous emulsified oil projects, methane concentrations downgradient from the treatment zone have varied between 5 and 20 mg/L. Immediately after oil injection, DOC concentrations released from oil barriers may exceed 500 mg/L. However, DOC concentrations decline with time reaching quasi-steady-state levels of 20 to 50 mg/L. Consequently, 60 to 100 mg/L DOC appears to be a reasonable range for the long-term average concentration released.

The barrier treatment design spreadsheets estimate the amount of substrate used for methane production and the amount of carbon lost from the barrier over time. These values are estimated by entering estimated methane concentrations and DOC concentrations. The total amount of oil required to support contaminant biodegradation is then calculated. This value is only the amount of oil required. Other materials including easily biodegradable soluble substrates, bacterial nutrients and vitamins, and surfactants may be added to aid in emulsion preparation and to stimulate rapid growth of desired microbial populations. However, these materials are rapidly depleted and are not expected to support long-term anaerobic biodegradation.

APPENDIX 3
EMULSIFIED OIL DESIGN TOOL -- BARRIER TUTORIAL

A3.1   Objective

Upon completion of this tutorial, the user will have a good understanding of how to design a single emulsified oil barrier to control plume migration. The tutorial will cover what information needs to be entered along with how to select a design by looking at a case study.

A3.2   Case Study

The site used throughout the tutorial is a facility located in eastern Maryland and manufactures fireworks, munitions, and pesticides. The water table aquifer is comprised of silty sand and gravel and extends to a depth of 15 ft below ground surface (BGS) where a clay confining layer is encountered. The water table is located between 3 and 10 ft BGS. The site is contaminated with trichloroethene (TCE), 1,1,1-trichloroethane (TCA), and perchlorate (ClO_4). Concentrations of TCA are shown in **Figure A3.1**. The contaminants were released from a small impoundment that was closed in the late 1980's. For the next 15 years the groundwater was treated through a pump and treat system that removed significant amounts of TCE and TCA, but ClO_4 levels were unaffected.

The tutorial will go through the design of a 400 ft long barrier as located in **Figure A3.1**. The barrier is located along a road where there are minimal obstructions and will prevent the plume from entering the stream.
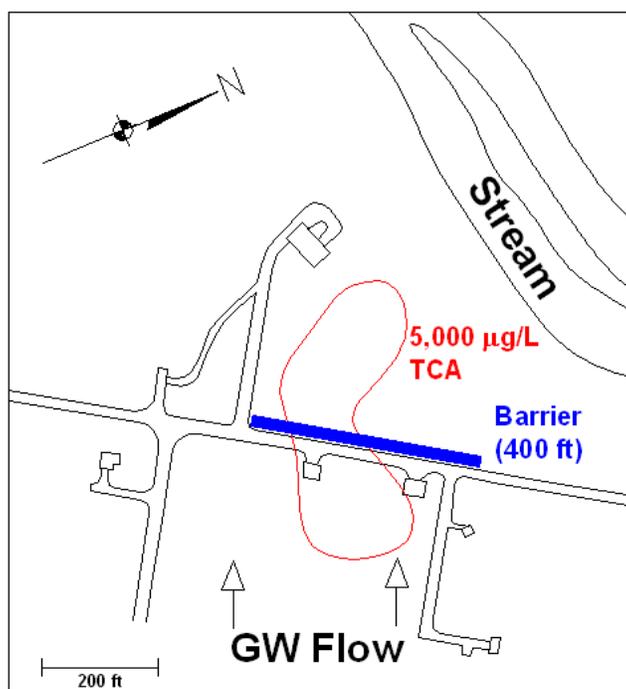

Figure A3.1. Map of the Maryland Site Showing Plume of Elevated TCA (µg/L) in Red and Location of the Proposed Barrier in Blue.

58

A3.3   Getting Started

Open up the Emulsified Oil Design Tool. The opening page gives a brief introduction as well as buttons that take you to the different pages. There are four sections in the design tool as shown in **Figure A3.2**.


Figure A3.2 Introduction Page of the Design Tool.

In order for the design tool to work all required information must be entered within the **Site Data** section and at least one of the **Installation and Injection** methods must be completed. This tutorial goes through designing a barrier, but designing an area treatment follows a similar procedure.

1. Click on *Aquifer Description* within the **Site Data** section to get started.

A3.4   Site Data

Cells that need to be filled in are white and outlined in red. All user input cells within this section must be filled in for the design tool to work properly.

A3.4.1 *Aquifer Description*

     A3.4.1.1 Site Information
     1. Enter **Pilot Test Site** for the *Name*.
     2. Enter **Case Study** as the *Description*.
     3. For *Location* enter **Maryland**.

A3.4.1.2 Hydraulic Characteristics
1. Enter **6** ft for the *Depth to water table*.
2. Enter **6** ft for the *Depth to top of injection zone*.
3. Enter **15** ft for the *Depth to bottom of injection zone*.
4. Enter **0.002** ft/ft for the *Hydraulic Gradient*.
5. Enter **20** ft/day for the *Hydraulic Conductivity*.
6. Enter **0.25** for the *Estimated Total Porosity*.
7. Enter **0.18** for the *Estimated Effective Porosity*.
8. The *Seepage Velocity* should be **0.22** ft/day.

A3.4.1.3 Soil Characteristics
1. For the *Description of Soil Lithology* enter **silty sand and gravel**.
2. Enter **115** lb/ft^3 for the *Bulk Density*.
3. Enter **0.002** lbs oil/lbs soil for the *Maximum Oil Retention*.
4. Click on the button *Go Forward to Next Page (Contaminant Concentrations)* to continue.

A3.4.2 *Contaminant Concentrations*

Using average concentrations for the site contaminants:
1. Enter **90** μg/L for *Trichloroethene (TCE)*.
2. Enter **5,000** μg/L for *1,1,1-Trichloroethane (TCA)*.
3. Enter **8,600** μg/L for *Perchlorate (ClO$_4$)*.
4. Leave all other *contaminant concentrations* **blank**.
5. The *e- equiv demand from contaminant concentrations* should be **9.21E-04** e- equiv/L.
6. Click on the button *Go Forward to Next Page (Biogeochemical Characterization)* to continue.

A3.4.3   *Biogeochemical Characterization*

Using average values for background electron acceptors:
1. Enter **2.7** mg/L for *Background Dissolved Oxygen*.
2. Enter **9.5** mg/L for *Background Nitrate*.
3. Enter **28** mg/L for *Background Sulfate*.
4. Enter **5** mg/L for *Estimated Methane Produced*.
5. Leave *Soil Manganese Content* **blank**.
6. Enter **2.0** mg/L for *Estimated Mn^{2+} Produced*.
7. Leave *Soil Iron Content* **blank**.
8. Enter **10** mg/L for *Estimated Fe^{2+} Produced*.
9. Enter **5.9** for the *pH*.
10. Leave *Alkalinity* **blank**.
11. The *e- equiv demand from biogeochemical characterization* should be **8.81E-03** e- equiv/L.
12. The *Total e- equiv demand* should be **9.73E-03** e- equiv/L.
13. Click on the button *Go Forward to Next Page (Substrates and Reagents)* to continue.

A3.4.4 *Substrates and Reagents*

1. For the *Brand and Product ID* enter **ABC Brand 600**.
2. Enter **C$_{56}$H$_{100}$O$_{6}$** for the *Chemical Formula*.
3. Enter **60**% for the *% vegetable oil*.
4. The *Electron equivalents per kg raw product* should be **217.75** e^{-}/kg.
5. For the *Cost per pound of product including shipping* enter **2.00** $/lb.
6. The *Cost per pound of oil* should be **3.33** $/lb.
7. **Save** design.
8. Click on the button *Go Forward to Next Page (Injection through Direct Push Rods)* to - continue.

A3.5   Installation and Injection

As stated previously only one of the three methods needs to be filled out, but we will look at each method in this tutorial.

A3.5.1 *Injection through Direct Push Rods*

A3.5.1.1 Injection Information
1. For the *Length of injection screen* enter **1.5** ft.
2. Enter **20** psi for the *Injection pressure*.
3. Enter **4** gpm for the *Injection rate to be used in Design*.
4. Enter **10** gal/ft for the *Gallons injected per foot of injection interval*.

A3.5.1.2 Fixed Costs
1. Enter $**0** for the *Prime contractor mobilization*.
2. Enter $**500** for the *Subcontractor mobilization*.
3. Enter $**100** for *Water Supply*.
4. Enter $**500** for *Piping and other equipment*.
5. For the *Time required for equipment setup and removal* enter **5** person-hr.
6. Enter **75** $/hr for the *Average labor rate for equipment setup and removal*.
7. The *Total fixed cost* should be $**1,475**.

A3.5.1.3 Prime Contractor Information and Daily Costs
1. Enter **1** persons for the *Prime contractor personnel on-site each day of injection*.
2. Enter **75** $/hr for the *Average labor rate of prime contractor personnel*.
3. For the *Hours billed per person per day* enter **10** hr/person/day.
4. Enter **60** $/person/day for *Per Diem*.
5. Enter **30** $/day for *Vehicle rental*.
6. Enter **70** $/person/day for *Lodging*.
7. Enter **100** $/day for *Additional costs*.
8. Enter **75** $/day for *Injection equipment costs*.
9. The *Total daily cost for prime contractor* should be **1,085** $/day.

A3.5.1.4 Subcontractor Information and Daily Costs
1. Enter **Geoprobe 6600** for the *Drilling Equipment to be used*.
2. Enter **1,800** $/day for the *Daily cost for DPT equipment and operator*.
3. For the *Productive working time per day* enter **9** hr.
4. For the *Rig time to complete one boring* enter **1.0** hr/boring.
5. Enter **50** $/boring for *Additional material and IDW costs per boring*.
6. The *Total cost per boring (without fluid injection)* should be **371** $/boring.

A3.5.1.5 Costs for Injection using DPT Equipment
1. The *Injection costs per day* should be **2,885** $/day.
2. Click on the button *Go Forward to Next Page (Well Installation by Direct Push)* to continue.

A3.5.2 *DPT Well Installation followed by Manifolded Emulsion Injection*

A3.5.2.1 Well Information
1. For the *Well Screen Diameter* enter **1** in.
2. For the *Effective Diameter of Sand Pack* enter **1.5** in.

A3.5.2.2 Well Installation Costs for Direct Push Installation
1. For the *Drilling Equipment to be used* enter **Geoprobe 6600**.
2. Enter **3,190** $/day for the *Daily cost for DPT equipment and operator*.
3. Enter **6** wells/day for *Wells installed per day*.
4. Enter **300** $/well for *Additional material and IDW costs per well*.
5. Enter **$0** for *Subcontractor mobilization*.
6. Enter **2** for the *Number of supervising personnel on-site each day*.
7. Enter **85** $/hr for the *Average labor rate of personnel*.
8. For the *Supervision Hours billed per person per day* enter **9** hr/person/day.
9. Enter **200** $/day for *Additional costs*.
10. The *Total cost per well* should be **1,120** $/well. This value will increase to **1,157** $/well as additional *Injection Costs* are entered in **Section 5.2.5**.

A3.5.2.3 Injection Information
1. Enter **5** psi for the *Injection pressure*.
2. For the *Well loss coefficient* enter **5**.
3. The *Theoretical estimate of injection rate per well* should be **3.9** gpm/well.
4. Enter **1.5** gpm/well for the *Injection rate to be used in Design*.

A3.5.2.4 Fixed Costs
1. Enter $**2,500** for *Mobilization*.
2. Enter $**0** for *Water Supply*.
3. Enter $**1,000** for *Piping and other equipment*.
4. For the *Time required for equipment setup and removal* enter **45** hr.
5. Enter **100** $/hr for the *Average labor rate for equipment setup and removal*.
6. The *Total fixed cost* should be $**8,000**.

A3.5.2.5 Injection Costs
1. Enter **2** persons for the *Number of personnel on-site each day of injection*.
2. Enter **85** $/hr for the *Average labor rate of personnel*.
3. For the *Hours billed per person per day* enter **9** hr/person/day.
4. Enter **40** $/person/day for *Per Diem*.
5. Enter **0** $/day for *Vehicle rental*.
6. Enter **70** $/person/day for *Lodging*.
7. Enter **750** $/day for *Injection equipment costs*.
8. Enter **100** $/day for *Additional costs*.
9. The *Injection costs per day* should be **2,600** $/day.
10. Click on the button *Go Forward to Next Page (Well Installation by Conventional Drilling)* to continue.

A3.5.3 *Well Installation by Conventional Drilling followed by Emulsion Injection*

A3.5.3.1 Well Information
1. For the *Well Screen Diameter* enter **2.0** in.
2. For the *Effective Diameter of Sand Pack* enter **2.5** in.

A3.5.3.2 Well Installation Costs for Conventional Drilling
1. For the *Drilling Equipment to be used* enter **Hollow Stem Auger**.
2. Enter **30** $/ft for the *Cost for well installation*.
3. Enter **3** wells/day for *Wells installed per day*.
4. Enter **250** $/well for *Additional material and IDW costs per well*.
5. Enter **$0** for *Subcontractor mobilization*.
6. Enter **2** for the *Number of supervising personnel on-site each day*.
7. Enter **85** $/hr for the *Average labor rate of personnel*.
8. For the *Supervision Hours billed per person per day* enter **9** hr/person/day.
9. Enter **200** $/day for *Additional costs*.
10. The *Total cost per well* should be **1,277** $/well. This value will increase to **1,350** $/well as additional *Injection Costs* are entered in **Section 5.3.5**.

A3.5.3.3 Injection Information
1. Enter **10** psi for the *Injection pressure*.
2. For the *Well loss coefficient* enter **5**.
3. The *Theoretical estimate of injection rate per well* should be **7.2** gpm/well.
4. Enter **3.0** gpm/well for the *Injection rate to be used in Design*.

A3.5.3.4 Fixed Costs
1. Enter **$2,500** for *Mobilization*.
2. Enter **$0** for *Water Supply*.
3. Enter **$1,500** for *Piping and other equipment*.
4. For the *Time required for equipment setup and removal* enter **45** hr.
5. Enter **100** $/hr for the *Average labor rate for equipment setup and removal*.
6. The *Total fixed cost* should be **$8,500**.

A3.5.3.5 Injection Costs
1. Enter **2** persons for the *Number of personnel on-site each day of injection*.
2. Enter **85** $/hr for the *Average labor rate of personnel*.
3. For the *Hours billed per person per day* enter **9** hr/person/day.
4. Enter **40** $/person/day for *Per Diem*.
5. Enter **0** $/day for *Vehicle rental*.
6. Enter **70** $/person/day for *Lodging*.
7. Enter **1,000** $/day for *Injection equipment costs*.
8. Enter **100** $/day for *Additional costs*.
9. The *Injection costs per day* should be **2,850** $/day.
10. Click on the button *Go Forward to Next Page (Summary of Installation and Injection Costs)* to continue.

A3.5.4 *Summary of Installation and Injection Costs*

1. Look at **Figure A3.3** which shows a summary of the three methods.

Figure A3.3. Summary of the Different Methods that Shows Which Items are Used in the Design.

2. Click on the radio button *Select this method* for **Well Installation by Direct Push followed by Emulsion Injection** as shown in **Figure A3.3**.
3. **Save** design.
4. Click on the button *Go Forward to Design a Barrier Treatment* to continue.

A3.6   Barrier Treatment

The objective of this tutorial is to design a 400 ft long barrier to stop the plume from migrating further downgradient. An area treatment to treat the source follows similar steps as outlined below.

A3.6.1 *Design Information*

    A3.6.1.1 Treatment Zone Dimensions
    1. Enter **400** ft for the *Width (perpendicular to groundwater flow)*.
    2. Enter **80**% for the *Percentage of injection zone that transmits most flow*.

    A3.6.1.2 Treatment Zone Contact Time
    1. Enter **60** days for the *Minimum Allowable Contact time*.

    A3.6.1.3 Targeted Carbon Released
    1. Enter **75** mg/L for the *Average Amount of DOC Released*.
    2. The *DOC Released per year* should be **197** lb.

    A3.6.1.4 Design Life
    1. Enter **25** years for the *Total Project Life (Max of 30 years)*.
    2. Enter **0.5** for the *Substrate Scaling Factor*.
    3. Enter **7** years for the *Maximum Time between Reinjections*.

    A3.6.1.5 Contact Efficiency
    1. Enter **0.8** for the *Volume Scaling Factor*.
    2. Enter **0.6** for the *Mass Scaling Factor*.
    3. The *Estimated Contact Efficiency for Injection* should be **74**% to **87**%.
    4. Click on the button *Go Forward to Next Page (Capital Cost Analysis)* to continue.

A3.6.2 *Capital Cost Analysis*

    A3.6.2.1 Well Layout
    1. Enter **5** ft for the *Minimum Well Spacing*.
    2. Enter **5** ft for the *Incremental Increase in Well Spacing*.

    A3.6.2.2 Fixed Costs
    1. Enter $**15,000** for *Planning, Engineering, and Permitting*.

    A3.6.2.3 Injection Information
    1. Enter **9** hrs for the *Hours of injection per day*.
    2. Enter **10** wells for the *Maximum number of wells to inject at one time*.
    3. Enter **50**% for the *Percentage of total wells to inject at one time*.

    A3.6.2.4 Total Installation and Injection Costs
    1. *The Total Installation and Injection Costs* for a *Well Spacing* of **5** ft should be
       $**378,607**.

2. See if graph of Well Spacing vs Capital Cost matches **Figure A3.4**.
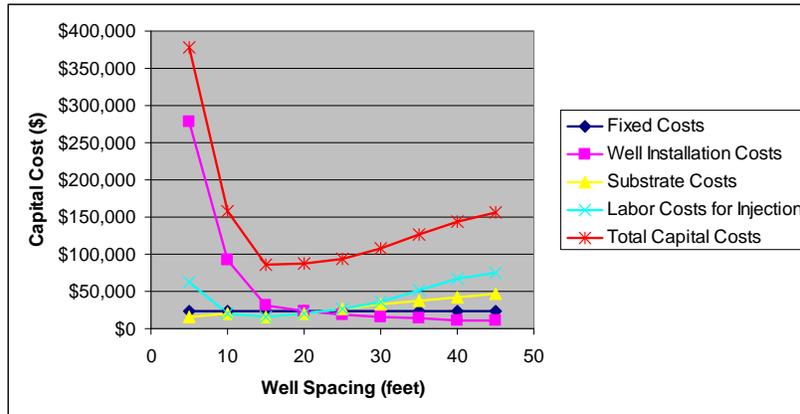

Figure A3.4 Graph of Well Spacing Versus Capital Costs.

3. Click on the button *Go Forward to Next Page (Life Cycle Analysis)* to continue.

A3.6.3 *Life Cycle Analysis*

A3.6.3.1 Life Cycle Analysis
1. Enter **4**% for the *Annual Interest Rate*.
2. Enter $**5,000** per future event for *Planning, Engineering, and Permitting Costs*.
3. Enter $**7,500** per year for *Annual Monitoring and Reporting Costs*.
4. Enter **20**% for *Well Rehabilitation and/or Installation Cost (% of Initial Drilling)*.

A3.6.3.2 Net Present Value for Design Life
1. The *Project Life NPV* for a *Well Spacing* of **5** ft should be $**832,590**.
2. See if graph of Well Spacing vs NPV matches **Figure A3.5**.
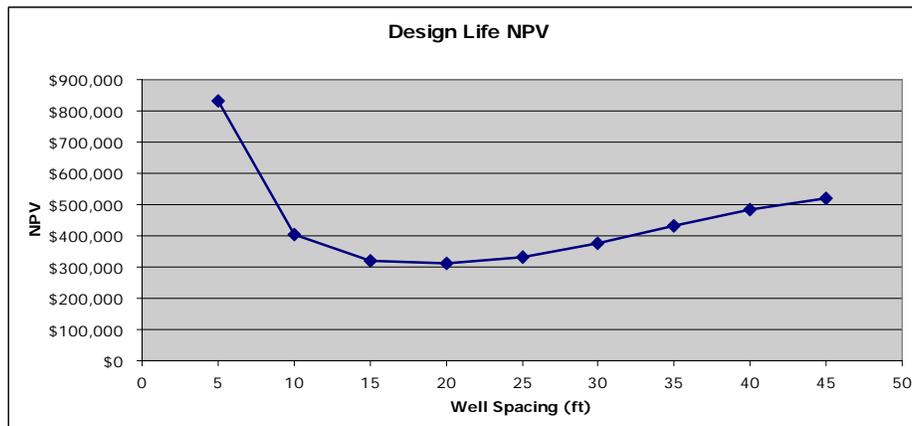
Figure A3.5. Graph of Well Spacing Versus Design Life Net Present Value.

3. From looking at **Figures A3.4** and **A3.5** click on the radio button *Select a Design* corresponding to a **well spacing** of **20** ft.
4. Click on the button *Go Forward to Next Page (Net Present Value)* to continue.

A3.6.4 *Net Present Value for Selected Design*

1. The *Total Cost* should be $**310,126**.
2. Check to see if the net present value graphs match **Figure A3.6** (a) and (b).


(a)

(b)
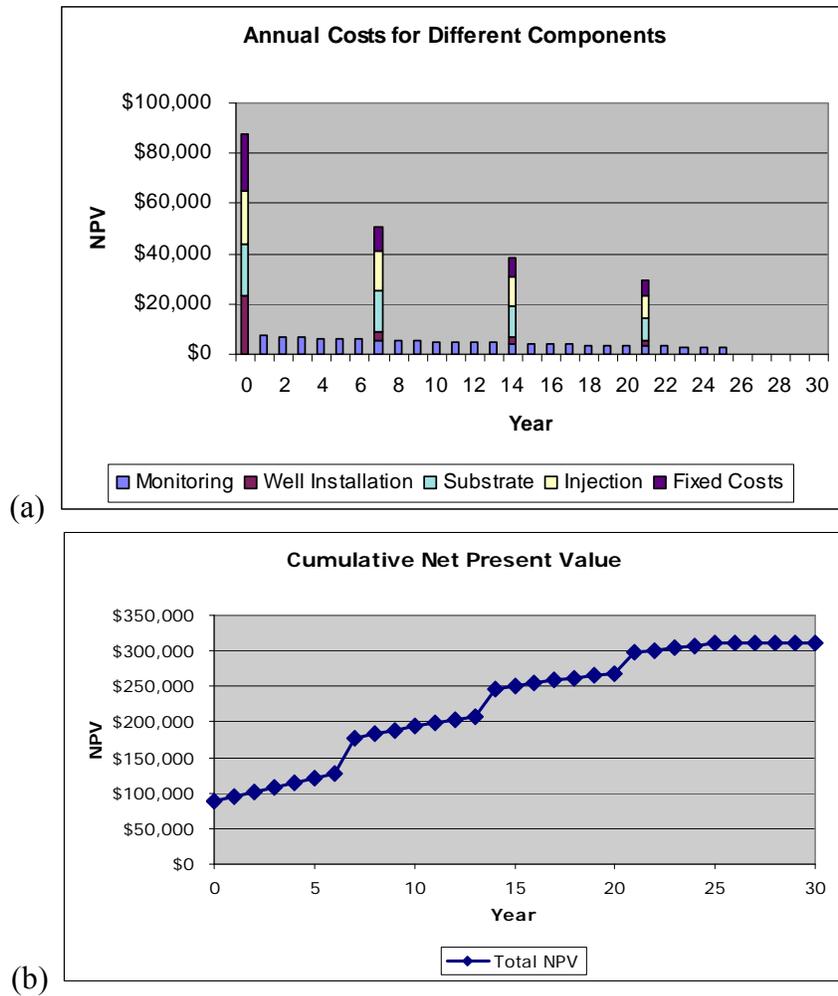
Figure A3.6. Graph of a Breakdown of the Costs Per Year (a) and Cumulative NPV over the Design Life (b).

3. Click on the button *Go Forward to Next Page (Summary of Selected Design)* to continue.

A3.6.5 *Selected Design*

This page summarizes the selected design that has a *well spacing* of **20** ft.
1. Review the information on the page.
2. **Save** design.
3. Click on the button *Print this Page*.

A3.7 Conclusions

This concludes the Emulsified Oil Design Tool – Barrier tutorial. Some additional comments are listed below:

- Different designs can be compared by selecting a different **well spacing** on the *Life Cycle Analysis* page and then printing the summary on the *Selected Design* page.

- Some of the main variables that directly affect the design are found on the *Design Information* page. They are:
    o Contact Time
    o Substrate Scaling Factor
    o Volume Scaling Factor
    o Mass Scaling Factor
  Another important parameter is the Maximum Oil Retention found on the Aquifer Description page.

- To design an area treatment go to the *Table of Contents* and click on the button *Design Information* under the heading **Area Treatment**.