PROCEEDINGS, TOUGH Symposium 2012
Lawrence Berkeley National Laboratory, Berkeley, California, September 17-19, 2012

SIMULATING MIGRATION OF CO_2 AND CH_4 GENERATED FROM GEOTHERMAL TREATMENT AND BIODEGRADATION OF SANITATION WASTE IN THE DEEP SUBSURFACE

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ABSTRACT

The Terminal Island Renewable Energy (TIRE) Project is the nation's first full-scale application of deep-well injection technology to treat and convert sanitation plant residuals (biosolids or wetcake) into a renewable energy source (high purity methane) while simultaneously sequestering greenhouse gases. During the past four years, a slurry mixture composed of digested sludge, trucked wetcake, and reverse-osmosis-treated brine has been injected into sandstone formations more than 1500 m beneath the City of Los Angeles Terminal Island Wastewater Treatment Plant. At that depth, the earth's natural high temperature biodegrades the organic mass into methane and carbon dioxide. The carbon dioxide dissolves in the aqueous phase, leaving relatively pure methane in the gas phase. The EOS7C module of TOUGH2 is used to model migration of these components in the target formation. Temperature and pressure are continuously monitored at the injection well and at two offset monitoring wells. Fluid and gas samples have been collected at the offset monitoring wells, for comparison and calibration of the 3D simulation results. We present herein simulation results and field monitoring observations.

INTRODUCTION

Millions of tons of sewage sludge (biosolids) are generated each year by municipal sanitation agencies around the world. In the United States and elsewhere, most biosolids are currently trucked long distances and applied to the land surface. But the ratio of rural land to urban development is decreasing, while the volume and costs associated with biosolid trucking and disposal are steadily increasing. With increasing urban development and population growth, environmentally sustainable alternatives are desperately needed.

GeoEnvironment Technologies has developed and successfully demonstrated an innovative new technology to manage municipal sludge with significant environmental benefits. Through appropriate geological formation selection, well design, and advanced geophysical monitoring, the biomass can be injected into soft, porous, sand formations in the deep subsurface (on the order of 1500 m or more).

Deep underground, the earth's natural geothermal heat pasteurizes the biomass quickly (within 24 hours), and then through continuing anaerobic biodegradation, converts the organic mass to methane and carbon dioxide (CO_2). The CO_2 is preferentially absorbed by formation waters (due to its high solubility in water) while relatively pure methane gas collects and may be stored long term, or eventually produced for beneficial use. (Bruno et al., 2012; 2005). As compared to landfill or land application, deep-well injection provides greater protection for shallow groundwater, significantly reduced pollution and greenhouse gas emissions, and provides large urban areas a local management solution without imposing on rural areas.

About 150 tons per day of biosolids have been injected at the City of Los Angeles Terminal Island Wastewater Treatment Plant since July 2008. Injection cycles last about 12 hours per day, five days per week, with extended shut/in over each weekend. Injection rates vary from 10 to 24 L/s (4 to 9 bpm).

The local surface-infrastructure footprint for the TIRE project is only 1,600 m^2; thus, the project could easily be embedded in an existing treatment plant. The system is shown in Figure 1. An image of the biosolids material that is being injected is shown in Figure 2.

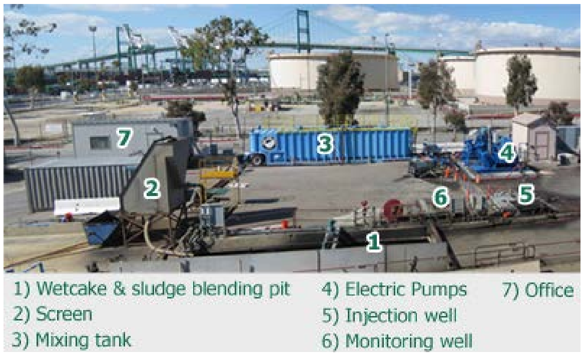

Figure 1. TIRE project site

Figure 2. Biosolids in the blending pit

SUBSURFACE GEOLOGY

The subsurface at the project site includes interbedded sands and shales to a depth of about 2,500 m. One injection well and two monitoring wells are drilled to a depth of about 1,500 m (5200 ft). The bottom-hole locations of the monitoring wells are located about 160 m north and west of the injection well—see Figure 3. The geologic setting and cross section between well SFI1 (injection well) and well SFI2 (monitoring well to the north) is illustrated in Figure 4.

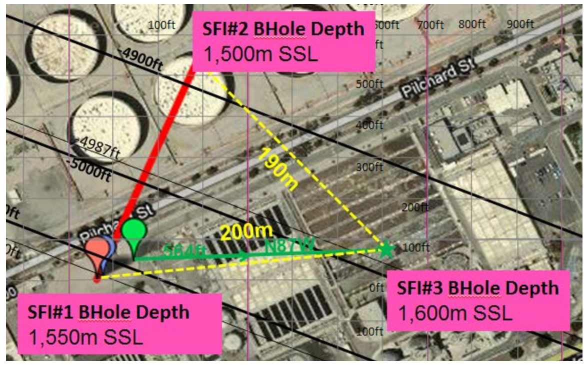

Figure 3. Well paths of monitoring wells

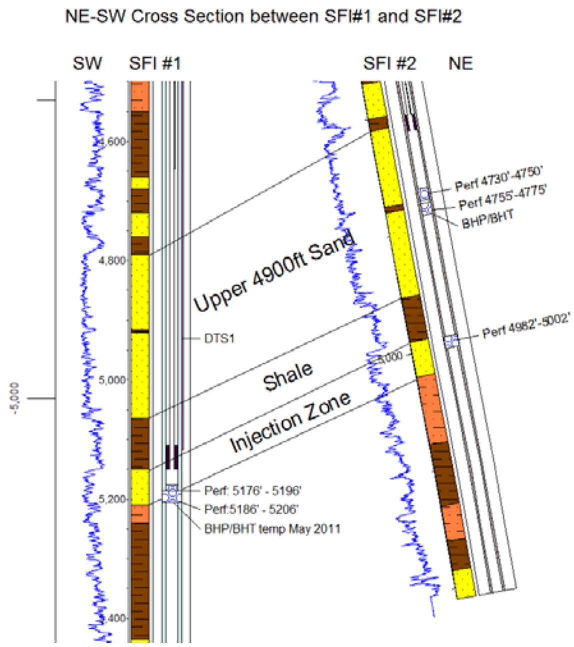

Figure 4. Gamma ray log data and lithology of SFI1 and SFI2 (numbers in ft)

TOUGH2 MODEL CONCEPT

A 3D simulation model for the subsurface has been defined using TOUGH2/EOS7C software. We take into account the dipping formation and directional fracturing observed during the initial phase of the project. A symmetry plane is applied in direction of the dip. Figure 5 shows a visualization of the model domain.

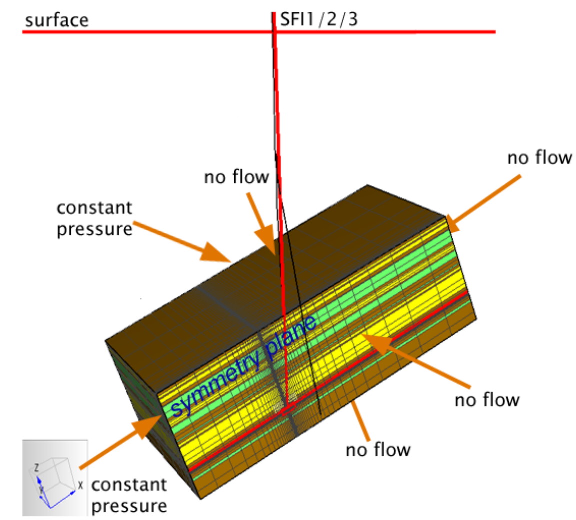

Figure 5. Reservoir simulation model grid covers 1500 m × 750 m × 500 m discretized into 47,200 cells

Material properties

Geological analysis of injection and monitoring wells identified a 16 m thick target formation (lower sand) shown in close up in Figure 6. Four different material types are defined (Table 1).

Table 1. Material properties

Material name	density [kg/m³]	porosity [-]	x permeability [mD]	y permeability [mD]	z permeability [mD]	pore compressibility [1/Pa]
SAND	2660	0.25	60	60	30	1.50E-09
FSAND	2660	0.25	500	500	500	1.5E-09
SHALE	2600	0.05	1	1	1	1.39E-09
SILT	2600	0.25	15	15	7	1.39E-09

	rel. Permeability				capillar pressure				
Material name	λ	S_{lr}	S_{ls}	S_{gr}	λ	S_{lr}	$1/P_0$ (PSI)	P_{max} (PSI)	S_{ls}
SAND	0.9167	0.1	1	0.01	0.4118	0.03	0.51849	1363	1
FSAND	0.9167	0.1	1	0.01	0.4118	0.03	0.51849	1363	1
SHALE	0.9167	0.2	1	0.02	0.4118	0.03	0.11583	1363	1
SILT	0.9167	0.15	1	0.015	0.4118	0.03	0.34474	1363	1

FSAND is a material with 10 times higher permeability than surrounding SAND. This represents the fracture opened during the initial phase of the project. For relative permeability and capillary pressure functions, the van Genuchten model is assumed.

Grid setup

The coordinate system is rotated to consider dipping formation layers. An average 20° up-dip angle is estimated. Vertical refinement is based on sand, shale, and silt layers from geological interpretation of well logs. Injection and cap rock zones are further refined in vertical direction. Horizontal (in dip direction) refinement starts with a smallest cell size of 0.006 m^3 at injection point and gradually increases with distance.

In the y-direction (away from the symmetry plane), we install a 3 cm thin cell layer. Thus we can apply the high permeability FSAND material to an area of 120×60 m around the injection point representing the assumed fracture plane. An extra source cell is connected to six perforated cells to facilitate injection of water in the target zone.

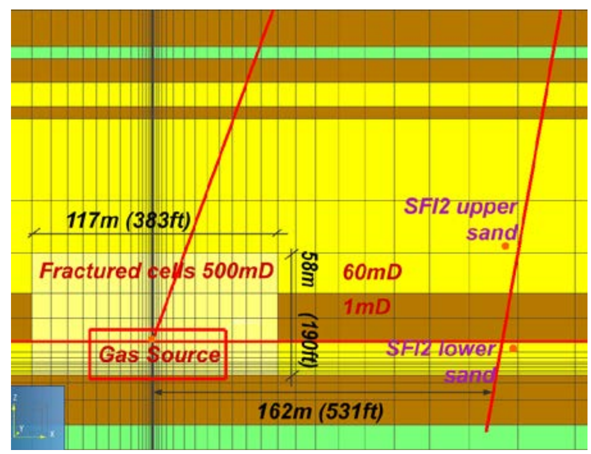

Figure 6. Closeup of injection well, assumed fracture, and gas source area

Initial conditions

Based on the analysis of an *in situ* pressurized sample taken prior to any injection of biosolids, salinity of 28,300 ppm (= 11% brine fraction for EOS7C input (Pruess et al., 2011)) is applied throughout the modeled area. Temperature and pressure gradient as measured in SFI1 are applied. Thus, we start with 14.2 MPa and 74°C at the point of water injection. Initial CO_2 and CH_4 mass fractions measured are not taken into account for *in situ* conditions, but shall be considered when estimating changes in concentration.

Dirichlet boundary conditions

The Thums Huntington Beach fault northeast of the modeling area is represented by a no-flow boundary condition. Bottom, top, and symmetry plane are also set to no flow. All other edges are set to constant pressure boundary. The modeling is done for isothermal conditions.

Neumann boundary conditions

Gas generation assumption

Lab experiments completed prior to start of injection give us an idea about gas-generation amounts under prevailing pressure and temperature conditions. Based on Bruno et al. (2005), we assume 900 L gas with a ratio of 70:30 for CH_4:CO_2 are generated per kilogram of volatile solids decomposed. It has therein also been observed that after 90 days, about 20% of volatile solids have been biodegraded. Assuming a linear degradation rate, material injected on Day 1 shall be fully biodegraded on Day 450. Until Day 450, gas generation is linearly increasing up to a stabilized daily gas-generation rate of 5,000 m^3. This amount is estimated based on average daily injection rates of 5,500 kg volatile solids.

Water injection rate

Biosolids have an average water content of 72%. Thus, we make the simplified assumption of pure water injection to simulate the injected volumes into the target formation. Field injection rates are applied, and a maximum time step of two hours is used to allow simulating the injection cycles.

FIELD MEASUREMENTS

Pressurized samples

Pressurized fluid samples have been taken at the injection well (SFI1) and the monitoring wells (SFI2 & SFI3). Monitoring wells hit the target formation at a distance of 160 m away from the injection point. Table 2 lists the mass fraction results from the pressurized samples.

Table 2. Mass fraction CO_2 and CH_4 (average of two sample analyses for each date)

Well	CO_2 (-)	CH_4 (-)
SFI1(*in situ*)	2.84E-06	5.30E-04
SFI2(518 days)	1.56E-05	6.77E-04
SFI3(889 days)	4.50E-06	5.81E-04
SFI3(1,383 days)	2.96E-05	9.63E-04

Starting from the first sampling in SFI2 monitoring well (Day 518 of injection), we found that the biosolids have reached a distance of 160 m away from the injection well.

Gas samples from monitoring wells

Starting November 2010, gas samples have been collected at the well head of the two monitoring wells (SFI2 and SFI3). Figure 7 shows steadily increasing methane concentration and steadily decreasing nitrogen content in Well SFI2. Note that at the end of 2011, the well was opened to atmosphere for a workover, allowing air (primarily nitrogen) to fill the well. After shut/in and starting in March 2012, the methane content again started to rise and the nitrogen content again started to decline. Well SFI3, which was sampled later in time than Well SFI2, showed consistently high methane content until late April 2012, when it was also opened to the atmosphere. After shut/in and starting in May 2012, methane also started to increase again in SFI3—see Figure 8. CO_2 amounts are below 0.1% volume in the head space gas for all of the samples analyzed.

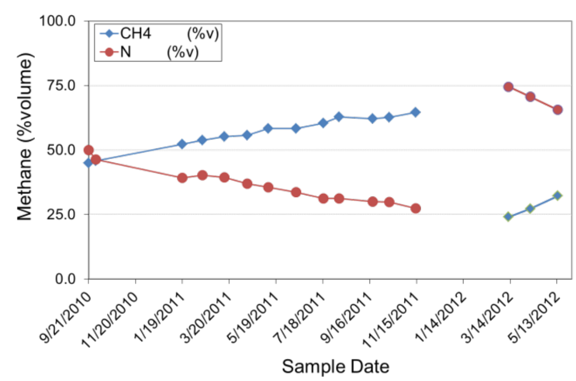

Figure 7. SFI2: methane concentration

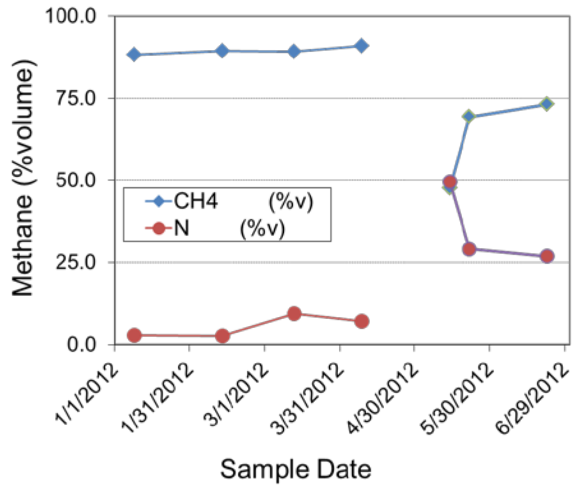

Figure 8. SFI3: methane concentration

RESULTS AND DISCUSSION

To date, we have been able to model one year of real-time simulation using the EOS7C module of TOUGH2. This module can simulate components CO_2 and CH_4 simultaneously at the subsurface conditions prevailing in our system (see Oldenburg et al., 2004).

Pressure

Initial calibrations focused on the pressure match during injection in the injection well (SFI1) and one of the two monitoring wells (SFI2). Good match has been found for an injection rate of 15 L/s (6 bpm) which is the average injection rate in the initial phase of the project.

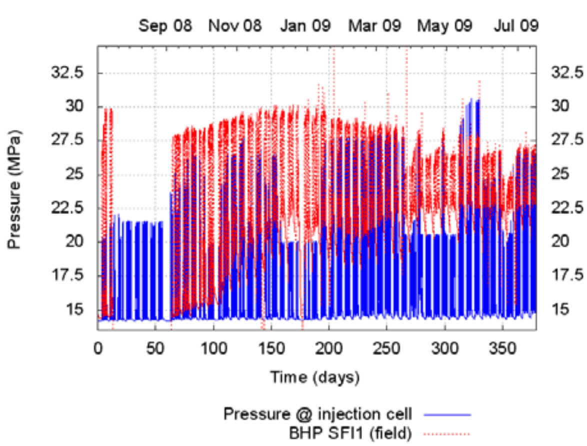

Figure 9. Measured (red) and simulated (blue) bottom-hole pressure of injection well SFI1

Fluid migration

As we inject pure water as a proxy for carrier fluid, we use the decrease in initial salinity as an indicator for injected fluid migration. Figure 10 shows that injected water has reached out to a radius of 100 m on top of target sand. Moreover, salinity at monitoring well SFI2 has started to decline after 362 days of injection. Changes are below 0.5% of initial salinity.

We cannot directly compare this result with our field measurement, because the project also injects high salinity brine with the biosolids. Salinity stays fairly stable over time in the field.

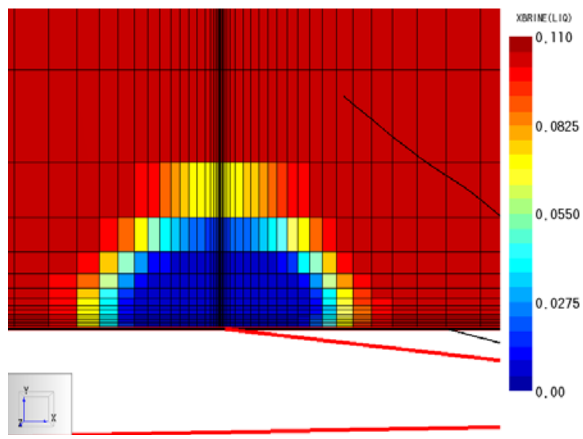

Figure 10. Brine distribution top of target zone—Day 362

CO_2 and CH_4 migration

After 362 days, a maximum gas saturation of 22% is observed in the model. An oxygenated activated (OA) log performed in June 2009 (about a year after injection start) did not detect any free gas phase in the injection well. Detection limits for OA logs are about 30% free gas. Thus, we have a reasonable qualitative match regarding free gas.

Distribution of gas phase (= inverse of liquid saturation) in the symmetry plane and top of the target zone sand is shown in Figure 11 and 12. Maximum extent of the gas plume into the model (= perpendicular to the symmetry plane) is 25 m. The gas plume migrates 75 m vertically and 90 m horizontally in the symmetry plane. Initial preferred migration of gas in the horizontal and vertical directions occurs due to the fracture plane.

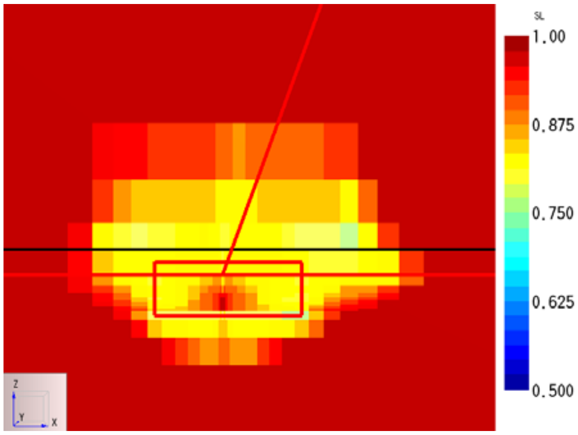

Figure 11. Liquid saturation in symmetry plane—Day 362

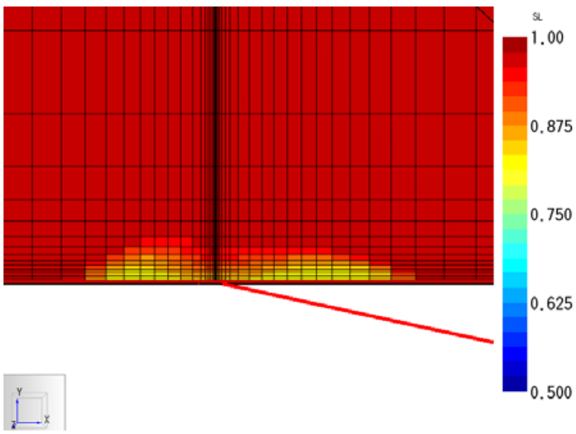

Figure 12. Liquid saturation at top of target zone—Day 362

Figure 13 and 14 show the mass fractions of CH_4 and CO_2 in liquid phase at the top of the target zone.

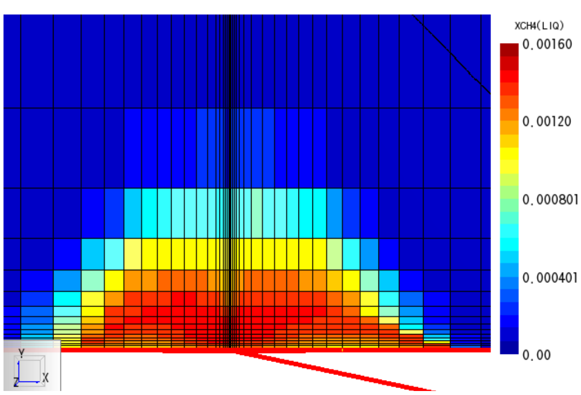

Figure 13. CH_4 mass fraction in liquid phase at top of target zone—Day 362

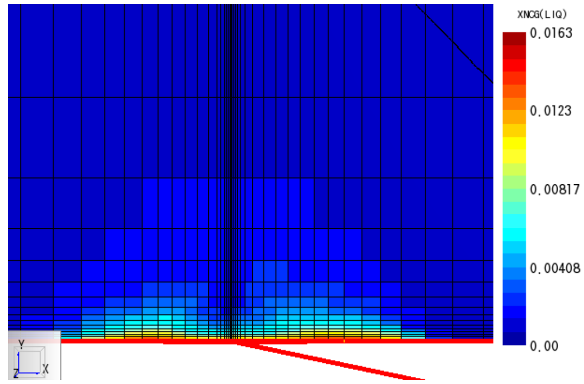

Figure 14. CO_2 mass fraction in liquid phase at top of target zone—Day 362

About Day 360, CH_4 appears in monitoring cell SFI2—see Figure 15.Slightly increased methane content has been measured at SFI2 on Day 518.

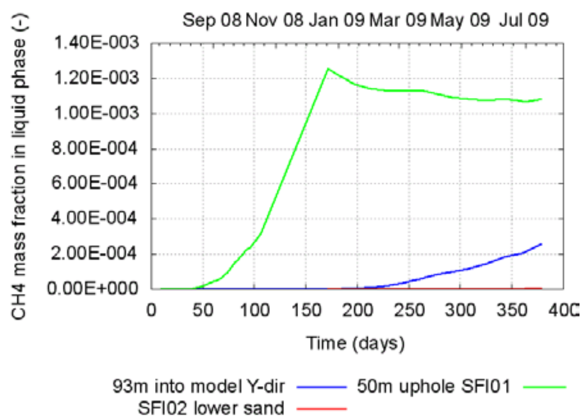

Figure 15. CH_4 mass fraction at different monitoring points

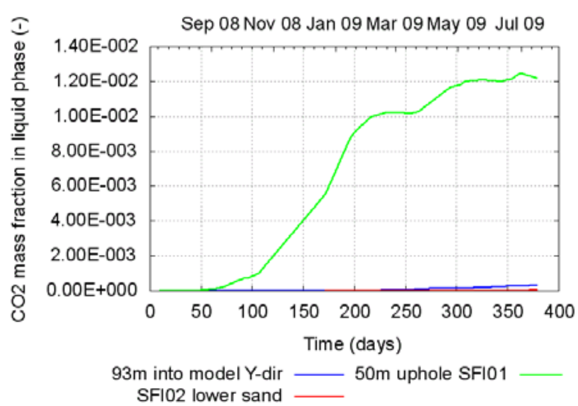

Figure 16. CO_2 mass fraction at different monitoring points

Liquid at prevailing conditions can hold CO_2 up to a mass fraction of about 1.60E-02 in liquid phase—see Figure 14. Field and simulation results at monitoring points are at least an order of magnitude lower. That is consistent with observations of no free CO_2 in the head space gas sampling. Up to 1.60E-03 mass fraction of CH_4 in liquid phase is observed on top of the target zone—see Figure 13.

Figure 15 and 16 show us that CO_2 and CH_4 components started reaching monitoring point SFI2, but at concentrations still significantly lower than saturation limits.

In order to make more detailed qualitative comparison between field and modeling measurements, we need to continue simulating for a minimum of 4 years. Currently, it takes us about 1 month of computer time to simulate one year.

CONCLUSIONS

More than 100 million gallons of slurry containing biosolids have been successfully injected at the Terminal Island Treatment Plant since mid-2008. The process is being monitored by a variety of techniques, including downhole pressure sensors, downhole temperature sensors, microseismic sensors, and offset well fluid and gas sampling. We have developed a 3D flow simulation model to simulate the process of *in situ* biodegradation of the organic mass into CO_2 and CH_4, with subsequent fluid and gas migration. The model currently provides a reasonable match to observed pressure behavior. Both simulation results and field measurements indicate that CH_4 and CO_2 have reached the monitoring wells. Initial simulations show reasonable qualitative results, but longer real-time simulation is still required and is continuing.

ACKNOWLEDGMENT

The authors would like to thank cooperation partners of TIRE project: City of Los Angeles, GeoEnvironment Technologies and Environmental Protection Agency (EPA). Appreciation goes to Curt Oldenburg for technical support with EOS7C.

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