Enhanced Geothermal Systems (EGS) R&D Program

EGS Report 2000-4B (Final)

EGS Workshop 3: August 1999

EGS Program Review and Planning of Objectives for Research

Workshop held at Lawrence Berkeley National Laboratory, Berkeley, CA,

August 17 and 18, 1999.

Report Date: July 17, 2002

Editor: Daniel J. Entingh, Ph.D
EGS Technology Development Director

Enhanced Geothermal Systems Research Management Project
Princeton Energy Resources, International, LLC
Rockville, Maryland

For: U.S. Dept. of Energy Idaho Operations Office, Idaho Falls, and
Office of Geothermal and Wind Technologies, U.S. Dept. of Energy, Washington, DC

Under Contract DE-AM07-97D13517

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

Enhanced Geothermal Systems (EGS) R&D Program

EGS Report 2000-4B (Final)

EGS Workshop 3: August 1999

EGS Program Review and Planning of Objectives for Research

Report Date: July 17, 2002

From: Enhanced Geothermal Systems Research Management Project
Princeton Energy Resources, International, LLC (PERI)
1700 Rockville Pike, Suite 550
Rockville, MD 20852

Editor: Daniel J. Entingh, Ph.D., EGS Technology Development Director

For: U.S. Dept. of Energy Idaho Operations Office
Idaho Falls, and
Office of Geothermal Technologies, U.S. Dept. of Energy
Washington, DC.

Under Contract DE-AM07-97D13517

For more information contact Dan Entingh, at 301-468-8418 or dentingh@perihq.com

TABLE OF CONTENTS

PREFACE

The purpose of this workshop was to develop technical background facts necessary for planning continued research and development of Enhanced Geothermal Systems (EGS). EGS are geothermal reservoirs that require improvement of their permeability or fluid contents in order to achieve economic energy production. The initial focus of this R&D program is devising and testing means to extract additional economic energy from marginal volumes of hydrothermal reservoirs that are already producing commercial energy.

By mid-1999, the evolution of the EGS R&D Program, begun in FY 1988 by the U.S. Department of Energy (DOE), reached the stage where considerable expertise had to be brought to bear on what technical goals should be pursued. The main purpose of this Workshop was to do that. The Workshop was sponsored by the Office of Geothermal Technologies of the Department of Energy. Its purpose and timing were endorsed by the EGS National Coordinating Committee, through which the EGS R&D Program receives guidance from members of the U.S. geothermal industry.

Section 1.0 of this report documents the EGS R&D Program Review Session. There, managers and researchers described the goals and activities of the program. Recent experience with injection at The Geysers and analysis of downhole conditions at Dixie Valley highlighted this session.

Section 2.0 contains a number of technical presentations that were invited or volunteered to illuminate important technical and economic facts and opportunities for research. The emphasis here was on fracture creation, detection, and analysis.

Section 3.0 documents the initial general discussions of the participants. Important topics that emerged were: Specificity of defined projects, Optimizing cost effectiveness, Main technical areas to work on, Overlaps between EGS and Reservoir Technology R&D areas, Relationship of microseismic events to hydraulic fractures, and Defining criteria for prioritizing research thrusts.

Sections 4.0 and 5.0 report the meat of the Workshop. Section 4.0 describes the nomination and clarification of technical thrusts, and Section 5.0 reports the results of prioritizing those thrusts via voting by the participants.

Section 6.0 contains two discussions conducted after the work on research thrusts. The topics were "Simulation" and "Stimulation." A number of technical points that emerged here provide important guidance for both practical field work on EGS systems and for research.

EGS Workshop 3 was funded by DOE Contract DE-AM07-97ID13517 to Princeton Energy Resources International, LLC, Rockville, Maryland, which at the time of workshop was known as Princeton Economic Research, Inc. The workshop coordinators, Dan Entingh and

Lynn McLarty, thank Lawrence Berkeley National Laboratory for hosting this workshop, and especially Marcelo Lippmann of LBNL for making the arrangements at LBNL. We also deeply appreciate the help of Nort Croft of Lawrence Livermore National Laboratory for his able assistance in facilitating parts of the workshop. And special thanks go to the presenters and participants, whose contributions were both essential and prolific.

SECTION 1.0

EGS PROGRAM REVIEW SESSION

1.0 EGS PROGRAM REVIEW SESSION

A workshop was held at Lawrence Berkeley National Laboratory on August 15 and 16, 1999, to define tactics for research on Enhanced Geothermal Systems (EGS).

This Section documents the first part of the workshop, which was devoted to reviewing what has occurred to date in this relatively new research subprogram of the Office of Geothermal and Wind Technologies, U.S. Department of Energy.

The presenters were all actively involved in the EGS research program.

- Lynn McLarty, the private-sector Project Manager for the EGS Research Subprogram. Lynn is on the staff of Princeton Energy Resources International, LLC (PERI), which was Princeton Economic Research, Inc, at the time of the workshop. He is the Executive Director of the EGS National Coordinating Committee.
- Paul Grabowski, was the DOE Headquarters program manager for EGS at the time of the Workshop. He assumed other duties at DOE Headquarters after October 1, 1999.
- Dan Entingh, is PERI's Director of Technology Development for the EGS project.
- Ann Robertson-Tait, is GeothermEx's manager of EGS-related activities.
- Steve Hickman, is on the staff of the U.S. Geological Survey, Menlo Park, California, and is a Member of the EGS National Coordinating Committee.
- Subir Sanyal, is President of GeothermEx.

These presentations set the stage for the later sessions at the workshop.

1.1 Introduction and Background.

Lynn McLarty, Princeton Economic Research, Inc.

We are approaching the end of the second year of our contract to assist DOE with the management of its EGS R&D program. I'll briefly review the first two years and then speak a little about where we are headed.

Fiscal Year 1998 was devoted to organization and conceptualization. We organized the EGS National Coordinating Committee. The NCC advises PERI, (Princeton Energy Resources, International, LLC, which was Princeton Economic Research, Inc. at the time of the Workshop) and in turn we relay some of its outlooks to DOE. The NCC currently has seven members, primarily from industry. Its purpose is to provide industry insight, technical information, expert opinion, specific analyses and evaluations, and recommendations that will benefit the planning, management, and execution of EGS research.

Also during FY 1998 we formulated the EGS concept & approach. It's no secret that the EGS R&D program grew out of the ashes of the Hot Dry Rock R&D program. In December of 1995, the Geothermal Energy Association convened a workshop to devise and submit recommendations to DOE on future directions for HDR research. The workshop recognized HDR energy as an important resource that could play an important role in the future of the geothermal industry. However, it recommended that the HDR R&D program at Fenton Hill be discontinued and that the term "hot dry rock" be replaced with a new, broader term. In response to the GEA HDR Workshop recommendations, DOE issued a solicitation in 1997 titled "Geothermal Hot Dry Rock Program." That solicitation resulted in the award of the contract under which PERI/GeothermEx Team now assists the DOE with R&D management.

Ironically, DOE's solicitation ignored the workshop's recommendation to "replace the term 'hot dry rock' with something more broadly descriptive." Although it was not stated in the solicitation, we knew that one of our primary mandates was to effect this change in terminology as part of a whole new approach to create an R&D program which industry would support and participate in. Industry was adamant that any long-term component of DOE research result in near-term spin-offs beneficial to industry along the way. We knew that industry would be supportive if the renamed futures-oriented R&D program was structured to meet the needs of the geothermal industry as it evolves.

PERI promoted the concept that the logical evolution of the industry will be to develop the highest quality resource sites first and develop sites with progressively lower permeability and/or fluid content as the necessity and opportunity for such coincide. Thus, it is appropriate to initially focus EGS R&D in and adjacent to commercially-operating hydrothermal reservoirs, with the intention of benefiting industry and simultaneously creating incremental technology improvements that are applicable to increasingly more geologically challenging areas over time.

As part of this approach, we solicited suggestions for new terminology from the US and international geothermists. The term "Enhanced Geothermal Systems" was chosen (by us, most of the members of the NCC, and some of the DOE staff) to refer to systems in which advanced technology is required to extract energy from the earth's crust in areas with higher than average heat flow but where the natural permeability and/or fluid content are limited.

We purposefully included fluid augmentation for fluid-depleted hydrothermal fields as part of the strategic approach in order to garner initial industry support and help ensure that there would be some tangible benefit to industry in the near-term.

The current fiscal year, FY 1999, has been devoted primarily to planning, although some field research has been going on in Dixie Valley and GeothermEx has been leading a team that is assessing the state of the art of geothermal reservoir simulators in the context of EGS. Our project team worked closely with DOE and the National Coordinating Committee to develop the EGS Strategic Roadmap. The strategy works toward having a pilot scale (1 to 10 MW) EGS project up and running by the year 2008. The project may or may not be adjacent to a producing hydrothermal field. Copies of the Roadmap are included in the notebook provided for this meeting and you are invited to read it for further details.

The next step is to identify and prioritize individual research activities for achieving the objectives of the Strategic Roadmap. That is the purpose of this Workshop. The information and ideas generated here will be used to develop an implementation plan to guide the EGS research program.

Before I finish I would like to point out some of the things that we feel the DOE/PERI/GX team has done well and some other things the team has not done as well. As you are all aware the federal bureaucracy moves slowly and funding for this program has been very limited. Thus we have not been able to achieve as much as we had hoped to by this time.

Table 1.1-1 indicates areas in which we and DOE think the team has done a reasonably good job. This includes transitioning from the LANL HDR Program to an industry friendly EGS Program, creation of the National Coordinating Committee, and helping the U.S. and international geothermal community know that change is underway, and how to participate in that change.

Table 1.1-2 shows areas where we and DOE believe that much work remains to be done, and done as soon as possible.

Table 1.1-1. What the DOE/PERI/GeothermEx Team Has Done Well
• Transition from LANL HDR Program to industry-friendly EGS Program • Coined and widely publicized the title "EGS" • Developed & publicized the EGS two-pronged strategy • Developed the EGS Strategic Roadmap • Established a good set of technical objectives • Established good industrial relationships and the seeds of credibility • Created the EGS National Coordinating Committee & got industry buy-in • Started EGS Baseline studies • Established good international relationships & a recognized position within the International Energy Agency Geothermal Implementing Agreement framework • Elicited a few research proposals

Table 1.1-2. What the DOE/PERI/GeothermEx Team Needs to Achieve Soon
• Found an influential, well known person to be an EGS Champion • Elicited much technical guidance from industry, National Labs, and academia • Defined and prioritized, well enough, the types of demonstration projects • Elicited many research proposals • Investigated new developments in parallel technologies (oil and gas, radwaste, mining) • Publicize and sell the EGS concept to non-geothermists, particularly leading environmentalists • Developed a comprehensive tactical plan for EGS R&D.

1.2 DOE Headquarters Outlook on EGS Research.
Paul Grabowski, U.S. Department of Energy

I'm going to talk a little bit about the goals of the EGS program and the NOPI (Notice of Program Interest) we have out, and an upcoming solicitation.

The goals of the EGS program:

You have a copy of the EGS Strategic Roadmap in your workshop materials. The EGS program evolved out of DOE's previous work on Hot Dry Rock. We want to have a more industry-focused program. We put together a Strategic Roadmap for the Office of Geothermal Technologies (OGT). In that there was a goal developing, by 2010, geothermal technology capable of providing 10 percent of U.S. non-transportation energy by 2035.

Under that, we fit in the EGS goals to say, by 2010, we'll have technology that we think will be making power from an EGS site. So what we did with the EGS Coordinating Committee, is that we put together this plan that said, that's our goal by 2010, what do we have to do to get there?

You've got to have projects. So let's line up some projects. What do we do? We start them. We analyze them, figure out if they work, if they don't work, pick out the good ones, and by 2010, we're going to have one, hopefully two or three projects that are working. Sounds simple enough. There's a lot to be done in the meantime. That's why we're having this meeting here today.

The goal is a long term goal. Who knows, the program might not be around by 2010. It's ten years off.

Solicitations for EGS Projects:

The next thing we need to talk about are the Reservoir Technology solicitation, and the recent Notice of Program Interest (NOPI), and their relationship. As you all know, DOE Idaho is running a solicitation for Reservoir Technology ("ResTech") research projects. That is open now and comes to a close this September 30. What we've done this past year is to allow EGS-type research projects to be proposed to that solicitation. We separated out those that as they came in and said, these look like they apply to an EGS type scenario and let's fund them out of our EGS budget.

In the future the plan is to have another solicitation, this time out of Albuquerque for EGS projects, field projects but also R&D projects. There will be one solicitation, for we're still trying to work out the details. It's either going to be one solicitation with two sub-areas, one for actual projects and then one for R&D, you know field projects or sites, and then one for R&D. If there is another ResTech solicitation, we'll probably have a sub-category on that also, that strictly R&D can be proposed to, not a field site. There is essentially going to be one, possibly two vehicles for R&D.

The Albuquerque solicitation will hopefully be coming out prior to the end of the Fiscal Year, which means early September, 1999.

The EGS NOPI, the Notice of Program Interest, is essentially for getting your ideas as far as, "Is this a good idea?" Is there industry interest from the geothermal field operators? Our idea behind that was that we can't really have a program unless we have some sort of site or a project out there to point to. The NOPI is still open. We're still getting comments in from industry. If there is anyone who wants to comment for an NOPI, it's still ongoing and if you just let me know afterwards, I can tell you about the details of it.

A number of firm have already responded. Staff of the DOE Idaho office have told me it's OK to tell you who some of them are, since there is no funding involved, and later everybody will get a fair shot at the money. CalEnergy responded. The Navy Geothermal Program Office (GPO) responded. These are field operators. ORMAT responded. And these folks responded expressing interest. They didn't respond saying this was a stupid idea. I don't think anybody has responded that way yet. GeothermEx and PERI have both responded with comments. There are about eleven responses so far.

Most of them of the replies have been a guarded response of, "We think it's good idea." In the NOPI, we're gathering comments to make us, DOE, feel good about putting out a solicitation. That, yes, there is an interest out that or that it's not going to be just sitting out there with nobody responding. If anybody has any interest in this NOPI, they need to contact the DOE Albuquerque Operations Office directly. Don't rely on rumor and secondhand information.

McLarty: If you send me an email, I'll send you the Web address. I'll also send you a file that has the NOPI and all the information for who you need to respond to.

Anybody can respond to the solicitation that we plan to come out of Albuquerque. We are working out the details. I want a solicitation that industry can propose a field site project to, but also one that you can propose R&D to, like the Reservoir Technology solicitation is now. And I'm trying to work out the details of having either two sub-topics under this particular solicitation or having a separate solicitation for R&D. I'd like to have two sub-topics so that it is just one solicitation document that everybody looks at. But I'm not sure if we're going to be allowed to do that.

Aims of this Meeting:

Now, I'll talk a bit about my take on this meeting. We want an industry-focused type of program. What we're trying to do is put together this NOPI that will bring in sites or projects out at existing geothermal sites. Then we're going to try to put together a portfolio, of R&D projects, but that R&D should support some site somewhere. For example, Dixie Valley, which Steve Hickman will talk about. If you have ideas which you think would make Dixie Valley a success, let's get them out over these next two days and we can line them up behind the Dixie Valley project. Coso, Imperial Valley, Roosevelt Hot Springs, any of those potential sites. If you think a certain type of R&D or in certain areas it is necessary to make that type of site a success, let's get that out so we can align a project and have all the supporting R&D below it. And that's what we're trying to get out of this meeting. In the EGS Strategic Plan, where are currently in the middle of Objective 2.10, Evaluation and Assessment of Technology.

Question: So part of the objectives for this group would be to identify the technical barriers?

Answer: Well, no. We've pretty much identified technical barriers and have come up with some technical objectives. What we want to do in this group is identify more on a microlevel what are the R&D projects that will get us to where we need to go. The technical barriers we've settled on are listed in the EGS Roadmap, and the EGS Technical Objectives are listed in the first paper in your materials, McLarty and et al., page 6, I believe. If you look on page 2 of the EGS Strategic Plan, there are the EGS Milestones. We are approaching Milestone 2. Section 3.0 in the Roadmap does address barriers.

Creed: One of things that comes up with this topic, is what's the difference in DOE's Reservoir Technology (ResTech) research and the EGS stuff? My opinion is the closer to the wellbore you are, the more likely it is to be totally EGS and the farther out, the more likely you are going to be in the ResTech world. In between, of course, is a continuum. Keep that in mind. We don't want to start a duplicate program. That would kill us programmatically at a certain level at DOE Headquarters. While we want competition in the R&D world, and we want to be able to get lots of different ideas from people, the geothermal R&D program is just not robust enough to support two competing useage objectives.

Outlook for EGS Research Funding

Grabowski: As you all know, geothermal has undergone a reorganization at DOE. We're going to be merged with the Wind Division, so it is going to be Office of Wind and Geothermal Technologies as of October 1, 1999. As far as operationally though, I don't think it's going to change the way things are going. We're still going to have geothermal program components of Reservoir Technology, Drilling, and Conversion. The EGS program will still be a small program tucked into the Geothermal just like it has been the past year or so. Funding-wise, it will probably be around a million and a half. Program-wide we will probably end up with level funding. Last year's budget was $28.5 with a $6.5 earmark for heat pumps which brought us down to $22 for the other parts of the program. After "taxes" and other reductions, we ended up with an operation budget of about $18. This year the Congressional marks came back between $22 and $24. There is no set-aside expected for heat pumps. Congress just took out the heat pumps, essentially.

The $22 is for geothermal as a whole. EGS again is a small part of that. Last year it was about $1.5 million, and this year its going to be about the same, if I were to guess. Unless there is real strong industry interest with this solicitation and we can make a big play for more dollars.

Question: Do you forsee any kind of long term commitment to EGS?

Grabowski: I don't know if I am at liberty to say that. There is long term commitment as much as there can be a long term commitment with any DOE program. And that's a just one way of saying, "I don't know." I think there is interest in DOE. There is interest in industry. But when push comes to shove, if someone wants money going somewhere else, it could go somewhere else.

Again the idea is that if we have this portfolio arrangement, we can make a better case for a program. These are our projects. This is the R&D we believe need to be done under each project and this is why we think we need that in the budget.

Koenig: Presumably when you are talking about these projects in the portfolio, you have also identified an industry partner or partners who would be able to support this effort, that is make the fields and/or facilities available for this effort.

Grabowski: Right. That's the purpose of the NOPI and the eventual solicitation out of Albuquerque. It's to get those industry partners to step up to the plate and say, Yes, we think we can do a project here. So with any kind of R&D in the future, I would encourage the R&D Principal Investigators, to have an industry partner lined up that they will allow you to do any kind of work at their field or in their wells.

Koenig: In the long term, if you garner this industry support, I think that you will have a much better chance of addressing the issue of: Will there be an EGS program in the future? And if you ignore that side of things and don't take it seriously and listen to what they have to say, it'll fall in the same waters that the Hot Dry Rock R&D program did.

Creed: There is a correlated issue I want to repeat about the parallel program potential. One of the ways this program will be able to survive is if we have a systematic program in place with rigorous objectives that we meet and that we show that we are organized and not duplicating work and using our funds efficiently and effectively. So there are programmatic reasons to be a tightly constrained focused program. That might be difficult to achieve.

1.3 Considerations in Planning EGS Research.
Dan Entingh, Princeton Economic Research, Inc.

I want to talk about background and objectives for Enhanced Geothermal Systems as a whole. It's already been said by both Paul Grabowski and Lynn McLarty that the EGS program grew out of the DOE Hot Dry Rock research program. In a sense that's true and in a sense EGS grew out of something a lot larger than that.

Early on, the DOE Geothermal R&D Program tried to look at four major kinds of geothermal resources in the United States. Those were hydrothermal, geopressured, HDR, and magma energy. Magma was addressed a little later than the other resource types.

Size of U.S. Geothermal Resources:

What was that about? If you look at only hydrothermal, there's not a whole lot of resource. EGS in a sense is intended to be a Phoenix rising from the ashes of the U.S. HDR experiments, but also from these others, so that geothermal technology can eventually make more than today's working hydrothermal reservoirs commercially useful to the nation.

To the credit of Los Alamos team, HDR wasn't exactly impractical, it was just very expensive. You might be able to get to a cost, a required price, of 8 to 10 cents per kilowatthour of electricity from HDR, if you have a 100°C per kilometer thermal gradient in stimulated granite. But today you would get paid less than 3 cents per kWh for that electricity.

In France you might get 4.5 or 5 cents for that kilowatthour, in Germany 7 or 8 cents and in Japan about 10 cents. Those are the places where they have a real economic interest in continuing to explore hot dry rock technology as a resource and they will do that.

Twenty years ago the identified U.S. hydrothermal resource, defined as KGRAs, Known Geothermal Resource Areas, was about 25,000 megawatts if produced for 30 years. About four or five times that, as estimated unidentified resources. A lot of that unidentified resource was thought to be in the Cascades Range, the volcanoes up and down the Pacific coast, and also quite a bit more in the Basin and Range province. A lot of that "unidentified hydrothermal resource" has turned out to be hot but dry.

The economic part of the 25,000 megawatts (or 18,000 to 40,000 MW as estimated by others more recently) is not very large. I think that the economic part, if you let the price cut range up even to five cents a kilowatt hour, isn't more than about 5,000 MW today in the U.S. Compare that to 800,000 MW of U.S. electric power capacity online, including both baseload and peaking systems. 5,000 out of 800,000 installed is less than one per cent.

Policymakers in Washington are coming to the conclusion that we might not want to do more R&D on geothermal because its proven potential is not very large. Renewable energy policy makers are saying that we get a lot more political mileage out of supporting photovoltaics and wind than we do out of geothermal. Wind installations are starting to take off. About a 1,000 megawatts of new wind machines are being installed this year in the U.S.

So the DOE Geothermal R&D program needs some sort of follow-on to hydrothermal, some sort expansion of hydrothermal, or it will be forced to close up shop. This is what I believe; this is a personal outlook. A great deal of what EGS is about is to put in place at least for a few years a place marker for what that bigger geothermal resource might be. The people in this room, plus maybe four people in the U.S. Geological Survey, are probably the only people competent to get at that question. That's a great deal of why we've asked you to be here.

Economics:

The economics is dominated by the fact that the current wholesale price of electricity, on the U.S. west coast, is about 2.5 cents per kilowatthour (kWh). That's not very much, compared to historical wholesale prices.

All of you who have worked in geothermal up to the last year or two -- except for at The Geysers where the power is sold at about 3 or 4 cents/kWh -- have been working on liquid dominated sites, where for most of the history on average the developer was paid about 10 cents or more per kWh for the electricity. That's not a retail price. That was the wholesale price under the California Interim Standard Offer 4 contracts.

Because of those high prices, industry people are used to working in places where it's OK to drill ten percent new production wells every year. Say at the beginning of production at Coso, CalEnergy was drilling 13 to 15 percent added wells a year. No one is going to do that again. I think that means that the only new geothermal production that will be developable in the U.S. during the next few years will be at very hot reservoirs. MidAmerica Corporation, formerly "CalEnergy," operates one of the best of the best such reservoirs, the Salton Sea, in California. Whenever the wholesale price gets to 3 or 3.5 cents, for example, 2.5 cents plus a light subsidy, they'll cookie-cutter out another plant there. And they'll continue to improve technologies and processes as they go along.

Geothermal power will also continue to come from The Geysers, as additional water is found to inject there. A few other hot sites will continue to be worth operating.

We have to define a lot of things. Some of you have asked, "What's defined so far?" What's defined so far is tentative. Many of the important first definitions are in the overall Geothermal Program Strategic Plan and EGS Strategic Roadmap. The tactics for those plans, though, need to be fleshed a lot.

What Kinds of Reservoirs Should EGS Pursue?

As Paul Grabowski has said, we'll start at the reservoirs that are already commercially opened and are now producing. That was John Sass's idea from a number of years ago. Ann Robertson-Tait has worked with him to amplify that (see their attached 1998 paper). John Sass and Mark Walters will have another paper on more aspects of that in the Basin and Range in the GRC Meeting and Transactions this year.

We mustn't ignore other possible reservoirs. My favorite is this: Is there a piece of rock that's pretty hot and fairly permeable but doesn't have much fluid in it. If we can find such a things, if we start injecting fluid into it, would it all leak off or not? I believe, that people in the community know about more reservoirs like that. Such reservoirs would be the next step to pursue after proving some concepts in margins of existing hydrothermal fields. Such a block of rock might be on the margin of some operating hydrothermal field now. If it's distinct enough, it may be something that we should go after.

What Kinds of Research Should be Done?

DOE Headquarters clearly needs to push to be working in the field. The perception is that's the only thing that will convince other policy makers, both inside and outside the DOE, that there is something real going on here. I happen to believe that we also have to do some earlier technology assessment work. For example, couple years ago Marshall Reed (DOE HQ manager of the Geothermal Reservoir Technology R&D program) collaborated with others to get the National Academy of Sciences to do a major study and report on fracture detection and manipulation, which is an important Baseline analysis for our work.

There are other Baseline studies that are needed before we all get onto the same page to move into field work. We've listed a set of specific "Baseline" studies that we think are important. These included three reviews, ongoing or completed, of Fenton Hill work that DOE asked us to do. They are shown in Table 1.3-1. I expect these Baseline studies to emerge, perhaps in modified forms, in the research topics and issues that we as a group will nominate and vote on in this workshop.

Table 1.3-1. EGS Baseline Studies
1. Reviews of Fenton Hill Work 2. Well stimulation methods 3. Predictive technologies for well stimulation 4. Detection and analysis of fractures 5. Rock mechanics 6. Advanced reservoir (numerical) simulation 7. Testing of low productivity wells

What should we stimulate?

One of the important things that we should get to today in discussions is the beginnings of answers to this question: What to stimulate? (Not "simulate," that comes later.) The four main goals that people have gone after with various downhole stimulation methods are shown in Table 1.3-2.

Table 1.3-2. Goals of Stimulation of Hydrothermal Wells
1. Increase near-wellbore permeability 2. Reach nearby existing fractures 3. Enhance bulk permeability by creating new large fractures 4. Improve injectivity

After a conducting a review of U.S. experience in trying to stimulate geothermal wells, I think that we know how to enhance near-wellbore permeability. The review is published in the 1999 *Geothermal Resources Council Transactions*.

But we don't know how to usually get over to nearby existing fractures. I think that was a Holy Grail in The Geysers twenty years ago. Bob Verity of Republic Geothermal, in charge of the eight-experiment DOE stimulation program in 1978-1983, said in effect, "The Grail of all of this is to avoid having to redrill a well when we don't encounter good productivity." That is, to avoid drilling doglegs. Sadly, the most economically successful incidences of enhancement that I've seen reported have been, in fact, doglegs (multiple completions) drilled in The Geysers. These are reported in the 1993 *Geothermal Resources Council Transactions*.

When we started working on EGS, Lynn and I thought that one of the most important things to do to "enhance geothermal systems" would be to able to create permeability in bulk volumes where there is very little permeability now. The more I read and the more I think about it, the more I think that that may be very difficult. But this group may have different opinions.

Of the stimulation experience, the evident successes in hot fractured rock have been in turning a few well bores into fairly good injectors, rather than into producers. So that's part of the background here. There is much more detail in the attached paper.

What to Simulate?

Can we use computers to enhance our attempts to build EGS? Subir Sanyal and I have been discussing this for about a year. We started GeothermEx out on a background study, the start of an EGS Baseline study, on what's important in simulation for industry for enhanced geothermal reservoirs. Dan Swenson has been involved in the study. This is a topic that we will spend some dedicated time discussing late in this workshop. I think that we need to nail down important things in other topical areas, such as: What aspects of rock mechanics may be needed to looked at in new ways? Then at the end we want to get to, if we look at such aspects of rock mechanics, how would we simulate that? How would we represent that in the body of information that we are trying to integrate through modeling?

What Can we Systematize?
One of the other things that I don't know what to do about is the question of what should be systematized. If you look at the old DOE geothermal well stimulation program, they did eight major experiments. They started at Raft River, a low temperature area. Then they went to East Mesa, at a moderate temperature, and later they went out to Baca to do some high temperature work. So there was something systematic.

I am both afraid, and certain, that if we go out to do six field experiments within the next three years that are somewhat loosely connected to the idea of enhancing geothermal reservoirs and geothermal production activity, and four or those experiments "fail," then -- unless there is a ladder of logical or technical or commercial succession, something that is systematic along one or two dimensions -- we're going to look a bit stupid.

The questions of technical interest and import may now be too diverse or too diffuse for us to "systematize" soon. But one of the things I think that we as a group need to really hammer at is to make "systematic" one of the main criteria for how we pick important research.

Do or Die Criteria:

The criteria I think are most important for EGS research projects are shown in Table 1.3-3.

I wrote down the first of these bullets as the single "Do-or-Die" criterion about two weeks ago. One of the things our industry advisors, the members of our EGS Coordinating Committee, always say is, "I have get any EGS proposal approved by Executive Committee." You've been involved in such presentations and negotiations over the years if you've had any involvement in field research.

Table 1.3-3. The Do-or-Die Factors for EGS Research
• What will Geothermal INDUSTRY executives invest in? • What will DOE and the U.S. CONGRESS invest in?

But on Friday afternoon Subir called me about something and we got into vigorous discussion what the Government's role in EGS work ought to be, about what aspects of EGS should be supported by Government funds. It dawned on me that there is an equally important second criterion for EGS projects: "People in the Government have got to want to support and fund this." I think if there is going to be a continuing geothermal R&D program, then both of these criteria for what is "supportable" have to be very high on the list of what defines good research projects.

Prairie: I want to emphasize one thing you said. I totally agree about the systematic part of the program. I think that another way of saying that would be to ask the question: Does this project, whether it is a technical success or failure, advance us towards our ultimate objective. If it is a failure, you still learn and so you still advance, and so then it's not a failure.

Entingh: I totally agree with that. I would like to drive us towards being more "scientific," so to speak. The details of that need more definition.

Robertson-Tait: But you are also managing the expectations of the people who are giving you money, which is really important.

Pruess: Could you clarify something? You said we could be looking for sites that are very permeable and have little fluid. How can they be permeable and not have fluid there?

Entingh: I haven't tried to think out a complete set of answers to that. Maybe, the water table wasn't high 40,000 years ago, when a permeable body of hot rock was formed. Similarly, a repeated question has been, "Is The Geysers field is recharged from beneath?" After almost forty years of production there, I don't think we know the answer to that. Maybe my idea that there are likely to be large reservoirs that are hot and permeable, but fluid limited is nonsense. But The Geysers field itself is very fluid-limited, or it would not be a "dry steam" field. The Geysers was the best U.S. field for the industry to start on because it had spaces that were not full of liquid. Another way to say this, is that the competitive geothermal power in the U.S. will come from flash sites, or flash-binary hybrids, rather than lower-temperature binary systems.

Pritchett: A comment on your statement of the need for high temperature to be economic. Although I understand where you are coming from, it's been my experience that the highest temperature systems that you can usually find at places you can afford to drill to are young volcanics. The hotter they get, the more chemically monstrous they get. So I wouldn't just be looking for maximum temperature. I guess my gut feeling is somewhere around 270°C is sort of an optimal world to be in. If you are much hotter than that, you always have chemistry problems. Anything over 180°C is going to be flash rather than binary.

Koenig: Yes. That has been repeatedly documented in the field in Iceland and other places, as in Italy, where they have hit high temperatures. Invariably you run into chemical problems, not the least of which chemical reaction that happen when you start putting water into environments that don't have it already. Water is a truly aggressive solvent and there are a lot of things down that it can modify. As another corollary I'd add that not only do we need to consider the temperature of the system, but the availability of the working fluid that we are trying to produce. Where are you going to get the water to inject? Also, I would not ignore the idea of doing things in environments at elevated temperatures using working fluids than water.

1.4 GeothermEx's Work and Outlook on Enhanced Geothermal Systems. Ann Robertson-Tait, GeothermEx, Inc.

I will talk about what GeothermEx has been doing in support of PERI's efforts here. You know about a few of those things if you attended the DOE Geothermal R&D Program Review in May, at the Berkeley Marina Hotel.

We were asked by DOE to do a review of the Fenton Hill HDR project from two points of view. One was to do a *Hot Dry Rock Program Peer Review* that summarized the important methodologies, procedures, and results that came out of Fenton Hill. The second, which was related to that, was to review the availability of data from Fenton Hill. That, in turn, links up with another task that PERI has to consider the indexing and archiving of Fenton Hill data for people who might be interested in it and have it accessible.

These were both fairly small studies but they got us through the Fenton Hill information and got us to move forward. On the Data Indexing and Archiving, GeothermEx has a small task underway now to prioritize the data that we think are important from Fenton Hill to be included in the archive.

Then we are doing a couple of other small EGS jobs. We are developing practical scenarios for EGS development to give a framework to any solicitation. We are also collecting and reviewing information on potential EGS sites.

Industry Perspectives on EGS

The other thing that we were asked to speak about today--I have some overheads for that which I do have copies of if anybody is interested--is what the industry perspective is on the EGS program. We think the industry looks at it in three ways: short term, medium term, and long term. Table 1.4-1 shows what we think the goals are for EGS in terms of industry's viewpoint.

Table 1.4-1. Industry's Goals for EGS
Industry wants the EGS program to:
Use existing technology to lower costs and increase profitability in the short term
In the medium term, develop new technology to further improve geothermal economics
Increase the commercial geothermal resource base for power generation in the long term

In the short term, imagine that 2.5¢ per kWh is the price for power. Just put it up there in your mind and you will know what industry wants. Table 1.4-2 summarizes that they want something to help them out immediately, to lower their costs, increase their profitability say in the next five years, for existing plants.

Table 1.4-2. What Types of EGS Projects will Attract Industry Interest in the Short Term (± 5 Years)?
Projects that: - Sustain output - Reduce operating costs - Increase profitability of existing contracts

Koenig: I'll augment that by saying don't ignore the power plants side of things here. When you're talking about EGS and drilling wells and putting in new wells, you also have to fight with industry's view point of, "Can I get the same bang--or a better bang--for my buck by investing in a power plant improvement than I can by drilling new wells or looking for new heat sources?" I'm just warning that outlook is a competitor for industry attention and investment.

Robertson-Tait: In the medium term (Table 1.4-3), the focus of our discussion today is: What kind of technology can we develop to improve the economics say in the next ten years, or maybe fifteen at the most? Our goal is by 2010 to have a working EGS system online, maybe adjacent to an existing facility or part of an existing facility. It may be on its own. We don't know yet. But to get there we're going to need to work on technologies that will enable us to develop these low permeability or fluid deficient areas.

Table 1.4-3. Industry's Longer Term Goals
MEDIUM TERM GOAL: Use new technology to further improve geothermal economics R&D that focuses on enhancement by developing artificial fractures - creation - definition R&D that enables accurate prediction of reservoir behavior after enhancement **LONGER TERM GOAL** Leverage the medium-term research to commercialize more geothermal resources in the U.S.

Finally, there is the big picture for the future of geothermal energy in the U.S. This speaks to policy making, and to increase appeal across the United States. The ultimate goal is to increase the size of the resource base that we can develop.

Now I'll talk a little bit about short term projects.

Essentially, these again speak to the bottom line. The developers are being paid 2.5 to 3 cents for their power now so anything that they can do to cost effectively sustain their output without having to drill new wells is going to be very much sought in the next few years. For example, Dan mentioned that at Coso there was initially a very aggressive makeup well drilling program. Makeup well drilling there is not aggressive at all now. It's a drop in the bucket compared to what it was. They are looking for other ways to keep output up. At Coso they are investigating things about injection and seeing what they can do to better manage their field with the resources that they have available. That's what they're going to be looking for. If they can reduce their operating costs and somehow leverage what they've got in the way of existing contracts--that's the kind of things that they are going to be looking for.

Economics of the Geysers Effluent Pipeline Project

I'm going to talk a little about the economics of the Southeast Geysers Area Effluent Pipeline and Injection project (SEGEP). Brian Koenig will talk about that in more detail later. SEGEP wasn't thought of as an EGS project when it started. It was born from many places, including a need to dispose of waste water from Lake County. They were dumping it into Cash Creek, which couldn't be done any more, due to a cease and desist order. While it wasn't EGS that was driving it, has turned out to be a very successful EGS project, as shown in Table 1.4-4.

Table 1.4-4. The Southeast Geysers Effluent Pipeline A Case History of a Short-Term EGS Project

Cost:	About $40 million Shared by operators and Government
Results:	40 MW additional generation At least two years of additional field life

It has achieved 40 megawatts of additional generating capacity from that already, and they've extended the field life by about two years. Steven Enedy presented two graphs of production history at the DOE Geothermal Program Review meeting which you may have seen already.

Figure 1.4-1 shows results for the two NCPA units. They at the very southern end of The Geysers. They got a nice boost in flow and eventually sort of trended back along their decline trend, although as always at the end of the data set, there's always something interesting so we'll see what that means.

Similarly in Units 13 and 16, two other units that were participating in the injection water, there were very similar results, as shown in Figure 1.4-2. The Figure sums the steam flow to the power plants, so it's not looking at things on a well by well basis, but looking over the area for those plants as a whole. Obviously you are going to have better benefits in some places and perhaps no benefit or perhaps a negative benefit in some places if you are watering out your wells. The graph for Unit 18, Figure 1.4-3, was again very similar. They really got a consistent response to the additional injectate.

What will happen if you project these graphs outward in time? Eventually you'll get back to your pre-SEGEP decline rate. It looks as if that period will be about two years. They've gained two years of field life. It's also interesting to note that the decline trends aren't any worse. In fact, the graphs make you wonder if things aren't going to be better in terms of the decline rate. So they haven't worsened anything and they may have made it better.

Those results are averaged across the field area so in individual wells they have had very encouraging responses, some wells actually going up in production rather than declining, and dramatically, not by small amounts. Of course that's not the case throughout the field because the area influenced by injection is limited in some cases.

Table 1.4-5 summarizes some of the results of the project.

Table 1.4-5. Benefits of the SEGEP Project

40 MW Additional Generation

- 750,000 lbs/hour boost ÷ 18,000 lbs/hour per MW = 40 MW.
- At $2,000 per kW installed, this equates to avoiding a capital investment of $80 million.

Two years of additional field life

- Decline trends are no worse and may be better than pre-SEGEP.
- Production rate will decline to pre-SEGEP levels no sooner than 2 years after SEGEP start-up, and possibly longer.
- Averaged results across four power plant areas (NCPA, Unit 13, Unit 16 and Unit 18).

Low Cost of Power

- At a $0.03 per kW-hour sales price, this equates to additional gross revenue of $10.5 million per year.
- Payout period is less than 4 years.
- Assuming a 10-year life and a cost of $40 million, the cost of SEGEP power is $0.012 per kW-hour.

There are 40 megawatts of additional generation. We took the steam flow increases off the graphs I showed you, divided them by about maybe a useful average of about 18,000 pounds of steam used per hour per megawatt to get the 40 megawatts. If you look at avoided costs, which was sort of the model that's been used in the utility industry for a long time, and you assume $2,000 per kilowatt installed, that's about $80 million of capital investment avoided. These are the kind of things industry likes to see -- those that talk about dollars.

There are other ways that you can look at it. If you use 3 cents per kilowatthour instead of 2.5, then you get about $10.5 million per year. That's a nice chunk of change for three operators (now two) to divide.

The payoff period is pretty short. The cost was $40 million. You get back about $10.5 million per year. In four years you're paid back. The lifecycle cost of that power, if you look at it in another way, is about 1.2 cents per kWh. If you get 40 megawatts and you have that for a 10 years life, the economic cost is 1.2 cents per kilowatt hour. So that's attractive. That's something that R&D proposers and evaluators should be thinking about--if only in the back of their mind--that this is the kind of thing we need to get to in the present economic climate.

Table 1.4-6 lists some of the things that still need to be done at The Geysers. There are a few questions that we've all wrestled with for a long time. For example, where does the injection fluid go? What about the rest of that fluid? I mean the fluid that drives the 40 megawatts is the only about 30 or 40 percent of what was actually injected. So where does the rest go? How do we get more of it back?

Table 1.4-6. The need for injection-related R&D at The Geysers remains
Where does the injected water go?
What has happened to the remaining (non-produced) ±70% of the injected effluent?
What is the distribution of water saturation?
How can injection be optimized for gas management?

Water saturation is always a big bugaboo at The Geysers. How can we use it for better gas management? In the area of the field where they are injecting that fluid isn't particularly plagued by gases although some areas are. But as you move further north in the field -- now of course the Santa Rosa water will be hitting those areas -- you do have lots of higher gas levels. This will be the kind of thing that they will be interested in doing at The Geysers to maximize the benefits of that injection.

Longer Term Outlooks

Just briefly about the medium term. I think fractures are what people are really interested in. How can we create them? How can we map them? How can we see how connected they are to everything? This is the kind of thing that people want to know. OK, we understand this. We know how to do this therefore we'll embark on a program. We can accurately predict the costs of doing such a program and at least get a range of results that we might expect.

Prediction of the reservoir after enhancement. Sabir is going to talk about numerical simulation later. In our experience with industry we have found that they want to know in advance what's this going to do? They have got a delicate balance set up in their reservoir. They are injecting over here. They are producing over here. They are getting some return. If we go and fracture the edges of the system or create new paths of permeability, what's going to happen? They want to be sure that they are not going to have a watering out situation or have some other unforeseen problem associated with the enhancement. The idea is to go that way rather than that way so they'd like to be able to say: OK, we understand this enough to be able to predict with confidence what's going to happen once we do something.

So the longer term goal, as you know, is just to be able to use more of this resource base that we have here in this country, and that we are very fortunate to have. I think the developers are probably not thinking about this a lot right now. They are really focused on the short term. But there has to be an upside for somebody. I mean, Is there going to be a geothermal industry, or not? I think that Dan talked about that earlier. We all could be the last generation of these people if we don't go further with this. That I think is the longer term goal.

That concludes GeothermEx's summary of what industry is interested in the EGS program.

Pritchett: Ann, I guess I am just troubled almost in a legalistic sense by something you said earlier in concentrating on by defining The Geysers pipeline as an EGS project. I realize this is a bit of semantics. But I think this is going to bounce somewhere. I'd always kind of perceived HDR/EGS as a process which at least always involves creation of permeability where there wasn't any before or increasing the permeability that was there before. The SEGEP pipeline didn't do that. The pipeline is essentially a reservoir engineering project where we injected where we weren't injecting before. I'm not saying you're doing anything improper with your comments about the value of doing smart things as opposed to doing dumb things with geothermal reservoirs. But to try to sort of coopt injection at The Geysers as part of the EGS program, I think it's going to raise some issues.

Robertson-Tait: That's absolutely a valid point. I've thought about that a lot, too. As I said when I started, The Geyers injection work certainly wasn't an EGS program when it started. But the definition of EGS encompasses both low permeability reservoirs and depleted reservoirs. And there are lots of other places, lots of other geothermal reservoirs in the U.S. that are either already depleted or becoming depleted. So I feel that because that is part of the definition of EGS, it is valid to talk about the geysers injection program in the context of what makes a successful project.

Pritchett: Well, then I guess maybe we need to define what an EGS project is. There are very few things that I've recommended to my Japanese clients that they do with their fields that would not be definable as an EGS project under that set of definitions.

Robertson-Tait: Remember that EGS is trying to embrace this sort of continuum concept. And the continuum is through permeability and the continuum is through fluids. So there are two continua, if you will. If you are in the commercial zone, you have high permeability, you have high fluid content. If you are in the fluid-depleated zone, maybe you started out with high fluid content, but you don't have it anymore. It is really a semantic thing and the definition of EGS just encompasses both of those continua.

Pritchett: I believe we need to have a definition of EGS that everybody agrees is the definition of EGS.

Robertson-Tait: Are you saying that fluid deficiency doesn't sort of jibe for you?

Pritchett: I'm not saying what that definition is. I'm just saying that we have to have some consistent story about that. It had never occurred to me that injecting water into a permeable zone in The Geysers constituted an EGS project.

Robertson-Tait: Well, the "E" is for "enhancement."

Pritchett: Well, of course, but so is drilling makeup wells. Building a better power plant enhances a system. Getting a better rate of return on your money enhances the performance of the system. Anything is an EGS project.

Sanyal: This definition was accepted a year ago. In fact at all of the DOE Geothermal Program Reviews we have used EGS in that sense. Anything you can do to enhance a reservoir. Two ways to enhance are to increase permeability or add more fluid. The reason that both aspects were included early on, was that industry said they are absolutely not interested in HDR. If you only talk about permeability enhancement, our reading is that then industry will not be interested. Therefore at that time the decision was made to include some other things. One of the things was fluid-depleted and/or fluid-deficient reservoirs. As far as I know in the last few years, in the entire DOE language lingo and the literature, EGS includes both low permeability and fluid-deficient reservoirs.

Pritchett: I thought they had to be both at once.

McLarty: Not necessarily. Either or.

Entingh: There is something trickier than that which I am going to say but which is somewhat sensitive. What industry said to DOE on the record is: Don't stop doing hot-dry-rock-related research. Don't call it "hot dry rock." Do integrate it into the hydrothermal research program. But what was said over and over was, but not for the record, was: "Don't let Los Alamos run the program because they have shut industry out of the research. And some dumb things were done in the HDR work." Those two things have been said by many people. So, "Do something other than what Los Alamos did" is part of the essence of how EGS is defined.

Kasameyer: Like John Pritchett, I also think that something that's not like what you do in a normal hydrothermal reservoir all the time ought to be in the definition. And that there's a continuum concept, I agree with. Hot dry rock was the most difficult end case and we want to move towards it, not start there, but we've got to move. I think John's concern may be that this program will become doing exactly what the Reservoir Technology program does, which is to enhance permeability and fluid interconnectivity and injectivity and those things.

Lippmann: Somebody said at the beginning that we have to be careful that we don't duplicate what the Reservoir Technology program is doing. The injection program, on injection procedures and methodology, is something that ResTech has been doing for the past 15 years. I don don't know of too many fields which are fluid-depleted. Many are depleted of hot fluids but they are full of cold fluids. So essentially it is important to include improving permeability as the goal of EGS. We might have to refine the goal of the program to avoid duplication.

Creed: We must also avoid the perception of duplication, which is just as important as whether technically you are duplicating it or not. That's what I think that John and Paul are alluding to. I think there's a perception out there: "We started this program -- my gosh -- we've got to have some big hit or big winner. Oh, I know, let's stick the EGS label on this Lake County pipeline project. By golly, we're good!" That's the same kind of stuff Los Alamos did at times.

Robertson-Tait: The purpose of bringing up The Southeast Geysers effluent pipeline was not to claim credit for it by the EGS program. Let's make sure that everybody understands that. It didn't come from there at all, as I said. However, it demonstrates the kinds of projects that industry will be interested in. It put forth a set of numbers and said, for this amount of investment we got this amount back.

Creed: I'm not questioning your motives. But from a skeptical viewpoint, that's going to be the perception.

Robertson-Tait: OK. But don't lose the point that the example speaks to the bottom line. For the short term, it is those kinds of projects that are going to attract the interests of industry. I'm not saying they have to be in fluid depleted reservoirs or strictly augmented injection, but this is the kind of thing that we are going to have to demonstrate to them.

Swenson: I want to express two thoughts that came up as I was listening to you. One question that you raised was: Where does the fluid go, and what's happening to it? It seems to me that later on as we talk about possible projects, that's very much tied to the use of tracers.

A second point you made concerns messing up an operating reservoir. That might lead us, when we think about projects, we should try to go to places where we really don't have the opportunity to do that. Perhaps we should taret a relatively new reservoir where you aren't going to mess people up.

Koenig: When I talk about The Geysers later, I'll address some of the things that Ann talked about. I'll include something about what we learned about how much water comes back. It is not as grim a picture, I think, as described so far.

Figure 1.4-1.

FIGURE 1: NCPA UNITS 1 & 2 FLOW RATES vs TIME

Data Normalized to 110 psig

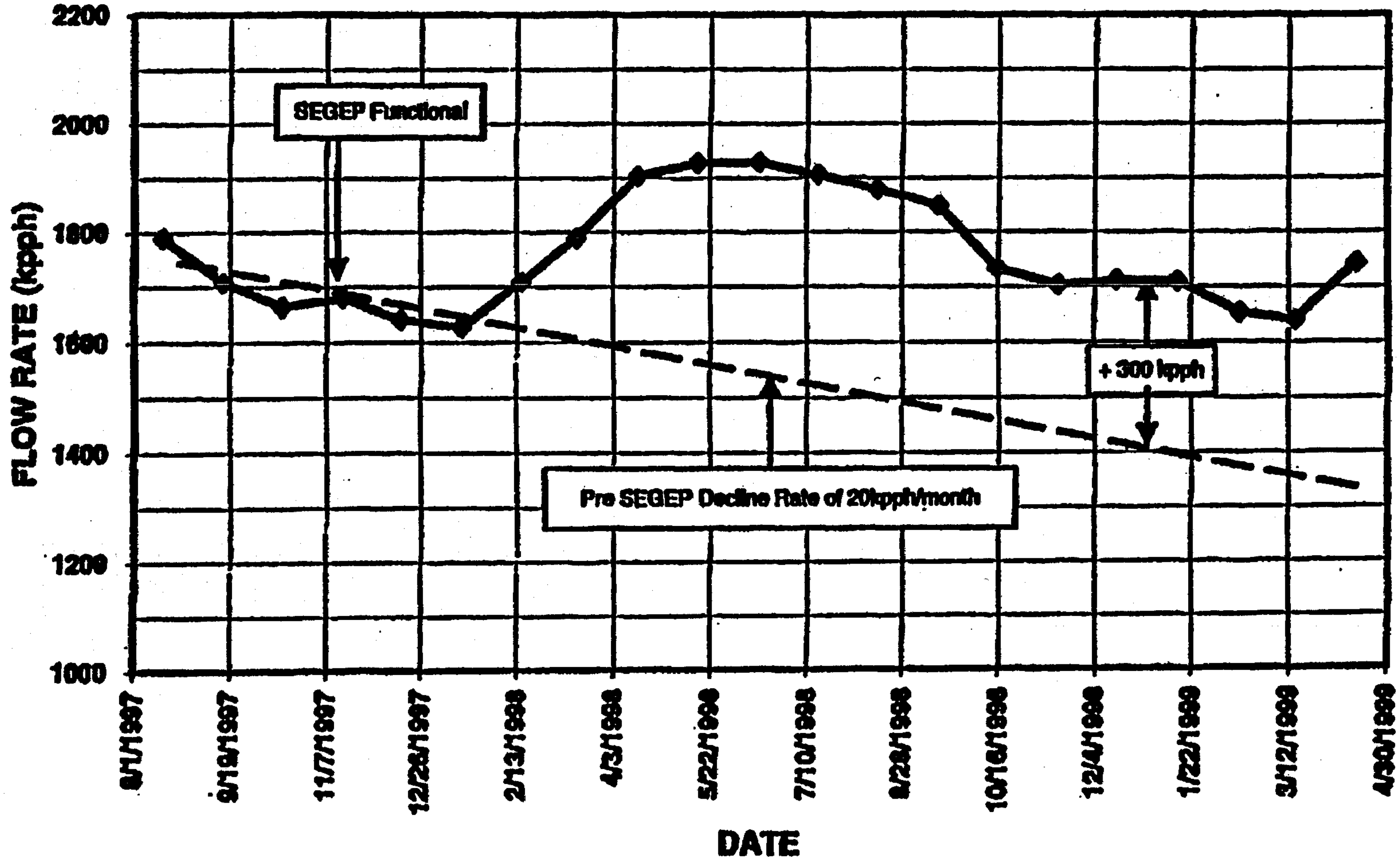


Figure 1.4-2.

FIGURE 2: UNITS 13/16 FLOW RATE vs TIME

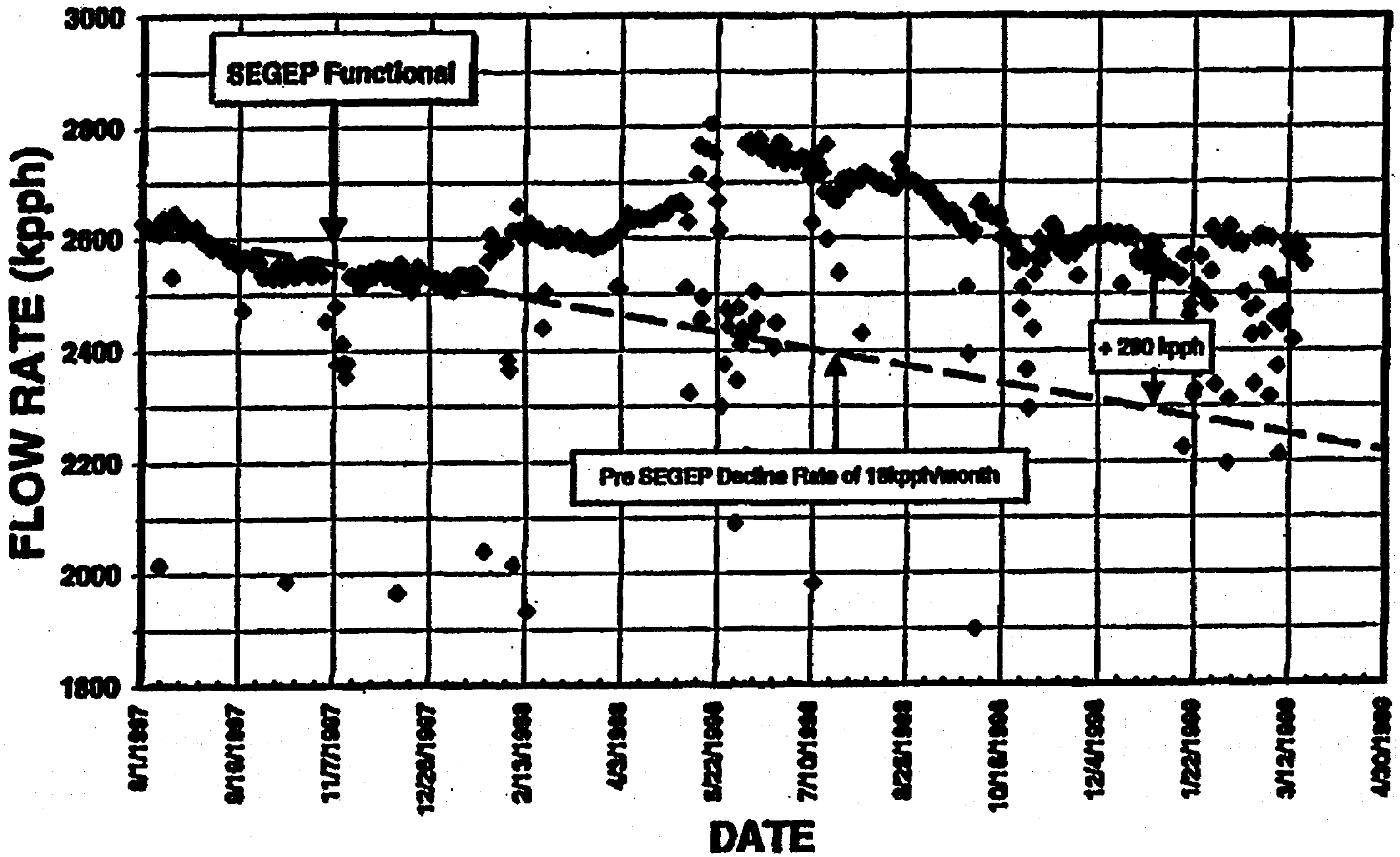


Figure 1.4-3.

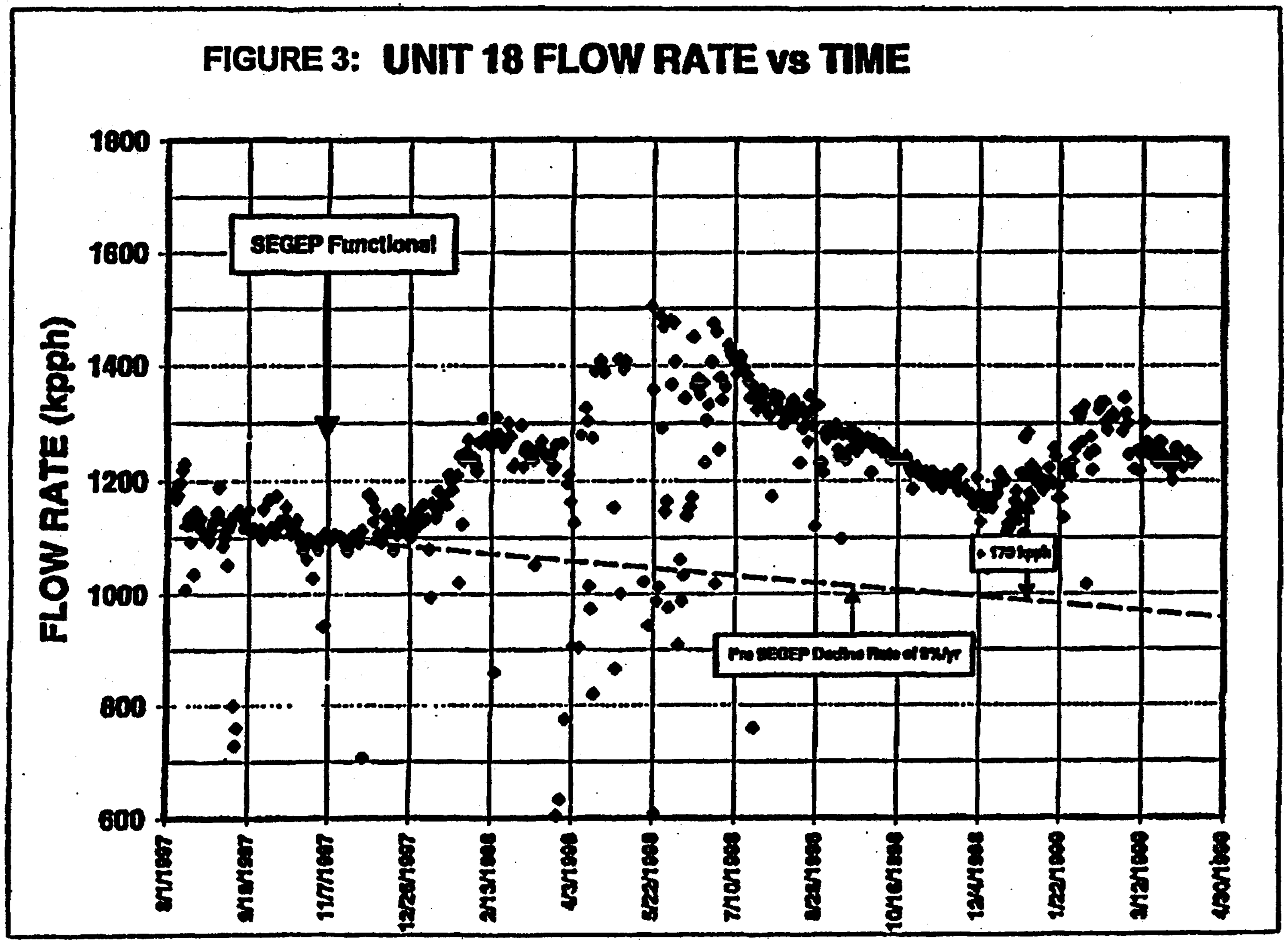


FIGURE 3: UNIT 18 FLOW RATE vs TIME
SEGEP Functional
FLOW RATE (kpph)
1800
1600
1400
1200
1000
800
600
9/1/1997
11/7/1997
12/26/1997
2/13/1998
4/3/1998
5/22/1998
7/10/1998
8/28/1998
10/16/1998
12/4/1998
1/22/1999
3/12/1999
4/30/1999

1.5 The EGS Project at Dixie Valley.
Steve Hickman, U.S. Geological Survey, Menlo Park, CA

I was asked to give a brief summary of a Dixie Valley experiment which is one of the field projects that have been discussed for potential EGS support. We were funded by EGS to do some work in this past year to do some work this past year in a dry well which we hoped to turn into a producer in the Dixie Valley field.

The Questions

There are only a few people in this room who haven't heard this story before so I'm going to make it brief. The Dixie Valley geothermal field is a 60 MW power plant that produces hot water out of an active normal fault in Nevada. You can see a string of injection and production wells in Figure 1.5-1. The fault zone here dips down to the southeast and there are a series of production wells and injection wells. There's about an 11,000 gallon per minute production, 9,000 gallon per minute reinjection into this reservoir.

Figure 1.5-2 shows a cross section through the field. All of the hot water produced for geothermal power here comes out of fractures associated with the fault zone. This is a fracture-dominated geothermal reservoir. A very significant point here is that there is thermal evidence for upwelling and geochemical evidence for upwelling of saturated solutions in the fault zone. Those solutions would be expected to seal up fractures in the fault zone. Yet the permeability is very high.

Understanding Permeability

One of the issues we wanted to address in this project is how is the permeability maintained here. Also, just as important, what controls spatial variations in faults zone permeability? Why are some wells dry and others wet? In terms of the amount of permeability present, these are all fluid saturated but there are four orders of magnitude variation of permeability in this field. The impermeable wells are definitely expensive to drill. It has been a problem trying to predict ahead of time where you might expect to find permeability within the fault zone.

We studied distribution and orientation of fractures in the fault zone using televiewer logs, temperature logs, spinner flowmeter logs. We then conducted hydraulic fracturing stress measurements and observations of cooling fractures and breakouts to determine the magnitude and orientation of the stress field. The bottom line is we are trying to relate the *in situ* stress field, that is acting on this normal faulting system, to the permeability, anisotropy, heterogeneity, and magnitude of the geothermal reservoir and the fractures that comprise it. This is a colaborative project with various folks including Coleen Martin, Mark Zoback, John Sass, Roger Moore, and most of all Dick Benoit of Oxbow Geothermal.

I won't get into the nitty-gritty details of the techniques. Figure 1.5-3 shows an example of a televiewer log from one of the producing wells. The depth here is in meters and azimuth relative to true North, as if we split the world down from the North and unrolled it. The natural fractures you see here are the major producing zones as identified on the temperature-pressure-spinner logs. We also used temperature logs alone to identify slightly permeable fractures. So we were able to look at the entire fault zone environment and classify (bin) fractures. We first obtained their orientation and we bin them as impermeable, slightly permeable, or extremely permeable. The extremely permeable fractures are the ones that make a producing well a producer. You can see the main range front fault. You can see examples example of some tensile or cooling cracks induced by circulation. These tell us something about the orientation of the stress field.

The bottom line for the wells we have studied in the producing part of the reservoir is that you make a lower hemisphere plot of poles to natural fractures, at the left side of Figure 1.5-4. Each little dot there represents the natural fractures seen in a producing well, in this case 73-27. A horizontal fracture would plot right in the middle of this. At the pole, a the fracture would be parallel to the plane of the screen. A perfectly horizontal fracture plot somewhere around the circumference.

If you look at all the fractures seen in this and a number of other wells we have studied in Dixie Valley, a total of 10 wells so far, we see a great diversity of natural fracture orientations. But in the producing wells, the highly permeable wells that constitute the geothermal resource, we see that the slightly permeable fractures that are showing up as temperature anomalies during injection under static conditions basically define a conjugate normal faulting set, most of them dipping to the Southeast, and some dipping to the Northwest.

The right side of Figure 1.5-4 highlights the fractures of that set that are extremely permeable -- they have transmissivities that correspond to fractures a millimeter or so and hydraulic apertures that are very permeable -- as shown by the crosses. In this case, only six of them in one well constituted the producing intervals. Those things are falling within this half of that conjugate set. They are parallel to the Stillwater Rangefront Fault itself, the shaded circle. So the stress field here has taken a very diverse population of fractures and created permeability on those fractures that are well-oriented for normal faulting. The arrow is the direction of the least horizontal stress we see in this field. So this is the extensional stress, measured with tensile cracks and breakouts. This extensional stress is exactly the orientation you would expect for shear failure on these fractures. We have a situation in which the permeability of the reservoir is dynamically maintained by shear failure, or frictional failure, on optimally-oriented faults.

We also did hydraulic fracturing tests in these wells to get the magnitudes of the stresses. Figure 1.5-5 is a cartoon of how we did that, using temperature-pressure-spinner-flowmeter logs down hole. I'm not going to talk about this. Norm Warpinski will be discussing hydraulic fracturing a little bit more later. Figure 1.5-6 illustrates the kind of results from the producing part of the field -- depth versus stress in three wells grouped together. The overburden stress is shown by a gold line. Fluid pressure in these producing wells is shown here. The squares show measurements of the least horizontal stresses we get from the hydraulic fracturing minifrac tests we've done. And significantly they fall very close, especially when you get close to the producing part of the fault zone, very close to the dashed pink lines which are the Coulomb failure lines for frictional faulting on optimally oriented faults with coefficients of friction with a mean of 0.6 to 1.

So not only is the Stillwater fault zone optimally oriented for normal faulting, it is also critically stressed. In other words the shear stress on it is very high relative to the normal stress, high enough to produce frictional failure based upon theoretical and laboratory considerations. And more important, really, all those producing intervals, the six big red X's showed in a previous slide, those things are also critically stressed. So the situation here again is critically stressed and optimally oriented for normal faulting.

That is the background. We think we understand the producing part of the field pretty well. We also did some measurements down here in some non-producers and found that those did not contain a combination of critically stressed Stillwater fault and critically stressed permeable cracks.

The Experiment

The key issue I want to talk about now in the context of EGS is that there are a couple of wells that should have been permeable but were not. Slide G shows the location of well 82-5. We don't understand the causes of that permeability heterogeneity, but Dick Benoit and I and our co-workers decided that this would be a very good candidate for an EGS type program.

The experiment was to go to a well like 82-5. Study the stress points in that well and see if we can understand first of all why this well, in spite of four legs, three redrills, failed to encounter any permeability of any significance when the space was adjacent to very productive parts of the reservoir to the north and south of it. So it is a great mystery as to why this well is as impermeable as it is.

Question: Is there any flow at all out of that well? Or could there be into it?

Hickman: No, the permeability is about a tenth of a millidarcy, averaged over the openhole intervals. That is very, very low. In fact it is one of the tightest wells we have studied, paradoxically.

Why is the permeability so low? It could be localized increases in the magnitude of the least horizontal stress. This basically acts to decrease the amount of sheer stress available for driving frictional failure or faulting. In other words, it could be and we think that there is some talc in the faults and we thoughts there would be a stress shadow from that talc. Or there could be different fracture orientations at Well 82-5. Or stress orientations that basically push the fractures that are available farther away from failure, and make them more stable in the existing stress field.

So it is a relatively straightforward hypothesis-testing exercise to go into this well and conduct stress measurements and fracture studies -- fluid flow, fracture orientation studies -- to try to figure out why it's impermeable. That was something that was of more interest to the Reservoir Technology program.

Now we move over into the EGS sphere. Well 82-5 is also, we thought, a very good candidate for massive hydraulic fracturing experiment for a variety of reasons. It is close to a very productive productive well, the most productive well in the field, 28-33, about five hundred meters along strike where it would penetrate the fault zone. 82-5 was redrilled three times. The open leg crosses the fault zone.

It's in a weak pressure communication with the surrounding reservoir which is very important. The long term draw down of the reservoir is reflected by pressure response in 82-5. Most important of all probably, 82-5 has reservoir temperatures. It is a very hot well. It's dry, and impermeable rather. And not mentioned here before, it is very close to the producing and injecting pipes network in Dixie Valley. If we are able to enhance the permeability, then Oxbow might be able to bring this on line.

In addition to the scientific or technical reasons we thought that Well 82-5 would be a good massive hydrofrac candidate, the producer, Oxbow Geothermal Company, is very interested in augmenting injection at Dixie Valley. They are losing water and they are losing reservoir pressure. The idea of having an injection well that would be targeted directly within the fault zone very close to major producers is very appealing to them. So it is most likely if we could increase the permeability in this well, we would turn it into an injector, and not a producer. Also by injecting cold water, you might take a marginally successful permeability enhancement job and turn it into a more successful one through thermal stressing.

What we needed, however, to design a massive hydrofrac was information on the local orientation of the least principal stress that controls the hydrofrac geometry. The magnitude of the least horizontal stress controls pumping pressure, fracture containment, and the pore pressure threshold for inducing microearthquakes, and the orientation and distribution of permeable or potentially permeable fractures that facilitate targeting of the hydrofracture.

In a massive hydrofracture here, we're not of course just talking about tensile cracks. We do know that the stresses are high in much of the producing reservoir, so simply by raising the fluid pressure, say from the leakoff from a massive hydrofracture, you're going to induce a lot of shear failure in the way it has been observed in other geothermal fields. You'll create kind of a cloud of enhanced permeability in this otherwise low permeability rock. So it seemed like a very appealing candidate.

As I talked about this at the DOE Program Review in early May, what we did in late May and early June was to go to 82-5 and conduct a suite of experiments to determine more about the stress field in that well and the orientation of permeability and fractures.

<u>Results</u>

Now this is preliminary analysis. There is still a lot to be done on these data, particularly in terms of fracture orientations and permeability. But the first thing that happened when we went out there is that the pipe got stuck in the hole. I can't think of a nice spin to put on this, it's basically a bummer.

When we got out there, it was supposed to be a relatively routine cleanout operation. There was a bridge in the well that prevented logging tools from going below a certain] depth. Once we received money from the DOE EGS program, the plan was to put a workover rig on here, run a relatively routine bit trip to the bottom, circulate out the bentonite drilling mud residue, and condition the hole for logging. It's something that's been done dozens of times in Dixie Valley. It's seems trivial, but it wasn't.

For some reason, when they got to the bottom, the bit plugged up so circulation through the bit ceased. In the process of taking out the circulation subassembly and coming out of the hole, they discovered that not only had the bit plugged but also the entire bottom hole assembly had become stuck to substantial pull. After many days were spent, with three point indicators and back-off shots and all the usual tricks (we had some of the best fishing persons in the business on site here), in the end we were not able to retrieve the fish.

We had to shoot off the pipe at a little over 2,700 meters depth which unfortunately for us is right at the top of the fault zone as defined during the drilling. So we don't have any data from below that point to the bottom. The Stillwater fault zone is shown in Figure 1.5-7. The healed fractures as evidenced from the cuttings during drilling are basically confined to the hanging wall of the Stillwater fault zone, just up to the top of the stuck pipe. We don't have any data from the stuck interval. That's the sad part of the story, but it's not fatal.

We did get beautiful data from the televiewer log. Figure 1.5-8 is a plot of depths versus azimuth of least horizontal stress. This is some of the best I've seen. We have tensile cracks, borehole, and we got one hydrofrac, as planned. The dots show that the least horizontal stress here basically assumes a consistent orientation down to a depth of about a hundred meters off the stuck pipe and then swings around ninety degrees. This orientation is the optimal for normal faulting on the Stillwater fault zone. This other is not. This is ninety degrees away from where it should be.

This behavior was seen in two other wells just to the north of this well. This is a characteristic of the northern part of the producing field. While I won't talk about it today, this is very easily explained in terms of almost total stress relief during large normal faulting earthquakes in the northern part of the field. So this ninety degree rotation in the stress orientation is a direct consequence of relatively large earthquakes that probably lead to permeability enhancement and lead to stress perturbations.

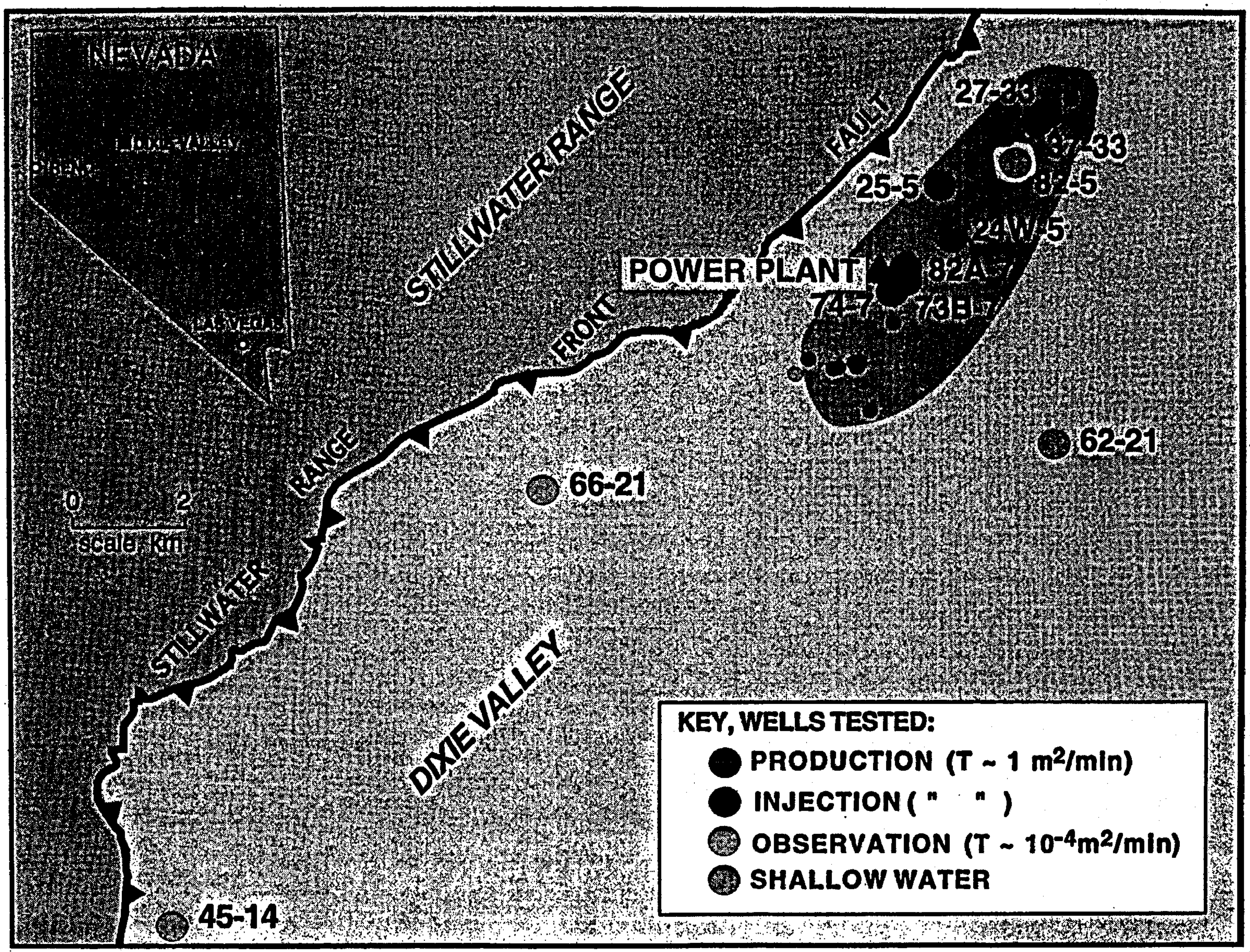
The important thing for an EGS job, is we would of course to target a massive hydrofrac down here in the fault zone. If, and I emphasize "if," this good stress orientation persists to total depth to the fault zone, then that massive hydrofracture would take-off in the right direction and head toward the nearby producing wells. I'm not going to talk about the magnitude of the least horizontal stress. We got frictional-failure type magnitudes in the hydrofrac. The hydrofrac was also a textbook case. So the results were very successful except we couldn't get in the bottom of the well which had been our plan.

Here is where we stand with this well. Slide 1.5-9 shows well 82-5 and the nearby producers. These arrows show the stress orientations that we obtained in nearby wells. 74-7, 73-D7, and the lower part of 82-5 and all of 25-5, all defined a consistent stress field in which we have extension perpendicular to the strike of the Stillwater fault. Perfect normal faulting and an ideal case for a massive hydrofrac which, if you were to do a hydrofrac in some of these wells, they would take off parallel to the Stillwater fault zone, intersect with those steeply inclined fractures, and potentially link up to the reservoir.

If we were to target the bottom of the well, the hydrofrac would head straight for the Section 33 wells and potentially link up with that permeability. If the stresses somehow swing back, e.g., behind a stuck pipe, you could have exactly the other problem, the least horizontal stress in the upper part of the wells here, the hydrofrac could go out into the valley or into the footwall, probably not doing us much good.

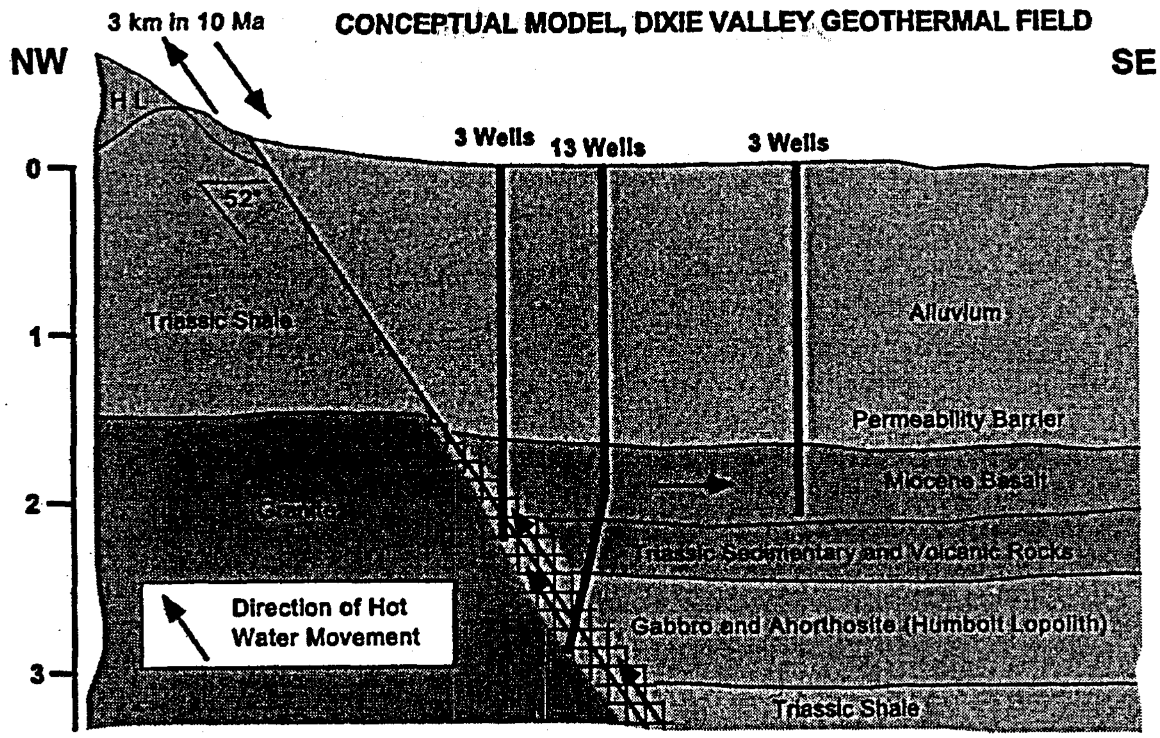
The data so far are certainly very appealing. They make the prospects for EGS look better. But we still haven't answered the question about the orientation behind the pipe is in the actual fault zone. So to actually do this thing correctly, you'd have to redrill that well, get a televiewer log through the fault zone itself, and then probably case, perforate, and do a mini-frac and a maxi-frac. So the job has gotten a little bit more complicated. We now have to sort of do more science before we can even answer the question if this is an ideal EGS site. We still think it is very appealing but it is going to require more money to pull this off, because the pipe is stuck and it's stuck for good.

The only way to get back into the fault zone is to do a side track. None of the other legs are open, all the other legs are cemented back. I talked to Louis Capuano of Thermasource Drilling about this just recently. He said to do the redrill and redrill about a thousand feet of hole would be about $300,000 to $350,000. To cement and case would be about $80,000. So we're not talking "cheap" here, but it is a lot less than the two to three million dollars typically spent on a new production well at Dixie Valley. So it would still be a bargain but again, you know, it's a risk. And without the stuck pipe I think we'd have the entire answer. Now we have about 60 percent of the answers to the science questions.



NEVADA
STILLWATER RANGE
FAULT
FRONT
RANGE
STILLWATER
DIXIE VALLEY
POWER PLANT
27-33
37-33
82-5
25-5
24W-5
82A
74-7
73B
62-21
66-21
45-14
0
2
scale km
KEY, WELLS TESTED:
PRODUCTION (T ~ 1 m2/min)
INJECTION (" ")
OBSERVATION (T ~ 10-4m2/min)
SHALLOW WATER

Figure 1.5-1.



Reservoir Temp: 220 - 250° C at 2.3 - 3.0 km
Pre-production water upwelling rate along FZ ~ 2.5 X 10^5 m^3/yr (Bodvarsson)
Resultant SiO_2 precipitation rate ~14 m^3/yr between 2.3 and 3 km

Figure 1.5-2.

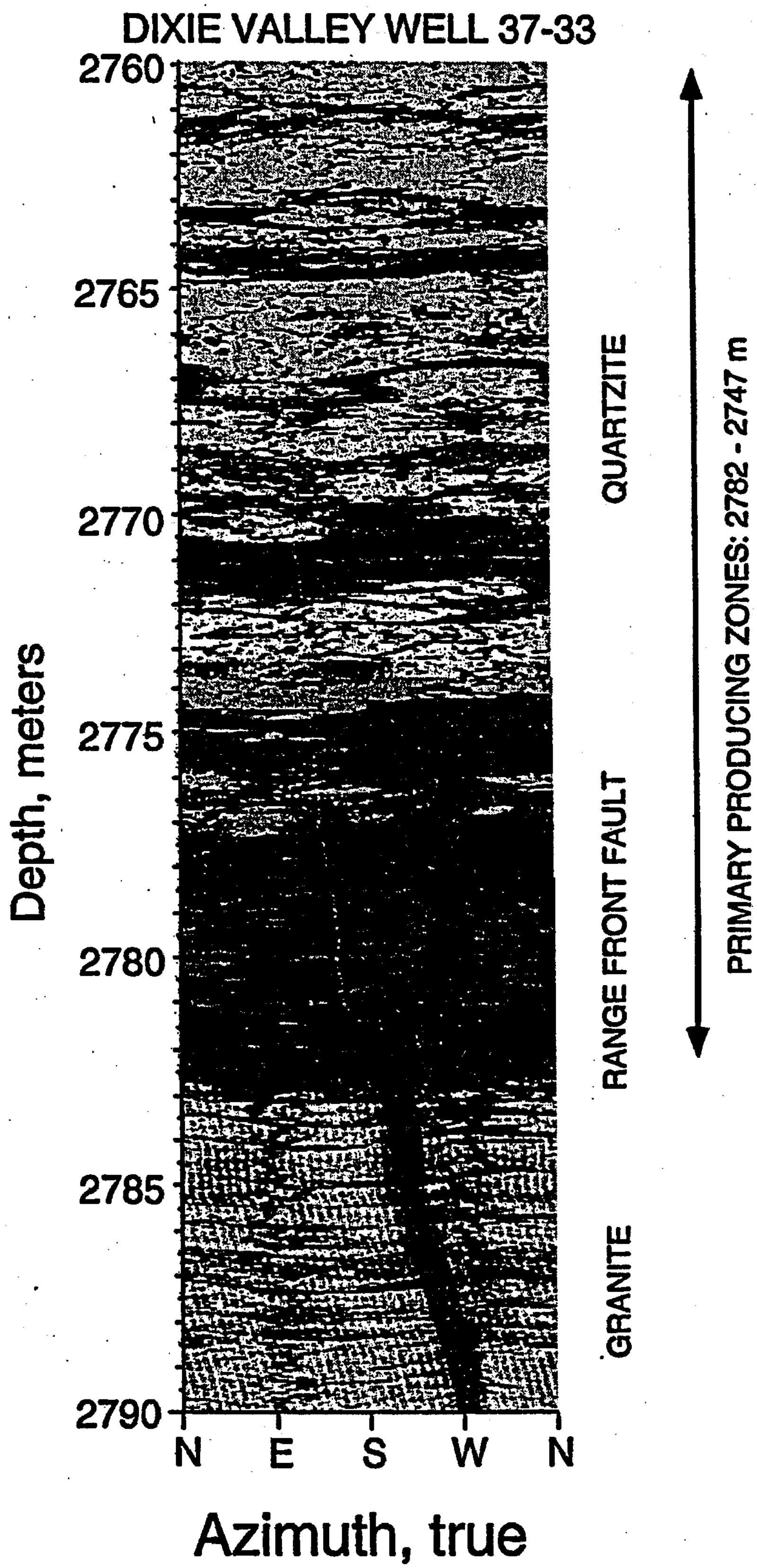

DIXIE VALLEY WELL 37-33
2760
2765
2770
2775
2780
2785
2790
Depth, meters
N
E
S
W
N
Azimuth, true
QUARTZITE
RANGE FRONT FAULT
GRANITE
PRIMARY PRODUCING ZONES: 2782 - 2747 m

Figure 1.5-3.

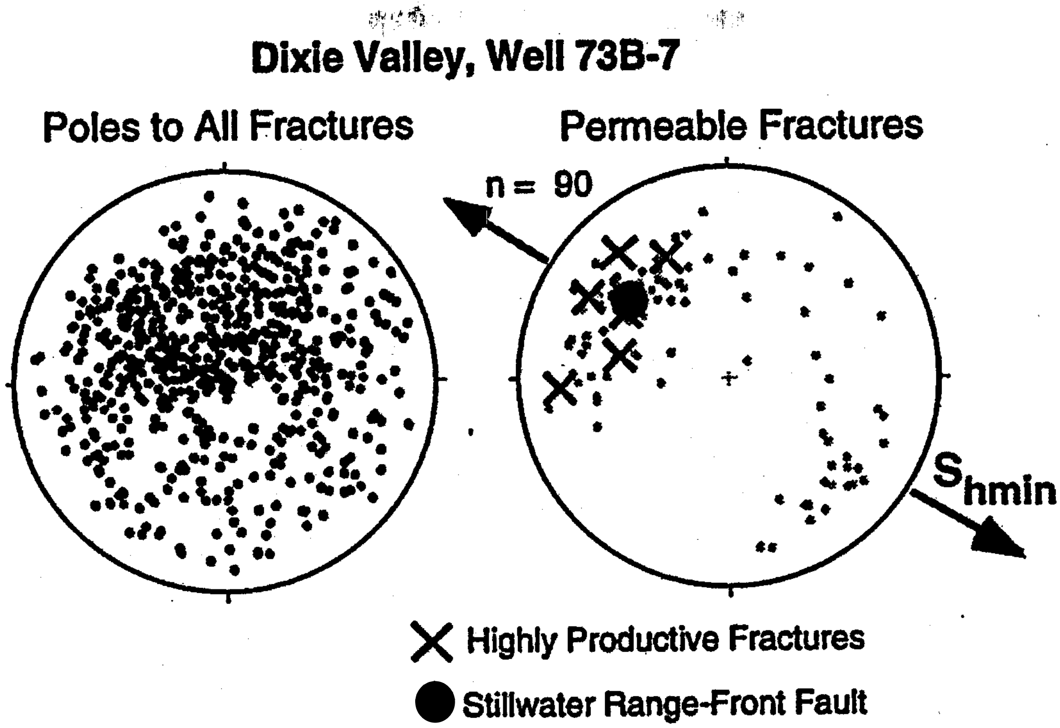
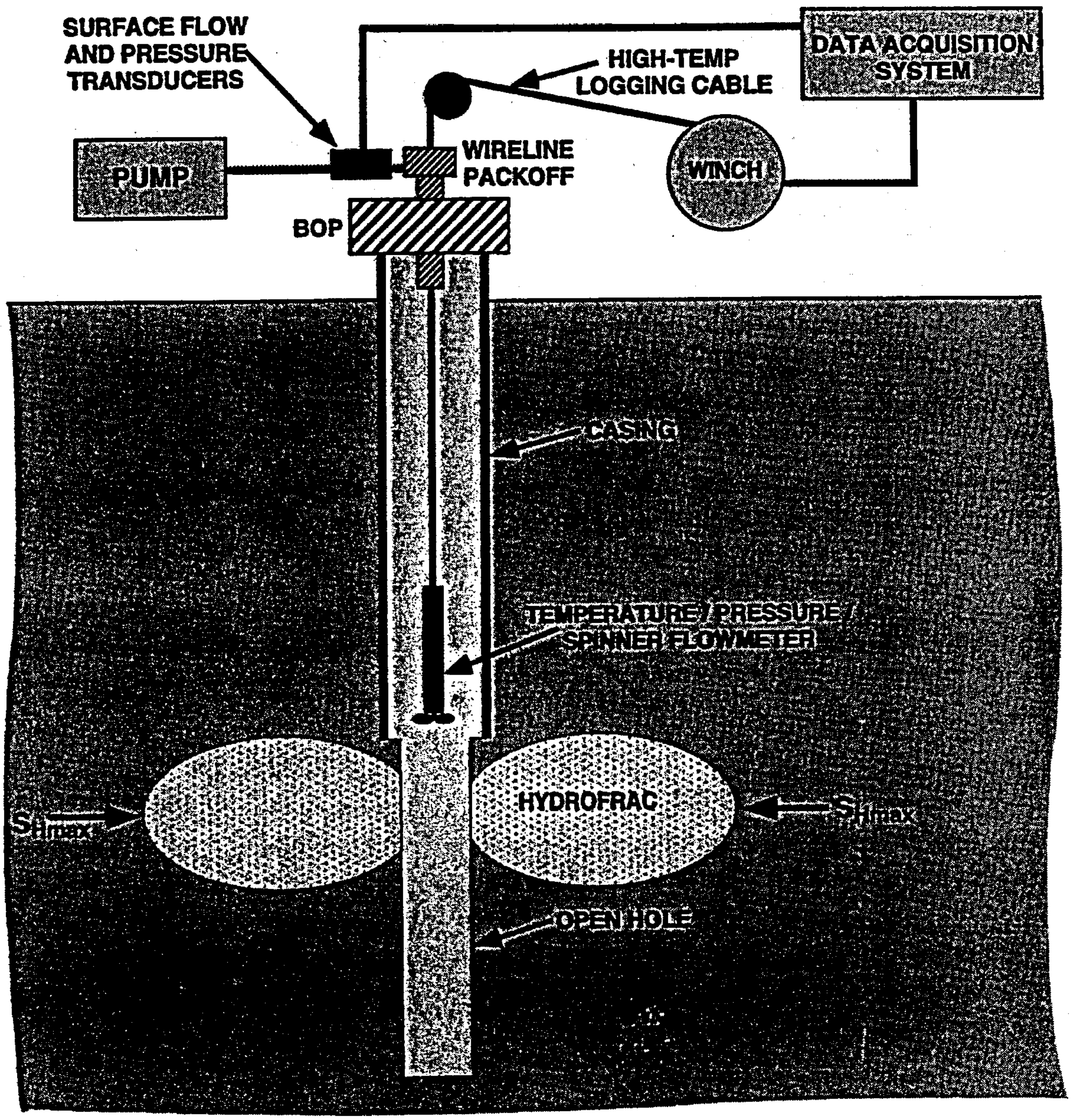
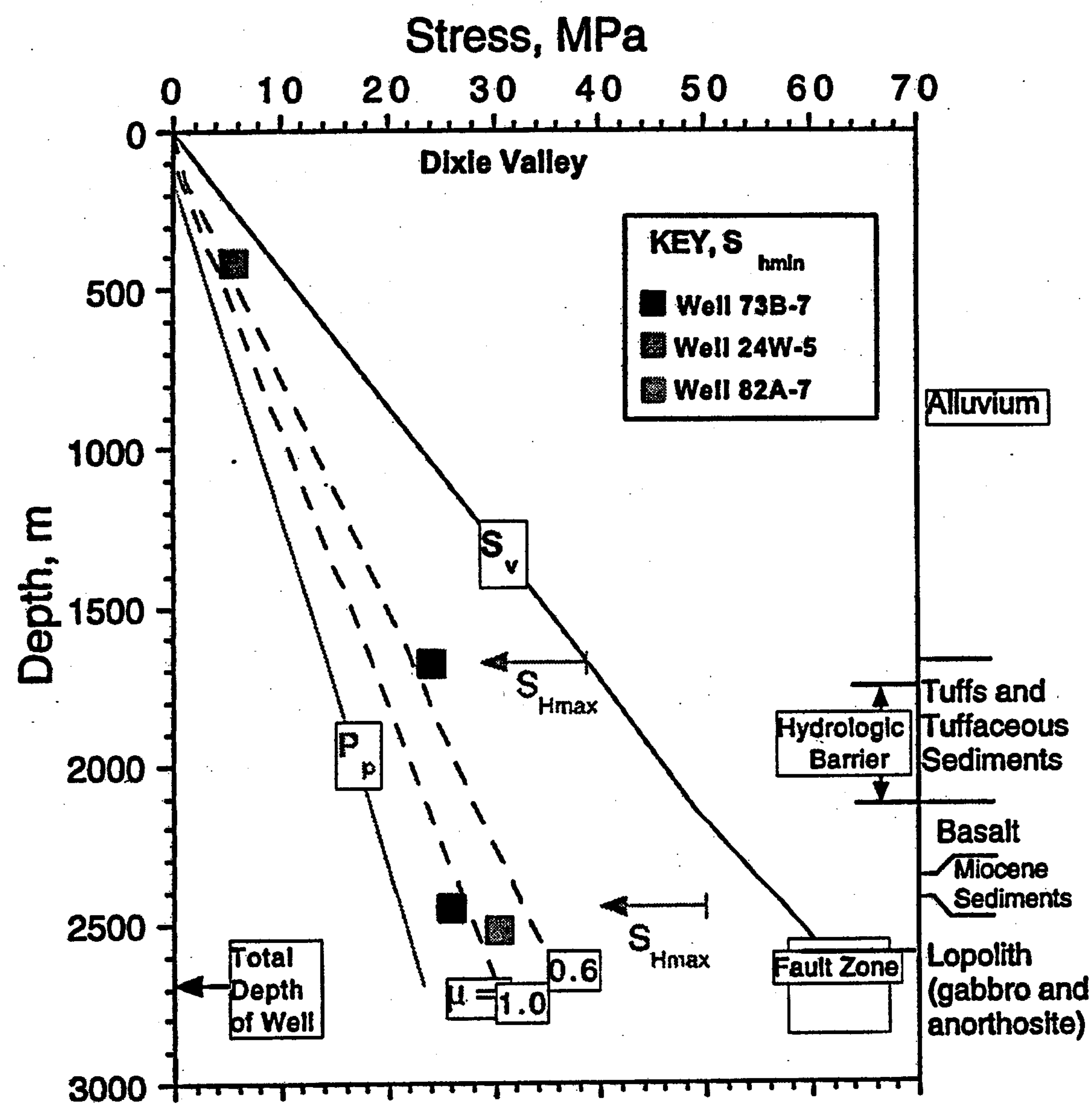

Dixie Valley, Well 73B-7
Poles to All Fractures
Permeable Fractures
n = 90
S_{hmin}
Highly Productive Fractures
Stillwater Range-Front Fault

Figure 1.5-4.



SURFACE FLOW
AND PRESSURE
TRANSDUCERS
HIGH-TEMP
LOGGING CABLE
DATA ACQUISITION
SYSTEM
PUMP
WIRELINE
PACKOFF
WINCH
BOP
CASING
TEMPERATURE / PRESSURE /
SPINNER FLOWMETER
HYDROFRAC
SHmax
SHmax
OPEN HOLE

Figure 1.5-5.



Stress, MPa
0 10 20 30 40 50 60 70
0
500
1000
1500
2000
2500
3000
Depth, m
Dixie Valley
KEY, S hmin
Well 73B-7
Well 24W-5
Well 82A-7
S v
S Hmax
P p
0.6
μ = 1.0
S Hmax
Total Depth of Well
Alluvium
Hydrologic Barrier
Tuffs and Tuffaceous Sediments
Basalt
Miocene Sediments
Fault Zone
Lopolith (gabbro and anorthosite)

Figure 1.5-6.

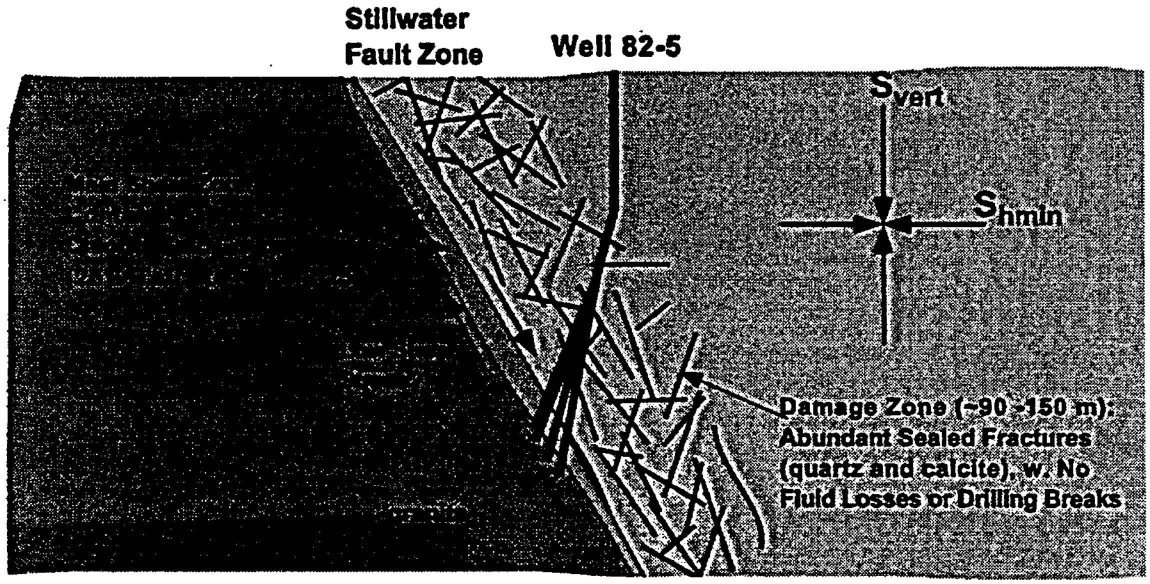

Stillwater
Fault Zone
Well 82-5
S_{vert}
S_{hmin}
Damage Zone (~90 - 150 m):
Abundant Sealed Fractures
(quartz and calcite), w. No
Fluid Losses or Drilling Breaks

Figure 1.5-7.

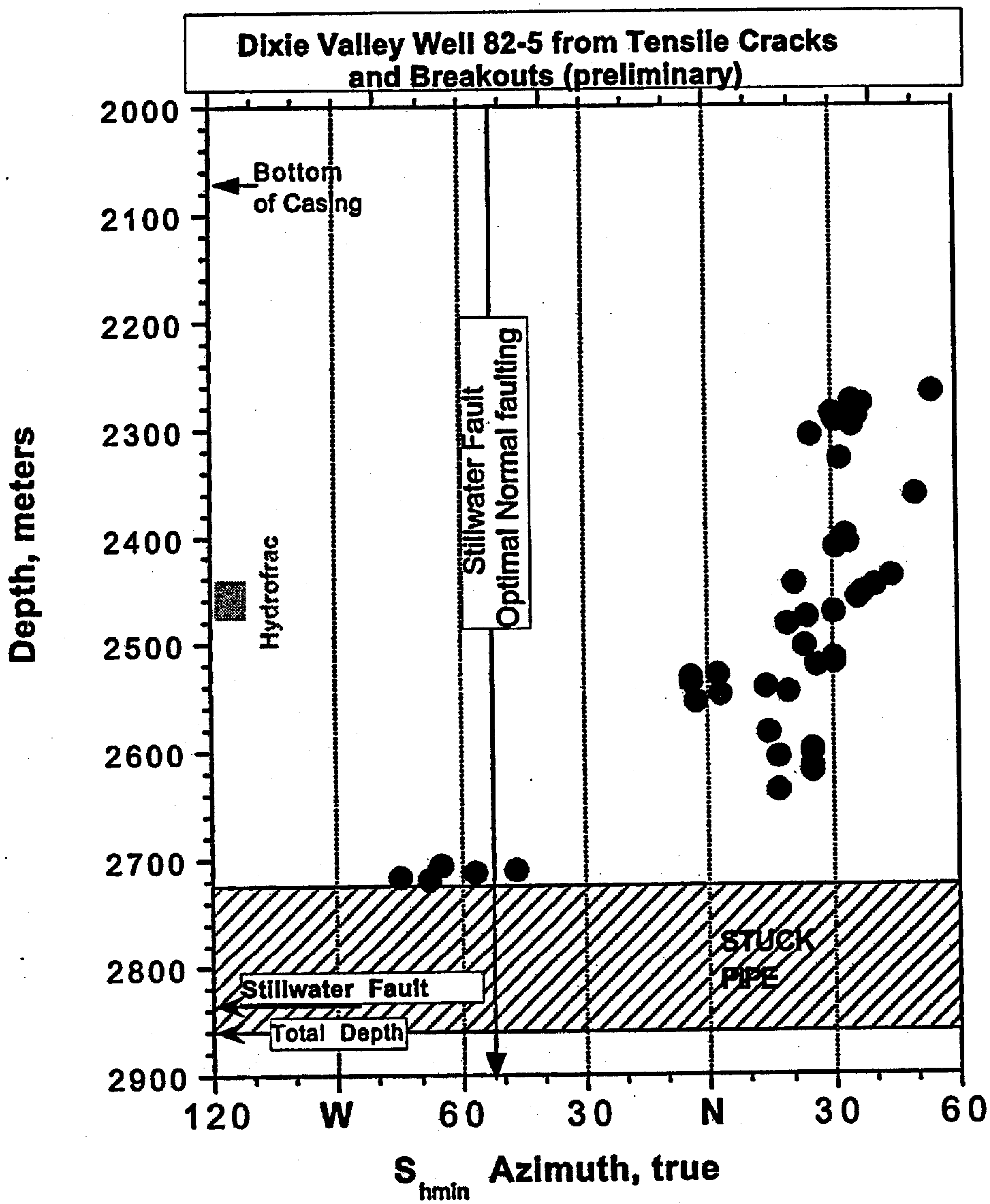

Dixie Valley Well 82-5 from Tensile Cracks and Breakouts (preliminary)
Depth, meters
2000
2100
2200
2300
2400
2500
2600
2700
2800
2900
Bottom of Casing
Hydrofrac
Stillwater Fault
Optimal Normal faulting
STUCK PIPE
Stillwater Fault
Total Depth
120
W
60
30
N
30
60
S hmin Azimuth, true

Figure 1.5-8.

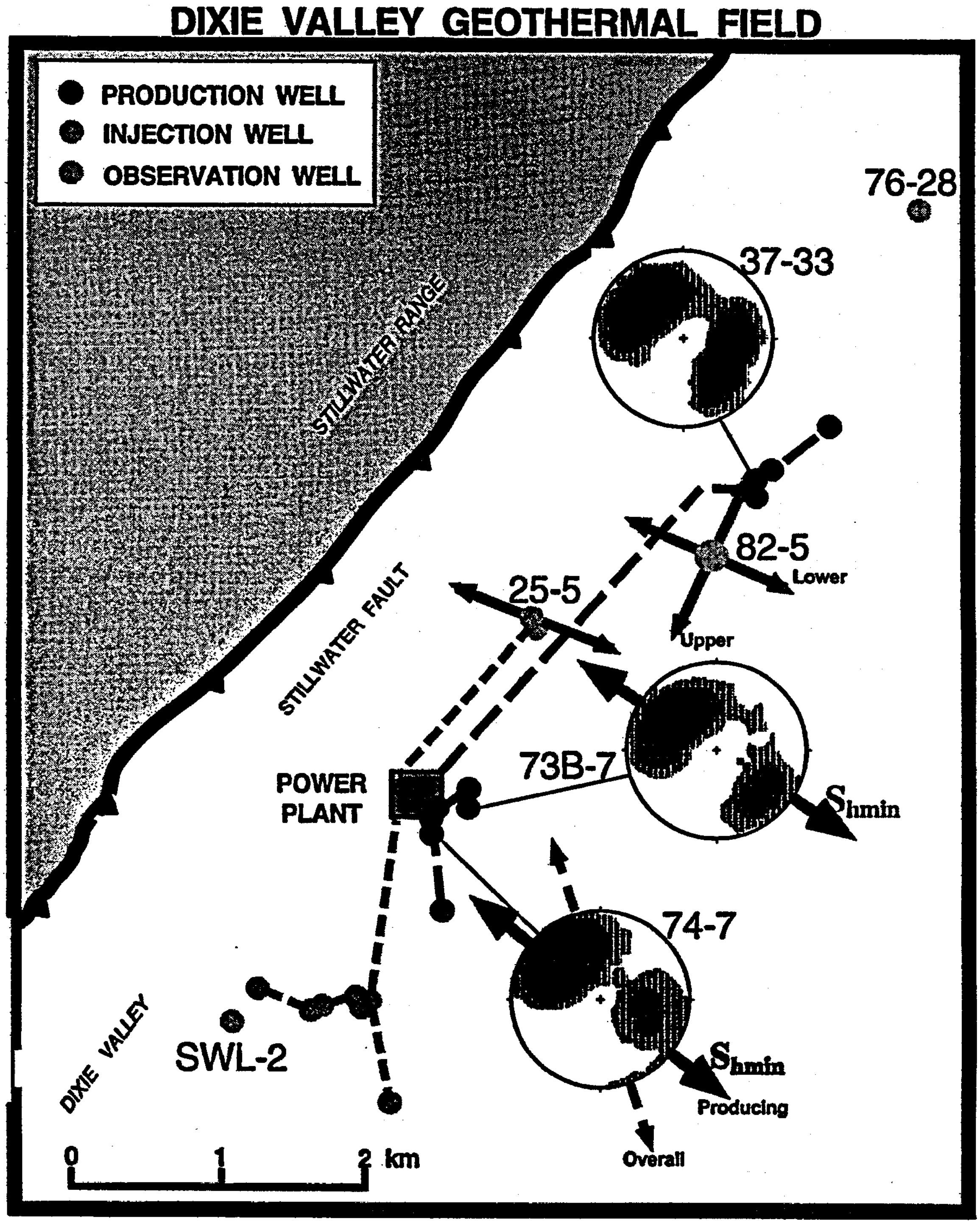

DIXIE VALLEY GEOTHERMAL FIELD
PRODUCTION WELL
INJECTION WELL
OBSERVATION WELL
76-28
37-33
STILLWATER RANGE
82-5
Lower
Upper
25-5
STILLWATER FAULT
POWER PLANT
73B-7
S_{hmin}
74-7
S_{hmin}
Producing
Overall
DIXIE VALLEY
SWL-2
0 1 2 km

Figure 1.5-9.

1.6 Review of Numerical Simulators for EGS Applications
Subir Sanyal, GeothermEx, Inc.

THE REVIEW OF SIMULATORS

Basically the typical conventional geothermal simulator has these things: multiphase flow across grid blocks, heat transfer and mass transfer, in porous or fractured media, two dimensional or three dimensional, usually with dissolved gases.

What you want ideally in an EGS simulator is the following extras. These came out of a meeting in Japan where 70 experts on HDR from different parts of the world brought together. They decided that in 1996 that these are the things they would like to have.

We would like to see explicit representation of fractures and fracture opening as a function of normal stress. And shear propagation and the associated jacking of fractures. And fracture conductivity as a function of aperture. Channeling of flow in the fractures and porous flow in the matrix. Thermoelastic effects. You should be able to get into and modify the grid. And rock-water interactions. But in reality, no one model can handle these things, because it would be unwieldy. What we did is to look at all the models available for hydrothermal, HDR, and nuclear waste isolation simulation. I will briefly go through a list of these software systems and say approximately what they can do.

Table 1.6-1 lists four simulators used for conventional hydrothermal simulation. FEHM that Los Alamos developed is a very good tool. It's been used in geothermal, HDR, and nuclear waste isolation projects. TOUGH2 has been used in geothermal and, nuclear waste isolation, and ground water studies. TETRAD has been used in oil and gas applications and in geothermal. STAR has been used, as far as I know, only in geothermal. Now all of these are fairly conventional and all have been fairly well tested against long history of projects.

There's another set of models (Table 1.6-2) that are strictly the HDR type and they are more special purpose in the sense of they were developed for a specific HDR project initially and therefore they have some limitations. But of these, almost all of them have at some, demonstrated success in matching results of experiments at Fenton Hill, Hijiori, or in Europe. Therefore, all of those could be considered potentially available for EGS.

Finally, there's a long list from nuclear waste isolation industry (Table 1.6-3 and Table 1.6-4). There we have something like 27 models to look at and we found at least 16 which potentially have some application in EGS. Many were developed specifically by or for government agencies involved in nuclear waste. Some of them have been used a little bit in HDR applications, but most of them are strictly for nuclear waste. Most of them actually have pretty good elastic mechanical properties included, but they do not usually have good heat transfer modeling.

Table 1.6-1. Simulators Developed for Conventional Hydrothermal Simulation

Software	Developer
FEHM	Los Alamos National Laboratory
	Lawrence Berkeley National Laboratory
TETRAD	Computer Modeling Group, Calgary, Alberta, Canada
STAR	Maxwell Technologies, San Diego, California

Table 1.6-2. Simulators Developed for HDR Simulation

Software	Developer
FRACTure	ETH, Zurich, Switzerland
GEOTH3D	Central Research Institute of Electric Power Industry, Abiko City, Chiba, Japan
FRACSIM-3D	Tohoku University, Sendai, Japan
GEOCRACK2D	Kansas State University, Manhattan, Kansas

Table 1.6-3. Simulators Developed for Nuclear Waste Isolation Studies, with Fracture Flow Representation

Software	Developer
FLAC & FLAC3D	Itasca Consulting Group
FRACMAN and MAFIC	Golder Associates
FTRANS	GSI Geotrans for US DOE
HYDREF, CHEF	Ecole des Mines de and VPLEF Paris for ANDRA (French radioactive waste management agency)
MAGNUM2D	Battelle Pacific Northwest Laboratories for US DOE
MOTIF	Atomic Energy Canada Ltd.
NAPSAC	AEA Technologies
ROCMAS	Lawrence Berkeley National Laboratory
SWIFT98	Sandia National Laboratory for US DOE
UDEC	Itasca Consulting Group

Table 1.6-4.	**Simulators Developed for Nuclear Waste Isolation Studies, with Fracture Flow Representation**
Software	Developer
CASTEM 2000 and TRIO-FF	Technology Department of the French Atomic Energy Agency
CFEST	Battelle Pacific Northwest Laboratory for US DOE
FEMWATER	Prof. G. Yeh (Pennsylvania State University) for US EPA
NAMMU	AEA Technology
PHOENICS	Concentration, Heat and Momentum Ltd.
PORFLOW W	ACRI
SUTRA	US Geological Survey
THAMES	Japanese Nuclear Fuel Cycle Development Institute
TRACR3D	Oak Ridge National Laboratory for US DOE

BASIC CAPABILITIES OF MODELS

We summarized basic capabilities of all the models. In Table 1.6-5 we compare the four that are conventional simulators for geothermal. You can see all four can handle big fractures. None of them can handle aperture as a function of normal stress, or shear, or flow rate as a function of aperture, or channeling. But all of these can handle porous flow in matrix, they can handle thermoelastic effects. Heat and mass transfer is no problem. Multiphase flow can be handled in all of these. All can be done in 3-D. For complex geochemistry only TOUGH-2 has a module now which is pretested.

If you look at the HDR simulators, it's a little bit of a mixed bag (Table 1.6-6). Distinct fractures, more or less all can do. None of them were designed for multiphase flow, which is important for EGS. Only FRACSIM-3D has some geochemistry in it. And, GEOTH3D doesn't handle transport of tracers, and is the weakest one overall. But FRACSIM-3D and GEOCRACK can do almost all the things you'd like to see in a EGS project.

In the nuclear waste area we have done a broad survey, but haven't gone into great detail. We have looked at mostly the publications and where we could get a manual and where we could talk to the developers. None of them quite applies to EGS. For example, most will not handle multiphase flow.

The question was, can we really take some of the best elements out of these various models? The problem is, it's much more difficult to try to take bits and pieces of models and try to come up with one. It's much better to take existing simulators and try to add some features to them. After careful review of all these models, we concluded the following.

All simulators by, all HDR and conventional hydrothermal ones and a few of the nuclear waste ones, except one, can be for modeling this EGS projects. Most can handle porous-flow matrix and thermoelastic effects. But none of these HDR simulators and almost none of the nuclear waste can handle multi-phase flow.

Table 1.6-5. Useful Features of Conventional Geothermal Hydrothermal Simulators

Capability	FEHM	STAR	TETRAD	TOUGH2
Discrete fractures	*	*	*	*
Aperture function of normal stress				
Aperture function of shear				
Flow rate function of aperture				
Channeling				
Porous flow in matrix	*	*	*	*
Thermo-elastic effects	*	*	*	*
Tracer transport	*	*	*	*
Multi-phase flow	*	*	*	*
3D	*	*	*	*
Irregular grid	1			*
Geochemistry				2

1) Possible
2) Preliminary

Table 1.6-6. Useful Features of Hot Dry Rock Simulators

Capability	FRACTRure	GEOTH3D	FRACSIM-3D	GEOCRACK
Discrete fractures	*	*	1	*
Aperture function of normal stress	*		2	*
Aperture function of shear			*	
Flow rate function of aperture	4		*	*
Channeling	5			3
Porous flow in matrix	*	*		3
Thermo-elastic effects	*		2	*
Tracer transport	*		*	*
Multi-phase flow				
3D	*	*	*	3
Irregular grid	6		*	6
Geochemistry			*	

1) Discrete fractures during stimulation, converted to equivalent porous media for operation analysis
2) Based on global stress, no local elasticity solution
3) Under development for GEOCRACK3D
4) Includes laminar and turbulent flow laws
5) Possible with user defined material properties
6) Possible

Furthermore, no conventional simulators that are used in the geothermal business today, includes fracture aperture as a function of normal stress, or shear, or flow channeling. But these features could be added.

About half of the simulators accepted a triangular grid. Some also allowed grid refinement, like TETRAD. Only one geothermal simulator (and one in nuclear waste) can handle geochemistry to some extent. None of these simulators handles dissolved gases. That is one of the limitations.

We concluded from this study that while each simulator has many of the necessary and desirable capabilities, none has them all. Each has strengths and weaknesses. And a single type of model may not be suitable for all EGS projects at every time or state of the project.

The need for developing a single all purpose model for EGS applications is really less urgent than taking advantage of the strengths of the simulators we have already available, such as TETRAD, TOUGH, GEOCRACK, etc. We have at least eight simulators available in HDR and conventional modeling which could be used.

But we believe funding should be provided for incorporation of additional features for EGS into conventional simulators such as TETRAD and TOUGH. And, research should be funded for improving both fracture network simulators and discrete fracture models for EGS use. And of course we heard a lot about fracture definition in the field, which is a very important aspect of simulation, anyway because the problem in EGS would be to have enough data about real world situations.

And multi-phase flow should be included in the fracture network, which is something developers want. Discrete fracture simulators must have multiphase flow for EGS simulation, which they don't have today.

OBSERVATIONS AND DISCUSSION

These are taken from the report: *Assessment of The State-of-the-Art of Numerical Simulation of Enhanced Geothermal Systems*, GeothermEx, Inc., GeothermEx, Inc., Richmond, CA; Thunderhead Engineering Consultants, Manhattan, KS; and Golder Associates, Redmond, WA. July 1999.

A. Categorization

In attempting to group, categorize, and evaluate the codes described in the previous sections, it is useful to focus on the approaches used to represent flow in fractures. Three broad approaches can be identified:

- Discrete representation of the fractures and rock matrix. This approach attempts to directly model each significant fracture and to directly model the rock matrix. Such a model assumes detailed knowledge of the reservoir. The advantage is that the model should provide realistic simulations with fewer approximations. The challenges are to develop methods to easily create such models and then to obtain solutions.

- Focus on the rock matrix, using approximations for fracture flow. Typically these models use a porous-medium flow model, in which the permeability has been modified to approximate the effects of fractures. These models typically include multi-phase flow. The advantage is that such an approximation allows relatively simple representation of a reservoir. It provides rapid solutions and is applicable in situations where the rock matrix is highly fractured or porous. The disadvantage is the level of detail lost in making the porous flow approximation, which may lead to more optimistic reservoir predictions than warranted.

- Focus on the fractures, using approximations for the matrix. Typically these models use a stochastic approach to develop a fracture network model with up to thousands of fractures. The fractures provide the connections in the global model, with a dual-porosity type of local representation of the matrix where a simplified matrix geometry is associated with individual fractures. The advantage is the complex fracture networks that can be developed, the disadvantage is the approximation to the matrix.

B. Current Capabilities Relative to Desired EGS Features

We can compare current capabilities to the necessary and desired features of an EGS simulator identified above.

1. *The simulator should include explicit representation of the fractures.*

   All simulators (except those many of those from the nuclear waste area) can be used to simulate fractures at some level. As discussed above, the mathematical formulation that describes the fractures and the ease with which fractures can be represented may differ from one simulator to the next.

2. *The simulator should include fracture opening as a function of effective stress.*

   This feature allows for an accurate representation of the effect of stress on the fractures. This will be important in reservoirs in which the natural permeability is low or when permeability enhancements are being modeled. Many of the models include approximations of this, either through permeabilities that are a function of stress or by discrete-fracture modeling.

3. *The simulator should include shear defo@ons and associated jacking of the fractures.*

   This feature is similar to the previous one and also subjected to similar limitations.

4. *The simulator should include a relationship between fracture aperture and fracture conducdwty.*

   This feature requires the fluid flow in the fracture to be a function of the fracture aperture. Practically speaking, all reviewed simulators have this feature. Presently, if the cubic law is used, only single-phase fluid flow can be accounted for because this analytical solution ceases to be applicable in the presence of multi-phase fluid. In the second equation, such restriction is not present, and the equation is applicable for all phases.

5. *The simulator should accommodate channeling in fractures.*

   While obviously important, obtaining sufficient detailed knowledge to successfully identify when channeling is occurring will require input from other technologies, such as tracers and other fracture-detection methods. These technologies are under development, but may not be achievable in the near future.

6. *The simulator should include thermo-elastic effects.*

   Stress the rock due to temperature change, in addition to the fluid-pressure stress, can alter the fracture aperture, which changes the fluid flow in the fracture. Since the aperture can not be measured directly, it must be inferred through the transient and steady-state flow simulation and by comparison with tracer data.

7. *Rock-water chemical interactions should be included in a complete simulation tool*

   Reactive chemical transport simulation in geothermal reservoir is a big subject itself, particularly if all typical chemical species are included. Work in coupling the reactive chemical transport module to a numerical simulator is in progress, and the preliminary results appear promising.

8. *The simulator must include a tracer module*

   All simulators reviewed here provide chemical tracer modules, but with somewhat different capabilities.

9. *The simulator should have multi-phaseflow c@ility.*

   All the porous/fracture simulators provide multi-phase flow capability.

SUMMARY AND RECOMMENDATIONS

It is apparent from the above discussion that, while each of the simulators has many of the capabilities listed above, none has all of them; each simulator has its strengths and weaknesses. A single type of model may not be suitable for all EGS projects or at every stage of a given project. For example, in the early development stage of an EGS project, when available information is limited and the primary need is for reserves estimation and project planning, porous-media or fracture-network models would be more practical to use. In a more mature stage of the same project, when reliable information on fractures becomes available, discretefracture models may become preferable for optimizing the injection/production strategy if the project involves an HDR application.

Therefore, the need for developing a single, all-purpose simulator for EGS applications at this time is less urgent than further developing existing approaches. This is particularly true in view of the conclusion of the EGS Mini-Workshop held during the 1998 DOE Geothermal Program Review. In the near-term EGS development will not be of the HDR type, but is likely to take place in hot, low-permeability areas in or around existing hydrothermal fields.

Three broad technology areas - Hot Dry Rock, hydrothermal, and nuclear waste - have developed simulation capabilities focused on their immediate needs. The available simulators can be broadly categorized into porous, discrete-fracture, and fracture-network simulators. In each category of simulator, there are several available implementations, none of which can address rigorously the entire range of analysis needs from reservoir creation (stimulation) to long-term production forecasting.

As part of this review, the opinions of experts in each area were sought. While useful, these discussions also highlighted the lack of experience with the conditions of EGS systems. Thus, many of the evaluations of required EGS features are statements of opinion, not fact based on experience. At this time, the EGS experience base does not exist to rationally commit to one particular simulator or approach. As such, it is premature to identify a particular simulator as the primary focus of development. Instead, developing an EGS simulation experience base should be the highest priority.

We strongly believe that meaningful reservoir modeling and simulator development can not done in the abstract. Meanin@l modeling is only done as an active participant in the development and operation of a reservoir. Only through such active interaction with realistic problems can the appropriate simulation needs be identified and skills developed to apply to other reservoirs.

Therefore, our primary recommendation is that the DOE support active simulation of real EGS reservoirs. This could be done either as part of ongoing international projects, such as I-Iijiori, Japan, or Soultz, Europe, or as part of future EGS development. We envision a situation where active participation is solicited from the three broad categories of simulators (porous, discrete-fracture, and fracture-network models). At least three organizations would be funded to apply their technology to prediction of the reservoir resources and to simulation of reservoir operation. The teams would meet regularly to exchange data and concepts. Only this hands-on experience will provide the background necessary to demonstrate what type of models are appropriate at different stages of reservoir development and what features need to be added to complete the models. Funding could be provided to develop these additional features.

At the end of such a project, the geothermal operator industry would have knowledge of the capabilities of the different simulators. Presumably, the simulators that perform well would be used by the industry in future projects. Thus, marketing forces (rather than opinions) would decide which approaches are most valuable.

There are also areas where a foundation could be developed in preparation for application to EGS reservoirs. Particular recommendations are:

- Ease of use has been identified as a stumbling block to many simulations. Funding should be provided to simplify the creation of reservoir models, performing the analysis, and viewing the results.

- Further research be funded for improving both fracture-network simulators and discretefracture simulators for EGS use. The mathematical formulation forming the basis of these simulators allows the detailed specification of the fracture geometry. This is useful and appropriate when detailed knowledge of in-site fractures is available. Most fracture-network and discrete-fracture simulators developed for HDR applications can not handle multi-phase fluid flow. This will be a major limitation in their application to most commercial EGS systems, where the reservoir fluid is not single-phase. Therefore, multiphase flow should be included in these models.

Simulation of flow in fractures requires both the capability to identify the hydraulically active fractures in a reservoir and the capability to simulate the flow after the fractures are identified and defined. Thus, independent of modeling development, part of EGS research should address identifying and defining the hydraulically active fractures in a reservoir.

DISCUSSION AT THE WORKSHOP

Koenig: With respect to the chemistry, have you been thinking about the time frame over which we do these things in the environment associated with EGS and how that effects the ability to do chemical modeling. Virtually all the chemical modeling is based on non-kinetic and equilibrium models. Thus, with the introduction of this theme, we may be able to suggest that the limitations of time constrains us from having problems that are associated with the chemistry. That should be investigated.

Kasameyer: What do you mean by "simulator?" One thing we need is the ability to simulate the aggressive modification of the permeability in a reservoir. It's not clear to me whether your summary is talking about that aspect of simulation.

Sanyal: It does. What I mean by "simulator" is a computer program that can handle fluid heat flow transfer and elasto-mechanical properties. And to the extent we can get that from conventional simulators, as upgraded.

Kasameyer: There are commercial stimulation simulators that you didn't talk about.

Sanyal: Right. I didn't because many of them don't have any heat transfer in them. There are a lot of purely mechanical simulators.

Swenson: I think it's good to keep in mind Norm Warpinksi's observations none of the models matched his description. The point of that is that the modelers need to actually have a project to work on. And develop their models based on experience, rather than theoretical features to be included in the model.

Hickman: You said what I wanted to say, basically, that I think it's really important that with this plethora of models out there, we should also discuss bench marking and testing of field data and identify those cases for which there is a closure. Some sense of agreement, either models based on similar assumptions agreement of each other or more important, they agree with actual field data predicting reservoir performance.

Sanyal: I mentioned 24 models but we looked at 11 more. And there are seven people involved in it.

Entingh: I want to add one more consideration. I think that some aspects of modeling are needed from a policy point of view. That says, if you spend so much money stimulating a georeservoir in one way or another, what you get out of it in terms of production? Now, you here might decide that's stupid, and if so I'll rest my case, but I think that the point of view that the people that interact with those in Washington, D.C. DOE headquarters and other places, an important question is, "Can there be large economic pay-offs of certain manipulations that you might want to perform?" That would be similar to what John Pritchet has been involved in with the geothermal slimhole evaluation program. The big question there was, "Can we estimate productivity of conventional size production boreholes using the results of slimhole tests?" The answer is pretty much, "Yes." But a lot of reservoir modeling had to be done to answer that question.

EGS Workshop 3
August 17-18, 1999
Lawrence Berkeley National Laboratory
Berkeley, California

SECTION 2.0

TECHNICAL PRESENTATIONS

Edited July 17, 2002 dje

2.0 TECHNICAL PRESENTATIONS

2.1 Hydraulic Fracture Research Experiments in GRI and Possible Implications for Enhanced Geothermal Systems Research.
Norm Warpinski, Sandia National Laboratory

Everything I will talk about has been done in oil and gas reservoirs, but I will try to link it to what may be done in geothermal. I'll focus on what I thing of what we learned that can help you, and other possibilities of what to do.

Most of this work was sponsored by the Gas Research Institute (GRI), with some sponsorship by DOE fossil energy. (Figure 2.1-1) A lot of the work has been done by Brenning and Associates as well as many other contractors. GRI has a lot going on in the stimulation area , where they are sponsoring much research. (Figure 2.1-2) I'm going to talk about two areas--in terms of fracture diagnostics, primarily microseismics. Eric Davis will talk about tiltmeter experiments later.

I'll mention some of the basic fracture research that has been done primarily at a place called M Site. There are other things going on with respect to fracture models. Restimulation may be of interest for people doing geothermal reservoirs. Basically I'm going to talk about comprehensive diagnostic tests, mostly at M site where we have done a lot of things with microsiesmics and downhole tiltmeters. (Figure 2.1-3) We cored through fractures. We used pressure tracers--all kinds of other advanced studies--stress measurements, material properties, five thousand feet of core. This is with DOE funding. I will mention the Mounds drill cutting injection, which interesting application to geothermal.

Let me start with M Site. Basically it was a field laboratory for fracture diagnostics. It was located in the Piceance Basin in central Colorado so it is an oil and gas reservoir site; formation in the upper Mesa Verde.

Our facility, if you look at a plan view (Figure 2.1-4), consisted of a well in which we were creating hydraulic fractures and two monitoring wells, where we had typically wireline tools. One down here we called the monitor well because we have cemented in tools of various sorts--receivers, downhole tilt meters. We eventually used this same pad site to come through and actually drill some deviated laterals through this site to see what those fractures look like. Three intervals that were tested between about 4,000 and 5,000 feet.

One quick word about microseismics. I know people have been doing microseismics for years in geothermal. It probably started in that area more than anywhere else. Of course the geothermal was more of the multi-well approach. There you had one well where you were creating a fracture, and receivers in a number of offset wells. From those you can very accurately triangulate to find where those microseisms occur and try and relate them to the hydraulic fracture or whatever you are doing in the injection process.

Our focus is a little bit different. Typically in the oil and gas industry, if you want create a service, there is no way you are going to have this many observation wells around. You are lucky to have one well. So the focus has been on multi-level arrays in a single well and developing the technology, essentially, and the processing techniques to do the same kind of thing from a single well with a multi-level array. Basically all the results you are going to see are based upon that approach.

If I had more time, I'd like to show visualizations and show how these things actually develop in time. But this is kind of a screen shot at the very end of one of those visualizations. This is the kind of data we get. We have a plan view over here where our fracture well is right there. These are our two monitor wells. This is the regression line of all these microseisms indicating where the hydraulic fracture went. This is a gas well. We pump much more viscous fluids than was done in hot dry rock work. We don't get this big, wide cloud like you see in the hot dry rock kinds of things because most of these failures are probably not leak-off produced. They are probably related to shear stresses that are induced at very high shear stresses at the tip of the crack. And they propagate along with the cracking as you watch these events move along.

So we have a pretty good idea of how these fractures propagate and move out and how fast they're going and what height growth occurs and those kinds of things. This is a plan view showing the orientation of this fracture.

We had a well that was drilled ahead of time. We actually fractured into this well so we knew how well this was working as a validation test. We could compare pressures in that well with what our microseisms saw. There was a very good agreement that said, yes, the length is pretty good. We're right on with that and then a side view over here showing the sandstone. Again this is at about 4,300 feet deep, the top of the sandstone, the bottom of the sandstone where all the microseisms occur. It is pretty well confined to that zone. The two different colors, by the way, the blue ones were taken from wire line tools in this well. The red ones were taken from cemented-in tools in this well. The idea was to compare and show we could get good data with wire line tools as well as with cemented-in receivers.

And then it is all correlated down below --with a histogram-- with pressure and things like that. I really don't have time to get into. But that's typical of the kind of data that are obtained in these tests.

Let me go over just a few sets of results. I'm just taking pieces out here and there that may have some application. Earlier someone mentioned, talked about fracture containment. Figure 2.1-5 is a side view of one of those sands. This is the top of those at about 4,300 feet. It shows one of the injections with a cross-link gel that is very well contained within the sandstone, which surprised everyone. But this is typical. We saw it many times--unexpected containment of the fractures in the interval. We have maximum pressure of 4,500 psi, yet the stress above and below the maximum stress was 4,000 psi. We were well above that. All the models predicted we would have radial fractures. We had nothing close to it.

First. In dealing with fracturing and fracture models, fracture models many times have a very difficult time predicting what the correct height is going to be. Of course after the fact you can always go back and remodel it and do things and you can get it to look pretty good. But what you get vs. what you predict is really questionable.

Second. This is probably closer to home to what we'd like to do in geothermal. This is the same sandstone. This is the last injection we did. This was a major stimulation with sand, cross-link gel, the whole nine yards. What this shows over here on the left side of Figure 2.1-6 is a plan view after about fifteen minutes of injection. What happened was that using this very viscous gel at high rates and a lot of sand, we started generating very high pressures. A normal fracture's azimuth would is in the single preferred direction. Early on we started seeing these secondary fractures occurring. This is just pressure related. There is no question that if you get the pressure high enough, use viscous enough fluids, pump at high rates, probably some sand helps to bridge a little bit, to generate the high pressure, you can get secondary fractures going off in different directions.

This is an area where no one expected this to occur. Everyone thought you would just get normal kind of fractures here. So it is certainly something that can be governed. And you have to know what the stresses are. As a matter fact, if you go back to the relationships that we used to figure out when this does occur, it matched pretty well with the stresses and the relationships. So in fact you could actually predict it based upon the pressure and all agree pretty well.

The same test, at the very end of the treatment, is shown in Figure 2.1-6. This was about fifteen minutes. This is actually about seventy-five or eighty minutes. This is looking at an edge view. This is kind of weird. If you were to stand right here and look down the edge of the fracture, this is what you'd see. With a normal fracture and the microseisms around it, you'd expect to see an ellipse.

While all this stuff over here is understandable, that's the secondary fractures, they are going off to the top part, to the North. But we also saw a zone that indicated we had a horizontal component in these fractures. So this was a T-shaped fracture, again in a place where no one expected this to occur. But it all agreed. The pressure, the pressure reached 4,800 psi, the overburden was 4,600 psi. You'd expect you could get horizontal fractures, and in fact, we did.

The trouble is no one would know any of these things just looking at the pressure or other indicators. In fact, the diagnostics are very important for telling us they occur, and they could be very useful for trying to stimulate reservoirs in other directions besides just the normal direction the fracture would propagate.

We saw very significant fluid system effects. Viscosity is extremely important in terms of height growth that you get and in terms of the size that you get. (Figure 2.1-7) These are two tests, same volume, one being a cross link gel, probably about a 1,000 to 1,500 centipoise fluid, this being a linear gel, probably about 50 centipoise fluid. And you can see that with the same volume, you get a fracture that is much stubbier. It's higher; it's much shorter; it's much wider because of the higher pressure. You get much longer fractures with these linear gel systems. And you also get significant changes in fluid leakoff and things like that as well.

One other one that is really of interest is that when you try to model these things without putting in all kinds of extra mechanisms, just trying to do the basic modeling, you find out that things don't match well. Maybe the model is an easier thing to talk about.

Figure 2.1-8 shows the same injection well 6C that was shown in Figure 2.1-6. You look at the side view of the microseisms and do a fracture model that is actually constrained so that the height reacts. So we agreed with the height; we matched the pressure; we find out that this thing should have been much larger than it actually was as observed by the microseisms. And we have other data, tiltmeter data, to back this up as well.

What we think is occurring--in fact there is other evidence that this is happening and more and more people are starting to use these ideas--is we are getting fissure opening out there. That is we are reaching high enough pressure. Whereas as you saw with the secondary fractures, not just the secondary fractures, but many of the natural fractures, you get a certain pressure level and they start accepting fluid.

In fact, that's actually a terrible thing for hydraulic fracturing because what happens is, when the fractures are closed and there is just a small amount of permeability, the full gel system can't get into them. If you open them up, the full gel system, a highly viscous fluid, gets into those fractures. But then when you are trying to retrieve the fluid, the pressure is lower and it's closed up on that gel and it has blocked it. So the fissure opening can be a good thing for geothermal. But how do you go about doing it and getting there is extremely important because you can clog up your reservoirs as well. And that happens a lot in the oil and gas business.

We did a lot of interesting things out there. Figure 2.1-9 is of interest to most people that deal with hydraulic fracturing. You core through a number of the hydraulic fractures that were created. The two right panels are from M Site. This is much deeper from a previous experiment. It's kind of interesting, coring through with a deviated lateral well through the fractures. We knew the fractures were there from the microseismic data. In fact, this confirmed that we had the right azimuth, right locations. We always saw systems of fractures rather than single fractures.

These are supposed to be conventional hydraulic fractures that everyone models the single plane of fracture. One case we see eleven fracture strands over three or four feet. One case there are about fifteen fracture strands over three or four feet and further up the hole, about forty feet up the hole, or fifty feet up the hole, there is another one, another fracture up there. You go further down to around the seven thousand foot depth where something was done in the mid-eighties, we have the same kind of thing. There were thirty fracture strands. This was actually a double fracture. Two intervals were stimulated at the same time and we came through both those intervals. In the main one, which is the bottom one, there were thirty fractures strands. On the top one but not even with the lower one, actually back fifty feet, there were eight fracture strands. So thoroughly complicated systems--even what is supposed to be a relatively simple system. And that is pretty typical of what we saw up there.

Let me jump quickly to a second set of experiments. (Figure 2.1-10) Most people are probably pretty familiar with drill cutting injections. Just for economic reasons and environmental reasons, the oil industry is trying to inject the hydrocarbon-contaminated cuttings back into reservoirs on site. That avoids problems with barging or trucking or in general just dealing with those contaminated wastes. Just put them back in the reservoir, or some other reservoir.

The question is: what happens? Economically this is a very significant problem for the oil and gas industry. What they want to do in this case, they want to create what they call "a disposal domain." That is, they inject the stuff and there are solid particles in there and they'll inject a certain volume, shut down for the night. Fractures will close up on those solid particles. They'll inject again, put more solids in there and eventually they clog that fracture up. They hope then that the stresses will reorient a little bit and start the second fracture. It may be off a little bit. And then later on another fracture. And eventually you get this fairly large domain of multiple fractures and this is pretty much clogged with all this fill, with these cuttings. The question is, does that really occur?

When we were out at a site called Mounds, doing the same kinds of things--microseismic monitoring and things like that--and this is just a quick side view of a few of the injections in one test. In fact we found that it basically does occur. I'm not sure if Eric is going to talk at all about Mounds. We saw the same kind of things with both the tilt meters and the microseismic data. We will see that if you look at different injections (and we did twenty of them in this particular one zone. It's called the Wilcox at a depth of about 4700 feet). If you look in plan view (Figure 2.1-11), you see the azimuth change with some of these injections. And if you look at a side view of the various injections for the microseismics (Figure 2.1-12), you see fractures going in different places each time. So for instance the first injection here is in blue. The point where it was initiated, there is a casing collar down to about here and then there was an open hole zone running through here. So we were injecting we thought into the sand stone but in fact most of the stuff was going upward. But the first one went primarily in one direction; it went upward. This is the fourth injection--I can't show them all because it's so complicated you can't see things. But these are some that are somewhat different. The fourth one, kind of the same direction, but it goes much higher. This ninth one which is right around here now tends to go back the other way. The thirteenth one starts showing some indication of breaking down as well as continuing up.

And you can see how these different fractures were going at a little different azimuth and breaking at different places. The suggestion here is that if you're looking to get fractures going in different orientations, there may be ways to do that by adding solids and bridge, solids and sand. So permeable that bridge stop the fractures from growing, change the stress field, try and get things to break out in different directions.

Figure 2.1-13 shows cores from two sets of tests out there. In the Wilcox sandstone we took one core. If you look at the scale, the scale is totally different than we had in the multiple experiment. When we saw fractures over three or four feet typically, we now see this fracture area over a little more like forty feet. So we have many fractures and if you play these back to the well, the span of angles of azimuth is about twenty-five degrees span. So we have fractures going in considerably different azimuths. Most of the activity was going upward, same kind of thing, same range of azimuths, same range of fractures, not quite as many, but the same sort of occurrence there.

We also did the same thing in an upper zone. It's actually the Atoka shale. The same sort of testing in shale. Again, same results--same results from the microseisms, from the tiltmeter, and from the core data--this zone of fractures. So it looks like the disposal domain in fact works and it may have some application for enhanced geothermal systems.

To conclude. Figure 2.1-14 is a selected summary of some of the results that we see out there that maybe have some application in geothermal. Certainly limited height growth, layering--this could be important. We don't know why this occurs most of the time. Most of the models are wrong in their predictions of what goes on. We think that has a lot to do with the layering and what's going on at the layering, looking maybe at the composite material rather than just this homogeneous elastic material.

Secondary and horizontal fractures: you can make those occur. It's totally pressure related to the stress field. So it's common everywhere if you get those pressures up there. We see a lot of volume discrepancy, which I think is very important and it has to do with fissure opening. It is probably going to be very likely in the case of geothermal reservoirs, and it is a very significant problem in the oil and gas industry. I think it is something that we will need to deal with very significantly right away. What's happening with the fluid? What are you trying to do for leakoff control? But avoiding damage to the reservoir--and all those sorts of issues. We see multiple fractures. We see an extended tip region, which I did not take time to talk about.

The complexity of the fractures is probably good. It generates multiple fractures that give you good offsets at cross natural fractures and they actually help somewhat. Typically, you think this occurs because of the high viscosity of the fluid systems we use. As I mentioned, I think in one of the slides, that the fluid systems are very significant. The selection of appropriate fluids for geothermal fracturing is going to be very important. It's a high temperature environment. Most of the fluids are not made for high temperature environments, but that's an issue that one certainly has to deal with.

As I said earlier, poor model agreement is a continuing problem. We have a lot of trouble in trying to predict *a priori*. If someone says, "We created a fracture that's 375 feet out there and we're not getting production," my first question is: "How do you know that it's 375 feet out there?" If the model says it is, I wouldn't believe it. It's probably something else that has gone wrong.

So that's just a quick summary of some of the things, some of the issues that maybe give some ideas or thoughts to people about fracturing related to this problem.

Question: Take a simplistic approach. A hydrofrac is going to generate fractures parallel in existing, probably dominant fracture direction. That is, perpendicular to the current least principle stress. You mentioned you can change the orientation of the fractures depending upon the fluids that you use, the pressures you use. Can you expand on that a little bit?

Speaker: Yes. What happens is of course the problem is actually fairly complicated in that as you increase the pressure in the hydraulic fracture, you're obviously changing the stress field because you're putting a lot more stress out normally. But the problem is you're also putting stress in the other directions, too. What is really interesting is the way this all decays. It turns out the normal stress decays fairly slowly and the other two stresses decay much faster. You can get that pressure off. The hard part is getting over the hump--getting right at the fracture wall, getting that fissure to open up. You get enough pressure and you can keep increasing the pressure and you will eventually reach the point where that fissure will open up. Once it opens up and you start getting more permeability and more fluid down there, it can increase the pressure further out, then it actually gets fairly easy to keep that fracture going. But the problem is it depends on the stress difference in the reservoir and all those sorts of things. But the problem is in getting to the point where you can get that fissure to open right at the rock wall there. And you can actually sit down and figure out fairly simply the relationship between the pressure and the stresses and Poisons ratio, whatever, depending upon which model you use and what pressure level you need to do that.

Hickman: I have kind of a general question. What are your thoughts about the pros and cons of using proppants in a geothermal environment.

Speaker: I think you have to. I think most of the time what we find out is if we do an unpropped stimulation, then we'll have pretty good production for three months, five months, some short amount of time. That will eventually drop down. Probably within six months to a year you have very little incremental advantage from that stimulation. My feeling has always been that some amount of props is important. I tend to think also that people use too much proppant in many cases and there is an optimum amount of proppant because if you have too much proppant , you get wide fractures, you put more stress on the reservoir. If you have stress sensitive natural fractures out there, you may actually hurt yourself. So there are a lot of considerations.

But I also think using solids to try to induce secondary fractures and other things could be advantageous in this case and maybe even planning to do that ahead of time might be worthwhile.

EXAMPLES OF RECENT GRI RESEARCH IN FRACTURING

- Fracture Diagnostics
  - Microseismic
  - Downhole Tiltmeter
- Basic Fracture Research
  - M-Site
  - Shell Laboratory Tests
- Fracture Models (FRACPRO™)
- Restimulation
- Consortium Projects

RELEVANT GRI RESEARCH

- M-Site Experiment
  - Microseismic Diagnostics (Also Downhole Tiltmeters)
    - Fracture Geometry & Growth (Containment, Secondary & Horizontal Fractures, Volume Discrepancies)
  - Intersection Wells And Cored Fractures
    - Fracture Complexity (Multiple Strands)
    - Pressure Distribution In Fracture (Extended Tip Region)
- Carthage Cotton Valley Experiment
  - Microseismic Diagnostics
    - Fracture Geometry & Growth (Unexpected Length & Containment)
- Mounds Drill Cuttings Injection Experiment
  - Diagnostic And Core
    - Disposal Domain

Figure 2.1-1 and Figure 2.1-2.

COMPREHENSIVE DIAGNOSTIC TESTS

- ◆ **M-Site Hydraulic Fracture Diagnostics**
  - Microseismic, Downhole Tiltmeters, Cored Fractures, BHP, Tracers, Other Advanced Studies
  - With DOE funding
- ◆ **Mounds Drill Cuttings Injection**
  - Microseismic, Downhole Tiltmeters, Cored Fractures, BHP, Tracers, Other Advanced Studies
  - Consortium
- ● **Carthage Cotton Valley**
  - Microseismic, Downhole Tiltmeters, BHP
  - Consortium
- ◆ **Other Tests For Individual Companies**

M-SITE BACKGROUND

- **Field Laboratory for Fracture Diagnostics and Fracture Mechanism Research & Validation**
- **Location: Piceance Basin, Co**
- **Formation: Upper Mesaverde**
- **Facility:**
  - 1 Treatment Well
  - 2 Monitor Wells
  - 2 Intersection Wells
- **Intervals Tested**
  - 3 Sands (A, B, C)
  - 4000-5000 ft Depth

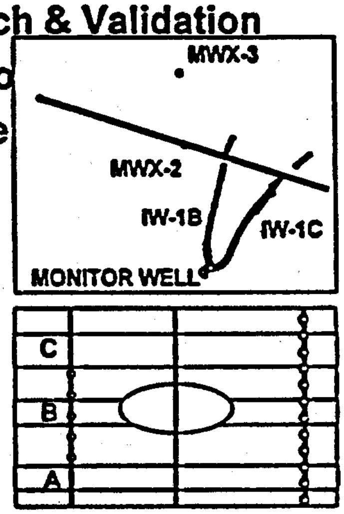
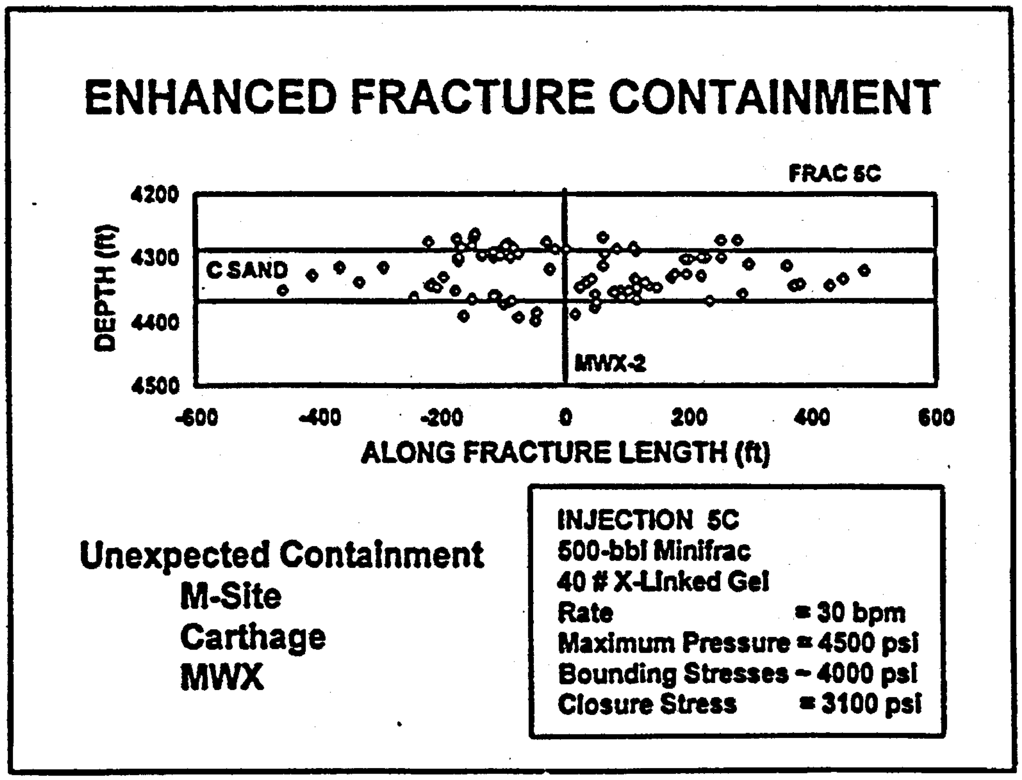


Figure 2.1-3 and 2.1-4.



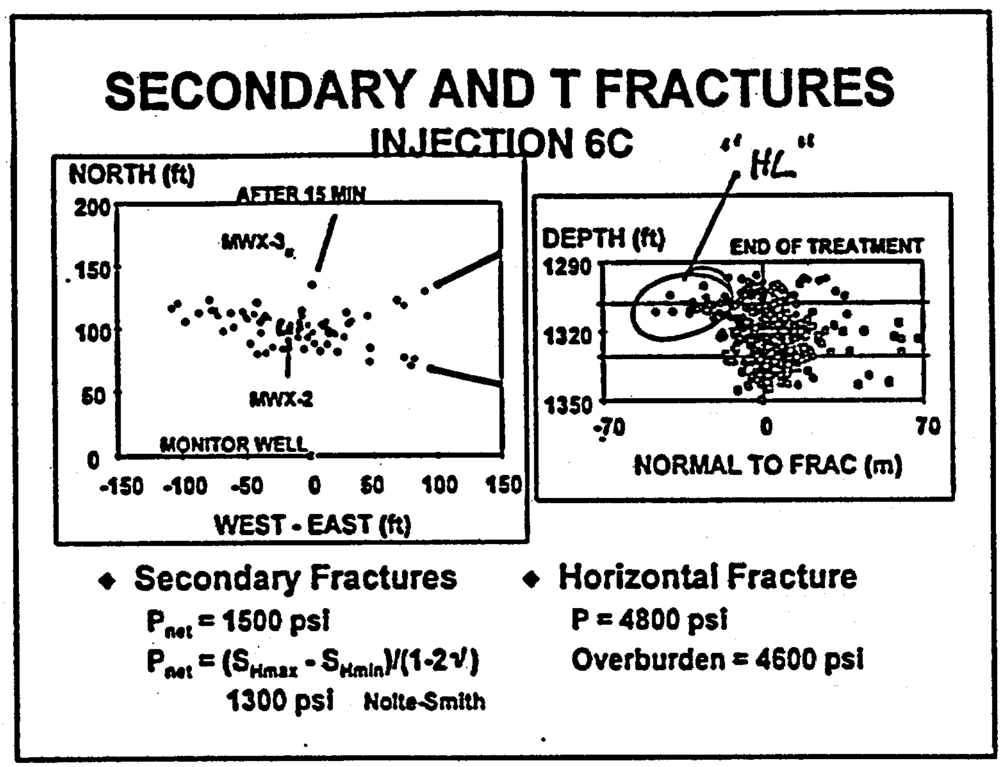
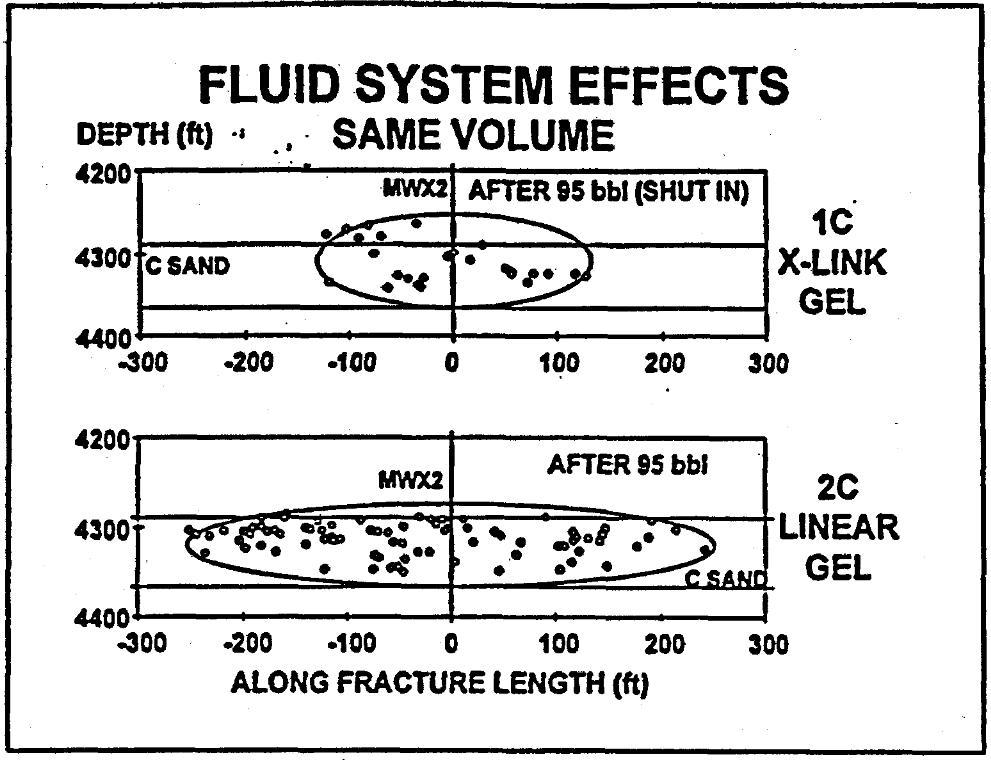


Figure 2.1-5 and 2.1-6.



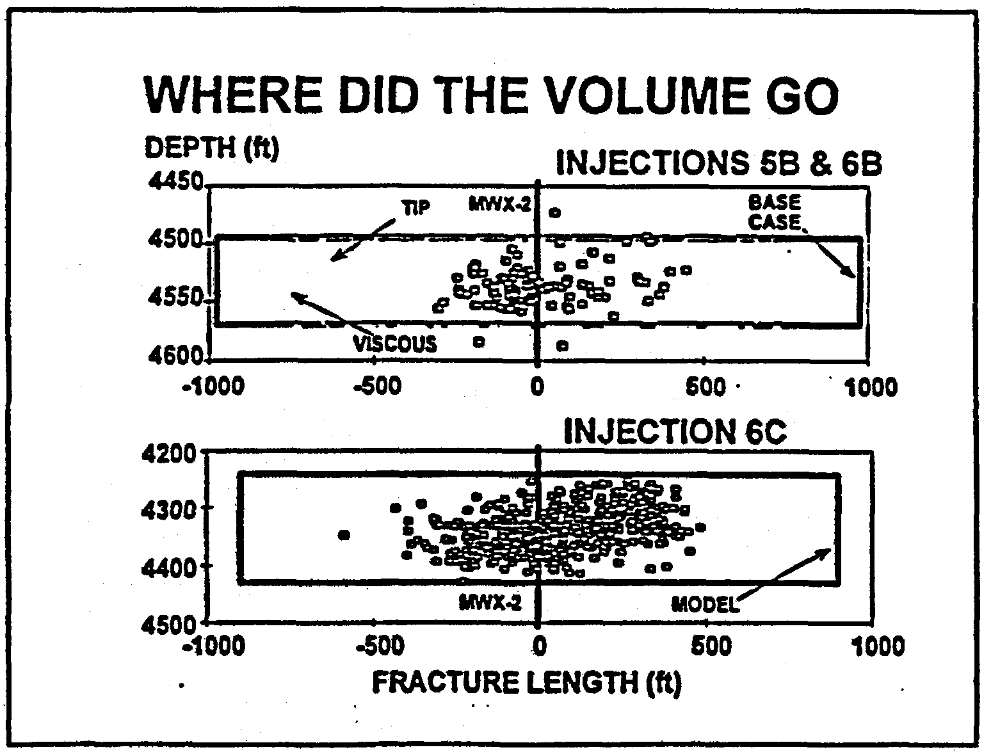
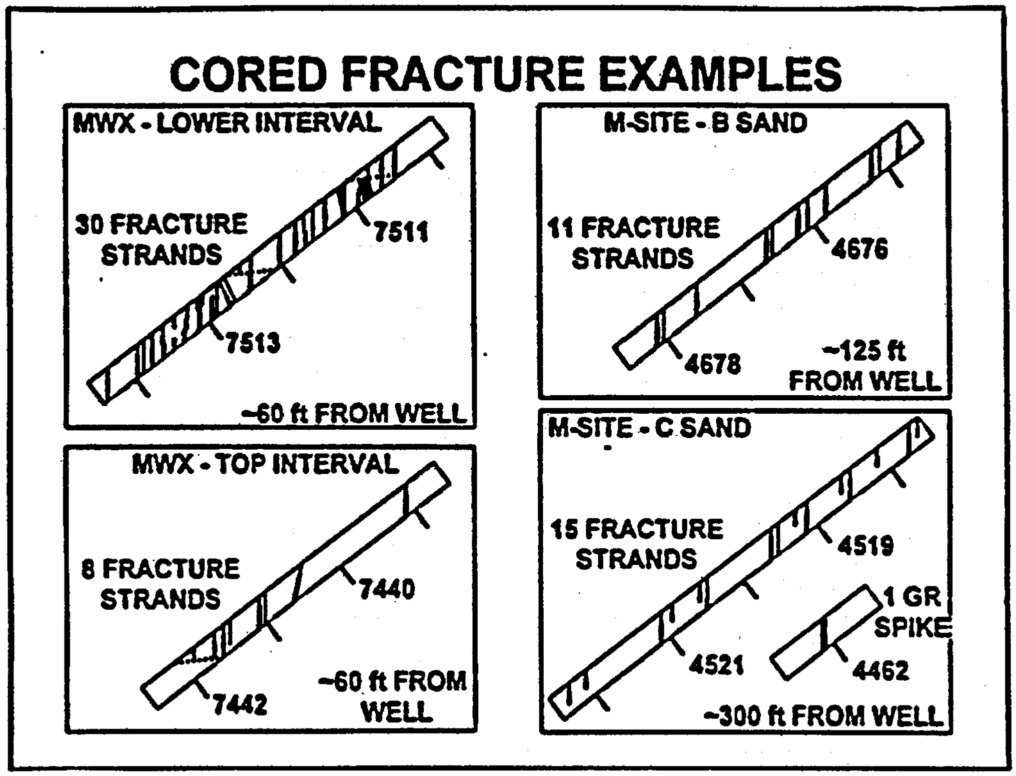


Figure 2.1-7 and 2.1-8.



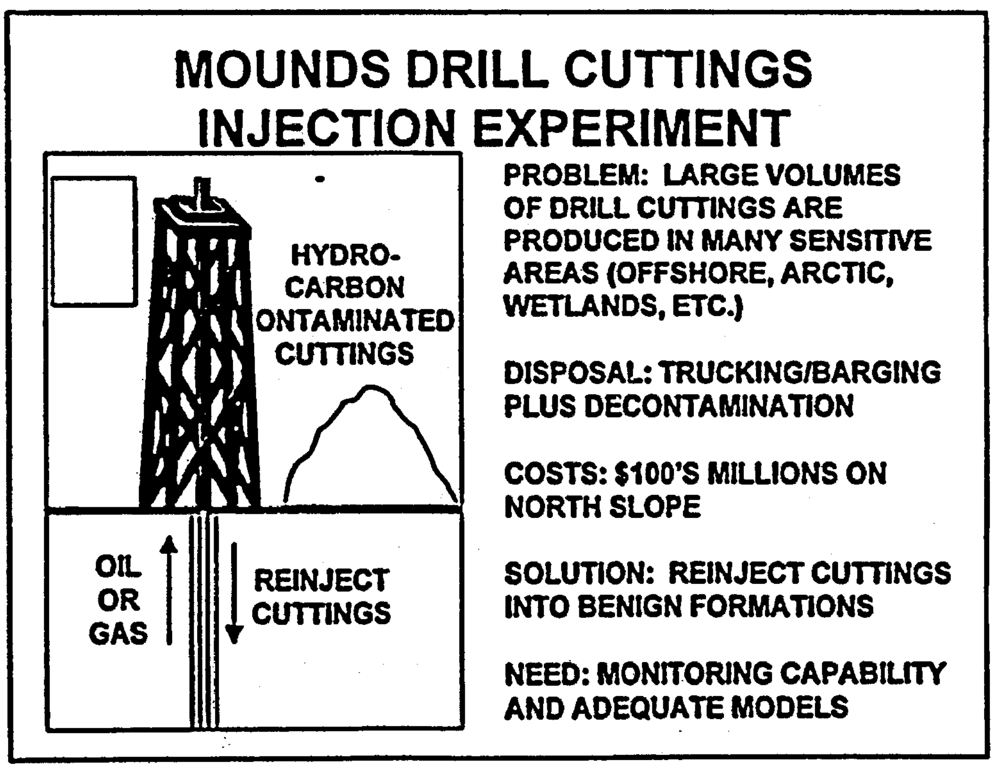
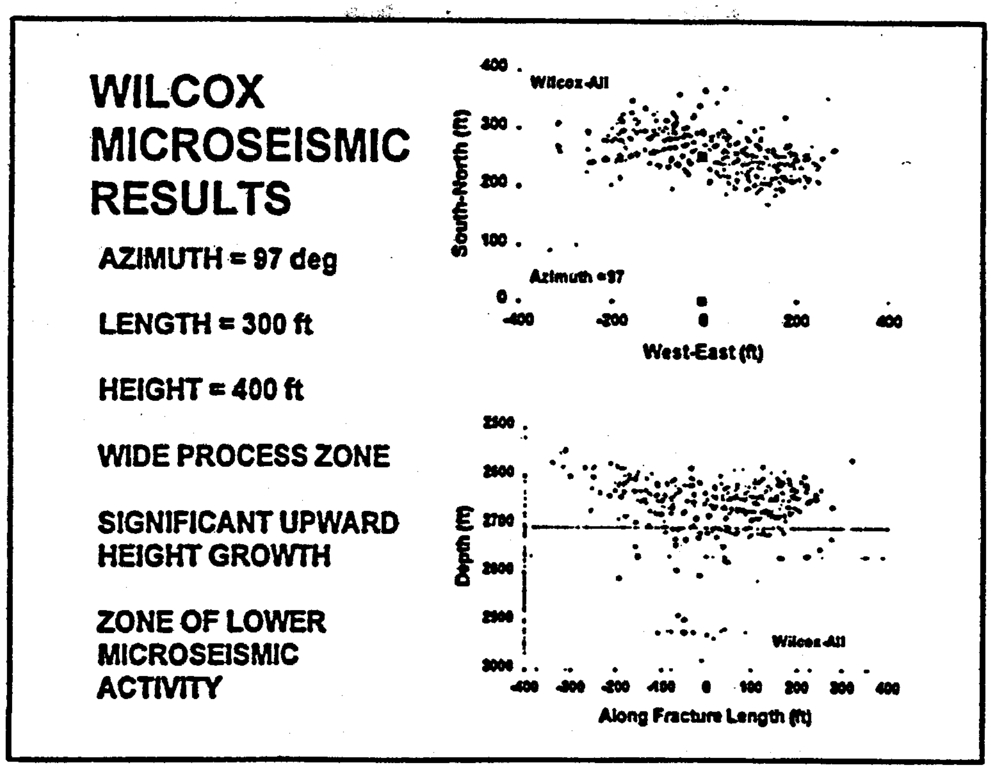


Figure 2.1-9 and 2.1-10.



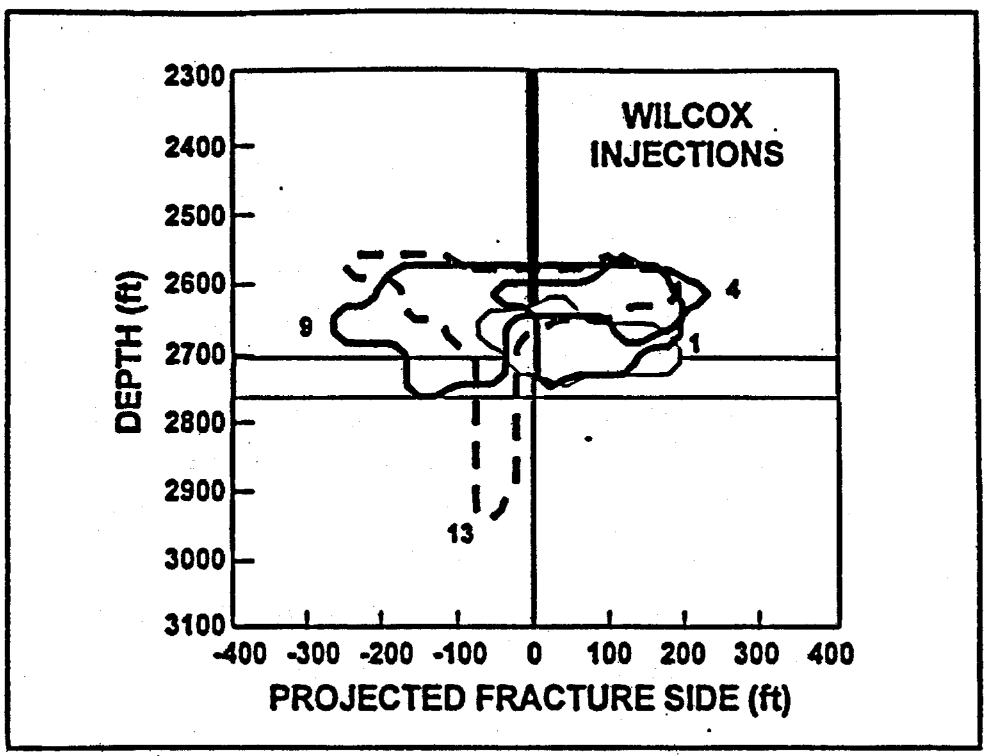
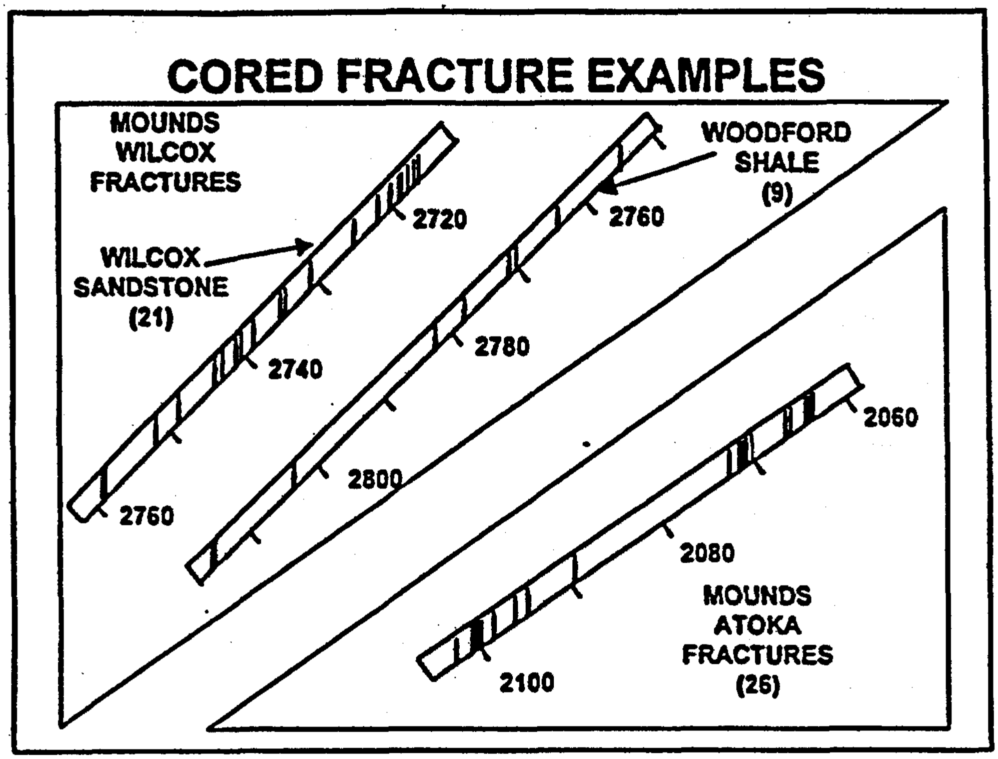


Figure 2.1-11 and 2.1-12.



SELECTED SUMMARY OF RESULTS

- **Limited Height Growth** (Layering)
  - May Be Important In Some Geothermal Reservoirs
- **Secondary & Horizontal Fractures** (High Pressure)
  - Complex Fracturing Is Common Everywhere
- **Volume Discrepancy**
  - Fissure Opening Likely In Geothermal Reservoirs
- **Multiple Fractures & Extended Tip Region**
  - Tip Complexities Likely In Geothermal Reservoirs
- **Fluid System Effects Significant**
  - Need Appropriate Fluids For Geothermal Fracturing
- **Poor Model Agreement** (Data Limited?)

Figure 2.1-13 and 2.1-14.

2.2 Use of Tiltmeters to Measure Fluid Movements.
Eric Davis, Pinnacle Technologies

To start. On the fracture orientation question, no one has been able to demonstrate an ability to steer fractures, yet . As many times as people have tried to do it, it doesn't seem to work. Also, it's useful for you to know that in order to be here, I had to delay a trip to the Hijiori, Japan, hot dry rock project. There we are actually going and using tilt meter mapping out there to map some injections and understand a little bit more about the stress in the rock. It's our second trip out there to learn a little bit more about what's going on.

Let me introduce what tiltmeter mapping is. Fundamentally, what we're doing is looking at rock move. When you create a hydraulic fracture, start with a perfect cube of earth and here we've got a fracture going into that cube, when you make room in that fracture for the fluid, you're deforming the earth. That deformation radiates out in every direction. It radiates out to the sides and it radiates up to the surface.

First I'll talk about putting tiltmeters on the surface to understand where that fracture is going. The easiest fracture to imagine for starters is a horizontal fracture. If you create a fracture underground, you bulge the earth. Way up at the surface you see a little bulge.

If you have a vertical fracture, you push the earth out to the sides. You get bulges out on the sides of a fracture and a trough that runs along the azimuth of a fracture. (Figure 2.2-1) The trough is what we look for to determine the orientation of a hydraulic fracture. If you've got a fracture that's dipping just a little bit off perfectly vertical, you'll be throwing one of those bulges up towards the surface of the earth, the other one down into the earth. So it changes the relative size of the two bulges. So here you can see that with a fracture dipping just ten degrees off perfectly vertical, one bulge is much larger than the other.

You might say, OK, forget all these bulges showing up on the surface of the earth. Why can't we just watch cars in a parking lot or whatever and see how they are moving and tell what the fractures are doing. These bulges are pretty small so the distance between these two is going to be roughly two thirds of the depth of the fracture. So over a distance of, for a 6,000 foot deep fracture over a distance of 4,000 feet, you will see a displacement of maybe 2/10,000 of an inch. It's hard to measure that but luckily we can measure the tilt and see the sides of those bulges much easier.

So what is a tiltmeter? It is just a carpenter's level with a glass bubble. (Figure 2.2-2) It's got a very precise curvature to it, and some pick-up electrodes. We send a current through it; the gas doesn't conduct the current but the fluid inside does. As the fluid covers more or less of the pad the current changes. We run it through a circuit that is like a strain gauge circuit. The tilt meter is sensitive enough that we can pick up tilts down to a nanoradian, one part in a billion. Our example is, if you have a beam between L.A. and New York City with a tool sitting on it in L.A. and someone in New York picked up his end by a quarter of an inch, you'd see that.

To deploy these tools, we drill some shallow holes around the well. (Figure 2.2-3) Typically these holes are between five and forty feet deep. The reason we go underground is because we are trying to get away from the surface of the earth. You've got a tilt meter right up near the surface of the earth, you're going to see all kinds stuff you don't want to see. Mostly you'll see the sun coming up in the morning, stretching the earth. If a cloud passes overhead, you'll see the ground contracting

underneath the cloud. Cars drive by, you'll see that. We don't like to look at all that stuff so we go down a little bit deeper where the only thing you see are the earth tides. We'll typically deploy maybe fifteen to twenty of these around a well to watch what the earth is doing. We get an array so we can map out what the deformation of the earth looks like.
This is typical data from a surface tiltmeter. Figure 2.2-4 shows a week's worth of data. We'll see these regular movements--two of these bumps every day. One is for the sun, one is for the moon going around the earth, flexing the earth. Over a period of a month you'll see these going in and out of phase. You can actually track what the moon is doing.

Here we've got a few extra bumps on one day. If we blow up that single day and look at that on this time scale, we've got three jumps in one day. These jumps are actually hydro fracturing treatments occurring nearby. We blow up one treatment and take a look at that, see what the tilt meter is doing. It is moving along through some background thing, jumps and goes back to the background immediately. That's a diagnostic fracture that's happening nearby. Then there's a big jump, where they are pumping the main treatment. We are watching the earth tilt during this period. What we will do is project this background information out to the end of the job. We'll say, here's the amount of induced tilt at that tilt meter.

The reason there are two lines on there is because each tool has two sensors. Think of one as a North/South and one as an East/West sensor. We put all those together and I've got two examples up here. On the left side for Figure 2.2-5, the circle is the well. Each cross is the location of a tilt meter and the black line is the measured tilt we saw during the treatment. If you look at the array you can see we don't really need a computer for this one. We can see that there is a trough that developed along this orientation. That's the fracture azimuth. This fracture is extremely vertical. You can see the magnitudes of the tilts on one side are very close to the magnitudes on the other side. It just tells us that this is a very near vertical fracture; it actually came out to 87 degrees off vertical.

Sometimes we see this kind of pattern, as in the right side of Figure 2.2-5, all the tiltmeters are pointing away from the well head. That's also pretty easy to analyze. It's basically a 100 percent horizontal fracture. Actually, it's not terribly uncommon. It does happen out there and sometimes it happens in deeper areas than you'd expect where maybe the local stress overburden stress, does not match what we think the integrated overburden is.

So what do you get from tiltmeter mapping? From a surface tilt meter array, we get hydraulic fracture azimuth and dip. We can do this in real time if we need to look at how a fracture is growing during a treatment. We can look at fracture growth in multiple planes. We can put multiple fractures in and map what we see. Very often, in fact most of the time, we'll get a main vertical fracture and some component of horizontal fracturing a long with it. We'll also get an approximate location of a fracture center. Surface tilt meters are not terribly sensitive to it but there is some sensitivity. If a fracture goes deeper, the humps from the vertical fracture move apart. If a fracture is shallower, the humps move together. Of course we define where the center of a fracture is on an x/y plane just by looking at where the deformation is.

The problem with surface tiltmeters is that they are typically pretty far away from the fracture and so it is blurry. If we are trying to locate the fracture center within a hundred feet and we're five thousand feet away, we're not going to be able to do it. But we can look for gross movements with a surface tilt meter array.

More recently we started putting wire line retrievable downhole tiltmeters in nearby offset wells, shown in Figure 2.2-6. This way, we can get much closer to the fracture. Now we're looking at it from a different vantage, and we can get hydraulic fracture length and height. We can also map in real time and see what's going on during the treatments. We use this to detect out-of-zone fracture growth, look for if you are missing some pay zone. We can look at an approximate hydraulic fracture width. Mostly what we are doing now at Pinnacle is using this data to try to calibrate fracture models to understand a little bit better and be able to use it in a predictive sense what is the fracture going to do. As Norm Warpinski mentioned a few times, models right now just aren't really that good. There are a lot of times when we have been extremely surprised. We run a model and we do the diagnostics right next to each other. We don't know why the model is wrong, but it's wrong.

Here's the principle of downhole tiltmeter mapping, shown in Figure 2.2-7. We'll go into an observation well and run a string of tilt meters. Each one is on centralizers so each tool will tilt as this observation well casing moves to make room for this hydraulic fracture that's being pumped. What do we see? When you have a hydraulic fracture out here, you've got a hundred foot tall fracture that is half an inch wide. Then out 100 feet away, the observation well casing is going to deform to make room for that fracture. We've got a maximum deformation here of a tenth of an inch. We don't measure that deformation; we measure the tilt, the gradient of the deformation.

If we take the derivative of this line, this is what we see. (Figure 2.2-8) We see a peak of tilt that corresponds with the top of the fracture. It goes to zero at the center of the fracture where the earth has just moved out, hasn't tilted at all. There is another tilt peak at the bottom of the fracture. We just see the absolute magnitude of this; we don't see the sign. So we get this characteristic shape where there is a peak, a zero, a peak, and then back to zero. As you get further away from the fracture, you start to apply a model and these peaks actually separate out a little bit. The top one goes up and the bottom one goes down.

We can't orient them yet. I'm experimenting with fiber optic gyros and things like that to try to do it, but I can't do it yet.

Here's what we typically see. (Figure 2.2-8) Here we had two observation wells. Each dot is a depth where we had a tiltmeter. This is the tilt magnitude, so you can see here that we have a peak, down to zero, comes up for another peak, basically we get the height of the fracture out of that. Since in this case we had one array that was directly normal to the fracture and one that was out further along one of the fracture wings, you can get the tilt out along a wing as well. The height matched but the magnitudes were very different. We'd look at the magnitudes and we could get the length of a fracture very accurately.

Figure 2.2-8 also shows where we take our model. We force different half lengths and tight fractures in, get an error fit to the data we measured and we can get an uncertainty bounds of where that fracture might be. In this case the half length was 170 feet plus or minus 35 feet, the height: 230 feet plus or minus 25 feet. We've seen a very wide range of fracture geometrics using this method.

Figure 2.2-9 shows one of the more interesting jobs we've done. You can see the tiltmeters at shallower depths, toward the end of the job they started to take off. We were actually mapping this job in real time and we saw right here in the perf zone that we were growing a fracture. After 20 minutes we had this fracture. After 40 minutes we had this fracture, 50 minutes we had this fracture, and then at the end of the job, the last 10 minutes we started getting this growing in length out at the top. This was actually above where the stage B perfs were going to be, but had not yet been shot. That kind of fracture growth is interesting, something we actually see on a fairly regular basis, but we've also seen all kinds of things -- extremely contained fractures going out very long. We've seen fractures that wanted to go down -- all sorts of stuff.

In closing, Figures 2.2-10 and 2.2-11 summarize some of the important features of using tiltmeters.

Pritchett: Could you comment on what you think the kind of background noise you're going to get in a typical geothermal volcanic tectonically-active environment , due to your ability to track artificial fractures using this kind of technology?

Speaker: We have surface tiltmeters employed, at Hijiori. We use tilt meters to monitor volcanoes looking for magma coming up underneath it. Surface tiltmeter would be the background noise.

Creed: Earth tides and other systematic noise I'll call it. What if you happen to be on or near a landslide?

Speaker: Very often in California you will get small earthquakes during a job. We've seen treatments trigger small earthquakes around a job. We'll take that five minutes of data and remove it. We can handle anything that is on the wrong frequency from what we're looking for. A typical hydrofrac job is an hour long, so we're looking for tilts that happen over a period of about that. An earthquake is a minute event or a two minute event and a landslide similarly is not going to go on for an hour.

Creed: Well you've got creep events that are longer than one hour.

Speaker: Yes, you can have creep events but if it was unfortunate enough to start at the same time as the hydrofracing and end at the same time. Yeah, it would confuse us.

Nielson: Could you differentiate this tilt meter technique from seismic monitoring for mapping out fractures that are created by a hydrofrac event.

Speaker: The difference is that tilt meters are looking for the low frequency deformation of the earth. Micro seismic mapping is you're pumping up fluid pressure in the ground, releasing shear stress that's built up around the fracture, and then listening for high frequency

Nielson: I understand that. Maybe I didn't ask the question correctly. I'm a client. I only have a certain number of bucks to spend and you're selling me a tilt meter vs. someone else is selling a three dimensional seismic monitoring to evaluate what's happening in my hydrofrac. Why should I use tilt meter technology?

Speaker: We sell reliability and volume and cost. We've mapped over eleven hundred fractures last year with tilt meters. It's done on a very regular basis. There are some formations that don't generate micro seisms. Modeling is a little more difficult with micro seisms if you are going through different layers and things like that. Tilt meter mapping works; it is relatively easy to do.

Nielson: You didn't give the answer I would give, which is: directly measuring the deformation which is what you're trying to do. Whereas as much as I like microseisms, you have to quantify for your dimensions.

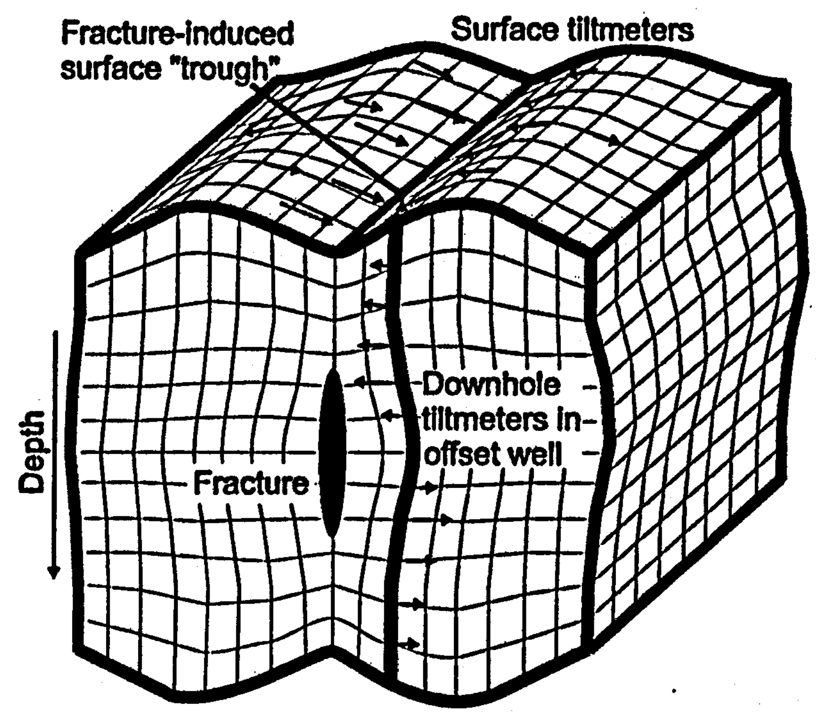
Speaker: Right. One more comment about microseismic. Nobody knows if they're telling you exactly where the fluid went. There could be tensile fractures that don't generate microseismics. But tiltmeters really tell you where the fluid went.

Warpinski: I disagree with that. Mechanically you can sit down and figure out exactly why microseisms occur. There are three reasons. There are tensile fractures. There are shear fractures generated by additional shear with the crack tip. And there is shear induced by leakoff of the fluid. And in fact if you wanted to put together a model, you should model when and how these occur based on the stability of the reservoir and those kinds of things. It is just that it is a difficult problem and most people don't bother to do that.

Figure 2.2-1.

PRINCIPLE OF TILTMETER FRACTURE MAPPING

- A created hydraulic fracture results in a characteristic deformation pattern in the rock around the fracture
- Measure the hydraulic fracture induced tilt (deformation) of the earth at several locations
- The induced tilt from an array of tiltmeters reflects the geometry and orientation of the created hydraulic fracture

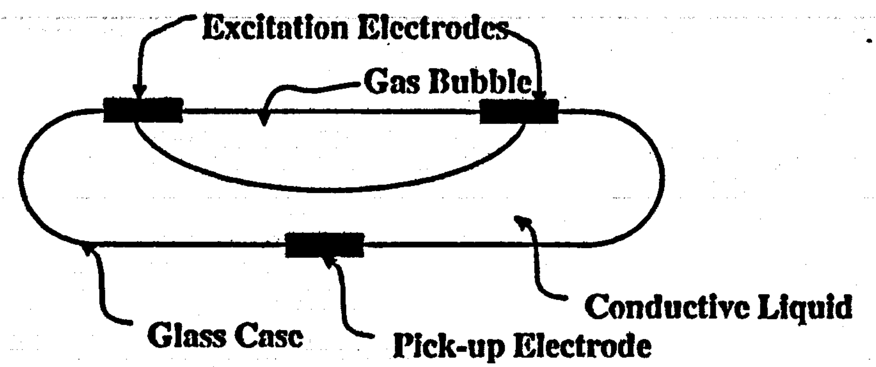


Tilt overview.ppt
09/29/98
slide 2

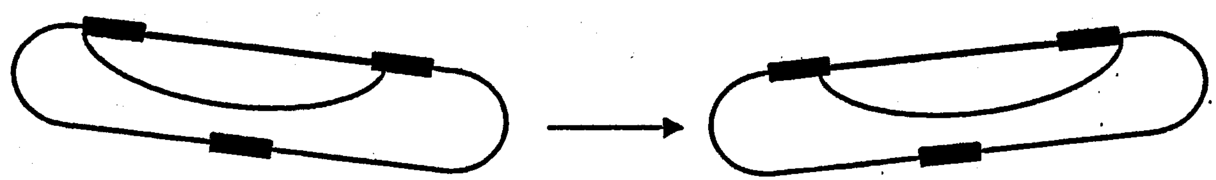
Pinnacle Technologies

Figure 2.2-2.

THE TILT SENSOR IS LIKE A VERY SENSITIVE "CARPENTER'S LEVEL"



When the sensor tilts, the resistance between the electrodes changes.



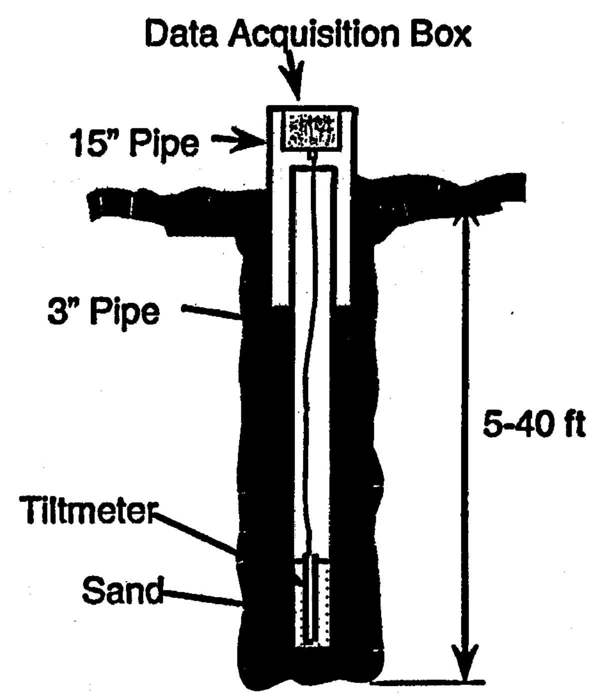
Tilt overview.ppt
09/29/98
slide 5

Pinnacle Technologies

Figure 2.2-3.

SURFACE TILTMETER ARRAYS

- Installed 5 - 40 ft below the earth's surface in 3"-diameter PVC pipe
- Deeper boreholes to eliminate "noise" from surface
  - Cultural noise
  - Thermal induced earth surface motion
- Surface array with 12 - 20 tiltmeters placed in concentric circles around frac (distance from well: 15-75% of frac depth)
- Tiltmeter sites installed several days before fracture treatment to allow "settling"
- Tiltmeter data stored in datalogger contained in tiltmeter
- Data collected after fracture treatment (manually or by radio)



Tilt overview.ppt
09/29/98
slide 6

Pinnacle Technologies

RAW TILTMETER DATA ON THREE DIFFERENT TIME SCALES

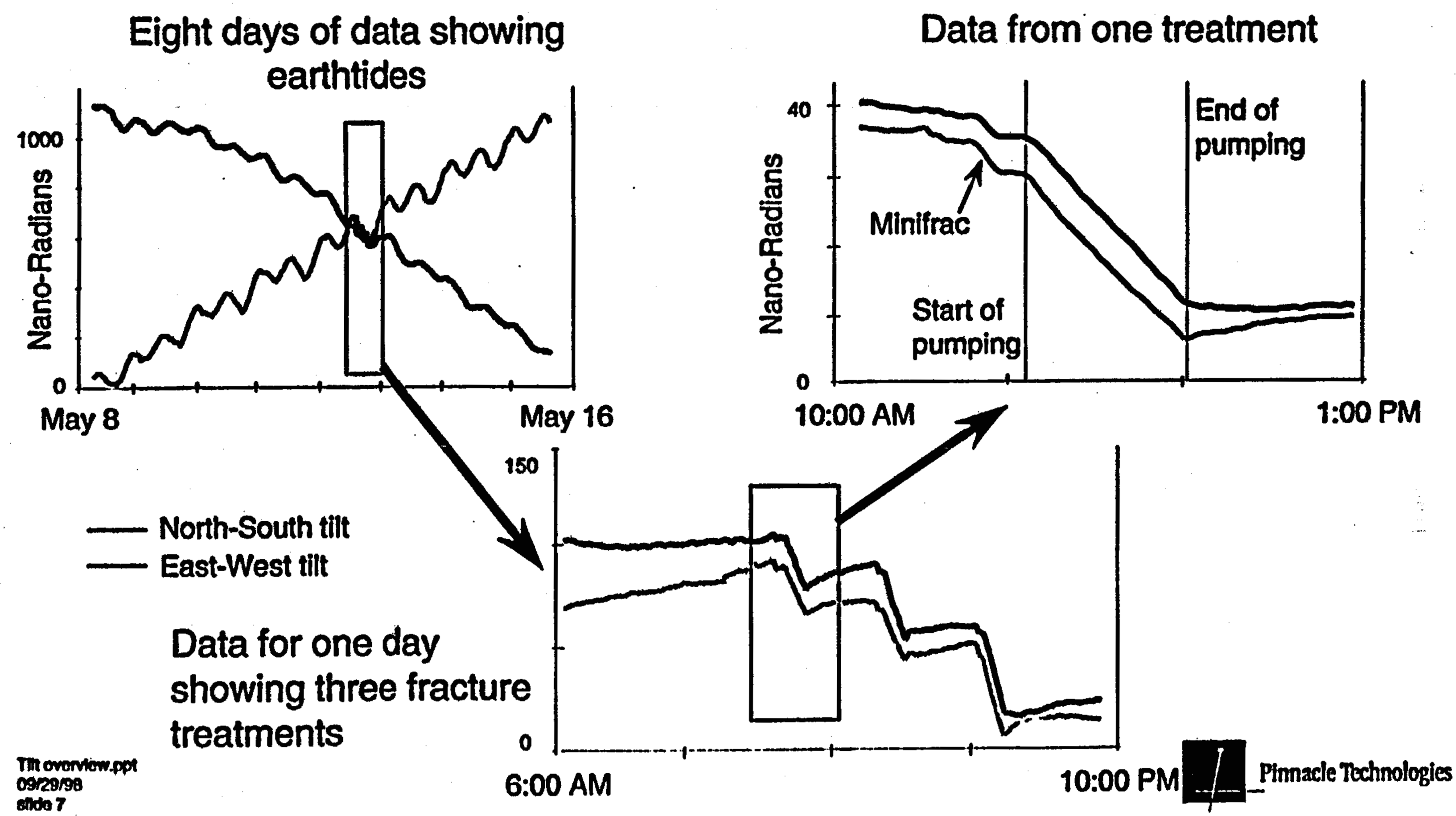
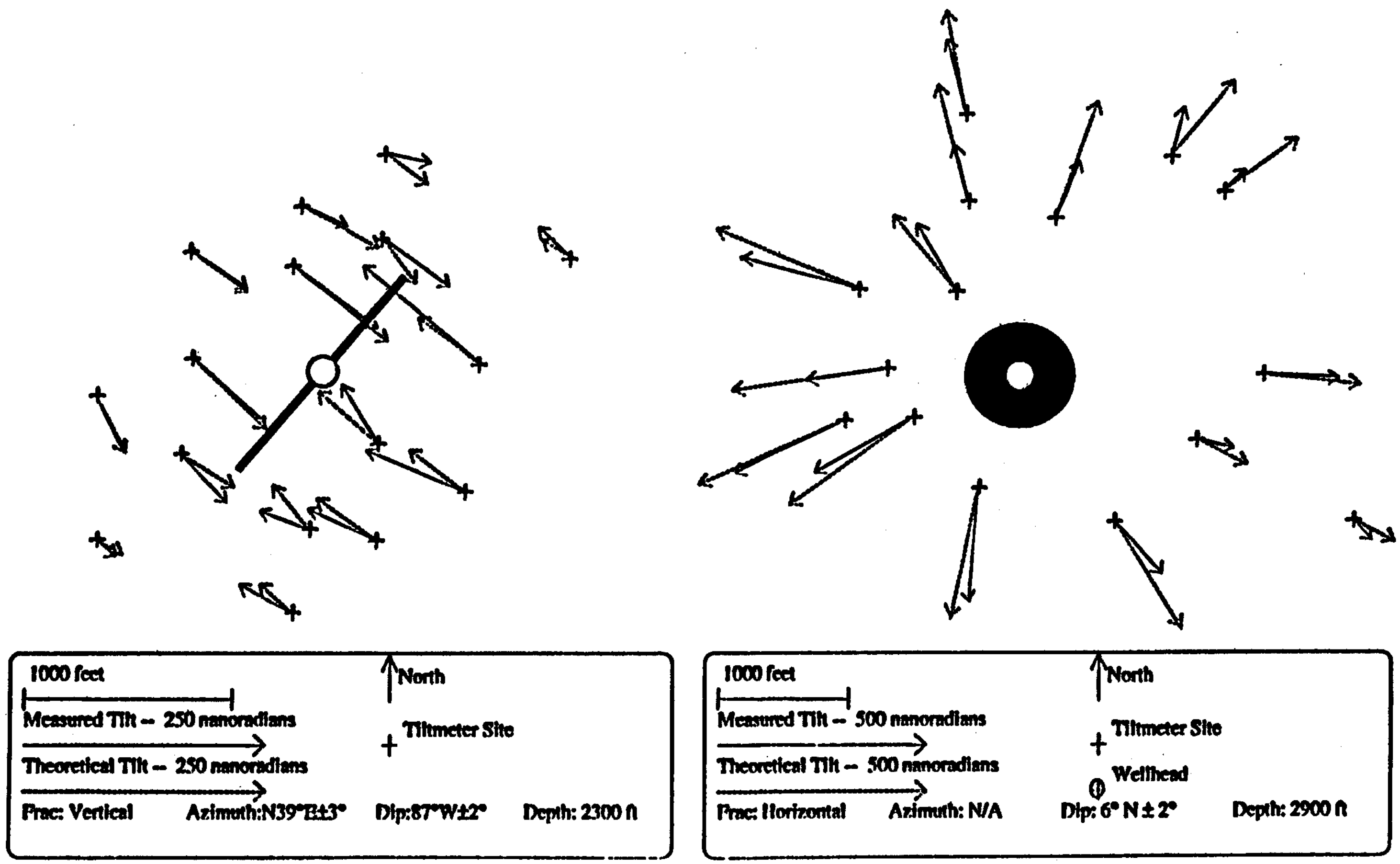


Figure 2.2-4.

Figure 2.2-5.

TILT VECTOR MAP FOR VERTICAL AND HORIZONTAL FRACTURE



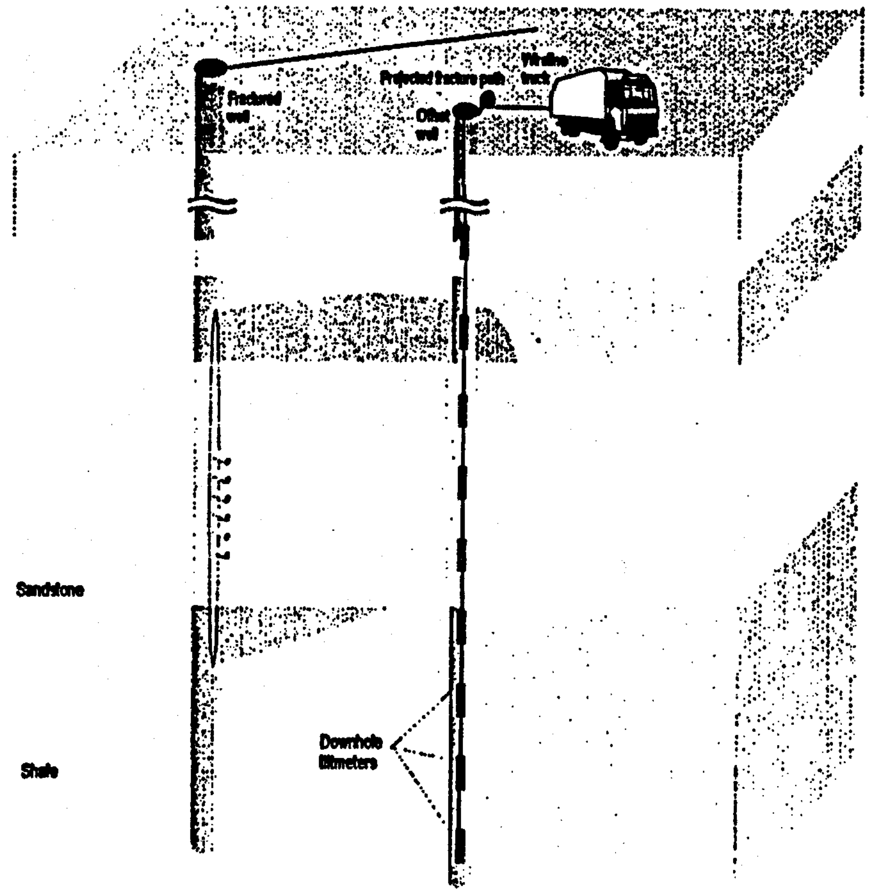
Tilt overview.ppt
09/29/98
slide 8

Pinnacle Technologies

Figure 2.2-6.

DOWNHOLE TILTMETER ARRAY
(used to measure fracture growth)

- **Downhole tiltmeters installed on wireline using *standard oil-field centralizers***
- **Large signal-to-noise ratio due to short distance to frac**
- **Downhole array(s) with 6-15 tiltmeters placed in offset well(s), depth of array centered around frac interval in treatment well**

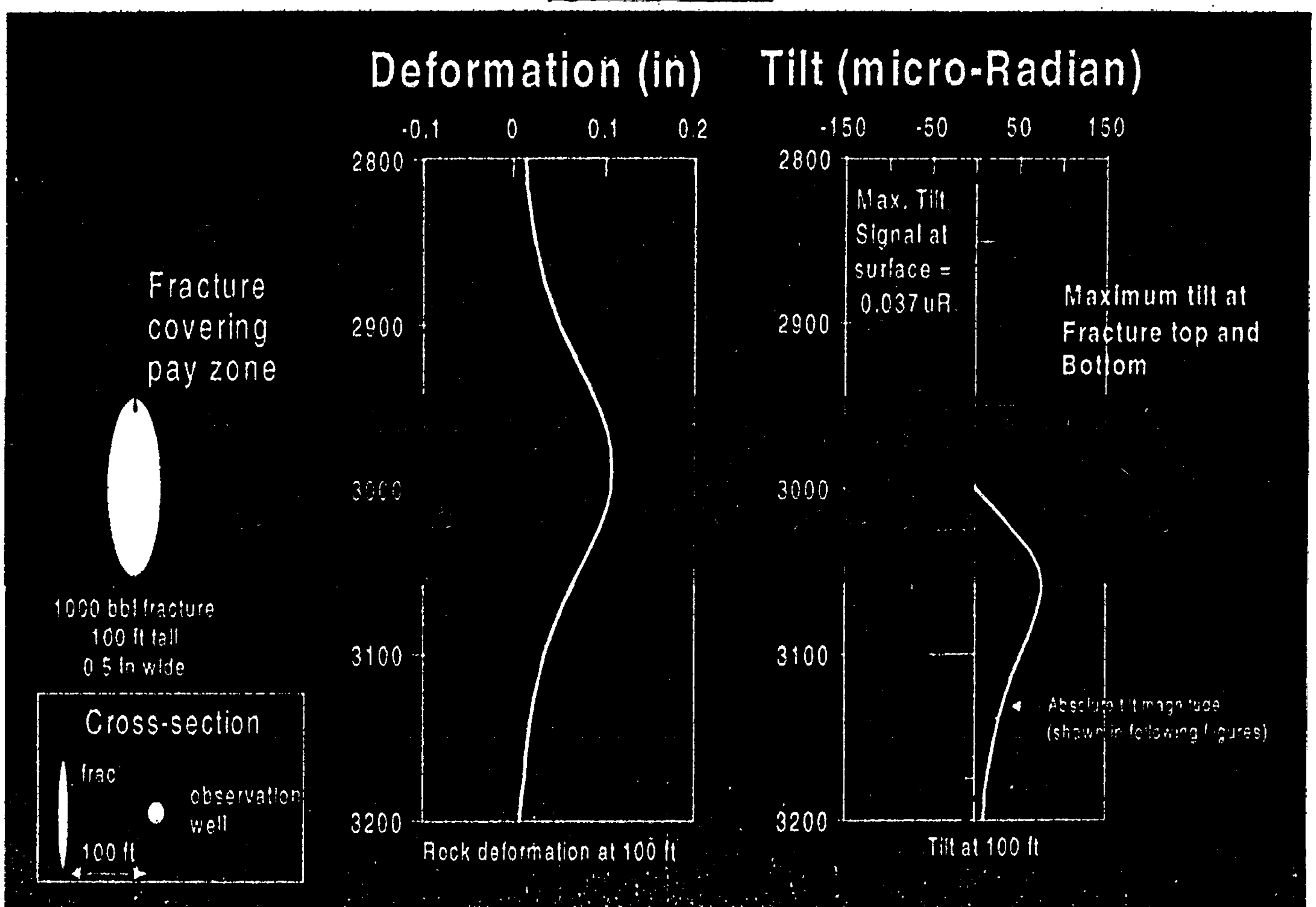


Tilt overview.ppt
09/29/98
slide 10

Pinnacle Technologies

Figure 2.2-7.

DOWNHOLE TILT MAPPING OF FRACTURE HEIGHT

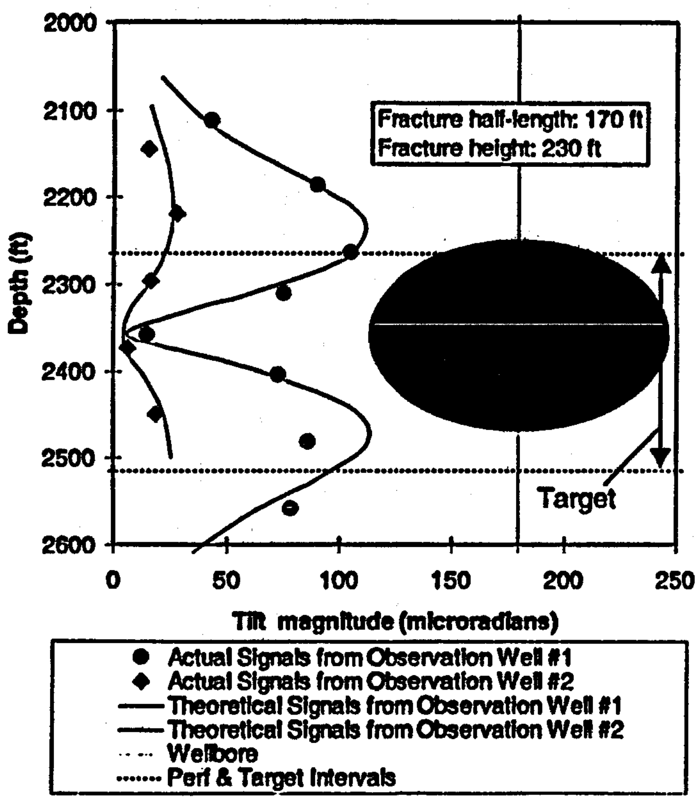


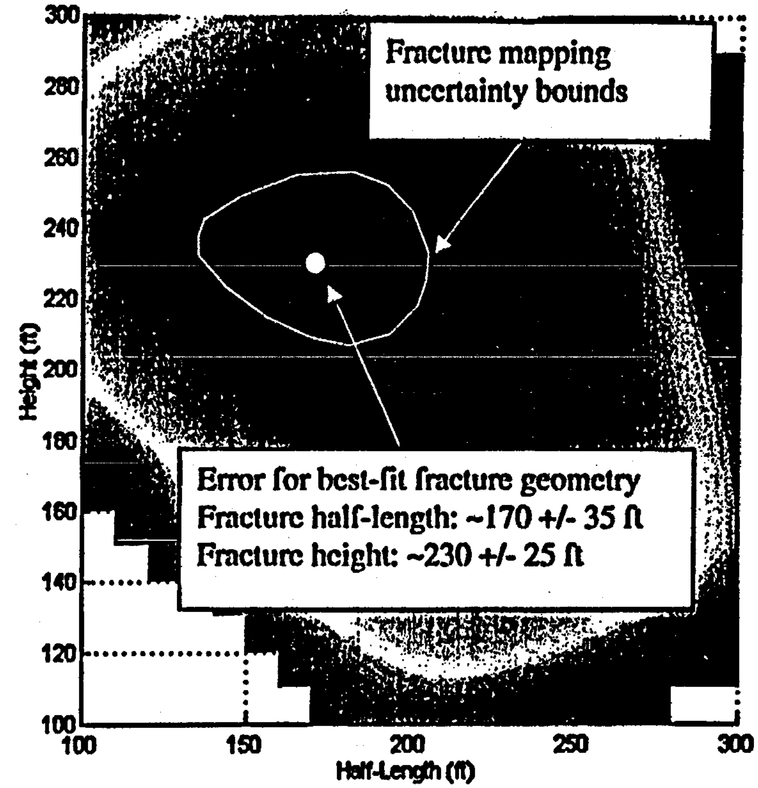
Tilt overview.ppt
09/29/98
slide 11

Pinnacle Technologies

Figure 2.2-8.

DOWNHOLE TILTMETER FRACTURE MAPPING ALLOWS MEASUREMENT OF FRACTURE DIMENSIONS





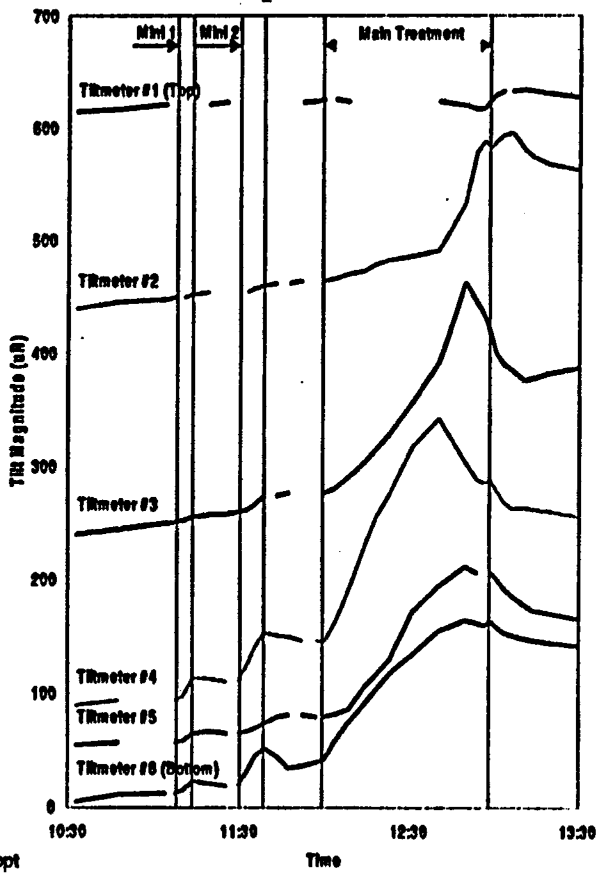
Tilt overview.ppt
09/29/98
slide 13

Pinnacle Technologies

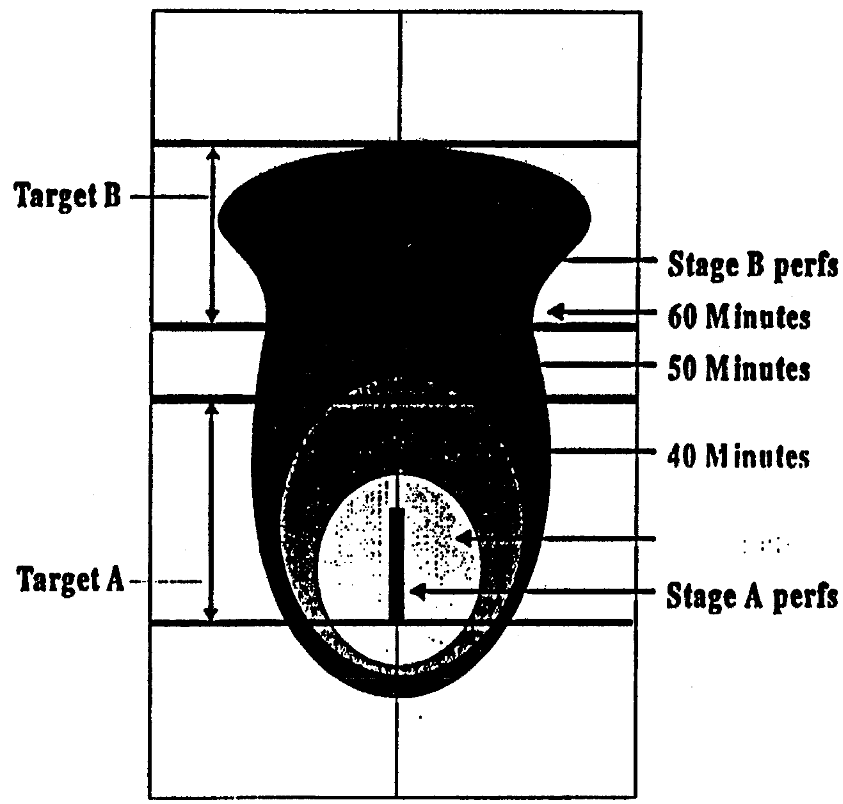
Figure 2.2-9.

EXAMPLE: REAL-TIME FRACTURE GROWTH ANALYSIS

Tilt Response vs. Time



Frac Geometry vs. Time



Pinnacle Technologies

Figure 2.2-10.

WHAT CAN YOU GET FROM TILTMETER FRACTURE MAPPING?

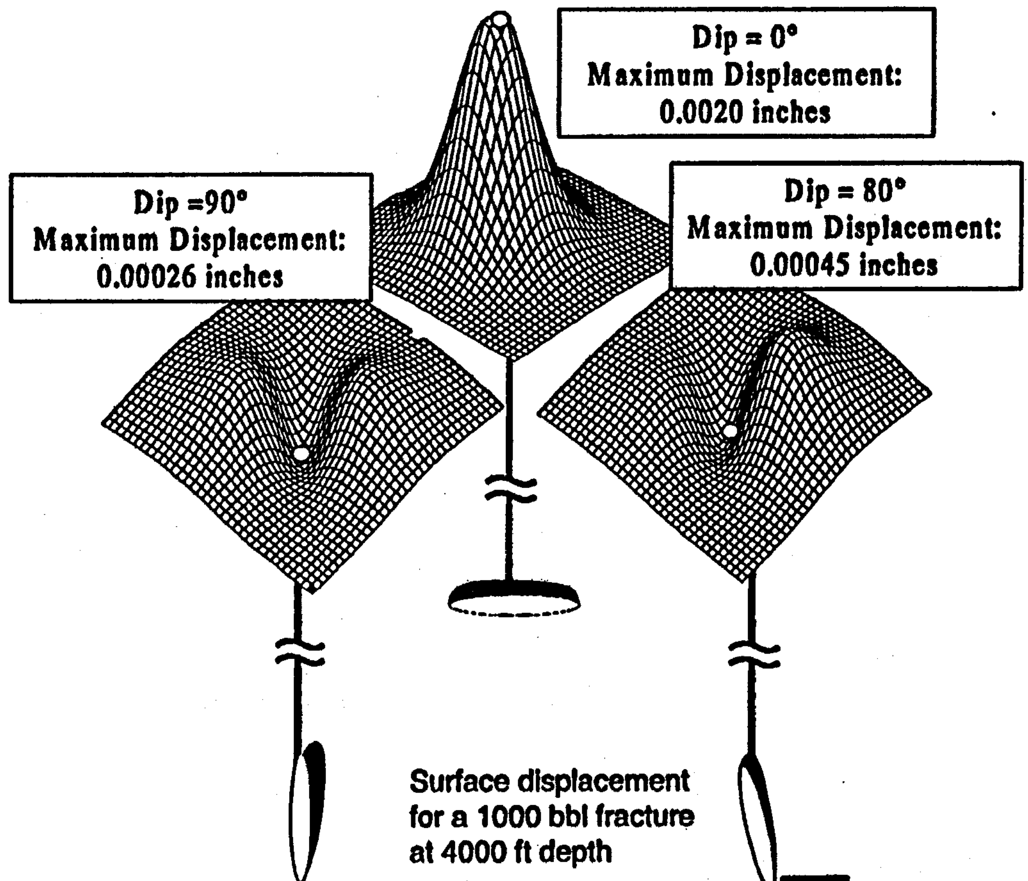
- **Surface Tiltmeter Array**
  - Hydraulic Fracture Azimuth & Dip (Versus Time)
  - Fracture Growth in Multiple Planes
  - Approximate Location of Fracture Center (Depth to Center and Lateral Center Shift)
- **Downhole Tiltmeter Array**
  - Hydraulic Fracture Length and Height (Versus Time)
  - Detect Out-of-zone Fracture Growth and/or Unstimulated Pay
  - Approximate Hydraulic Fracture Width (or Cumulative Width for Overlapping Multiple Fractures)
  - "Calibration" of Fracture Growth Models for Economic Optimization

Tilt overview.ppt
09/29/98
slide 4

Pinnacle Technologies

SURFACE DEFORMATION IS DIFFERENT FOR DIFFERENT FRACTURE ORIENTATIONS

- Very characteristic surface deformation pattern makes it relatively easy to distinguish fracture dip, horizontal and vertical fractures
  - Gradual "bulging" of earth's surface for horizontal fractures
  - Trough along fracture azimuth for vertical fractures
  - Dipping fracture yields very asymmetrical bulges



Tilt overview.ppt
09/29/98
slide 3

Pinnacle Technologies

Figure 2.2-11.

2.3 Injection Beneath Hydrothermal Reservoirs.

Dennis Nielson, Energy and Geosciences Institute, University of Utah

I'm going to give a brief presentation on a conceptual level of a proposal we have submitted to the EGS program. There are at least three other organizations represented in this room that are part of this proposal.

Our concept of an enhanced geothermal system is based on some of the following. First of all, all high temperature geothermal systems in the U.S. are really magmatic hydrothermal systems. They are driven by a magma body. They have a zone of conduction on top it, and then that zone, in turn, drives a zone of fluid circulation. Figure 2.3-1 is a composite diagram that shows these different zones. Here's a hydrothermal circulation system where we have spent most of our time and efforts so far. This seismic data, for instance, is from Coso. It shows you the number of seismic events increase up to a divide between the frictional zone and ductile zone. The figure also shows approximate temperatures at depth.

Our concept is that we are already reasonably comfortable with the hydrothermal part of the system, so lets start to look down in here in the transition between frictional and ductile zones. Our idea is to develop these deeper parts of existing hydrothermal systems through the process of deep injection. Why do that? There are a number of reasons. The main reason is that the greatest thermal energy is located beneath the hydrothermal circulation zone.

Let's look at some of the Japanese results from Kakonda. Figure 2.3-2 shows the WD-1 well at Kakonda. Those of you who have been following this project know the Japanese were actually able to complete a hole and measure temperatures up to 505 degrees C. Their hydrothermal reservoir ends at a little over 1,500 meters depth. So, this is the formation they have been producing from. They have a relatively tight zone down beneath that they have termed, in one publication, the microcrack reservoir. Then they get into a ductile zone down beneath that where the rocks are not able to sustain brittle fracture. Pressures at that point will increase from hydrostatic, evidence suggests, very rapidly to lithostatic conditions.

Again we are into all the problems that Brian Koenig described at The Geysers where they are into relatively high gas contents. So just for the sake of argument, the left-hand trace in the figure describes the temperatures that were measured just after drilling. The right hand trace is supposed to be the equilibrium temperatures. Just for the sake of argument let's say I think I can extract the heat from this reservoir between the temperatures that lie between the two traces. I've taken it down to about 4,200 meters, where I think it is going to probably get close to the magma heat source here. If you do that and then do some thermal calculations, you discover about 80 per cent of the heating system is located down beneath the present hydrothermal circulation system.

Is that heat accessible? I believe it is, and I think evidence shows that it is because these systems cool naturally. They cool naturally through fracturing and the ingress of meteoric fluid. I think that's been shown over and over again at hydrothermal ore deposits and in many existing geothermal fluid systems. So what we want to do is to enhance this natural group – we want to engineer it. We want to do that with deep injection, and we ought to see first of all if we can stimulate the fracture growth without using hydrofracturing techniques. We will just give you what nature would use. That is thermal contraction by reducing the effective stress in the zone where we've got a tectonic environment present.

The advantage of this to producers I think is considerable. If we are able to do this, we will be able to utilize a project's existing infrastructure - the roads, wells, gathering systems, power plants, and we ought to be able to extend the project life with a relatively minimal additional capital cost. We think that we can do it also under the concept is that what we are going to be doing is investing in injection wells rather than production wells. We also believe that these injection wells can be drilled somewhat inexpensively using slimhole technology. One of the differences is we just have to put water into the reservoir selectively. We are not looking at producing tremendous volumes.

So, what we are doing here is proposing a field experiment that will take an existing well, whether it be production or injection, and deepen it by slimhole methods down into this transition zone, between the existing hydrothermal reservoir and what we know to be the ductile zone. We'll see if we can't find a fracture and grow it into an interconnective fracture. We don't know quite where we are going to have to stop to do that. That's where a lot of the planning process is involved. The general concept is that the injection well ought to be able to support any number of production wells around it. That is the general concept of the field project.

Sanyal: So, you plan to create a fracture in the transition zone that would grow toward the hydrothermal reservoir? First you have to get the fluid into the system?

Nielson: That's right.

Lippman: Otherwise you are going to just take the water that flows into the fractured reservoir?

Nielson: That's right. For example, looking at the diagram of Kakonda, if I inject up here, I'm just doing what we already do, that is injecting into the existing hydrothermal zone. If I go down here into the ductile zone and try to put water into that, I'm just going to destroy my well. It's just going to spall off. It's just going to chill it. The little temperature deviations in the micro-crack region indicate some of the fluid has been accepted by the formation. And one of the tricks is going to be deciding where in here you are going to inject, so that you actually will be able to take a fracture that may not be connected with the reservoir and try to grow that into the reservoir. Now is that possible to do? The answer is, we don't know.

So, you can start down in here and inject cold water and try to lower this boundary. We think there is a boundary at around 340 degrees C - somewhat below the temperature of the actual ductile flow of rock. So there is a boundary here of problematic origin, but there certainly is fracturing that exists down into this micro-crack reservoir. So the idea is to start with one of those and grow it.

Paulsson: Is there technology to place packers so that you can concentrate the injection at a certain depth – we're talking about 300 plus degrees C.

Nielson: No, we intend to try not to use packers.

Person: How are you going to make sure that water is going into the proper interval?
Nielson: Some wells at The Geysers are cased to the depths at which we will.

Prairie: Do you think that to verify this concept you could do it with one well?

Nielson: The initial program will probably be a single well test. A single injection well, with a number of surrounding production wells.

Lippmann: The Kakonda, Japan, project was originally to exploit the deep reservoir. They couldn't do it. Now they propose stimulation work at Kakonda. Dennis, have you thought to work with them in doing a stimulation experiment at that well?

Nielson: We have not proposed it to the Japanese. I went over and reviewed the Japanese proposal to drill near there. I guess it was my impression that they were not interested in extraneous suggestions and experiments. They didn't quite have the program for drilling into those temperatures at that depth and being able to evaluate the production. And indeed, following drilling into that hole it did as it should do, it closed up. Since we drilled the kick-off, I don't think they've gotten quite to those temperatures. But I'm not quite sure what their program is in evaluation.

Prairie: I asked them recently what they are trying to do with that well, and they said it's just a headache.

Lippman: I think that well is just ideal for stimulation experiments.

Nielson: Well, there are other places that are ideal, too. Brian Koenig sort of initiated this discussion. One of our concepts is that the ideal place to actually try this is at The Geysers because it is pretty well defined in terms of tracing some of the seismic events associated with some of the early injections at The Geysers. (Figure 2.3-3.) I've superimposed on that the geology, so we've got the cap rock here and the reservoir here. The production wells come down to here.

Then we've got the felsite underneath. Of course a million years ago, some of the felsite was molten and that's where the ductile zone was. And we think that the ductile zone was actually probably up in about 500 meters or so above the contact. It's pretty well documented this through the fluid-inclusion work. Obviously what's happened is, just as I portrayed to you in our model here, the entire system has subsided. We are now getting brittle fracturing down within the felsite. We also have a floor on the seismic events that would be caused by brine injection. So we think that this is probably that brittle-ductile transition right now, at 300 degrees C or so.

There are a number of advantages in using The Geysers, as Brian Koenig indicated. Certainly in the high temperature zone, we have hot gas and high hydrochloric acid. You know injection would be a mitigation factor for that.

Another very important thing is that in the vapor phase transport of tracers is extremely rapid. In some of our experiments in The Geysers, in some initial work Mike Adams he injected a tracer in the well and then waited for 24 hours before he started sampling. The tracer peak had already passed at a well over a kilometer away. So if you get this flashing into the vapor phase, it moves very quickly. The potential advantage to us is, we don't have to wait until we retire in order to see the tracer results. We can try maybe an injection, and evaluate whether or not we got we got some interconnection with the reservoir.

Koenig: There is another reason for considering the particular location suggested for this because it is in a currently problematic area in the field for the operator. It is also in an area with numerous production wells whose chemistry suggests they are connected to the same system. So there is an opportunity in the very near term to see if effects are readable in the data that came out of it with respect to tracers for its gas contents, etc.

Hickman: It sounds like you need to exploit natural permeability of a situation like that. So there are some fundamental differences you are talking about in deep injections as opposed to more shallow. Is it likely that in a lot of cases, you wouldn't hit that kind of permeability? You may have to resort to hydrofracturing if you didn't encounter zones of sufficient transmissivity to take the kind of injectate volume you need.

Nielson: You may have to hydrofracture, but we are hoping you don't have to.

Truesdell: I would like to say briefly that The Geysers is a very special case. If you learn something at The Geysers, it will be applicable to The Geysers, but not necessarily to other fields.

Nielson: I think that is in large case true for many of these geothermal systems. They are to some extent unique. I could equally easily do this at Coso, Roosevelt Hot Springs, or any number of places where we have very well defined magmatic hydrothermal stratigraphy. But you've got to start someplace. And by starting at The Geysers I think you can evaluate several different processes that are taking place.

I believe also that you can demonstrate to an operator there that you are providing real value in a near term rather than something where we are going to develop power in 2030. So, this concept may not work. But if it does, you've got 80 percent of the heat down there perhaps that could be extracted that you could get after with existing infrastructure. So, it's probably not a bad bet. Much of what we are going to be doing is going to be process oriented, and we are looking at simulations, we are looking at the concept of growing fractures without doing hydrofracing. We are looking at evaluation of deep injection -- how do you actually do that? We are looking at developing high temperature tracers. So there are enough components I think hanging on to that plus the benefit of actually doing it at The Geysers.

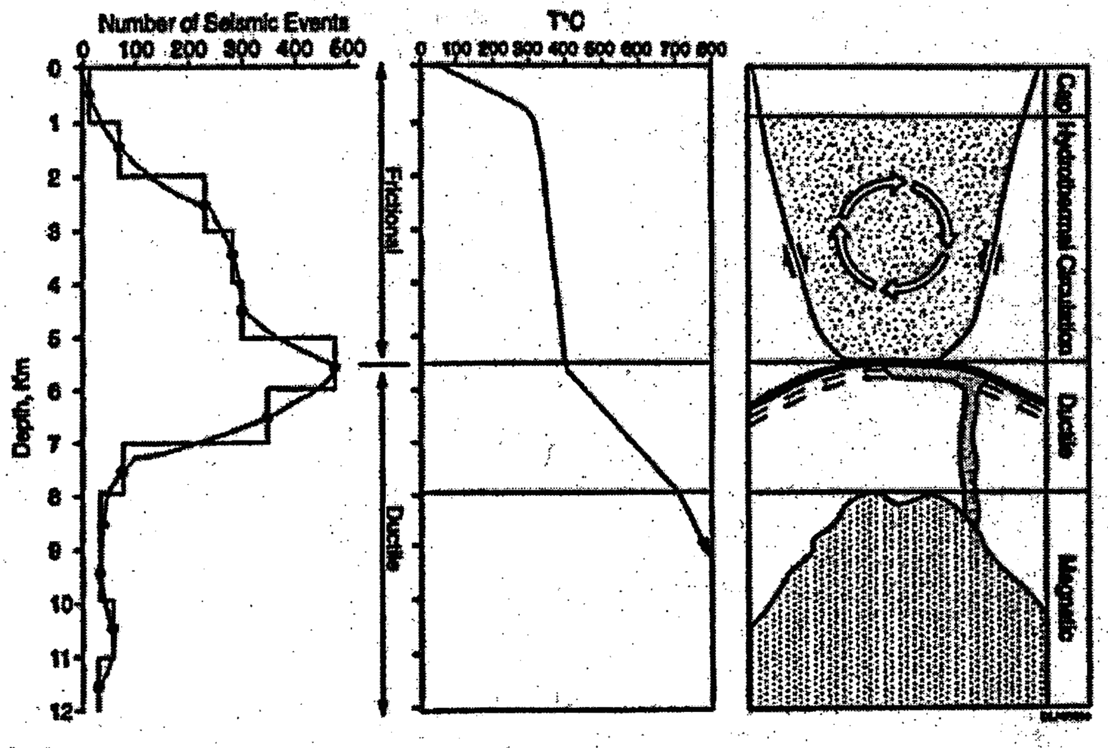


Figure 1. Schematic model for zonation within active hydrothermal systems constrained by data from the Coso system. Zonation is discussed in the text. The distribution of seismic events is from Walter and Weaver (1980) and is consistent with the model os Sibson (1982) for the depth to the brittle-ductile transition. Temperatures are estimates that are discussed in the text.

Figure 2.3-1.

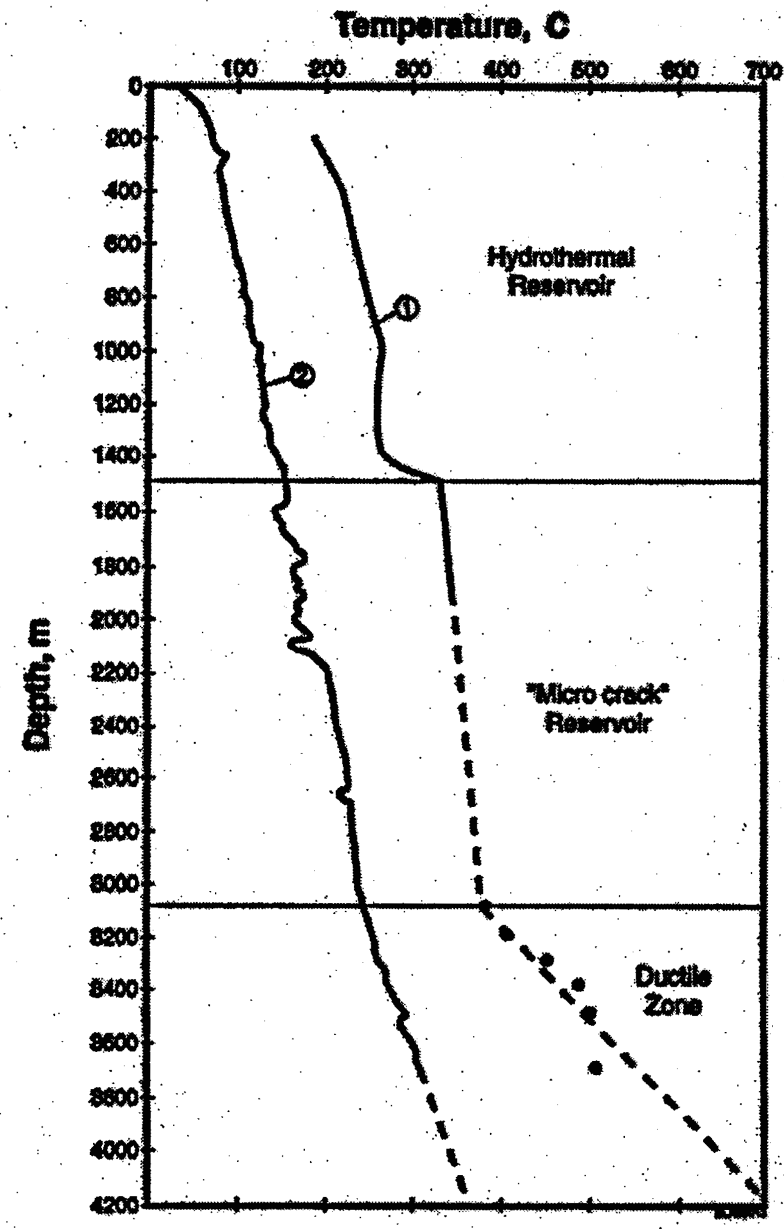


Figure 2. Temperature profile of WD-lat Kakkanda geothermal field-1. Curve 1 shows the equilibrated profile and curve 2 shows the temperature following drilling. (Ikeuchi *et al.* 1996).

Figure 2.3-2.

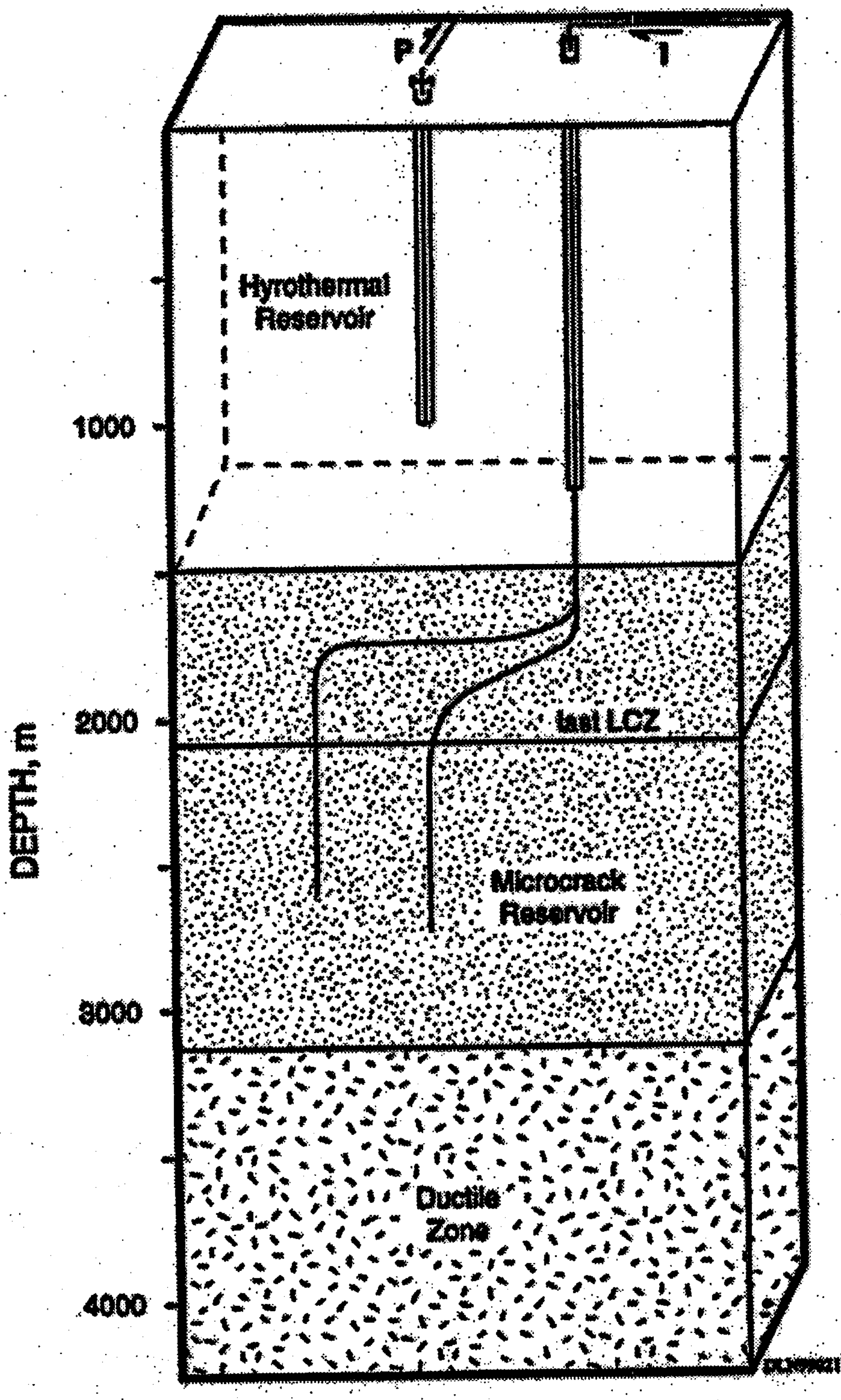


Figure 3. Schematic diagram of injection for deep heat mining.

Figure 2.3-3.

2.4 EGS Research Opportunities at The Geysers.
Brian Koenig, Consultant

I won't bore you with visual aids because I don't have them. The presentation that I was asked to give here was done for Calpine when I was working as a transition employee with them. The slides are in one of their computers sitting up at The Geysers and no one was able to find them.
I'm going to kind of wing it but I'm also going to try to build on some of the questions and things that were posed earlier, some of the issues that were a little bit contentious. One of them, just from the view point of an industry person who has worked at The Geysers. At The Geysers the use of injection has been taking place for about 30 years. Originally it was a disposal option but with time and the changing reservoir conditions it has become a mass-depleted situation.

That has become a very favorable thing with respect to possible EGS work at The Geysers. So putting water in and getting it out is very important because it allows you to make use of heat that still remains in that reservoir in a way that is acceptable. So the SEGP project, which Ann Robertson-Tait addressed, was really an attempt to solve problems that occurred in a public environment with respect to the sanitation district and the steam suppliers who needed a working fluid, in this case water, to extract the heat that was out there. It was a heat mining issue. So injection has been around for a long time.

With respect to thinking about The Geysers, or thinking about regions as I think someone said earlier, we need some regions that have elevated temperatures and possibly limited permeabilities. Just from my own experience and work of other people at The Geysers, I can tell you that The Geysers itself and the region surrounding it may be the perfect vehicle for looking at something for an EGS system. This is because wells have been drilled at distances of miles from the existing Geysers reservoir that is producing and have encountered temperatures of up to 500 degrees F at depths of 10,000 feet, and even hotter. There is a very large region of high heat flow.

I tend to think of The Geysers actually as a permeability anomaly in a very large region of high heat flow. So with respect to enhanced geothermal systems there may be areas around The Geysers, surrounding the current existing reservoir, that would work without risk to the current reservoir. However, I think there are a lot of reasons to consider the current reservoir for enhanced geothermal system operations.

With respect to the injectate returns and the fact that in the SEGP project we are only seeing 30 or 40 percent of them, that's wonderful for a one year operation in the SEGP project--to get 30 or 40 percent of the injectate back. Long term studies using isotopes which allow us to track what is going on in the reservoir demonstrate that over time--periods of 10 to 12 years--we will get back 75 to 80 percent of all the material that we've injected. And I'd say that's a really wonderful return on your investment. And that injection has had a big influence on decline rates in The Geysers. Some of those things that Ann was showing you that have to do with projected decline rates, a lot of the change that occurs with injection, and that I think is principally what's happened with injection, is that it has been mitigating those decline rates. Without injection we would have seen significantly higher decline rates.

Why is the enhanced geothermal system idea potentially important? Not so much because of SEGP, obviously that's been used in the Southeast Geysers in a region that has been produced already. But potentially for what's coming up with respect to Santa Rosa wastewater. We're looking at about a 50 percent increase in the amount of water that's going to be delivered compared to the SEGP project. It becomes important to think about how you can use that water effectively, and from the industry standpoint, mine heat and mitigate other problems that exist in the reservoir. I think this is where the Enhanced Geothermal Systems part of it comes into play with respect to The Geysers.

Two problems that plague The Geysers with respect to development and continued operations have to do with the production of non-condensable gases. They interfere with power plant operation and limit the efficiency of those plants. A second one is the evolution of chlorides, which are corrosive. Probably hydrogen chloride is the culprit here. That hydrogen chloride is generated and produced and in certain areas of The Geysers. With time, that has been getting worse. It can force an operator to spend $100,00 to $150,000 on a single well to mitigate this problem through time. Plus put in maybe $20,000 to $30,000 a year in chemical mitigation measures.

So these are questions that become really important to the operators at The Geysers. So we're looking at heat but we're also looking at worrying about problems that have to do with chemical mitigation of both non-condensable gases and chlorides.

The concept here was to get some feeling for where injected material goes and what happens to it between the time it's injected and where it's produced. The central portion of The Geysers and it contains basically two regions that. The first is what I call the normal reservoir, which is at about 240° C. It's the portion that has been produced from early on. Here there are liquids in pore spaces, flashing and receiving heat as the liquid migrates toward the producing fractures, and eventually becoming essentially steam with no liquid water to encounter.

The second part is called the high temperature zone. Some of this has been actually physically documented, particularly by people at what used to be the Cold Water Creek facility. There, temperatures of up to about 354 degree C have been documented. I believe Alfred Truesdell and associates have done some gas work that suggests there may be a magmatic component to this one. I'm not sure whether that's necessarily what's going on here but certainly there have been documented cases in another reservoir which I'm not sure I'm able to tell about. But high temperatures have been in the Unocal former reservoirs. We've seen temperatures of about 275 to 280°C as well up in the northern end of what Unocal was doing.

So there definitely is a zone in which there are higher temperatures down there. One of the big questions is where is that zone located? How far does it extend under the normal reservoir? And what potential does that zone have with respective to supplying heat in the future for The Geysers? If you could actually target wells to inject materials into that and have surrounding producing wells, you tend to have three potential, really good outcomes from that.

One. You can get a short term return of this material which is injected as a liquid coming back up to you because of the elevated temperature. Thus there is a new heat source. This could expand The Geysers potential heat reserves substantially, maybe fifty percent or more. Two. If this issue of chloride is caused by hydrogen chloride generated in the reservoir, if you are able to get liquid water into this portion of the reservoir, hydrogen chloride loves to be in the liquid water. If it gets into the liquid water and its association into the hydrogen ion which is the culprit that is causing all the corrosion problems, occurs in the reservoir rocks, then it can interact with the reservoir rocks and be neutralized down there. The subsequently flashed fluid would not have the offensive hydrogen chloride species. So again, getting the water down into this source region is a big issue with respect to the operators ridding themselves of a problem that's going to cost them a lot of money each year. Three. It has been demonstrated repeatedly in various parts of the field that the introduction of water can substantially reduce the amount of non-condensable gas produced. In some cases it has accounted for reductions of as much as 70 percent of the non-condensable gas that's produced at well.

Injection looks like a really beneficial thing. The question becomes, how do I figure out where to put it. And how do I determine if this resource is underlain by this high temperature zone, and what is the extent of it? Hence, I guess you would say that in this region--if it is based on what we saw at CCPA- - the permeability is maybe lower there, the temperature is higher, and the fluid saturation is lower. So we could be dealing with a region that would in fact produce higher gases, higher chlorides, and has lower permeabilities and higher temperatures. This is, I think, exactly the kind of thing that people are looking for in the Enhanced Geothermal Systems arena. So I think The Geysers offers a wonderful test ground for that.

So there are a lot of things that are associated with potentially using this Enhanced Geothermal System that make it very attractive. If we can demonstrate that this is the case, we can really look at these things. Because we've determined by studies that the water that we inject down here can show up as far as about a mile and a half away in the reservoir about a year and a half later, as steam. And it has crossed pressure boundaries to do that. So it is not traveling as steam; in fact it was probably as a liquid over long distances - probably through this high temperature zone that's here. It's very intriguing because it suggests that a lot of the water that we poured in, especially in The Geysers and concentrated in the central portion of the old field. We've done that over very long periods of time without degradation. Those wells are some of the wells that have the lowest decline rates and highest productivities in the field. It's very interesting to think about the idea that if that's happening because in fact we are, at least in some cases, tapping into this underlying high temperature zone.

So with respect to this upcoming water from the Santa Rosa project, it is very important for the operators to think: How can I maximize the utilization of this water? And the issue of: Where do I put it? What are the characteristics of the reservoir? In fact, Do I want to drill wells for injection that are deliberately drilled to save four kilometers because we are specifically trying to introduce this water directly into that zone rather than let it infiltrate down through what we consider the normal reservoir into the underlying zone.

So to summarize, The Geysers is in a region of high heat flow where there is a definite permeability anomaly. That is fortunate for the operators because it allows us to produce the reservoir. But the whole region is one that is potentially useful for EGS study. In particular, if the EGS studies can identify the characteristics and extent of a high temperature zone and how to exploit that, it holds a great deal of promise for the operators. And I think for the industry in general with respect to the success and advancement of the EGS program.

2.5 Multi-source Multi-receiver Seismic Measurements. Bjorn Paulsson, Paulsson Geophysics, Inc.

[**Editor's note:** The following report is condensed from the actual presentation. The speech was so interactive with the visual materials that it was impossible to reconstruct much of what was said.]

Paulsson Geophysics is working on high-resolution borehole seismology. We believe that, in order to map fractured reservoirs, we need to have a polarized source, probably a polarized shear wave, and broad band high frequency in both sources and receivers. We are using three-component receivers with broadband response and long range capability, on the order of a kilometer, about 3,000 feet. And we use a very large array, with up to 80 stations, to record a massive amount of data in order to create a large volume image. Our data show this is far from a pipe dream. We have actually started to achieve some very high-resolution results.

The approach basically uses a reaction mass-based source in the borehole base, like a surface vibrator. Most of our data is from an axial reaction mass but we have designs and some thoughts about how to do it in the other two axes as well. The advantage with this polarized source is the radiation pattern is very simple. So when looking at the data, the complexities are generated by the geology of the job and not by our source.

It's basically a point force because our wavelength is much larger than the borehole. In essence, we create horizontal p-waves vertically up and down in the vertical well. For the other two components, the radial reaction mass, we basically have the same radiation pattern. We just tilt it in two other directions. So combining those three motions of the reaction mass, you get three-component motion. That's the complement to the three axes in the receivers. We have had this operational since March, 1997.

Why do we use three-component receivers? There are large differences in the two wave fields recorded by the vertical and the horizontal components. You really need both in order to understand a fractured reservoir. And you really need geophones. If you have just hydrophones, you will not be able to really appreciate the full complexity of the reservoir. (Figure 2.5-1)

The high frequency signals and responsiveness are very important. As soon as you are moving away from the surface of the earth, the surface seismology is typically 70-80 Hz on a good day. But 800 HZ in 80,000 feet per second material is tens of wavelengths. You can resolve less than a meter, 2.5 feet. With the same frequency in shear waves, you can halve the wavelengths and double the resolution.

We also moved away from the surface, went downhole, to avoid the near-surface tremendous noise field. And within the boreholes we find the competent information, which really helps us generate and record the high frequencies.

And here is the full wave field--one thousand one hundred and sixty receiver points. Figure 2.5-2 shows both P-waves, and S-waves. This is unstacked data, which means it is just one sweep of the data points. Normally when you do seismology you stack a number of sweeps to enhance the signal. But we found that it is usually not necessary when you go down a borehole because the noise is so low.

It's important to stress the long range because if you want to cover a large part of the reservoir, you need to have the range. If you are only doing a couple of hundred feet, in my mind you don't have an economic system because you need it in this large volume. In some of our work, the transmission range is almost one mile.

The waveforms are free of distortion because you are moving away from the noise field on the surface. Again looking at the three component wave field we recorded is a vertical component, P waves, shear waves. Interestingly, the shear wave reflections are picked up only on the two horizontal components. We record approximately the same quality of shear waves as we do the p-waves in these boreholes and that's a very rare event on the surface because of the low shear wave modulus.

In terms of the long arrays, we introduced last year an 80-level receiver array. It is very important that in order to analyze the arrivals from a different component, you need to have well balanced sensors. If you have different response from vertical and horizontal components you have a very hard time figuring out what the data means. Our approach was to design a very light weight sensor clamped with a very high force. but small light weight.

Here's where we will go in with large seismic arrays in the future. Less than two and a half years ago we did the first use of all fiber optic layers to form an array. That was a twelve bit system. It was a low resolution system but based on these results we felt encouraged and went ahead and designed the next generation of fiber optic receivers, a 24 bit all fiber optic receiver array. This has no electronics in the borehole. This is just fibers wound around the mandrel. It is mounted on our truck right now and we will test it for the first time in about a week and a half. This technology allows us to put down up to 3,000 sensors in the bore hole in one payload. So that would allow us to put in a massive number of sensors necessary to record at high frequencies. Our first work with fiber optics used hydrophones. In a year or so we will have the same technology available for geophones.

We need to build large seismic arrays for geothermal boreholes. Right now, we have a large one, 80 sensors, but it is a low temperature array. If you want to go for geothermal, you need to develop that for higher temperatures. We just got an SBA grant to demonstrate nine component cross-hole seismology to map fractures, but that was from the DOE natural gas program. We are working with Lawrence Berkeley Lab on that proposal. We will do that survey probably sometime in September or October this year.

Larry Myer: What are the source temperature limitations?

Speaker: The source is designed for 200 C The low temperature limitation on the system right now is the cable, which is 150 C, but the source itself is 200 C.

Steve Hickman: Could you talk about the high frequency imaging which would be good for short fractures and things like that? What kind of interwell spacing are you limited to given the high attenuation expected for six to eight hundred hertz, in terms of cross well tomography? How close would two wells have to be when you are firing 800 hertz or 600 hertz between them to get a good image?

Speaker: I would be comfortable today to go out to 3,000 to 4,000 feet. It's a, they have reversed VSP with this. With MIT, the data there is actually 7,000 feet between the source and receiver. And we recorded at 360 hertz all the way to the end of the surface seismic recorder system. Remember that was on the surface, and the surface noise we shot through 600 feet of till and despite that were able to record 360 hertz. So between the boreholes, I feel confident that we can do 4,000 feet spacing.

[Editor's note: Handouts provided by the speaker are attached after the Figures for this talk.]

Figure 2.5-1.

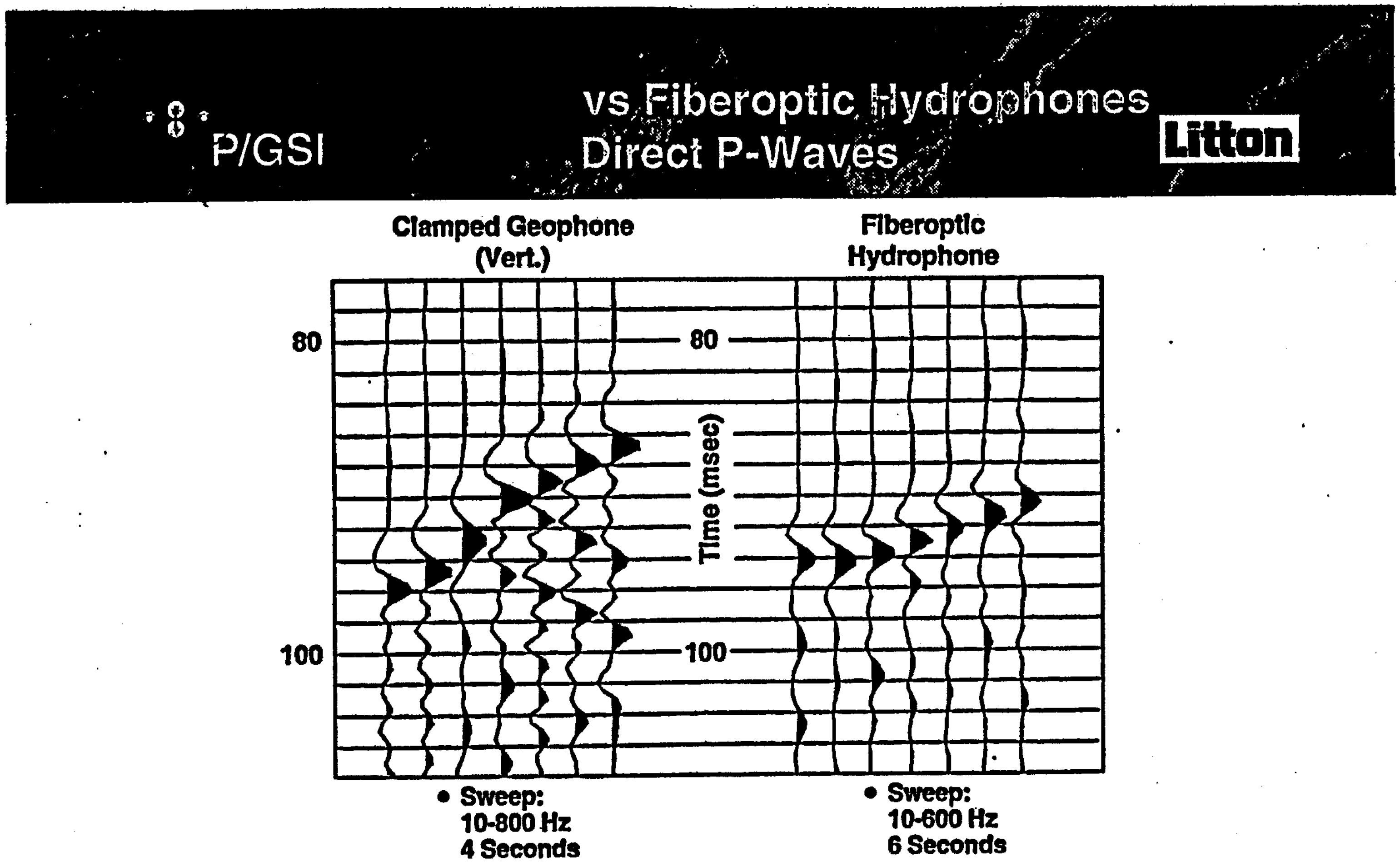
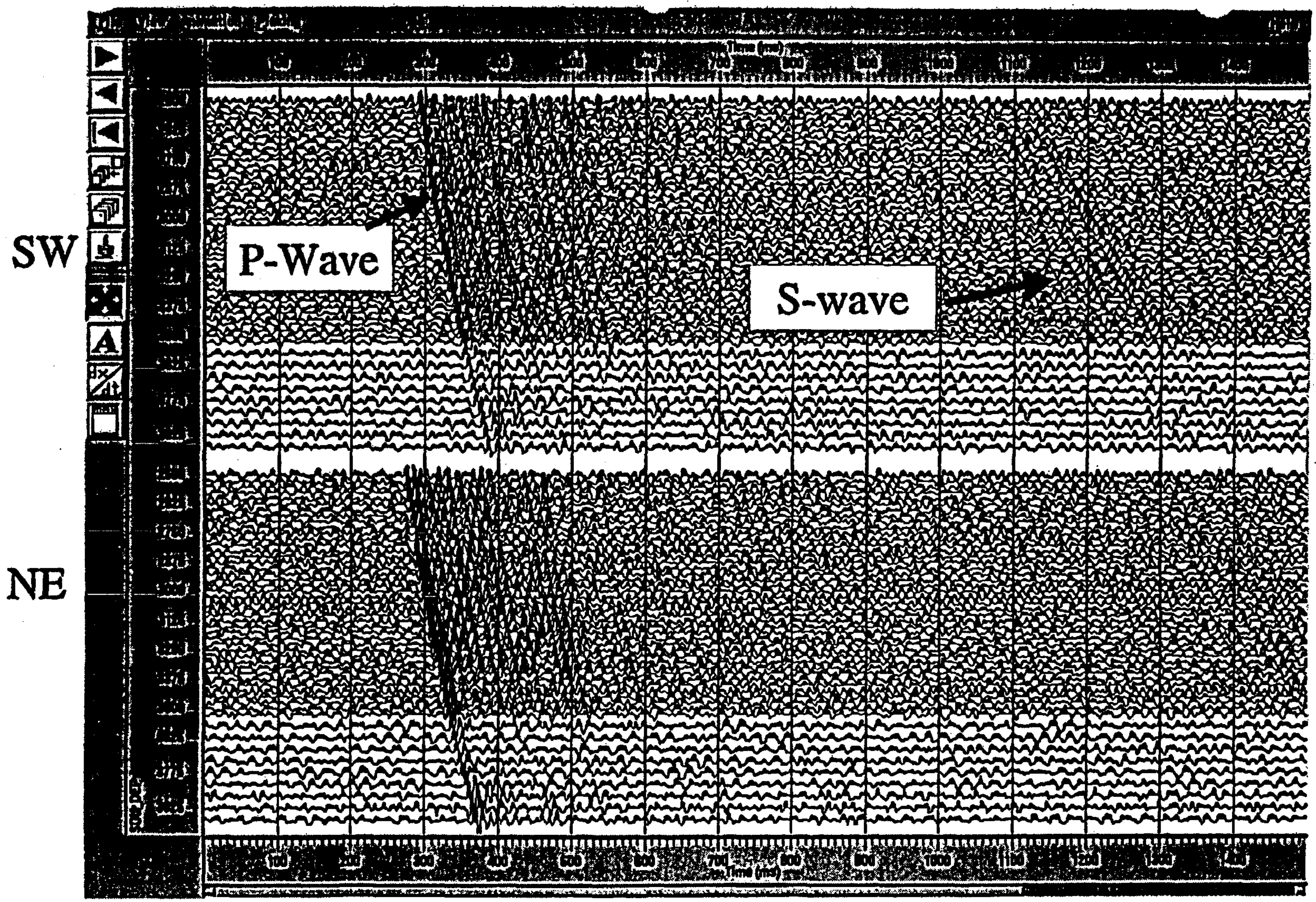


Figure 4. One the left, the P-wave arrivals recorded by the vertical component of a clamped geophone; on the right the P-wave arrivals recorded by the fiber optic hydrophones. Although the total distance between source and receiver is the same the depths are reversed; that is, on the geophone traces the source is at 500 feet, and the receivers range from 140 to 200 feet and on the hydrophone traces the receiver is at 500 feet and the source range from 140 to 200 feet. Note the waveform consistency and symmetry are quite similar, and the preshot noise level for the hydrophones is similar to noise on the clamped geophones.

Figure 2.5-2.



First 1.5 seconds of raw data showing both P-waves and S-waves.

3D and S-wave
Processing of Borehole Seismic Data
From a San Joaquin Valley Oilfield, California
Recorded with a 40-level, 3 component, Clamped Receiver
Array deployed during a 3D Surface Seismic Survey

Survey dates: September 1998

Paulsson Geophysical Services, Inc. (P/GSI)
1300 Beach Blvd.
LaHabra, CA 90631-6374
Phone: (562) 694-7161
Fax: (562) 694-7161

April 13, 1999

Table of Contents

I. Introduction

In September 1998 Paulsson Geophysical Services, Inc. (P/GSI) was contracted to deploy one 40 level, clamped, three component borehole receiver array in a well in a San Joaquin Valley oil field. The objective of deploying the receiver array was to record and monitor the data generated during acquisition of a surface 3D seismic survey. The data set recorded was thus a large 3D VSP data set. The borehole receiver array data was recorded simultaneously with the surface data on the same I/O-II recording system.

The 40 level array is a sub-array of the P/GSI 80 level clamped, three component receiver array for boreholes.

II. Surface Base map with source locations and the receiver well

Figure 1 shows a map of the seismic source locations and the receiver well location. There were 262 shots recorded into the receiver array. The source point locations of the first 91 shots recorded on the P/GSI array are shown at the top (North half) of the map. These source points were recorded on the first day of data acquisition. Sometime between day one and day two of the data acquisition a short tubing segment in a geophone clamping pod failed at a heat crack caused by an incorrect weld. The array fell to the bottom of the borehole separating the seismic cable in the process. The array was easily fished in less than 3 hours, and without removing the array from the well, the array was re-deployed with 28 receiver levels still in the borehole. There were 171 shots recorded on the 28-level array. The receiver depths for the 40-level array ranged between 90 ft and 2040 ft at an interval of 50 ft. The first live channel on the 28-level array was also at a depth of 90 ft and ended at a depth of 1440 ft, also at a receiver interval of 50 ft.

The welding procedure that caused the tubing to fail has been corrected and all of the equipment has easily passed required strength tests.

III. Examples of data recorded during the survey.

Figure 2a shows the vertical and two horizontal components from FFID 484. The source location was 2212 ft NNE of the receiver well. The figure is shown with a single scalar for the entire screen so amplitudes can be directly compared. An interactive hodogram analysis was done on the H1 and H2 components for the purpose of rotating the two horizontal components. The H1 and H2 components for the purpose of rotating the two horizontal components. The H1 and H2 components in Figure 2a are the rotated data. The goal of the rotation was to simulate the recorded data as if one of the horizontal components had been pointing in the direction of the source at the time of recording and the other horizontal component had perpendicular to the first horizontal component. The vertical component was unchanged by the rotation but it is shown here for later comparisons. A sign that the rotation was successful is that the direct P-wave recorded on the two horizontal components has been projected almost entirely on to the component pointing toward the source (H1 in this case). There is very little direct P-wave energy left on the H2 component.

Evidence for S-wave Anisotropy and High S-wave Reflectivity

A striking feature of Figure 2a is that most of the direct S-wave energy arrived on the H2 or crossline component and that the S-wave arrival is at least 30 ms earlier on the H2 component than on the Vertical component. This may mean that there are anisotropic conditions, at least with respect to S-waves. Another very important feature of the data in Figure 2a is that the S-wave reflectivity appears to be higher than the P-wave reflectivity. For example, a high-amplitude S-wave reflection must be the high-amplitude downgoing S-wave recorded on the H2 component because the amplitude of the upgoing wave on the H1 component is higher than the downgoing wave on the H1 component. This conversion of S-wave energy at the reflecting interface is evidence of anisotropy, perhaps caused by fractures.

At least as interesting as the S-wave conversion is the fact that the downgoing P-wave first arrival does *not* generate a strong P-wave reflection at a depth of 1600 ft. There are many other locations at which S-waves are reflected in the data but for which there is no proportionally large P-reflection.

The richness of the reflected S-wave field is seen better in Figure 2b in which the data in Figure 2a was velocity filtered to preferentially remove downgoing waves with apparent velocity range of 2500 ft/sec to 300 ft/sec, a dominant downgoing S-wave velocity. The upgoing S-wave reflections are very apparent, particularly on the H2 component.

The data in Figure 3 is from a shot on the West side of the 3D seismic survey 3531 ft NW of the receiver well. This shot record contains only shear wave arrivals. The reason for the lack of P-wave arrivals is most likely free gas distributed in the diatomite pore structure. This will increase the P-wave attenuation and lower Q to the extent that P-waves do not propagate. The gas does not affect the shear rigidity of the formation so the Shear waves propagate as well in the formation with gas as in the formation without gas.

From the above data there are three ways in which S-wave seismic surveys might prove to be an important alternative to P-wave seismic surveys at this site.

1. S-wave survey might provide images in parts of the field in which there was little or no transmission of P-wave energy as document by the borehole data.
2. The appearance of S-wave conversions and differences in S-wave travel times on horizontal receiver components suggest anisotropy may be present in the rocks which may in turn be related to fractures. Fractures are an important oil production parameter. An S-wave seismic survey may giver a clear indication of the orientation and density of fractures.
3. Given the high level of S-wave reflectivity observed in the VSP data, S-wave reflection surveys might provide high-quality structural and stratigraphic information to supplement the P-wave data.

Obviously 3-component geophones (or at least 2-component horizontal geophones) would be needed for an S-wave survey at this location since the energy shifts easily between transverse and inline components.

IV. Map Views of first arrival energy

In this section maps are presented showing the average energy (mean squared amplitude in a window) for first P and S-wave arrivals at a constant receiver depth. Figure 4 shows P-wave first arrival average energy at a receiver depth of 1,240 ft below ground level. Note that the western-half of the source locations did not result in a P-wave first arrival so the average energy values are set to 0.0, but the source locations are shown. In spite of there being only a few source points immediately North of the receiver well, the shape of the contours is fairly concentric. Figure 5 shows the S-wave first arrival average energy at a receiver depth of 1,240 ft. The contours are not nearly as concentric as the contours for the P-wave energy in Figure 4. Probably it is not a coincidence that the orientation of the contours in figure 5 is to Northwest-Southeast, roughly collinear with the axis of the anticline.

V. 3D VSP-CDP Transform images using P and S wave reflections

The shorts in the Northeast quarter of the map were processed to create a 3D P-wave structural reflection image. The following processing steps were applied to the vertical components of the shot records.

- Geometry assignment
- P/GSI's wavefield separation to remove downgoing P- and converted arrivals
- Bandpass filter (8-12-60-80)
- AGC (350 ms mean scalar)
- First break top mute
- Bottom mute to remove data after the S-wave arrival
- P/GSI's 3D VSP-CDP Transform using velocities derived from near-offset VSP shots
- Depth-to-time conversion
- Bandpass filter (8-12-60-80)
- Time-to-depth conversion
- P/GSI's 3-trace spatial mix (1 trace to each side of a center trace, total of 9 traces)
- Display (entire screen scaling)

Figure 6 shows a 2D slice from the 3D image. The 2D splice is oriented South (left side) to North (right side) and is just North of the receiver well. The image location is noted on the map in Figure 1. This image contains many reflections with structure. The reservoir is at a depth of about 2000 ft on the left side of the image. The distance between data traces is 50 ft.

Data from the Southwest quarter of the map contained no P-wave arrivals but the S-waves were strong, though a bit spatially aliased because the survey had been designed for P-waves. The same processing flow shown above was applied to the S-wave short records in the Southwest quarter of the map. The velocity field for the 3D VSP-CDP transform in this case, however, was derived from S-waves first breaks on near-offset shots. Also the velocity filter only removed the downgoing S-waves.

Figure 7 shows the resulting S-wave reflection image in depth. The data image shows some dim reflections which gives us reason to think that a survey designed to generate and record S-waves might be a good way to generate reflection images. This is an extremely important fact given that roughly half of the shots recorded by the P/GSI receiver array contained only S-wave data and the surface data is reported to be very poor to the West side of the survey.

V. Conclusions

The conclusions to be drawn from this work are important to future seismic work in this San Joaquin Valley oil field.

1. Roughly half of the source records that were recorded on the P/GSI borehole seismic array contained no P-wave direct arrivals, only S-wave arrivals. The shot records with no P-wave arrivals correspond to shot points in the Western half the survey area. The fact that S-waves *do* propagate through the sediments suggests that surface imaging of the reservoir may need to be done with an S-wave source, or at least with horizontal geophones using the S-wave energy that is generated by the "P-wave" sources. We know from this dataset that the S-waves can be recorded on borehole seismic arrays. We also know that the vertical S-wave velocity gradient is lower than the vertical P-wave velocity gradient from measured travel times and shot records in which the turning ray depth of the P-wave and S-wave first arrivals are at different depths. This can only be a result of having a different vertical velocity gradient between the P-waves and the S-waves.

2. P-wave reflections recorded on the borehole array can be used to image the subsurface in a radius at least 1400 ft around the well. Longer shot offset shots could allow imaging further from the borehole. If the P/GSI 80 level array had been used higher frequencies could have been recorded without aliasing the data.

3. The S-wave reflectivity is different, and higher, than the P-wave reflectivity. An S-wave reflection survey would generate a reflection image that is different than the P-wave reflection image. The combination of the two images were both P-wave and S-wave reflections are present would provide more statigraphic information than either of the two images could provide alone.

4. S-wave reflections can be used for imaging. If data acquisition parameters were optimized for S wave they may allow S-wave imaging of even the area to the west of the receiver array. Closer spacing of the receiver pods in the borehold would greatly enhance the usability of the S-waves. This could have been achieved by using the 80 level array with a vertical spacing of the geophones of 25 ft rather than 50 ft that was used during the survey.

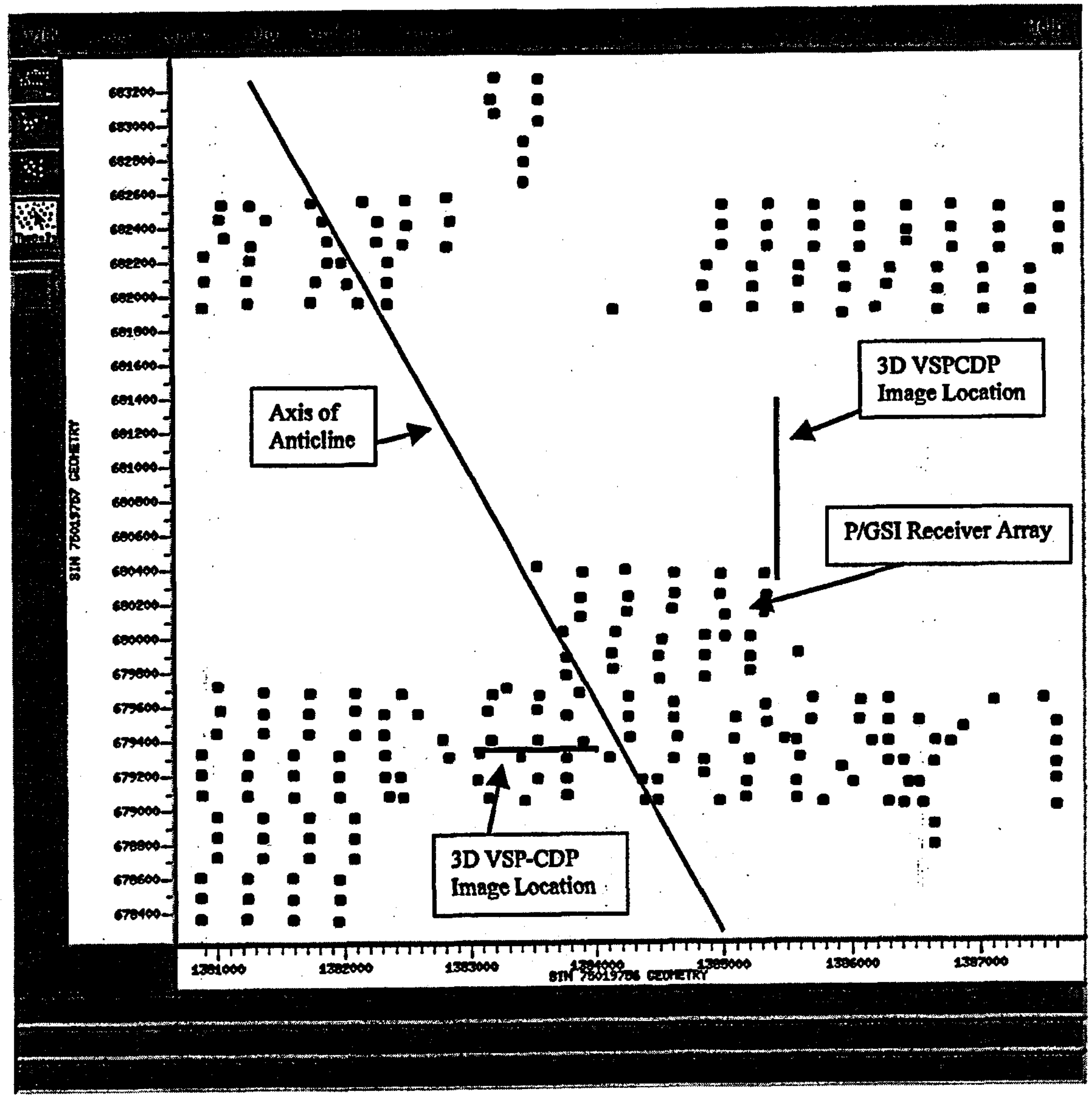


Figure 1. Shot location map of 3D survey area. The black dots are shot locations. The location of 2D slices that are shown in other figures are plotted as well as the approximate axis of the anticline.

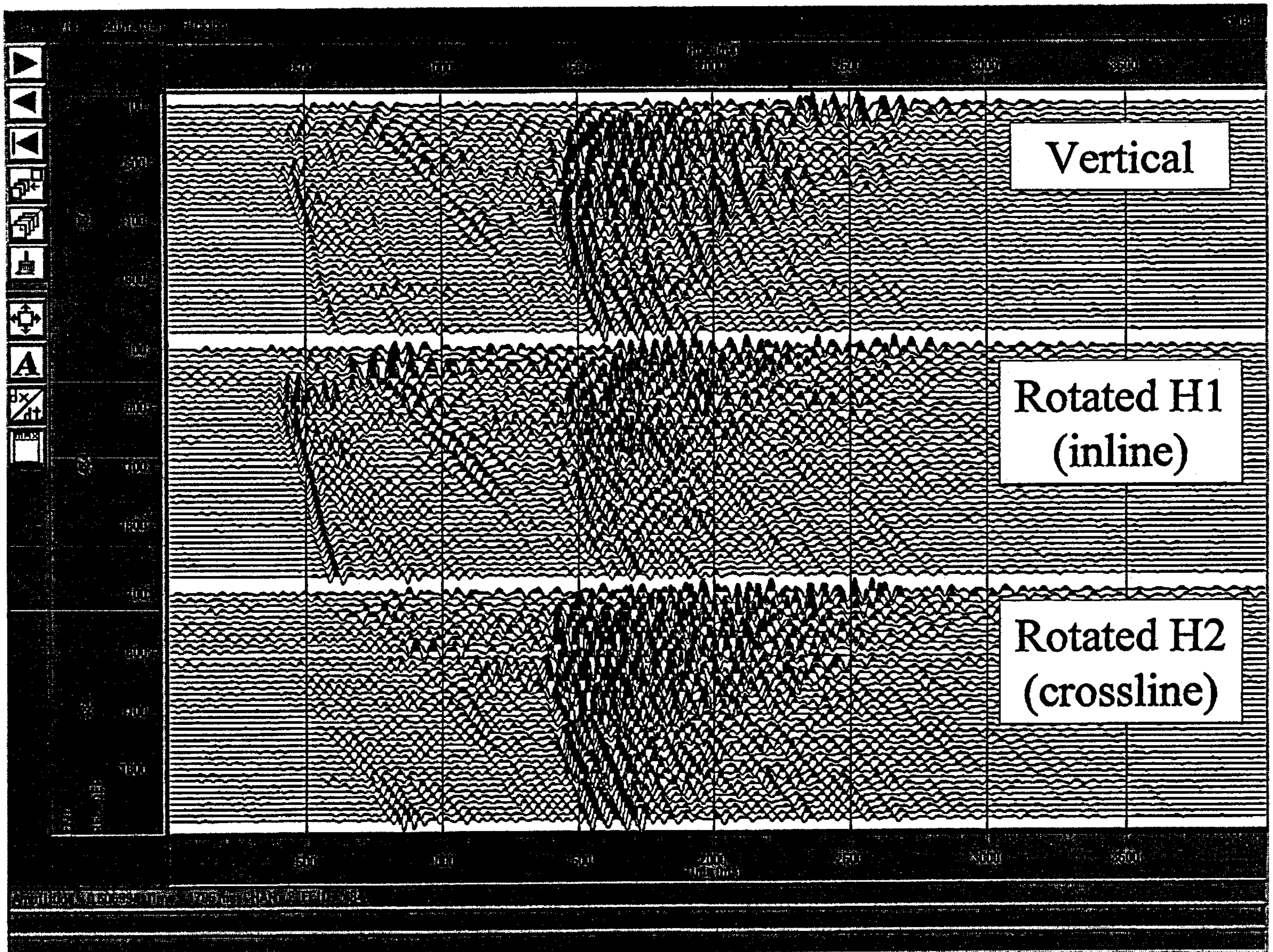


Figure 2. Vertical and rotated H1 and H2 components. Most of the direct S-wave energy is on the transverse H2 component.

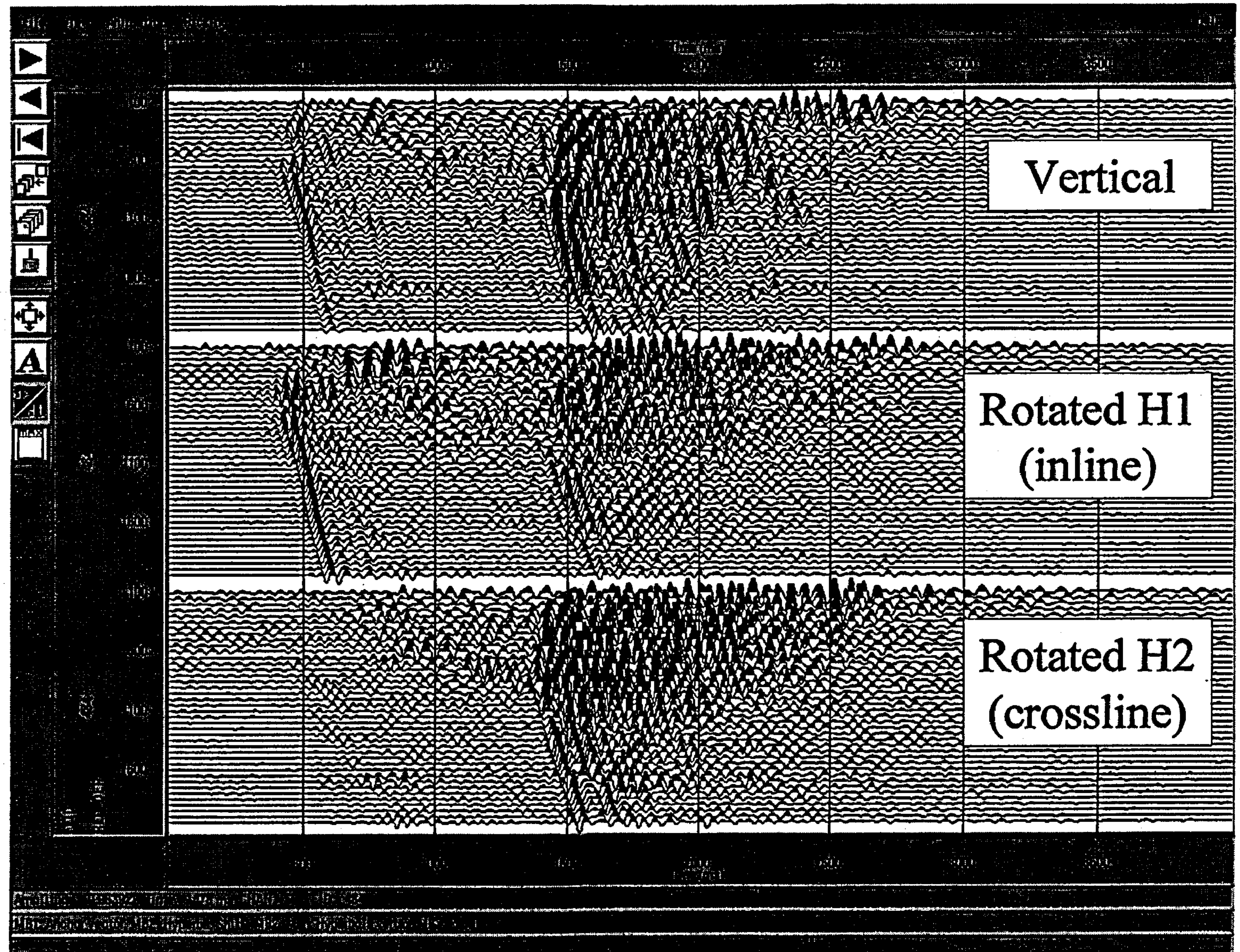


Figure 2b. Same data as in Figure 2a with some downgoing S-waves removed revealing more upgoing S-wave reflections.

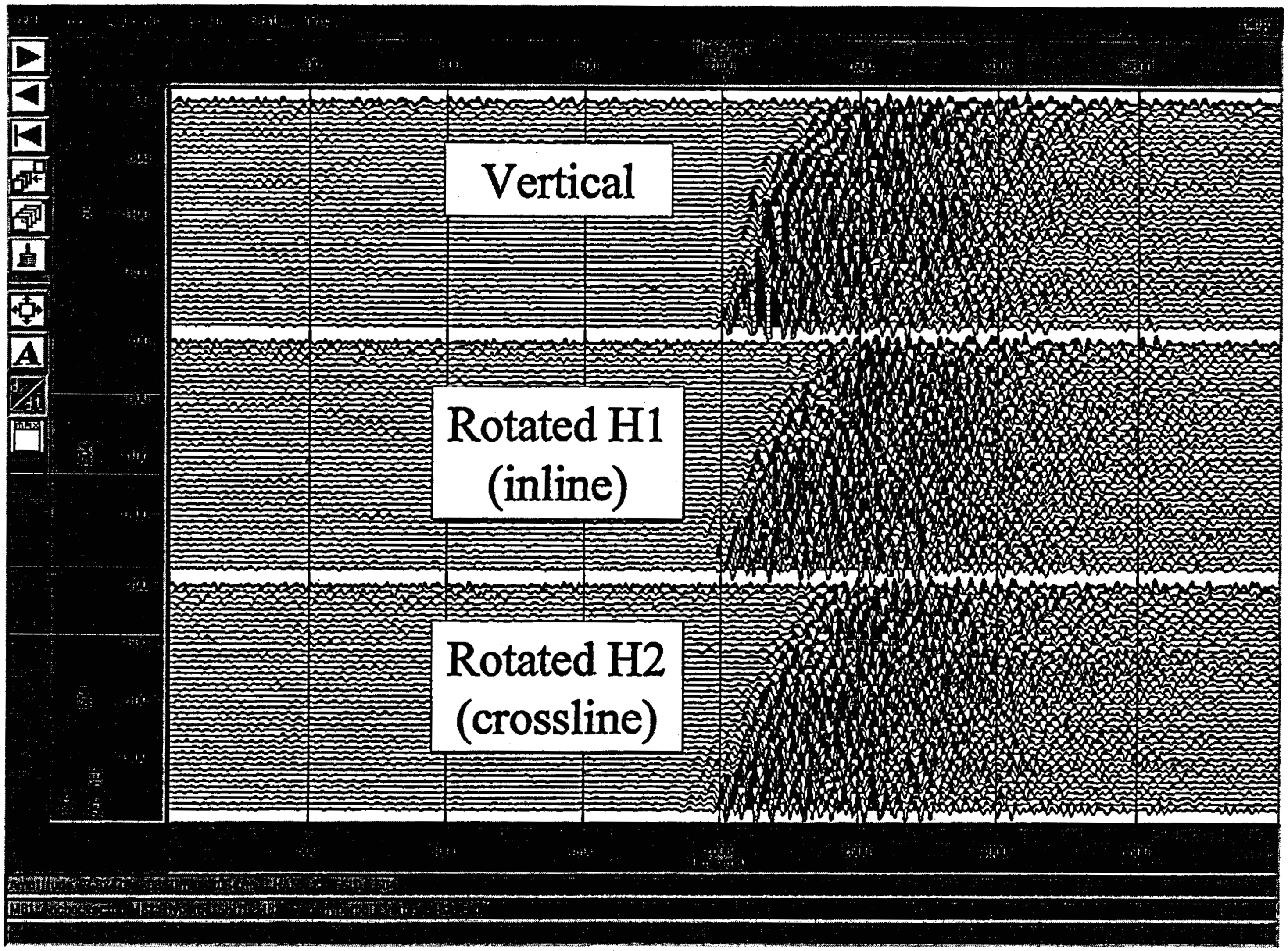


Figure 3. This shot record shows the three oriented components from a shot in the Northwest quarter of the survey. The H1 component is pointed toward the source. The first arrivals are all S-waves. P-wave arrivals are not generally visible in shots from the West half of the survey. Note the first arrivals are up-going waves. Offset of the shot from the receiver was 3500 ft.

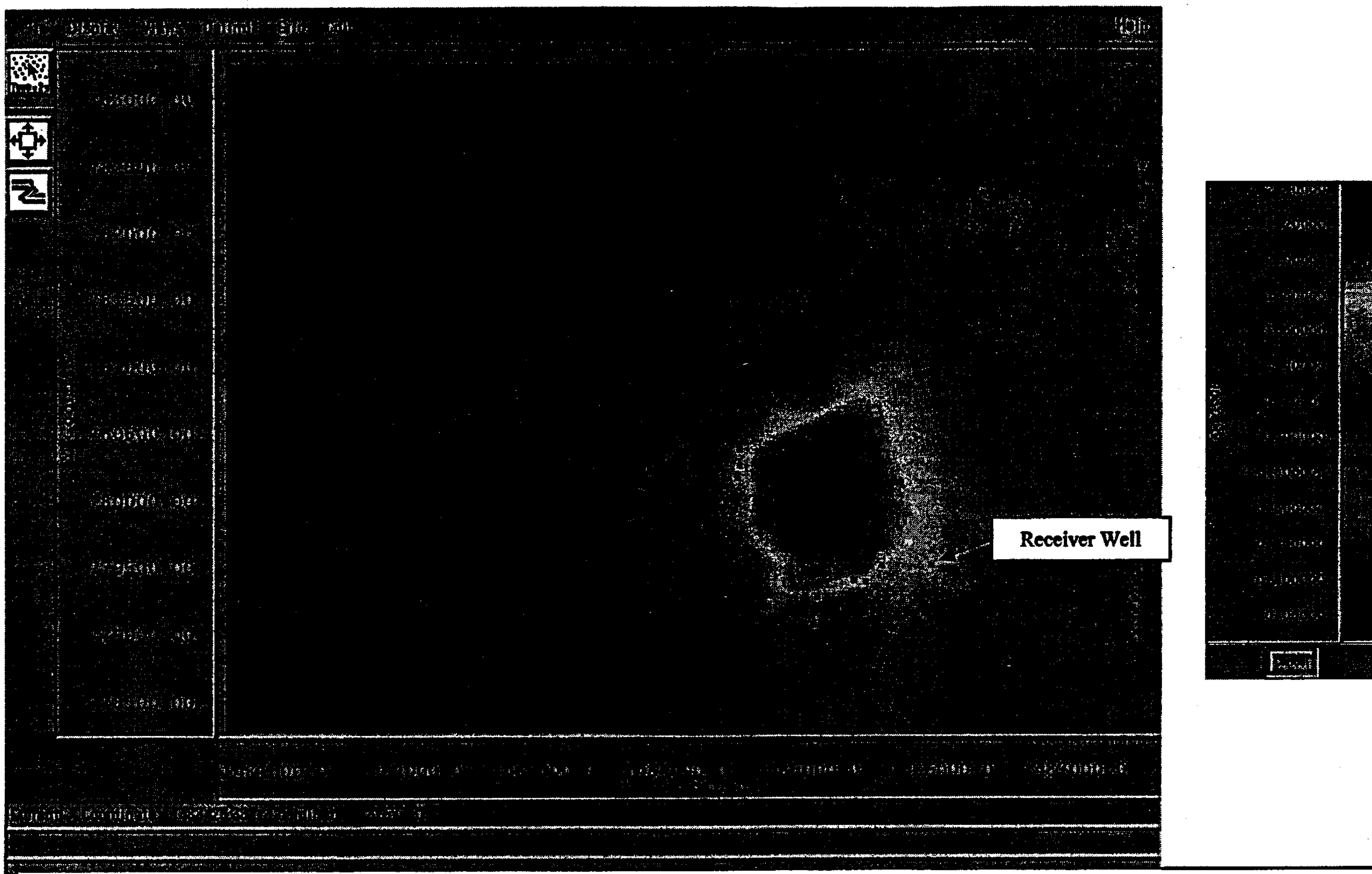


Figure 4. Surface map of average P-wave first arrival energy at receiver elevation -860 ft (depth 1240 ft). The black dots are source locations and represent the control points of the plot. The plotted values are the log (base 10) of the mean squared amplitude in a 200 ms time window around the first breaks. The dark blue on the left of the plot is due to there being no P-wave signal received. These zones are assigned a value of 0.0. In flat-lying isotropic layers the colors would form concentric circles around the well.

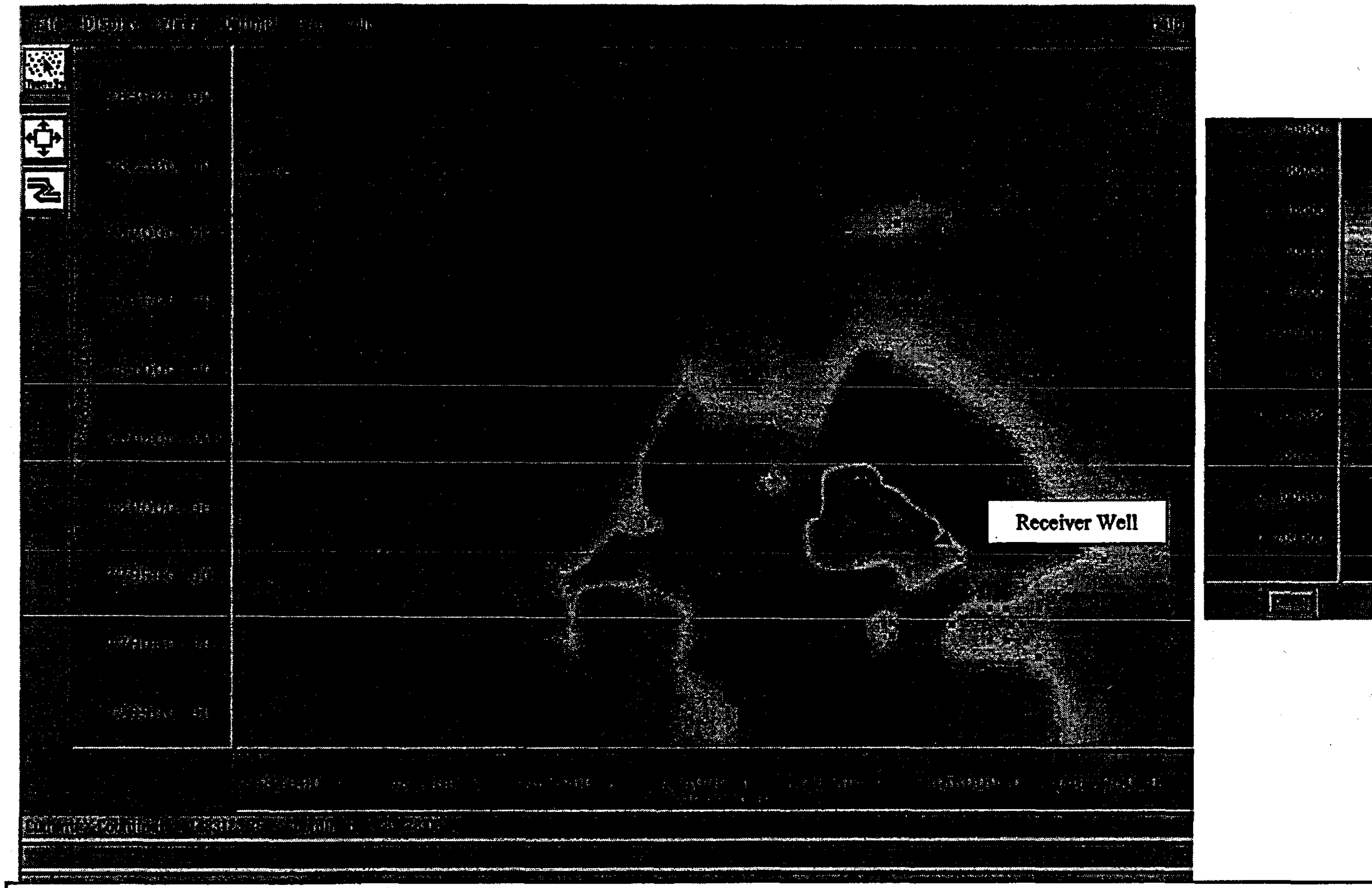


Figure 5. Surface map of average S-wave average first arrival energy at receiver elevation -860 ft (depth 1240 ft). The black dots are source locations and represent the control points of the plot. The plotted values are the log (base 10) of the mean squared amplitude in a 200 ms time window around the first breaks. In flat-lying isotropic layers the colors would form concentric circles around the well.

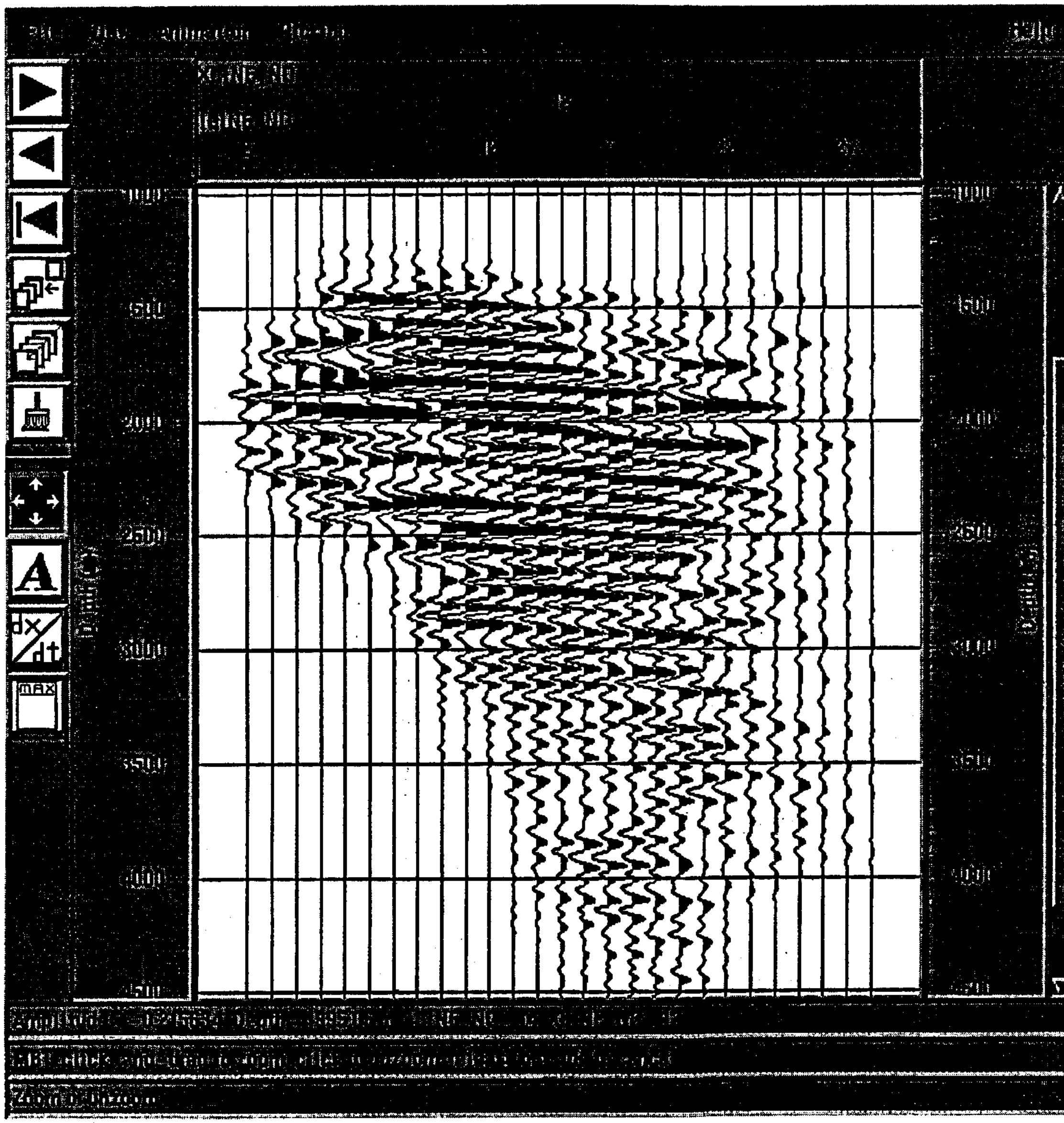


Figure 6. A South (left) to North (right) 2D slice from a 3D VSPCDP transform. The image was generated from the shots in the Northeast quarter of the survey. The trace interval is 50 ft and the depth is in ft (not meters as indicated on the ProMAX display).

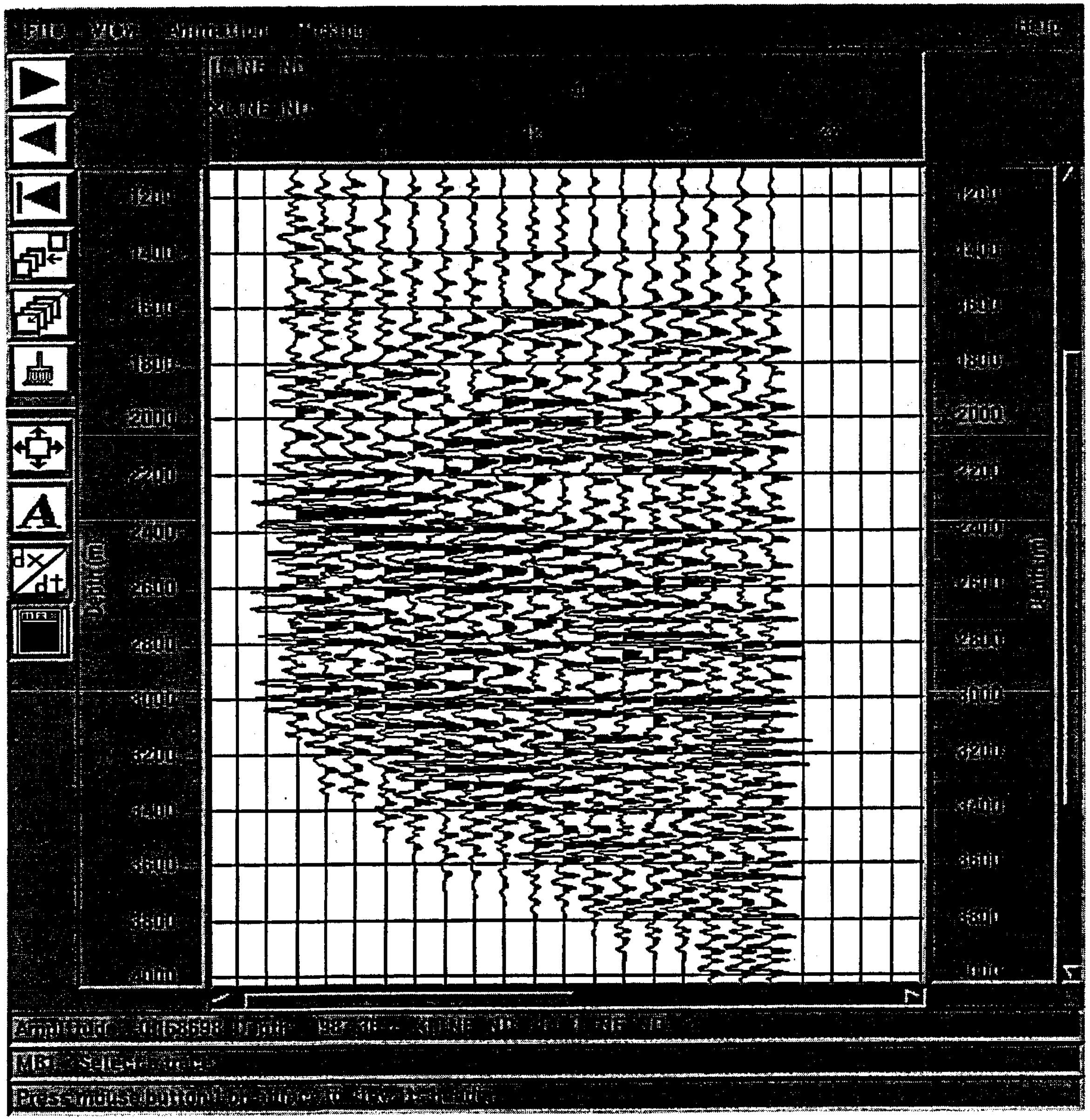


Figure 7. S-wave image from shots in the Southwest quarter of the survey. This image is a preliminary result but shows that reflection signal can be extracted from the converted S-waves. The image is near the crest of the anticline.

2.6 Modeling the Hijiori HDR Reservoir.
Dan Swenson, Kansas State University

I want to briefly discuss what we've been doing with the Hijiori, Japan, hot dry rock (HDR) reservoir.

The first point is how important it is to actually work with real reservoirs, to understand what is going on. The second point is how important, at least at Hijiori, that flow on fractures is for the reservoir performance, and so it's important to be able to model that to understand that. Because fractures are so important in a place like Hijiori, it's important to be able to detect fractures, to detect the flow in the fractures so that we maybe get some idea of technologies we want to develop. I want to show some 3-D visualizations of Hijiori which will indirectly show how that's important.

This is a plan view of the Hijiori reservoir (Figure 2.6-1). The reservoir is at the southern end of a caldera. There are these steeply dipping ring fractures around the caldera that the reservoir intersects. In the plan view you can see fractures that have been identified. Figure 2.6-2 is a vertical view looking north, east is to the right side.
The well in the east is HDR-3, a producer. The well on the west is HDR-2A, another production well. The well in the middle is HDR-1. It is cased down to an injection interval of about 2,200 meters deep. So, HDR-1 is the injection well. Both of the production wells are open down to about 1,500 meters.

The Hijiori team has some really nice data that they have recorded during their testing. Figure 2.6-3 shows the PTS data for the well on the west, HDR-2A. I want to point out a couple of things.

First, this is the spinner data. The left part is where the well is shut in. You can see they actually have a lot of recirculation when the well is shut in. During the operation there may be flow to two fractures. A lower fracture which is about 21 to 50 meters and a higher fracture here, and there are a couple little fractures that see flow in between. But the point I want to make from this spinner data is there is very distinct flow in the fractures.

Second, from the temperature log data in the Figure you can see the important thing is how much cooling they actually get at that lower fracture as they are testing. And this happens in tests about 20 days long. So they drop about 30 degrees C in a relatively short test. So the important thing is to get flow on fractures and that flow on fractures has a lot of consequence to what the production fluid temperature is.

If you look at the well on the east, this is HDR-3, Figure 2.6-4. Again in this well there is distinct fracture flow. This well doesn't have as direct a connection, and you can see it hasn't cooled off as much. We have done previous 2-D work, and in preparation for developing a 3-D model of this, we were looking at this fracture data. One thing that we noticed, which I don't think has been noticed before, is that if you take the HDR-3 data, shift it down about 150 meters, you start getting good correlations of the flow paths across the fractures. So that you can see there's a very strong flow here and in HDR-3 there's a very strong flow, and so you can see, one, two, and at least four common fractures that look like they intersect both of the wells.
The second important thing from this picture is that there appears to be a fracture below HDR-3 that is not intersected by HDR-2. So there is the possibility that penetrates additional reservoir volume. This is on the southern end of the caldera, and it's dipping about 70 degrees from the horizontal. If

you assume that as a fixed 70 degree dip, then this can give you the strike because you know the two points at the wells. If I want to make this point correlate with this point in the two wells, there is a vertical distance that I know, and so I can rotate my fracture keeping the dip constant until I get the proper vertical displacement. And if you do that, you get a strike of about 62 north, 62 degrees east. Eric Davis and I were comparing notes at an earlier break, and he me that this is one of the fracture sets that Pinnacle Technologies has detected at Hijiori using tiltmeters. And so, this builds up the idea that, yes, you can develop this kind of conceptual and practical model of the fractures.

Remember how HDR-2 cooled off so much. If you are injecting into HDR-1 (we are looking at it in 3-D), if we inject cold water right here it's just runs right down the hill, down the bottom of the production in HDR-2A. So there are a lot of things that can be explained by looking at these kinds of pictures. Another thing it does is allow you to start to think about what can you do to make the production different. For instance, one thing you could do is to make the injection of HDR-3 and let the water run down hill into the production part of HDR-2, so there is a possibility of maybe changing the operation strategy.

So, to summarize, here are the four points I wanted to emphasize. One: you really need to work with real reservoirs. Two: fractures are really important and completely dominate the flow in some situations. Three: because of this, you need some mechanisms for detecting flow in fractures. For instance, tracers would be very important, and tracers not only just at the top, but actually downhole tracers so that you can actually look at the intervals and individual fractures as they produce the tracers, and the PTS data are very important. Four: the 3-D kind of modeling can help you visualize it and really start to see how that reservoir looks.

Entingh: At the 4th European Hot Dry Rock conference in 1998 in Strassburg, France, I learned that the Soultz HDR project of the European Commission is located in what is an old oil field in northeastern France. The project staff said they had lots of structural information from hundreds of oil wells, from which to work to decide where to go to try to find hot fluid. Hijiori is also well characterized in many ways. There's been a lot of work there, four wells, many downhole surveys and so forth. Is that going to be the typical case? Are we going to have this much information in many of the fields where we would want to work?

Swenson: Obviously, at the beginning you don't. And I think that's part of the problem. I know you want to be able to predict the production you are going to get out of an individual site. At least with hot dry rock, it appears there are many different sites that always surprise you when you go into that site.

The Hijiori site behaves much differently than the Fenton Hill site where they had very tight (impermeable) reservoir rock. The Soultz site is a much more open formation, and apparently, it has water cross flowing through the reservoir, and so they take the water out, and they pump the water back in, but the water they take out is not the same water that they just put in. I think what's important is that you start with an idea and as you get more information you can then develop your concept of the reservoir. So you have to have this interplay between data gathering and reservoir modeling which then should help you operate the reservoir.

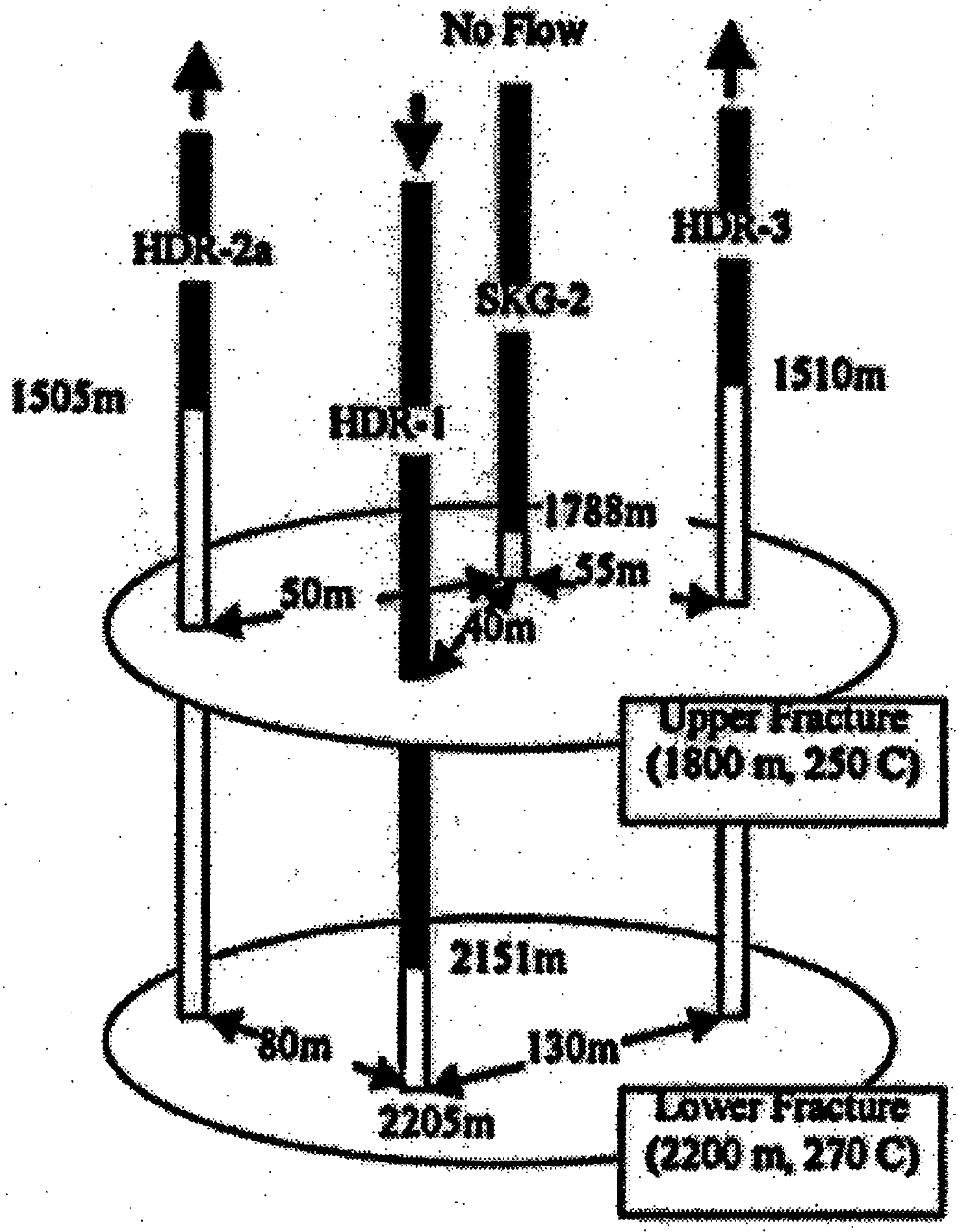


Figure 3: Schematic of wellbores during 1995 and 1996 testing

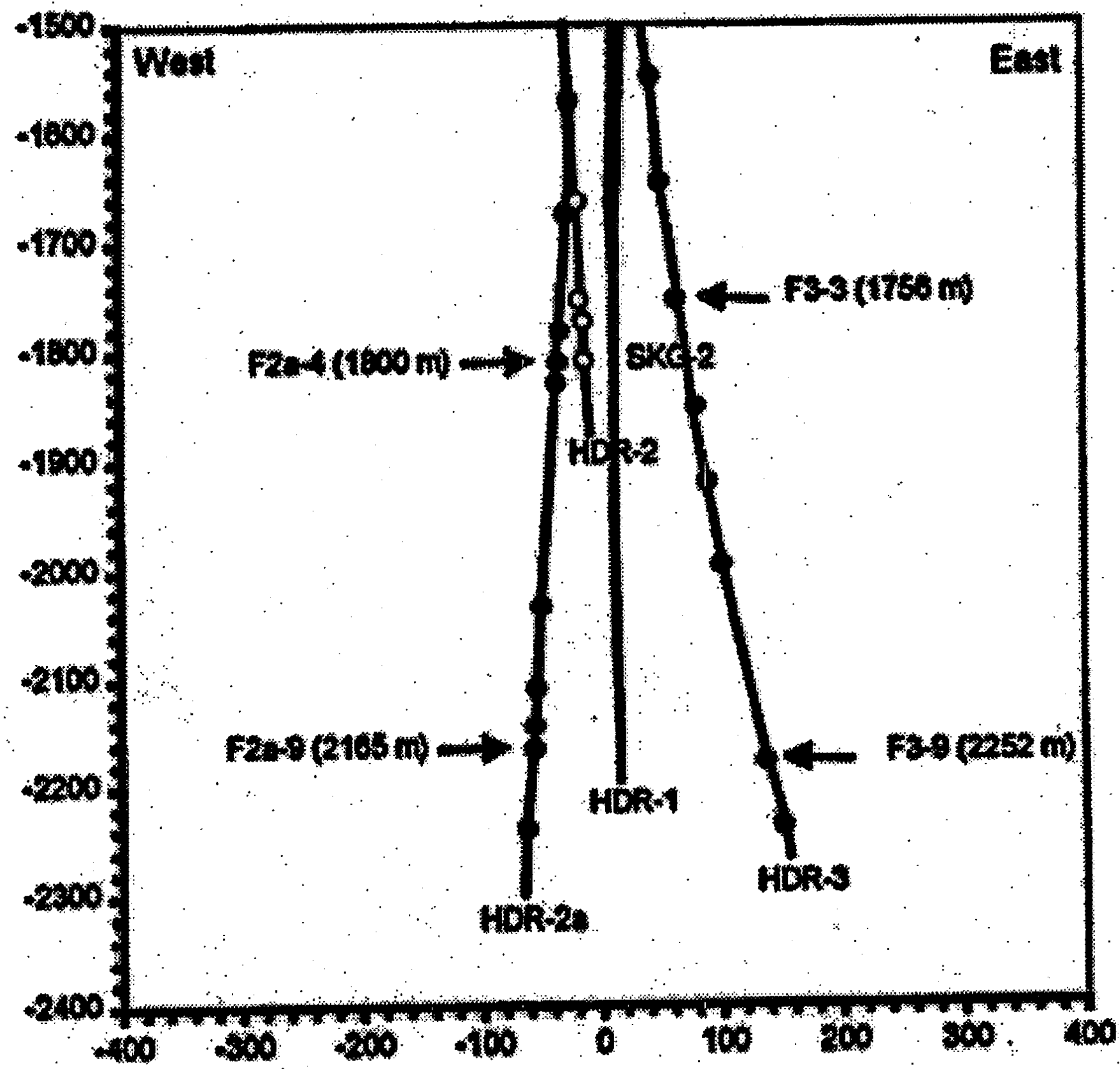


Figure 1: Vertical section of Hijiori reservoir. Dots indicate fracture intersections with wellbores.

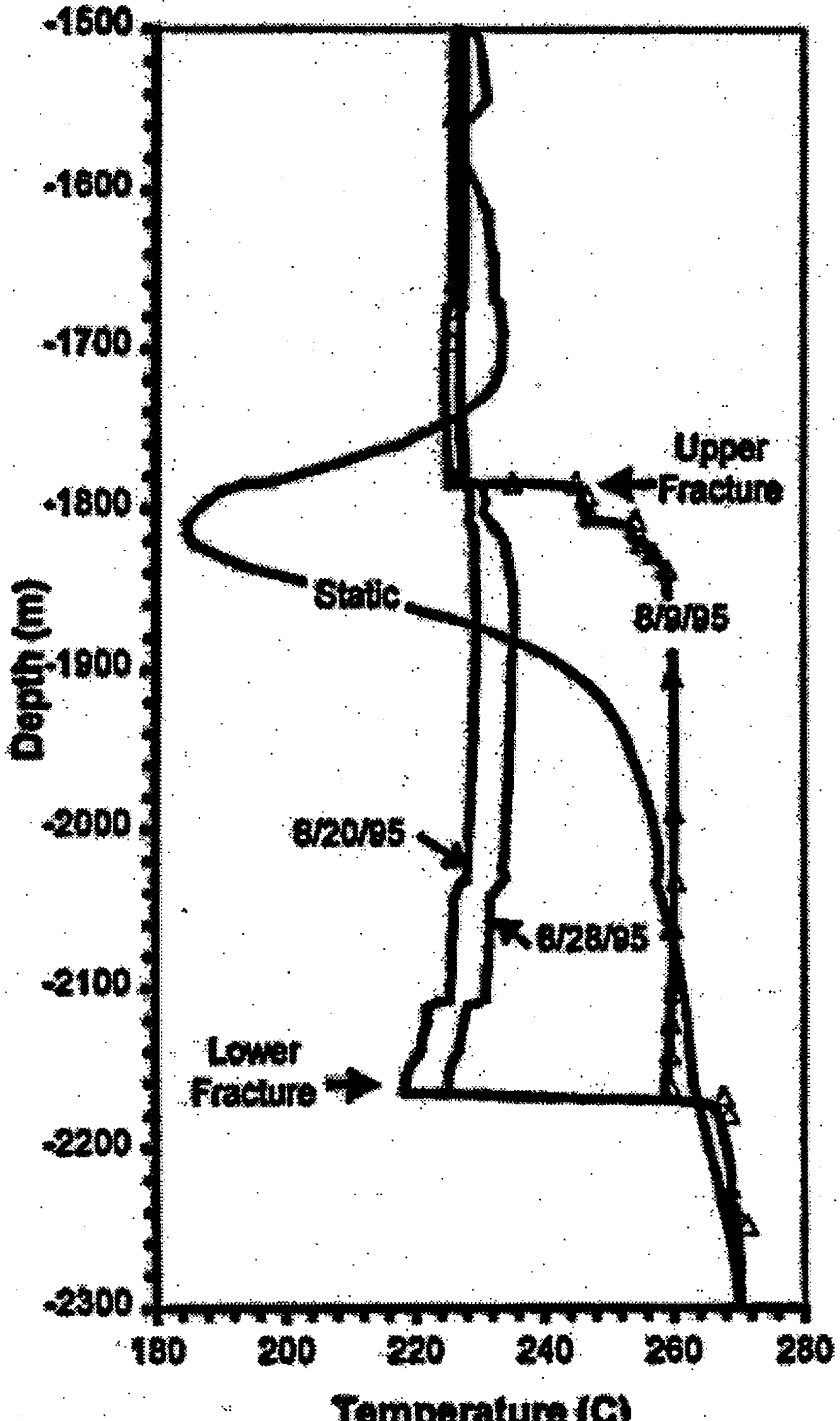


Figure 6: HDR-2a temperatures before and during 1995 testing (triangles are WELF97 results)

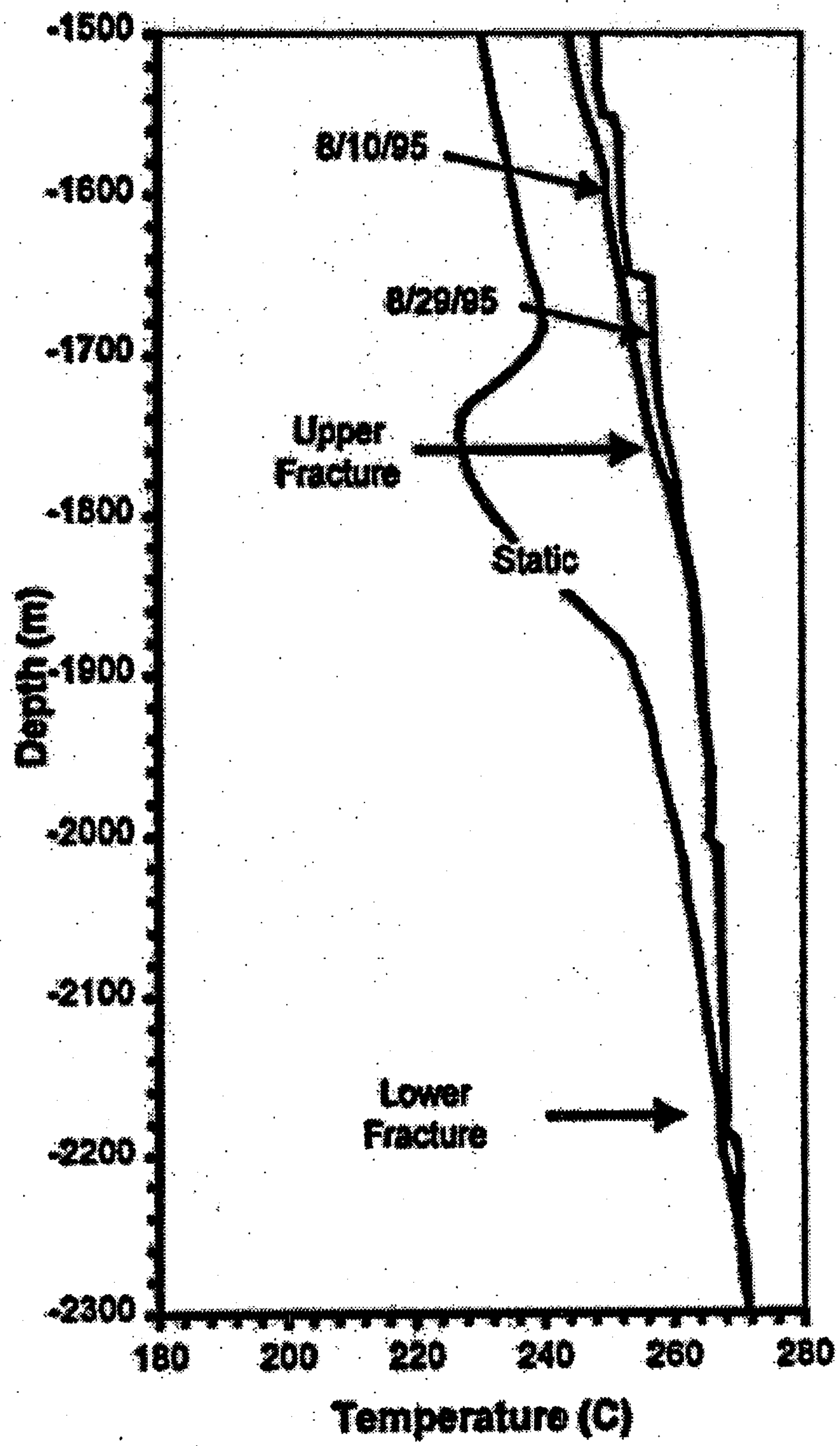


Figure 8: HDR-3 temperatures before and during 1995 testing

2.7 Geophysical Measurements in EGS.
Brian Bonner, Lawrence Livermore National Laboratory, and Larry Myer, Lawrence Berkeley National Laboratory

Brian Bonner:

This will be an interactive presentation from both of us.

When I started to think about this talk, I realized that it would be quite unconventional. Most talks have a beginning, middle, and end. This talk is mostly going to be beginning, beginning, and beginning.

I'll talk about some things that on the outset look like dogs and cats, quite a mixture, but you will see that there is an underlying theme. Here are the main elements of the outline.

- Mechanical properties of geothermal rocks are distinctly different. Are there consequences for stimulation?

- The importance of fracture propping. Steve and Norm have already raised that topic. This is a very important aspect of the EGS problem.

- Permeability enhancement by geochemical interaction and/or precipitation. This is based on some new and old experiments at Livermore that show some results from the hydrothermal part of the geothermal program that might in fact apply to EGS. I think as we discuss the political implications of separating and bringing these two apart, we shouldn't lose sight of the fact that there are scientific synergies between these two things.

- Coupled thermal and hydrological and mechanical (and possibly geochemical) models are needed for prediction of fluid flow. Some of this modeling work has been done as part of the nuclear waste isolation program at Livermore. That is an example on a small scale, one to ten meters.

- Finally we'll highlight some field scale results from Larry.

The underlying concept here is, as always, permeability. How do we create it? How do we control it? How do we make it work for us? How do we stop it from working against us? That is the most essential problem in rock mechanics that we come to in the geothermal business.

Slide 2.7-1 gives an overview of mechanical properties of typical crustal rocks. This is a textbook example of the behavior of what are the most important mechanical properties that we measure in the laboratory to characterize rocks. This is the compressional velocity. Compressional velocity is a function of effective pressure. It is the difference between the pressure imposed on a sample at its outside boundary and the pore pressure. We have results for granite, for several sandstones from an excellent book by Bourbie and others. I want to point out that the velocity rapidly changes below the first couple hundred bars. That is because very compliant features that are structurally

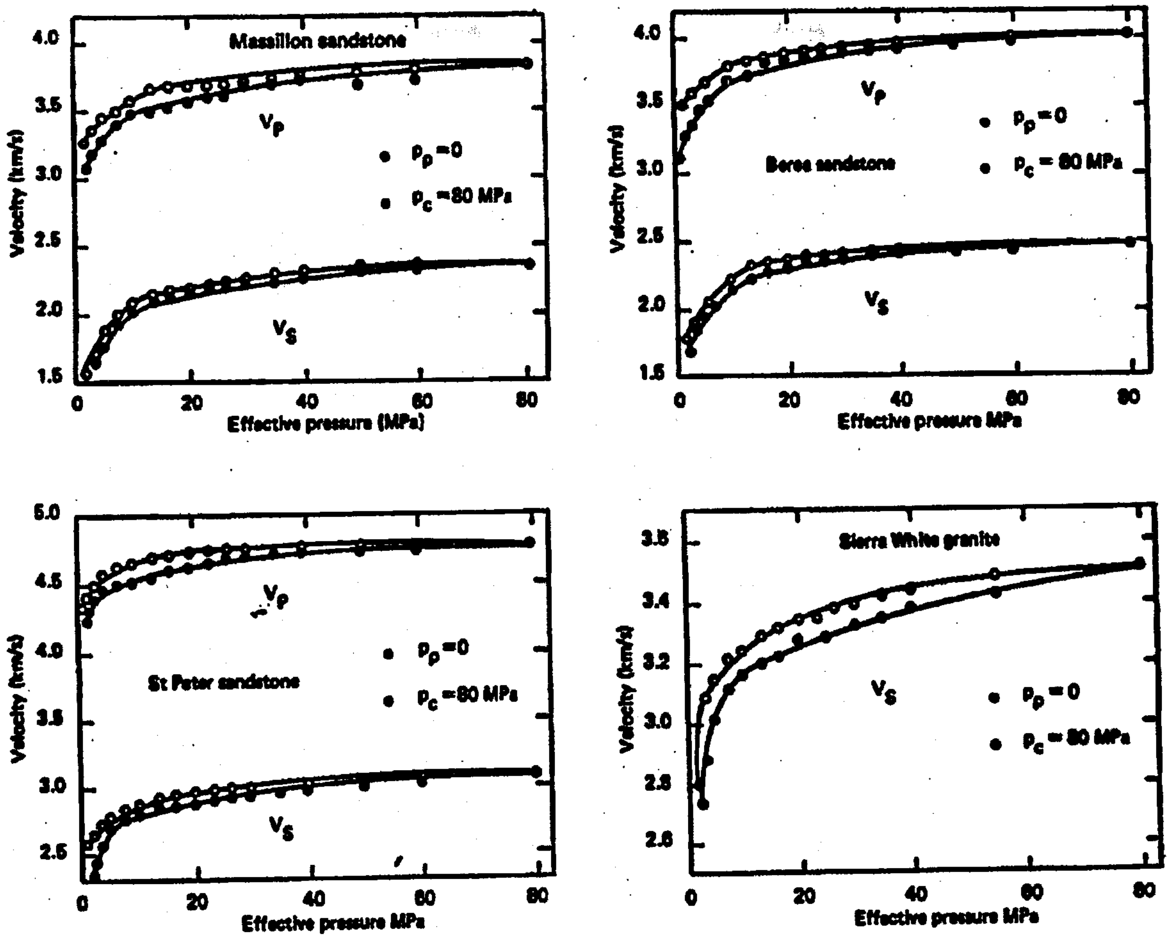


Fig. 5.5 Velocity/effective pressure relationships for cases of zero pore pressure ($p_p = 0$) and constant confining pressure ($p_c = 80$ MPa), (ultrasonic measurements) (after Jones, 1983).

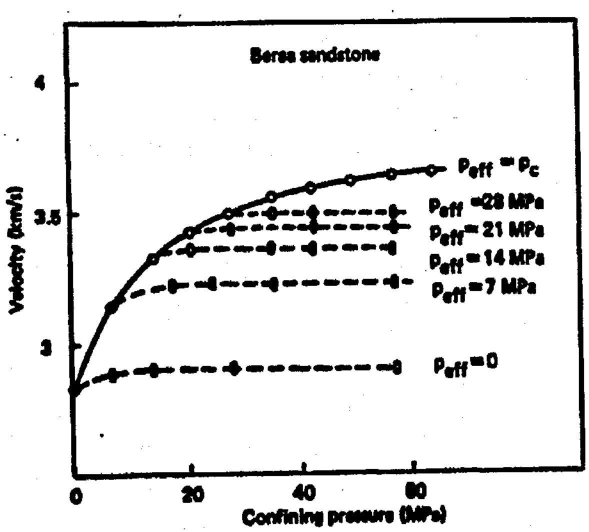


Fig. 5.6 Compressional wave velocities in Berea sandstone vs. confining pressure and effective pressure (ultrasonic measurements) (after Wyllie *et al.*, 1958).

important in the rock, *i.e.*, micro cracks, the fine grain features, are very highly stressed during loading. However, as we've gathered more and more experience from rocks in geothermal regions (the first really extensive data set we have is from well SP15-D in The Geysers), we found very different behavior.

What Greg Boitnott of New England Research began to see, and this was consistent with hints of this behavior that I saw as early as the Salton Sea project twenty years ago, was that the chemical environment of the geothermal systems cause the mechanical properties of the materials to be quite different. Figure 2.7-2 is a typical plot from Greg's web page, www.ner.com. You can see many examples of this behavior there.

Notice in Greg's data the lack of change in the P velocity. The important result here is the negative observation--that these materials are already in their high pressure form. And that mechanically, I think, is something we haven't dealt with, particularly in our oil patch experience, as Norm alluded to and Bjorn talked about. This is the first thing I want you to remember from this presentation: that indications are that the chemical environment causes important mechanical changes. That is something we have to think about in all of our applications.

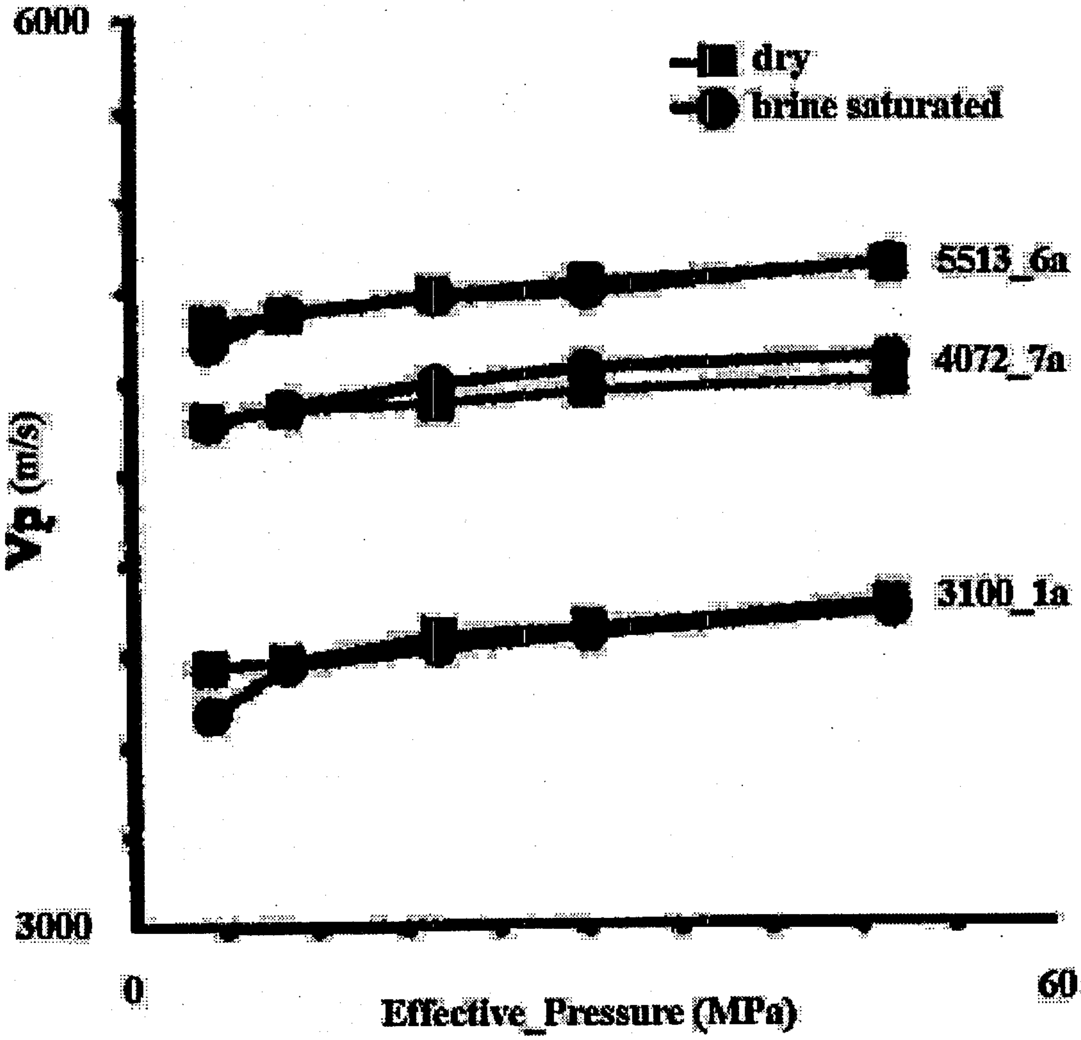
Now I'll talk about simulation results from John Shatz. John is an independent consultant who has been very active in the stimulation field in the oil business and has for the last ten years worked with propellant fracture. In a GRI project, John has modeled the fundamental differences between explosive stimulation, propellant stimulation and traditional hydrofracs. With explosive fracturing you get a lot of formation damage and in fact *decrease* the permeability in the borehole region. But, by igniting propellant and pushing with an over supply of gas in the borehole at the right rate, you can under, certain conditions, create multiple fracturing and limit formation damage.

As Dan said, we know how to make fractures close to the borehole, from experience in the oil patch. So I think that propellant fracturing, which is in some sense mature, can be exploited to good advantage for intersecting existing fractures in EGS applications.

In the explosive loading situation, a lot of the energy goes in the system very early, in the first few milliseconds. That energy is in some sense lost in rock crushing creating damage near the borehole. Fracturing occurs later. If you tune the stress pulse, you can put most of your energy where it will do you some good, and get fracturing and with very little formation damage. This is the theory, of course.

In hydrofracs the fluid pushes very slowly and typically will give fractures that are aligned with the *in situ* stress field.

In summary, propellant has potential advantages. I wanted to make sure we had this on the table to think about it. I'll summarize analyses by Schatz of an experiment done in Lake Erie for GRI. He found he was able to predict seven or eight fractures. What we're talking about here is the ability to drive a fracture one to ten meters into the formation, independent of the stress field. Industry has produced modeling capability that has done a fairly good job of producing agreement with experiment.


6000
3000
Vp (m/s)
dry
brine saturated
5513_6a
4072_7a
3100_1a
0
60
Effective_Pressure (MPa)

Now with fracturing as a central theme, I'll tie those two things together in the next section. In the early eighties we had an experimental program at Livermore, run by Bob Swift and Andre Kusubov, to look at the effects of tailored pulse loading on fractures. They wanted to get at the problem of creating multiple fractures in rock. It turns out that they picked a rock called the Nugget sandstone, which is good in our context because it has a low porosity of only about eight percent, which is not typical with oil reservoir rock. They did a series of very elegant laboratory experiments, using a machine still in place at LLNL, which is quite unique.

Experiments were done on rock cores fifteen centimeters in diameter, with a borehole in it connected to a fluid reservoir. We had the capability of pumping up this fluid reservoir very rapidly with rise times on the order of one to ten milliseconds, shaping the pulse, and producing fractures. The apparatus and results are in the open literature.

About forty or fifty shots were done in Nugget sandstone. In one series of experiments, called "quasi-dry," in which you first pump the fluid up and let water diffuse into the material, they demonstrated that fluid around the borehole was necessary to produce multiple fracturing. So that's an important detail. They were able to determine optimum loading rates to produce multiple fracturing for different confining pressures. Higher and higher pore pressures are needed to produce fracturing, as the loading rate increases. [A slide shown here was not available for printing.]

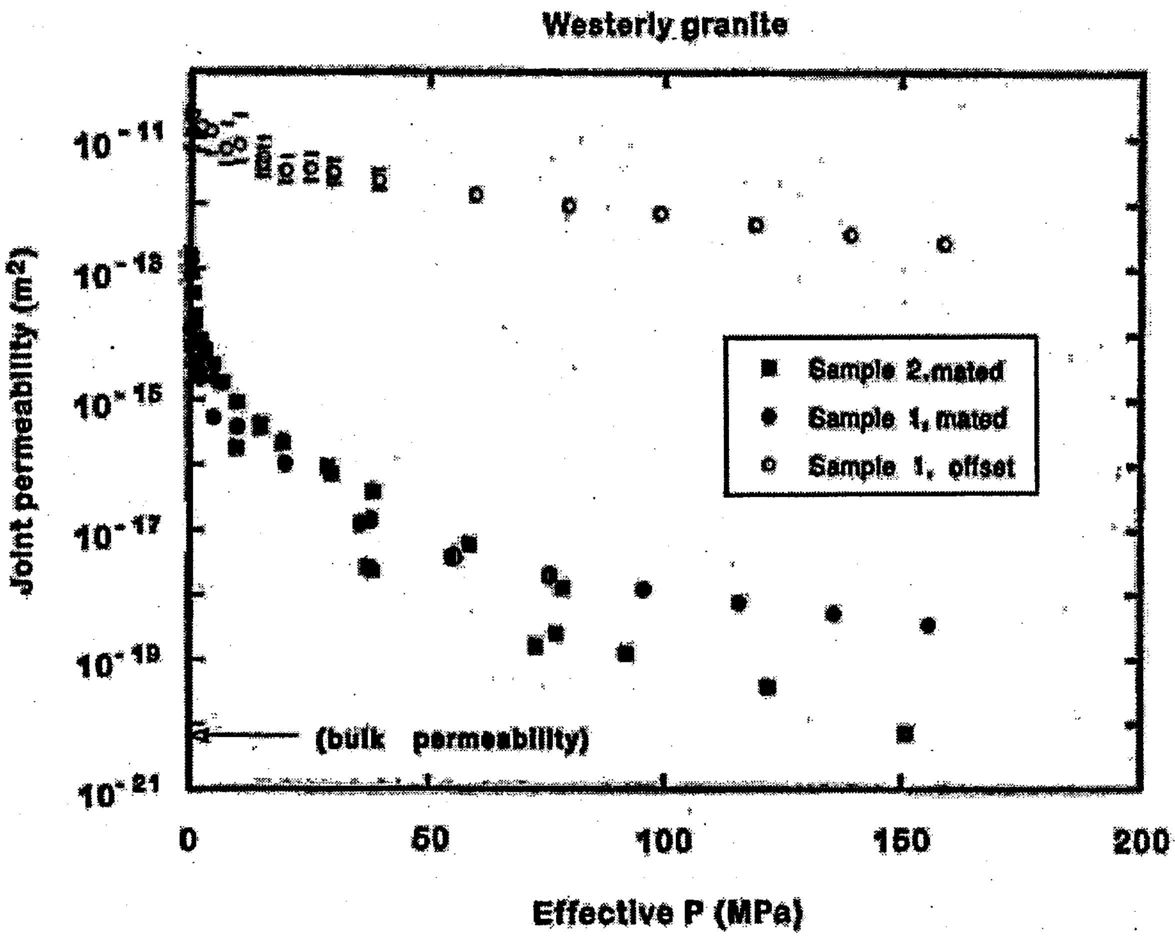
Think back to my first point about the mechanical properties of rocks from geothermal regions. The geothermal rocks seem to be already in a high pressure mechanical state. The microcracks are closed, so therefore, if we design a propellant job in a geothermal system, we expect that we need higher pressures for multiple fractures than those that work in oil reservoir rocks.

Now, I'll move on to joint propping and once again I'll talk about some laboratory experiments to measure permeability as a function of effective pressure squeezing on an artificial joint. This is shown in Figure 2.7-3.

There are two cases of a well-mated joint. These joints were made in a laboratory so they are in good shape, and spatially correlated. For a mated joint, permeability changes Here as you can see six orders of magnitude with increasing pressure.

Now you offset this joint, mechanically, half a millimeter. So you see, you don't need much offset to get natural propping. Permeability stays way up here. So, my headline point here is that if we can learn to use joint propping creatively and well in this context, and, as Norm Warpinski said about the environmental problem of disposal of wellbore chips -- they can avoid it by sending us the chips that the oil companies don't want to geothermal regions and get rid of them down there. (Laughter.)

Surprising results, have occurred when we've done simulations of The Geysers reservoir conditions. In this case we created a situation in the laboratory to study boiling events using synthetic rocks samples, made from fused glass beads. We found that after multiple boiling events when we recovered the core, the porosity of the core can increase by twenty or thirty percent, with fractures that run the whole length of the core. A process analogous to freeze/thaw, well known in nature, causes increases in porosity. Salt crystals wedge open the materials creating new porosity.


Westerly granite
Joint permeability (m^2)
10^{-11}
10^{-13}
10^{-15}
10^{-17}
10^{-19}
10^{-21}
0
50
100
150
200
Effective P (MPa)
Sample 2, mated
Sample 1, mated
Sample 1, offset
(bulk permeability)

This I think is a very complicated process that involves stress corrosion with the very strong bonds in there. This is something that I think we ought to be aware about this context. We can certainly talk more about it when we have time.

Now, I will skip ahead to the modeling part. Before I distract you with confusing visual information, this is the result of a coupled thermal mechanical hydrological modeling study for the Yucca Mountain nuclear waste repository. The headline is that if you don't take into account the existing fractures and how they move in response to the thermal and *in situ* stress fields, you get the wrong answers as to where the fluid goes.

These calculations were done by Pat Berge and colleagues at LLNL, using used a very loosely coupled computational approach. She used a thermal code to get the thermal fields, and fed that into a mechanics code which then calculated the stresses. By putting in the existing fractures that we know about, the vertical and horizontal fractures that are critically stressed can be identified. When electrical resistance tomography was done to look at the wet areas, the wet areas identify these as the active fractures. In a perfectly symmetrical calculation without the mechanical coupling, the wet areas are below the drift. So, without putting in the fractures with the mechanical effect you get the wrong answer.

And now, I give you Larry Meyer.

Larry Meyer
We don't have much time. My punch line is the same as Brian's. You need to include explicitly the fractures in the system. Now this happens to be a reservoir scale model and it's to look at well failures. This is a geomechanical finite element model of the South Bell Ridge diatomite reservoir. They have experienced many well failures at a interface, which is at the bottom of the lower Tulare formation there. And that interface is a weak unconformity, which is quite analogous to a fracture. So the bottom line question was, could pressure changes in the reservoir cause well failures at that interface? The answer was, "Yes." The way we did it was we to use a black oil simulator to generate the pore pressure fields, put the pore pressure fields into the geomechanical simulator, and then you can show that you get the large displacements which occur at the slip interface or at this weak boundary. And the reason I put this graph up, which is actually horizontal displacement on this axis as a function of depth.

The blue line on the slide [slide not available for this report] shows the result that you get from the model in which you do not explicitly incorporate a interface or a slip line in this particular finite element simulation. And you can see the very different results that you get by explicitly incorporating the fracture or the slip interface into the model.

Bonner:

As I said, I don't have any conclusions because this is all beginnings. We are left with a number of key questions. First, how general is this observation that geothermal rocks are mechanically different from many non-geothermal rocks? What are the consequences for stimulation? Can we modify the permeability *in situ* by exploiting the deposition of dissolved solids? Can we modify propping using *in situ* stress? Can we induce fracture propping by propellant fracturing? Can we create or use these two stress fields to get slight offsets and make natural propping effective?

2.8 Economics of the Fenton Hill HDR Reservoir.
John Pritchett, Maxwell Technologies, Inc.

The reason I want to say something about economics is that I think one of the important criteria, for picking EGS research projects, is convincing people like corporate boards and government officials that this kind of thing has some merit. The Hot Dry Rock program is inextricably linked to Los Alamos National Laboratory, I think, and the Hot Dry Rock program has not exactly covered itself with glory in terms of looking practical to corporate boards. I will try to explain my perception of why this is.

This isn't an analysis in the sense that's it the kind of thing a professional economist would do. This is just back of the envelope work, so everything I'm going to say here is good within maybe a factor of two. But I think the important point is valid anyway.

I spent about 30 minutes looking at the literature and another hour doing some algebra to see what it meant. As some of you may recall, two or three years ago there was a Request for Proposal (RFP) put out by DOE soliciting somebody to go to Fenton Hill and start operating that reservoir as a commercial power plant. Build a power plant and run it and sell the power to somebody. Some people at DOE seemed to be a little bit surprised that they weren't absolutely overwhelmed by the stampede of people getting in line to do that. I thought I might get some insight as to why that might have been.

Let's just look at some numbers. Total amount of money that Uncle Sugar spent on the Hot Dry Rock program at Los Alamos over the years amounted to about $185 million, over about a 25 year period. If you take that $185 million and integrate it times the consumer price index and turn it into 1997 dollars which was the year they terminated the project, that amounts to actually about $330 million total in 1997 dollars.

Now just for comparison, the history in the industry over the last ten or fifteen years has been that building one megawatt of capacity, figuring in all your costs, exploration or whatever, costs about $3 to $3.5 million per megawatt. So what was spent at Fenton Hill should have bought about 100 megawatts of electric capacity, as a first order approximation. It didn't buy any at all!

But let's see what one might have been able to do if "smart private industry" had done this instead of "stupid government" which wastes so much money which people are so fond of telling us about. Let's just suppose that you could build a new Fenton Hill, one just like the old one but you tried to do it to make money, not to make a research project out of it. What would be the capital costs of doing it? Probably a tenth of that, maybe a twentieth of that.

If you make a lot of really reasonable assumptions, you might be able to build a new Fenton Hill for say $15 or $20 million. I just said, "Let's assume you could do that." That means drill a couple of wells, maybe have one bum hole, two good holes, build a power plant, do your exploration, get your permits, get your grid connections, pay off all the people you have to pay off. Suppose you could do that for $15 to $20 million. I think that's kind of optimistic but suppose you could do it.

Question: To build about five megawatts?

Pritchett: It doesn't matter how many megawatts. Suppose you just want to drill and frac the wells, and that's it. If you divide by net power output, you get into trouble instantly because you get infinite numbers with the existing system. So I am just talking the capital costs. We'll worry about the power in a minute.

So if you can get a really, really sympathetic banker to fund this enterprise, you might be able to get an operation that if you could spin off say $1.5 million dollars a year to pay for your costs of money, he might let you actually have that much. I think you'd have to get a pretty sympathetic banker because this is pretty risky technology. But let's just assume that. I'm trying to be a little generous here. So suppose you have to pay $1.5 million per year for debt service.

Let's also be kind of optimistic and say you could do your O&M costs on the plant and the wells and the rest of the system for $0.5 million dollars per year. I think that's really generous, and I think it would really cost more than that. After all Los Alamos was spending over $1 million a year on O&M costs on Fenton Hill and they didn't have a power plant.

So what this says is to make this thing go you can maybe do it for $2 million a year of revenue. It might be $4 million, I don't know, but it's going to be somewhere around there. What do you get for that?

I took a look at the Fenton Hill system and what its performance had been. We all remember Los Alamos people running around and saying things like, "Well, if you tweak this thing a little bit, we could actually be economic. We're real, real close." Somebody yesterday said that a Fenton Hill type system ought to be able to make money at 8.5 cents a kilowatthour. I said, "Gee, what could it really do?" Not a tweaked Fenton Hill system, but Fenton Hill as it was.

In 1993 they ran something called the Long Term Flow Test at Fenton Hill. That had about the highest output they ever got. It was sustained for a little bit longer than one month.

I said, O.K., let's be generous; let's assume that they can run it indefinitely at that rate without any degradation. First off they ran it at real high pressure. They wanted to run it at high pressure so they propped the fractures real wide open so the thing would flow like a train and they could get a lot of water out of it. They actually ran the thing so that on the production side, the wellhead pressure was 97 bars. So there was a big back pressure on it when they did this. On the injection side they put a whacking great injection pump on the line to get these kind of pressures. The well head pressure on the injection pump was I believe 273 bars to get it to run at this high rate. That means you are using a 176 bars of pressure to overcome friction in the system -- most of which is in the reservoir, a little bit of which is in the plumbing. That's about the best performance they were ever able to get.

The flow rate coming out the production wellhead under those conditions was 5.7 liters per second of water at 184°C, averaged over the test.

I said, "O.K. suppose I have water at 184°C and at high pressure, that's a liquid. There's no steam in it. What would I do to generate power? It turns out that the best way to do that is with a binary plant. A real well-designed hydrocarbon type binary plant using recuperation, but limiting the back end temperature on the heat exchanger to avoid silica scaling, will give you roughly 59 kW for every liter per second of 184°C water which you pass through the heat exchanger. That's the capacity which you can design to which means that the gross capacity of Fenton Hill is about 340 kW. The 340 kW is the net for the plant, including consideration of hydrocarbon pumps and cooling fans. It's the bus-bar power before you run your injection pumps.

But, whoa, that's too optimistic. Remember our big pump sitting on the injection hole. Well that thing has got to pump 5.7 liters/second at 176 bars. That's assuming no fluid losses in the system. If there are fluid losses -- and there were -- you have to pump even more. But let's be generous and say that by some magic you make the fluid loss problem go away, so you only have to pump the 5.7 liters, not the makeup water, too, and never mind who you have to pay for the makeup water. It turns out that to do that, using handbook values for pumps, will cost you about 150 kW for the pump, leaving you a net exportable power capacity of 190 kW for Fenton Hill.

So the cost of power is the annual cost of $2 million divided by the annual output from 190 kW. If you assume a capacity factor of 100 percent, it turns out to be that your costs of power to break even, making all these optimistic assumptions, comes out to be $1.20 per kilowatthour (kWh).

So are there any further questions about why there wasn't that stampede? This is the kind of history that corporate boards have seen from the Hot Dry Rock program. And they have seen people from the Department of Energy get up and say, "This is a plausible project."

Prairie: This is, I am sure, a very naive question. But did not the planners on the DOE side go through a similar process?

Pritchett: I don't know.

Entingh: I've followed the economics analyses of the Fenton Hill-like HDR concepts for about the last 15 years. Typically everything comes out at 5 to 7 cents a kilowatt hour, in whatever year dollars the report is published. This is from studies from Los Alamos, MIT Energy Lab, Bechtel. In the studies that come out with those relativey low costs, they almost always said, "We will have a production flow rate -- from a <u>triplet</u> of wells, or a series of parallel penny-shaped fractures -- similar to that of a very economic hydrothermal system, a good hydrothermal system. That is many times the experienced flow rates from any of the Fenton Hill experiments.

That's an important thing to look for when you read these studies, an estimated flow rate is that's much higher than what was ever experienced for the particular engineering configuration. Doing that, you can get just about any nice number you want.

Pritchett: Don't forget. I used a pretty low estimate on the capital costs of this system. If we actually look at what was really spent on it, that $1.20 turns out to be about $20/kWh.

Question: You can't deliver heat at that rate indefinitely. Don't you deplete the heat out of the well?

Pritchett: Yes, the calculations above assume the system will last long enough to pay the debt back.

Entingh: I'll add one more thing. It's my belief that LANL staff planned to run the "long term flow test" originally at a much higher rate. For that you would have had to have an even higher pressure differential, but once the pressure differential went a little bit above what they did use, the leakage in that system was so enormous that it made no sense to run such a test. The leakoff rate would have been 20 to 30 percent of the fluids, every time they tried, with no self-sealing. Somewhere down in that particular block of rock there's a place where water just goes away. The final tests were conducted using an artificially low flow rate. The initial criteria for this test was going to be that one would see significant temperature draw-down within one year, so that industry could make sense out of how to run a system like this. By the time the test was run, LANL stated that industry had told them they want to see the maximum sustainable flow rate with no temperature drawdown and that was the stated reason for running at the low flow rate that was used.

Kasameyer: I don't want to jump to Los Alamos's defense but one of the big problems they had was claiming they had an economic system. I mean if you did this analysis with Thomas Edison designing the light bulb, you come to exactly the same conclusion. But he was a little ahead of the economic curve. He was doing the research. I think the EGS program is going to have to be very clear about when it's doing the research, it ought to do research that might lead to some kind of economic sense of a system. I was never convinced that Fenton Hill had a shot at that. But you can't do cost estimates based on the research period.

Pritchett: That's right. And that's why instead of burdening it with $330 million of capital cost, the present value of the research outlay, I burdened it with $20 million, as an estimate of what it would cost today, after we know the results of the research. I've taken the difference as a research cost component.

Kasameyer: But the objective of this should not have been to make a system that looked economic. The objective should have been to understand what you can do in this area to know things.

Pritchett: I'm not commenting on what should have been done or what shouldn't. What I am commenting about is the fact that the last time industry was presented propositions that were allegedly economic by much this same community, this is the story they were told. You'd better keep that in mind. They heard it, and they are suspicious.

Hickman: I think the big problem is the "allegedly" trying to sell a research program as something that produces an economic resource is a big strategic mistake that EGS should not make.

McLarty: That's a point well taken. I'd like to point out the attempt to commercialize Fenton Hill happened before Paul Grabowski was involved. And it also happened before this EGS contract began. We were involved with supporting DOE in managing their programs at that time, and we recommended to them that they not float that solicitation to commercialize Fenton Hill.

Grabowski: This EGS program is in part a result of that failed NOPI and solicitation. So now that Don Brown's ears are burning and bursting into flames, why don't we get on with the task at hand.

Entingh: The Los Alamos staff told DOE headquarters that they had much interest from many firms in industry. And that was true. But there wasn't a single major geothermal firm among them.

Many very small firms that had no geothermal energy track record showed up at the pre-bidding conference. "Sure we'd like to get these two wells for free. Now, how are we going to deal with this." I believe that not one of the firms had been involved in any kind of production geothermal energy from a commercial site in the United States was part of that process.

So once again, and I will say this once again you had a process ongoing where a group of researchers could say to a group of policy makers, "Man, we got industry here." Too bad. But "industry" on one day is not "industry" another day. It's not always kept clean and I think it really needs to be. And it's one of the things that have this kind of discussion in this kind of group is extremely important, and we will not edit most of this out.

Swenson: Again I was involved with some of the Los Alamos project doing some analysis there. I don't know all that went on in that solicitation. I believe at least one of the persons who responded, who would have had a chance of making a viable go. I don't know how much money they would have made. There were some committed people to work on that. However, John may be raising a bigger point. Are you saying, John, that if you drill into a tight system, you can never get the permeability needed, the flow rates that you need to have an economic system?

Pritchett: Never say, "Never." But that time it didn't. My point here is that, once again, just that, so many times, people have been told these incredibly unrealistic stories. They are going to be extremely difficult to convince about anything that even smells the same. You had better, in designing this program, come up with some really achievable targets. And you had better achieve them.

Creed: I think one of the lessons we need to learn from this is that we need to make sure we don't repeat the same mistakes that led to the Los Alamos folks having to promote themselves as an economic project and not a research project. That's the bottom line.

Nielson: I think there are a couple of issues. I like John's analysis. I believe that one of the things that led to the downfall of the LANL HDR program was they not only had these sorts of numbers to play to, but they also had many reports on economic analyses that people in the geothermal industry would look at and say, "LANL is coming up with HDR costs of five to eight cents per kWh."

People in the industry would look at that and say, "These are unrealistic numbers because these are the numbers that the industry is getting in primary production at high-temperature hydrothermal systems right now. How can you possibly get the same costs when taking an inherently impermeable block of rock and hydrofrac? There's no way you can possibly get the flow rates. There's no way you can possibly get around the problem of sweeping the heat out relatively rapidly, and likely short circuiting through some of the flow paths?"

And so there was a total disconnect even though the numbers look good and people behind the numbers are credible. Just from the standpoint of the concept of the whole thing--it just didn't make any sense. The more they tried to push those numbers, I think, the more the credibility went down, until they were in such a deep hole that they could never get out.

And so, I think that you're going to have a very difficult time producing realistic numbers that a company is going to like if you take a block of tight rock and just rely on hydrofractures to do the work for you.

And the other lesson is, don't oversell these things economically. In fact, you ought to back off from that and look at transferring technology more than trying to kick the economists in the pants.

McLarty: I don't think anybody in this room has any delusions that EGS systems are going to be economic in two or three years from now. We're looking at hopefully there will be some spin-offs that hydrothermal technology can use in a few years. But EGS-type systems, we're looking down the road eight to ten years, optimistically. Realistically, with budget limitations, it may be fifteen or twenty years.

Sanyal: Even hydrothermal will not be economic for another eight, ten years. Right now you cannot afford to build the hydrothermal plant and compete in the market for the next ten years.

SECTION 3.0

GENERAL DISCUSSION

3.0 GENERAL DISCUSSION

3.1 Introduction to the Approach

Entingh: For the rest of this meeting, today and tomorrow we have two very specific goals. The first is to define a large group of R&D projects that are important to EGS. Second, we are going to try to evaluate projects and pick a few that seem most important.

When Lynn, Nort, and I met Monday to refine the approach for this workshop, I said that for a long time I've had a sense that a robust R&D program has a portfolio of projects and project ideas that are laid out, some of which are being funded and all of which are candidates for funding. So that when the powers above say, "Well if you an another $5 million to use next year, which projects would you fund?" You can say, "Oh! That's no problem. Here they are." You can have a richness of thought, a richness of readiness, so to speak.

One of the things that needs to be discussed is the degree to which specific technical or deployment projects, at specific geothermal sites, need to be discussed in order to define what is EGS, and what technical approaches and development are the most important. We have received conflicting opinions from some of you about how "specific" such a focus should be, and legally can be.

It was very clear from this morning, that as we expected, that a third of the people in the room have different definitions of what EGS ought to be. It's not unusual in meetings like this -- when you are trying to start a program, define it better, amplify it, and add more detail to it -- that early in the discussion the definitional question comes up. Once we list those projects, then we can ask, "Do most of us believe this is an appropriate project for something called EGS?" By answering that, we will have operationalized, better than anybody's done before, a definition of "EGS" experiments. A definition that most people that are associated with this program can support.

Then we could go project by project and say, what is the supporting research needed? What are the three or four or five disciplines that would constitute the main bases for supporting research? In which of those areas do we have to conduct baseline studies? Those would be studies that are needed because most folks in the geothermal area aren't familiar with particular technologies and methods?

Norm Warpinski has been doing or stimulation experiments very successfully over the last ten years. People know of it a little, but they don't know the characteristics of what happens if you try to do a hydrofracture. I think in geothermal, the answer to that question is DOE tried that 20 years ago, and it didn't work very well, so they all went home. That's what folks said when we ran the first EGS workshop last year. But there have been advances, so a baseline study would be useful in this area.

One of the things that Lynn and Nort want to do after we define these projects, is to talk about criteria for selection, so that we can all get on the page about technical value, economic value, policy value, and "How do I explain this to my lab chief?"

3.2 Specificity of Defined Projects

Robertson-Tait: Do you want to go from generic to specific, or the opposite?

Creed: I have an administrative issue here. You've got to do this in the most general way possible. Otherwise we look like we're setting up projects for selection and funding.

What we can suggest is general research issues and topics. From this general list of topics and initiatives, we will produce a specific solicitation that says, DOE is interested in funding project along these lines. Then we'll set up formal Merit Review Committee and evaluate the these proposals or if possibly fund the best proposal.

We'll fund all, none, or part of it, as we say. So, I can see where we are kind of steering toward picking and choosing a few projects here or tomorrow to be funded. So far we've said that's the way we are going and I want to make sure we don't do that.

Hickman: I echo that and I think we should keep this generic, peppered with illustrations, but we have no idea what will come back in response to this solicitation. There may be great ideas we haven't even thought about.

Creed: Also, you have to be very careful that people who do submit are eligible to get the information that is produced in this meeting. You've got to give everybody the chance that they have a fair shot at the money.

Kasemeyer: As a result of that, you will not get some ideas from some people who might want to submit a proposal, but don't want to describe to everyone else what the content of that proposal going to be.

Creed: Proposers don't have to be that specific at this point. All you have to do is give the group a general idea is a good idea.

Robertson-Tait: You could always name a field as an example. That doesn't mean you're promoting anything specific.

Creed: Another problem you run into is that at some places you would be able to get data and other place you won't. The Government is very hesitant to fund research and work based on data that can't be released. Some field operators you know will not release proprietary data.

Entingh: That explains why, for so many years the DOE geothermal research program worked on mostly on Italian and Mexican field, and so rarely on American fields. I started in this in 1978, when it was a continuing perception problem that the Government wasn't doing very much work with geothermal reservoirs in the United States. It could work on better drill bits and downhole electronics, that was sharable. But it was not allowed to work in many of the most interesting commercial fields.

Creed: Paul Grabowski knows more about this than I do, but there's a push in DOE Headquarters for, "deployment," am I correct? That we actually have to sort of actually get away from the, if it fails, then it's okay kind of research to put something in the ground where you can take the Secretary or DOE Deputy Secretary to show them the geothermal project. Personally, I'm more a researcher kind of guy, but pragmatically deployment projects seem to be what we're looking at. Now that changes with just about every Congress, but right now you don't want to be proposing laboratory research. You know more about this than I do Paul.

Grabowski: There's no push to do demos, but again, there's a reason why we want to talk about specific sites or general sites, I guess I should say. When you're talking about research, it puts a real-life entity out there with a real-life value to do something. We're just not talking about theoretical geothermal fields.

Creed: You have to watch out for whiplash though. Next year, today's deployment projects might be "industrial welfare."

Prairie: Decision makers might say, "This year the technology is mature, right, not researchy enough." Do we need to have a discussion about where this technology needs to go eventually and what are the technical challenges that need to be addressed along the way and maybe that will guide us in project selection? For example, ultimately, we are going to have to fracture deep rock, therefore we need to do a project where we look at fracturing technology in the near term.

Creed: One of the ways to look at is, that in this room it would help if we could decide which useful research, technology development or deployment, would give us the most bang for the buck. In my view, that would be one of best contexts for the discussion. Long term research is easy, you're not making critical decisions.

Koenig: Perhaps what we need to do is establish some milestones, qualify some things, and say, in one year, we want to be here, in three years we want to be here. I'm speaking about what projects or what things we can do that will bring us 10% increase in generation in years X, Y or Z.

Nielson: One way I look at this is that Los Alamos for fifteen years or so, was telling us that hot dry rock was going to be generating electricity in Kansas and places like that. They were going to go very, very deep and get into the basement rocks and fracture them. I guess what led me to my approach was that I think you're basically going to have to start with highest temperature resources to start with, right?

I think in that context you either go lateral to geothermal systems, like the Japanese hot wet rock project, at hydrothermal margins. You can do something like Steve Hickman talked about where isolated within an existing geothermal system there are pockets of impermeable rock that could perhaps be developed. Those are really going to be the models. We are going to learn so much from doing that. If it doesn't work there, the chances of trying to pull it off in Kansas would be miniscule, right?

Kasameyer: I don't think you want to solicitation that says we're looking for a proposal to something in Dixie Valley, to do such and such. That eliminates other people from thinking about something, and someone might have a better thing to do. But if we, say, talk about a specific project, like The Geysers, or Dixie Valley, and tried to figure out how you would write a solicitation that that would be one of the things you would get from that solicitation. It seems like, if we start going down the generic list of what disciplines are useful, I've been to those meetings before, you get a very long laundry list.

Grabowski: You have been working in geothermal for many years, so we could probably sit right here and in three minutes, you could name the potential sites where we could augment the field. There are just so many out there in the U.S., key operating fields in the US. So let's name those, and then start putting together the topical areas that we think are necessary in each one of those fields. And we're not pre-selecting fields, there are just so many out there.

McLarty: I wouldn't think about this as a basis of a solicitation because I think the solicitation ultimately will try to be very broad and general in order not to be limited. That's what we're hoping. That's what we're recommending. The purpose of this meeting is not so much to guide solicitation as to guide thought and direction for the program. What comes down on paper out of this will a part of the consideration when people evaluate what comes in as a result of the solicitation.

3.3 Optimizing Cost Effectiveness

Pritchet: At the risk of getting myself in all kinds of trouble with a whole lot of people, let's back off here. We're talking about a program that's funded at the level of maybe one to two million dollars. We're talking about doing demonstration projects in the field that are going to be exciting, and are going to show some results. You're not going to be doing a whole list of them, if you're real lucky, you can do one. And maybe it will work, and maybe it won't.

So, if there is one thing you want to do for sure, you want to pick something that isn't real expensive to do. You want to find something to do that you can do for a small amount of money that has a high likelihood of doing something relatively spectacular that you can then point at and say, see, give me more money. And do it more places. And do it later, somewhere else, somewhere bigger.

So my thinking has been, and once again it's going to get me into all kind of trouble, is find a relatively small project somewhere, that is already in trouble so if you screw it up, it doesn't do so much damage.

You'd try to see if you can stimulate it somehow so that it's measurable in the sense that Ann showed whether, with The Geysers pipeline graphs, you know, in six months or a year, you are going to be able to draw a graph where the difference in performance is bigger than the scattering in the data points. And you can point at that and you can do for the kind of budget you're talking about. And I think, if you do that successfully you got a fairly decent chance of getting more money down the road. But if this all gets all diffused looking at half a dozen projects, and doing twenty different paper studies, with the budget you've got, it's just going to fizzle out.

McLarty: I agree very much with John, with one exception, which is that I think there is some flexibility in the budget. We anticipate one and a half, at most two million dollars. But if we can go to upper management at DOE and say look we've got three great projects instead of just one. If we can go to them with something we can sell then there may be some thought of getting more budget. So, I don't' want to just say, well, lets look at this as a million and a half dollars worth of work, if that's all we get.

Pritchett: I think you better plan on a million and a half. I don't have a problem with your idea saying, if Santa Claus shows up tomorrow morning, do I have a wish list? Okay. Make a wish list, all right, but don't plan on it.

Entingh: Three or four times in the geothermal research program, that someone above said, "If you were given 50 percent more budget, what would you do with this?" And some of the research program managers had to say, "I don't know."

Pritchett: But, did anybody ever get the money?

Entingh: Yes. The Reservoir Research Subprogram got most of the money. Because the manager of that subprogram always had a working portfolio list. Then Sandia eventually, figured it out and re-programmed, with a long list, and has been working it successfully.

Prairie: Yes. We get that question every year.

Sanyal: I agree with John Pritchett, because even today The Geysers and deep well cost three and a half million dollars. So if you're going to do anything in the field of any of any consequence, you have to be realistic.

Hickman: Well we can drill for less than that.

Sanyal: You can, but the question is will the operator let you do that, there are safety considerations. Today Calpine is drilling those wells for about $3.5 million. They're not going to compromise their procedures. So you have to be careful, you've got an expensive project if you are going to go into drilling deep wells or fracturing, it gets expensive.

Grabowski: Everyone has to agree with John here, so I do to. We need something that's going to pay off big. But remember, we are not designing a project here today. That's not why we're here. I think it's a good idea to list projects, hypothetically maybe, loosely define them. But what we want out of them is what type of R&D is going to be necessary from you folks, because you are the R&D community. So, what type of technology development is going to be necessary to make those projects a success if, the big if, they ever get proposed to our solicitation.

For example, say some improvement related to slim-hole drilling might be applicable at The Geysers. If a project on that never gets proposed, that idea gets trashed. If it does get proposed, after this Workshop we will now have a planning document that says this it the type of R&D that our research experts think should be done to make that a success because we sat down and talked about it today. We are not pre-selecting projects. We are just making ourselves smart as far as what we think needs to be done to make different potential projects a success.

Robertson-Tait: Adding to the discussions about the budget, it's not necessarily helpful to constrain yourself by the budget in the work we're trying to in the Workshop. It's not why all these people are here. Why we're here is to discuss the possibilities and what needs to be done. To develop a portfolio of needs and concepts. What is available as funding enables you to distill those into something workable. But it shouldn't limit your thinking and the discussion in this room.

Truesdell: I want to say that I think that there is a way of attacking this by treating these things generically. You discussed this morning, and I wasn't here, what is and isn't EGS? You can make an intermediate definition of this and it allows you to reach some heat that you couldn't otherwise reach. Or you can reach some heat that you were already reaching, but do that more efficiently. You can divide that first part into reaching heat that is deeper in the system, reaching heat that is carrying bad chemicals with it, and you have a way of getting around this. I'm just saying you can think of this as a number of relatively simple objectives that are not site-specific.

3.4 The Main Technical Areas to Work on

Entingh: I think that's right. Let me try to reframe things a bit now. And replicate some things that have been said. Bob Creed said this morning that he thinks EGS stuff is being done near the wellbore, and not some at distance not some distance from the wellbore. Lots of people here have said, that one of the essences needed for EGS, and the reason we brought Norm Warpinski here, is to reach out some distance from the wellbore to increase the permeability of certain volumes of rock. A number of people have said that should be one of our relatively high goals.

I believe we need to consider two main kinds of cases, and one of them is when we are dealing with treatments that have effects near wellbores, either trying to measure or manipulate. Relatively short distance connectivity. There's another set of cases where we might be trying to enhance some aspect of relatively large volumes of rock. If we make that distinction we could start listing out various subsidiary technical projects.

I also think simulation becomes a major area to work on, for various reasons.

Creed: Perhaps it might help if I described a little of what we do in the geothermal Reservoir Technology solicitation. I think we'd be successful here if we came out with three technical sentences you'd want to put into a solicitation for this thing. In the Reservoir Technology solicitation, we asked for three types of work: (a) Identifying and characterizing permeability, (b) Improving injection efficiency and strategies, and (c) Improving reservoir characterization technology. So, it might work out well here if, for the solicitation, everybody would come up with three phrases describing the technology you want.

(Those three areas were then listed on a flip chart of "geothermal" technology needs. Eventually "Reservoir Chemistry" was added to this list of four primary technical areas.)

Pruess: It seems to me that from a technical point of view, we have to distinguish two end members. One being fluid-limited systems, and the other being permeability-limited systems. In the fluid-limited systems, we just have to inject more fluid and optimize that, and we basically already know how to do that. So it's wise to have some projects like that in the bag, since we know how to approach those with incremental improvements.

But for holding out the possibility of tapping into some much larger resource base, the heat down to some depth, we need to deal with permeability-limited systems. And that is the really hard part. Not just in terms of creating the kind of permeability you want, but then also avoiding the pitfalls once you created it that you don't short circuit your flow paths and so forth. And some of these issues may end up being insurmountable, I don't know.

But where I have a real problem is, that I see the need on one hand, given the limited amount of funding, that we need to do something that we can be successful with. So that would counsel for conservatism, and to work on fluid-limited problems, because we know we can be successful with that.

But that does not get the attention for going after this much larger potential resource base. For that you we have to deal with creation and maintenance of permeability. And I don't see any cheap or fast way in making any dent in that, or showing that you could do much more there, and getting attention that way.

Koenig: This gets back to what John Pritchett was saying. Isn't what we are trying to produce here the enhancement of productivity from a geothermal system that ultimately contributes to generation, and can affect the bottom line of a firm. And if that being the case, no matter what project we choose, can we not form some objective that says we're going to go to some system where the answer we want to get is to improve the productivity of that system by X, no matter what methodology we choose to do it, that's what we're trying to get at.

Hickman: My thoughts agree a lot with what you've been saying. But one of the things that concerns me is that we talked about ways of defining success even if the project fails. For example, if your goal is to increase the productivity of a particular field by amount X, and you increase it by X divided by 20, have you failed? Yes, if your only goal was to help out that company with their economic problem. No, you have not failed, if that particular field helped you advance the state of the art so that the next time someone else does that operation, they do it a little bit better. I guess when I look at this list, I think a parallel structure would be creating permeability, what are the technological hurdles that prevent us from creating permeability and characterizing the permeability you create. What are the technological hurdles that prevent the industry from doing that in a cost-effective manner?

Truesdell: There are different types of systems which are less than ideal. Some are permeability limited. I think chemistry limited is also an important type that has only been discussed a little. Another type, heat or temperature limited, is very common, but perhaps not so important to us here.

Entingh: I wrote those off this morning, I said with two and a half to three cents kilowatt hour, low-temperature reservoirs are not going to make it.

Kasameyer: But, what if someone came up with some clever way to move that heat up from deeper to shallow or so and became more economic?

Truesdell: There are probably ways of producing the energy that we haven't discussed. For just as an example, the Fenton Hill Hot Dry Rock project was based on high pressure injection. High pressure injection leads to short circuiting. How about trying low pressure injection where you basically are getting steam out, so that the highest temperature parts of your reservoir will dominate the flow. This was something Don White and I suggested a number of years ago, and was just blown away by the HDR people.

Prairie: Where will we get the people who will say, "Come into our site and do this?"

Entingh: When we were organizing this workshop, we at one point said we are going to invite the people from the EGS Coordinating Committee, and then a couple of us decided no, they don't really want to be here, we won't invite them. Then a couple of people said, "Where are all the people from industry?," So in the last week or so Lynn invited them all, and they all said, "No I didn't really want to come." "I'm too busy." Or, "Just go ahead and do what you're supposed to do, and get the technology folks together." So, that's what happened.

Sanyal: I think much of what I have to say has been said. But let me point out Bob Creed listed the three or four points about the Reservoir Technology solicitation. Maybe for the EGS solicitation, you could have, rather than "identify and characterize the reservoir, or fracture," lets say, "Improve permeability, or improve fluid saturation, or improve reservoir performance." You are taking a more active role here because you have improved the permeability or saturation or performance. Crack it, add more water or place the wells in the fractures in such a way that you improve the long-term performance. Or as Al Truesdell said you take a bad chemistry situation and somehow manage to produce out of this. So, in other words, lets try to push on the enhancement aspect.

Entingh: I've never been uncomfortable in trying to help define what EGS might be and might not be. I've always started from: "We are going to measure or manipulate." I've never been too worried about encroaching on the Reservoir Technology Program ground because I've been pushing for about 10 years to get Res Tech people to quantify objectives for what they are trying to do.

What are the effects of what is it is that they are doing? I don't mean the modelers, but rather the geologist the tracers, experiment people, so forth. And I finally concluded that most of the people that work in reservoir technology are geologist. They work on the basis of words, not numbers, unless it's a brief calculation about impedance in a wellbore, and so on. So I continue to believe that one good way to think about what EGS might be about is to try to start quantifying what some of these manipulations might do for operators.

It's very easy for the Geothermal Program to do a reservoir-related experiment and then sort of walk away from it. If we have an experiment that works, then we have a success. But, how does that help the operator, where are the extra dollars?

I've thought often that one of the useful things that might come out of EGS is to create yet a new kind of geothermal expert that works on new issues about quantitative relationships within reservoirs. Steve Hickman may be one such expert already. It's somebody that understands a lot about rock and understands a lot about flow and tries to create quantative interfaces in the relationships among those things. Maybe this is simply a "rock mechanics" task. But my outlook on this has been informed also by what Ken Williamson of Unocal said at the Stanford Geothermal Reservoir Engineering Workshop this past January. He said, that the reservoir engineer often just doesn't understand what the geologist tries to tell him about conditions in the reservoir. They have to go back and forth, back and forth, before they both feel they understand what they have learned.

Pritchett: I have an idea that might help people narrow this a little bit. The way you get power and get money really has two parts, an injection part and a production part. You're taking fluid out of the ground and you're sticking it back under after you've taken something you want out of it.

I like to think of a conventional hydrothermal system as one in which that's really easy to do, because there's lots of permeability and you just let the well flow naturally or use a down hole pump. A Hot Dry Rock system is when you can't do either one of those things very easily, where's there's no permeability on either side of the process. That leaves two other kinds of systems. That leaves systems where it's easy to inject but hard to produce, or it's easy to produce and hard to inject. Those two latter kinds of systems are what I think of as EGS systems.

From a practical point of view, all EGS systems are peripheral to hydrothermal reservoirs. I don't know if they are in the middle, off to the side, or down under, but the idea is you stimulate one half of the circuit and you use a naturally permeable system for the other half.

The other way to do it, of course, is you find some place where you've got low permeability in the hottest part of the reservoir, you stimulate that and produce from it, taking your natural either natural recharge for your fluid supply or other water from nearby.

I personally believe it makes a whole lot more sense to go after injecting into the impermeable zone than trying to produce from it. If for no other reason than injection is a high pressure process that's going to keep your cracks open for you rather than production, which is a suction process which is going to slam them shut. Injecting into an impermeable zone is the easiest possible problem. It is more likely to pay off than the other possible approaches.

3.5 Overlaps Between EGS and Reservoir Technology R&D Areas

Paulsson: Where is the limit between this Reservoir Technology and EGS?

McLarty: Basically Res Tech is more the understanding of permeability and the hydrology and the EGS is going to be more aimed at manipulating permeability and hydrology. There is crossover. You have to understand it in order to manipulate it and understanding is more the aegis of reservoir technology program and manipulation is more the aegis of the EGS program. So they are intertwined.

Hickman: Reservoir technology actually funds a lot of the kinds of projects you just alluded to, already. So there is a lot of work, seismics and fracture mapping, that has already been done under that program so there is a lot of overlap here.

Meyer: On this topic of overlap, certainly there is overlap but I'd argue for example in this issue of fracture detection that one could have circumstances in EGS system where it was even more critical than in Res. Tech. So you can focus, for example for your fracture detection, into solving problems which are particularly critical in EGS. For example, finding perhaps the fracture ten feet away from your dry well which actually connects to the system that you want to connect to. So that's a relevant question to ResTech, but it's certainly one that you could focus on in EGS.

Pritchett: As Karsten Pruess pointed out quite properly earlier, I don't know of too many systems except for The Geysers in which there is permeability but no fluid. Typically if you have one, you have the other and actually there is plenty of fluid in The Geysers. I was just saying, it's just in the wrong place. Coso also has a serious depletion problem, but there was plenty of fluid in it to start. I'm not trying to argue about that. All I'm saying is these things can be coupled together. When we say we're talking about a fluid limited system, does that mean it's very permeable or could it also mean it might also not be very permeable?

Kasameyer: I think it means we don't want to re-write all the things we're going to write under permeability limited under fluid-limited.

A later interchange, during work on the "permeability-limited" topics:

Lippman: Can I be a little destructive of the process? I feel that the only item which should be EGS is reservoirs that are permeability limited. The rest has been done by others. That's what I feel.

Pruess: (Repeating what he has said before.) Working with the fluid-limited reservoirs is what will enable us to be successful, pushing the envelope beyond what's already working and finding success. We've got to have something like that on the package. If we only do the permeability limited, there is no way in the world that we can get to a reasonable assurance of early successes.

Hickman: For now can we just say that these are needed solutions whether this program does it or whether you buy them from the Res Tech people or use their stuff?

3.6 Relationship of Microseismic Events to Hydraulic Fractures

The discussion presented here occurred during the process of nominating concepts for research. Its length and importance dictated that it be reported in this Section.

Pruess: Micro-earthquake monitoring will be important for this business. There is this perennial question whether the fluids are actually getting to the locations where seismicity is observed, or not. And if this has anything to do with the permeability structure. As far as I know, this is still just a question mark. People have different opinions about it but no one knows. There is basic work needed on how do you interpret the microseismic events that occur.

Pritchett: What's the correlation coefficient between micro earthquake density and permeability change.

Entingh: I believe, with Karsten Pruess, that nobody knows. In some of the Fenton Hill reports, Mike Fehler, LANL's lead HDR microseismic expert, said that for what we have come to call the Phase I-B reservoir -- where they were extending the first big crack and then got that series of odd cracks -- he was able to account for less than one tenth of one percent of what he expected to see as the seismic moment out of all that injection and associated cracking. In simpler terms, they didn't see nearly as much seismicity as they expected, so the general conceptual model of how fracturing and seismicity would be related is not very good. So the remaining question is, "Is most of the seismic signal due to shear pings or does all fluid just go off somewhere, over my left shoulder?"

Some of the Europeans analyzing seismic data from hydrofracturing at the Soultz HDR project have the same question. Do you know the fractures are being formed where you hear the microseismic signals, or not? Some people believe very strongly that the seismic cloud must be where all the fractures are, and vice versa. Other people don't believe that at all.

What would you do? What would you do to get at that?

Warpinski: People have been making this an article of faith and it's an article of mechanics. You can sit at a simulator and put together any system of fractures you want, put the stress on it, put pore pressure changes on it. You can look at the stability of any one of those fractures and decide, based upon coefficient of friction all these things, are they going to slip or aren't they? And which ones are favorable for slipping.

You can come to some rational decisions about if it's a gas saturated reservoir, the crack doesn't go very far. Because you don't pressure couple very far out into the reservoir. So the in the example I showed during my talk, you get this very narrow band which pretty much limits the microseisms around the fracture.

Bu in a liquid saturated reservoir, you are pressure coupled far out into the reservoir. You have this huge cloud that extends hundreds of meters off to the side. And its all a very rational decision based upon putting it in a mechanics model. But no one bothers to do that. They just wave their hands and say, "Oh, lets just try it."

Pruess: But it doesn't tell you whether you get fluid connectivity. That was the experience in the British HDR program where they drilled right through the microseismic cloud and had no connectivity between the two well bores.

Warpinski: That's right, it doesn't. All it says is that you have changed the stress conditions in the reservoir. You have generated microseisms. So what should have been done in the HDR work was to ask: "Well, why were there microseisms? What is likely to have occurred out there?" You can take a model of a fracture, a penny shaped fracture, or other shape fracture, calculate the stresses all around it. Put in more fractures, calculate the leakoff down fractures, calculate what the pressure coupling is in a gas saturated reservoir, or liquid saturated, or some combination. And you can figure out what that pressure pulse looks like, how far away it will be. And that same calculation can indicate how far the actual fracturing fluid has moved vs just some other pressure coupling up into the reservoir. You can do those kinds of things.

Had they done that, I think the answer would have been, "Shoot, our frac fluid never came close out to there. That's just activating fluids already in the reservoir through a pressure pulse somewhere far out there."

Hickman: There's another issue here, of whether or not a shear event on a fracture is going to generate enough that way to see if you increase or decrease the permeability in a substantial way. There's plenty of laboratory evidence showing that certain kinds of rocks with certain porosities, shearing will decrease permeability, but that in other kinds of rocks, typically low porosity, crystalline rocks, shearing increases permeabilty. So in terms of fundamental understanding, the relationship between shear failure and permeability change, I would see as the big issue here.

Warpinski: Yes, absolutely.

Pruess: I think that there's even more to it than that and that is experience from various nuclear waste isolation programs such as in the Streefall (sp? [][]) mine in Sweden and the Grinfall (sp? [][]) tunnel in Switzerland, where fractures pre-exist. We're not talking about doing any hydro-frac job. There are numerous examples of drilling bore holes through the same fracture plane, and having no communication. This is with single phase flow. It boggles the mind, but we have to accept that fluid flows not an simple areal phenomenon in the fracture. It is highly channelized.

Hickman: But also that all fractures don't behave the same and that sometimes a shear fracture is a barrier to fluid flow and sometimes it's a conduit. I think that's a fundamental research topic.

Warpinski: And if you wanted to monitor the hydraulic fracture or monitor the fracture system in the reservoir, you might do things totally different. To monitor the hydraulic fracture, I'd use a real stiff fluid and I'd pump as fast as I can and try to minimize leakoff and get my microseismic activity near that fracture, to increase shear stresses, tensile fracturing.

Otherwise, like hot dry rock, when you pump a low viscosity fluid for long periods of time, all you do is activate the reservoir. You're right, you have no way of knowing whether that has any communication whatsoever with your fracture system or whether it is just that you created pore pressure, stress changes out there.

I think we have to sit down and say, "Well, what are we trying to do? What are we trying to map, and what's a good strategy for doing it?" I think we can come up with some reasonable answers, put together models and do that kind of thing. And that's never been done, is the problem.

Hickman: Not even for oil and gas?

Warpinski: For oil and gas, we have done that in a number of applications. Looking at microseismic activity and drill cuttings in injections was an Arco task in Jasper in Beaumont, Texas, that went through exactly the same question: "Why did we get the particular pattern in doing that kind of thing?" We've done it some gas well situations, trying to understand the size of the cloud and why it has a certain width and those kinds of things. So in some limited applications in the oil and gas industry, we have done that. But I've never seen it applied to the hot dry rock and other kinds of things in geothermal.

Swenson: There are people who do that. Like Willis Richards. He has a model in which you set up a random stochastic set of fractures and then he starts pumping in and he tracks how much fluid he's injected and he can tell you where it goes.

Warpkinski: He looks at stability of the system and everything?

Swenson: I think so, although I'm not sure. He has one stress that doesn't change as the fluid is injected.

McLarty: So does understanding the effects of shear failure on permeability pretty much capture the main effects in the reservoir?

Pritchett: I would say, what if any is the relationship between observed seismic micro events and regions of permeability increase. It seems to me the correlation is less than unity. The question is under what conditions is this likely that microearthquake monitoring is useful to understand changes in permeability?

Entingh: Is this the fifty million dollar R&D question that would be worthwhile having energy program offices other than just Geothermal get interested in? Or is this something important only for geothermal? It sounds like a hard problem.

Pritchett: Yes, in a flash. Some people think micro earthquake monitoring is wonderful. Others think its a waste of time, the correlation is zilch. But they're looking at different systems. We need to know when is this useful?

Warpinski: I think there's another aspect to this, too. Both for microseismic and for tiltmeters, if we really want to do a good job, we should be fairly close to the fracturing zone. And right now because of temperature we can't. I would say that if people really want to monitor these fractures with these two techniques, that we need to get some high- temperature sensors. And I think it would help Bjorn Paulsson as well, because I would love to do the cross-well kind of thing, with time lapse. Not just when we are drilling the well but also then do it six months down the road after we have done the injection for a while then in another six months and see how things are changing with time. If we had the high temperature sensors to do that, we'd be in a lot better shape.

Pruess: Other program offices said, maybe in this connection between seismicity and permeability (it could be EPA, not DOE), for deep well injection where typically there is seismicity and there's concern about confinement and integrity.

Kasameyer: For us, these things need to be done with geothermal rocks, which have different mechanical problems than a lot of other things. They have to be done at high temperature, too.

3.7 Criteria for Prioritizing Research Thrusts

McLarty: Another thing we need to do is talk about criteria for prioritizing these ideas. Some came out in the discussion yesterday. They are a little bit broad. I think we need to try to focus them down to four to six criteria to use for prioritizing research areas.

I propose that the first and foremost criteria would be that the research areas contribute to the general goal of enlarging the geothermal resource base while simultaneously providing some short term technological spin offs for the hydrothermal industry. Does that sound reasonable?

Robertson-Tait: I think some of the things you've proposed are more medium term, in my view. The fracturing technology, some of the other things might be more medium term so you might broaden that just a little bit. I mean of short term as being completed within the next five years. I don't think that if you can't get something out of it in five years it should be eliminated from the mix.

McLarty is saying, "Attractive to industry or some benefit to industry -- short term benefit to industry." I take that to mean some method of reducing costs, improving efficiency, or improving operations at an existing site. So I hesitate to have a firm criterion that anything that doesn't pay off within five years isn't included. I think we should look a little bit longer than that.

McClarty: I agree with that. What's a better way to word it.

Pritchett: Are you kind of saying, you need at least something that you can wait around and say, "Victory, Victory" about four or five years from now?

McLarty: The program definitely needs that, but not every aspect of the program has to be focused on that. There should be some aspects that are focused on longer term things but hopefully some short term, medium term spin offs will be available from pursuing the longer term goal.

Entingh: I think we shouldn't use the terms short-term, medium-term, long-term. Within Government, long-term means, "Within my grandchildren's lifetime." To industry, we've been told, that long-term means, "Not more than three years from now." I would suggest you decide that from a research point of view what the periods should be. I suggest to use periods of five years and ten years, but five years starts sounding pretty far out for industry.

Pritchett: Yeah, but realistically, what are you going to do when you're not going to get anything back in one or two years.

Sanyal: Shouldn't we be tying this to the EGS Road Map because there is a plan by year 2008 there will be large scale pilot project. And anything that contributes toward getting that reality should have the priority. We have to tie it to something and I think the road map, for better or worse, has been agreed upon by everybody.

Pritchett: Just a question about that though. What do we mean by a pilot plant? Are we talked about a Fenton Hill model, full HDR-type system, or are we talking about an extra unit at The Geysers driven by injecting.

Grabowski: The Road Map pilot plant operating by 2008 is something that has augmented an existing field. Period.

McLarty: Something that in an existing field produces more power, whether it be a separate power plant or whether it be increased production, to increase generation.

Entingh: For two years there has been the question of whether a demonstration project is something like a standalone Fenton Hill site at a new place, or is it something in the middle of an already producing field? Everybody, at DOE and us, was quite willing to sluff that question. It's really reached the time where if you are going to get anything done by 2000, 2003 or something like that, it's going to have to be in an existing field. So I'm glad that Paul picked the right answer. Because it doesn't take any sense to do anything else at this point.

Prairie: It seems to me that we should do two things at once. We should try to advance the state of the art of technology, develop new techniques that head towards our long term goals of hot dry rock-like systems. At the same time provide near term benefits for the industry. So by doing the a project that enhances productivity at the geysers while you learn some new frac technique, although somewhat risky, is the perfect project to take on.

McLarty: Yes. That's basically what's said in the EGS Strategic Roadmap. I think this single criteria encompasses all the criteria. Maybe a good way to do this is before we start voting is to have everybody open that Roadmap and spend five or ten minutes looking at those milestones, on page two of the Road.

Grabowski: Let me draw your attention again to the table on page 6 of the EGS Strategic Road Map. I want to draw attention again that the EGS National Coordinating Committee recommended we concentrate on that block that falls under "manipulating permeability." So maybe that should be a criterion: Does it manipulate permeability?

Robertson-Tait: That would eliminate all your injection augmentation programs which I agree with Karsten Pruess said yesterday. I think we need them in the bag.

Pritchett: I would like to nominate a second criteria. But I'm not sure how to phrase this. What I want to suggest is that what we're trying define a figure of merit which is in some sense bang for the buck. We need to pick projects that are relatively minor investments of funds and time because we don't have much funds and we don't have much time. Yet it is going to do something that is visible and spectacular.

McLarty: So basically what you are saying is it should have a good cost/benefit ratio.

Criterion: Relationship to Reservoir Technology R&D Program

Truesdell: It seems like manipulating chemistry is a lot easier than manipulating permeability. So if you can find geothermal systems that haven't been developed because of adverse chemistry, and there is one glaring example in the Northwest Geysers, by a little bit of manipulation -- in fact it we know how to do it right now -- you could have a lot of bang for a very little buck.

Grabowski: I think that falls outside this program though. Not that it's a bad idea but I think that falls into the Conversion or ResTech program.

Entingh: Why would that be?

Grabowski: Because it's not manipulating permeability or hydrology.

Creed: It's clearly outside the aegis of the EGS work.

Truesdell: So you wiped out the topic of a chemistry program.

Creed: No, it's in the ResTech program.

Lippmann: We were talking yesterday about the injection in the hot temperature zone of The Geysers. Now we're dropping them?

McLarty: I think that what we decided earlier was that we prioritize what we've already done and then come back and look at the chemistry later.

Creed: I want to emphasize what Paul's pointed out. When you're talking about bang for the buck, industry support, etc, etc., and that's what they've told us they want--techniques to manipulate permeability. That's what we should focus on. The long term research stuff is noble and good but we don't have that time it requires. We don't have the budget that requires a parallel path like that. Also it has been my experience that even when we pursue the relatively straight forward techniques, you come up with questions and issues that turn into little research projects that are much more focused.

Robertson-Tait: I think that injection as a tool to manage chemical problems is a valid thing to include under injection. We could eliminate the chemically challenged reservoirs from our discussion, but you know injection as a means of controlling chemistry could be, I think could fit into manipulating hydrology.

Koenig: Based on my own experience, this has already been done at The Geysers, by industry there. It's already known that injection has done this. So using injection as a tool to manage chemistry problems would not be a way of demonstrating something new or showing big bang for the bucks, since it has already been shown.

Sanyal: Based on what Bob said, there really are essentially three issues at this time that the U.S. geothermal industry would be interested in.

1. Improve the technology for creating fractures.

2. Define the fractures.

3. Three, make predictions about reservoir behavior based on the fracture definition.

Those are the three real points that industry wants from EGS.

McLarty: Yes. And those are inherent in these technical objectives.

Prairie: We probably should note those.

Creed: Should we add a clause on Advancing the State of the Art with something to the effect that "this compliments the Reservoir Technology research program?"

Prairie: I don't think that we necessarily have to worry about that in this group. Later when we figure out how the projects get done, that separation can happen.

McLarty: I would agree with Mike on that. That has also been factored into that technical objectives matrix because the upper two quadrants of that are primarily the ResTech area.

General: There was more light general discussion about this point, but it ended with the group deciding that it would sort itself out later.

Criterion: Advancing the State of the Art

Hickman: I would add something else, based in part by Brian Koenig's comments. Your statement is too severe, that tweaking chemistry is kind of the standard thing. There needs to be work done in advancing the state of the art in this area, so that industry might do more of this.

So I would add a Criterion (or add to what is now Criterion number 4) something about advancing the state of the art leading to fundamental improvements and knowledge, not just applying accepted practice somewhere else. We talked about this yesterday. I think we all agree but I think we need to list it. This is a Federally funded program. Federal dollars should be spent on advancing the state of the art.

Pritchett: Let me expand on that for just a minute. I guess that's the response I had to what Ann presented yesterday. I said then, "Wait a minute! You can't claim that. You're basically saying that you're advancing the state of the art by injecting water into a reservoir?" We've known that injecting water into a reservoir raises pressures, for a good long time. This is nothing new. Sure, it's a good idea, but it does not advance the art.

Prairie: But the way you would advance the state of the art is to learn how to do the injection properly for a geothermal application, by developing a new fracture method or some other means, perhaps. It seems to me that's how you advance the state of the art with that.

Pritchett: You've got to basically do something that hasn't already been done, to impress people. You couldn't just go out and reinvent the wheel again and again and say "See, Look what we did!"

Sanyal: It is not reinventing the wheel when for the first time in history of The Geysers, somebody actually increased production. This never happened before. After 30 years of work there. Therefore, it is a success story and it is also advancing the technology because nobody ever thought you could exceed the traditional injection limit. In fact, Unocal had papers going back to the sixties when they said the injection would not work.

Pritchett: Absolutely right. But that wasn't an EGS program. It was something that was going to happen anyway.

Prairie: Let's take another example: At the Dixie Valley project. If you were to take this well that Steve Hickman is working on, do the frac, make the connection to the other producing part of the reservoir, would that not advance the state of the art?

Pritchett: Now that would be something new. That hasn't been done.

Hickman: In creating new permeability, I see many more fundamental advances there than I do with the augmented injection. Although I also think with respect to augmented injection, there are testable ways of tracking the success of the injection that are new.

Koenig: Let me add one thing. One aspect of injection that may play a role in doing something new, is something that Dennis wants to look at in the proposal that he's talking about. That is to use the thermal cooling effects of injecting water into a significantly higher temperature region of the reservoir to actually enhance the permeability.

Lippmann: But that's something which we are just going around on. We need to develop high temperature tools and equipment to do that. We are just saying we're going to inject at high temperature -- 400°C. Do we have the tools to do that? That would be one goal for the EGS.

Creed: I think that's important and that's one of the ways you're going to monitor your results and evaluate success. Now you don't have sufficient ways to monitor what you've done.

Lippmann: If you can't do it, there is no sense in developing a monitoring technique. We have monitoring techniques already. We have to improve them but we need to have everything hardened for high temperature, high corrosive environments.

Grabowski: I agree but however that shouldn't be a criteria. We talked about that yesterday as some of the solutions to the barriers. And that's going to fall out in some of the R&D projects.

Criterion: Influencing National Opinion

Entingh: I want to repeat something I said yesterday. Part of the state of the art for this industry and this research community is figuring out how to influence national opinion about whether geothermal energy, as a whole, is worth continuing to invest in.

It the past ten years I've heard it said over and over again in Washington, DC, "Geothermal energy is junk. Just look at The Geysers and how it's disappeared. That field just proves that any investment in geothermal disappears very, very quickly."

But today, something interesting is happening at The Geysers. The power output is disappearing, but not so quickly. Now we can say, "Oh, it's being sustained somewhat!" And the other people, the advocates for other renewable systems that compete with geothermal for research and policy funding, environmentalists, Capitol Hill, etc., need to be made more aware of that. But when I think about carrying that message forward to those folks, I end up thinking, "But, gee, it's still depleting, isn't it?" So how do we sell that? It still can be criticized as weak.

It's conceivable to me that within twenty years, The Geysers might be able to support much more capacity than it does today. If you understood enough about the rock and understood enough about where to pump liquids without cooling producer wells, and I think you probably can, then The Geysers might be able to sustain 1,500 to 2,000 megawatts of production for 100 years. That, however, cannot be a goal of industry right now, because it's simply too complicated for them to think about accomplishing.

So I believe that part of State of the Art is not just about the next increment in temperature capability of a widget. Part of the State of the Art is the overall look and feel of the energy resource and energy technology system that becomes an important consideration for the White House it is laying out domestic policy. Don't forget that. So sometimes it looks like what's being done doesn't advance technology directly but it may be advancing this other part.

Creed: If that is your objective, then just do some nice, fancy 3-D and 4-D visualizations and claim success.

Entingh: I don't think so. That was like what was done with the economics of Hot Dry Rock. It didn't work very well.

Lippmann: I'm coming back to the fact that we're talking about the same story as before, as usual. You talk about the resource, the huge resource. The huge resource is high temperature at very low permeability rock masses. So the whole program should be directed to see how we can circulate fluids through that mass which means increasing permeability, increasing fractures. That should be the main goal of the whole thing and developing the necessary technology.

That's it. We are just running around a big question. We don't want to talk about Hot Dry Rock. We should call it Hot Wet Rock, like the Japanese have. We should just find which is the minimum temperature we should look at and which would be the type of fracturing we should look at. We should never go back into trying to hydrofracture tight, completely unfractured systems. We should go to a place which has microfracturing which we could stimulate by hydraulic fracturing and just go into increasing permeability. That should be the goal.

The Geysers is the only dry steam field in the United States. There might be ten fields like that in the world. At The Geysers, we know what to do and we should have to have the technology, the tools to do it.

Entingh: John Sass and Mark Walters have a draft paper in for the GRC transaction accepted. Some of you have seen that, too, because they have sent it around. Roughly at the margins of hydrothermal fields may be about another 5,000 megawatts, total, if you could make it economic. From the point of view of national policy makers, that doesn't cut it.

Even though that's the estimate for the Basin and Range only, and 5,000 MW is about twice the geothermal capacity the U.S. has installed now, that's still a very small number in terms of the national policy perspective.

Marcello: So now we have to, instead of an economics, go making some kind of dream pipe, pipe dream estimation about the cost. We're going to have to come out with some dreams about the size of the resource.

Robertson-Tait: What sells in Washington and what doesn't should not be one of our criteria.

Pritchett: I think we ought to be looking at cost-benefit, not just benefit. I mean the point is, sure, sure 10,000 megawatts is small compared to the national electricity consumption. It's miniscule, but we're not asking for the whole DOE budget here. Right now we're talking about $1 million a year. If we can give them 10 megawatts for a program that costs $1 million per year, or 1,000 megawatts for a program that's running $10 million or $100 million a year, it's a bargain.

Pritchett: I know we already have the cost/benefit criterion up. But I'm talking about this more global issue. I'm suddenly hearing that in order to get their attention, we've got to promise them 100,000 megawatts or a million megawatts, down the road. That's going to be unrealistic.

<u>Criterion: Fit with the Technical Objectives of the EGS ROAD MAP</u>

Prairie: Can we review the Road Map technical objectives?

Croft: These objectives are sort of the global guidance from which we are working, so you all ought to have those fixed in your minds.

Kasameyer: We're only looking at the lower left corner of Table 1?

McLarty: The lower left corner is the primary technical objectives and secondary would be lower right. And then the upper left and upper right are more the aegis of the Reservoir Technology (Res-Tech) part of the DOE geothermal program. There are six technical objectives of which three are high priority and three are lower priority.

Kasameyer: It's much more narrow than we've been talking about.

Prairie: But it doesn't say anything here about developed fracture techniques for geothermal reservoirs. It says "develop models" and "develop ways of monitoring."

Hickman: It says, "Improve well stimulation and enhanced recovery techniques." You can't do the second part of that without doing the first. Understand the permeability first and then improve stimulation techniques.

Pricthett: Nowhere here does it say anything about getting any more megawatts.

Grabowski: That's not a technical objective. That's one of the milestones of the Strategic Roadmap.

Hickman: I think in the process of going through this we are going to find that -- especially if we apply the criterion about the advanced state of the art -- that we will see that most of the work will fall under manipulating permeability and just a few things fall under augmented injection. That will address concerns of a number of people here that we don't diffuse ourselves too much. We would be really focusing on advancing the state of the art and hopefully in the process, having some big splashes, successes.

Table 3-1 shows the final list of decision-making criteria.

Table 3-1. Decision-Making Criteria

Purposes and Values:

- Projects should be attractive investments for both industry and the government. For industry, those features should include either capital cost avoidance or reduction in operating expenses. For the government, the main target is to increase the fraction of geothermal resources that are economic to produce.
- Projects should offer the promise of improving the economics of some aspect of geothermal energy production.
- Increase the productivity of an existing (geothermal) systems to increase the bottom line and/or shed light on technological challenges.

Technical Focus:

- EGS projects should focus more on enhancing permeability, since other aspects of the DOE Geothermal Reservoir Technology R&D program already focus somewhat on enhancing reservoir fluids.
- This research should not duplicate what is being done in other technologies (e.g., petroleum engineering and environmental remediation.)
- Projects should have clear applicability to both EGS reservoirs and broadly to other types of geothermal systems.
- There should be a clear rationale for the value of each project to research contributions versus the improvement of economic production systems.
- Find novel ways of producing fluids. For example, use low pressure injection in a hot dry rock-like situation.

Management Principles:

- Each project should advance us toward our ultimate objective(s), whether the project succeeds or not. There should be at least knowledge gains in failed projects.
- Projects should seek to overcome the identified barriers.
- Projects should fit into a systematic framework of technology development.
- There should be parallel program possibilities that promote scientific synergism.
- Do something inexpensive that may produce clear, useful results with big payoffs.
- Projects should seek a large bang for the buck, as rapidly as possible.

SECTION 4.0

NOMINATION AND CLARIFICATION OF TECHNICAL THRUSTS

4.0 NOMINATION AND CLARIFICATION OF TECHNICAL THRUSTS

4.1 The Working Methodology

After much discussion, the group decided to concentrate on an eight-cell matrix, as follows. There were two main goal-driven Topics.

A. Enhance reservoir permeability
B. Enhance reservoir fluid contents.

Two other important Topics (rows) had been proposed: Improving Reservoir Characterization Technology, and Chemistry, but those were ignored to concentrate on the two topics that survived.

Under each Topic, there were four technical functional areas:

1. Barriers to development
2. Develop and use methods
3. Measurement needs
4. Basic Knowledge needs.

In matrix form, this looked as shown in Table 4-1.

Table 4-1. Matrix for Nomination of EGS R&D Needs

	Technical Functional Areas			
Goal-Driven Topics	1. Barriers to Development	2. Develop and use technical methods	3. Measurement needs	4. Basic knowledge needs
A. Enhance reservoir permeability	Chart 3	Chart 7	Chart 11	Chart 15
B. Enhance reservoir fluid contents	Chart 1	Chart 5	Chart 9	Chart 13

In the first functional area, "Barriers," items were nominated, but not prioritized, because the group had trouble defining "barriers" in a non-circular manner, and thought that the importance of various technical barriers would be clear from the priorities assigned to the other classes of items.

Discussions clarified that Area 2. <u>Develop and used method</u> was the cell at which general "solutions" to the main problems in each of the goal-driven topics were to be nominated. The group first nominated research topics for all of the cells of the matrix, and then made a second pass to clarify and expand the meanings of some of the items.

The nomination phase was preceded by the following comments:

McLarty: Please don't be too constrained by your idea of how big the EGS budget might be. We want to have more of a blue sky approach. Tomorrow when we get down to prioritizing things, some of the blue sky stuff might kind of shake out and disappear. But we want to give people the chance to be creative. For example, there's already a question about the heat limited category. Let's leave that in for now. That may fall out tomorrow and prioritization as well but let's go ahead for discussion's sake and leave it in this afternoon. I've numbered each of the matrix squares just for convenience of referencing our flip charts.
Don't limit yourself to these broader solutions. Larry Myer suggested that we pretty much as a group know what those are. Let's identify those but let's also add some suggestions for very specific topics or concepts for research projects within those larger categories. You know limited permeability is a pretty large category. Let's get some more narrow projects defined within that larger category.

Paulsson: In the oil and gas reservoir before you start to plan the production of the reservoir, you have a very comprehensive reservoir characterization program. I don't know if I'm not hearing the right words or if I'm just a beginner in the geothermal field. But I don't hear reservoir characterization talked about very much at all. I mean characterization of the bulk reservoir, the characterization of permeability paths, like fractures. Should we have at least a column in the matrix talking about reservoir characterization of these various types of reservoirs? And what methods are best suited for the different types of reservoirs?

McLarty: Well, that could fit into the Barriers column as one of the barriers is not having all the knowledge or data you need about particular reservoir and how do we get that data. Well, that falls over into Solutions. So I would suggest, rather than having adding a specific column called reservoir characterization, that that be part of the barriers. Also, I'm sure a lot of people are thinking reservoir characterization, here we go again, that's Res Tech. We're talking about the EGS program. There is some similarity and some cross over and carry over between the two.

Additional Process Notes

In much of the text below, nominators and discussants are not identified, because the discussion often involved a number of people speaking rapidly and adding to each other's ideas. But in some instances, persons expert in particular technical areas are identified to clarify the importants of certain questions and ideas.

In actual fact, ideas were nominated and recorded on flip charts on Tuesday afternoon, and then clarified and then prioritized (voted for) on Wednesday morning. To make the discussion easier to digest, in these proceedings we have colated the materials that arose during Nomination and Clarification. In each major Subsection here we show the final list of ideas nominated in each block of the 2 X 4 matrix, and then present all material that helped to clarify the intent, meaning, and/or importance of what had been proposed.

The lists show the number of votes received by each nominated issue/item, which -- of course -- the participants did not see as they Nominated and Clarified.

To make this clearer, some of the condensed final results are shown at the top of each block of discussion. The condensation is essentially what was recorded on the flip charts in their final form. Since the voting occurred after the clarification step, the participants did not see the votes that are recorded in the tables below.

We covered Topic B., Enhance Reservoir Fluid Contents, first, since most of the community's working experience is there. Then we addressed Topic A, Enhance Permeability.

4.2 General Topic B. ENHANCE RESERVOIR FLUID CONTENTS

As mentioned elsewhere, votes were not taken on barriers.

B.1	**Barriers to Enhancing Reservoir Fluids** (Flip Chart 1)
Item	
a.	Where will the water come from? Cost of water versus benefits.
b.	Where do we put the water to do the most good?
c.	Lack of reservoir data.
d.	How do you confirm that the water went where you wanted it to?
e.	Lack of ability to design the needed system.
f.	Will the water change the reservoir in unexpected ways?
g.	Unlikelihood of industry's drilling new wells for injection.

B.2 Methods for Enhancing Reservoir Fluids
(Flip Chart 5)

Votes	Item	
15	a.	Map the fractures to know where to inject.
19	b.	Credible predictive modeling (especially to convince stakeholders to invest.)
8	c.	Credible testing and monitoring program, to appraise what has been accomplished. This should include tracers, geological mapping, pressure transients, well logging, and seismic imaging.
1	d.	Inventory of water available for injection.
0	e.	Hardware design.
1	f.	Develop drilling techniques for under pressured reservoirs.
1	g.	Improve wellbore imaging.
1	h.	Develop methods to determine core orientation.

Total for this panel = 128 votes.

Discussion:

Clarification comments follow. In some cases, there were no clarifications for an item.

15	a.	Map the fractures to know where to inject.

- We need to map the fractures, including their direction, size, and extent.

- How do you confirm that the water went where you wanted it to go?

- Where do you want to put the fracture, one that will do the most good?

- Where do you try to put injected water, to do the most good? That needs credible predictive modeling. That tells you by trial and error where you should be injecting. Ultimately, the actual modeling using the tracer results and other testing results will tell you where you put the water.

- Do you know how your injection will change what the rocks are like? Maybe your injection is going to cause the fractures to fill up with calcite or the injection's going to cause hydrofracing. Is the water going to change the reservoir in ways you don't expect? Gum it up or open it up. Water/rock chemical interactions are a potential barrier to utilization of the system.

- It's also important to note that lack of knowledge about water/rock interactions is a barrier to designing a system.

- It might also be important to understand chemically-induced cracks or fissures.

- How to characterize formation stresses using micro-fractures is an example of lack of knowledge by some.

19	b.	Credible predictive modeling (especially to convince stakeholders to invest.)

- This should include "Flexible conceptual models." "Flexible" means that you have to be able to do many kinds of things, for a particular injection program.

- We could just mark out the second line of that and just add "Credible."

- The implication is whatever modeling you do has to be robust enough to take multiple inputs.

8	c.	Credible testing and monitoring program, to appraise what has been accomplished. This should include tracers, geological mapping, pressure transients, well logging, and seismic imaging.

- There is a need for some kind of reasonable testing program. You better have some tracer tests. You better have some pressure transient tests. Somebody ought to take a look at reservoir structure, geological mapping, whatever you always do. Somebody has got to sit down and put all this together and put a picture together out of it.

- Categories listed under this topic, during the clarification phase, were: 1. Tracers, 2. Geological mapping, 3. Pressure transients, 4. Well logging. The four categories should not be individual items for voting. They should be cited as examples of important things to work on in a testing program.

- Tracers and pressure transients really are the most typically used methods here, to describe the reservoir's properties.

- "Seismic methods" should be included under well logging, and then possibly at other places also, e.g., cross-wellbore seismics.

- Seismic is different from well logging. I think you could add it later. This is in part about bore hole seismics.

- Testing and monitoring are two different things and I think you're downhole seismics would be more in the monitoring category than in the testing category.

- Testing for what? Is it to design the program, or test for what?

- We're looking at appraising what you've done. Where is the water going when you are injecting? When is it going to show up at the production hole? You do that with tracer studies; you do that by looking at pressure transients.

- For instance in a steam flood, we combined cross-well testing and tracers, and combine the cross sections we got from the two.

- When we talked about this yesterday, we were testing the performance of the injection system. How fast can you inject? Where does the water go? Which is slightly different than "characterization."

1	d.	Inventory of water available for injection.

- How about some sort of hydrologic inventory? Where will you get the water? You know that begs for an inventory of sites and somebody to really look at credible sites for EGS type work, and ask, well, are there available sources of shallow ground water or effluent?

- The cost of the water vs the benefit of the electricity is an important issue. To get that cost-benefit ratio, you're going to have to have some idea of how much electricity you're going to get per unit acre foot of water, too.

0	e. Hardware design.

- What about hardware? Is it feasible to mention some sort of new injection hardware that might help with new approaches?

- Do we need better downhole samplers? Injection is a pretty simple thing. You just dump it in.

- Maybe we need a high-temperature or moderate-temperature circulation-cooled packer that lets you run injection pipe to some great depth at The Geysers that you might not have run into otherwise. Would that be new?

- But the DOE Geothermal Program has a drilling program R&D at Sandia that's designing packers and that's doing all this stuff. We don't need to do it in this program, too.

- What we're talking about under this Topic area is injection, not hydrofracturing.

- You might want to isolate a particular zone for injection for long term injection, so it's a valid question.

- But there was never any problem in the hydrothermal industry with this.

- The packer business is not an EGS problem. That's Reservoir Technology work.

- But if you look at what's happening today. People are injecting in very high temperature reservoirs, e.g., Coso and The Geysers. There's never been any problem with hardware.

- The high temperature packer is really important for EGS, but it belongs over in the impermeability list, because no one's going to put in inflatable open hole packer in a long term injection well.

1	f. Develop drilling techniques for under pressured reservoirs.

- There's not any technological problem with under-balanced drilling at The Geysers. The Geysers are the world's most under pressured reservoir. People have been drilling into it routinely.

- That may not be true. I keep reading that enormous damage is done to most wells in the oil sector. I think enormous damage is done to many wells in hydrothermal drilling. I've heard contention between American drillers and New Zealand drillers, for example about the best ways to come up with a clean well, rapidly.

1	g.	Improve wellbore imaging.

Issue: Improve well bore imaging for fluid-limited reservoirs such as The Geysers. Borehole imaging techniques are used frequently in fluid-saturated reservoirs, to map fractures right at the wellbore. These work well in fluid-saturated boreholes, but not as well in steam filled holes. For example, there are no imaging logs at The Geysers.

One of the solutions to this, is to develop mechanisms for oriented core.

All the things are related to mapping fractures that are going to show up here and in other technical areas. That's one of those overlapping methods.

1	h.	Develop methods to determine core orientation.

(No comments)

B.3 Measurements for Enhancing Reservoir Fluids
(Flip Chart 9)

Votes	Item	
4	a.	Tracer tests, natural and artificial.
3	b.	Monitor production well pressure, enthalpy, and flow.
1	c.	Downhole samplers that work.
9	d.	INSAR and tilt meters.
14	e.	Geophysical measurements. Gravity, seismic, microseismic. Continuous monitoring.
3	f.	Electromagnetic logging tool. High temperature NMR tool.

Total for this panel = 34 votes.

Discussion:

4	a.	Tracer tests, natural and artificial.

- Geochemistry is important. We should develop better tracer tests, both natural and artificial. This should be broadly called, "Chemical stuff."

3	b.	Monitor production well pressure, enthalpy, and flow.

- Track the discharge enthalpies, temperature, pressure, and flow from production wells.

1	c.	Downhole samplers that work.

- Develop a downhole sampler that works.

9	d.	INSAR and tilt meters.

Hickman: Use INSAR, interferometric synthetic apperture radar. That consists of monitoring precisely the two dimensional pattern of ground subsidence over a reservoir. It's used to monitor ground water depletion and recharge. Add "tilt metering" here, because you run the two together. INSAR sensitivity is in the range of two centimeters.

These two are used together, because INSAR gives you a detailed map of how the ground sags, and where, over the reservoir. So if you'd like to reinject you can keep track of the plume by the effect it has on reversing the subsidence that occurred during depletion. But tilt meters are more accurate.

So in an ideal world you would have INSAR (Interferometric Synthetic Aperture Radar) maps, which are from satellites flying over and taking radar pictures. It's cheap. And then you put a couple of tilt meters to give you more precise benchmarking on the contours you see on the INSAR. Together, that's used all the time in ground water studies.

14	e.	Geophysical measurements. Gravity, seismic, microseismic. Continuous monitoring.

- Apply and improve the standard geophysical tests used for hydrothermal reservoirs. Gravity. Self potential. Seismic monitoring. CSAMT. Micro-earthquake monitoring; that will sometimes track where the cold water is going.

- Microseismic includes continuous monitoring of microearthquakes.

- Are some of those more important than others, or more important to develop than others?

Kasameyer: I contributed this item. I can't tell you what geophysical measure is important -- even though I love geophysics -- until I know specifically what project you're talking about. I don't know that voting one amongst the other in here is going to add anything to this. I mean it's clear that a project involving injection will have to involve some geophysical monitoring, but until you know what the specific project is, I don't think you'll know what specific monitoring methods to use.

Hickman: There's some lobbying going on here. I see this (geophysical methods) and wellbore imaging kind of belonging together. Similar, what we listed as electromagnetic logging, and mapping the fractures, are involved. Lumped together, this would be: "improved techniques for characterizing fracturing and fracture permeability near the wellbore." Improving techniques for characterizing fracturing and fracture permeability near the well bore would characterize, taking that one : well bore imaging and number A.

Other: All we have to decide for now is decide whether to break this area into two pieces. Some said yes, others, no.

Entingh: I think we need two components here, because some people will say, "Mapping the fractures is defined where the entry points at the wellbore are," and others will say, "Mapping fractures is detecting their course at some distance from the wellbore." Is that what you are thinking?

Robertson-Tait: We could call the one, "Mapping the fractures at the well."

Hickman: I was actually thinking at all scales (of length and distance). I'm not just thinking at the bore hole wall, but using the electromagnetic logging tool looks deeper than the borehole televiewer or FMS or FMI. Tilt meters look even farther away; so do seismics. I would say just, "Improving techniques for characterizing and mapping out permeable fractures."

Others: Let's not forget that we put those things up there for the main purpose of how do you know where to target your injection.

Pritchett: I think we want to put that dividing line on the chart back in. I'm not sure what we do with what's below. The difference is that the ones above the line there are basically looking at large scale motions of big masses of water in the reservoir and seeing where they go: gravity, resistivity, surveying from the surface, that kind of stuff. I don't think we're talking about inventing any technology here. How to do those things is pretty well known. I think what you want to do is do it and show that it works in this kind of an environment.

Paulsson: Back to something that Bob Creed said, that seismic is problematic for monitoring in geothermal work. In the oil and gas industry, that would be the primary technique to map the advances of steam flows. I mean, you can actually see the fluids and the steam and the pressure fronts moving through the reservoir. I think that is something we should adapt it to this kind of monitoring technique.

Creed: But you want to track that back to the individual fracture in the well. You'll never be able to do that.

Paulsson: Well, we did fracture shadowing experiments where we inflated the fracture and we saw the shear waves shadowing appearing at specific places.

Creed: So your resolution is sufficient that you can identify fractures in the bore hole at the points of entry?

(At this point, the moderator timed out this discussion, since it was starting to "solve a problem" rather than "clarification.")

Sanyal: I have a question. Are these lists for monitoring and all that, is it for an ideal project? Because no developer can afford to do all of that and be economic. If you look at what happens in injection at The Geysers or Coso or Salton Sea, all they do is find unused production wells and just dump the water there. The only time that any logs or any tests are done is when there is a problem. If you go and tell an operator, this is the laundry list of what he should be doing, he'll laugh. I mean, we'll lose credibility again. So is it that what you are doing here is showing what an ideal world should be if we had the monitoring project? Because no operator can do all of these.

Hickman: Imagine for example gravity. There's some gravity logging being done at Dixie Valley now funded by OGWT (Marshall Reed) as a research project. What if it proves to be so outrageously successful that all operators now adopt it as standard operating procedure? That would be a very desirable outcome. No operator would do it now and pay for out of their own pocket.

Sanyal: So you're going to try all of these and then find out, see what works.

Hickman: That's what "state of the art" means.

Prichett: See what works in terms of cost/benefit.

3	f. Electromagnetic logging tool. High temperature NMR tool.

- This item was added as a separate item during discussion of item (e.) on this list.

- The Reservoir Technology research program has been paying to develop an electromagnetic logging, tool, works in a single hole. It probably can tell you whether the water goes sort of to the left or sort of right or pretty much down, or pretty much up, with California Energy Commission support also. That's an example of a kind of thing that's out there that might be useful in some places.

Hickman: Electro-magnetic logging tool and high temperature NMR are ways of characterizing porosity and fracture permeability and things like that in the near-borehole environment. What's that got to do with fracture detection?

Creed: My strong suggestion is you break those geophysical measurements into long term vs. difference measurement methods. The National Research Council recently, Marcelo Lippmann was part of the panel, made a recommendation to do that.

If you characterize the fracture flow, one of the ways to do it is differential measurements methods in particular electrical methods such as radar, electro-distance tomography, and some other things.

Things like gravity and seismic are not strictly difference methods. Although they can be, using them like that is problematic.

Pritchett: Yeah, but I think that in this context they are different methods. The idea is you measure gravity at Time 1, you measure gravity at Time 2. You see a difference. That means there has been some mass moved around. That is presumably you're injecting so you're tracking where it's going. That's the idea.

Creed: Are you going to find individual fractures with that?

Pritchett: No, but you'll find out where the water's going.

Creed: Well, what I want to see here are devices and methods in or near the borehole that will tell you where the water's going. That's the only way you'll do it.

B.4	**Basic Knowledge Needs for Enhancing Reservoir Fluids** (Flip Chart 13)

Votes	Item
10	a. Rock-fluid interactions.
8	b. Degree of matrix saturation.
9	c. Effects of water temperature and saturation on resistivity, seismic properties, and rock properties.
7	d. Permeability alterations, e.g., time-dependent changes.
5	e. State of stress of rock, and proximity to failure.

Total for this panel = 39 votes.

<u>**Discussion**</u>**:**

General question: How is this different from "reservoir data" you were talking about? Isn't anything mentioned here just reservoir data? What's the basic knowledge versus something else?

<u>Answer: This is just more than just data, this is the science of understanding what's going on there.</u>

10	a. Rock-fluid interactions.

(No comments)

8	b. Degree of matrix saturation.

- That is how much water is in place, how much of the core volume is fluid.

- The issue is to evaluate what state of saturation you're in.

9	c.	Effects of water temperature and saturation on resistivity, seismic properties, and rock properties.

- If you're going to be using these things like resistivity or seismics, etc., to try and track the cold water flowing through this thing. One thing it really kinds of need to know is what is the effect of temperature and water saturation on the electrical resistivity other properties of the rock. These characteristics are frequently, not very well known at all. Most people just guess.

- That ties back to chart 9-F. If you don't know what changing reservoir conditions do to the rocks, then there's no point in monitoring the effects.

7	d.	Permeability alterations, e.g., time-dependent changes.

- This is time dependent changes in permeability due to chemical fluid rock interactions.

- HT-NMR. You might want a high temperature nuclear magnetic resonance tool, used fairly successfully in the oil patch to measure water saturation some distance away from the well bore.

- Pumping pressure required to inject. Injectivity? You need something like hydrodynamic models for flow down in injector.

- Does that also include the effect of changing the pore pressure, changing the state of stress around area, changing the fracture aperture?

- We need to measure time changes in all of those.

- There is overlap with (a). Yes, everything is covered under (a).

5	e.	State of stress of rock, and proximity to failure.

- We should have something about state of stress, getting back to this injectivity thing. Knowledge of the in situ stress determines the pumping pressures be used during the injection. We should say, knowledge of state of stress and proximity to failure. It's important for both producing and injecting.

- That depends on the state of the reservoir. In some, you don't have to use pressure at all. In The Geysers there is literally a vacuum.

- But there are some cases, we just heard Dennis talking about a proposal in which they were injecting positive well pressure, you might have to do a minifrac in a situation like that you might need to know through these principles if you are going to succeed it and the consequences.

In fluid-depleted reservoirs, you don't need any pressure or fracturing to inject.

I guess I would be willing to stipulate that if you have to put a well head pump on a cold water column to get the stuff into a formation, your problem is no permeability.

- This was described above, and with respect to Topic A, also.

4.3 General Topic A. ENHANCE PERMEABILITY

Again, as in Section 4.2, Barriers were not voted on, and so not clarified with respect to detail.

A.1	**Barriers to Enhancing Permeability** (Flip Chart 3) (Votes not taken here.)

Item	
a.	Temperature constraints for borehole seismic instruments
b.	Lack of control of preferential flow (channeling)
c.	Lack of effective stimulation methods to create sufficient heat transfer area
d.	Inability to quantify amount of channeling
e.	Lack of good predictive methods for stimulation

A.2	**Methods for Enhancing Permeability** (Flip Chart 7)

Votes	Item	
3	a.	Seismic measurements while drilling. Both measuring during rotation, and during brief episodes when rotation is halted.
13	b.	High temperature fracturing fluids, proppants, and packers (open hole packers and others.)
21	c.	Stimulation methods, including physical, thermal, and chemical methods. For example, hydrofracturing and propellant fracturing.
7	d.	Characterizing permeability near the borehole.
18	e.	Methods to control channeling, the currently unpredictable preferential flow in different segments of a downhole fracture system.
15	f.	Improve modeling for predicting fracture behavior and reservoir behavior.
5	g.	Better structural models for large-scale geological structure, tectonics, and natural fracturing stresses (Suggested by D. Neilson.)

Total for this panel = 82 votes.

Discussion:

3	a.	Seismic measurements while drilling. Both measuring during rotation, and during brief episodes when rotation is halted.

Paulsson: Develop seismic analysis while drilling, for geothermal reservoirs. We are developing equipment specifically targeted for geothermal reservoirs. This means that seismicity is monitored during active drilling, and during pauses in drilling and drillstem tests.

One thing we run into is extremely high temperatures. The one time when you can control the temperatures, is when you drill, because you have the circulation of fluid. And that's the time to record seismic data. The way to do that is to combine a downhole source with the drill bit, and record and stop your operation occasionally and generate seismic energy in the bore hole. You are recording from the surface for both general reservoir characterization and fracture mapping.

Sanyal: This is a very good idea. But unfortunately in most cases when it's fluid depleted there are a lot of production wells that are shut in. Therefore you chose some of those wells for injection. That's what happened at The Geysers. You rarely drill a new injection well in a system that is already depleted, because obviously it's very bad economics at that point. So chances of getting a brand new well to drill and putting seismic equipment in there are very small.

- But how many geothermal wells are drilled each year?

- That's zero right now, literally. In California there have been one or two wells drilled each year for the last six or seven years.

- This approach will probably be most appropriate for field that is permeability limited, rather than one that is fluid limited.

13	b.	High temperature fracturing fluids, proppants, and packers (open hole packers and others.)

Prairie: Someone mentioned a high temperature fracture technology, high temperature polymers. For instance, if you want high temperature hydrofrac technology, you probably have available chemical polymers and that sort of thing. And proppants. (Prairie)

Hickman: Open hole packers for mini-fracs and characterizing stress distribution before a maxi-fracturing job. There is no high temperature open hole packer. So that, plus proppants, plus fluids, are part of a fracturing technology package that's needed. In a few words, we need high temperature fracturing fluids, proppants, and open hole packers. High temperature here would be 150 to 300°C, a packer that could work in an open hole.

Koenig: If you are doing a permeability-limited task, you might want extend that to about 350°C.

Others: And such packers should also work as low as 150°C. Because you might do something in injection while it's cool. And in long-term production, it starts out hot; then you're going to cool it off.

21	c.	Stimulation methods, including physical, thermal, and chemical methods. For example, hydrofracturing and propellant fracturing.

- Stimulation includes hydrofracturing, explosives, corrosives, salt fractures. In other words, the entire solution is fracturing and stimulation. Everything else goes under barriers or basic knowledge.

- The program will need to consider:

    - Thermal stimulation: This includes thermal stress cracking, occasioned by cooling of the reservoir. It also might include attempts at cryogenic stimulation, using liquid nitrogen or carbon dioxide, both of which have been use in oil/gas setting.

    - Physical stimulation: Under physical there's really several kinds. Small, hydro fracturing, medium cracks, propellents. And explosion, God help us, if someone wants to try that again.

    - Chemical stimulation: This includes extension of the relatively commonplace acidization to treat injection wells.

- We need ways to ensure creation of enough reservoir volume. And surface area. Often you don't create enough area, since all you get is just one big crack.

7	d.	Characterizing permeability near the borehole.

Hickman: Identifying and characterizing permeability near the borehole in terms of targeting. We talked about seismic imaging, cross well imaging. Talking about stimulating, it's nice to know what the permeability is. So we need to add: identifying, and characterizing permeability near the bore hole. In other words, how far away is it? If you're trying to, if you think your hydrofrac would go five hundred meters but it's only going to get three hundred meters and you spend a million dollars to make it. A big failure! So that couples into this modeling capability.

18	e.	Methods to control channeling, the currently unpredictable preferential flow in different segments of a downhole fracture system.

This topic received considerable discussion.

The idea here is: "What kind of things can you put down a hole to try avoid channeling?" This could be called "flow diversion." It includes the use of foams, polymers, and other kinds of diverters.

If your fracture goes off in a direction that does not connect to intrinsic permeability, then this won't work. Also, if most of the fluid flows off through a low impedance path, then you'll get breakthrough or cooling of producers.

We need to find ways to create not just single, one, two, or three fractures, but complex networks with close spacing, so you can get enough diffusion between them.

Is that what you are calling channeling?

What's he's talking about is a little bit worse even. What we are talking about is the system may not have much channeling at the beginning, but as soon as a flow path starts looking particularly good, all the molecules tend to go over there, they rout the thing out and all of a sudden it's the superhighway and now fluid is not going anywhere else.

It's not a question of predicting, you know, it's like chaos theory, you're not going to predict it in advance, but you predict that something like it going to happen. It's a danger, so what you need to do is figure out ways that give you a whole lot of flow channels more or less the same size, rather than just one big one.

This is similar to the equation for the diffusion equation of radioactive materials that you want to contain. Here you have the same situation. You want to make good permeability but once you have it, even if your flow paths are almost identical, one will be one percent stronger and that one will grow and go a lot of ways. Somehow the basic physical system seems to want to work against sustaining this huge sweep for any long length of time. (Pruess)

Think of a sloping hill. Nice and smooth out, raked out. You start with a water hose at the top. It starts out all uniform like that, but after five minuses it all going down one little rivulet. That's what's happening here. (Pritchett)

In the oil patch this happens all the time, but we've found a way to deal with it. It's called diverters. We put a diverter in there, which plugs it up, and then the fluid finds another way to go. It's a simple solution to the problem that they use it out in the far field, they use it at the wellbore. It's a common thing that's done. (Warpinski)

(There was disagreement about whether this would work in a geothermal reservoir, in part because of temperature differentials.)

Do you see any possibility of using something like foam or polymers, that are used in the oil field and use that.

Yes, maybe you can do it, but the question is, can you do this successfully over a long period of time. This will be an uphill engineering battle.

One participant noted: There's a possibility of a solution here, but there's no guarantee because the instability mechanism is somewhat different. In oil and gas reservoirs, it happens because of a material discontinuity. In geothermal it happens in part because of a thermal one, which is a different critter.

The participants agreed that "channeling" was an important problem, that research needed to be done on it, and that there was a lot of disagreement as to approaches for finding solutions.

Sanyal: Let me give you one example: you know in 1980, I was involved in an experiment with DOE funding for injecting steam and foam in a project in Bakersfield in an oil field. It was a very successful because enhanced recovery pilot project. I was in charge of the project. We showed, just like Ann showed about the SEGEP Injection Project, a bump in production that was maintained for a while. The project got paid for in about three months. There are high temperature foams you can use. We controlled the mobility using foam. The temperature was over a 100°C. The foam was validated in the lab for 600°F.

Other: But we have a foam that when we inject it, it sets up and is stable at 240°C, but it only lasts a week.

Sanyal: But that's something DOE has to locate, whether or not something can be done to improve that. Unless we have enough evidence in the literature that indicates to just forget it, this method is not going to work, using diverters. Then we would have a problem of figuring out some other means to control channeling.

Croft: What is the basic knowledge needed?

Pritchett: What you need to understand is what's the character of the instability and what's likely to shut it down.

Prairie: Then you need a simulator.

Pritchett: I think you need a lot more than a simulator. I think we need some experiments here. I think that if you think that we can do something here with chemicals, with polymers, if we can make the polymers stand up, we're going to be doing this on the injection side, remember. We're sticking a liquid into a gas system, not the other way around. That's even more unstable.

So you have to look at what's going to happen to that polymer as it passes through the thermal zone from the cool injection into the hot liquid zone and then it gets to the steam. Is it going to drop out where you want it to? I don't know. Somebody's got to look at a bunch of materials. Can you do something some other way?

Swenson: It's not necessarily so negative as everybody's talking here. There was evidence at Fenton Hill which can be argued that things were diverted. You get thermal cracking that can open up new surface area. The viscosity of water does go up as you get it over into the cold area. So there are some different ways you can operate your reservoir so it's not only a foam solution that you have to look at. You can go into a kind of a huff, puff mode. There are a lot of things that you can do to address this.

Pritchett: But I think somebody has to kind of sit back a ways and take a look at all of them and start appraising it. I don't think we are in a position to sit here this afternoon and say this is going to work and that isn't.

Sanyal: The other thing to do would be quantifying the extent of channeling. Now whether we can use tracer and absorptive tracers of some sort, to find out how much channeling is really happening. Because unless you know the fracture aperture and the amount of channeling, then we won't be able to predict with confidence what will go on. It's not a unique problem. I mean, you don't know either the aperture or the amount of channeling. So there has to be some fundamental research in that direction.

Pritchett: For instance if you've got a preferential path, you've got cold water going down the preferential path. What's going to happen is that the viscosity goes up but the aperture goes up, too, because you're shrinking the rock. Which wins?

15	f.	Improve modeling for predicting fracture behavior and reservoir behavior.

This item was identified during discussion of the need for credible predictive modeling of production flow from reservoirs that were receiving augmented injection: "There is also a need for useful modeling of what to expect from a fracturing operation."

Kasameyer: One of the things that I think is useful here is improved modeling capabilities for predicting what happens -- as Brian Bonner was talking about earlier. What are the mechanical properties as you try to fracture?

Hickman: There are all these issues of predicting the extent and height and containment of hydrofracs.

Sanyal: Predicting the reservoir behavior is important. Both fracturing and producing the reservoir. Flow and heat transfer.

5	g.	Better structural models for large-scale geological structure, tectonics, and natural fracturing stresses (Suggested by D. Neilson.)

Structural models of reservoirs would include the effects of geological complexity on permeability.

Pruess: How about the geology? Often permeability limited systems do have lots of pre-existing fractures. For some reason they just aren't connected right.

Warpinski: You certainly need measurements of state of stress.

Hickman: Some of that was carried over from fracture mapping and data stress and stuff like that from the injection piece we described.

Pruess: Right, but it was mentioned earlier, geologists will talk qualitatively about these things. Somehow the nature of this rock and its lack of permeability should be explainable in terms of its geologic history. Right now that's maybe rather qualitative but we shouldn't neglect that entirely.

Hickman: Well, certainly knowledge of the relationship between the state of stress and fracture permeability, or broaden it to say, "state of stress, tectonic history, and fracture permeability," would be under the heading of fundamental knowledge.

Koeing: I would suggest hydrothermal history as well. Chemistry can play a big role in plugging fractures.

Entingh: I think a great deal of what we're hearing here could apply regardless of what kind of rock or mineralogy is downhole. I believe that a day will come fairly soon when it'll be essential to say: this part of the reservoir, this rock has this composition, this block has that composition, to a much greater extent than is done now. Even such information from drilling cuttings will get factored in more and more. Is it worth starting to raise that discussion in this meeting? Or is that twenty years down the road?

Hickman: Is that about whether a fracture in a particular rock is going to be permeable for the same fracture and the same stress state in another rock's going to be impermeable? Absolutely, yes. That gets back to the shear fracture and permeability issue. Shales are soft. There you can shear all you want to, it's not going to do anything for permeability. The same is not true for granite. And so I'd say that issue belongs under the relationship between shear and permeability, maybe as a function of rock type.

Nielson: I think there's a real fundamental issue here that we haven't quite dealt with. That is: we used to have the old Don White model of range front faults. This is where the geothermal systems will be. I think you all remember Don's model. As we've gotten into these systems, we find that White was right in only a very, very few instances.

Today, our structural models of what these things look like vary dramatically from one system to another. So when we're talking about permeability-limited systems right now, fractures are not necessarily through-going events, they're isolated. You have a fracture and then you may have a couple hundred meters of barren rock and then you may have another fracture, another fault. If your well's in the middle of that barren zone, that's one way to treat it.

If you are in another type of system which I call more a distributed fracture type system, such as Roosevelt Hot Springs, The Geysers, where you have a orthogonal fracture relationships, there your fracture systematics are really quite different and you treat those systems, indeed, differently. So I think you need to start to arrive at some at least basic structural models for what is actually controlling your permeability within these systems and then move on from there. I think that can be of great help to you.

Koenig: I would add to that. You can also consider the original depositional environment, especially in volcanic areas. In addition to the existing structures and stress fields, the original depositional textures in volcanic hosted deposits, which is where a lot of the worlds major systems, can also contribute significant permeability, and dramatic permeability changes that may or may not be connected over long periods. You may or may not hit one with a well.

Nielson: And so many of our volcanic systems like The Valles Caldera, for instance, you go through one fracture system up in the Bandelier Tuff, and then you get into the Paleozoic section which is essentially impermeable. And then you get into the underlying Precambrian granite, and that probably has a different fracture relationship. So these things are not simple, I think, when you get into them. You really have to define in terms of your structural models, to sum up, where you are within that system--if you've got a permeability limited problem and you'll solve it differently. Sometimes the explanation might be well, we'll continue to drill until you hit that main fracture

Myer: We shouldn't neglect the stress changes associated with changing temperature in pumping the fluids in and out.

Comments for Clarification:

Kasameyer: I think what Dennis is saying is that you can learn a lot about what's going fracturing and what's going to control the growth of fractures from understanding the structural geology of the field in great detail. And Dennis has been doing that a lot.

Hickman: I would make that more general: Improved fracturing models, incorporating geologic structure, induced stress, stress fields. I believe that structural models is just one aspect, one way to treat the problem. Basically better fracturing, well, better models for natural fracturing, not to it confuse with stimulation.

Warpinski: Basically you want to understand the stress state.

Pritchett: What's the difference between (f) and (g), here? This includes fracture behavior, but I also see reservoir behavior in there. That presumes, Then you're saying, "O.K. what did that fracture do in terms of altering the flow paths in the reservoir?"

Creed: I think what, as stated before, Dennis Nielson's general approach is the incorporation of relatively large scale tectonic and structural models to get at the structure evolution of the reservoir. Such that when you enclose these stresses you have some idea of what's going to happen. So I think his idea, he would say something to the effect that, yes, we want to take a look at the structural tectonic history and the stress and see what is going to happen when you impose a new stress. As opposed to looking at just what you measure in the borehole in terms of breakouts and other things. Steve Hickman is shaking his head.

Hickman: There is no such thing. There is only one stress field. You measure the current stress field. It's a consequence of the geologic history and local structure. It's artificial to separate the two. Dennis and I have some disagreements on this, so it's not fair to have an argument with him when he's not here. I think we should say, "Better models that are a development of large scale fracture systems." Can we generalize it like that?

Creed: "The general large scale context of stimulation experiments" may be a better way to put this in terms of structural stuff.

Pritchett: Any time you say "reservoir," that sounds "large scale" to me.

Robertson-Tait: No, I think "large scale" means regional. It means the regional tectonic stress framework.

Hickman: Say, "Natural fracturing, large scale measurements," and put in parentheses "stress, tectonic history, geologic structure." You know those are kind of the three things that people will think in terms of. And then once you have that model, then you can address the one right above it, letter (f).

Pritchett: Is there more than one item under all that? I think that those things were all ways of kind of tracking where these fractures are going: micro-earthquake monitoring, tilt meter from the surface to try to catch the surface expression. It's all the same stuff. Do we really want to say which way it ought to be done?

A.3	**Measurements for Enhancing Permeability** (Flip Chart 11)

Votes	Item	
19	a.	Measurements to locate and characterize fractures. These include microearthquake monitoring, nuclear magnetic resonance (NMR), seismic, reactive tracers, and measurements of stress states.
18	b.	Measurements of productivity, to characterize effects on reservoirs. These include production rate, chemistry, fluid enthalpy (heat content), and pressure. (Panelists noted that this item is similar to items 9b and 9c.)

Total for this panel = 37 votes.

__Discussion__:

19	a.	Measurements to locate and characterize fractures. These include microearthquake monitoring, nuclear magnetic resonance (NMR), seismic, reactive tracers, and measurements of stress states.

This item triggered a long discussion about the value of microseismic monitoring for detecting where fractures have been created by hydraulic stimulation. That discussion has been placed in Section 3.0 above, because of its length and general importance.

__Other comments__:

Kasameyer: So under monitoring, you're hearing tilt meters. You'll hear INSAR. You're going to hear electromagnetics (EM), and nuclear magnetic resonance (NMR). But in this case tilt is especially attractive.

Koenig: One of the other things at The Geysers, our experience has been there is another variable to be used here and that is the changes induced in stress fields by thermal phenomenon associated with the rapid cooling and trying to differentiate those from core pressure changes associated with fluid loading.

Comments during the Clarification session:

Hickman: The "monitoring" on the other chart and this monitoring are the same. B.2, Chart 5, Item C.

Pritchett: The distinction is, this isn't a method of improving steam quality. What it is, it's a method of appraising what you've done.

Consensus: Much of what is here is a lot like B.3, Chart 9, item (a). And 9-c and 9-b

18	b.	Measurements of productivity, to characterize effects on reservoirs. These include production rate, chemistry, fluid enthalpy (heat content), and pressure. (Panelists noted that this item is similar to items 9b and 9c.)

Subir: How about production monitoring?. If you monitor the production rate, you learn a lot of things that you don't learn by other means.

Pritchett: I think Subir is right. I think we need another item under there. Underneath stress state, it ought to say something about keeping track of what we've done. How much extra steam have we made. The objective of the injection is to increase the steam supply. The object of the fracturing is to increase the steam supply. You have to monitor what you've improved.

Robertson-Tait: What separates (a) & (b) here?

Pritchett: My take on that. Item (a) is monitoring the fracture, itself. Where's the fracture going? Item (b) is monitoring the economic benefit of the whole program, the effect on the reservoir. How much have you increased the steam? How have you changed the discharge chemistry? Hopefully in some useful manner.

A.4	Basic Knowledge Needs for Enhancing Permeability (Flip Chart 15)

Votes	Item	
23	a.	Relationships between fracture permeability and stress state, tectonic history, geochemical environment, and stress changes associated with induced stress. Additional concerns here include fracture aperture effects on permeability, and understanding effects of shear failure on permeability, as a function of characteristics of the rock.
10	b.	What is the character of the instabilities that lead to channeling of fluid in systems of fractures?
6	c.	Under what conditions is it likely to be useful to use microearthquake monitoring to determine permeability?
15	d.	Geothermal fracture mechanics and hydraulic fracture properties.
13	e.	Develop high temperature sensors for use close-in to the borehole wall. Perhaps fiber optics.
7	f.	Develop non-reactive and reactive tracers.

Total for this panel = 74 votes.

<u>**Discussion**</u>:

23	a.	Relationships between fracture permeability and stress state, tectonic history, geochemical environment, and stress changes associated with induced stress. Additional concerns here include fracture aperture effects on permeability, and understanding effects of shear failure on permeability, as a function of characteristics of the rock.

<u>Relationship between fracture aperture and flow rate</u>

Sanyal: There's another fundamental thing that we have to look into: the exact relation between fracture aperture and flow. The so-called Cubic Law apparently doesn't work very well. The question is, "Where do you go from here in terms of predictive modeling?"

Pritchett: This whole business about aperture as it pertains to permeability really kind of comes up two different ways: one is in the correlative sense. If I know something about the distribution of fracture aperture by some technique, what does that tell me about permeability? Is that information useful anywhere but this particular place?

The other one is an incremental sense: if I can change the aperture of the fracture, if I increase it by 20 percent, does that increase the permeability by 20 percent or 200 percent, or 2,000 percent? And what else does it depend upon? The latter question is really more interesting, I think, because the first one, you don't really care. You're not going to sense aperture, you're going to sense permeability anyway. What you want to know is if I can blow up that fracture by either cooling it or pressurizing it, how much am I going to change the permeability?

You can stick any algebraic rule you want in a computer program. It's not the simulator that's the problem. The problem is the fundamental law. What does that depend upon?

Sanyal: The problem is that, from the data, how do you do that? Because there is a non-uniqueness problem here.

Pritchett: Really, you don't care. What you want to know is what's going through those control surfaces around there.

Pruess: There is a lot of data to suggest that the Cubic Law is pretty good over many orders of magnitude. Not just because of parallel plate models.

Pritchett: It just happens to come out that way if you plot the data. I hear people throw rocks at things like parallel plate models and I certainly agree. But the essential question is, what happens to the mass flux through this control volume subject to a fixed pressure gradient if I raise the pressure? If I know that, I know the answer.

Other: I disagree that the modeling is not necessarily a problem. Certainly the physics is a problem because people have been beating on fracture flow for a while.

Pritchett: I said simulation is not a problem.

Other: The geomechanics simulations for these fractured systems is a non-trivial issue that hasn't been adequately resolved. You can't talk about flow without talking about stresses in a geomechanical simulation.

Sanyal: I think the bottom line here is that all these things are going to cause us to make over-estimations of heat recovery. For example,
we have been underestimating channeling problem and so on. My worry is that unless these things are improved, HDR and EGS projects have always been overestimated.

Pritchett: I want to talk to you about channeling sometime. Tell me the difference between channeling and dispersion, sometime. I don't think there is one. What I read "channeling" as meaning is the fact that you have fluid tending to go through your control volume in little discrete paths, preferentially, and getting kind of hung up and not moving very fast. What this does is it takes a sharp front that heads in one side of your element of rock and converts it into something that looks like a broader front coming out the other side the element of rock.

Pruess: The exact opposite is true. Just like a whole bunch of tributaries can form and make a river, a bunch of channels can come together. You know it's not necessarily dispersive, it can be anti-dispersive. That's why it's so complicated.

Sanyal: Would you agree that ultimately, that most models have over estimated the recovery from an HDR/EGS system?

Pruess: Not necessarily. It depends on what allowance you make for it. You may overestimate the allowance for it and underestimate the heat recovery. It just makes it very complex.

Pritchett: All I'm saying is that in a continuum representation, you can generally handle this by fudging around with your permeabilities and your dispersion coefficients to get the behavior that you want to get. The problem is getting what the right coefficient is.

Comments during the Clarification session:

- Add tectonic history and chemical environment.
- Add stress changes associated with induced stress.
- This is about, "What makes permeability change?" On some kind of fundamental level.
- Add fracture aperture effects on permeability. And shear failure effects on permeability.

10	b. What is the character of the instabilities that lead to channeling of fluid in systems of fractures?

- Clarification: The group decided that "channeling" was the appropriate code word to use for the types of questions that arose for this item.

6	c. Under what conditions is it likely to be useful to use microearthquake monitoring to determine permeability?

Pritchett: That's a little different. Because the idea here is that in some fields it seems like there's a really good correlation between microearthquake swarms and drilling success but in other fields there isn't. And the question is: Why?

Koenig: In some fields, both relationships are observed.

Pritchett: Under what conditions is it going to be worth while?

15	d. Geothermal fracture mechanics and hydraulic fracture properties.

Clarification Note: While some of the group initially wanted to merge this with A, Paul Kasameyer prevailed with the following points.

- I thought one of the things we were talking about there is how mechanical properties of rock relate to things like the rate of enhancement you use for stimulation programs.
- There is a distinction between understanding how the permeability of a rock changes and understanding how it is going to respond to this stimulation. That was the distinction.
- We need to know the mechanical properties of the rocks in order to stimulate them.

Hickman: This is about how you break rocks. This would be like fundamental mechanics of fracture propagation and growth. You so fracture mechanics in a geothermal environment so when you make a massive hydrofrac in a geothermal environment, is it any different than an oil and gas field and why?

13	e. Develop high temperature sensors for use close-in to the borehole wall. Perhaps fiber optics.

Warpinski: We said that if you really want to map these things, you need to have the sensors for tilt meters, accelerometers, geophones, whatever, we need high temperature things to do that.

Pritchett: So you can deploy them in that hole. This is basically temperature hardening existing technology. Isn't there somebody else that might be willing to cost share with EGS, maybe even in geothermal.

Prairie: Well, we at Sandia are working on some of that stuff right now.

Paulsson: With respect to high temperature sensors, fiber optic sensors, that are coming out now. There are fiber optic cables which can go up to 300°C or 400°C. If you can develop the manufacturing process for the fiber optic sensors using in the high temperature fiber, you're there.

Pritchett: They've been using that stuff for real time downhole temperature profile in the geothermal wells. They've done it up to mid-200°C. And they deteriorate fairly fast, which is OK for the current uses. But you're going to want to put them in the hole and leave them down there for five years.

7	f. Develop non-reactive and reactive tracers.

Pruess: For monitoring, should we put down the active tracer such as, either temperature sensitive tracers or tracers that absorb on the rock in some fashion? Some progress has been made. There are some examples where these things have been applied. You know the unreactive tracers basically measure the fluid volume and with a reactive tracer you could measure the heat transfer area.

Koenig: You can do that by using different tracers, tracers that have different signatures in terms of decay with respect to temperature and using pairs of tracers. That's a technology that's available.

Entingh: Is the mathematics of that simple enough that it will tell you anything practical about a geothermal reservoir?

Koenig: Yes. It's been used in Dixie Valley.

Pritchett: Yes. You basically look at ratios. You know you put in 100 pounds of A and 100 pounds of B. You get back 10 pounds of A and 1 pound of B. So what happened is: there's something about A and B that responded differently in the path they saw.

Koenig: You have to define decay curves for each one of the tracers in the land environment but then once you have that, you can ratio them out assuming that there is no other process.

Pritchett: Yes. That's the temperature-sensitive kind and then there's the kind that absorbs on rocks so it gives you some idea of how much surface area which seems to tell you something about the fracture. The mathematical solutions are non-unique but they make a useful constraint on what you say about the reservoir. Whatever you do has to match that.

Others: The fundamental issue here is developing the tracers. This includes characterizing their absorption properties and their temperature capabilities.

Hickman: There are important things that have to do to do with how chemicals absorb these or react to surfaces and fractures that very basic and will lead to development of these kinds of tracers. There's some surface chemistry and kinetics etc., etc., buried in number F that aren't necessarily buried statements about the use of such tracers.

SECTION 5.0

PRIORITIZATION OF RESEARCH THRUSTS

5.0 PRIORITIZATION OF RESEARCH THRUSTS

5.1 Prioritization Scheme

Dan Entingh described the general plan.

What we plan to do generally is this: We have these two sets of panels up. We're not going to spend any votes on the problems, the barriers. Nort will tell the details of the voting method.

When we're done transcribing this, we're going to take what's happened in the meeting, including what's on the walls where the influence votes have gone. We'll craft a report out of the transcript. We're going to send the report out to all of you and then say: Fill in a little bit more. Clarify a little bit more. Don't add four pages per line of the draft report.

In the meantime, working with Paul Grabowski, we'll probably take the most highest voted elements and work them into something that looks like an implementation plan. That becomes stuff to concentrate some of the solicitations on. And I think we probably ought to send that back out, too. I don't know. Or maybe have the draft float around DOE while its being worked on by you guys.

I asked Norm Warpinski yesterday, is this similar to planning processes used at the Gas Research Institute, GRI. GRI has spent many years working stimulation methods and then working really hard to train operators to use them, to understand them, and so on and so forth. Very successfully. And he said, "Yes, it is just about like this but there are always many fewer people in the room." This kind of work usually is done by many fewer people. The reason we couldn't do that here is that we didn't know exactly which fewer people to pick. We picked each of you because we thought each one of you would be able to make some important contributions. Next time we do this, it is likely to be in smaller groups, each with a more detailed focus.

Nort Croft, our facilitator from Lawrence Livermore National Laboratory, explained again the salient features of how the prioritization process worked.

- Before you go to vote or sell your votes or whatever, just remind yourself of the four criteria we talked about earlier this morning: contribution of mile stones, tech objectives, cost/benefit, advance the state of the art. Put those in your head.

- You will each have 21 votes. You can use any of these votes any way you want. You can put all 21 of them on one topic. You don't have to use 21.

- Why 21? It's simple. We expected there would be fifty or sixty items. The rule of thumb is to have about a third as many votes (stickers). So we said, O.K. there will be 20. And then we looked at the sheets it turned out that it was easiest to cut out 21 stickers.

5.2 Global Results of the Voting

Table 5-1. Summary of Importance Attached to Topics and Subtopics

Topic		Votes Received			
		Develop & Use Methods	Measurement Needs	Basic Knowledge Needs	Row Total
A.	Enhance reservoir permeability	**82**	**37**	**74**	**193**
B.	Enhance reservoir fluid contents	**46**	**34**	**39**	**119**
	Column total:	**128**	**71**	**113**	**312**

The participants placed more emphasis (votes) on work for Topic A. Enhance reservoir permeability (193 votes), than on Topic B. Enhance reservoir fluid contents (119 votes). This was expected, since there was a general consensus that for 15 years, Topic B has been and should to a large degree remain within the non-EGS portion of the DOE Geothermal Reservoir Technology research subprogram.

It is, however, interesting that the participants gave as many votes to Topic B as they did. The Workshop leaders (Entingh and McLarty) believe that this outcome reflects an emphasis -- during much discussion in the Workshop -- that relatively early and impressive commercial successes in enhancing geothermal fields will most likely come from projects where substantial new injectate is found to augment reservoir fluids. Examples are the Lake County injectate pipeline into The Geysers (acronym SEGEP - the South East Geysers Effluent Project), and the possible Santa Rosa injectate pipeline being discussed there (acronym GRP - The Geysers Recharge Project).

However, consensus was also strong for the idea that better methods for increasing the permeability of many bodies of hot rock is likely to be the component of EGS R&D that will have by far greater long-term payoffs for the industry and country.

From these votes and the discussions, it is clear that these researchers believe that high priority should be placed on projects that test or demonstrate improved technology and methods in the field. However, the large number of votes cast for "Basic Knowledge Needs" indicate that these experts believe that substantial emphasis also needs to be placed on basic studies whose goal is to improve understanding of below-ground conditions, phenomena, and possibilities.

5.3 Participants' Comments after the Vote

McLarty: What we'd like to do right now is talk a little bit about what we observe on the results and ask you, "Does this kind of make sense? Do you think this was an effective process? "

The first thing I observe is, in counting the dots, we have 113 over on the fluid limited side vs. 193 on the permeability limited side which is kind of what we had hoped for because that speaks.

- It's clear that there's winners and losers here. Some categories only got one, two, three dots where some got up to 19.
- One got a zero.
- One got 23.
- 23 votes is more than there are people. I think there are about 20 people. So someone put more than one sticker on that item.

<u>Some Specific Comments</u>:

Hickman: I believed, during the voting process, that there's some identity again that wasn't mentioned before, between items on the two sides. One example is "Characterizing permeability near the bore hole." which is number 7-D under Stimulation vs. Map of fractures to know where to inject, which is under Injection, number 5-A. They're the same thing in my mind and I think the way the discussion was going, I think most people would agree those are the same kind of issue. So I'm just urging in cases like that, there's some other ones in monitoring the tilt meters are in both sides, in similar ways. So I would just, whoever puts this together should try and tally the votes in a way that recognizes there's a lot of overlap between these two categories.

Entingh: A certain aspect of mapping fractures is to map them in the well hole using PST (pressure, spinner, temperature) logs. And now televiewers, while it used to be calipers you'd have to use, now televiewers if you have liquid in the bore. Is there something here that's called: "mapping fractures" that means they're further away from the well?

Koenig: Well, that is exactly why I thought of them as two different things, different sizes of things. When I looked over here and saw near-wellbore things, that's one thing and I think of things like: looking at tools like the televiewer that see in the near-wellbore environment. Where, when I thought about: "Map the Fractures With Injection," it's not necessarily looking at an individual wellbore but rather: "What is the fracture field that this system was drilled into?"

Pritchett: Cross hole correlation.

Koenig: Where do you want to drill if you haven't drilled now to put an injection well to intersect these fractures? So I see that it was two different things.

Entingh: Is that the sense of the group now that what, if there's a vote up there. Number 5, we can

think of that as being more as a field property and then over on this side, 7-D, that's more a near-wellbore emphasis? How many votes did that one get? Fifteen?
And this one only got seven.

Hickman: I was thinking that an important issue in D was what you just said. I mean, characterizing permeability near the bore hole under stimulation. The reason you would do that is to know where to target, for example. But I still don't see, even though they're worded in a kind of a different way, Brian (Koenig). They sound more similar to me than dissimilar. I'm not talking televiewers here; I'm talking where that permeable blob you're trying either to inject into or hit with a fracture.

Koenig: I agree with you, Steve. I think that what we are talking about is just a continuum and it is just a matter of where you happen to be looking at that continuum.

Interpreting the Votes:

Pritchett: I would like to comment that I think that there are a lot of issues like that on these sheets and I would hope that whoever's job it is to interpret these uses log paper and a big, fat thumb. The fact that one thing got 18 votes and another one got 15 votes is not very significant. If something got zero and something else got 50, maybe that's significant.

Entingh: Well, that's what we think.

Creed: As a solicitation writer, I'll tell you that this type of stuff is useful in that where you are writing up the requirements you don't exclude anything of concern. You never try to include everybody, but you don't want to exclude any of this stuff.

Entingh: I was arguing that too, when Lynn and Nort and I were talking about cleaning up the design process, after most of you had left late yesterday. I think we shouldn't make almost any of the ideas here disappear. We can note that it got one or zero votes, but it was important to one person at some point during the discussion. It might be important, or remind someone of something else later.

Pritchett: One other comment that I think everybody realizes but maybe ought to be on the record is that there are a lot of people who are not here whose votes count a lot more than ours. I'm thinking of those on the Board of Directors of CalEnergy Corp, or Calpine.

Entingh: This is good. No say this more thoroughly. What we could do is send this out also to the industry folks on EGS National Coordinating Committee. With, "Oh, this is good, or bad". So we'll get industry's input, which may take a year. It'll be a year before this is all settled.

McLarty: I think we need to push it to the industry for, to the Coordinating Committee for comment on before we finalize it but I wouldn't try to push it to a whole bunch of people in industry before we get final comment on it.

Because I think a big purpose of this meeting is to give people that are more research-oriented and less bottom-line-industry-oriented a chance to say what they think is important. That's the main purpose of this meeting, perhaps to look a little bit more of a long-term approach to it as opposed to the industry's very near-term quick payoff approach.

The EGS Coordinating Committee already has a chance for input. And industry will have a tremendous vote by putting up dollars for research project in their fields. They have a tremendous influence and say in that regard.

5.4 Detailed Lists, in Priority Order

Letters on the voted-upon items reflect the order of nomination of the items.

5.4.1 Topic A. Enhance Permeability

A.2 Methods for Enhancing Permeability		
Votes	Item	
21	c.	Stimulation methods, including physical, thermal, and chemical methods. For example, hydrofracturing and propellant fracturing.
18	e.	Methods to control channeling, the currently unpredictable preferential flow in different segments of a downhole fracture system.
15	f.	Improve modeling for predicting fracture behavior and reservoir behavior.
13	b.	High temperature fracturing fluids, proppants, and packers (open hole packers and others.)
7	d.	Characterizing permeability near the borehole.
5	g.	Better structural models for large-scale geological structure, tectonics, and natural fracturing stresses (Suggested by D. Nielson.)
3	a.	Seismic measurements while drilling. Both measuring during rotation, and during brief episodes when rotation is halted.

Total for this panel = 82 votes.

A.3 Measurements for Enhancing Permeability		
Votes	**Item**	
19	a.	Measurements to locate and characterize fractures. These include microearthquake monitoring, nuclear magnetic resonance (NMR), seismic, reactive tracers, and measurements of stress states.
18	b.	Measurements of productivity, to characterize effects on reservoirs. These include production rate, chemistry, fluid enthalpy (heat content), and pressure. (Panelists noted that this item is similar to items B.3-b and B.3-c.)

Total for this panel = 37 votes.

A.4 Basic Knowledge Needs for Enhancing Permeability		
Votes	**Item**	
23	a.	Relationships between fracture permeability and stress state, tectonic history, geochemical environment, and stress changes associated with induced stress. Additional concerns here include fracture aperture effects on permeability, and understanding effects of shear failure on permeability, as a function of characteristics of the rock.
15	d.	Geothermal fracture mechanics and hydraulic fracture properties.
13	e.	Develop high temperature sensors for use close-in to the borehole wall. Perhaps fiber optics.
10	b.	What is the character of the instabilities that lead to channeling of fluid in systems of fractures?
7	f.	Develop non-reactive and reactive tracers.
6	c.	Under what conditions is it likely to be useful to use microearthquake monitoring to determine permeability?

Total for this panel = 74 votes.

5.4.2 Topic B. Enhance Reservoir Fluid Contents

	B.2 Methods for Enhancing Reservoir Fluids
Votes	Item
19	b. Credible predictive modeling (especially to convince stakeholders to invest.)
15	a. Map the fractures to know where to inject.
8	c. Credible testing and monitoring program, to appraise what has been accomplished. This should include tracers, geological mapping, pressure transients, well logging, and seismic imaging.
1	d. Inventory of water available for injection.
1	f. Develop drilling techniques for under pressured reservoirs.
1	g. Improve wellbore imaging.
1	h. Develop methods to determine core orientation.
0	e. Hardware design.

Total for this panel = 128 votes.

	B.3 Measurements for Enhancing Reservoir Fluids
Votes	Item
14	f. Geophysical measurements. Gravity, seismic, microseismic. Continuous monitoring.
9	e. INSAR (interferometric synthetic-aperture radar) and tilt meters.
4	a. Tracer tests, natural and artificial.
3	g. Electromagnetic logging tool. High temperature NMR tool.
2	c. Monitor production enthalpy.
1	b. Pressure monitoring.
1	d. Downhole samplers that work.

Total for this panel = 34 votes.

	B.4 Basic Knowledge Needs for Enhancing Reservoir Fluids
Votes	Item
10	a. Rock-fluid interactions.
9	c. Effects of water temperature and saturation on resistivity, seismic properties, and rock properties.
8	b. Degree of matrix saturation.
7	d. Permeability alterations, e.g., time-dependent changes.
5	e. State of stress of rock, and proximity to failure.

Total for this panel = 39 votes.

SECTION 6.0

FINAL DISCUSSION

6.0 FINAL DISCUSSION

After the rankings had been completed, two general discussions were done to wrap up possible loose ends on two important topics: simulation and stimulation. The two sessions are reported in somewhat different degrees of detail because of the types of expertise attached to various statements.

6.1 Discussion of Simulation

"Simulation" deals with using computers to understand and predict the characteristics (e.g., permeability and pressure in a block of deep rock) and behavior (e.g., flow rates of each of a number of wells over time) of a geothermal reservoir. Numerical simulation has become a useful practice for the hydrothermal electric industry, and is likely to be an important tool for developing and understanding EGS systems.

Should Conceptual Simulations be Done to Inform Policy Makers?

Entingh suggested that some conceptual simulation be done to help policy modelers estimate what the cost of electricity might be from EGS systems with various characteristics. This could eventually help research managers and others in Government make more sense of the current and future value of these types of resources and extraction systems.

In general, the participants thought that such simulations would be premature. The simulators now available could easily be used to conduct such studies. But there is little information available about the characteristics of either natural or artificial fractures in geothermal reservoirs. Most of the estimates of the length, width, and thickness (effective aperture) of fractures are speculative.

Most participants believed that simulations of EGS systems will be the most valuable as adjuncts to research and development of specific real-world reservoirs. This may take a considerable amount of time to bring into reality.

Toward the end of the discussion, however, something of a compromise consensus emerged. That was that limited conceptual modeling might be of use to industrial firms that are considering pursuing EGS approaches -- especially of stimulation of wells -- to help them understand the degree to which achieving certain geophysical successes would translate into economic improvements at a reservoir. For example, for a given volume and natural effective permeability of a reservoir block, to what degree would adding one or more successful large fractures increase the profitability of producing the reservoir? In over-simplified terms, it turned out that three such fractures would be needed in a particular type of reservoir, then the operator would be able to assess the economics of trying to create such fractures using then-available methods.

Near-term efforts to improve simulators -- by adding some of the features deemed useful in the review by GeothermEx, should not be done in the abstract, but coupled with work to improve a real reservoir. Rather than spending research dollars to improve the simulators, existing simulators could be used, in conjunction with measurements of properties of real reservoirs, to estimate if getting two or three good fractures would deliver additional electricity at a marginal cost of two cents, twenty cents, or two dollars per kilowatthour.

Nevertheless, it may prove to be the case that progress on both sides of the fence: (a) measuring reservoir general properties and the properties of new fractures, and (b) creating more integrated numerical modeling systems, might have to proceed in parallel, sort of hand-in-hand, so to speak.

There was a fair amount of comment suggesting that a "national scale" economic assessment of EGS-capable or HDR-capable resources would not be of much value. Much exaggeration is possible of the huge amount of resource that is potentially reachable by physically feasible means, but so little is known about the potential producibility of such resources that not much useful can be done until much more is known about how specific types and configurations of formations could be produced economically. There was a general sense that this would be a long-term rather than a short-term program.

Studies related to the Kyoto protocols on global warming include some that anticipate sequestering carbon dioxide in the earth. Under one scheme, that is estimated to require, for the output of two ordinary fossil-fueled power plants, a third plant whose energy would be used to sequester the carbon releases of all three. That would raise the wholesale cost of electricity by at least 50 percent. Strategic plans place technology readiness of this at about 2025. So there is some movement in the Government toward valuing more expensive (non-polluting) generation systems. Discussion of the worth of EGS potential needs to be presented in similar terms.

Simulation of Stimulations

Participants mentioned that a lot has been done -- in petroleum and nuclear waste isolation, but not so much in geothermal -- to simulate the effects that stimulation treatments would have under various geological and geophysical conditions.

If the geothermal industry pursues stimulations as EGS projects, then this technical area will become important. It will help industry predict what kinds of fractures are likely to form when using different fracturing pressure profiles, fracture fluid viscosities, total volume pumped, proppants, and so on. And to predict what is likely to work best under various geological conditions.

Many of the relevant tools exist in the oil and gas domains, and will have to be integrated, in some manner, with geothermal reservoir performance simulators. Of the participants, at least Warpinski, Hickman, and Swenson are familiar with many of these tools.

Types of Resources to Study

While not originally intended as part of the topic of "simulation," there was a fair amount of discussion about how the magnitude of "EGS" related resources in the U.S. might be estimated and represented to the public and to research planners. There was a general consensus, as has existed in the U.S. geothermal community for many years that there is an enormous amount of heat in the earth's crust under the U.S. But there is no way to estimate the fraction of that might be economic to exploit now or say thirty years from now.

Overall, the group agreed that it made the best sense to concentrate on trying to do new things at resources that are at the margin of currently produced hydrothermal fields. This approach will give a number of different types of geological situations to evaluate, and has the obvious advantage of using colocated existing infrastructure and some knowledge of the geology. There are likely to be in the low thousands of megawatts of potential at these sites, but not tens of thousands.

Economics are likely to be not terrible at some of these sites. This would give the Department of Energy the advantage of being able to say, "We are continuing to expand the fraction of geothermal resources that could be produced economically, especially in the cases where the going price for electricity goes up somewhat."

Non-producing sites with specially promising characteristics (e.g., high heat and high permeability) might also be worth studying.

Some participants noted there is a great deal of high quality heat in crustal rocks that are not the tight granites that Los Alamos worked on at Fenton Hill. These rocks might be much easier to fracture and to extract heat from.

Good Strategic Projects

Given that rendering very large amounts of EGS resources economic might take a Herculean effort and many years, some attention was devoted to what experiments or demonstrations might be useful in the short term. What came to mind for many was to stimulate hydrothermal injection wells to improve injectivity. This is likely to be more successful, immediately, than trying to stimulate production wells to produce more -- for a number of technical reasons. Improving injectivity is of interest to industry at a number of sites. Attempts at and successes in improving injection would afford test beds for improving measurements and particulars of stimulation methods.

And what is successful for industry often affects Congress positively. Mike Prairie pointed out that successes here would be equivalent to reducing the cost of drilling, at least on the injector side, which is one of the general "strategic" goals of the DOE geothermal R&D program.

It is important to raise the "EGS technical issues," e.g., improving ability to localize and characterize fractures, in ways that people can work with them in practical settings. Then the various pieces of technology out there that might be useful could come together.

Channeling

This was a recurrent topic. By channeling, participants meant the preferential enlargement of low impedance (higher velocity) flow paths, so that an artificially stimulated reservoir might have a tendency to develop short circuits. In those short circuits, much of injected cold fluid would flow through quick, and not be heated up enough to be useful.

Participants with petroleum experience are aware of thermally degradable materials that might be able to block short circuits for useful periods of time. That might allow an operator to force fluids into different parts of a reservoir for various intervals of heat extraction from different volumes of rock.

General Conclusions about "Simulation"

- We don't need to or want to build a Rolls Royce integrated simulator for EGS work. That is because we can use various existing simulators to model fluid flow, heat transfer, and perhaps chemistry in one existing model, and then study needed aspects of rock mechanics, fracture dilatency, etc., in one or more other existing models.

- It is more important to do the experiments to find out what things we need to put into such models, before we just go ahead and do it.

- We need to emphasize to the DOE Geothermal R&D Program and to the industry that we should try to get people doing more hands-on work on specific problems at specific fields.

The group was split on the idea of constructing an inventory of U.S. sites that might present favorable conditions for EGS experiments.

6.2 Discussion of Stimulation

As discussed in many other places in this report, especially Norm Warpinski's presentation in Section 2.1, "stimulation" deals with a wide variety of techniques for increasing the rates at which fluids between geological formations and the wells that penetrate them. The purpose of this session was to consolidate information and opinion about methods of modifying or creating permeability through stimulation of downhole formation by hydraulic or other means.

Summary of Prior Discussions

Norm Warpinski of Sandia began the session with a summarization of what had been said about stimulation earlier in the Workshop.

There are there main technical goals.

A. Interconnect Existing Permeability. Hickman's work at Dixie Valley is an example.

B. Enhance Existing Permeability. The SE Geysers Effluent Project (Lake County water) is perhaps an example of this, to the extent that cold water will contribute to new fractures via thermal stresses.

C. Create New Permeability. This was a main goal of the LANL Fenton Hill HDR concept and work.

These three goals form a conceptual map of the alteration or creation of fractures. Goal C.,

Create New Permeability, is the "Holy Grail" of stimulation. Most researchers believe that this needs to be achieved if extracting large amounts of heat from non-hydrothermal reservoirs is to become an important source of energy. Goal A., Interconnecting Existing Permeability, has been an announced goal of the industry and DOE for a long time, but with little actual progress. B. Enhancing Existing Permeability could include use of acids to widen flow paths.

The project of injecting deep in The Geysers or Coso suggested by Dennis Nielson lies perhaps halfway between goals B. and C. Goals A. and B. are likely to be achievable with relatively short fractures. Goal C. will require very large and long fractures.

The second Holy Grail for stimulation is control. This is going to be gained through creating secondary fractures. This is an augmentation stimulation, a totally different process, done on top of the primary stimulation. Once you got the thing created, then, everyone's right. You create this permeability system and the fluid is going to find the most easily accessible path and it's just going to try to channel through there. If you don't do something about that, you're going to have problems. And I think we can do things about that.

There's not much more to say here except that all these things are at least in some way "research," in that you need a lot of other information. They're all probably a little longer- term for the most part than some of the other research thrusts we've discussed.

Entingh: What are some of the fracturing capabilities that have been created for gas wells that geothermists gave up on 20 years ago, in particular, trying to create fractures at angles to the preferred direction? I believe most geothermists are convinced that you never get anything other than what's parallel to the preferred direction. What is it that would need to be done in order to try replicate that effect in a few geothermal wells?

Warpinski: The first thing that must be considered is, "What are the horizontal stress differences?". You have to choose a place where they aren't large, because the larger they are the harder it's going to be to do it. If you can find a place with a relatively small difference in the stresses, you need very viscous fluid because you have to develop pressure and you're not going to do it with water or thin fluid so that means we need high temperature, viscous gels to be able to develop the kind of pressure we need to get up there.

We have models we can run. We've done models for drill cutting injection that say how much pressure you need to get any fracture before you alter the stress field enough on this thing that's plugged up now. The next one's going to go off at some different angle, not just run the same direction. We can actually do those calculations. It's just mechanical calculations in the stress field around cracks. There's a site characterization issue and a site selection issue that are very important in talking such efforts.

Hickman: I think Dan is right that a lot of geothermists think that's true. But a lot of times it's not true. There's a general assumption that the permeable cracks are perpendicular to the least principal stress in existing reservoirs. But we know, like in Dixie Valley and in other places where we and others have looked at this kind of problem, that often times impermeable cracks, especially at greater depth are ones optimally oriented for shear failure, not for tensile opening. Certainly for Dixie Valley that's true. We don't see permeable tensile cracks.

Before we got there the prevailing wisdom based upon surface outcrop studies was your permeable cracks can be vertical. It was then shown that they don't exist at depth and those vertical surface cracks are probably a consequence of special stresses on the hanging wall. So you can be misled. If you don't understand your reservoir, you're going to have that problem in your thinking.

You can alter the stress field if the horizontal stress difference is low. I think in many cases, the first step is to really characterize the stress field and the orientation of permeable cracks and how they are genetically related to the stress field. Then if you are lucky, in a case like Dixie Valley, where there is a series of 50 to 60 degree dipping cracks that are striking parallel to the hydrofrac, the hydrofrac will come in like along strike but will intersect that set and not just kind of go between them. So the first step is to be really careful about that assumption about fractures being vertical only.

Other: Steve, how restrictive is that requirement, that the two horizontal stresses be pretty much the same? Would that requirement eliminate a lot of geothermal sites where you might want to try these methods?

Hickman: It eliminates a lot of places. The volume over which you perturb stresses is determined by the volume, say, in which you inject your cuttings. If you want to start that crack off in a non-optimal orientation and keep it going in that non-optimum orientation for some distance, you'd better create a pretty big, fat pancake along the optimum orientation first.

Warpinski: And the other issue with how much stress difference really depends upon how much pressure we can build in the stimulation. If we can develop very high viscosity fluids and easily get 1,500 to 2,000 psi net pressures and fractures with leakoff control and other things, then we could probably handle 6,000 to 8,000 psi kinds of stress differences and overcome them. If our fluids will not build enough viscosity and we can't get more than 500 psi in pressure, then we're talking about looking for a place that may be maybe a 100 to 200 psi only in stress differences. It has a lot to do with the fluids.

And then the higher the horizontal stress differences, the faster those things will wrap around to come into the optimal orientation. But it's relatively rare to get the two horizontal stresses equal. Typically they are sort of middle, between the least and the greatest. You can design pressurization rate, a viscosity to deal with that.

Other: Norm, I thought that at least one of your examples, one of your T shaped fractures, the top of the T was at an inhomogeneity.

Warpinski: Right, an inhomogeneity. Most geothermal thinking has assumed a homogeneous earth. Inhomogeneity is going to be important. The oil field experience probably has different kinds of inhomogeneity, e.g., between flat layers. So one thing we probably need to do in geothermal is gain some understanding of what's going to happen.

We don't talk about this much in fracture models, but we find that in many cases the inhomogeneities dominate the process, at least parts of the process and people just ignore that most of the time. It certainly affects velocity structure, very important for the micro-seismic, the layering, the different models are very important for analyzing the tilt meter data and fractures cut into interfaces, a lot of times, it looks like these laminate, the various layers we have in sedimentary basin stats -- shale, mud stones, sand sequences. It looks like its getting deposit material, but fractures are having a hard time growing across these layered systems. There's a lot of things we don't know.

High Temperature Equipment and Materials

Entingh: Is this whole area of possibility important enough that we should start quickly getting somebody to work on high temperature materials both proppant agents and viscosity agents?

Warpinski: I think someone should do a survey. Certainly see what's out there. Because I honestly don't know. Back in the Fenton Hill HDR days, there were not a lot of high temperature fluids around, certainly. I think the intermediate strength province is probably a good choice for proppants. There is ceramic material that are pretty good in terms of pressure, fatigue, chemistry and things like that. They're a little more expensive than sand but certainly it's something we can use in this environment.

Pritchett: It seems to me that about twenty years ago, there was a lot of work in that for the steam-flooding to extract heavy oils.

Others: There have been a number of papers published in SPE about proppants for steam flows. That would be a good literature research to kind of catch up. Also in Russia, there's work that's been done that's more primitive in some ways, but perhaps a little more robust as well, that we can learn from.

Others: There are additional questions about the degree to which fluids will dissolve materials from fracture walls, and perhaps redeposit them also. And other kinds of things. Are you willing to pump a large volume of water to try to cool down the tubulars during at least the initial part of the fractures so that you give your gel the longest life possible if there is still some thermal degradation, you can try and do things like that.

Other: Is there any experience in actually hydrofracing a system and undergoing combustion with temperatures near 300°C inside the reservoir?

Warpinski: I don't think so; not that I know.

Will Tiltmeters Work for Geothermal?

Other: I have a question for Norm. In terms of some of these methods used for gas wells, for example, putting up tiltmeter mapping arrays and trying to adjust proppant load and gel in real time, what is the state of the art in that? Is that going to do us any good?

Warpinski: There are cases and situations like that in California. There have been so many stimulations there. They've done so many tilt meter mapping jobs that they know what they are looking for. They know what's happening and they can tell that, O.K. here we have a case that this thing is going upwards instead of going out and we have to stop. We're just wasting fluid and proppant.

In the situation where there is a lot of experience, I think the answer is, yes, we can do that, particularly in tilt, in real time. But in new fields, we have no idea what's going on. The prospect of deciding in a second by second basis whether you should trim back the flow rate depends on experience in a particular field. Maybe eventually, like ten years down the road, we'll have enough understanding of what's going on and a pretty clear picture all over the place of how this works so we can do it, but now, it's just based on experience in specific locations.

The Importance of Natural Fractures

Entingh: New topic: Is there any currently commercially producing geothermal reservoir in the U.S. that's hosted in volcanic rock? There the rock may be easier to deal with than in large granite bodies.

Others: Mammoth-Long Valley is in volcanics. Coso is in granite. Hawaii is another one in volcanics. And Medicine Lake -- Glass Mountain.

Warpinski: Volcanic rock has a large number of natural fractures that presents all new problems for stimulation. One of the most difficult things in stimulation is trying to get hydraulic fractures propagating where we want them and the lengths we want in a naturally fractured reservoir. There's a lot of pooling into those natural fractures, the sandy hydrates and bridges, we get what we call screen out. What also happens is, you plug those things up trying to control this and then you can't get the stuff back out again so that now you have ruined your production. It's a tough job. We do it. People do it and those reservoirs are stimulated. But there's a lot of additional concerns in that kind of a reservoir. So there is just more planning involved.

Pritchett: I guess my question is, what are we talking about here when we are talking about these volcanic systems. Are we talking about looking at the effect of frac jobs in volcanic systems or are we talking about just looking at the natural fractures that are already sitting there? If the latter, all somebody really needs to do is go back and look at the mud logs on some of those things and you're going to see all the big cracks. You don't have to do anything unusual.

Hickman: Well, you've got to do image logging and TPS logging and things like that to actually determine the orientation of those fractures.

Pritchett: I agree. But the important question is, do you have a crack every 100 meters or every 500 hundred meters or every 5 meters. You're going to see that in something as simple as a mud log. I was focusing more on the question of, how many cracks have you got at the beginning? Then run your frac job. How many cracks have you got now?

Thermal Fracturing

McLarty: Another new question. In oil and gas there's cryogenic fracturing in which they use CO_2 and nitrogen at cryogenic temperatures. They use it primarily to control damage during the fracturing process near the wellbore. Might there be some application of cryogenic fracturing that would be beneficial and would promote stress thermal cracking? I know there would be some tremendous technical challenges and probably expense would be a major factor.

Hickman: We certainly see thermal stress cracking in Dixie Valley. We see thermal tensile cracks in virtually every well and I've modeled that. It's very straight forward. You can come up with a slight amount of cooling during normal drilling in a reservoir that is hot. With that kind of modulus rock it's exactly what you'd expect so I think most of these geothermal reservoirs, if they're not thermally fractured already with relatively shallow initiation of a hydrofrac, they can easily fracture after the fact by intentionally pumping cold mud down through there.

That just gets you started. If you have a thermal tensile crack in a well, you've gotten over any kind of tensile strength barrier there may be to producing a big hydrofrac. But it doesn't accomplish much in terms of heat exchange area. You've got to pressurize that fracture and propagate it even further and so I'm not sure that gains you much.

Kasameyer: I've heard many times, with respect to both Soultz and Fenton Hill was that the thermal stress, that cooling off the fracture is also a problem. I mean the reason these don't work is the fracture wall gets cool. Are there ways of modeling that and understanding where you could apply it?

Hickman: I was talking more about the near-borehole environment. You're right, once you get down the fracture and you start circulating cold fluid, whatever it is. And it's been modeled. People have modeled it and there are ways to continue modeling that. The question is that you can produce all sorts of cracks and additional shear stress but the question is does the fluid follow any of that or is it kind of off there in a damage zone around your hydraulic fracture? Does it do you any good?

Kasameyer: That's a question I think should be looked at.

Hickman: It's an important question.

Sanyal: I have a related empirical observation. It's very common in Japan, U.S., and other countries to inject just surface water. What you typically see if you look at the history of the injection well for 10 or 20 years, gradually the injectivity increases rather than decreases. Now often we have said, well, it's thermal cracking. It does reach a plateau. In other words, you just don't keep on propagating the fractures. Invariably we see in this hot reservoir the injectivity increase through time, unless there is precipitation of silica or something like that.

Warpinski: The main reason to use nitrogen or CO_2 is in foam systems to minimize liquids in the reservoirs. We also use it with regular fluids to give us the pressure assist to get the fluids back. For cryogenic purposes, I really don't think it's used. And in fact, probably just based on heat capacity alone, you're probably better off with water. It's not for cryogenic purposes per se.

Also, with those fluids there is a limited amount of sand they can pump. It's a great idea for that application but I don't know that we could use that one per se. We could probably use a foam system but that doesn't really get us where we want to go anyway. There are dangers in doing too much thermal stressing at the bore hole, too. You can get sanding-in problems and all sorts of things if you really overdo it. Skin damage. So putting liquid CO_2 down there kind of makes me nervous. Not to mention casing problems.

Chemistry Effects in Injection

Koenig: One of the effects that may be taking place there is if you are putting hot water into a previously unaltered rock and throwing it in there, that you may actually be dissolving silica and creating permeability.

Pritchett: It's usually meteoric water being injected, so it's relatively low in solutes.

Koenig: That's right. So it's well out of equilibrium and it's a tremendous solvent at elevated temperatures.

Entingh: A few papers from Los Alamos on solution effects of putting meteoric water into kinds of rocks they anticipated finding at depth. There are some rather significant changes in the continuum of dissolving and then minerals and they get redeposited as if a certain kind of clay like things really foul up heat exchange surface. That kind of thing can happen.

Koenig: Even if you take the case in which you put the silica solution into the formation, if you eventually boil it someplace, you're going to cause that silica to deposit again so it is always an issue. But I agree with what Subir says. In The Geysers some of these wells have been operating for 30 years and they haven't lost injectivity.

Hickman: At Dixie Valley the same thing has happened. They reinject solutions that are supersaturated with respect to silica, and have for 10 years, and they are still not losing injectivity. It's remarkable that they haven't plugged up those cracks yet.

Isolating Zones for Stimulation

Robertson-Tait: On our lists, we did not include a "barrier" of isolating zones for stimulations. Will zone isolation for stimulation in geothermal wells be a problem?

Others: That's included under the Hardware Development thrust, which received 13 votes.

Entingh: I think it might be interesting if someone knowledgeable did a quick review of the capabilities of open hole packers for fractured media. They're using drillable aluminum open hole packers at Soultz.

In the DOE-sponsored stimulation experiments of 20 years ago, one of the big limitations in what they could try to do, was that they couldn't set packers in some open zones they wanted to stimulate. So they would sand wells up in order to isolate a zone to stimulate into. That worked one time well, at East Mesa. It was the only commercial success. They stimulated twice, stimulating the bottom of the well first. And then they sanded up the bottom of the well, and perforated the casing to stimulate again at a middle depth. They finally washed the sand out to get the whole thing going. They roughly doubled the production flow out of the well. In Raft River, there were some sanded zones they couldn't wash out and so they could not reclaim the original productivity. But I think that's important for the industry to know some technologies exist that could be used.

Hickman: I've looked into that for our own purposes. We've talked to TAM, and course with Fritz Rummel, in Germany, who makes the aluminum packers. The aluminum packers are the ones that work at high temperatures. For the other ones the amount of differential pressure (how much you have to inflate from run-in diameter to the hole diameter) these packers can withstand drops off really fast above about 150°C. Above 200°C, typical elastomers are no good at all. The aluminum packers work a lot hotter but they don't deflate so you basically inflate them one time and then you mill them out. It's basically a drillable packer, and works pretty well. Fritz Rummel had a company built up around these things.

So if you were going to do an open hole system, a series of tests, you would use probably an aluminum packer. My preference, if you want to do a massive hydrofracture, would be to cement in a casing, maybe a polished bore receptacle and then perforate, do mini fractures at the perf, squeeze off the perf, and then do a maxi fracture in the zone you think you have a decent chance of containment, targeting the zone you want.

I'm a big fan of fracturing through perforations because CTS has solid rubber packers. Haliburton makes ones that go up to really high temperatures. At the open hole, a packer is really important for doing like stress profiling and maybe spot injection. But if you go in for big tests, you're going to do a massive hydrofracturing, I think you're much better cementing and casing and perforating it. There's much less risk of losing the whole well.

Warpinski: I agree. If you're worried about the perforations plugging up and things like that, you can always just hang that casing and pull it when you are done, so you can solve some of those problems, too.

Hickman: At Dixie Valley, ideally I would prefer to work with packers because I like to do vertical profiles. But Oxbow wouldn't let us put packers in the holes at Dixie Valley because they had bad experience losing holes from open hole packers as has anyone who has used an open hole packer. So there is a real risk in taking a valuable asset and losing a packer in it. These things are hard to mill out and stay on track. You have to keep that in mind. You don't want to take a risk of losing a well with an open hole packer.

If you are going to spend a couple hundred thousand dollars in a well and end up doing a massive hydrofrac and then turn them into a commercial injector or producer, just case, cement, and perforate; it's safer. One reason a lot of work has gone into these open hole high temperature packers is because of the ones that can be run in casing are pretty mature. Haliburton runs their solid rubber packers in casing at Dixie Valley and hotter places all the time very reliably. So I think it is important but I don't think a lack of a packer for hot open holes is going to kill us.

The solid rubber packers work to 275 or 300°C, something like that. There is as much metal as rubber in them. It is completely different technology than inflatables. Inflatables are big balloon that have to go back in. They have metal braids behind them and they go from a fairly small diameter to something that is pretty big. The solid casing packers may only have a quarter inch clearance between the inside of the casing and their ordinary diameter. You just squeeze in this little pancake, got metal grips and slips and all sorts of metallic backup, so you don't rely on a lot of strength in the elastomer. It doesn't have to expand much.

I've never intended to put an open hole packer in Dixie Valley because they won't let me, first of all, and because I don't think you really need it in most cases.

Warpinski: Actually, the problem is there's not a lot of open hole work done in the oil business. So all their development stuff which you'd like to use, forgot it, it's not there. Most open hole is done in mining, so in geothermal we're better off if we stay in cased hole.

Hickman: Where it does pay off is when you go into a hole with a big open hole interval and you want to figure out what the stress gradients are like. You could spot those intervals with a resettable straddle packer. If such a thing existed at high temperatures, you could learn an awful lot about that and it would be very useful for addressing issues of containments, stress heterogeneity, things like that.

Entingh: Does this go back to Sandia as another valuable reason to continue to work on straddle packers?

Prairie: At Sandia we are working on straddle packer right now. But it's for a fairly low differential temperature. It's a deflatable and drillable, straddle packer. It was developed for lost circulation in relatively cool zones. But that wasn't a high temperature testing straddle packer. It was something that we could certainly work on but we're not doing it.

Hickman: I think it would be worth looking at. The aluminum packer, I think, is about the best that's out there. Certainly Fritz Rummel's company has looked a lot into various options. If you get into these high temperature teflons and similar materials, they have some memory. But they won't come back to shape. You'll end up milling them out anyway, so you might as well plan on using aluminum. That was kind of his strategy. So you know I think if you were forced into it, you probably use aluminum packers right now just like they are at Soultz.

But I personally feel we could spend a lot of time on this and not have much to show for it if you are trying to get into truly an elastomer based system. And so I wouldn't put a lot of emphasis on the packers if I was making the research decision.

Prairie: It doesn't sound like it's really needed.

Sanyal: I think there is no problem here.

SECTION 7.0

LIST OF PARTICIPANTS

7.0 LIST OF PARTICIPANTS

Brian Bonner
Lawrence Livermore National Lab
P.O. Box 808, MS L-201
Livermore, CA 94550
Phone: 925-422-7080
Fax: 925-423-1057
Internet: bonner1@llnl.gov

Robert J. Creed, Jr.
U.S. Department of Energy
850 Energy Drive, MS 1120
Idaho Falls, ID 83401-1563
Phone: 208-526-9063
Fax: 208-526-5964
Internet: creedrj@id.doe.gov

Norton E. Croft
Lawrence Livermore National Laboratory
P.O. Box 808, MS L-728
Livermore, CA 94551
Phone: 510-422-7167
Fax: 510-422-9613
Internet: croft2@llnl.gov

Eric Davis
Pinnacle Technologies
600 Townsend St., Suite 160W
San Francisco, CA 94103
Phone: 415-861-1097
Fax: 415-861-1448
Internet: ericd@pinntech.com

Daniel J. Entingh
Princeton Energy Resources International
1700 Rockville Pike, Suite 550
Rockville, MD 20852
Phone: 301-468-8418
Fax: 301-230-1232
Internet: dentingh@perihq.com

Paul Grabowski
U.S. Department of Energy
1000 Independence Ave., MS EE-12
Washington, DC 20585
Phone: 202-586-0478
Fax: 202-586-8185
Internet: Paul.Grabowski@hq.doe.gov

Pablo S. Gutierrez
California Energy Commission
1516 9th Street, MS 43
Sacramento, CA 95814-5512
Phone: 916-654-4663
Fax: 916-653-6010
Internet: Pgutierr@energy.state.ca.us

Stephen H. Hickman
U.S. Geological Survey
345 Middlefield Road, MS 977
Menlo Park, CA 94025
Phone: 650-329-4807
Fax: 650-329-5163
Internet: hickman@usgs.gov

Paul Kasameyer
Lawrence Livermore National Lab.
7000 East Ave., MS L-203
Livermore, CA 94551
Phone: 925-422-6487
Fax: 925-422-3925
Internet: kasameyer@llnl.gov

Brian A. Koenig
2943 Santa Marta Ct.
Santa Rosa, CA 95405-8201
Phone: 707-538-8283
Fax: 707-538-8283
Internet: sakoenig@ix.netcom.com

Marcelo J. Lippmann
Berkeley National Laboratory
One Cyclotron Road
Berkeley, CA 94721
Phone: 510-486-5035
Fax: 510-486-5686
Internet: MJLippmann@lbl.gov

Lynn McLarty
Princeton Energy Resources International
1700 Rockville Pike, Suite 550
Rockville, MD 20852
Phone: 301-468-8442
Fax: 301-230-1232
Internet: lmclarty@perihq.com

Dennis L. Nielson
University of Utah
Department of Civil and
Environmental Engineering
423 Wakara Way
Salt Lake city, Utah 84108
Phone: 801-585-6855
Fax: 801-585-3540
Internet: dnielson@egi.utah.edu

Bjorn Paulsson
Paulsson Geophysical Services, Inc.
647 South Palm Street, Unit G
La Habra, CA 90631-5794
Phone: 562-694-9598
Fax: 562-694-3909
Internet: bjorn_paulsson@paulsson.com

Michael R. Prairie
Sandia National Laboratories
P.O. Box 5800, MS 1033
Albuquerque, NM 87185-1033
Phone: 505-844-7823
Fax: 505-844-3952
Internet: mrprair@sandia.gov

John W. Pritchett
Maxwell Technologies
8888 Balboa Ave.
San Diego, CA 92123-1506
Phone: 619-576-7760
Fax: 619-637-7411
Internet: john@maxwell.com

Karsten Pruess
Berkeley National Laboratory
Bldg. 90, Room 2024K
One Cyclotron Road, MS 90-1116
Berkeley, CA 94720
Phone: 510-486-6732
Fax: 510-486-5686
Internet: K_Pruess@lbl.gov

Joel Renner
INEEL
P.O. Box 1625
Idaho Falls, ID 83415-3830
Phone: 208-526-9824
Fax: 208-526-0969
Internet: rennerjl@inel.gov

Ann Robertson-Tait
GeothermEx, Inc.
5221 Central Ave., Suite 201
Richmond, CA 94804
Phone: 510-527-9876
Fax: 510-527-8164
Internet: mw@geothermex.com

Subir Sanyal
GeothermEx, Inc.
5221 Central Ave., Suite 201
Richmond, CA 94804
Phone: 510-527-9876
Fax: 510-527-8164
Internet: mw@geothermex.com

Mike Shook
INEEL
P.O. Box 1625
Idaho Falls, ID 83415-2107
Phone: 208-526-6945
Fax: 208-522-0875
Internet: ook@inel.gov

Daniel V. Swenson
Kansas State University
351 Rathbone Hall
Manhattan, KS 66506-5205
Phone: 785-532-2320
Fax: 785-532-7057
Internet: swenson@ksu.edu

Alfred H. Truesdell
700 Hermosa Way
Menlo Park, CA 94025
Phone: 650-322-6135
Fax: 650-324-4009
Internet: ahtruesdell@lbl.gov

Norman R. Warpinski
Sandia National Laboratories
P.O. Box 5800
Albuquerque, NM 87185-0750
Phone: 505-844-3640
Fax: 505-844-7354
Internet: nrwarpi@sandia.gov