Research Program

Energy Resources

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The Energy Resources Program (ER) is responsible for two major program areas: Oil and Gas Exploration and Development, and Geothermal Energy Development.

OIL AND GAS EXPLORATION AND DEVELOPMENT

Multidisciplinary research is being conducted in reservoir characterization and monitoring, optimization of reservoir performance, and environmental protection. Using basic research studies as a source of innovative concepts, ER researchers seek to transform these concepts into tangible products of use to industry within a time-frame consistent with today's rapid growth in technology. Reservoir characterization and monitoring involve development of new seismic and electromagnetic techniques focused at the inter-well scale. Field acquisition, laboratory measurements, and numerical simulation play important roles in the development activities. Optimization of reservoir performance is focused on simulation-based methods for enhancing reservoir management strategies. Emphasis is placed on the integration of geophysical data, production data, and reservoir simulation. The next major step in research will focus on methods to optimize performance through integration of monitored geophysical data, production data, and reservoir simulation.

International and national concern about the variable climatic effects of greenhouse gases produced by burning of fossil fuels is increasing, while it is also recognized that these fuels will remain a significant energy source well into the next century. In response to these concerns, ER has initiated research focused on development of technologies that will minimize the impact of fossil-fuel usage on the environment. Methane hydrates constitute a huge potential fuel source with lower carbon emissions than coal or oil. ER researchers are developing and evaluating possible methods for producing gas from such deposits. Geophysical data acquisition and inversion methods developed in the ER program are also being applied in a new project on geologic sequestration of CO_2 carried out in the Climate Variability and Carbon Management Program within the Earth Sciences Division.

Principal research activities include:

- Development of single-well and crosswell seismic technology, including instrumentation, acquisition and processing
- Applications of seismic methods for characterization of fractured reservoirs
- Laboratory measurement of the seismic properties of poorly consolidated sands
- Development of efficient 3D elastic-wave propagation codes
- Improved inversion methods for reservoir characterization, with a focus on combining production and geophysical data
- Application of x-ray CT and NMR imaging to study multiphase flow processes
- Pore-to-laboratory-scale study of physical properties and processes, with a focus on controlling phase mobility, predicting multiphase flow properties and drilling efficiency
- Development of reservoir process-control methods
- Development of new methods to mitigate environmental effects of petroleum refining and use
- Enhancement of refining processes using biological technologies
- Numerical simulation of subsurface methane hydrate systems

Since 1994, the major part of the Oil and Gas Exploration and Development program has been funded through the Natural Gas and Oil Technology Partnership Program. Begun in 1989, the partnership was expanded in 1994 and again in

1995 to include all nine Department of Energy multiprogram laboratories, and has grown over the years to become an important part of the DOE Oil and Gas Technologies program for the national laboratories. Partnership goals are to develop and transfer to the domestic oil industry the new technologies needed to produce more oil and gas from the nation's aging, mature domestic oil fields, while safeguarding the environment.

Partnership technology areas are:

- Oil and gas recovery technology
- Diagnostics and imaging technology
- Drilling, completion, and stimulation
- Environmental technologies
- Downstream technologies

Projects are typically multiyear, are reviewed and reprioritized annually by industry panels, and are collaborations between national laboratories and industry

GEOTHERMAL ENERGY DEVELOPMENT

The main objective of ER's geothermal energy development program is to reduce uncertainties associated with finding, characterizing, and evaluating geothermal resources. The ultimate purpose is to lower the cost of geothermal energy for electrical generation or direct uses (e.g., agricultural and industrial applications, aquaculture, balneology). The program encompasses theoretical, laboratory, and field studies, with an emphasis on a multidisciplinary approach to solving the problems at hand. Existing tools and methodologies are upgraded, and new techniques and instrumentation are developed for use in the areas of geology, geophysics, geochemistry, and reservoir engineering. Cooperative work with industry, universities, and government agencies draws from Berkeley Lab's 25 years of experience in the area of geothermal research and development.

In recent years, DOE's geothermal program has become more industry-driven, and the Berkeley Lab effort has been directed toward technology transfer and furthering our understanding of the nature and dynamics of geothermal resources under production, such as The Geysers geothermal field in northern California, which has begun to show the effects of overexploitation.

At present, the main research activities of the program include:

- Geothermal Reservoir Dynamics: development and enhancement of computer codes for modeling heat and mass transfer in porous and fractured rocks, with specific projects such as modeling the migration of phase-partitioning tracers in boiling geothermal systems; modeling of mineral dissolution and precipitation during natural evolution, production, and injection operations; and geophysical-signature prediction of reservoir conditions and processes
- Isotope Geochemistry: identification of past and present heat and fluid sources, development of natural tracers for monitoring fluids re-injected into geothermal reservoirs, better understanding of the transition from magmatic to geothermal production fluids, and enhancement of reservoir-simulation methods and models by providing isotopic and chemical constraints on fluid source, mixing, and flow paths
- Multicomponent 3D Seismic Imaging: development and implementation of 3D surface and borehole methods for defining permeable pathways in geothermal reservoirs
- Geochemical Baseline Studies: documentation of geothermal-fluid behavior under commercial production and injection operations (e.g., field case studies), with specific emphasis on The Geysers field
- Electromagnetic Methods for Geothermal Exploration: development of efficient numerical codes for mapping high-permeability zones, using single-hole electromagnetic data

Future research will concentrate on the development of innovative techniques for geothermal exploration and assisting in a reassessment of geothermal power potential in the U.S. The emphasis will be on expanding existing fields, prolonging their productive life, and finding new "blind" geothermal systems, i.e., those that do not have any surface manifestations, such as hot springs, fumaroles, etc., that suggest the presence of deeper hydrothermal systems.

FUNDING

Within ER, The Oil and Gas Exploration and Development program receives support from the Assistant Secretary for Fossil Energy, Office of Natural Gas and Petroleum Technology, through the National Energy Technology Laboratory, the National Petroleum Technology Office, and the Natural Gas and Oil Technology Partnership, under U.S Department of Energy Contract No. DE-AC03-76SF00098. Support is also provided from industry and other sources through the Berkeley Lab Work for Others program. Industrial collaboration is an important component of DOE Fossil Energy projects.

The Geothermal Energy Development program receives support from the Assistant Secretary for Energy Efficiency and Renewable Energy, Office of Power Technologies, Office of Wind and Geothermal Technologies, of the U.S. Department of Energy.

Fractured Reservoir Modeling: Coupled Seismic and Fluid Response

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RESEARCH OBJECTIVES

Fractured reservoirs are more difficult to model and typically less well understood than porous reservoirs. These problems lead to greater expense in resource exploration/exploitation and in environmental characterization and cleanup. We are coupling state-of-the-art fractured-media modeling codes to allow investigation of the seismic response to fluid-induced changes in reservoir properties, such as pore pressure and permeability. This research could lead to improvements in remote sensing and time-lapse monitoring of dynamic processes in fractured reservoirs.

APPROACH

We have coupled two previously independent modeling codes, a hydromechanical finite-element code and a 3-D seismic finite-difference, elastic, anisotropic modeling code. In both codes, fractures are defined by their mechanical stiffness, which is in turn linked to permeability and seismic response by recently developed theoretical relationships. Using the hydromechanical code, we simulate injecting fluid into or withdrawing fluid from a reservoir for a length of time. This creates fluid-pressure gradients that act to change the fracture stiffness. Conceptually, the spatially variable fluid pressure causes fractures to open or close inhomogeneously. In a dynamic process, as fracture stiffness changes, fracture permeability and fluid pressure distribution change, which then influence the next change in fracture stiffness.

At any given time, we can apply spatially variable fracture-stiffness values to model the seismic response of the reservoir. These stiffness values are used to calculate anisotropic elastic constants, which control seismic wave propagation. In general, the reservoir has a unique set of elastic constants for each finite-element cell or finite-difference grid point. The seismic response of the reservoir can be used to spatially map the variations in elastic constants, which can then be related to variations in fracture stiffness and, in turn, to pore-pressure and permeability variations in the reservoir. In this manner, time-lapse seismic surveys can monitor reservoir changes.

ACCOMPLISHMENTS

We have successfully coupled the hydromechanical and wave-propagation modeling codes. The initial study considered a 3-D vertically fractured reservoir layer sandwiched between two homogeneous, relatively impermeable nonfractured layers. The layer is assumed to have a single dominant fracture direction. For two months, fluid is injected into the center of the reservoir via a vertical well at 80 liters per minute over the 60 m thick reservoir. A 3-D, three-component surface seismic survey was modeled at various times. Figure 1 shows the response at pre-injection (left) and at 2 months post-injection (right). A distinct change is seen in reservoir seismic reflectivity. This change is most evident in the amplitude and time of a P- to S-wave converted reflection polarized normal to the fractures. This change in seismic response is caused by the fluid injection changing fracture stiffness.

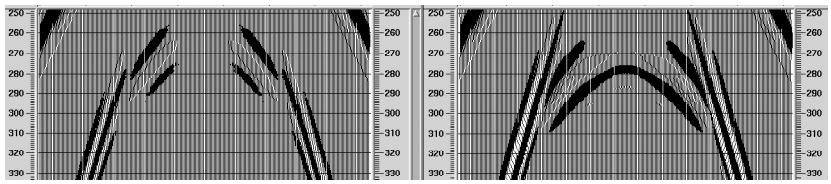

Figure 1. Surface seismic shot gather for the three-layer model described in the text. Pre-injection (left) and post-injection (right) comparison shows a substantial change in the event between 270 and 310 ms. This change in seismic reflection response is caused by fluid pressure changes in the reservoir due to injection.

SIGNIFICANCE OF FINDINGS

Understanding fractured reservoirs is important for many problems facing the U.S. Department of Energy (and the U.S. in general), including resource development (oil and gas production), underground storage of high-level waste, remediation of contaminated aquifers, geologic sequestration of CO_2, and groundwater exploration and storage. Currently, fluid flow modeling and seismic imaging are considered separately. Linking these fields through a consistent conceptual and theoretical framework will allow improved understanding of coupled processes, and may lead to improved monitoring of reservoir conditions.

RELATED PUBLICATION

Schoenberg, M., K. Nihei, T. Daley, J. Rutqvist, and E.L. Majer, Fractured reservoirs: An analysis of coupled elasto-dynamic and permeability changes due to pore pressure variation. Presented at the Society of Exploration Geophysicists' Pore Pressure Workshop, May 2002; Berkeley Lab Report LBNL-50697, 2002.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Fossil Energy, Federal Energy Technology Center (FETC). Processing was performed at the Center for Computational Seismology, which is supported by the Director, Office of Science, Office of Basic Energy Sciences, Division of Engineering and Geosciences, of the U.S. Department of Energy under Contract No. DE-AC03- 76SF00098.

A Portable X-Ray Computed Tomography Sysytem

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RESEARCH OBJECTIVES

Drilling boreholes is an expensive activity, whether conducted for environmental monitoring, resource extraction, or scientific purposes. Retrieving geologic samples (core) from the ground adds significantly to this expense, potentially doubling or tripling drilling costs. Beyond a geologist's visual inspection, much of the core often goes untouched. Frequently, core is subsampled for use in subsequent tests (such as oil/gas/water relative permeability). Some samples, such as those containing gas hydrates, change rapidly upon retrieval. In these cores, on-site core examination and evaluation is critical. Our objective in developing a portable x-ray computed tomography (CT) system is to (1) provide personnel in the field with a real-time comprehensive picture of core structure and (2) provide a tool for selecting subsamples.

Figure 1. Berkeley Lab's portable scanner has sailed the high seas and endured arctic cold, imaging more than 2,000 feet of core along the way.

APPROACH

Soil scientists and petroleum engineers have used x-ray CT to perform measurements on recovered core. The bulk of this work has been conducted using large medical scanners designed for imaging humans. These large, immobile systems, often costing a million dollars or more, are used in a laboratory and require water-cooling systems and air-conditioned lead-lined rooms. Our portable system had to be rugged, compact, lightweight, and fast. We were able to eliminate most of the weight by producing a novel multicomponent lead-shielding arrangement that reduced the footprint of the system and eliminated the need for a dedicated room. Special collimators and filters, optimized for geologic core, enabled us to use off-the-shelf industrial imagers and obtain results that rivaled the performance of expensive scientific instruments. As a result, our final product costs significantly less than the baseline medical technology that we set our sights on.

ACCOMPLISHMENTS

This unique portable x-ray CT scanner was fabricated in July 2002. Its first deployment was on Ocean Drilling Program (ODP) Leg 204 off the Oregon Coast, a research cruise to investigate methane-hydrate-bearing cores retrieved from Cascadia Ridge. Afterwards, the scanner was transported to the ODP Gulf Coast Core Repository, where it was used for follow-up studies. It was briefly back at Berkeley Lab to image hydrate dissociation experiments, before heading off for two months (March–April, 2003) to the Alaskan North Slope to image permafrost cores in another hydrate research project. The scanner will be used next for ODP Leg 210, a cruise to study the Newfoundland half of the Newfoundland-Iberia nonvolcanic rift.

SIGNIFICANCE OF FINDINGS

A portable x-ray CT system can provide geologists in the field with detailed information (such as density and macroporosity distribution) from recovered drill core. Additionally, subsamples can be selected knowing not just what is on the surface, but also the structure throughout the core. As a result of CT imaging, detailed structural information can be obtained quickly, and an electronic record can be generated. Ultimately, information will be extracted from recovered core quicker, with more precision, and at a lower cost.

RELATED PUBLICATION

Freifeld, B.M., T.J. Kneafsey, L. Tomutsa, and J. Pruess, Development of a portable x-ray computed tomographic imaging system for drill-site investigation of recovered core. Proceedings of the 2003 International Symposium of the Society of Core Analysts, Pau, France, September 21–24, 2003.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Fossil Energy, Office of Natural Gas and Petroleum Technology, through the National Energy and Technology Laboratory, of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Joint Crosswell and Single-Well Seismic Studies of CO_2 Injection in an Oil Reservoir at Lost Hills, California

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RESEARCH OBJECTIVES

The objective of this research is to study whether crosswell and single-well seismic techniques can be applied to monitor the sequestration of CO_2 in oil reservoirs. The advantage of injecting CO_2 into oil reservoirs is two-fold: (1) it offers one method of geologic carbon sequestration, while it (2) enhances the recovery of difficult-to-extract oil, which otherwise would remain locked in place.

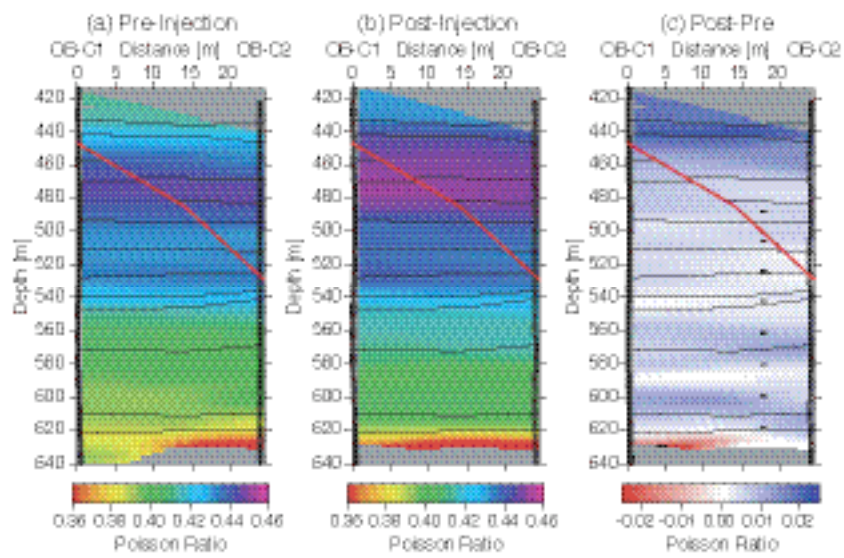

Figure 1. Poisson ratio based on P- and S-wave velocity: (a) pre-injection ratio; (b) post-injection ratio; (c) result of differencing the pre-post injection ratios. The black dashes represent the projection of the CO_2 injection intervals onto the imaging plane, while the red line indicates the location of a fault in the reservoir. The high values in (c) correspond to regions of increased CO_2 concentration spatially correlating with the injection intervals.

APPROACH

The subsurface CO_2 injection program was operated by Chevron USA Production Company in the Lost Hills, California, oil field. We conducted a series of time-lapse seismic crosswell and single-well experiments in a diatomite reservoir to monitor the injection of CO_2 into a hydrofracture zone, based on seismic P- and S-wave data collected during pre- and post-CO_2 injection phases. Tomographic images of the differences in P- and S-wave velocities were constructed, because the differencing of the data sets is particularly sensitive to time-lapse changes in the reservoir. Estimates of Poisson ratio were then calculated from the velocities to determine the state of the CO_2 in the reservoir.

Figure 1 shows three tomographic cross sections of Poisson ratio before and after injection, as well as a difference image of the two. The pre- and post-injection tomograms show the stratification and compaction of the reservoir rock with depth (decreasing Poisson values). The difference tomogram shows an increase in Poison ratio throughout the imaged area, indicating an increase in pressure in the reservoir. This information, in conjunction with the P- and S-wave results, led to the conclusion that the injected CO_2 dissolved into the liquid phase, which was corroborated by *in situ* pressure measurements and reservoir simulations. The seismic single-well supported the crosswell results.

ACCOMPLISHMENTS

The experiment has shown that seismic crosswell time-lapse P- and S-wave data can be used to successfully monitor CO_2 injection and migration in oil reservoirs, and to determine the state of the injected gas. Single-well seismic measurements provide independent data that are useful in corroborating crosswell results without adding much data acquisition time in the field.

SIGNIFICANCE OF FINDINGS

The analysis of the CO_2 injection experiment revealed that both P-and S-wave data sets are essential in determining the migration and state of the injected gas in the reservoir, because one data set by itself would yield inconclusive results. The availability of time-lapse data reduces the effect of reservoir heterogeneity, which would be difficult to estimate in an absolute sense. Poisson ratio can be applied to determine whether the injected gas has dissolved into the liquid phase or remained in gas form. It also appears that seismic crosswell data are useful in delineating the structural features of the reservoir, whereas single-well seismic data are applicable in determining the location and possibly the properties of a hydrofracture zone.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Fossil Energy, Office of Coal and Power Systems and the Office of Natural Gas and Petroleum Technology, through the National Energy Technology Laboratory (NETL), of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098. Support was also provided by Chevron USA Production Co. and the National Petroleum Office under Contract No. DE-FC22-95BC14938, Class III Field Demonstration Project.

Joint Geophysical Imaging

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RESEARCH OBJECTIVES

The objective of the Joint Geophysical Imaging project is to ultimately develop formal joint geophysical imaging algorithms for simultaneously inverting different types of geophysical data—to find a common, self-consistent earth model. The initial stages of this work have concentrated on demonstrating a methodology for combining time-lapse changes in electric conductivity and compressional- and shear-wave velocity with a detailed rock-properties model, to produce quantitative estimates of the change in reservoir pressure and fluid saturations.

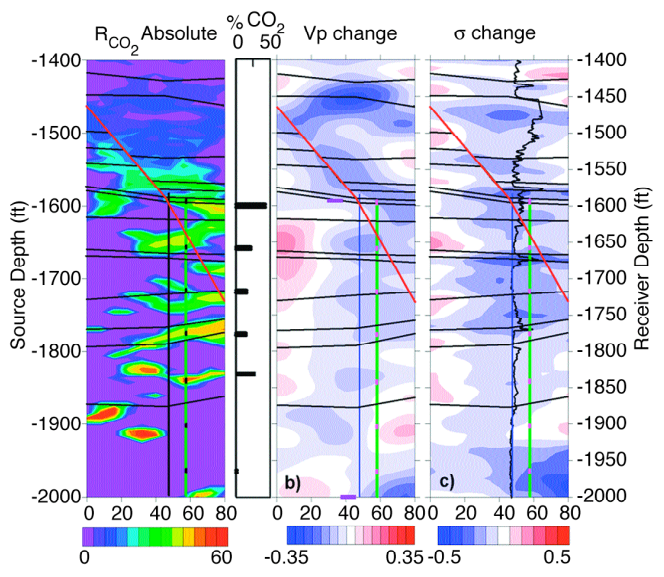

Figure 1. Changes in CO_2 dissolved in oil (a), changes in p-wave velocity (b), and changes in electrical conductivity (c). CO_2 injected into different depths is shown as % CO_2.

APPROACH

Crosswell electromagnetic (EM) and seismic data were acquired during CO_2 injection into the Lost Hills Oil field. Data were recorded before and during CO_2 injection. From well log data, a detailed rock-properties model was developed that related changes in the electrical and seismic properties of the reservoir to changes in pressure and fluid saturations. The rock-properties model was used to constrain inversion of the time-lapse data sets to produce time-lapse changes in the seismic compressional, shear, and electrical conductivity as CO_2 was injected. These time-lapse changes in geophysical parameters were combined with the rock-properties model to produce changes in reservoir pressure and fluid saturations (including changes in hydrocarbon gas, water, and CO_2 saturations).

A critical step was to first remove the effects of the reservoir-pressure and water-saturation changes by combining the EM and shear-wave velocity changes. Once the effects of reservoir pressure and water saturation changes were stripped off, the changes in acoustic velocity were used to map CO_2 saturation changes within the reservoir.

ACCOMPLISHMENTS/ SIGNIFICANCE OF FINDINGS

The newly developed procedure for unraveling the combined effects of reservoir pressure and fluid saturation changes produced a predicted change in CO_2 content in the reservoir oil. This change in CO_2 content is substantially better that that which can be obtained by traditional predictions (based on changes in geophysical parameters alone). Figure 1 shows the changes in CO_2 dissolved in oil compared to the changes in compressional velocity and electrical conductivity between the two observations wells used in the survey. There is a clear improvement in spatial resolution, along with accurate quantitative prediction of the CO_2 volume in place.

RELATED PUBLICATIONS

Hoversten, G.M., P. Milligan, J. Byun, J. Washbourne, L.C. Knauer, and P. Harness, Crosswell electromagnetic and seismic imaging: An examination of coincident surveys at a steam flood project. Geophysics, 2003 (in press); Berkeley Lab Report LBNL-48703.

Hoversten, G.M., R. Gritto, J. Washbourne, and T.M. Daley, Pressure and fluid saturation prediction in a multicomponent reservoir, using combined seismic and electromagnetic imaging. Geophysics, 2003 (in press); Berkeley Lab Report LNBL-51281.

ACKNOWLEDGMENTS

Support for this work was provided by the Assistant Secretary for Fossil Energy, Office of Coal and Power Systems, Office of Oil, Gas, and Shale Technologies, through the National Energy Technology Laboratory, under U.S. Department of Energy Contract No. DE-AC03-76SF00098.

Gas-Hydrate Imaging Using X-Ray Computed Tomography

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RESEARCH OBJECTIVES

Gas hydrates are ice-like crystalline solids formed from a mixture of water and natural gas at high pressures and temperatures near freezing. They are abundant in deep oceans and underlie vast stretches of permafrost. There is general scientific agreement that naturally occurring hydrates contain significantly more energy than is stored in traditional fossil fuel reserves. While gas-hydrate dissociation (the process of hydrate separating to gas and water or ice) is well understood, there is very little known about hydrate behavior in oceanic sediments or porous media. Our objective was to develop a technique capable of observing gas-hydrate dissociation in oceanic sediments or porous media, so that we may eventually extract the natural gas as an economic resource.

APPROACH

We used x-ray computed tomography (CT), coupled with physical measurements of temperature, pressure, and volume, to observe hydrate dissemination and monitor dissociation of synthetic samples. We compared the results from the physical measurements to the x-ray CT scanning to examine the effectiveness of using x-ray CT scanning in quantifying hydrate dissociation.

ACCOMPLISHMENTS

We have performed several experiments to accomplish our objective. In one experiment, we used a modified medical x-ray CT scanner to observe the changes in a hydrate/silica sand sample. The sample contained two different mixtures of hydrate and sand. We measured the temperature at the bottom of the sample, as well as the volume and composition of the produced gas. The sample warmed from top to bottom, and as dissociation occurred, methane gas was produced. Simultaneously, changes in x-ray attenuation were observed in the top of the sample. The location where the hydrate was dissociating was identifiable in the x-ray images as a horizontal front, and we were able to track the front from the sample top to the bottom. As expected, gas production ceased when the front reached the sample bottom.

We conducted another experiment using the Berkeley Lab portable x-ray CT scanner. In this experiment, we measured the pressure change and temperature as the sample, consisting of clean 1 mm sand as well as chunks of hydrate and ice (Figure 1), warmed from –196ºC. As in the first experiment, the x-ray CT images clearly show changes in the hydrate as dissociation occurs.

SIGNIFICANCE OF FINDINGS

We have shown that x-ray CT scanning is a valuable tool in examining samples containing hydrates, and can be used to track hydrate dissociation. The use of x-ray CT scanning at remote locations can be performed using the Berkeley Lab portable x-ray CT scanner, allowing examination of natural samples in their most representative condition. The x-ray CT results, combined with pressure and temperature measurements, provide clear indications of hydrate changes in samples.

RELATED PUBLICATION

Freifeld, B.M., T.J. Kneafsey, L. Tomutsa, L.A. Stern, and S.H. Kirby, Use of x-ray computed tomographic data for analyzing the thermodynamics of a dissociating porous sand/hydrate mixture. Proceedings of the Fourth International Conference on Gas Hydrates, pp. 750–755, Yokohama, Japan, May 19–23, 2002.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Fossil Energy, Office of Natural Gas and Petroleum Technology, through the National Energy Technology Laboratory, of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

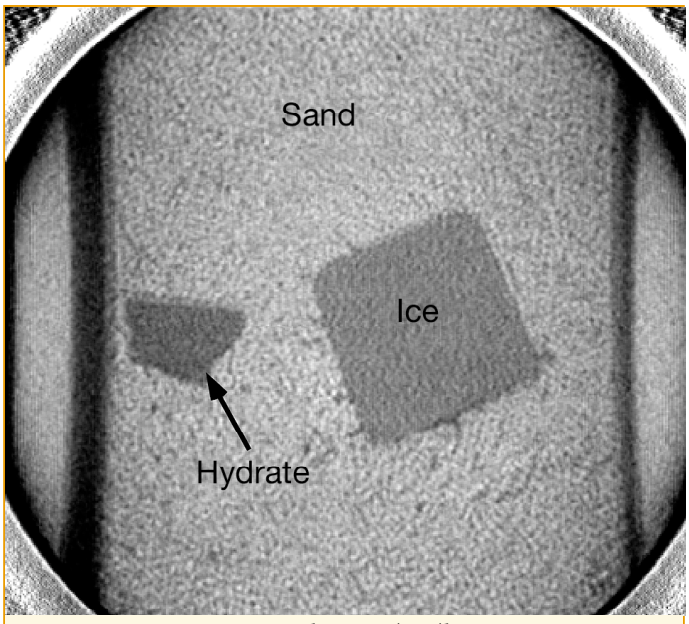

Figure 1. X-ray CT image of the sand/ice/hydrate sample

Fracture Quantification in Naturally Fractured Gas Reservoirs

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OBJECTIVE

The objective for this work is to apply high-resolution seismic-imaging fracture-identification methods (logging, single-well vertical seismic profiling [VSP]) to naturally fractured gas reservoirs, and to integrate the results with three-dimensional (3-D) surface imaging. The goal is to determine the optimum technique for not only locating fractures, but also quantifying their properties in a manner that allows the fractures controlling flow to be identified.

APPROACH

As part of the U.S. Department of Energy's Natural Gas Program, Berkeley Lab is leading a multi-institutional project to develop methods for mapping the fractures that control flow in naturally fractured gas reservoirs. This project strives to extend surface information with current borehole methods (VSP, crosswell, and single-well seismic) to quantify fracture characteristics. The work has progressed from lab studies to controlled field studies, and now to a full-scale application in the San Juan Basin in New Mexico.

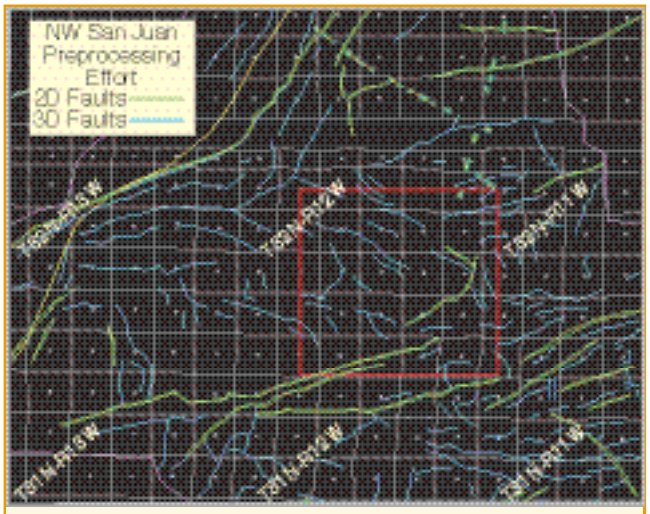

Figure 1. Study area (red box) in relation to the fault structure as determined by 2-D and 3-D seismic imaging

ACCOMPLISHMENTS

The project effort during 2002 focused on three areas: (1) modeling seismic wave propagation in fractured media, (2) acquisition of an extensive set of VSP data, well logs, and single-well data, and (3) initial processing of the field data.

The thrust of the modeling effort has been to model the actual field data that was processed in both 2-D and 3-D. Existing 3-D data from the 20-square-mile target area was reprocessed to apply processing that would enhance interpretation for fracture and fault identification. The result was an analysis of predicted well performance across the 20-square-mile area.

The objective of the field tests was to augment the existing data sets at both the borehole scale (logging and single-well seismic) and VSP scale. The objective of the interpretation and processing effort has been (and will be) to derive images that are indicative of fracture characteristics. Each method (surface seismic, VSP, crosswell, single well) has a different image produced at a different scale. The following data have been compiled:

- Multi-offset (approximately 70 source points per well) 3-D, 9-C VSP at 20 ft spacing (10 to 100 Hz)
- Single well with three component receivers at 10 ft spacing, using orbital source (50 to 400 Hz)
- Single well with hydrophones at 5 ft spacing, using piezoelectric source (200 to 4,000 Hz)
- FMI and dipole sonic (4,000 to 8,000 Hz)

Together with the reprocessed seismic data, this information will form the basis of a unique multiscale data set to process for fracture properties. To check the predictions, each well will be put on production after the seismic studies are completed.

SIGNIFICANCE OF FINDINGS

Overall, the project has made the anticipated progress towards the goal of developing and testing seismic methods for fracture quantification. The drilling of the well by ConocoPhillips (an over-$1.5 million investment alone) and the acquisition of the field data sets mark a significant milestone in this work—and in general a significant scientific contribution to the discipline of fracture imaging. The final phase of the project will involve additional work in modeling, data processing, and reservoir simulation.

RELATED PUBLICATIONS

Majer, E.L., J.E. Peterson, T. Daley, B. Kaelen, J.L. Myer, J. Queen, P. D'Onfro, and W. Rizer, Fracture detection using crosswell and single well surveys. Geophysics, 62(2), 495–504, 1997.

Daley, T.M., T. Nihei, L.R. Myer, E.L. Majer, J.H. Queen, M. Fortuna, J. Murphy, and R.T. Coates, 2002, Numerical modeling of scattering from discrete fracture zones in a San Juan Basin gas reservoir. In Proceedings of the SEG Annual Meeting, Salt Lake City, Utah, 2002.

ACKNOWLEDGMENTS

This work was funded by the Assistant Secretary for Fossil Energy, Department of Natural Gas Exploration, Production, and Storage, through the National Energy Technology Laboratory, of the U.S. Department of Energy under Contract No. DE-AC03-76SF200098.

Classification of Gas Hydrate Deposits and Corresponding Production Strategies

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RESEARCH OBJECTIVES

Gas hydrates are solid (ice) crystalline compounds, inside the lattices of which gas molecules can be encased. Vast amounts of hydrocarbons are thus trapped in hydrate deposits. The objective of this study is the analysis and development of appropriate strategies for gas production from a wide range of natural hydrate accumulations. These strategies involve the three main hydrate dissociation mechanisms (depressurization, thermal stimulation, inhibitor effects), either individually or in combination. Selection of the appropriate strategy is strongly influenced by the geological setting and the conditions prevailing in the hydrate accumulation.

APPROACH

The TOUGH2 general-purpose simulator with the EOSHYDR2 module was used for the analysis. EOSHYDR2 models the nonisothermal gas release, phase behavior, and flow in binary hydrate-bearing porous and fractured media (involving methane and another hydrate-forming gas) by solving the coupled equations of mass and heat balance. This model can describe any combination of hydrate dissociation mechanisms—and can also account for up to four phases (gas phase, liquid phase, ice phase, and hydrate phase) and up to seven components (CH_4-hydrate, water, native methane, dissociated methane, native and dissociated components of a second hydrate-forming gas, salt, water-soluble inhibitors, and heat).

ACCOMPLISHMENTS

In terms of production strategy and behavior, hydrate accumulations are divided into three main classes. In Class 1, the permeable formation includes two zones: the hydrate interval and an underlying two-phase fluid zone with free (mobile) gas. In this class, the bottom of the hydrate stability zone occurs above the bottom of the permeable formation. Class 2 features a hydrate-bearing interval overlying a mobile water zone (e.g., an aquifer). Class 3 is characterized by the absence of a hydrate-free zone, and the permeable formation is thus composed of a single zone, the hydrate interval. In Classes 2 and 3, the entire hydrate interval may be well within the hydrate stability zone (i.e., the bottom of the hydrate interval does not necessarily indicate hydrate equilibrium).

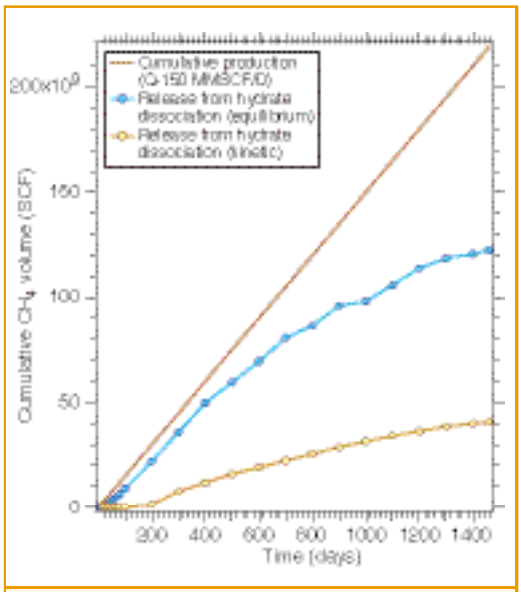

Figure 1. Cumulative release of CH_4 from hydrate dissociation during gas production from a Class 1 hydrate in the North Slope of Alaska

The numerical simulations indicate that, in general, the appeal of depressurization decreases from Class 1 to Class 3, while that of thermal stimulation increases. Thus, simple depressurization appears to enjoy an advantage over other production strategies in Class 1 hydrate deposits. The most promising production strategy for Class 2 hydrates involves combinations of depressurization and thermal stimulation, and is clearly enhanced by multi-well production-injection systems (e.g., a five-spot configuration). Because of the very low permeability of hydrate-bearing sediments, the effectiveness of depressurization in Class 3 hydrates is limited, and thermal stimulation through single well systems seems to be the strategy of choice in such deposits (and especially so in high-hydrate-saturation regimes).

SIGNIFICANCE OF FINDINGS

This is the first-ever (a) classification of gas hydrate deposits and (b) development of general principles for gas production strategies based on the hydrate deposit classification.

RELATED PUBLICATIONS

Moridis, G.J., Numerical studies of gas production from methane hydrates. SPE Paper 75691, SPE Journal, 2003 (in press); Berkeley Lab Report LBNL-49765.

Moridis, G.J., Numerical simulation studies of thermally induced gas production from hydrate accumulations with no free gas zones at the Mallik Site, Mackenzie Delta, Canada. SPE Paper 77861, SPE 2002 Asia Pacific Oil and Gas Conference and Exhibition, Melbourne, Australia, October 8–10, 2002; Berkeley Lab Report LBNL-50256.

Moridis, G.J. and T. Collett, Strategies for gas production from hydrate accumulations under various geologic conditions. Berkeley Lab Report LBNL-52568, 2003.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Fossil Energy, Office of Natural Gas and Petroleum Technology, through the National Energy Technology Laboratory, under U.S. Department of Energy Contract No. DE-AC03-76SF00098.

Anisotropic Properties of Compacted Clay-Rich Rocks

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RESEARCH OBJECTIVES

The principal objective of this work is to characterize the elastic anisotropic properties of clay-rich rocks for consolidation conditions simulating compaction at depth. A novel consolidation cell containing sets of ultrasonic transducers and a phased array has been designed to allow measurement of the five transverse isotropy (TI) elastic constants of a rock sample during compaction. During the testing phase of this project, we will conduct a series of laboratory anisotropy tests on clay-rich rock samples provided by our industry partners from basins worldwide.

APPROACH

The standard laboratory ultrasonic transmission method for measuring the five elastic constants of rock with TI requires a minimum of three oriented cores taken parallel, perpendicular, and at an angle to the bedding. This method is unsuitable for measuring the stress-induced TI elastic constants of clay-rich rocks during compaction because: (1) the process of unloading-recoring-reloading is time consuming, and (2) it is difficult to realize the same stress state in the sample cored at an angle to the bedding. The apparatus developed in this project utilizes a P-wave phased array and three sets of polarized ultrasonic transducers to recover the five TI constants during uniaxial strain consolidation.

ACCOMPLISHMENTS

A series of ultrasonic tests on clay-rich rocks provided by ChevronTexaco were performed to determine the attenuation of P- and S-waves in the 200 kHz to 2 MHz range. These tests were carried out on clay samples compacted under drained, uniaxial strain conditions to axial stresses of 2.5 MPa. Based on these results, the design of the compaction cell, the P-wave phased array, and the ultrasonic P- and S-wave transducers were finalized.

A schematic of the compaction cell, including the locations of the phased array and the ultrasonic transducers, is shown in Figure 1a. The cell accommodates an approximately 2 cm thick clay sample in a slot with the geometry and dimensions given in Figure 1b. A pair of 1 MHz P-wave transducers are used to directly measure c_{11}—P(0°) in Figure 1b. Two sets of 40 kHz S-wave transducers with polarizations parallel and perpendicular to the bedding direction— SH(0°) and SV(0°), respectively, in Figure 1b—provide direct measurements of c_{44} and c_{66}. A 1 MHz, 32-element P-wave phased array and a P-wave pinducer (Figure 1a) are used to obtain c_{33} and c_{13} from plane P-wave measurements made over a range of angles (0° to approximately 60°).

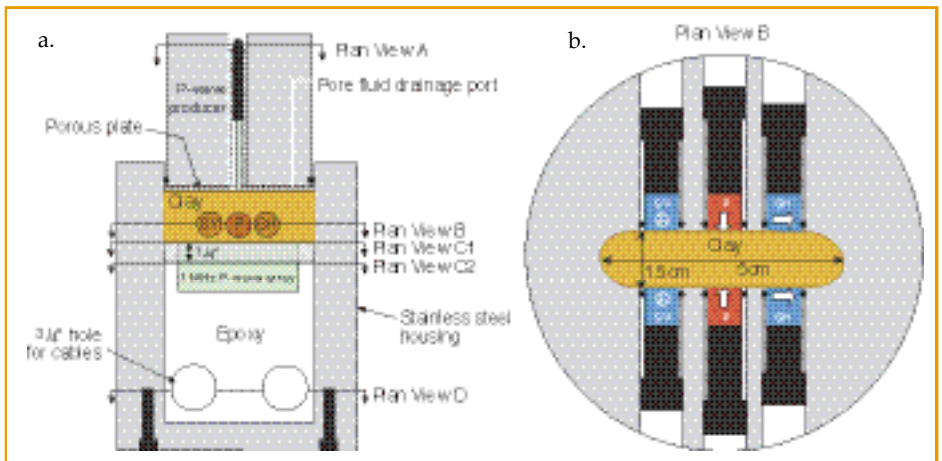

Figure 1. Schematic of the compaction cell for clay anisotropy measurements: (a) view in cross section showing the locations of the P-wave phased array and pinducer, and (b) plan view illustrating the location of the clay sample and the P- and S-wave transducers

SIGNIFICANCE OF FINDINGS

The apparatus developed in this project utilizes a pair of P-wave transducers, two pairs of polarized S-wave transducers, and a P-wave phased array to recover the five TI constants during uniaxial strain consolidation. Because the measurements are performed during consolidation without the need for unloading-recoring-reloading, the apparatus can be used to investigate the development of stress-induced anisotropy in geomaterials such as clay-rich rocks and benthic sands. We anticipate that this apparatus will prove useful in investigations of the anisotropic properties of soft sediments relevant for oil and gas imaging in sedimentary basins, and for the characterization of the shallow sea floor.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Fossil Energy, Office of Natural Gas and Petroleum Technology, through the National Petroleum Technology Office, Natural Gas and Oil Technology Partnership, of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Simulation of Partitioning Tracers

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RESEARCH OBJECTIVES

Noble gases widely exist in nature, and except for radon, they are stable. Modern techniques can detect noble gases to relatively low concentrations and with great precision. In addition, different noble gases have different transport properties. These factors suggest that noble gases can be useful partitioning tracers for subsurface characterization. Previous research has shown that the solubility and dispersivity of a gas have strong temperature dependency, and that the dependency is gas-specific. We wanted to develop a numerical code that both simulates the transport of noble gases in the subsurface and also accounts for how temperature affects gas properties.

APPROACH

We base our code development on TOUGH2, a simulation code for multiphase, multicomponent, and heat flow. Among the many TOUGH2 modules, EOS7R specifically simulates two-phase, five-component flow and transport problems. The two phases are water and gas, and the five components are water, brine, air, and two radionuclides (Oldenburg and Pruess, 1995). For our studies, we added two subroutines to EOS7R and slightly modified the original code. One subroutine, called NOHEN, uses the laboratory-experiment-based Crovetto et al. (1982) model to calculate the Henry's law coefficient; the other, called GASDIF, uses the theoretical model given by Reid et al. (1987) to calculate noble gas diffusivity in the gas phase. At every time step and iteration, the program substitutes the most current temperature/pressure data to the two new subroutines to update the two coefficients for the next step of simulation.

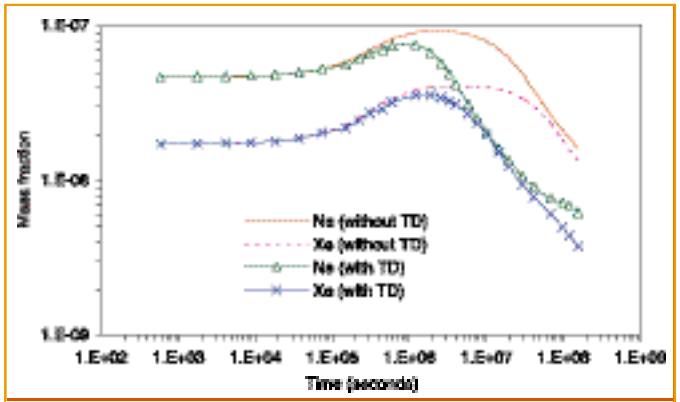

Figure 1. Noble gas mass fractions at the discharge face for example calculation.

ACCOMPLISHMENTS

A new fluid property module, EOSN, was developed for TOUGH2 to simulate transport of noble gases in the subsurface. Like most other sister modules, TOUGH2/EOSN can simulate nonisothermal multiphase flow and fully coupled transport in fractured porous media. In applying the new module, users need only to give the names of the two selected gases; all required thermodynamic properties are provided in an internal data bank. There are, however, options for users to overwrite internal molecular weights for modeling specific isotopes. Currently, six user-selectable gases are available: helium, neon, argon, krypton, xenon, and carbon dioxide. Radon may be added in the future; a capability to model radioactive decay by means of a half-life is already included in EOSN.

SIGNIFICANCE OF FINDINGS

Preliminary TOUGH2/EOSN simulations have shown that the temperature effect may play an important role in gas diffusion-dominant processes and in fluid exchange between matrix blocks and surrounding fractures. The difference in solubility and diffusivity between two different noble gases leads to a difference in resulting noble gas mass fractions (see Figure 1), which may provide additional information for subsurface studies. Vaporization and condensation of water may greatly affect mass fractions of gases, which is a factor to be considered in data analyses. The study of noble gases may be extended to any other noncondensable gases or even volatile organic chemicals (commonly referred to as VOCs).

RELATED PUBLICATIONS

Oldenburg, C. M., and K. Pruess, EOS7R: Radionuclide transport for TOUGH2. Berkeley Lab Report LBL-34868, 1995.

Shan, C., and K. Pruess, EOSN: A TOUGH2 module for noble gases. Berkeley Lab Report LBNL-52379, 2003.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Energy Efficiency and Renewable Energy, Office of Technology Development, Office of Geothermal Technologies, of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Physics-Based Reconstruction of Sedimentary Rocks

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RESEARCH OBJECTIVES

The relative permeability and capillary pressure functions define how much oil can be recovered from a reservoir. These parameters are the key input data for any reservoir simulation. The objective of this project is to develop methods of estimating the absolute permeability, capillary pressure, and relative permeability functions by analyzing 3-D images of the rock.

APPROACH

High-resolution images of rock are obtained both by electron-scanning microscopy of cores and by physics-based computer simulation of the sedimentary-rock formation process [Jin et al., 2003]. In either case, the geometry of the pore space is studied by applying methods of mathematical morphology to the digital images [Silin and Patzek, 2003; Silin et al., 2003].

ACCOMPLISHMENTS

A general approach for process-based reconstruction of sedimentary rocks has been developed [Jin et al., 2003]. The procedure includes dynamic grain sedimentation and compaction, followed by diagenesis. The results are confirmed by statistical comparison of computer-generated and natural images of sandstone cores. The mechanical properties of the natural rock, such as stress-strain curve, are also well reproduced in the computer-generated rock. Computer simulations provide an insight into rock-damage propagation as a system of coalescing microcracks.

A new, robust approach to studying the pore-space morphology of rocks from their 3-D digital images has been developed. An efficient and stable algorithm, which distinguishes between the pore bodies and pore throats and establishes their respective volumes and connectivity, has been proposed and tested. The output of this algorithm has been used to compute a dimensionless drainage-capillary-pressure curve, which simulates mercury injection. This curve is a robust descriptor of the pore-space geometry that can be used to determine the quality of natural-rock computer reconstruction (see Figure 1). An appropriate scaling of this image-analysis-based curve should enable prediction of the rock capillary pressure.

SIGNIFICANCE OF FINDINGS

Our approach provides a practical, inexpensive, and fast alternative to tedious core-flood experiments and allows the investigator to run many "what-if" scenarios. The predictive capability of the pore-scale calculations is especially important for imbibition experiments in mixed-wet rocks and in multiple drainage-imbibition cycles with two or three fluids present. For unconsolidated reservoir rock, analysis of computer-generated images, based on the known grain-size distribution, is virtually the only way to get insight into rock transport properties.

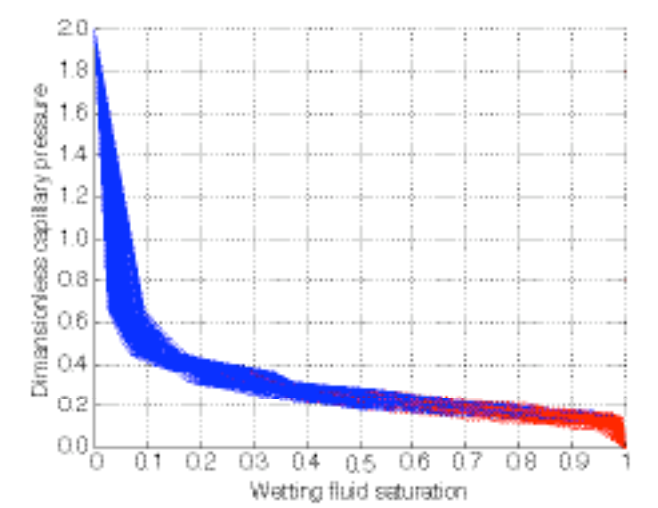

Figure 1. These 800+ dimensionless capillary pressure curves have been obtained for images of Fontainebleau sandstone. The porosity of the imaged rock samples varies between 11% and 22%.

RELATED PUBLICATIONS

Jin, G., T. Patzek, and D. Silin. Physics-based reconstruction of sedimentary rocks. SPE Paper 83587 presented at SPE Western Regional/AAPG Pacific Section Joint Meeting. Long Beach, California, 2003; Berkeley Lab Report LBNL-52966, 2003.

Silin, D., and T. Patzek, An object-oriented cluster search algorithm. Berkeley Lab Report LBNL-51599, 2003.

Silin, D., G. Jin, and T. Patzek, Robust determination of the pore-space morphology in sedimentary rocks. SPE Paper 84296 presented at SPE Annual Technical Conference and Exhibition, Denver, Colorado, 2003; Berkeley Lab Report LBNL-52942, 2003.

ACKNOWLEDGMENTS

This research was supported by the Assistant Secretary for Fossil Energy, Office of Natural Gas and Petroleum Technology, through the National Petroleum Technology Office, Natural Gas and Oil Technology Partnership, under U.S. Department of Energy Contract No. DE-AC03-76SF00098. Partial support was also provided by gifts from ChevronTexaco and ConocoPhillips to UC Oil, Berkeley. Synchrotron images of Fontainebleau sandstone were provided by Schlumberger.

Nanoscale Three-Dimensional Rock Imaging Using Focussed Ion Beam

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RESEARCH OBJECTIVES

Computation of effective flow properties of fluids in porous media based on three-dimensional (3-D) pore-structure information has become more successful in the last few years, due to improvements in both input data and network models. Computed x-ray microtomography has been successful in 3-D pore imaging at micron scale, which is adequate for many sandstones. For other rocks of economic interest, such as chalk and diatomite, nanoscale resolution is needed to resolve the 3-D-pore structure. To achieve such resolution, a new method of pore imaging using Focussed Ion Beam (FIB) technology is being developed.

APPROACH

To directly access the pore structure at nanoscale scale, the FIB is used to mill successive layers of the rock material. FIB mills layers as wide as 50 micrometers and as thin as 10 nanometers by sputtering of atoms from the sample surface. The FIB, consisting of gallium ions (Ga+) accelerated by potentials of up to 30 kV and currents up to 20,000 pA, yields very clean, flat surfaces in which the pore-grain boundaries appear in high contrast. No distortion of the pore boundaries caused by ion milling is apparent. After each milling step, as a new surface is exposed, a 2-D image of the surface is obtained using either the ion beam or the electron beam. While epoxy impregnation improves the contrast in the images, unimpregnated samples can yield excellent images (Figure 1). The high pore-matrix contrast is used next to binarize the 2-D images and, by stacking them, to reconstruct the 3-D structures of the pore space.

ACCOMPLISHMENTS

The FIB method was used to generate, for the first time, 3-D images of the pore spaces of Belridge diatomite and North Sea Chalk. Both these rocks have pores and pore throats in the tens to hundreds of nanometer range.

SIGNIFICANCE OF FINDINGS

Large oil reserves are present in both diatomite and chalk formations. By obtaining the 3-D pore structure of these rocks, we accomplished the first step in generating the input data needed for pore-network simulators. The 3-D pore images of complex fragile rocks, such as diatomite and chalk, are essential for the construction of idealized pore networks and the subsequent simulations of flow experiments for various displacement processes (drainage, imbibition, water-alternating gas, secondary drainage, etc.). Such experiments would be extremely difficult, if not impossible, to perform in the laboratory. The calculations provide scientific understanding of the pore-scale flow phenomena of mixed-wet rocks, which control large-scale hydrocarbon or carbon dioxide flow.

RELATED PUBLICATION

Tomutsa, L., and V. Radmilovic, Focussed ion beam assisted three-dimensional rock imaging at submicron scale. Proceedings of the 2003 International Symposium of the Society of Core Analysts, Pau, France, September 21–24, 2003.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Fossil Energy, Office of Natural Gas and Petroleum Technology, through the National Energy Technology Laboratory; and the Director, Office of Science, Office of Basic Energy Sciences, Materials Science Division, of the U.S. Department of Energy under Contract No. DE-AC3-76SF00098

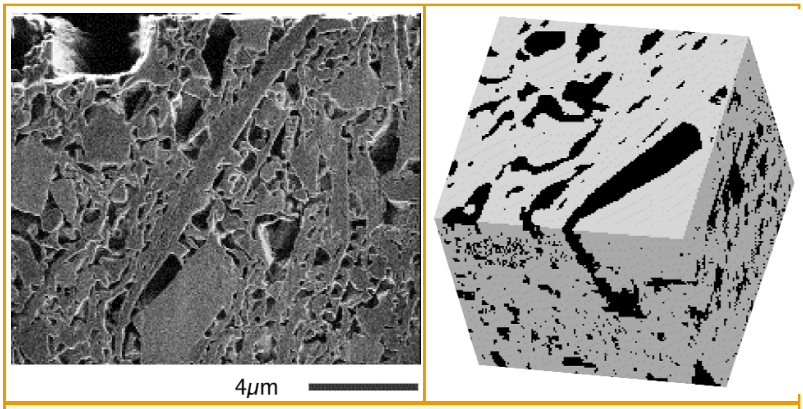

Figure 1. (a) Ion-beam image of diatomite at 20,000x magnification, (b) Diatomite volume reconstructed from binarized successive images spaced at 0.2 micron intervals. The pore space is dark .

Finite-Difference Modeling of 3-D Anisotropic Wave Propagation Using Variable Grid Spacing

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RESEARCH OBJECTIVES

Finite-difference modeling is routinely carried out to aid interpretation of seismic data acquired during hydrocarbon exploration. Most hydrocarbon reservoirs are overlain by low-velocity sediments, whose effects on the wavefield must be considered in order to successfully image deeper structures. However, the computational expense associated with finite-difference modeling is greater for low-velocity materials than for high-velocity materials. Including the effects of anisotropy on the seismic wavefield further increases the computational expense. Three-dimensional anisotropic finite-difference modeling has thus been restricted to small-scale models, unrealistic velocity structures, or long wavelengths due to its demand on computer time and memory. This research overcomes these limitations by using parallel computation and improved computational algorithms, enabling larger and more realistic geological models to be tackled.

APPROACH

We are using a fourth-order staggered-grid finite-difference (FD) solution to the wave equation. In a fourth-order scheme, the wavefield must be sampled with at least five gridpoints per seismic wavelength to avoid numerical dispersion. Geological models containing low-velocity zones require fine discretization, and hence a large number of gridpoints, because of the shorter seismic wavelengths in these zones. When a uniform grid is used, oversampling of the wavefield occurs in high-velocity zones. Using variable grid spacing improves the efficiency of the FD method by partially avoiding this oversampling. We are using the variable-gridding scheme developed by Pitarka (1999). The grid spacing is adapted to the velocity structure using spatial differential operators designed for grids with nonuniform spacing. The coefficients to the spatial differential operators depend on the spacing between gridpoints and are calculated at the beginning of the simulation.

ACCOMPLISHMENTS

We have implemented the 3-D variable-gridding anisotropic FD code to run on a 30-processor Beowulf cluster using message passing interface (MPI) . Pentium III processors with 2 GB RAM and speeds ranging between 1 GHz and 1.4 GHz were used. On a single processor machine, model sizes were limited to 200 × 200 × 200 gridpoints. This has increased to 620 × 620 × 620 on the cluster (a 30-fold increase).

The accuracy of the variable-gridding code was tested for a homogeneous anisotropic model with the elastic properties of shale (a transversely isotropic material). We used a mesh with a constant grid spacing of 6 m in the two horizontal directions. The vertical grid spacing decreased abruptly from 6 m to 3 m within a 300 m thick layer. A 20 Hz Ricker wavelet was used as a pressure source. Figure 1 shows a snapshot of the wavefield showing quasi-P- and -S-waves and a pure SH wave. Horizontal black lines mark the change in grid spacing, which clearly has no effect on the wavefield.

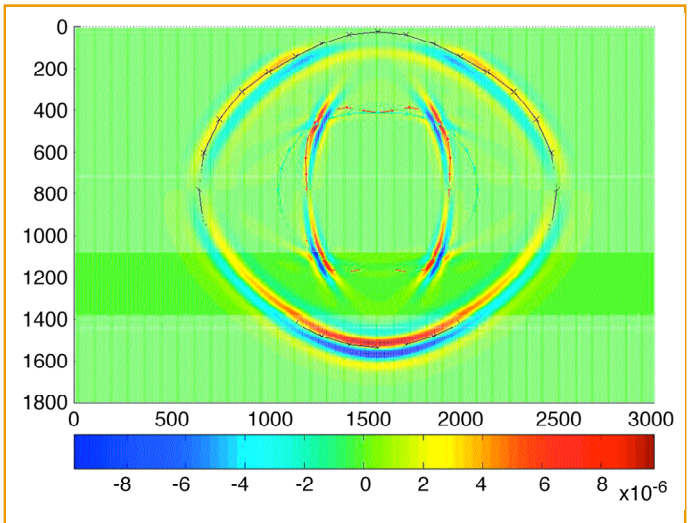

Figure 1. Snapshot of the wavefield in a homogeneous VTI model with vertical variations in grid-spacing indicated by thick black lines. Quasi-P and -S waves and a pure SH wave are unaffected by the change in grid-spacing.

SIGNIFICANCE OF FINDINGS

Our results show that variable-gridding and parallel computation can be used to reduce the computational expense associated with finite-difference modeling without any sacrifice in accuracy. These tools will enable us to incorporate more realistic velocity structure and geological complexity in large-scale 3-D anisotropic finite-difference modeling.

RELATED PUBLICATION

Pitarka, A., 3-D elastic finite-difference modeling of seismic motion using staggered grids with nonuniform spacing. Bull. Seism. Soc. Am., 89(1), 54–68, 1999.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Fossil Energy, Office of Natural Gas and Petroleum Technology, through the National Petroleum Technology Office, Natural Gas and Oil Technology, of the U.S. Department of Energy under Contract No. DE-AC3-76SF00098.

Changes in Noncondensable Gases in Steam from the Cerro Prieto Geothermal Field

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RESEARCH OBJECTIVES

Changes in CO_2 content and nitrogen/argon (N_2/Ar) weight ratios in the steam produced by wells from the eastern parts of the Cerro Prieto geothermal field of Baja California, Mexico, were studied to determine the effects of the main active processes in the reservoir (i.e., boiling, condensation, groundwater recharge, and mixing) on the gases contained in the steam.

APPROACH

Comprehensive data sets have been collected on this >300°C liquid-dominated geothermal field since the beginning of the exploration phase of the project in the late 1950s. Electricity began to be produced in 1973. Chemical and production data for the period 1990–2000 were analyzed and plotted to determine changes in the distribution of CO_2 concentrations and N_2/Ar values with time. Only the physical aspects of the reservoir gases were studied, mainly in connection with earlier work on solute chemistry and enthalpy of well discharges.

ACCOMPLISHMENTS

The results of this study agree in general with our earlier understanding of the response of the Cerro Prieto reservoir to pressure drawdown due to large mass extraction rates. (About 14,000 tons/hour are extracted and some 3,500 tons/hour are injected back into the reservoir.) In areas of boiling, production enthalpy increased greatly, and CO_2 content in steam increased two to three times. Nitrogen/argon ratios remained near that of air-saturated surface waters, but were lower in areas where boiling decreased and where production originated from gas-depleted brines residual to boiling. Newly drilled deeper wells also produced steam that was low in gas and N_2/Ar ratios, suggesting that these zones were also affected by boiling and gas loss. Injection of highly evaporated, air-equilibrated brine seemed to have little effect on the gases in the steam. There is evidence of a 1990 short-term, high N_2/Ar anomaly in the eastern part of the field (Figure 1), possibly from injection of air with the residual brine. There is also evidence that in 1995 and 1996, the northeastern region of the field produced steam with much higher N_2/Ar ratios, perhaps reflecting a bubble of altered magmatic gas that entered the system at depth.

SIGNIFICANCE OF FINDINGS

The results show that it is possible to identify reservoir processes by studying the chemical and physical response of wells to large-scale exploitation. These studies are valuable for anticipating changes in fluid production behavior. The information helps design appropriate changes in the field management plan that may reduce any future negative impact on the field's energy output. This is especially true at Cerro Prieto, since its electricity output satisfies the needs of about a million people (the present installed capacity is 720 MW). The work also seems to indicate that bubbles of magmatic gas are injected periodically into the geothermal reservoir as part of the recharge mechanism of the system. This hypothesis warrants further study.

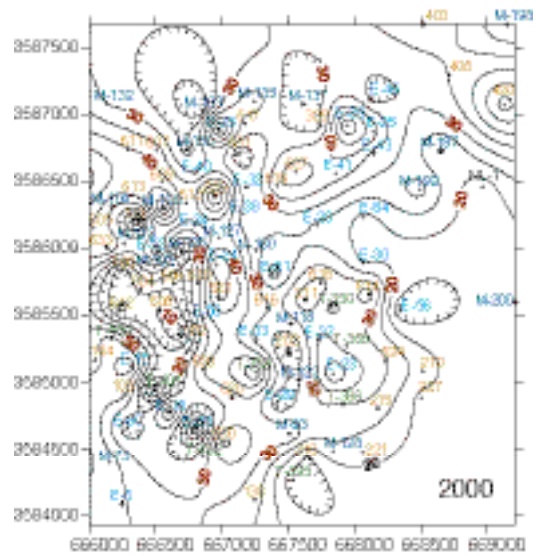

Figure 1. Nitrogen/argon weight ratios in geothermal steam produced by eastern Cerro Prieto wells for the years 1990, 1995, and 2000. The shaded area corresponds to the intersection of the main fault in the field (normal Fault H) with the top of the deeper reservoir (Beta Reservoir) (distances in meters).

RELATED PUBLICATIONS

Lippmann, M.J., A.H. Truesdell, M.H. Rodríguez, and A. Pérez, Response of Cerro Prieto II and III to exploitation. Geothermics, 2003 (in press).

Truesdell, A.H., M.J. Lippmann, M.H. Rodríguez, and A. Pérez, Influence of reservoir processes on gas in Cerro Prieto steam. Geothermal Resources Council Trans., 27, 2003 (in press); Berkeley Lab Report LBNL-53499.

ACKNOWLEDGMENTS

Most of this work was supported by the Assistant Secretary for Energy Efficiency and Renewable Energy, Office of Technology Development, Office of Geothermal Technologies, of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098. The rest of the support came from the Comisión Federal de Electricidad of Mexico.

3-D Resistivity Imaging of Single-Hole EM Data

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RESEARCH OBJECTIVES

Traditionally, electromagnetic (EM) induction logging has been widely used for directly measuring the formation conductivity surrounding uncased wells. Such a logging tool primarily consists of a magnetic dipole transmitter and a receiver in a coaxial configuration, in line with the borehole axis. As a result of this cylindrically symmetric nature of source and receiver, induction logging data offer no information about the 3-D conductivity distribution in the vicinity of the borehole. We can only characterize the 3-D conductivity structure surrounding a borehole if we can acquire multiple components of the magnetic fields resulting from various source polarizations. However, 3-D interpretations using such single-hole EM data are difficult because of the richness and complexity of the data and the very large number of discretized conductivity elements needed to construct a realistic earth model. Taking advantage of the computing efficiency of an algorithm based on a modified extended Born approximation (MEBA), we have developed an algorithm for simulating and interpreting EM data acquired in a single-hole environment.

APPROACH

Successful 3-D interpretation of geophysical EM single-hole data depends on the efficiency of a fast forward simulation as well as a sound inversion strategy. For EM simulations, scattered magnetic field at observing locations can be calculated, provided the total electric field in a confined conductivity inhomogeneity is known. This electric field can be derived using the integral equation method. However, this method quickly becomes impractical if the number of discretized cells making up the anomalous region exceeds a certain limit. Based on an approximation approach, the MEBA technique avoids this problem by calculating the total electric field in the electrical conductivity anomaly without solving any huge matrix equation. This methodology also provides an efficient way to calculate the Jacobian matrix for a 3-D inversion, which is based on a least-squares criteria and uses a conjugate gradient method for solving the system matrix equation.

ACCOMPLISHMENTS

We have verified the algorithm with simulation data. A set of single-hole data collected at a site for a pilot CO_2 injection project in southern California was used for inversion. The inverted conductivity structure around a borehole is displayed in Figure 1. Electrical conductivity variation within 8 m around the borehole is clearly indicated—this could never have been achieved with logging data. The results conform well to induction logging data and a crosshole section.

SIGNIFICANCE OF FINDINGS

With multicomponent magnetic data, 3-D interpretation of geophysical EM single-hole data is now practical on PC-based computing platforms. Weightings of the data must be carefully selected because of the strong transmitter-receiver coupling between the transmitting and receiving units for coaxial and co-planar components.

RELATED PUBLICATION

Tseng, H.-W., K.H. Lee, and A. Becker, 3-D interpretation of electromagnetic data using a modified extended Born approximation. Geophysics, 68, 127–137, 2003.

ACKNOWLEDGMENTS

This work was supported by the Assistant Secretary for Energy Efficiency and Renewable Energy, Office of Technology Development, of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098. We are also grateful for financial support and field data offered by Electromagnetic Instruments, Inc.

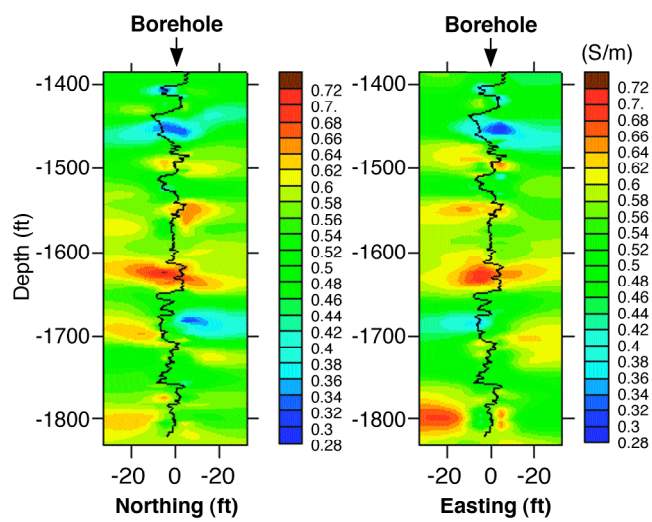

Figure 1. Inverted conductivity structure centered at a borehole in the CO_2 injection project site. Transmitter-receiver separation was 5 m; transmitter operating frequency was 6 kHz. Because of a vertical source, all three magnetic-field components were used for the inversion. The induction logging data is also displayed at the center of each panel for comparison.

Rapid Imaging of Interwell Fluid Saturations Using Seismic and Multiphase Production Data

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RESEARCH OBJECTIVES

Seismic imaging is a very powerful tool for obtaining high-resolution views of the subsurface. The current goal of this research project is to use seismic and fluid flow observations to estimate reservoir flow properties such as porosity and permeabilities.

APPROACH

This year, we have developed a method that maps estimates of reservoir pressure change, obtained from geophysical observations, into interwell permeability variations. This technique allows us to obtain high-resolution images of reservoir permeability in a reliable fashion. The method derives from the fact that if we fix the pressure in the equation for fluid flow, we have a linear first-order partial differential equation for permeability. Thus, we use the time-lapse data to estimate pressure variations in the reservoir. We then substitute these pressures in the flow equation and solve for permeability.

ACCOMPLISHMENTS

We have applied the imaging technique to a set of crosswell seismic and electromagnetic data gathered at the Lost Hills oil field. Time-lapse crosswell data were collected before and after the injection of CO_2. The data were first mapped into water and CO_2 saturation changes and pressure changes between the wells (Figure 1a). Based upon these changes, we then inferred reservoir permeability variations (Figure 1b).

SIGNIFICANCE OF FINDINGS

The results are significant because they enable us to estimate permeability directly from geophysical observations. Note specifically that reservoir simulation is not required in this approach. Furthermore, the inverse problem for permeability is linear in nature, and consequently the solution is more robust and less sensitive to an initial reservoir model. Also, we can estimate permeability in regions that have undergone pressure changes. Thus, we can estimate permeability for portions of the reservoir that have not yet been produced.

RELATED PUBLICATIONS

Vasco, D.W., K. Karasaki, and K. Kishida, A coupled inversion of pressure and surface displacement. Water Resour. Res., 37, 3071–3089, 2001.

Vasco, D.W., A. Datta-Gupta, R. Behrens, P Condon, and J. Rickett, J., 2003. Seismic imaging of reservoir flow properties: Time-lapse amplitude changes. Geophysics 2003 (submitted).

Vasco, D.W., Seismic imaging of reservoir flow properties: Time-lapse pressure changes. Geophysics, 2003 (submitted).

ACKNOWLEDGMENTS

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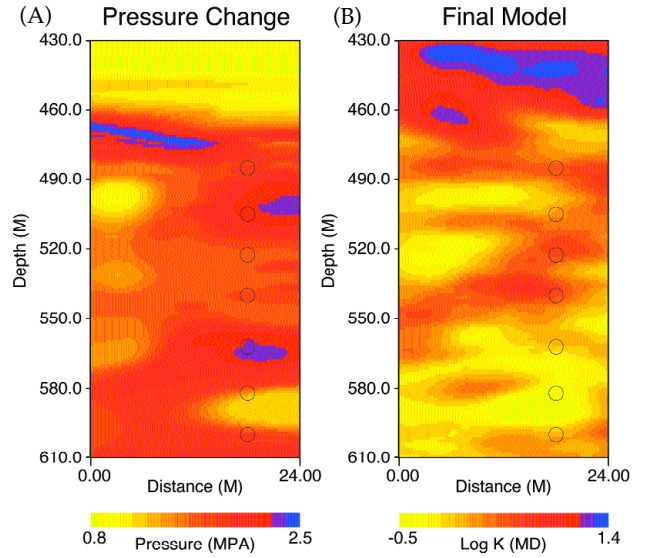

Figure 1. (A) Pore pressure changes due to the injection of CO_2. (B) Estimates of reservoir permeabilities in the interwell region.