PTTC
WEST COAST RESOURCE CENTER

Problem Identification Workshops

I	November 20, 1996	Red Lion Inn Bakersfield, California
II	November 25, 1996	Petroleum Club Long Beach, California
III	November 26, 1996	Double Tree Inn Ventura, California

Jointly Sponsored by:

Petroleum Engineering Program, University of Southern California
SPE San Joaquin Valley Section
SPE Los Angeles Basin Section
SPE Coastal Section
California Independent Petroleum Association
Tidelands Oil Production Company
Pacific Operators Offshore

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Workshop Summaries

The West Coast PTTC conducted three Problem Identification Workshops during November 1996. List of participants for all three workshops are provided in the corresponding sections.

The first workshop was held in Bakersfield, California on November 20th and was attended by 66 professionals from operating, service companies and various regulatory and private agencies. The format of this workshop consisted of seven presentations, two luncheon talks followed by four breakout sessions in the afternoon.

The bulk of the discussions centered among the selected topics, directional drilling, detection of hydorcarbons behind pipe, development of hydrocarbon resources in diatomites, and sand consolidation techniques.

Furthermore, issues related to idle well and well abandonment were reviewed by representatives from the California Division of Oil, Gas and Geothermal Resources. Additionally, the capabilities of an on-line oil and gas database were presented by the developers of the system from the Lawrence Berkeley National Laboratories. Finally a review of DOE sponsored projects for the oil and gas industry was made to familiarize the audience with the opportunities for cooperative work.

The workshop was repeated, with some minor modification in the technical presentations, in Long Beach and Ventura on November 25th and 26th, respectively. The Long Beach meeting had 52 and the Ventura meeting had 51 attendees.

From the discussions generated at the break-out sessions, the moderators prepared summary reports which were presented at the meeting. Based on the comments from the participants, the workshops were successful to initiate discussion on some critical issues of interest to oil and gas producers and in particular to the independents.

The problem identification workshops are a stepping stone to the more focused forums on individual technical subject addressing the advances in technologies and their applicability to marginal wells and fields.

Bakersfield

Agenda

Moderator: *Les Clark, IOPA*

Presentations:

9:30 Case Studies of Successful Horizontal and Multilateral Drilling
Dr. George Cooper, UC Berkeley and LBL

9:50 Recent Advances in Estimation of Porosity and Detection of Hydrocarbons in Cased Holes *Dr. Dan Moos, Stanford University*

10:10 Problems and Opportunities in the Development of Hydrocarbon Resources in The Diatomites *Dr. Tad Patzek, UC Berkeley and LBL*

10:30 Break

10:45 Novel Sand Consolidation Completion Technique Using Alkaline-Steam Injection in The Tar Zone, Wilmington Field *Scott Hara, Tidelands Oil Production Co.*

11:05 Idle Well and Well Abandonment Issues *Mike Glinzak, CADOGGR*

11:25 New Interfaces for the On-Line Oil and Gas Database
Jeff Wagoner, LLNL, and Shahed Meshkati, USC/PTTC

11:50 DOE's Oil Technology RD&D Program in California *Norman Goldstein*

12:00 Luncheon

PTTC and Oil & Gas Producers *Chris Hall, PAG Chairman*

Producers Point of View *Dan Kramer, Executive Director, CIPA*

1:30 p.m.-3:00 p.m. <u>Workshop Sessions</u>

Multimedia and Petroleum Tech Transfer *Mark Kapelke, Vice President of Tidelands Oil Production Co., and The PAG Vice Chairman*

Q & A on Environmental Regulations - Well Abandonment
Discussion Leaders: Mike Glinzak, CADOGGR, Patty Gradek and Jim Haerter, BLM Moderator: Kent McBride

Point/Counter Point on Horizontal/Multilateral Drilling
Discussion Leaders: Dr. George Cooper, UC Berkeley/LBL and Eric Upchurch, THUMS Long Beach Co.

Point/Counter Point on Estimation of Oil Behind Pipe
Discussion Leader: Dr. Dan Moos, Stanford University and Scott Walker, Tidelands Oil Production Co. Moderator: Buz Delano

Point/Counter Point on Diatomite
Dicsussion Leader: Dr. Tad Patzek, UC Berkeley
Moderator: Kyle Koerner

3:00 p.m.-3:30 p.m. <u>Summary and Wrap-Up</u> *Dr. Iraj Ershaghi, USC/PTTC*
Reports from workshops/Upcoming Events

Bakersfield Attendees List

Attendee Name	*Company Name*
Adams, Randy	CDOGGR
Akkutul, Yucel	University of Southern Califor
Aube, Karl	Pacific Gas & Electric
Bilodean, Bruce	Chevron USA Production Co.
Bopp, Hal	CDOGGR
Brannon, Ed	CDOGGR
Bronson, Jon	University of Southern Califor
Cales, Gerry	Chevron USA
Chaudry, Vic	Bechtel Petroleum
Clark, Dave	CDOGGR
Clark, Les	IOPA
Clifford, Jim	Geo Drilling Fluids
Cooper, George	University of California Berke
Crawford, Tim	Arco Western Energy
Dean, Greg	B. J. Services
Degenhardt, Kalon	Texaco
DeRose, Bill	Bechtel
Dunbar, Walt	
Duncan, James	Griffin & Carrick
Duncan, Paul	M. H. Whittier Energy LLC
Ershaghi, Iraj	University of California
Ganong, Dick	Ganong Oil & Gas Operation
Glinzak, Mike	CADOGGR
Glinzak, Mike	CDOGGR
Goldstein, Norman E.	Lawrence National Lab Berke
Grader, Patty	Bureau of Land Management
Haerter, James	Bureau of Land Management
Haerter, Jim	Bureau of Land Management
Hall, Chris	Drilling Production Co./PAG
Handlin, John	Arco Western Energy
Hara, Scott	Tidelands Oil Production Co
Holcomb, Silvet	Bureau of Land Management
Horace, Charles	Trio Petroleum

Attendee Name	*Company Name*
Kapelke, Mark	Tidelands Oil Production Co
Katragadda, Dave	Bechtel
Kharabaf, Hooshang	University of Southern Califor
Knauer, Larry	Bechtel Petroleum
Koemer, Kyle	
Kramer, Dan	CIPA
Marino, Tony	Arco Western Energy
Martin, Mike	P. G. & E.
Mayer, David F.	System Tech.
Meshkati, Shahed	USC/PTTC
Moore, David	Bechtel
Moos, Dan	Stanford University
O'Brein, Freda	O.Y.Y
O'Bryan, Patrick L.	Arco Western Energy
Palermo, Robert	System Technology
Patzek, Tad	University of California Berke
Pierson, Raymond	Epoch Well Logging Inc.
Prude, Jeff	Bureau of Land Management
Ryall, Phil	Stockdale Energy
Ryan, Kevin	Berry Petroleum
Schwalm, Jeffrey	Dynamic Graphics, Inc.
Seymour, Bradley	Williams Tool Company/Ener
Shaudery, Vic	Bechtel Petroleum Operation
Snow, Lysle	Commander Oil Company, O
Starcher, Mark	Bechtel Petroleum
Thomsen, Mark	Mobil Oil
Upchurch, Eric	THUMS Long Beach Compa
Urdaneta, Alfredo	CalResources
Verrier, Carol	Bureau of Land Management
Wagoner, Jeff	LLNL
Waldo, Lyndon	Texaco
Walker, Scott	Tidelands Oil Production Co
Weyland, Ginny	Elk Hills

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company? geologist

2. Where is your main production or the production you are associated with?
Oil

3. How did you find out about this workshop? Supervisor

4. What particular topic(s) did you find relevant and beneficial in this workshop? Horizontal wells, Lawrence Livermore, Fractures, Alkaline Steam

5. How can this problem identification workshop be improved? Liked it fine-

6. What additional topics should be included in future workshops?
downhole chemistry + changes in formation water

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?
Petroleum Engineer: Production and Reservoir Engineering

2. Where is your main production or the production you are associated with?
Elk Hills

3. How did you find out about this workshop?
Society of Petroleum Engineers' Newsletter

4. What particular topic(s) did you find relevant and beneficial ~~in this~~ workshop? (1) Fracture Geometry Imaging — How this is related to injection projects (2) Internet oil water gas rates!;

5. How can this problem identification workshop be improved?
Possibly shorter presentations – more speakers. This would likely bring less technical people into the audience thereby presenting to more independents

6. What additional topics should be included in future workshops?
Water production and disposal techniques and regulations; particularly disposal regulations.

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:
The production data on the internet is worthy of more effort. The industry is not aware of this service, generally speaking.

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

2. Where is your main production or the production you are associated with?

3. How did you find out about this workshop?
Was asked to participate on a panel & shared the agenda with others - this was the first

4. What particular topic(s) did you find relevant and beneficial in this workshop?

5. How can this problem identification workshop be improved?
More time for participant questions/feedback

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification? Perhaps try to cover less in the technical sessions so there's more time for interaction

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

   Region Technical Manager

2. Where is your main production or the production you are associated with?

   All of CA and AK

3. How did you find out about this workshop?

   Mailer

4. What particular topic(s) did you find relevant and beneficial in this workshop?

   Horizontal
   [illegible]
   LLL internet database

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?

   [illegible]

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

   [illegible]

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Staff Reservoir Engineer

2. Where is your main production or the production you are associated with?

Offshore & Coastal California - Turbidites - Waterfloods

3. How did you find out about this workshop?

Mail-in

4. What particular topic(s) did you find relevant and beneficial in this workshop? Sand consolidation using steam at Wilmington

5. How can this problem identification workshop be improved?

With more shows like the CD Rom/and discussion - Good job!

6. What additional topics should be included in future workshops?

- Injection Conformance in Waterfloods/Steamfloods

-

7. What would you suggest as alternative methods for problem identification?

Multiple choice survey of independent producers; ie. design the survey with emphasis on the perceptions of the small independent. Provide meaningful choices & so.

8. Additional comments:

Invite people that know about technology to come & share their experience; ie. THUMS for multilaterals.

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Team Leader (Petrol. Engrs, Geol, Techs)

2. Where is your main production or the production you are associated with?

Elk Hills

3. How did you find out about this workshop?

Mailer

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Horiz. Drilling, F&F, Oil Saturation in cased holes

5. How can this problem identification workshop be improved?

- Allow attendance of more than one workshop session.
- Set-up bulletin board online for suggestions / discussion
- Progress reports / presentations on group topic leaders

6. What additional topics should be included in future workshops?

Case Histories on:
Operating cost reduction
Revitalization of mature/SI fields
Horizontal redrills (including use of coiled tubing)

7. What would you suggest as alternative methods for problem identification?

Look at recoveries in various fields/reservoirs to identify high/low recovery efficiencies. Provide this info. to respective operators to improve production practices.

8. Additional comments:

Great seminar. Might want to consider compiling list of industry contacts and their areas of expertise

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

PRESIDENT / GEOLOGIST

2. Where is your main production or the production you are associated with?

SAN JOAQUIN / EDISON / KERN FRONT

3. How did you find out about this workshop?

MAIL OUT

4. What particular topic(s) did you find relevant and beneficial in this workshop? HORIZONTALS & SAND CONSOLIDATION WITH STEAM

5. How can this problem identification workshop be improved?

— MORE TIME FOR DISCUSSION WORKSHOP

6. What additional topics should be included in future workshops?

MECHANICS OF CABLES, PUMP SYSTEMS VARIETIES & OIL PROCESSING

7. What would you suggest as alternative methods for problem identification? SEND OUT QUESTIONAIRE FOR PRODUCERS AGAIN — JUST SMALL?

8. Additional comments:

VERY GOOD ATTEMPT AT TECH TRANSFER — I HOPE IT WORKS

ANON

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Manager

2. Where is your main production or the production you are associated with?

San Joaquin Valley

3. How did you find out about this workshop?

Was asked to serve on panel & I shared agenda with others. Panel could have been better. Moderator did not introduce panelists. He needed to encourage more audience questions.

4. What particular topic(s) did you find relevant and beneficial in this workshop?

- Idle Well issues
- Internet Info sources

5. How can this problem identification workshop be improved?

Perhaps start the day identifying questions, then hear fewer presentations, then ~~answer questions that~~ bring panel together again and answer questions that were not answered by the presentations

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

Moderator could ask for problems to be identified & list on a flip chart. I have a sense we didn't hear enough about what people see as problems.

8. Additional comments:

- Need more time for participant questions/feedback
- More emphasis on problems they need to have resolved... Seemed like too much time conveying information & not enough identifying problems

(Great lunch!!)

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Log Analyst

2. Where is your main production or the production you are associated with?

Kern River

3. How did you find out about this workshop?

Pacific Oil + Gas Show

4. What particular topic(s) did you find relevant and beneficial in this workshop?

ALL

5. How can this problem identification workshop be improved?

Get more people involved

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Geologist

2. Where is your main production or the production you are associated with?

Shallow Oil Zone

3. How did you find out about this workshop?

a mailing

4. What particular topic(s) did you find relevant and beneficial in this workshop? horizontal drilling, ϕ, Tideland's CD

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?

designing a horizontal well path with 3D ~~geo~~ geologic software.

7. What would you suggest as alternative methods for problem identification?

8. Additional comments: Great workshop. A very worthwhile Day.

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

PRODUCTION / RESERVOIR ENGINEER.

2. Where is your main production or the production you are associated with?

MIDWAY - SUNSET, COALINGA, LOST HILLS

3. How did you find out about this workshop?

WORKSHOP SESSION ANNOUNCEMENT / REGISTRATION FORM WHICH WAS SENT TO MY OFFICE & PERSONAL CONTACT FROM HERMAN SCHALLER

4. What particular topic(s) did you find relevant and beneficial in this workshop?

HYDROCARBON DETECTION WORK BEHIND PIPE, ALKALINE SAND CONTROL, ON LINE OIL & GAS DATABASE INFO.

5. How can this problem identification workshop be improved?

I FOUND TOO MANY AREAS OF INTEREST AT SAME TIME

6. What additional topics should be included in future workshops?

STEAM QUALITY MEASUREMENT, CONTROL & DISTRIBUTION & MORE EXTENSIVE REVIEW OF METHODS TO IDENTIFY OIL BEHIND PIPE & INFO ON HOW HORIZONTAL WELLS ARE PERFORMING.

7. What would you suggest as alternative methods for problem identification?

MORE EXTENSIVE USE OF INTERNET FOR INQUIRY & COMMENT

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?
Corporate Account Rep.

2. Where is your main production or the production you are associated with?
Gas + electric utility

3. How did you find out about this workshop?
Fellow employee

4. What particular topic(s) did you find relevant and beneficial in this workshop?
Horizontal drilling info.
On-line oil + gas database

5. How can this problem identification workshop be improved?
Ensure presenters have adequate time for presentations.

6. What additional topics should be included in future workshops?
Energy saving techniques in the industry
Educational presentation on horiz/multi-lateral drilling

7. What would you suggest as alternative methods for problem identification?
This is my first conference of this type so no suggestions at this time.

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Senior Geologist

2. Where is your main production or the production you are associated with?

Shallow Oil Zone (SOZ) @ Elk Hills

3. How did you find out about this workshop?

Friend told me

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Successful horizontal + multilateral drilling
Idle Well + Well Abandonment Issues

5. How can this problem identification workshop be improved?

Start earlier in the morning so speakers won't be rushed and short question and answer period after each talk

6. What additional topics should be included in future workshops?

Recompletion methods

7. What would you suggest as alternative methods for problem identification?

Survey

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

   PET ENG

2. Where is your main production or the production you are associated with?

   SAN J. V.

3. How did you find out about this workshop?

   MAIL

4. What particular topic(s) did you find relevant and beneficial in this workshop?

   DIATOMITE
   PRIMARY REASON I ATTENDED

   ALSO FOUND INTERESTING:
   IDLE/ ABANDONING WELLS
   ON-LINE DATABASE

5. How can this problem identification workshop be improved?

   TOPICS LIMITED TO A MAJOR AREA:
   IE. PROD, RES, GEOLOGY

6. What additional topics should be included in future workshops?

   COULD SPEND A WHOLE DAY ON DIATOMITE ISSUES.

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

- NEED TO STRICTLY LIMIT SPEAKERS TO TIME REQUIREMENTS. - STICK TO AGENDA
- MAYBE COVER FEW TOPICS TO ALLOW MORE DETAILED PRESENTATIONS.
- WORKSHOP IS WHAT DREW ME TO ATTEND SHORTENING

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

ENGINEERING SUPV

2. Where is your main production or the production you are associated with?

S.J.VALLEY – LOST HILLS

3. How did you find out about this workshop?

MAILER

4. What particular topic(s) did you find relevant and beneficial in this workshop?

BREAKOUT SESSIONS

5. How can this problem identification workshop be improved?

SOME WAY TO GET MORE PEOPLE TO ATTEND.

6. What additional topics should be included in future workshops?

HEAT MANAGEMENT – ADMITTEDLY THIS IS A LARGER INDEP. - MAJOR PROBLEM

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

GOOD STEP IN THE RIGHT DIRECTION

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company? SENIOR GEOLOGIST

2. Where is your main production or the production you are associated with?

Elk Hills, KERN CO., CA

3. How did you find out about this workshop? CONTACTED BY PTTC TO HELP with JANUARY '97 WORKSHOP ON CA geology and to lend support as President of PACIFIC SECTION AAPG

4. What particular topic(s) did you find relevant and beneficial in this workshop?

HORIZONTAL DRILLING
Hydrocarbon detection through CASING
SHUT IN WELL REGULATIONS

5. How can this problem identification workshop be improved?

INClude an example problem TO VIEW and discuss.

6. What additional topics should be included in future workshops?

Anything to do with HYDROCARBON detection behind CASING

7. What would you suggest as alternative methods for problem identification?

8. Additional comments: PTTC needs to be in to the professional Society conventions IE. SPE & AAPG. AAPG convention in BAKERSFIELD MAY '97.

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company? OWNER

2. Where is your main production or the production you are associated with?
I AM A CONSULT, THEREFORE I WORK WITH PRODUCING WELLS ALL OVER CALIFORNIA.

3. How did you find out about this workshop?
THROUGH DR ERSHAGI

4. What particular topic(s) did you find relevant and beneficial in this workshop? 1 DIATOMITE PROBLEMS/OPPORTUNITIES. 2 CASED HOLE DETECTION OF HYDROCARBONS. 3 MARK KAPELKE'S TALK ABOUT SAND CONSOLIDATION et. al.

5. How can this problem identification workshop be improved?
ACTIVELY SOLICIT PARTICIPATION FROM THE MAJORS & MAJOR SERVICE COMPANIES

6. What additional topics should be included in future workshops?
~~TO BE IDEN~~ FRACTURE IDENTIFICATION &

7. What would you suggest as alternative methods for problem identification? SURVEY CONSULTANTS & SERVICE COMPANIES

8. Additional comments:

CONTACT BURT DELAND @ 805-325-3977

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

   SENIOR RESERVOIR ENGINEER

2. Where is your main production or the production you are associated with?

   ELK HILLS – SHALLOW OIL ZONE

3. How did you find out about this workshop?

   MAIL

4. What particular topic(s) did you find relevant and beneficial in this workshop?

   HORIZONTAL WELLS
   ABANDONMENTS

5. How can this problem identification workshop be improved?

   MORE INPUT FROM INDUSTRY

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

   PAGE ON INTERNET

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Asset Team Leader

2. Where is your main production or the production you are associated with?

NPR-1, Elk Hills, California

3. How did you find out about this workshop?

SPE Newsletter

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Horizontal/multilateral drilling
Diatomite development, Idle well issues

5. How can this problem identification workshop be improved?

Q&A immediately after presentation would be desirable.

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company? Partner

2. Where is your main production or the production you are associated with?
Kern Co.

3. How did you find out about this workshop?
Bill Rintoul's column in the Bakersfield Californian

4. What particular topic(s) did you find relevant and beneficial in this workshop? cased hole logging + online access

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?
   PLANNING & EVALUATION CONSULTANT

2. Where is your main production or the production you are associated with?
   MWSS

3. How did you find out about this workshop?
   Colleague

4. What particular topic(s) did you find relevant and beneficial in this workshop? Horiz drilling trends, diatomite, internet tech. transfer

5. How can this problem identification workshop be improved?
   Focused discussions on specific issues

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company? Sole proprietor

2. Where is your main production or the production you are associated with?
San Joaquin Valley

3. How did you find out about this workshop? SPE newsletter

4. What particular topic(s) did you find relevant and beneficial in this workshop?
Horizontal wells & sand consolidation

5. How can this problem identification workshop be improved?
Longer planned presentations – concurrent presenta

6. What additional topics should be included in future workshops?
Waste disposal Reduced hole size
Drilling muds Neutron hydrocarbon logs

7. What would you suggest as alternative methods for problem identification?
No alternative to talking to people

8. Additional comments:
This was a good meeting

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Engineer

2. Where is your main production or the production you are associated with?

Midway Sunset

3. How did you find out about this workshop?

SPE

4. What particular topic(s) did you find relevant and beneficial in this workshop? Diatomite

Cased-hole Hydrocarbon ID
Horizontal / Multilateral

5. How can this problem identification workshop be improved?

Joint Venture topics with appropriate groups such as AAPG/AADE/Well log Society etc.

6. What additional topics should be included in future workshops?

- water disposal
- aging equipment/infrastructure
- practical topics

7. What would you suggest as alternative methods for problem identification?

Industry surveys

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Formation Evaluation Geologist

2. Where is your main production or the production you are associated with?

Siliceous shale/ diatomite

3. How did you find out about this workshop?

Mailing

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Diatomite

5. How can this problem identification workshop be improved?

Better moderation in breakout session — must ~~____~~ have process and goal in mind and guide participants to accomplish something

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification? You have to do more than identify problems. Run through formally published processes for problem solving/ decision making. Allow more time for this, say, 1/2 day.

8. Additional comments:

Train people who run discussion sessions in group discussion techniques (problem solving/decision making, Nominal Group Technique, meeting facilitation, etc.) or use professional facilitators.

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

   Sr Engr.

2. Where is your main production or the production you are associated with?

   San Joaquin Valley

3. How did you find out about this workshop?

   Company Correspondence

4. What particular topic(s) did you find relevant and beneficial in this workshop?

   Behind pipe oil estimation

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?

   more emphasis on alternate methods to determine behind pipe potential.

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

President / Consultant

2. Where is your main production or the production you are associated with?

Heavy oil, - California, Alaska, & overseas.

3. How did you find out about this workshop?

by mails.

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Government supports.

5. How can this problem identification workshop be improved?

more case studies

6. What additional topics should be included in future workshops?

reservoir description, well problem diagnosis.

7. What would you suggest as alternative methods for problem identification?

Specify problems

8. Additional comments:

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company? PROF, U.C. BERKELEY

2. Where is your main production or the production you are associated with?
NONE SPECIFIC.

3. How did you find out about this workshop?
INVITED BY PROF ERSHAGHI.

4. What particular topic(s) did you find relevant and beneficial in this workshop?
ALL DRILLING, DOE / DOGG.R. INFO.
IN FACT, ALL PRESENTATIONS WERE INTERESTING.
JUST MEETING + MAKING CONTACT IN BREAKOUTS WAS VERY VALUABLE.

5. How can this problem identification workshop be improved?
SEE #8.

6. What additional topics should be included in future workshops?
TRAINING METHODS / NEEDS
- POTENTIAL FOR SHORT COURSES, SEMINARS - - - - .

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:
1). MAKE TIME IN THE PROGRAM FOR STARTING & STOPPING THE MEETING – "INTRODUCTORY REMARKS" ETC., OTHERWISE THE SCHEDULE SLIPS
2). GET A LIST OF NAMES, AFFILIATIONS, PHONE NOS / E-MAIL ADDRESSES OF ALL PARTICIPANTS! THIS COULD BE AS SIMPLE AS HANDING ROUND A CLIPBOARD IN THE MORNING & HANDING OUT XEROXES

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Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Faculty at U.C. Berkeley; Researcher at LBNL

2. Where is your main production or the production you are associated with?

San Joaquin: Diatomites, Kern River, Midway Sunset

3. How did you find out about this workshop?

Through USC

4. What particular topic(s) did you find relevant and beneficial in this workshop?

All presentations were interesting,

5. How can this problem identification workshop be improved?

But ran overtime - Timing could improve

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

V

PTTC West Coast Resource Center

Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Lead Petroleum Engineer

2. Where is your main production or the production you are associated with?

Midway Sunset

3. How did you find out about this workshop?

Flier came in the mail to my Supervisor

4. What particular topic(s) did you find relevant and beneficial in this workshop? Several : 1 well completion without liner & steaming

: 2 estimation of production behind the pipe.

5. How can this problem identification workshop be improved?

would like additional handouts — someone type the minutes + ~~the~~ distribute at end

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

It was very informative

PTTC West Coast Resource Center

Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company?

   PRODUCTION ENGINEER

2. Where is your main production or the production you are associated with?

   LONG BEACH

3. How did you find out about this workshop?

   FELLOW WORKER

4. What particular topic(s) did you find relevant and beneficial in this workshop?

   - NOVEL SAND CONSOLIDATION
   - ACOUSTICALLY DERIVED POROSITY

5. How can this problem identification workshop be improved?

   HAVE MORE FIELD DEMONSTRATIONS

6. What additional topics should be included in future workshops?

   PRODUCTION EQUIPMENT & TECHNIQUES

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

PTTC West Coast Resource Center

Bakersfield Problem Identification Workshop Evaluation Form

1. What is your position at your company? Supv. Petr. Engr.

2. Where is your main production or the production you are associated with?
BLM - reg. agency

3. How did you find out about this workshop? flyer in the mail

4. What particular topic(s) did you find relevant and beneficial in this workshop? Sand consolidation techniques, idle wells/well abandonment questions

5. How can this problem identification workshop be improved? We needed a Q & A period after each talk.

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

Long Beach

Agenda

Moderator: *Ed Mayer*

Presentations:

9:30 Case Studies of Successful Horizontal and Multilateral Drilling
Dr. George Cooper, UC Berkeley/LBL

9:55 Recent Advances in Estimation of Porosity and Detection of Hydrocarbons in Cased Holes *Dr. Dan Moos, Stanford University*

10:20 Novel Sand Consolidation Completion Technique Using Alkaline-Steam Injection in The Tar Zone, Wilmington Field *Scott Hara, Tidelands Oil Production Co.*

10:30 Break

11:00 Development and Operations Under Environmental Constraints
Paul Mount, Chief of Mineral Resources Management Division, State Lands Commission

11:25 Multimedia and Petroleum Tech Transfer *Mark Kapelke, Vice President Tidelands Oil Production Co., and PAG Vice Chairman*

11:30 DOE -Industry Partnership Projects in California *Norman Goldstein*

12:00 Luncheon

PTTC and Oil & Gas Producers *Chris Hall, PAG Chairman*

Producers Point of View *Dan Kramer, Executive Director, CIPA*

1:30 p.m.-3:00 p.m. Workshop Sessions

Q & A on Environmental Regulations
Discussion Leaders: Bruce Hesson, CADOGGR and Paul Mount, SLC
Moderator: Allan Spivak

Point/Counter Point on Horizontal/Multilateral Drilling
Discussion Leaders: Dr. George Cooper, UC Berkeley/LBL and Eric Upchurch, THUMS Long Beach Co.

Point/Counter Point on Estimation of Oil Behind Pipe
Discussion Leader: Dr. Dan Moos, Stanford University and Scott Walker, Tidelands Oil Production Co. Moderator: Mike Bruno

New Interfaces for the On-Line Calif. Oil and Gas Database
Discussion Leaders: Jeff Wagoner, LLNL Shahed Meshkati, USC/PTTC
Moderator: Dexter Yuen

3:00 p.m.-3:30 p.m. Summary and Wrap-Up Dr. Iraj Ershaghi, *USC/PTTC*
Reports from workshops/Upcoming Events

Long Beach Attendees List

Attendee Name	*Company Name*
Anderson, Russ	Suma Oil & Gas
Barto, Craig	Signal Hill Petroleum
Breitenbach, Randy	BreitBurn Energy Corp.
Bruno, Mike	Terralog Technolgoies
Clifford, Jim	GEO Drilling Fluids
Cooper, George	University of Berkeley
Crosby, Fredric C.	Crosby Construction
Delano, Buz	
Du, Chang-An	Petroleum Engineering Progr
Duda, Cecilia	California State Lands
Emanuel, Alan	Consultant
Ershaghi, Iraj	University of Southern Califor
Graham, Patrick	
Graner, J. B.	Graner Oil Co.
Gunkel, Fritz	Thums Long Beach Compan
Hall, Chris	Drilling & Production Compa
Handy, Lyman L.	USC
Hara, Scott	Tidelands Oil Production Co.
Hassibi, Mahnaz	USC
Hesson, Bruce	CADOGGR
Jepson, John	D.O.G.G.R
Johnson, Eric	Victory Oil Co.
Kapelke, Mark	Tidelands Oil Company
Kharabaf, Hooshang	University of Southern Califor
Koerner, Kyle	
Koerner, Roy	City of Long Beach Dept. of
Kramer, Dan	CIPA
Lanson, Tony	CalResources LLC
Long, Robert	Pan Western Petroleum Co.
Mayer, Ed	Consultant
McGurk, Scott	Consultant
Meshkati, Shahed	University of Southern Califor
Moos, Dan	Stanford University

Tuesday, April 01, 1997

Attendee Name	*Company Name*
Mount, Paul	State Lands
Riva, Steve	ASIOCO
Scott, James	Pacific Energy Resources
Shah, Dharmen	
Smith, Linda	Texokan Exploration Service
Spivak, Allan	Intera
Sullivan, Dennis	City of Long Beach Dept. of
Swanson, Glenn	Intera
Torabzadeh, Jalal	California State University Lo
Voelker, Ronald	Keystone Oil Co.
Voskanian, Marian	California State Lands Comm
Wagoner, Jeff	LLNL
Walker, Scott	Tidelands Oil Production Co
Washburn, Halbert	BreitBurn Energy Corp.
Webster, Mark	Signal Hill Petroleum
Yang, Zhengming	USC
Yoelin, Sherwin	Consulting Engineer
Young, Richard	Pacific Energy Resource
Yuen, Dexter	State Land Commission

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

2. Where is your main production or the production you are associated with?

3. How did you find out about this workshop?

4. What particular topic(s) did you find relevant and beneficial in this workshop?

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:
Very helpful from my point of view - especially new Interface section.

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Professor

2. Where is your main production or the production you are associated with?

Education

3. How did you find out about this workshop?

SPE Newsletter

4. What particular topic(s) did you find relevant and beneficial in this workshop?

all

5. How can this problem identification workshop be improved?

more attendance

6. What additional topics should be included in future workshops?

- Reservoir characterization (
- Geological studies

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

Very useful workshops

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

OWNER

2. Where is your main production or the production you are associated with?

SEAL BEACH FIELD

3. How did you find out about this workshop?

CIPA

4. What particular topic(s) did you find relevant and beneficial in this workshop?

HORIZONTAL DRLG
SAND CONTROL
INTERNET

5. How can this problem identification workshop be improved?

HAVE MORE OF THEM!

6. What additional topics should be included in future workshops?

DOWN HOLE PRODUCTION PROBLEMS

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Partner

2. Where is your main production or the production you are associated with?

LA Basin

3. How did you find out about this workshop?

CIPA

4. What particular topic(s) did you find relevant and beneficial in this workshop? Horizontal Drilling

5. How can this problem identification workshop be improved? send questionaires to independent producers for problems they would like to be addressed at PTTC

6. What additional topics should be included in future workshops? well logging of cased holes in Long Beach - Signal Hill area

7. What would you suggest as alternative methods for problem identification? see 5

8. Additional comments: PTTC is a great program for the small independents, we can now draw on the resources that were only available to the majors. Edward Moss

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

   TOP GUY

2. Where is your main production or the production you are associated with?

   NO PRODUCTION - yet

3. How did you find out about this workshop?

   DR. ERSHAGHI

4. What particular topic(s) did you find relevant and beneficial in this workshop?

   Speakers on environmental Regulation and idle/stripper well mangmt.

5. How can this problem identification workshop be improved?

   Make examples more specific to producer needs.

6. What additional topics should be included in future workshops?

   SUCCESS STORIES AS A RESULT OF APPLICATION OF TECHNOLOGY LEARNED at one of these sessions.

7. What would you suggest as alternative methods for problem identification?

   Telephone Surveys
   one-on-one meetings w/ small producers

8. Additional comments:

   GOOD SHOW!

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Consultant

2. Where is your main production or the production you are associated with?

L/A Basin

3. How did you find out about this workshop?

SPE Newsletter

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Horizontal drilling
Well logging

5. How can this problem identification workshop be improved?

Shorten to ½ day. Fewer talks
Make (subject specific

6. What additional topics should be included in future workshops?

Well abandonments
Water production

7. What would you suggest as alternative methods for problem identification?

Single brainstorming session every 2-3 years on problems.

8. Additional comments:

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Owner

2. Where is your main production or the production you are associated with?

CONSULTANT - Wilmington, BREA, Huntington BEACH

3. How did you find out about this workshop?

SPE NEWSLETTER

4. What particular topic(s) did you find relevant and beneficial in this workshop?

ALL - Especially the data Bases

5. How can this problem identification workshop be improved?

Just cover additional topics

6. What additional topics should be included in future workshops?

Down hole producing problems & Solution
Chemical Solutions

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

Good work shop, Keep it up.

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

OWNER - consulting company

2. Where is your main production or the production you are associated with?

Torrance / Wilmington

3. How did you find out about this workshop?

ON Mailing list

4. What particular topic(s) did you find relevant and beneficial in this workshop?

LLNL computer interface
Case studies - horizontal + multilateral wells

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?

Computerization of DOG Hardcopy Files; with non-operational microfilm machines, how much data from hardcopy files will be put into computer format; will it be actual pages or just selected data entered into some kind of table (This is proposed + in my view, not acceptable)

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

Another topic is computerization of DOG production data pre-1977 now on microfiche + in boxes at State Archives in Sacramento.

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company? General Partner

2. Where is your main production or the production you are associated with?
Deer Creek Field, Tulare Co.

3. How did you find out about this workshop?
CIPA

4. What particular topic(s) did you find relevant and beneficial in this workshop? Well Abandonment & Regulation's

5. How can this problem identification workshop be improved?
More participants

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments: Excellent — even for small independents

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

President

2. Where is your main production or the production you are associated with?

Service Co.

3. How did you find out about this workshop?

Newsletter

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Horizontal/Multilateral Drilling

5. How can this problem identification workshop be improved?

Stay on schedule.

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Staff Reservoir Engr.

2. Where is your main production or the production you are associated with?

Huntington Beach Field

3. How did you find out about this workshop?

mailing.

4. What particular topic(s) did you find relevant and beneficial in this workshop?

All of them.

5. How can this problem identification workshop be improved?

The workshops (breakouts) should be driven by a trained facilitor. The facilitor would focus the discussion, capture key points, summarize the discussion w/ a written report out (short, ~~brief~~ brief). outstand problem would float to the surface

6. What additional topics should be included in future workshops?

water shut off technology

7. What would you suggest as alternative methods for problem identification? The problems were predetermined before the workshop. A solicitation of problems before the workshop might identify other problems.

8. Additional comments:

Breakout summaries could be posted on the PTTC Web Sight.

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Reservoir Engr

2. Where is your main production or the production you are associated with?

Statewide Offshore Fields

3. How did you find out about this workshop?

Esfaghi

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Sand consolidation

5. How can this problem identification workshop be improved?

– Need broader participation, particularly from producing companies

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

PTTC West Coast Resource Center

Long Beach, Nov. 25, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Chief engineering

2. Where is your main production or the production you are associated with?

Long Beach Unit

3. How did you find out about this workshop?

Dr Ershaghi

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Novel Sand Consolidation

5. How can this problem identification workshop be improved?

More focus on problem solving

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

Poll on internet or
Via mail

8. Additional comments:

Ventura

Agenda

Moderators: Rod Eson, Veneco and Arlie Skov, Consultant

Presentations:

9:30 Case Studies of Successful Horizontal and Multilateral Drilling
Dr. George Cooper, UC Berkeley/LBL

9:55 Recent Advances in Estimation of Porosity and Detection of Hydrocarbons in Cased Holes *Dr. Dan Moos, Stanford University*

10:20 Break

10:30 Idle Well and Abandonment Issues *Ed Brannon and Pat Kinnear, CADOGGR*

11:00 Problems and A Potential Solution to Excess Water Production From the Turbidite Sands, The Carpinteria Field *Steve Coombs, Pacific Operators Offshore, Inc.*

11:30 Multimedia and Petroleum Tech Transfer and Novel Sand Consolidation Completion Technique Using Alkaline-Steam Injection in The Tar Zone, Wilmington Field *Mark Kapelke, Vice President Tidelands Oil Production Co., and PAG Vice Chairman*

12:00 DOE-Industry Partnership Projects in California *Norman Goldstein*

12:15 Luncheon

PTTC and Oil & Gas Producers *Chris Hall, PAG Chairman*

Producers Point of View *Dan Kramer, Executive Director, CIPA*

1:30 p.m.-3:00 p.m. Workshop Sessions

Q & A on Environmental Regulations
Discussion Leaders: Ed Brannon and Pat Kinnear, CADOGGR
Moderator: Fariba Niece

Point/Counter Point on Horizontal/Multilateral Drilling
Discussion Leaders: Dr. George Cooper, UC Berkeley/LBL and
Moderator: Steve Coombs

Point/Counter Point on Estimation of Oil Behind Pipe
Discussion Leader: Dr. Dan Moos, Stanford University and Scott Walker, Tidelands Oil Production Co. Moderator: Mike Bruno

New Interfaces for the On-Line Calif. Oil and Gas Database
Discussion Leaders: Jeff Wagoner, LLNL Shahed Meshkati, USC/PTTC
Moderator: Harold Syms

3:00 p.m.-3:30 p.m. Summary and Wrap-Up Dr. Iraj Ershaghi, USC/PTTC
Reports from workshops/Upcoming Events

Ventura Attendees List

Attendee Name	*Company Name*
Andersen, Eric	GRC International, Inc.
Basenberg, Cecil	Cbase Corportion
Basenberg, Jeff	Cbase Corporation
Benton, John	
Benton, John H.	Benton Engineering
Bernstein, Carl	Consultant
Brannon, Ed	CADOGGR
Brierley, Gary	Stockdale Oil & Gas, Inc
Clawson, Floyd	Clawson Petroleum Consulta
Compton, Robert	Nordman, Cormany, Hair & C
Coombs, Steve	Pacific Operators Offshore, I
Cooper, George	University of California Berke
Delano, Buz	
Downs, Clelland	GRC International, Inc.
Ershaghi, Iraj	University of California/PTTC
Eson, Rod	Venoco, Inc.
Estill, Wayne	Drilling, Exploration & Operat
Frame, Tim	B J Services Co.
Giddens, Kermit	West Montalvo Corp.
Gillette, Chip	Venoco, Inc.
Hall, Chris	
Hara, Scott	Tidelands Oil Production Co
Herrera, Pat	Cal Energy Resources
Hull, Harry	Cbase Corporation
Hunter, III, Kenneth	The Hunter Living Trust
Hunter, Jr., Kenneth	The Hunter Living Trust
Janes, Debbie	Silicon Graphics
Kerns, Jeff	Venoco, Inc
Keyes, Keven	Environmental Drilling & Clea
Kharabaf, Hooshang	University of Southern Califor
Kinnear, Pat	CDOGGR
Lyons, Ed	GMS
Meshkati, Shahed	University of Southern Califor
Miller, Dave	CalResources
Moos, Dan	Stanford University

Attendee Name	*Company Name*
Neese, Fariba	Seneca Resources
Reeves, Mark	Cal Resources LLC
Regeber, Wolf	R & R Resources, LLC
Romming, Petter	United Energy Inc.
Rothaupt, Gunther	R & R Resources, LLC
Schrage, Greg	Unocal
Shah, Dharmen	University of Southern Callifo
Sickles, Kurt	Stockdale Oil & Gas, Inc.
Skov, Arlie	Arlie M. Skov, Inc
Syms, Harold	MMS
Tuttle, John D.	Enterprise Drilling Fluids Inc.
Wagoner, Jeff	LLNL
Walker, Scott	Tidelands Oil Co.
Warren, Phil	Cal Resources
Warren, Phillip	Cal Resources
Whittaker, Jeff	Consultant

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?
District Engineer
Ventura CA BJServices

2. Where is your main production or the production you are associated with?
Service co. handling Santa Maria, Ventura, & CAOCS basins

3. How did you find out about this workshop?
Through SPE and Kevin Williams

4. What particular topic(s) did you find relevant and beneficial in this workshop? Drilling
LLNL database access

5. How can this problem identification workshop be improved?
Have service companies show their experience. This could be done without making a "sales pitch" meeting.

6. What additional topics should be included in future workshops?
Seismic

7. What would you suggest as alternative methods for problem identification? Survey of operators needs before next workshop.

8. Additional comments:

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

MANAGER

2. Where is your main production or the production you are associated with?

VENTURA CO. / KERN CO.

3. How did you find out about this workshop?

CIPA MAILER LIST

4. What particular topic(s) did you find relevant and beneficial in this workshop?

HORIZONTAL

5. How can this problem identification workshop be improved?

SPEAKERS -

6. What additional topics should be included in future workshops?

FRACTURING IN SOFT ROCK.

7. What would you suggest as alternative methods for problem identification?

UNIVERSITY TYPES MIXING WITH INDUSTRY TYPES IN ~~[illegible]~~ SPECIAL BREAKOUT SESSIONS

8. Additional comments:

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?
   Production Management

2. Where is your main production or the production you are associated with?
   Ventura County, Ramona Field

3. How did you find out about this workshop?
   Notice thru Mail

4. What particular topic(s) did you find relevant and beneficial in this workshop? All topics are of interest

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?
   ways to enhance production in stripper wells.

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:
   Enjoyed the workshop, very informative, thank you.

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Sales Manager

2. Where is your main production or the production you are associated with?

Not a producer, I represent a videologging service company.

3. How did you find out about this workshop?

~~Mailed~~ PTTC mailed me a flyer.

4. What particular topic(s) did you find relevant and beneficial in this workshop? The CD-Rom/sand consolidation work done by Tidelands.

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Owner/President

2. Where is your main production or the production you are associated with?

Edison Oil Field, Kern Co., CA.

3. How did you find out about this workshop?

Received Registration Form & Program by mail from PTTC, USC.

4. What particular topic(s) did you find relevant and beneficial in this workshop?

1) On-line Calif oil & gas data base
2) Q & A on Environmental Regulations.

5. How can this problem identification workshop be improved?

1) Hold more workshops
2) Promote or encourage larger participation by oil & gas producers

6. What additional topics should be included in future workshops?

Consolidation of all or ~~most~~ most oil and gas related regulations under the management of DOGGR i.e. sump management & water quality control.

7. What would you suggest as alternative methods for problem identification?

Ask the small oil & gas producers what their problems are.

8. Additional comments:

Keep up the good work.

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

President

2. Where is your main production or the production you are associated with?

San Joaquin - Lost Hills

3. How did you find out about this workshop?

CIPA

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Steam to control Sand Production

5. How can this problem identification workshop be improved?

Include economic costs in the alternatives presented Such as were shown in the Alkaline Steam Sand Control

6. What additional topics should be included in future workshops?

other steaming information - cyclic - flood designing steam floods.
Seismic 2D + 3D + Modeling - Reservoir management

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

ENGINEER

2. Where is your main production or the production you are associated with?

KANSAS, NORTH DAKOTA

3. How did you find out about this workshop?

FROM PTTC NEWSLETTER

4. What particular topic(s) did you find relevant and beneficial in this workshop?

SAND CONSOLIDATION
IDLE /ORPHAN WELL ISSUES

5. How can this problem identification workshop be improved?

CASE STUDIES PRESENTED NEED TO SHOW COST EFFECTIVENESS OF APPLICATIONS OF TECHNOLOGIES

6. What additional topics should be included in future workshops?

STIMULATION TECHNIQUES
NOVEL WTR TREATMENT/DISPOSAL TECHNIQUES
RESERVOIR MGMT.

7. What would you suggest as alternative methods for problem identification? ENCOURAGE OPERATORS TO PUT TOGETHER 10-MIN SUMMARIES OF PROBLEMS, PRESENT 4 OR 5 INITIALLY AS DISCUSSION TOPICS FOR REST OF DAY.

8. Additional comments:

WELL RUN, WELL RUN WORKSHOP

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

   Vice President and Director, West Coast Operations

2. Where is your main production or the production you are associated with?

   Not an oil or gas production company.

3. How did you find out about this workshop?

   From a consultant with ties to independent O & G producers

4. What particular topic(s) did you find relevant and beneficial in this workshop?

   - Efforts at enhanced recovery
   - Applications of information technologies

5. How can this problem identification workshop be improved?

   No Judgements yet.

6. What additional topics should be included in future workshops?

   No opinions yet.

7. What would you suggest as alternative methods for problem identification?

   No opinions yet.

8. Additional comments: A good mix of perspectives: academic, practical, economic. Good show.

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

OPNS MGR

2. Where is your main production or the production you are associated with?

OFFSHORE CA.

3. How did you find out about this workshop?

4. What particular topic(s) did you find relevant and beneficial in this workshop?

PROBLEMS INVOLVED WITH MULTILAYERED RES.
HOR. ~~DR~~ & MULTILAT. DRLG

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?

METHODS/APPLICATION/TECHNOLOGY OF:
1. GRAVEL PACKING OR PRE-PACK INNER LINERS TO EXTEND EXISTING WELL LIFE.
2. PCP PUMPS & PROBLEMS WITH ROTATION OF RODS
3. REPAIRING/PATCHING OF DAMAGED OLDER CASINGS STRINGS

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

NOT SURE THAT ABOVE ARE "TECHNICAL" ENOUGH BUT ARE VERY REAL PROBLEMS THAT EXPERIENCE/SHARING OF OPERATORS COULD BE BENEFICIAL

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

PRODUCTION ENGINEER

2. Where is your main production or the production you are associated with?

WHITTIER FIELD, BEVERLY HILLS FIELD, SANTA CLARA AVE. FIELD

3. How did you find out about this workshop?

MAILER

4. What particular topic(s) did you find relevant and beneficial in this workshop?

SAND CONSOLIDATION
HORIZONTAL DRILLING

5. How can this problem identification workshop be improved?

DON'T GET TOO TECHNICAL.

6. What additional topics should be included in future workshops?

- PRODUCTION PROBLEMS
- COST-CUTTING MEASURES

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Sr. Reservoir Engineer

2. Where is your main production or the production you are associated with?

Ventura Ave Field

3. How did you find out about this workshop?

Mail

4. What particular topic(s) did you find relevant and beneficial in this workshop? Horiz Wells
LL Database
Oil Saturation Behind Pipe

5. How can this problem identification workshop be improved?
Good Format
No Recommendation

6. What additional topics should be included in future workshops?
Water Shut Off Solutions for producers
& injectors.

7. What would you suggest as alternative methods for problem identification?

8. Additional comments:

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Vice President Operations

2. Where is your main production or the production you are associated with?

Bakersfield.

3. How did you find out about this workshop?

Invitation in the mail (from SPE listing ?)

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Horizontal wells and steam projects

5. How can this problem identification workshop be improved?

More question and aswer section

6. What additional topics should be included in future workshops?

Steam injection, practical examples with details about the soulutions
Environmental issues.

7. What would you suggest as alternative methods for problem identification?

Phone people and ask.

8. Additional comments:

Great hand out !!!

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

Engineering Manager

2. Where is your main production or the production you are associated with?

S. California

3. How did you find out about this workshop?

Mailing

4. What particular topic(s) did you find relevant and beneficial in this workshop?

Horiz well application & sand consolidation

5. How can this problem identification workshop be improved?

6. What additional topics should be included in future workshops?

Matrix acidizing, 3D seismic

7. What would you suggest as alternative methods for problem identification?

8. Additional comments: The best part of the PTTC that I can determine from my limited exposure is that producers are forced to share their experiences with other producers early in their projects. Technology transfer sessions are always good. My question is: Would other groups such as the SPE fill this need if the PTTC didn't exist. I have attended equally interesting seminars sponsored →

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

V.P. Operations

2. Where is your main production or the production you are associated with?

Coastal & Sac. Valley

3. How did you find out about this workshop?

Called by Dr. Ershaghi

4. What particular topic(s) did you find relevant and beneficial in this workshop?

The disks/CD's of work being completed

5. How can this problem identification workshop be improved?

Use more direct contact. Participants calling people to let them know about workshops.

6. What additional topics should be included in future workshops?

* Lift System innovations
How to work with/comply w/ AQMD's, Sanitation Districts etc

7. What would you suggest as alternative methods for problem identification?

Request input from various industry associations for input from members

8. Additional comments:

Enjoyed this workshop very much!

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?
PRESIDENT

2. Where is your main production or the production you are associated with?
TEJON-GRAPEVINE & MIDWAY SUNSET
ALSO CONSULT FOR LAND/MINERAL OWNERS THROUGH-OUT STATE

3. How did you find out about this workshop?
PTTC MAILING, CIPA MMIR, CIPA BROADCAST FAX.

4. What particular topic(s) did you find relevant and beneficial in this workshop?
DOGGR PRESENTATION.
LLNL DATABASE
TORCO CD ROM.

5. How can this problem identification workshop be improved?
BE MORE SOLUTION/EXAMPLE SPECIFIC.

6. What additional topics should be included in future workshops?
WATER: CONTROL & HANDLING.
IMPROVING WELLBORE INFLOW.
IDENTIFYING BEHIND PIPE & RESERVOIR POTENTIAL IN OLDER FIELDS.

7. What would you suggest as alternative methods for problem identification?
SURVEYS
TECHNICAL WORKSHOPS ENDED WITH 1/2 hr SESSION OF "WHERE DO WE GO FROM HERE"

8. Additional comments:
GREAT

Chris Hall

PTTC West Coast Resource Center

Ventura, Nov. 26, 1996
Problem Identification Workshop Evaluation Form

1. What is your position at your company?

EXECUTIVE DIRECTOR

2. Where is your main production or the production you are associated with?

NO PRODUCTION

3. How did you find out about this workshop?

U.S.C. – CHRIS HALL

4. What particular topic(s) did you find relevant and beneficial in this workshop?

IDLE WELL PRESENTATION

5. How can this problem identification workshop be improved?

FOCUS, IN DETAIL, ON PARTICULAR SUBJECTS FOR EACH SESSION

6. What additional topics should be included in future workshops?

MARGINAL WELL INCENTIVES AND HOW TO TAKE ADVANTAGE OF THEM.

7. What would you suggest as alternative methods for problem identification?

1) SURVEYS 2) DIRECT MAIL 3) PHONE CALLS 4) FOCUS GROUPS 5) TAKE TO THE NOTES W/ PRODUCERS AT THEIR OFFICES: INTERVIEWS

8. Additional comments:

Good!

PTTC

PTTC **Petroleum Technology Transfer Council**
West Coast Resource Center

Petrolerum Engineering **Resource Center** for The

West Coast Oil and Gas Producers

| **National PTTC** | **Sponsors** | | Courses/Forums | Directory | Organizations| **SPE**|

| Daily Sites| Search Engines | **Upcoming Events**| FAQ| Email

|**Oil and Gas Database** | **DOE Sites to Visit**| Oil on Line | Software|

| Other Energy Resources| Miscellaneous | Discovery Place|

|**PAG Members** |PTTC Address| **Advisors** | PTTC Staff |

This site has been accessed [counter] times since June 2, 1996

Petroleum Technology Transfer Council Mission

The Petroleum Technology Transfer Council (PTTC) was formed in 1994 by the U.S. oil and natural gas exploration and production (E&P) industry. The PTTC mission is to identify and transfer technology for the benefit of the domestic oil and natural gas industry.

PTTC also transfers upstream E&P technologies to help domestic producers reduce costs, improve operating efficiency, increase ultimate recovery, enhance environmental compliance, and add new oil and gas reserves. The Program identifies producers' priority technical problems and communicates them to the R&D community. PTTC serves as an integrated clearinghouse for E&P technology information but it does not perform or fund R&D.

Partial start-up funding has been provided by the U.S. Department of Energy. Additional funds come from several state governments, industry, in-kind contributions from Regional Lead Organizations, and PTTC regional and national activities. The Board of Directors is comprised of producers from ten PTTC regions, with a representative from the Independent Petroleum Association of America, Gas Research Institute, the Interstate Oil and Gas Compact Commission, a major oil or natural gas producing company, a major service/supply company, and one representative each from the three main professional societies. The PTTC Board is supported by a headquarters staff. In each PTTC region, there is a Producer Advisory Group (PAG) and a Regional Lead Organization (RLO), operating under contract.

Building on the new paradigm in technology transfer, the PTTC's approach is customer-driven. Problem Identification Workshops have been held in all regions to allow producers to identify problems, and set regional technology transfer priorities. Focused Technology Workshops are being held around the country to provide producers with cost effective solutions to priority problems.

PTTC Resource Centers in each region provide inter-disciplinary technical assistance and referrals. The centers have computer equipped facilities with access to data, analytical software, and technology information. PTTC also has many other outreach efforts in the form of Newsletters, information systems, technical forums, on-line surveys, feedback mechanisms, and regional user groups.

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DOE R&D Program

U.S. DEPARTMENT OF ENERGY OFFICE OF FOSSIL ENERGY

OILtechnology

RD&D PROGRAM

Sustaining a Vital U.S. Energy Industry

The Department of Energy's Oil Technology RD&D Program has two major components, as summarized in this overview: (1) the Reservoir Class Field Demonstration Program, an initiative to forestall the premature abandonment of still-productive U.S. oil reservoirs, and (2) a longer-range R&D program to develop more advanced upstream and downstream oil production and processing technologies.

One of America's most serious energy problems is the premature abandonment of still-productive domestic oil fields.

Already, over half of the crude oil discovered in the United States lies in fields that were abandoned when they became no longer viable economically - and the rate of abandonment is accelerating. As much as 70 percent of the Nation's remaining oil resources could be lost by shortly after the year 2000. The high capital costs of drilling wells and returning pumps, piping, tanks, and other equipment to these fields (and, in some cases, the difficulties of restoring production leases) make it unlikely that abandoned fields will ever be reopened, even if oil prices rise in the future. Unless slowed, the trend to abandonment will lead directly to further job losses and declining oil production.

The DOE Reservoir Class Field Demonstration Program

To counter this alarming situation, the Department of Energy has begun the "Reservoir Class Field Demonstration Program," an intensive effort to increase production from U.S. oil fields and prevent them, and the jobs that go with them, from being prematurely abandoned.

Federal Cost-Sharing

The program focuses on the next few critical years. Its thrust is to provide Federal matching funds of up to 50 percent to oil field operators, ranging from small oil companies to major producers, along with other organizations who agree to demonstrate existing or novel advanced technologies that can prolong the economic life of U.S. fields. Many technologies currently available are underused, despite dwindling production levels, and many new advanced processes are becoming available that can dramatically improve the economic productivity of a reservoir.

Buying Time

The demonstration effort is one of the highest priorities in the Federal oil research and development program. If successful, it can "buy time" for many of the Nation's oil field operators, while simultaneously proving that advanced technologies are highly cost-effective in real life situations. In addition to producing more oil today, the technologies provided by this program can help sustain the domestic oil industry well into the 21st century.

How the Program Is Run

The United States has more than 96,000 oil reservoirs. To determine those that should receive priority attention, DOE first grouped 2,500 of the largest domestic reservoirs into geologically similar reservoir classes." This represents 65 percent of the oil-in-place in the lower-48 States.

The reservoir classes were then prioritized by:

- the amount of producible oil remaining in them.
- the likelihood of premature abandonment.

Once priorities were set, DOE began running competitions, asking private operators, universities, State agencies, and others to recommend technologies and candidate projects that would increase production from the most threatened of these geologic classes. Three competitions have already been conducted. Thirty-two projects are currently in the program or have completed field test operations.

Technology Transfer

The theory behind the program is simple: if a technology is successful in one field, it will be successful in a field with similar geology.

Industry partners will spread the success stories. They must help to convey these potential solutions to other producers, and the program encourages partnerships among oil field producers, universities, State agencies, service companies, and consultants to carry out the projects and to conduct related technology transfer efforts. Industry associations such as the Petroleum Technology Transfer Council, and groups of project participants in California and the Permian Basin are also helping to provide detailed, regionally specific technology information to others operators through workshops and field tours.

Reservoir Classes

Class I: Fluvial Dominated Deltaic Sandstones
These reservoirs, one of the first priorities, were formed from ancient river deltas and contain more than 28 billion barrels of crude oil. In April 1992, 14 projects were picked in nine States: Alabama, Colorado, Illinois, Kansas, Louisiana, Oklahoma, Texas, Utah, and Wyoming

- **Funding:** $48 million in Federal funds; $65 million in private funds.

Class II: Shallow Shelf Carbonates
These reservoirs were formed from shallow ocean shelves now found as far north as the Canadian border, which originally contained more than 68 billion barrels of crude oil. Most of the 48 billion that remain are at risk of being lost forever. In April 1993, 11 projects were selected for matching funds in eight States: Kansas, Michigan, Nebraska, New Mexico, North Dakota, Oklahoma, Texas, and Utah. (Two projects subsequently withdrew from the program.)

- **Funding:** $38 million in Federal funds; $50 million in private funds.

Class III: Slope and Basin
These reservoirs of light and heavy oil were created from the sediment deposited in deep ocean basins, and are estimated to have once contained nearly 60 billion barrels of crude oil; most of the remaining 44 billion are in danger of being abandoned unless more sophisticated techniques are widely deployed. In September 1994, nine projects were selected in California, New Mexico, and Texas.

- **Funding:**$38 million in Federal funds; $50 million in private funds.

Listing of Reservoir Class Field Demonstration Projects

Project Success Stories

As the first group of projects nears completion, increased production is being reported both in the project areas and in nearby properties where other operators have adopted the successful demonstration technologies For example, 11 production units in the Uinta Basin, northeast Utah, have started or are designing waterfloods based on the demonstration by Lomax Exploration Company (Class I). These are expected to add 31 million barrels of additional oil production, which could return $160 million in Federal taxes and royalties.

In another project in the Gulf of Mexico, Columbia University in partnership with several universities and oil companies has developed and demonstrated the successful use of 4-D seismic (multiple 3-D seismic surveys conducted several years apart) to locate bypassed reserves, leading to drilling of a well that will return the entire cost of the project in Federal taxes and royalties in 5 years.

DOE's Longer-Term Oil Technology R&D Program

America taught the world how to find, produce, and process hydrocarbons. It was in the United States that "rock oil" was transformed from a 19th century geologic curiosity to an easy source that has reshaped the post-World War II way of life.

Today, however, the U.S. oil industry needs the help of technological innovations to counter the serious and growing problems of declining domestic oil production and steadily increasing dependency on oil imports. To help provide these new technological tools for the 1990s, the Department of Energy has refocused its Oil Technology Program:

- Federal oil research is now concentrating on innovative approaches that can slow down the abandonment of still-productive oil reservoirs and locate new oil-bearing formations.
- Improvements in oil processing technology are being pursued to improve the efficiency and environmental performance of today's oil refineries
- The Department is working with States and the industry to improve and simplify the regulatory framework to ensure environmental protection in oil and gas operations.

America - An Oil-Abundant Nation

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Contrary to popular belief, the United States still has enormous oil resources. Right now, more than 135 years after the birth of the U.S. oil industry, the Nation has twice as much oil remaining in its reservoirs as it has so far produced. For every barrel of oil produced to date, two barrels have been left behind. The U.S. oil industry has produced almost 160 billion barrels, but some 350 billion barrels remain as the target of improved oil technologies.

Most of this remaining oil, however, is hard to produce Locked in complex geologic structures, bypassed by conventional technologies, or simply beyond the capability of today's recovery processes, this oil remains elusive.

It is against this backdrop that the Department of Energy has begun an intensive effort to develop a new generation of oil exploration and production technologies.

Exploration and Production.
The United States could more than double its current proven oil reserves of 25 billion barrels if it could pinpoint and recover the producible oil that remains in known fields. Yet another 25 to 60 billion barrels of available reserves could be added by successful exploration in new areas.

While these goals are based on an oil price of $20 per barrel or more, advanced technology will be equally critical. A 1992 independent study by a panel of oil experts concluded that new technology - in any reasonable price scenario - could boost recoverable oil discoveries by about 45%.

The Federal program is focusing much of its effort on independent producers, the smaller companies that today bring us nearly 40% of all domestic oil. They also drill almost all new exploratory wells. For these companies, new technology increasingly spells the difference between economic success or failure.

Revealing a Reservoir's Architecture.
Understanding the "architecture" of an oil reservoir - its geology, the way oil moves through the pores and fractures of the reservoir rock and its underground pressures - can give an oil producer valuable insights into how to design and carry out an effective field production project. The Department's research program is aimed at providing the advanced tools that can unlock these geologic secrets:

- Researchers are using CAT scan imaging to examine reservoir rock.
- Nuclear magnetic resonance imaging (MRI) is being applied to core samples to study how fluids flow through the rock.
- New electromagnetic instruments are being designed to image oil-bearing zones.
- Extremely sensitive geophones are being developed to detect 'micro-earth quakes" that reveal reservoir fractures
- Rock outcroppings in oil producing areas are being used to test sophisticated computer models that help predict how a reservoir will respond to a new oil recovery approach.

These new "reservoir characterization" techniques often reveal bypassed "compartments" of additional oil that are hidden between producing zones of a reservoir. In some cases, drilling has passed through these oil bearing structures in search of larger payzones.

With a better understanding of a reservoir s geologic makeup, producers can often drill between existing wells (infill drilling) or open existing wells at different levels (recompletion) to produce additional oil. In some cases, horizontal wells drilled laterally through a reservoir will contact many more oil carrying fractures than a traditional vertical well.

New Life for Older Fields.
When first penetrated by production wells, the oil in most reservoirs flows freely to the surface, pushed by the natural pressure of the reservoir. When this "primary production" declines, operators often inject water or gases to maintain the underground pressures. Water injection will also push more oil toward the producing wells. These "secondary" recovery techniques are in use in most U.S. fields.

The Department is carrying out several targeted research efforts to improve secondary recovery techniques.

For example, after extensively flooding a field, water will usually find the easiest path through the reservoir. Oil along its path is swept toward the producing well. But oil that has not been contacted by the water remains unproduced. The Department is funding research into more effective ways to divert the waterflood to untouched areas of the reservoir.

Once waterflooding is no longer effective, operators may turn to "enhanced" or "tertiary" recovery. The Department is developing several approaches to increase the effectiveness and predictability of these advanced processes:

- Certain environmentally safe chemicals can be injected into a reservoir to reduce the tendency of oil to cling to surrounding rock.
- Certain types of polymers - long-chained molecules - can make water "thicker so that it drives more oil through a reservoir.
- Gases such as CO2 can be injected into the rock to move oil more easily through a reservoir.
- Microbes that can survive the harsh rigors of an oil reservoir can produce gases or chemicals underground that increase the mobility of remaining oil.
- In some heavy oil fields, thermal processes can thin oil that is too thick to flow from the reservoir.

Processing and Downstream Research.
U.S. crude oil supplies are getting heavier and their sulfur content is increasing. This creates new challenges for refiners who need to produce light-end motor fuels and other products and at the same time reduce the amount of heavy residual oil left unprocessed.

The Department's processing program is a relatively new area. It responds to the increasing need for more effective processing and environmental technologies that can cope with new regulations and the declining quality of today s domestic crude oil.

Better understanding of thermodynamics and the chemical properties of the various fractions of crude oil will help researchers design processes that produce higher quality products more efficiently and economically. New refinery catalysts have the potential to generate breakthroughs in process economics. Better thermal efficiencies - the way a refinery minimizes its heat losses-can reduce fuel consumption and improve costs. It may also be possible to develop new separation processes - new membranes, for example - that are more efficient than traditional distillation.

Ensuring Environmental Compatibility.
The U.S. exploration and production industry spends more than $1.5 billion a year to comply with environmental protection requirements.

As environmental standards tighten, the Department has undertaken an intensive effort to ensure that future regulations are scientifically sound and based on an adequate assessment of environmental risks. This effort includes, for example, the development of comprehensive data on the environmental and economic effects of regulations that restrict discharges of water and sand from oil and gas operations in the Gulf Coast area. It also includes an intensive effort to develop a better understanding of how such substances as naturally occurring radioactive materials are produced and how they collect in oil and gas handling facilities.

Failure to make environmental regulations more site-specific and scientifically grounded could reduce production by 330,000 barrels per day or

120 million barrels per year in 2020, resulting in even higher oil imports.

Additional Online Information

The Department of Energy's National Oil Program is managed by the Bartlesville (OK) Project Office. This link will connect with the Bartlesville Office's National Oil Program Home Page.

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Report from Previous Problem ID Workshops

Report from Previous Problem ID Workshops

(The following is a report of information prepared by the Petroleum Technology Transfer Council (PTTC) and submitted to the U.S. Department of Energy through its management and operating contractor, BDM-Oklahoma Inc., as part of PTTC's partnership in oil and gas technology transfer with DOE)

Executive Summary

The Petroleum Technology Transfer Council (PTTC) is a national non-profit organization that serves as the technology clearinghouse for the oil and natural gas exploration and production industry -- mainly independents. Its mission is to accelerate the flow of technology information to producers and to provide input to the technology and research and development (R&D) community about the technical problems, needs, and priorities of petroleum producers.

To help focus future technology transfer efforts on the industry's highest priority national and regional needs, PTTC -- together with its regional lead organizations, the Texas Independent Producers and Royalty Owners Association (TIPRO), and the Kansas University Energy Research Center (KUERC) -- has conducted 32 "problem identification workshops" in ten oil and gas producing regions of the United States. The results of these workshops, held between 1991 and 1995, are being made available to the industry technology and service companies, and the R&D community. This should help accelerate public and private research and technology transfer efforts toward the highest-priority areas.

The results of these workshops identify a broad array of technical barriers, technology needs, and related concerns in all categories of petroleum exploration and production (E&P) operations in all producing regions of the nation. In many of these areas, technologies and solutions already exist that can be brought to bear to address the problems under current economic conditions. In some cases these technologies need to be improved to increase their efficiency or reduce their costs.

These findings underscore a clear and fundamental message previously voiced by technology transfer studies of the Interstate Oil and Gas Compact Commission (IOGCC), the National Petroleum Council (NPC), and numerous other organizations. That message is that current technology transfer mechanisms have not been able to increase the awareness, use and adaptation of cost-effective technologies by vast segments of the oil and gas producing industry, and especially independent producers.

The results of PTTC's regional problem identification workshops indicate technology marketing efforts of service and supply companies should take into account specific regional needs. The PTTC, NPC and IOGCC studies reveal significant problems yet to be addressed by private-sector technology providers, especially in the area of providing education for the application of the technologies. The value of outreach programs similar to PTTC's regional resource centers (combining private sector, state and federal government, and university efforts) is clearly demonstrated.

These findings make it clear that investments must continue to be made in public, private and collaborative R&D for the technologies of tomorrow. Perhaps even more strongly, these findings demand that the industry, public and private funders of research, and commercial providers of technology need to invest in a more targeted and aggressive course of technology transfer. The mission of technology transfer efforts must be to accelerate and expand producers' awareness, understanding, access to, and acceptance of current and emerging technologies that are cost-effective. With technology transfer, industry can apply technologies to improve exploration successes, detect bypassed and unswept resources, replace and add new reserves, extend the economic life of marginal wells, defer abandonments, and enable the maximum economic production of America's oil and natural gas resources while protecting the environment. Without effective technology transfer, the full value of our public and private sector investments in R&D may never be realized.

In this report, the results of the PTTC workshops have been categorized and presented according to major areas of industry oil and gas E&P operations. These include exploration, reservoir management, drilling and completion, production, and environmental protection and compliance. The results also address specific producers' needs for cost-effective environmental regulation and improved technology transfer functions.

In summary, the findings of the PTTC workshops identify several broad problems and needs, including:

Inadequate well and reservoir level geologic and production data, case studies, and analogs to enable effective analysis and implementation of existing and emerging technologies. (Example: Significant lack of production histories, completion data and well records in Appalachian Basin.)

Insufficient producer access to or awareness of regulations and requirements for environmental compliance and associated financial liabilities. (Example: Operators in Pennsylvania were not provided adequate information and training in preparing operating permits for the new air quality compliance regulations. In addition, the EPA bonding requirements for underground injection permits are onerous and inflexible.)

Insufficient availability of or awareness of tools, technologies, and approaches for cost effective environmental protection and regulatory compliance. (Example: Although no specific example exists, the proliferation of various government rules and regulations from a multitude of agencies makes compliance a difficult task regardless of locale.)

Inadequate producer awareness, and understanding of and access to advanced seismic and remote sensing technologies for exploration and reservoir development. (Example: Operators in the Midcontinent and Rockies have not been well-informed about applications of advanced seismic techniques. It is likely that these technologies may be more useful and cost-effective than is currently perceived by smaller regional producers.)

Insufficient awareness of availability, performance, and economics of improved drilling and completion technologies such as horizontal drilling, coiled tubing, slimhole, air drilling and extended reach drilling. (Example: Operators in the Rockies have expressed a desire to know how to determine if their fields might be candidates for horizontal drilling and if so, what are the most cost-effective methods.)

Need for cost-effective, environmentally safe technologies to manage water channeling, reduce water cut, increase recovery, and address related corrosion, scale, and other problems. (Example: Operators in the LA Basin are not aware of recent advances in gel technologies that may help reduce the producing water cut from older, mature waterfloods and water-drive reservoirs.)

Inadequate education in and understanding of applications of reservoir management, logging, simulation, and characterization tools. (Example: A number of producers in the Midcontinent and other regions have expressed a desire to learn more about how to make effective use of simulation software published by the Department of Energy. The documentation that exists is not easy to understand and can lead to misapplication of the software.)

Inadequate awareness, applications, performance, and economics of currently available technologies and operating approaches to remediate well, reduce operating costs, and improve or sustain economic production, including primary, secondary, and improved oil and natural gas recovery technologies. (Example: Producers in Wyoming, Kansas, Louisiana and other states where large numbers of wells are electrified would benefit greatly from improvements in artificial lift mechanisms that would decrease electricity usage. Operators in Texas could benefit from additional knowledge in cost-effective fracture-treatment design.)

A need for improved technology transfer mechanisms to inform producers objectively about the availability, application, history, potential costs and benefits, and potential performance of technologies that address their priority problems and needs. (Example: This problem is so widespread that a specific example is not too useful. In general, the initial willingness to accept and utilize a technology is determined by the number of case studies presented that clearly demonstrate its usefulness.)

These results, defining needs and regional priorities of producers, have been compared and correlated with two other recent studies on R&D Needs by the NPC and the Research Committee of IOGCC. Where these studies overlap, the findings are mutually supportive. The NPC and IOGCC studies independently validate the findings of PTTC. The PTTC workshops, however, identified many specific technology needs and regulatory concerns that were not identified by either of the other two reports.

The PTTC problem identification process built on regional technology forums conducted earlier by TIPRO and KUERC, before the PTTC's formation. The analysis of the PTTC problem identification workshops presents the needs of producers not only by category, but also by region and regional priorities. This report provides a highly valuable tool to be used by America's research institutions and technology providers to target focused technology transfer efforts to the specific topics and regions where they are needed the most. PTTC urges them to respond through the PTTC network to meet the urgent needs of the industry and the nation.

Table 1

Locations and Dates of PTTC Regional
Problem Identification Workshops

PTTC Region	Workshop Location	Workshop Date
Appalachia	Morgantown, WV	May 16, 1995
	North Canton, OH	September 6, 1995
	Ashland, KY	September 21, 1995
Central Gulf	Lafayette, LA	November 1, 1994
	Shreveport, LA	November 29, 1994
Eastern Gulf	Jackson, MS	August 22, 1995
Midwest	Mount Vernon, Il	October 14, 1994
	Grand Rapids, MI	September 21, 1995
North Midcontinent *	Wichita, KS	1992-93
	Chanute, KS	1992-93
	Liberal, KS	1992-93
	Hays, KS	1992-93
	Great Bend, KS	1992-93
Rocky Mountains	Denver, CO	June 21, 1995
	Casper, WY	August 17, 1995
	Billings, MT	October 3, 1995

Table 1 Continued

South Midcontinent	**Norman, OK**	**January 28, 1995**
	Okmulgee, OK	**March 21, 1995**
Southwest	**Farmington, NM**	**August 24, 1994**
	Roswell, NM	**August 30, 1994**
	Hobbs, NM	**August 31, 1994**
Texas **	**Wichita Falls, TX**	**1991**
	San Antonio, TX	**1991**
	Midland, TX	**1991**
	Longview, TX	**1991**
	Houston, TX	**1991**
	Dallas, TX	**1991**
	Amarillo, TX	**1991**
	Abilene, TX	**1991**
West Coast	**Long Beach, CA**	**September 12, 1995**
	Bakersfield, CA	**September 13, 1995**

Technical Papers

Case Studies of Successful Horizontal and Multilateral Drilling

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SPE 36660

Integrated Petroleum Engineering Simulation and Decision Making Teaching Program

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Abstract

A course of exercises has been developed that trains the student in the different steps involved in discovering and evaluating the economic worth of an oil field. The objective is for the course to act as a link for several different aspects of petroleum engineering - seismic analysis, drilling and completion, logging, well testing, reservoir evaluation and economic analysis - that the student has been taught in detail in the specialist courses that he/she has attended during the course of his/her petroleum engineering education.

To do this, a fictitious oil field has been invented, and its details incorporated into a simulator that allows drilling, logging and other operations to be carried out so that the student gradually learns about the properties of the field during the course of a series of "hands on" exercises. Once the investigation is complete, the student has enough information to make an economic evaluation of the field, and is in a position to determine the necessary economic criteria - investment required, net present value, return on investment etc. - that will allow the "company" owning the lease to decide whether to go ahead with developing the field.

Introduction

Petroleum Industry Technical Managers have often expressed the view that although new engineering graduates entering the industry from a university have extensive technical knowledge, it tends to be held in isolated blocks that reflect the disciplines in which it was taught, rather than being available as a means for solving problems that require the combination of information from several different sources. For example, although the graduate may have an extensive knowledge of fluid mechanics, electrical engineering and materials science, he/she has never been exposed to the process whereby elements from each of these disciplines are brought together to make an efficient and effective design for an electric pump.

With this in mind, we have developed a course for petroleum engineering students that guides the student through various steps that are involved in discovering and evaluating a petroleum reservoir. The course consists of a series of eleven exercises, each of which deals with a different engineering topic, and which together lead from the early discovery of the field through to the decision to develop it or not. The exercises make extensive use of a computer-based drilling simulator (1) that allows a "hands on" feel so that, for example, the costs of drilling a well are partially determined by the skill of the student in controlling the drilling process. The simulator also allows wells to be logged so as to get information on the extent and type of hydrocarbons in the well, and the porosity and water saturation of the surrounding formations.

Since each exercise deals with a separate area of knowledge, but only comprises less than ten percent of the course, it is not possible to treat each area with the degree of detail that it might need for the student to understand it fully. Instead, only the material necessary to solve the immediate problem is presented, and it is left to the student to research the necessary background. Indeed, it is hoped that by the time the student is taught this course, he/she will already have taken a range of specialty courses in drilling, logging, reservoir engineering and so on, and the background material should already be entirely familiar. In this way, the course will fulfill its intended function, to act as a "capstone" experience, where knowledge from all the separate specialty courses is brought together in a logical whole.

In order to make the material transportable between different instructors, it has been assembled in the form of an instruction manual with printed versions of the exercises and their solutions, together with the necessary software.

Construction of the oil field

The field to be evaluated is loosely based on the Railroad Gap field in Kern County, California (2, 3). The field geology is in the form of an elongated dome. It contains two reservoirs, one vertically above the other. These are the "Carneros" and the "Phacoides" reservoirs, that are, respectively about 6,400 x 2,000 and 6,400 x 1,800 ft. across at their oil-water contacts. Both have gas caps. The Carneros reservoir top is at approximately 5,858 ft depth, while that of the Phacoides is at 7,754 ft. To simplify the calculations, the strata were made to have the form of an inverted parabola along the narrow axes of the reservoirs, and to be straight in the orthogonal direction. To obtain closure, it was postulated that there is a "fault" that allows one half of each reservoir to dip down at seven degrees from the fault in a north westerly direction, and at ten degrees down from the fault in the south easterly direction. **Fig. 1** shows a representation of the sealing layer on one half of the Carneros reservoir.

The device of choosing a field with two reservoirs that are broadly similar but not identical helps the teaching process, as in many of the exercises, the student can be shown a worked example for one reservoir, and then be assigned a parallel exercise on the second reservoir as homework.

In order to make a meaningful project, all the physical properties of the field had to be made self-consistent as far as possible. This means that, for example, the depths of various features seen on the seismic sections have to correspond in depth with those that are encountered while drilling. This includes the intervals between hard and soft drilling strata, that can also be "seen" in the seismic sections, the position of an oil-gas contact that appears both in the logging data and the seismic sections and so on. It was also essential that the depths of the various reservoir cap rock strata, and the depths of the oil-gas and oil-water contacts have to correspond in each of the wells that the student drills so as to allow the determination of the extent of each reservoir and its geometry. More subtle effects had to be included. For example, the physical chemistry of the oil and gas in each reservoir had to be consistent with the density, phase behavior and flow characteristics of the fluids as "reported" in the well tests, and as needed for calculating reservoir engineering data such as the oil-gas ratio, the oil formation factor and the likely recovery.

This need for self-consistency frequently required the exercises to be constructed in a "first backwards, then forwards" manner, i.e. to get a self-consistent answer, it was necessary to start from a desired, physically reasonable answer, to work back to the geological or other conditions that would produce that answer, and then develop the teaching exercise in the "forward" direction, knowing that the answer to be obtained would be of the correct magnitude. This applied not only to issues of the physical chemistry of the reservoir fluids mentioned above, but also, for example, to the assignment of values for the rock strength and abrasivity, the properties of drill bits and the drilling rig rental rates that would allow the finding of "reasonable" lives for drill bits, and reasonable costs for drilling and logging each well.

Finally, efforts were made to bring an element of challenge into the exercises. This was done by introducing a degree of choice on the part of the student. This could easily be done, for example, in some of the drilling exercises where the students are free to choose the drilling parameters, casing depths and so on in an attempt to minimize the cost of each well. Unfortunately, there are limits to this process if the set of possible "solutions to exercises" is not to expand without limit.

The Exercises

We now briefly describe each of the exercises in order to indicate the range of activities that are covered and the sequence of operations that lead to the economic evaluation of the field.

Introduction. The first exercise serves as a frame and introduction to the course. The lease boundaries are set as a rectangle of sides 12,000 ft in an east-west direction by 8,000 ft north-south. This defines a local coordinate system to which all field operations subsequently refer. There is a description of the regional geology that mentions a series of folds whose dips run approximately NE-SW, and "reports of oil strikes" in adjacent leases.

Seismic exercise. Based on the existence of the folding, a seismic section running approximately NE-SW (i.e. along the direction of folding) is authorized and obtained (**Fig 2**). This shows a clearly defined anticline, and in the center, the horizontal trace of an oil-gas contact. The students are expected to recognize this, and then, using some information on the average speed of sound as a function of depth, to find its approximate depth. They must also estimate the lateral extent of the contact, infer which reflector is the sealing layer, and then estimate the depth to the top of the reservoir.

Having found strong evidence for the presence of hydrocarbons by virtue of the gas-oil contact, "authorization is obtained" to make another seismic section, orthogonal to the first, running through the highest point of the anticline. This reveals that the strata in this direction are unfolded, but that closure is obtained by a fault that causes the strata to dip down at seven degrees to the north west of the fault, and at ten degrees toward the south east of the fault. Again, evidence for the gas-oil contact is found, consistent with the data from the first section.

This allows an approximate mapping of the extent of the gas cap on the Carneros reservoir, and a request for authorization to drill a wildcat well.

Planning the Wildcat. Exercise three requires the student to estimate the cost of drilling the wildcat well. Compiling an AFE is a difficult exercise to make interesting, as the student has to be told how much each operation or type of goods costs, and it is not easy to make the exercise more challenging than the task of entering data into a spreadsheet. Nonetheless, there is scope for the instructor to discuss how rig rates, for example, might vary between different locations, how many drill bits of each size might be needed, and how severe the environmental constraints might be. Alternatively, students may be asked to estimate all values for themselves by calling local oil companies, although the scope for variability is very large. These data may be used to start a useful discussion on the relative costs of operations in different parts of the world.

Drilling the Wildcat. This exercise uses the drilling simulator to drill a wildcat at the intersection of the two seismic lines. A typical depth-time plot generated by the simulator is shown in **Fig. 3**. The lithology corresponds to that "seen" in the seismic sections, and allows a correction to the speed of sound in the strata as a function of depth. It also allows an accurate identification of the depth of the Cameros reservoir. Logging the well allows the discovery of the Phacoides reservoir, whose existence until now was only hypothetical.

The exercise also serves to instruct the students in the choice of casing depths. Initially, the only objective is to drill the well to as great a depth as possible. To this end, each casing is set as deep as it can be. However, once the depth of the Phacoides reservoir is known, and it is decided to drill no deeper than that, an improved casing design can be developed, based on a "bottom up" design that sets each casing only as deep as it needs to be to reach TD. This results in the casing costs dropping from $648,000 to $516,000.

Once the casing plan is fixed, each section of the well can be drilled repeatedly while experimenting with different choices of drill bit, mud and hydraulics parameters, and operating parameters. With a little perseverance, the student will see the cost of the well drop from about $ 1.2 million to $ 836,000.

Casing and Drill String Design. This exercise concentrates on the design of the drill pipe and the casings required in a typical well in this field. The design could be carried out for the wildcat well, but by now the project team will have decided that they must drill some evaluation wells to check the extent of the reservoir. The simulator is therefore used to drill and log another well, and this is used for the casing and drill pipe design exercises.

The casing designs follow a simple methodology based on resistance to collapse, burst and tension. **Fig. 4** shows the design diagram for the 13 3/8" casing. The required design parameters are derived from the well data as it is drilled. In a similar manner, the strength necessary for the drill pipe is calculated for each section, based on depth and hole diameter. The latter, of course, determines bit size and thence the number and weight of collars required.

In each of these operations, the student is given the design method and a worked example for one section of the well, and is then asked to make a design for another section. There is thus always an example to follow.

Cementing. In a similar manner, the next exercise concerns the design of a cementing operation. Another well is chosen for this purpose, with the objective of accumulating additional information concerning the reservoir on the way. As in the case of the previous exercise, the cementing exercise proceeds by giving an example of the calculation for the 20" casing, and the student is asked to follow that example to design the 13 3/8" casing cement job (**Fig.5**). Again, the student is required to log the well and thereby gather important information on the reservoir properties.

Logging. The course now turns away from drilling engineering towards logging and reservoir engineering. The next exercise requires the student to evaluate the log data from a new well and combine it with information obtained during the drilling of the wildcat and other wells. The student must first examine the logs of the four wells that were drilled so far to determine the heights of the reservoir tops and the oil-gas and oil-water contacts. Next he/she must interpret the wireline data to determine porosity (obtained directly from the logs) and hydrocarbon saturation. In the latter case, a simple method is used employing Archie's law (4), and assuming that the lower part of each reservoir (the water zone) has no oil saturation so as to be able to determine the water salinity. No corrections are applied for changes in temperature, "shaliness" or other effects that are required in more sophisticated evaluations. The porosity and hydrocarbon saturation information gathered from this exercise will later be used to estimate the gas and oil initially in place.

The Well Test. The well test is an essential part of the reservoir evaluation process. The student is told that a well test has been carried out on the wildcat well, and is given the pressure-time data (**Fig 6**). A brief summary of the theory of the drawdown test is given, although it is assumed that the student is already familiar with one or more of the classic texts on this subject.

The student is expected to analyze the test results, and to derive values for the skin and permeabilities from the early-time (transient) data, and the drainage area and the Dietz shape factor (5), from the semi-steady state results. As usual, the exercise takes the form of a worked example, in this case, using the data from the Carneros reservoir, while the student is expected to solve the equivalent problem for the Phacoides reservoir. The method employed is very similar to that given by Dake (6).

Solution of this exercise gives the important results that for the Carneros reservoir, the permeability, at 25 mD, is sufficient to produce an adequate flow if we install production wells, and the drawdown area is about 30 acres, thus indicating that the wells can be spaced a reasonable distance apart. The corresponding data for the Phacoides reservoir are 0.25 mD and 9.3 acres, which make a less attractive prospect.

Oil and Gas in Place. The next essential step is to determine the overall dimensions of the Carneros and Phacoides reservoirs, and to calculate the oil and gas in place. To do this, the student must drill and log a number of delineation wells, making a total of thirteen in all, that will give an adequate view of the geometry of the reservoir. It would of course be possible to have the student drill each of the wells using the simulator, but by now it is assumed that he/she has had enough exercise in drilling, so the positions of the reservoir tops and gas-oil and oil-water contacts are simply tabulated. From this information, and the known positions of the delineation wells on the lease map, the student must determine the shape of the reservoir and the volume of hydrocarbons. It would be possible to do this by drawing a series of contour maps, but since our reservoirs have a very straightforward geometry, we can make the simplifying assumption that they can be approximated to parts of cones on an elliptical base (**Fig 1**). This allows the student to carry out an exercise in solid geometry, and to determine the reservoir volumes analytically.

Having found the volume of the gas and oil parts of each of the reservoirs, and knowing the porosity of each reservoir, the student must determine the volume of gas under standard conditions, and the stock tank oil initially in place (STOIIP).

These calculations use data concerning the known pressure, temperature and molecular composition of the gas and oil phases in the reservoir, all of which are given to the student as "data obtained from lab tests". However, the lab test data are not fully reduced, so the student must actually calculate pseudo critical temperatures and pressures, the solution gas-oil ratio, the oil formation factor and other values from the lab data.

Economic Analysis. At this point, the student has sufficient information to make an assessment of the economic worth of the two reservoirs. This is simply carried out by making a spreadsheet analysis. Input information includes the number of wells that will be needed to drain the reservoir, and the cost of each well. The total number of wells (13) is based on the calculated drainage area of each well, (derived from the analysis of the drawdown test). However, the student will have to take into account that four of those wells miss the Carneros formation, and 7 miss the Phacoides formation.

Ultimate recovery is estimated from Arps's correlations (7), taking into consideration the physical properties of the oil and reservoir rocks as well as an assumption that the reservoir is pressurized by solution gas, a gas cap and an active water drive from below.

An assumption must be made as to the likely productivity of each well, and this can again be derived from the well test data. It is further assumed that after the go-ahead is given, the necessary production wells can be drilled in two years. Finally, the cost of the wells is obtained from the results of the drilling exercises. These are estimated to cost one million dollars each.

Various economic assumptions must now be made, concerning the rates of interest and inflation, tax rates and so on. From these data, a spreadsheet can be constructed to show any of the common economic yardsticks such as Return On Investment (ROI), Net Present Value (NPV), Discounted Profitability Index (DPI) etc. Graphs can also be constructed to show cash flow as a function of time (**Fig 7**) and other data.

Naturally, however, it is a simple matter to change values in the spreadsheet to investigate the results of changes in the financial parameters such as the rates of inflation and interest. It is also instructive to investigate the merits of making changes to the investments in the field, by, for example, increasing the number of wells to increase the production rate. Each of these proposals can be simulated by making adjustments to the spreadsheet and then discussed by the class.

Conclusions

The above notes give a brief overview of a training course that covers most of the technical elements involved in the discovery and evaluation of a typical oil field. Since the course was designed to fit into the time available in a typical university semester, it has not been possible to enter into as much detail as may be applied in the evaluation of a real reservoir in the industry. However, it was not the purpose to go into exhaustive detail in each technical field. Indeed, it is hoped that students taking this course will already have greater knowledge of the basic petroleum engineering disciplines than are treated here.

Rather, the objective has been to bring together the components in a way that illustrates the influence that each brings to the other, and to illustrate the sequence of operations that is necessary in the rational development of an oil field. In addition, it is hoped that the use of computer simulation, the ability to try different scenarios and to learn by trial and error will prove interesting and challenging to future students.

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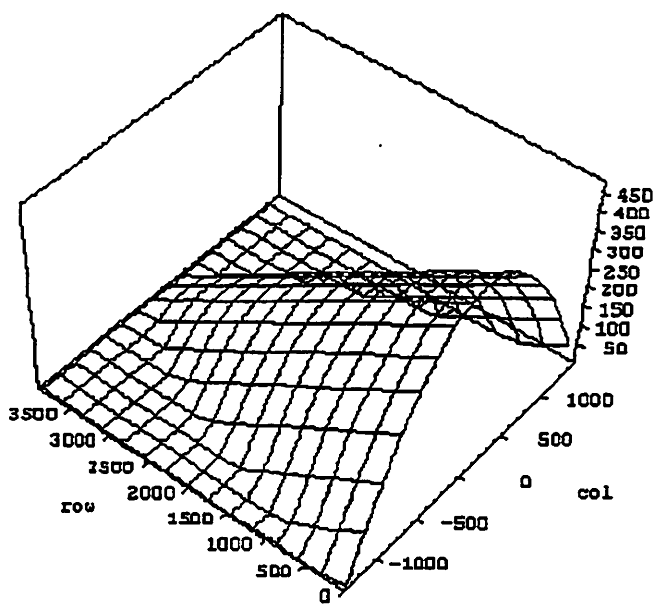

Fig 1. View of the sealing layer above the NW section of the Carneros reservoir.

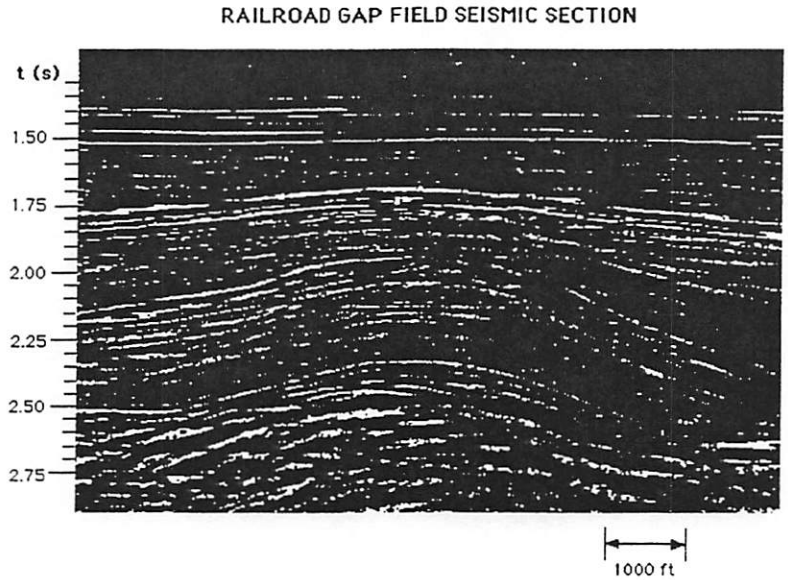

Fig. 2. The first seismic section. Note the horizontal trace at approximately 2.15 seconds that indicates an oil-gas contact.

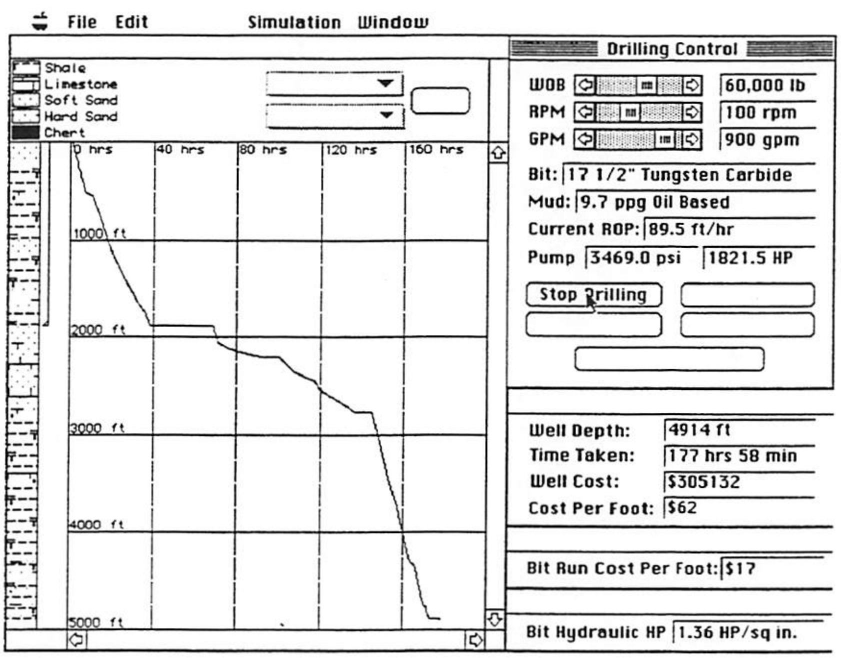

Fig. 3 Typical depth-time simulator screen, showing the drilling control panel and diagnostics windows, the depth-time plot, the "mud log" showing the rocks that have been penetrated, and a casing symbol showing that one casing has been set.

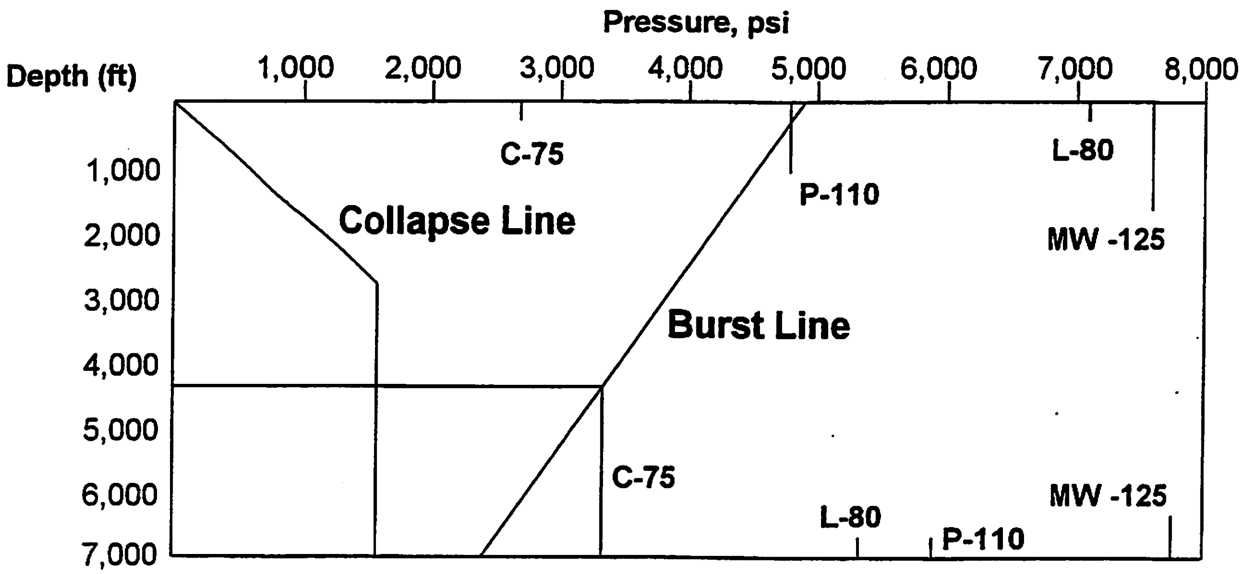

Fig 4. Casing design diagram for a 9 5/8" casing.

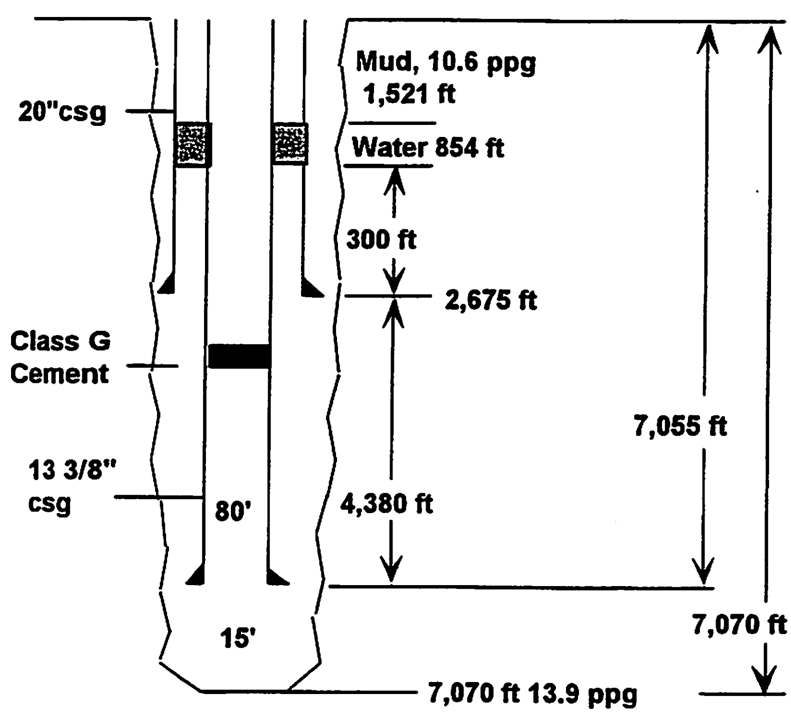

Fig 5. Cementing planning diagram for designing the cementing of a 13 3/8" casing.

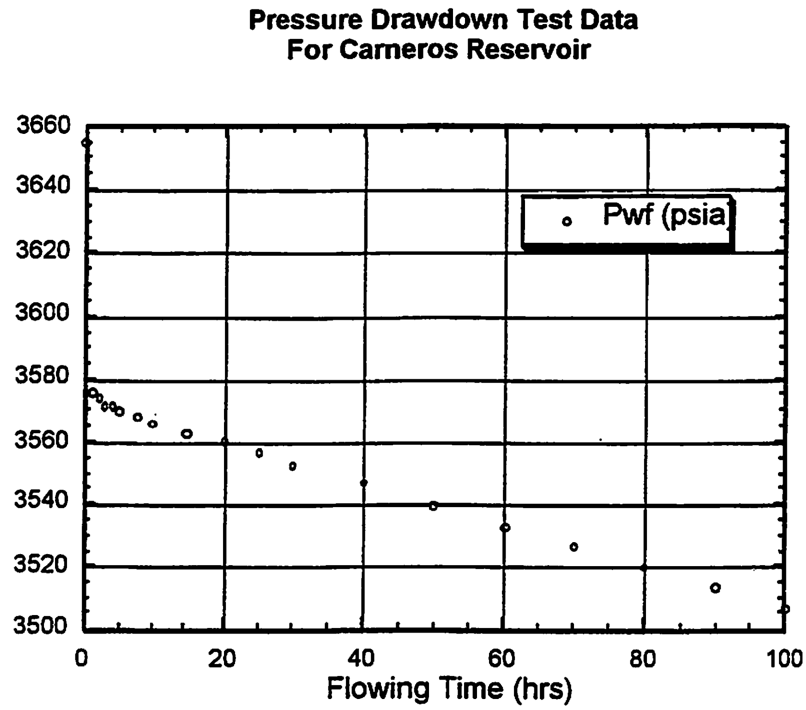

Fig 6. Drawdown test data for the Carneros reservoir performed at the wildcat.

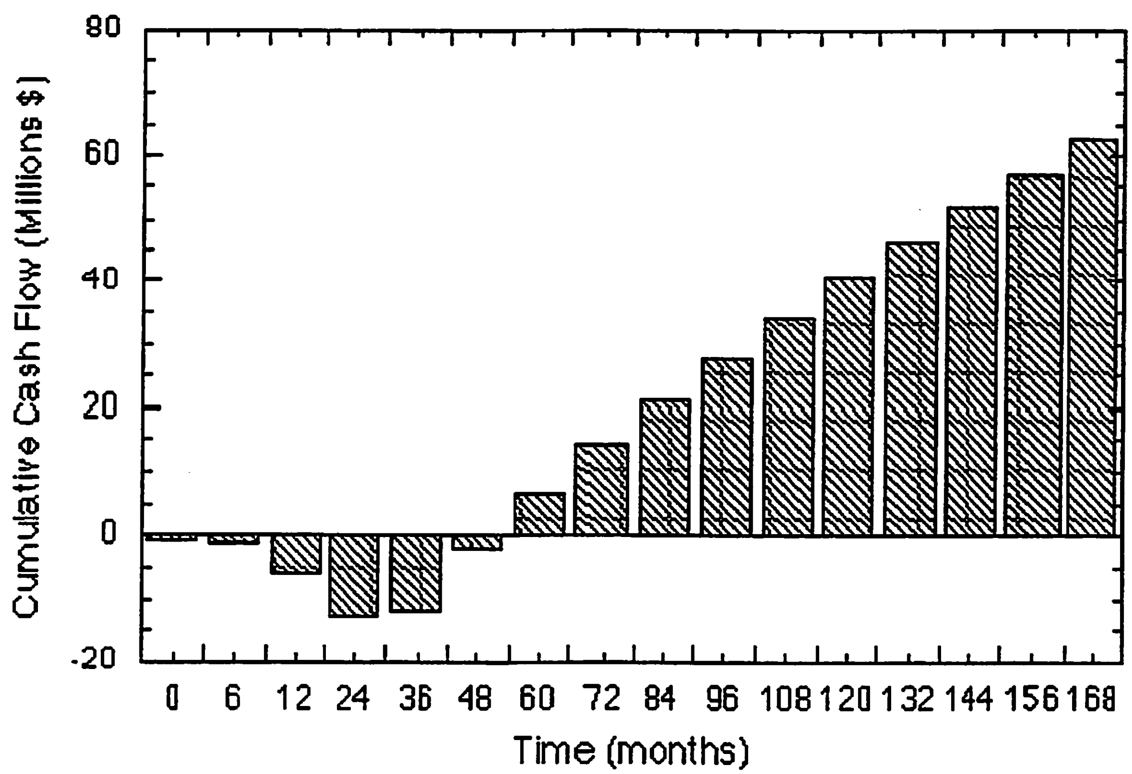

Fig 7. Economic Analysis: Cash flow for the Railroad Gap Field Carneros Sand.

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SPE 30213

An Interactive Drilling Simulator for Teaching and Research

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Abstract

An interactive program has been constructed that allows a student or engineer to simulate the drilling of an oil well, and to optimize the drilling process by comparing different drilling plans.

The program operates in a very user-friendly way, with emphasis on menu and button-driven commands. The simulator may be run either as a training program, with exercises that illustrate various features of the drilling process, as a game, in which a student is set a challenge to drill a well with minimum cost or time under constraints set by an instructor, or as a simulator of a real situation to investigate the merit of different drilling strategies.

It has three main parts, a Lithology Editor, a Settings Editor and the simulation program itself. The Lithology Editor allows the student, instructor or engineer to build a real or imaginary sequence of rock layers, each characterized by its mineralogy, drilling and log responses. The Settings Editor allows the definition of all the operational parameters, ranging from the drilling and wear rates of particular bits in specified rocks to the costs of different procedures. The simulator itself contains an algorithm that determines rate of penetration and rate of wear of the bit as drilling continues. It also determines whether the well kicks or fractures, and assigns various other "accident" conditions. During operation, a depth vs. time curve is displayed, together with a "mud log" showing the rock layers penetrated. If desired, the well may be "logged", casings may be set and pore and fracture pressure gradients may be displayed. During drilling, the total time and cost are shown, together with cost per foot in total and for the current bit run.

A demonstration version of the program is available on the World Wide Web at the Berkeley Petroleum Engineering Page. Its current address is: mse16.mse.berkeley.edu

Figures and References at end of paper.

Introduction

Various types of equipment have been developed in recent years to simulate the drilling of hydrocarbon wells for training, operational or research purposes. Some simulators include elements of "real" drilling hardware, in which the operator controls the simulator via a realistic brake, throttle and other controls, and sees the output of the simulator displayed on gauges and meters that are typical of real drilling equipment (1, 2). This type of simulator is mainly intended for the use of rig personnel, often to train drillers in the techniques of dealing with kicks or blow-outs. Its principal intention is to give as real an impression as possible of the situation on the rig floor.

Other types of simulator have been more directed towards simulating the drilling of a particular well, in order to optimize the drilling process or to predict the effects of changing the operating parameters (3, 4). In these simulators, the objective is more to make an accurate simulation of the drilling process within the computer, and to examine the results in terms of numerical output, than to generate a realistic "real time" response for the driller. It should, however, be noted that such simulators have been used to model and optimize the drilling of specific wells as they are being drilled, and also in the design of rigs (5) and rig equipment (6). Probably the greatest use of drilling-related simulators has been to model well kicks (7 - 10).

A disadvantage of the first type of simulator is that, since the intention is to make an accurate material simulation of the real life situation, the equipment is necessarily bulky and expensive, and although portable versions of such equipment are available, the more portable they are made, the less "realistic" they become. Simulators of the second type, that are intended to make simulations of specific real wells, are inevitably very complex in the way that the simulation program is constructed, since the main objective in using them is to make an accurate model of the entire drilling process. This requires the specification of a large number of input parameters, from the properties of the rocks being drilled to the mechanics of the drilling process, the properties of the drilling fluid and many other factors. This complexity has meant that such simulators are only used when substantial resources are available to determine the set of input parameters that are required, and skilled personnel are available as operators.

We have taken a third approach, in which the objective has been to make a simple simulator that is above all easy to use, and that conveys a realistic "feel" to the operator while being entirely within the computer. This has meant constructing a drilling model that, while being adjustable so that many different drilling situations can be reproduced, gives a physically reasonable and easily understood response under almost any conditions that are applied. It has also required the construction of a simple, intuitive and largely visual user interface, with the objective of making the simulator attractive to the operator.

Overall layout of the simulator

When the simulator is used as a teaching tool, it reproduces the behavior of a drilling rig under sets of conditions that allow the trainee to observe and react to the response as he or she changes the operating parameters. In this mode, the simulator calculations start from a defined compilation of the properties of the rocks to be drilled (the Lithology), and the output is their drilling and log responses. It is therefore different from some field simulators that work in the opposite sense, whose purpose is to infer the formation properties from the measured drilling and log data. Further, the simulator usually does not calculate or suggest what should be done to optimize the drilling operation, since a major teaching objective is to make a trainee engineer learn how to carry out such optimizations by him- or herself. The simulator thus differs from some other simulators that have been developed to help field engineers calculate answers to particular engineering problems. Such simulators tend to be of the type in which once all the necessary parameters are input, the simulator outputs a "recommended course of action" or value without necessarily explaining why. The instructional value of such simulators is therefore much more limited.

If the simulator is to be used to optimize a real field operation, it must first be used to deduce the properties of the rocks that are being drilled. This is done essentially by running it "in reverse" i.e. setting the simulator operating conditions to match field conditions, and then "tuning" the rock and other properties so that the simulator response corresponds to the field results for the known field conditions. Once the simulator is tuned to reproduce this response, the operating conditions may be changed to investigate a range of "what if" scenarios in order to optimize the field operation.

User interface

In designing the user interface, we have aimed for simplicity. We have also tried to prevent the operator entering unrealistic values of the operating parameters, and generating "impossible" results. The operator choice is therefore limited by various means, for example, when selecting weight on bit, rotary speed or mud flow rate, the value is input via a slide bar whose upper and lower limits cannot be exceeded. When the operator has to choose the bit type and diameter, the nozzle sizes and similar parameters, the choice is frequently made via "radio buttons" that allow a defined choice of options - for example, the nozzle sizes have to be in integral 1/32" increments (see Fig 6, for example). Other parameters can only be input in selected ranges. Alternatively, the operator is warned that values exceeding certain limits are unacceptable. In this way, even a novice operator is more or less guaranteed of obtaining a physically reasonable response.

Output is largely graphical, with the main result being a depth-time curve that plots the progress of the operation. In addition, a "mud log" is presented, showing the rocks encountered as a function of depth as they are penetrated, together with symbols showing casings that have been set. Further graphs may be displayed that show pore fluid pressure gradient and fracture pressure gradient, and wireline logs may also be shown. Some data, however, must be numerical. Thus overall costs, cost per foot, current depth, pump pressure and horsepower and other data are presented numerically. Such figures are essential for the operator to be able to make engineering and economic calculations.

The entire operation of the simulator is accompanied by a simple accounting procedure that calculates total cost and time, cost per foot for the current bit run, and cost per foot for the entire well.

Construction of the simulator

The simulator is programmed in "C", and runs on Macintosh computers. It is composed of five linked modules. These are the Lithology Editor, Settings Editor, Drilling Simulator, Exercise Editor and "Run An Exercise". When the program is launched, a window appears from which each of the above modules can be opened by clicking the appropriate button (Fig 1). "Help" and "Quit" are also available. When any one of the modules is opened, further windows appear, with choices and actions to be taken as appropriate.

Lithology Editor.

This editor allows the construction of the sequence of rocks that are to be drilled. When the editor is activated, a window appears listing each of the rock layers in sequence (Fig. 2). Each layer can have its particular properties changed, or layers can be cut, copied or pasted as required. Parameters to be specified include first the thickness of the layer and its mineralogy (from a choice of five types - shale, hard or soft sandstone, limestone or chert). Two parameters govern the drilling response. These are the "Softness Factor" (S) that determines the initial rate of penetration, and the "Wear Factor" (W) that determines the rate of bit wear. Thus, although the choice of rock types is limited to five "mineralogies" the range of possible rates of penetration and wear is very large. Next, the pore fluid pressure gradient and the fracture gradient at the bottom of the layer can be set; these values are made to change linearly through the layer from the values set at the bottom of the layer above. In this way, any desired profile of pressure with depth can be constructed. The nature of the pore fluid can be set to be gas, oil, water or "nothing" and three "wireline log" parameters can also be set. These are a "Sonic porosity" the "Natural gamma ray emission value" and a "Formation resistivity". The values are plotted against depth when the command "log well" is activated during operation of the simulator, and the log and pressure graphs can be "previewed" while constructing the Lithology Editor (Fig. 3 shows the pressure gradient preview). Once a suitable sequence of layers has been constructed, it can be saved and called up subsequently to be drilled by the simulator.

Settings Editor

The Settings Editor allows all the operating parameters of the rig and drilling system to be set. There are two purposes. The first is to allow the simulator to be tuned to match a particular type of operation, and the second is to govern the complexity of the simulation so that the operator may work selectively with particular aspects of the drilling process. Thus a student may start in a simple way and increase simulation complexity as he or she learns, or an engineer may limit the simulation to a restricted set of parameters to emphasize the effects of a particular set of variables.

The choices are presented in a suite of six windows that cover different aspects of the simulation. One window controls the drilling model that lies at the heart of the simulator (Fig 4). Here one may decide on the complexity of the simulation by selecting or not the different factors in the drilling model itself. Each of these determines the response of the model to a particular input parameter. If all of the factors are deactivated, the model generates a constant rate of penetration for which changing any of the operating parameters has no effect, and for which bits never wear out, and all bits behave identically in all rocks. As each factor is activated, the model becomes more complex, with rate of penetration and wear eventually reacting to the specific bit, the bit size and bit nozzles being used, the rock being drilled, weight on bit, rotary speed, and the mud density and its flow rate.

Another window in the Settings Editor deals with the characteristics of each of the four bit types that is available (PDC, Milled Tooth, Tungsten Carbide Insert and Natural Diamond). This part of the editor allows the setting of typical rates of penetration and rates of wear for each bit in the different rocks, and the number, cost and size of each bit type that is available (the latter for "missions" in which the operator has to do his best under time, money or materials constraints).

Other windows deal with the costs and availability of other services, for example, whether wireline data can be obtained, or whether it is possible to have information on pore and fracture pressures. Other adjustable features concern the introduction or exclusion of certain "accident" phenomena - for

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example, the well may be allowed to fracture or kick, the borehole may collapse a certain time after entering a shale if the correct choice of mud was not made, or cones may be lost from roller cone bits after a certain fraction of the bit life is consumed.

Drilling Simulator

Clicking the Drilling Simulator button launches the simulation program itself. The display is composed of a main window, in which are shown a depth-time plot, the "mud log" and casing data, and some smaller windows that allow controls to be set or output data to be displayed (Fig. 5).

Before commencing drilling, the operator must choose the rock sequence that is to be drilled, and then select a drill bit. Bit selection is made from a control panel that concerns operations that are to be conducted with the bit "Out of Hole" (see Fig. 5). These include selecting or changing the bit (Fig. 6), running and cementing casing, logging the well, carrying out a fracture test, fishing junk and of course "running in hole", Having selected a bit, the operator chooses "run in hole", which closes the "Out of Hole" control panel and presents the "Drilling Control" panel (Fig 7). Here the operator sets the operating parameters and then clicks "Start Drilling". This starts the simulation, which then calculates and displays a graph of depth versus time, displays the "mud log" and calculates and displays depth, time, cost and cost per foot, and the mud hydraulic parameters of standpipe pressure, pump horsepower, and hydraulic horsepower per square inch of bit area.

At any time the display may be scaled or scrolled to allow viewing of specific details of the display, and the simulation speed may be adjusted to allow rapid drilling through straightforward sections or slow drilling when special attention is required.

The Drilling Model

As drilling proceeds, the drilling model is continuously calculating the state of wear of the bit and its rate of penetration. The wear algorithm starts by calculating a "wear factor". The "wear factor" is the result of first combining the two wear parameters mentioned above, set in the Settings Editor and the Lithology Editor respectively, that are specific to the particular combination of bit and rock. This result is then combined with two factors that represent, respectively, the effects of weight on bit and rotary speed on the rate of wear of the bit. Both factors cause the rate of wear to increase more than in proportion to increases in the weight on bit and rotary speed. Finally the combined parameter is scaled to give a value somewhat less than unity.

The state of wear of the bit is associated with a remaining "Life". All bits, when new, are assigned 100% "Life". At each time step the "Life" is multiplied by the "wear factor", (less than unity), that reduces the "Life" by a certain fraction of its current value. This has the effect of reducing the "Life" asymptotically towards zero as time increases.

To obtain the current rate of penetration, the present "Life" is combined with two more factors that represent the interaction of the particular bit with the rock being drilled, and influence the underlying rate of penetration. The factors are set in the Lithology Editor and the Settings Editor respectively. The result is further combined with factors that depend on the weight on bit, the rotary speed and the mud density. These operations result in the calculation of a rate of penetration that would be characteristic of a bit for which the cuttings are removed as soon as they are formed, i.e. perfect cleaning of the workfront. At this point, the effect of the mud flow is introduced, and a final rate of penetration is calculated based on the effectiveness of the mud flow in cleaning the cuttings away from the hole bottom. This procedure is adopted because it is believed that the effectiveness of the mud flow is partially dependent on the quantity of cuttings that need to be removed, i.e. the greater the rate of penetration, the greater the mud flow must be to attain "perfect cleaning". Thus it is necessary to calculate a theoretical rate of penetration based on all the other operating parameters before the effect of the mud flow can be calculated. Once this is done, however, the final rate of penetration for the present timestep is known, and the distance drilled can be calculated and added to the depth-time plot.

If the operating parameters are held constant, the effect of multiplying the present "Life" by the wear factor at each timestep is to produce an exponential decrease in rate of penetration with time. This function appears to be a reasonable approximation to the behavior of real bits operating under field conditions, provided that the wear process is uniform. Failure by "catastrophic" processes is not well modeled in this way, but provision is made in the simulator for at least one such behavior, by allowing sudden failure by "cone loss" in roller cone bits at a fraction of "Life" remaining that can be set in the Settings Editor.

As drilling proceeds, the drilling model checks at each timestep to see if the well has kicked or fractured, or if an uncased shale interval has collapsed. If any of these events occur, an alarm message is sent to the operator. Alarms also occur if the mud flow rate is inadequate to lift the cuttings, or if the mud pump maximum pressure and/or horsepower are exceeded. If an alarm is triggered, drilling is stopped until the appropriate remedial action is taken.

The pore pressure gradient and fracture gradients to the depth drilled may be displayed at any time if these facilities have been allowed in the Settings Editor, and their graph may be matched in scale to the depth-time plot, or printed for later reference.

The drilling assembly may be pulled out of hole at any time, and various "Out of Hole" activities carried out. These include setting casing and logging the well. Log data is graphed in a similar manner to that used to present the pressure information, and the graphs may be matched to the depth-time plot, and scaled, scrolled or printed as desired. It should be noted that if the well is "logged" after a casing has been set, the porosity and resistivity values will not be displayed over the cased interval, although the natural gamma ray data is always available This behavior is shown in Fig 8.

At any time during operation of the simulator, a "Note" may be added to the depth-time plot (three examples are shown on Fig 8), and the current status of the well may be saved for future reference or re-drilling.

<u>Exercise Editor</u>

This editor allows an instructor to build specific exercises for the students or trainees. Access to the editor is limited by the use of a password that prevents the students from obtaining restricted information, or from changing the exercise parameters. To create an exercise, the instructor follows a sequence of operations. These are: 1) Select or create a lithology in the Lithology Editor, 2) Set the desired settings in the Settings Editor, 3) Set the starting conditions for the well (the exercise may begin in a part-drilled well, for example), 4) Set module availabilities (e.g. is the student allowed to examine the Lithology or change the Settings ?) 5) Set various exercise options (for example, printing a "summary sheet" at the end of the exercise), 6) Write a set of instructions, and finally 7) Save the exercise.

"Saving" the exercise has the effect of packaging the entire set of instructions listed above into a single file that the student can run by clicking "Run an Exercise" in the Module Chooser window (Fig 1). (see below).

Run an Exercise

When "Run an Exercise" is selected in the Module Chooser window, the operator is given a choice of all available exercise titles. By selecting a particular exercise, the complete set of instructions, lithology and operating parameters that were set in the Exercise Editor are loaded into the simulator, allowing the student to commence the exercise without having to "set up" the simulator beyond choosing the exercise that is to be run. In particular, when the exercise is launched, a window appears that displays the set of instructions for the exercise. This may be printed to form a reference text. In many cases, we have made this text form a self-contained chapter that not only explains the requirements of the exercise but includes a quantity of background information that will help the student to understand the larger context of the exercise.

Other features

The program contains various supporting features, such as the ability to append notes to the drilling plot, mentioned above, printing text and graphs, a "Help" section etc. Overall, the objective has been to make the simulator easy to use and to understand.

Conclusions

In this paper, we have reviewed some of the main features of our drilling simulator program. The main philosophy underlying the construction of the simulator has been to make a program that is simple to understand and use, and in which the effects of changing particular operating parameters are obvious.

We believe that these features will make the simulator not only a useful teaching tool, but also a vehicle through which drilling engineers concerned with field operations can experiment with the effects of changing the operating parameters in order to optimize drilling operations.

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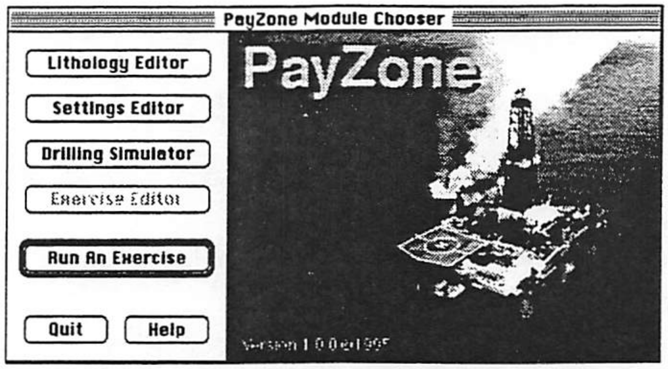

Figure 1: Module Chooser window.

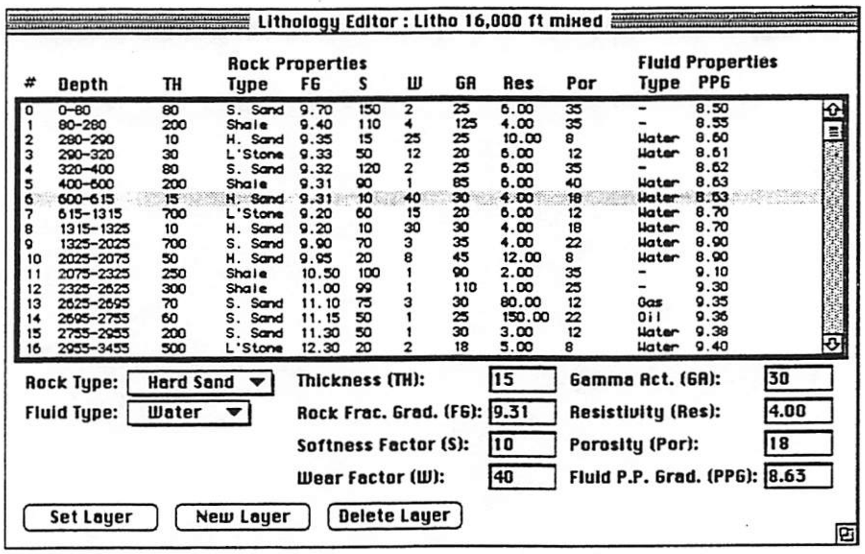

Figure 2: The Lithology Editor, with layer number 6 being edited.

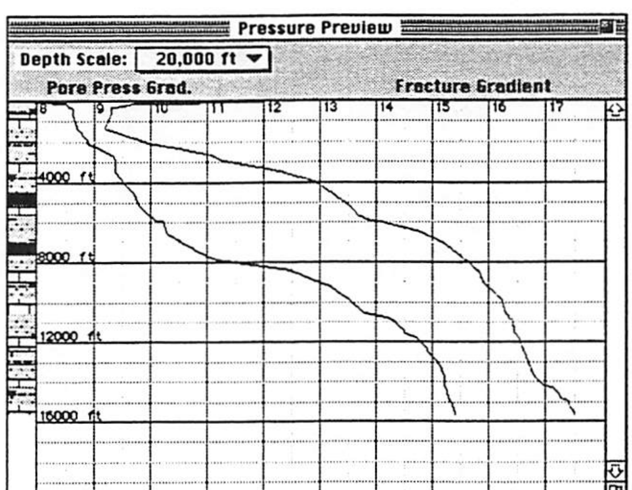

Figure 3: Preview of the Lithology and Pressure Gradients.

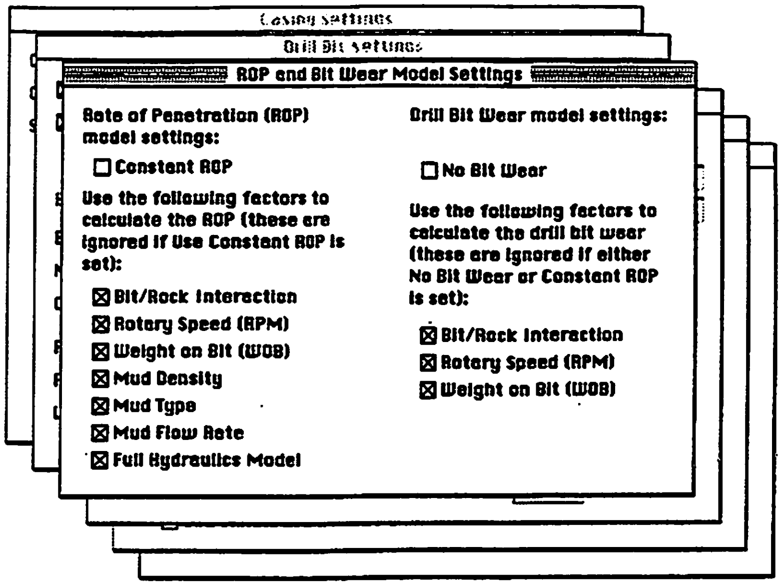

Figure 4: The Settings Editor, with the ROP and Bit Wear Model window active.

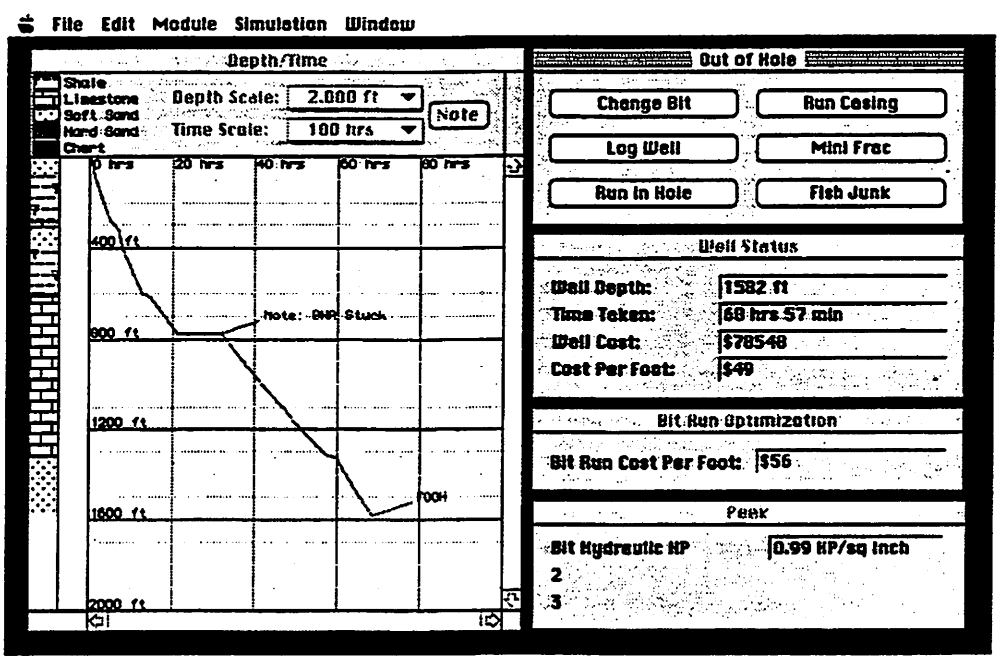

Figure 5: Overall view of the simulator layout, showing the depth vs time window and some of the control and diagnostic windows.

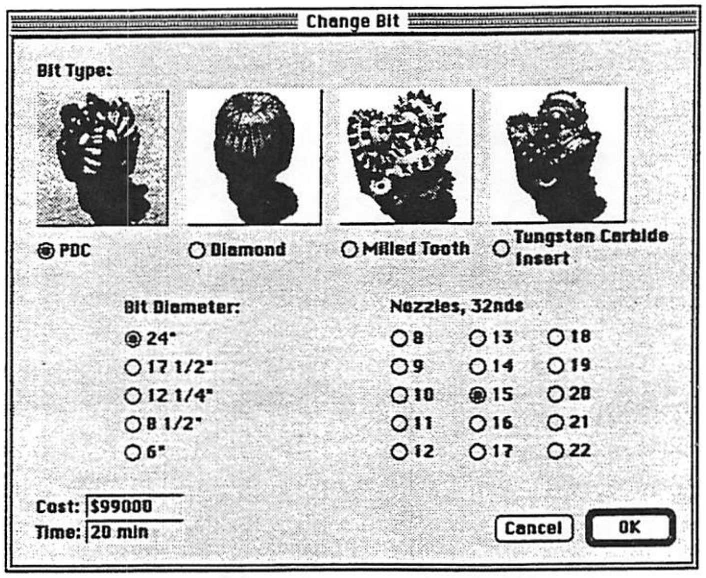

Figure 6: Drill bit selection window.

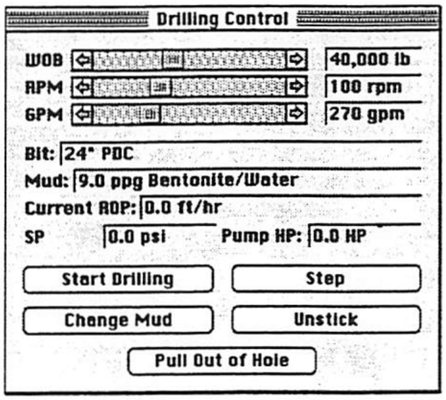

Figure 7: The Drilling Control Panel.

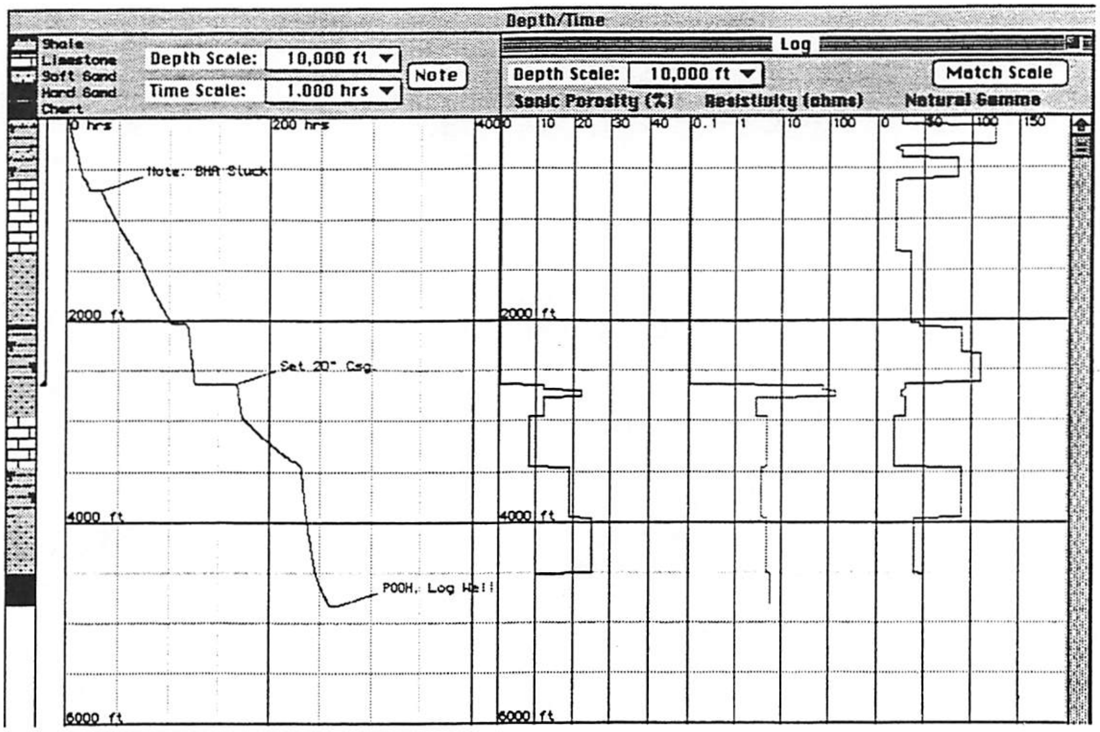

Figure 8: The Depth-Time window with the Well Log window superposed.

Recent Advances in Estimation of Porosity and Detection of Hydrocarbons in Cased Holes

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Recent Advances in Estimation of Porosity and Detection of Hydrocarbons in Cased Holes†

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PTTC, November 1996

Outline

- Hydrocarbon Detection
- Porosity Determination
- Acoustic Logging
- Field Results
- Future Trends

Hydrocarbon Detection

- Resistivity
  - » Standard open-hole technique
  - » Uses Archie's Law
- NMR
- Carbon / Oxygen
  - » Pulsed Neutron (Inelastic) Log
  - » Direct chemical detection
- Capture Cross Section
  - » Neutron (capture) Log
  - » Measures Σ
- Acoustic Detection
  - » Vp and Vs (dtP and dtS)

Seismic Detection of Pore Fluid Properties

Theory (Gassman; low frequency):

Moduli: K is a f^n of K_{frame}, K_{rock}, K_{fluid}, Ø

μ independent of fluid properties

Density: ρ is a f^n of ρ_{fluid}, ρ_{rock}, Ø

Example: replacing water with hydrocarbons

since:

$K_{H\text{-}C} < K_w$

$\rho_{H\text{-}C} < \rho_w$

$V = (\text{Modulus/Density})^{1/2}$

therefore:

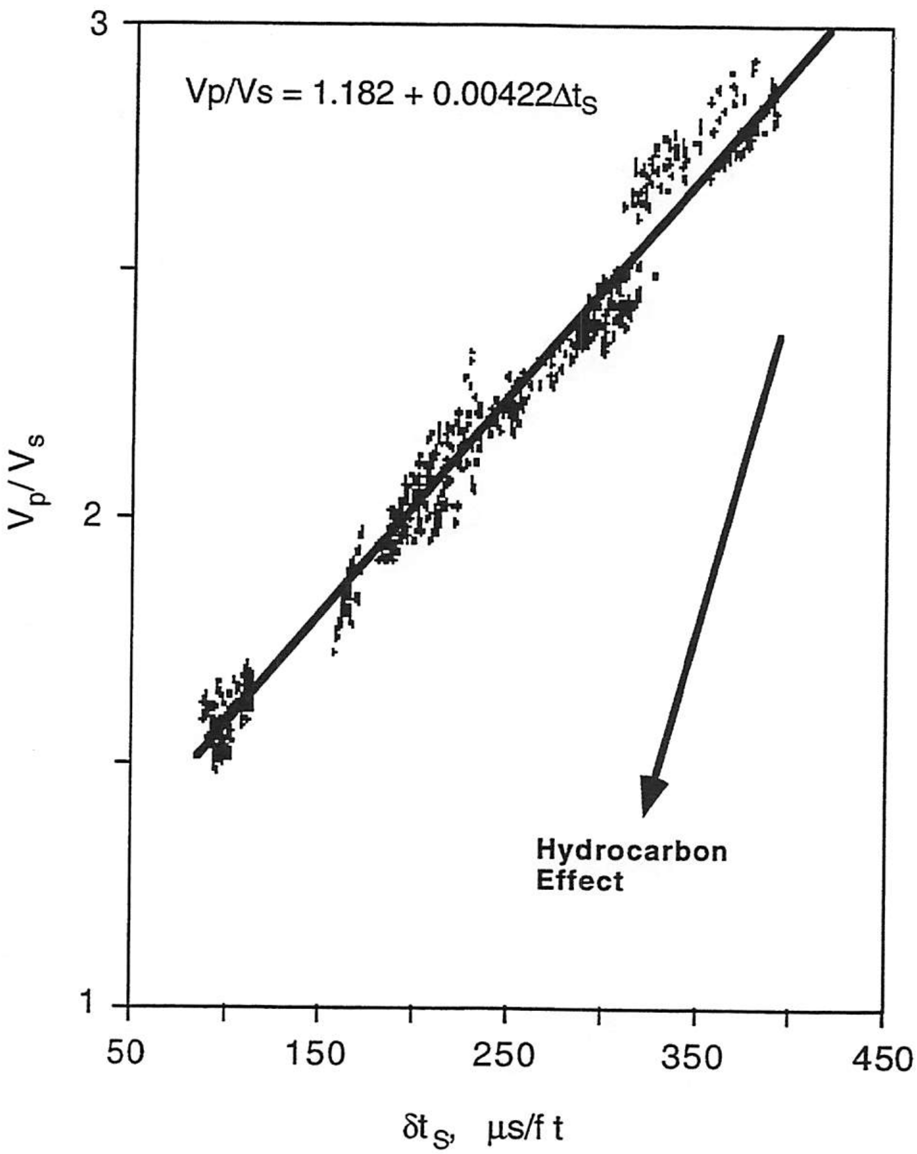
Vp lower

Vs higher

Vp/Vs lower for the same Vs

This allows the development of an Acoustic Log Hydrocarbon Indicator (ALHI) - Williams, 1990

ALHI - Williams, 1990



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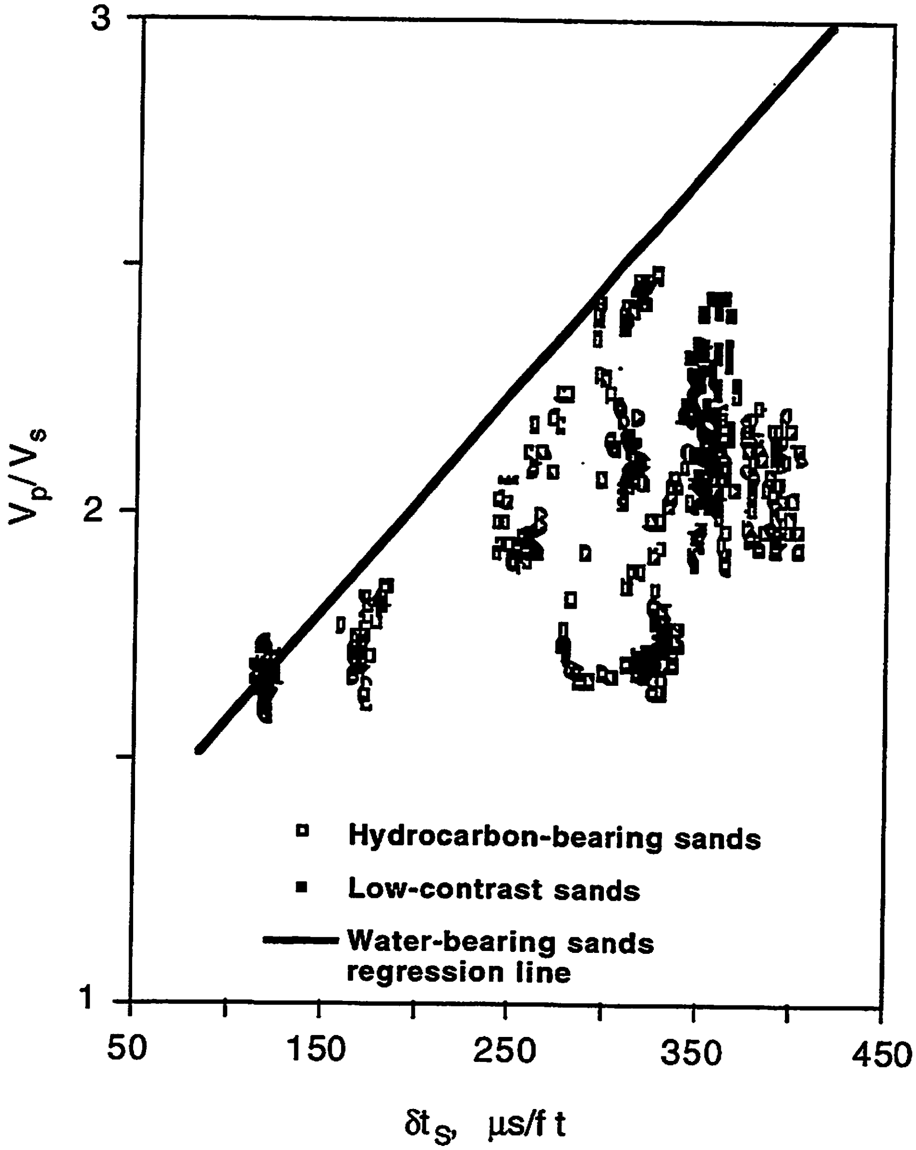
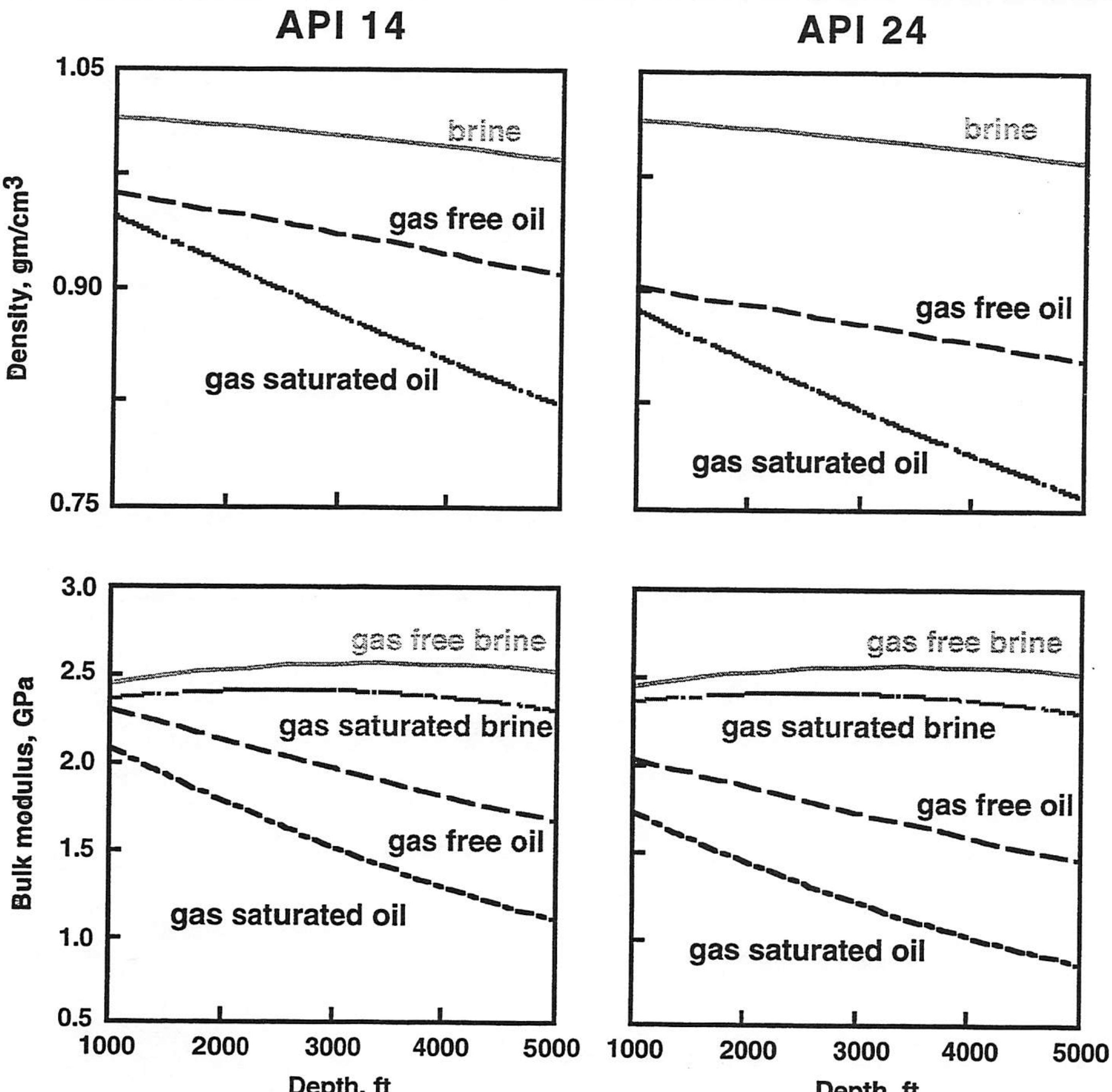
ALHI - Williams, 1990



Pore Fluid Properties



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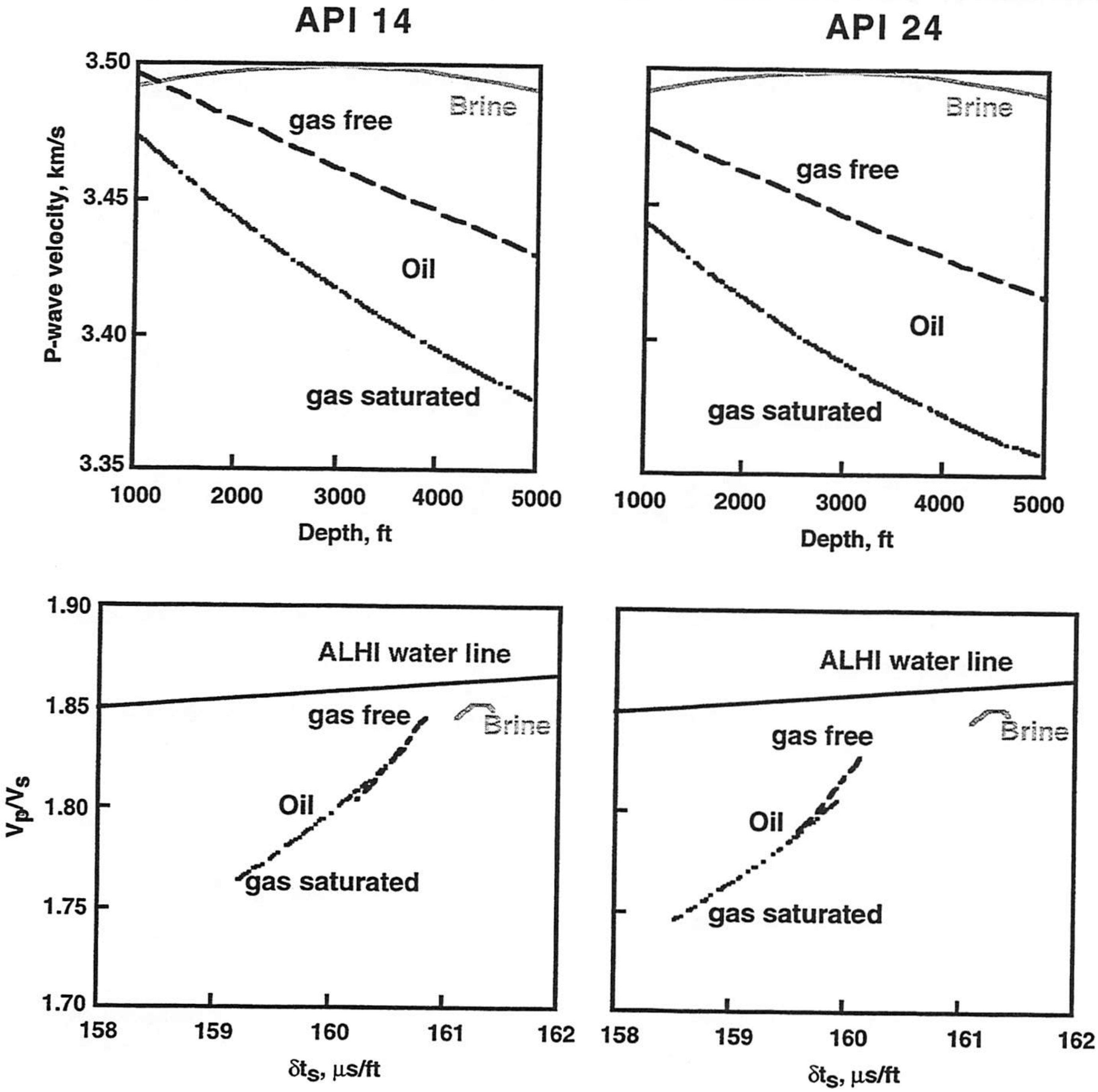
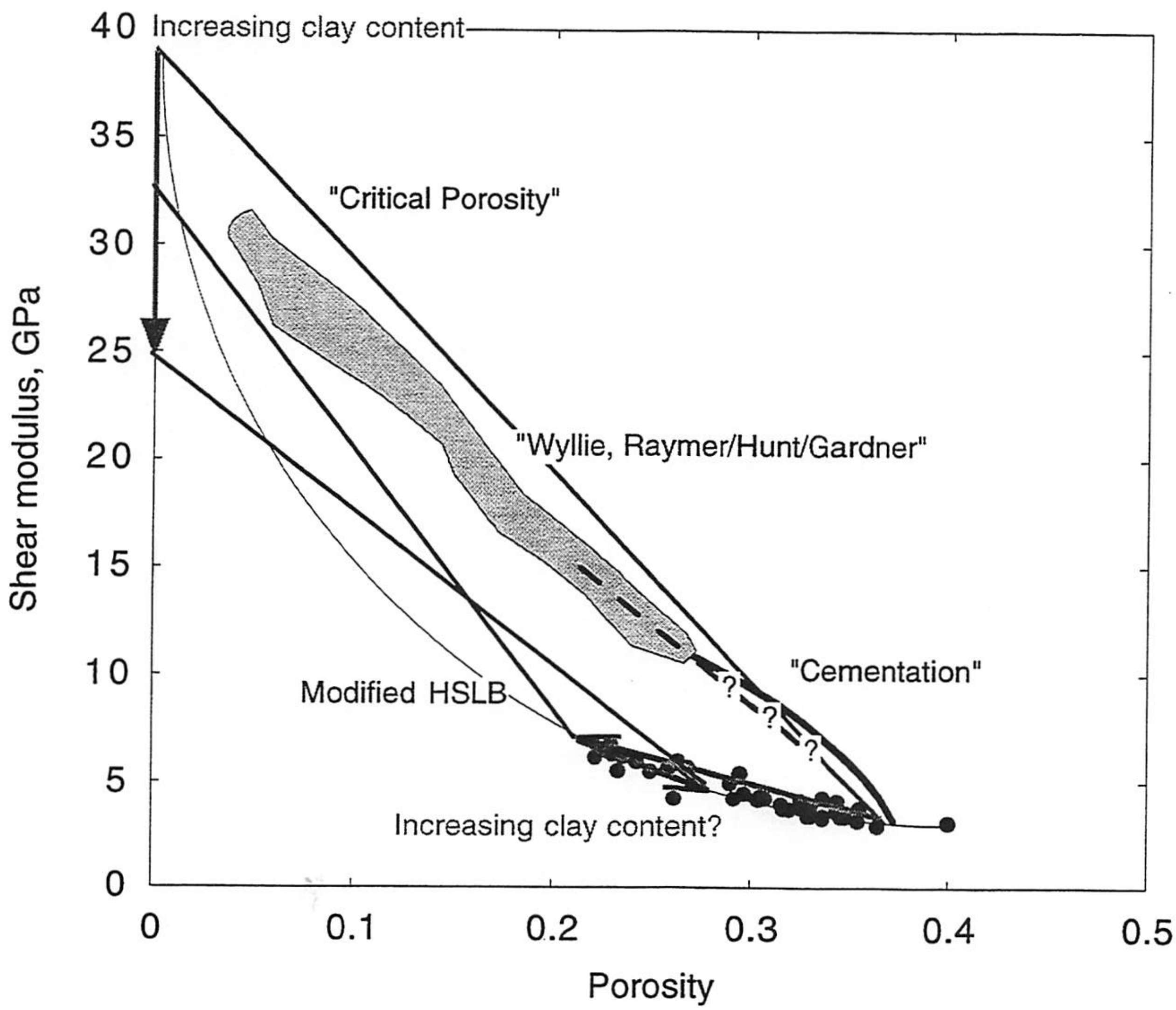
Rock Properties with Pore Fluids ($\varnothing_c$ model)



Porosity Determination

- Open-hole
  - » density, neutron, resistivity, sonic, …
- Cased-hole
  - » “near-wellbore effects” critical
  - » need “deep-reading” method
- Sonic
  - » Consolidated formations: Wyllie, Raymer/Hunt/Gardner
  - » Unconsolidated formations: modified HSLB

Porosity /Modulus Relations - Lab



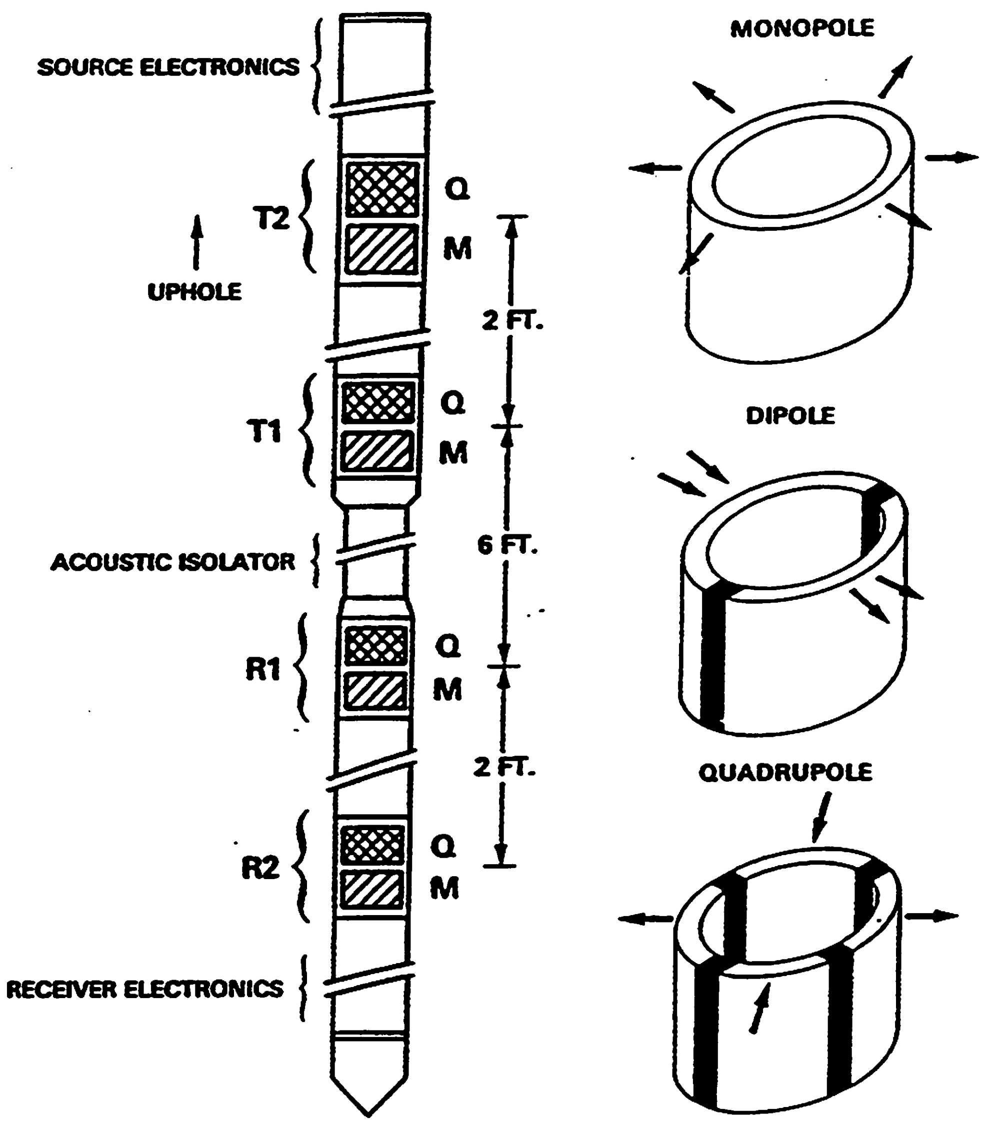
Acoustic Logging

- Measure travel-time of refracted acoustic signal
  - » dtp, dtco - P-wave (compressional)
  - » dts - S-wave (shear) in "fast" formations
- Porosity from Wyllie or Raymer/Hunt/ Gardner ("consolidated formations")
- Depth of investigation related to wavelength, offset
- Through casing "requires good bond"
- Lower frequency, higher energy
  - » longer offset
  - » less casing effect
  - » deeper penetration

Dipole Logging

- Works in "slow" formations
  - » $dt_s > dt_f \approx 200\ \mu s/ft$
- Low frequency
  - » required for penetration
  - » required to excite the mode
- Wave mode interference
  - » tube wave
- Not as sensitive to casing bond
  - » CBL, USI, ... cannot guarantee good log

Acoustic Logging



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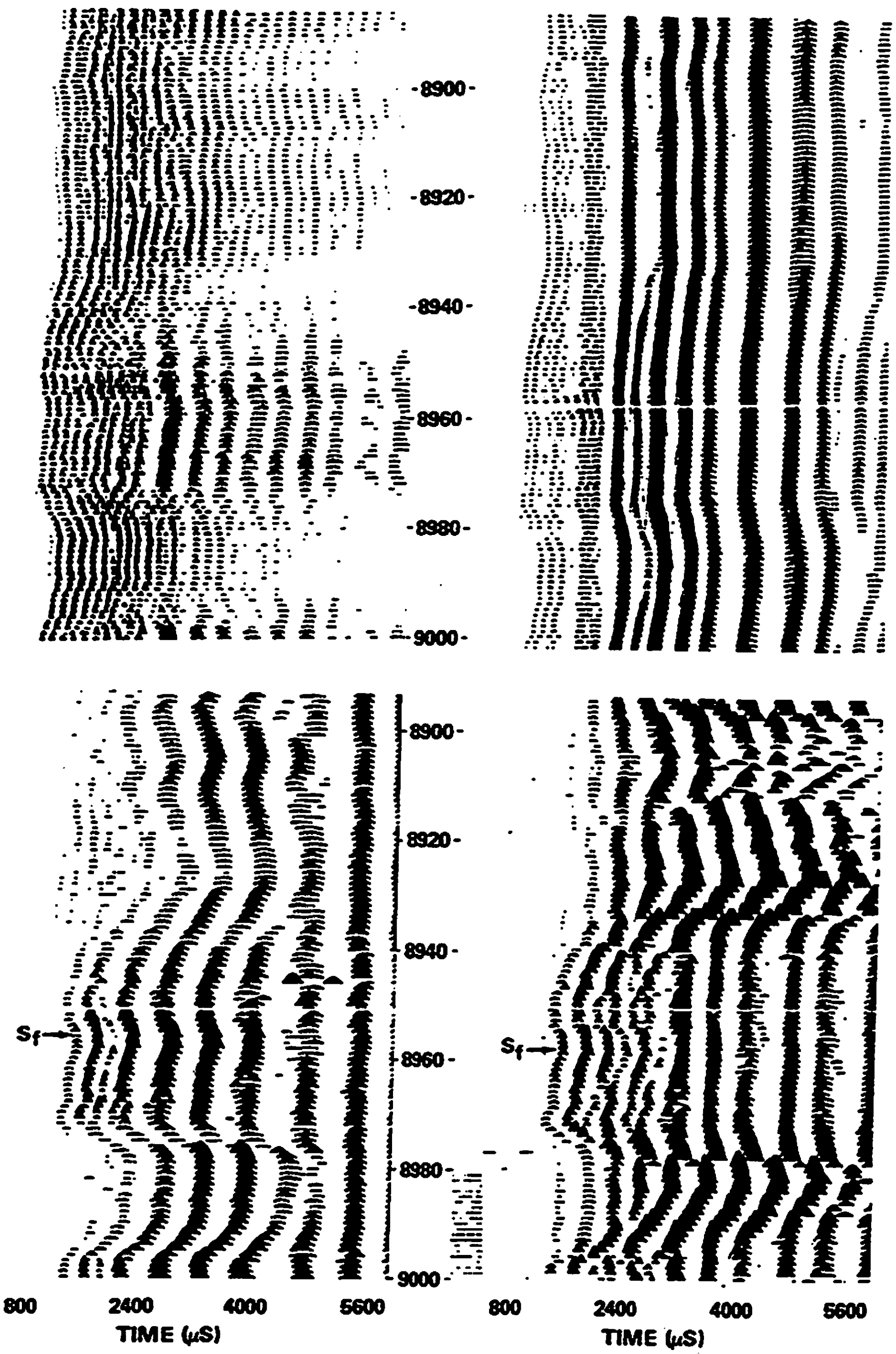
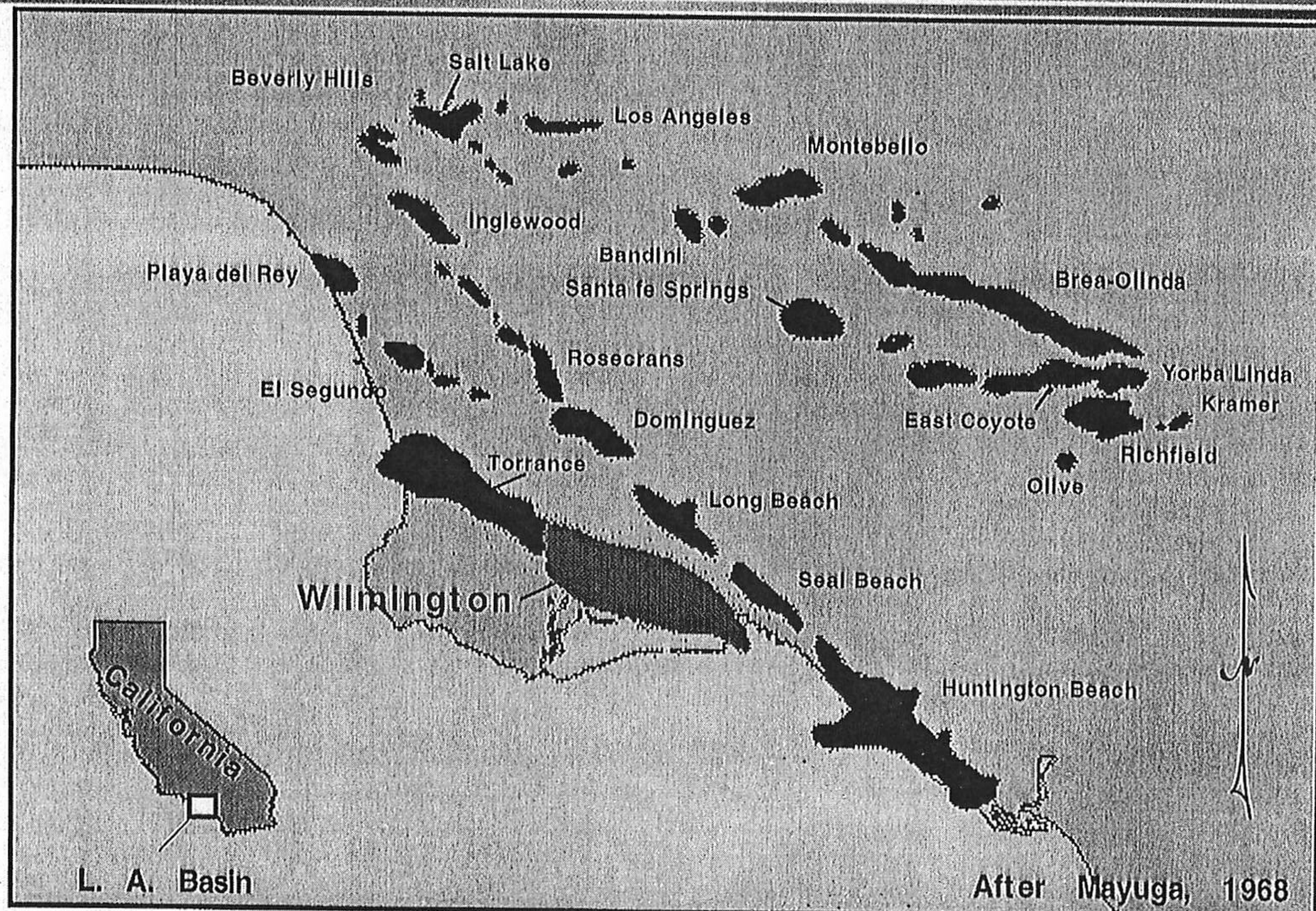
Acoustic Logging



Oilfields in the LA Basin



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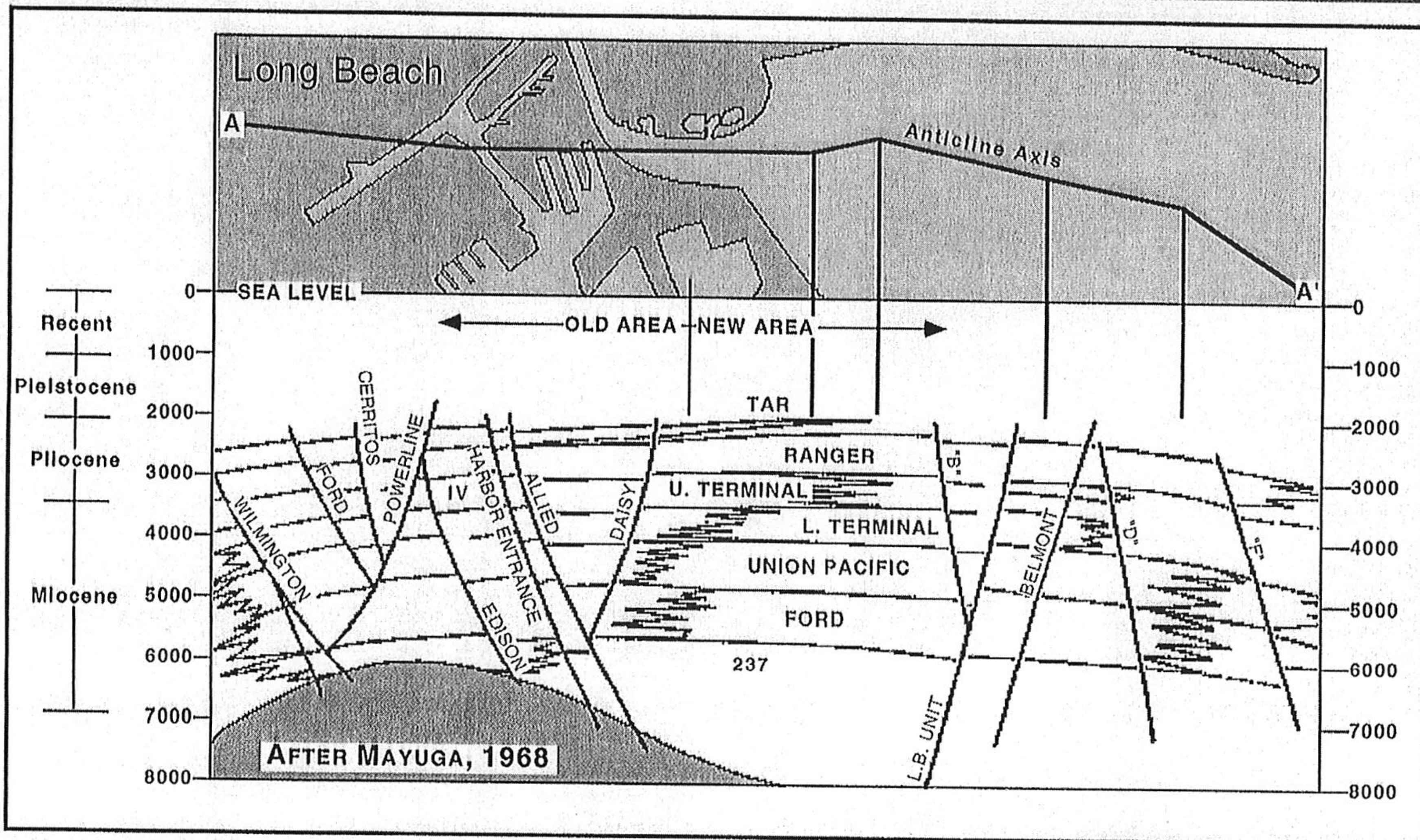
Wilmington Field cross section



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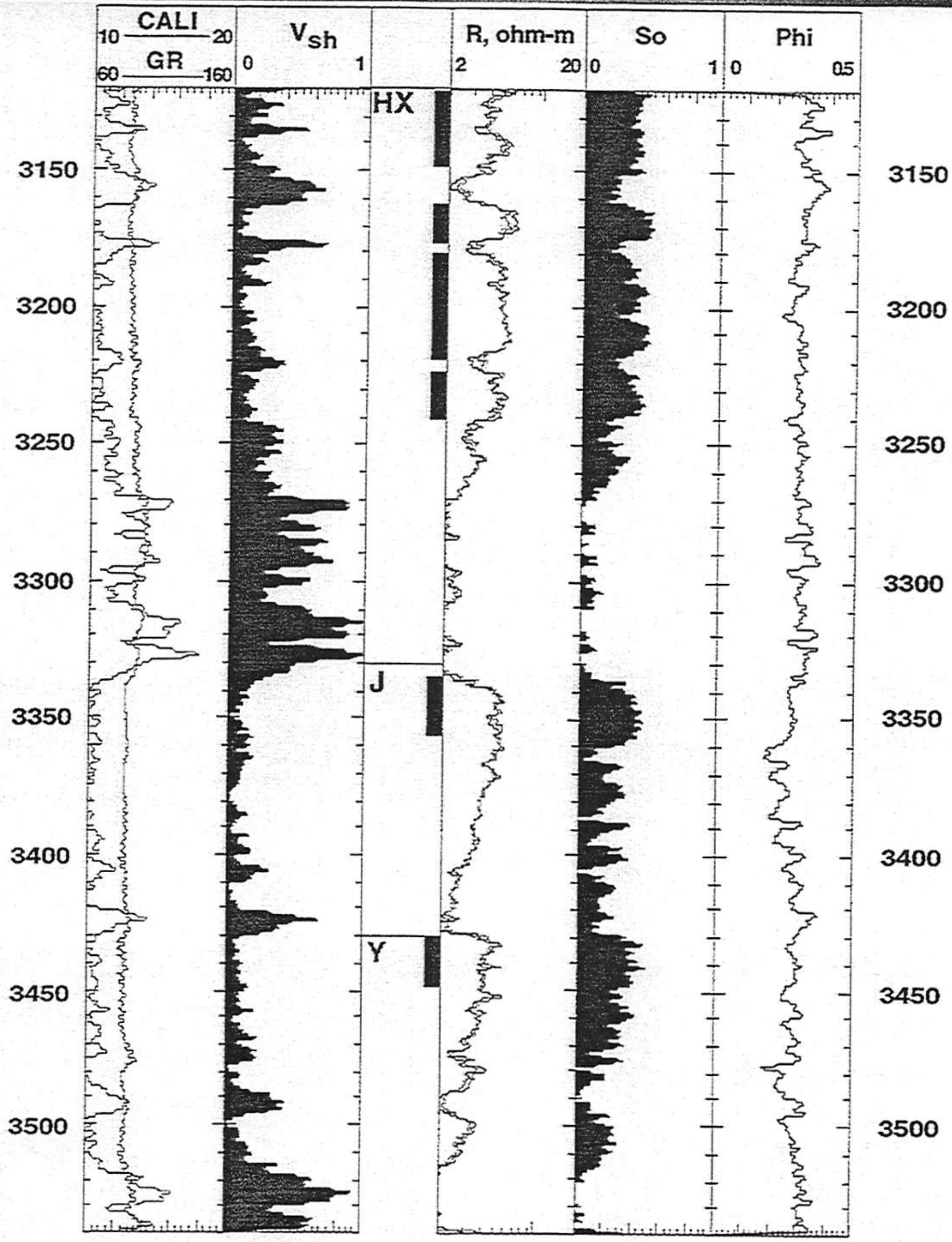
Log Data, M-499



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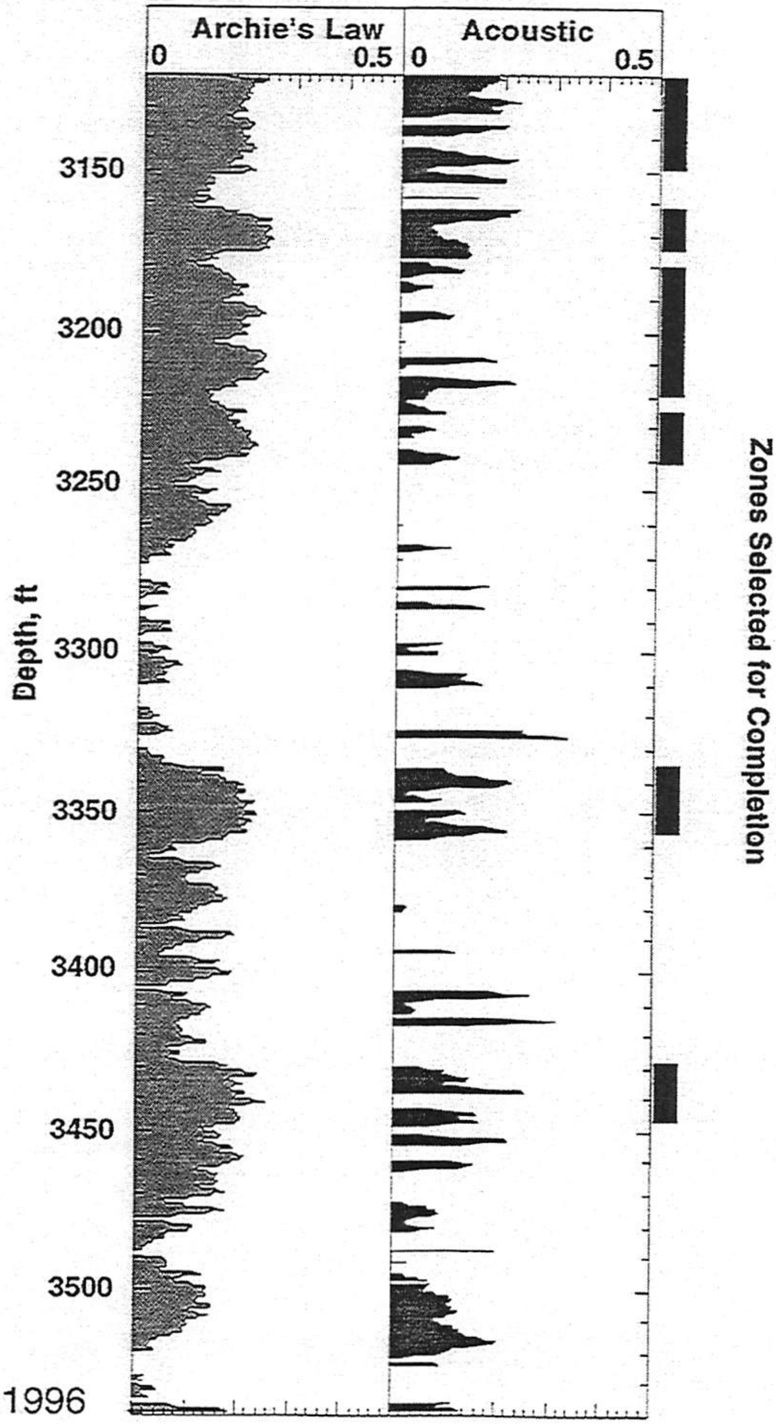
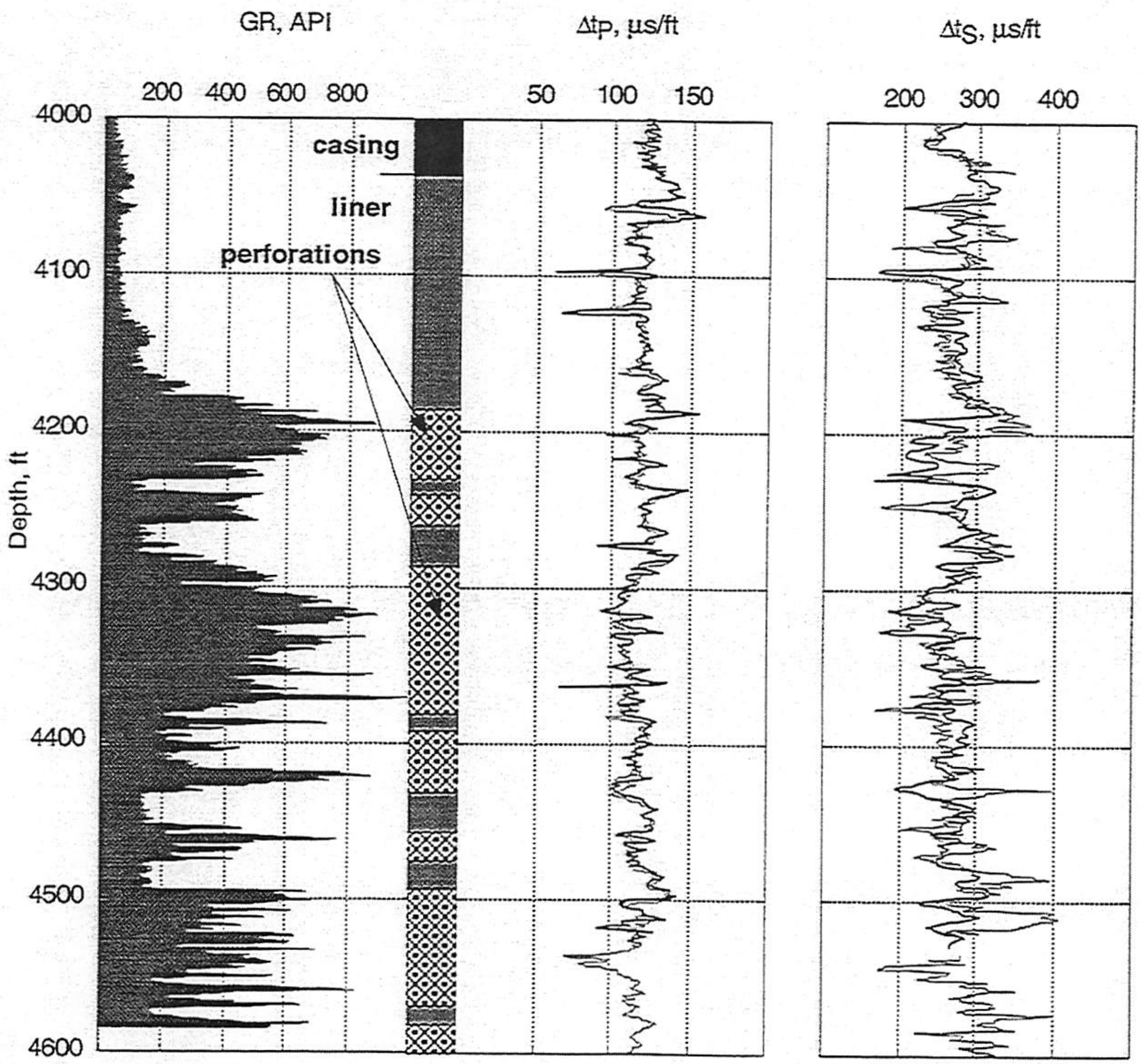
Saturation, M-499



Log Data, 167-W



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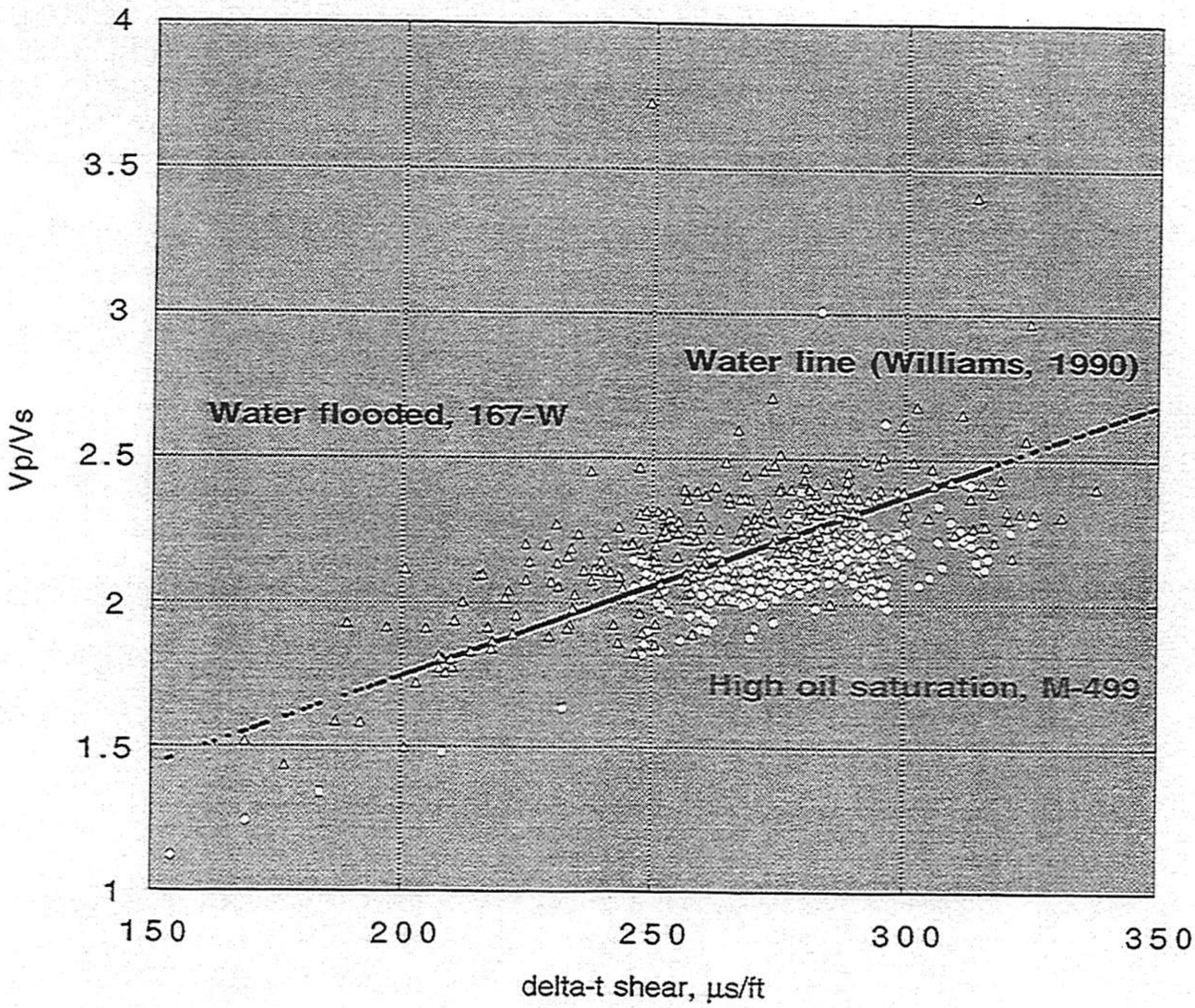
ALHI
167-W vs. M-499



Porosity from Velocity

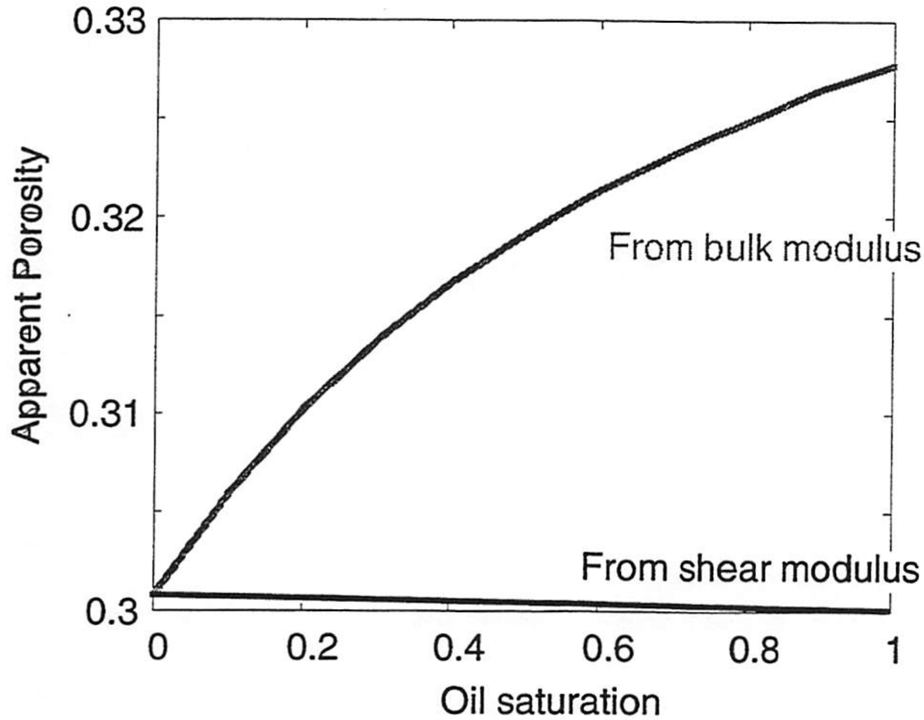
- Shear modulus is related to porosity by HSLB
- Velocity is related to modulus and porosity by:

$$G = \rho V_s^2$$

$$\rho = \phi\rho_f + (1-\phi)\rho_g$$

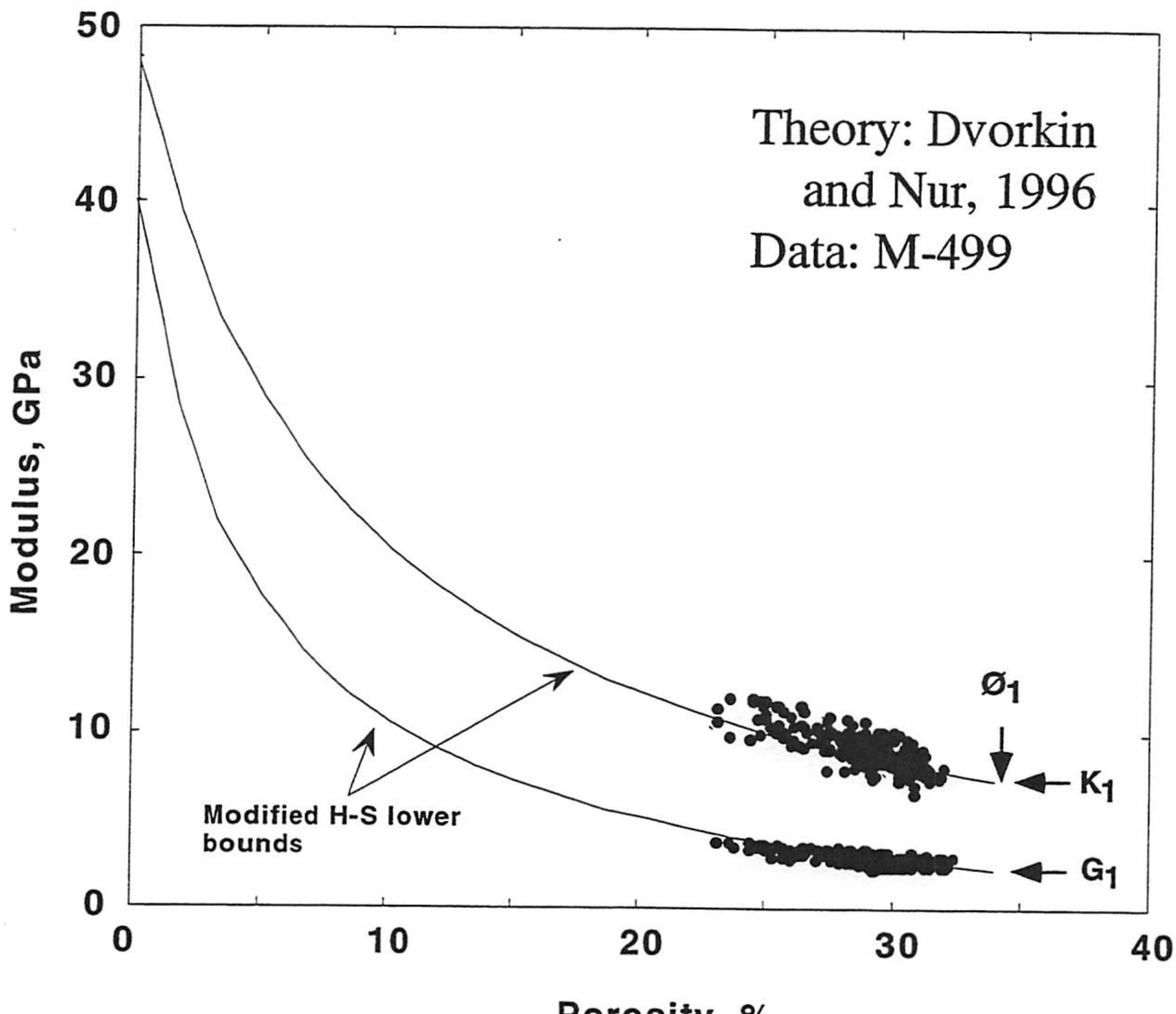
- Errors can result from incorrect densities
  - » if $\rho_f \neq \rho_w \approx 1.00$
  - » if $\rho_g \neq \rho_{qtz} = 2.65$
- These are generally smaller than effects related to fluid modulus

Porosity from Velocity

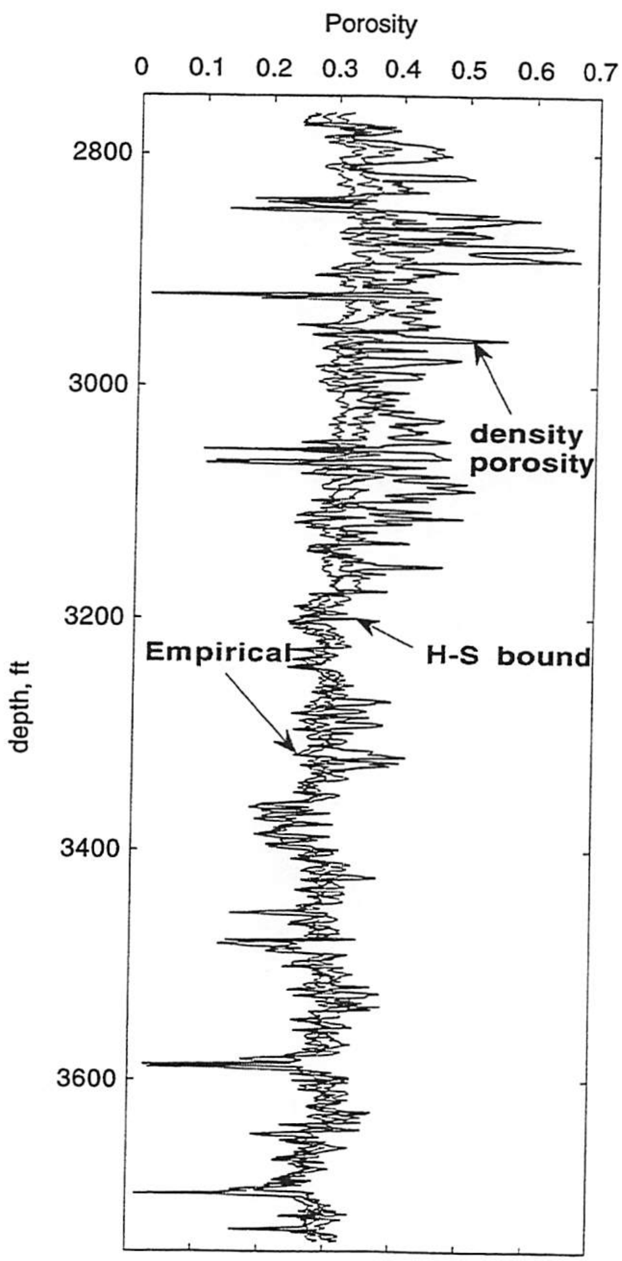


Porosity 0.3; API°14 oil 5000 ft.

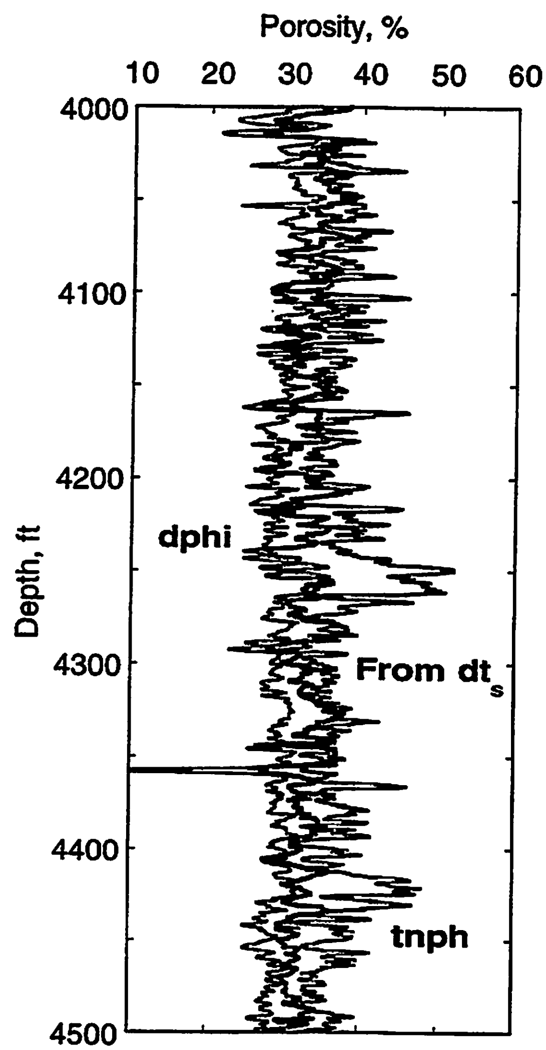
Porosity /Modulus Relations - M-499



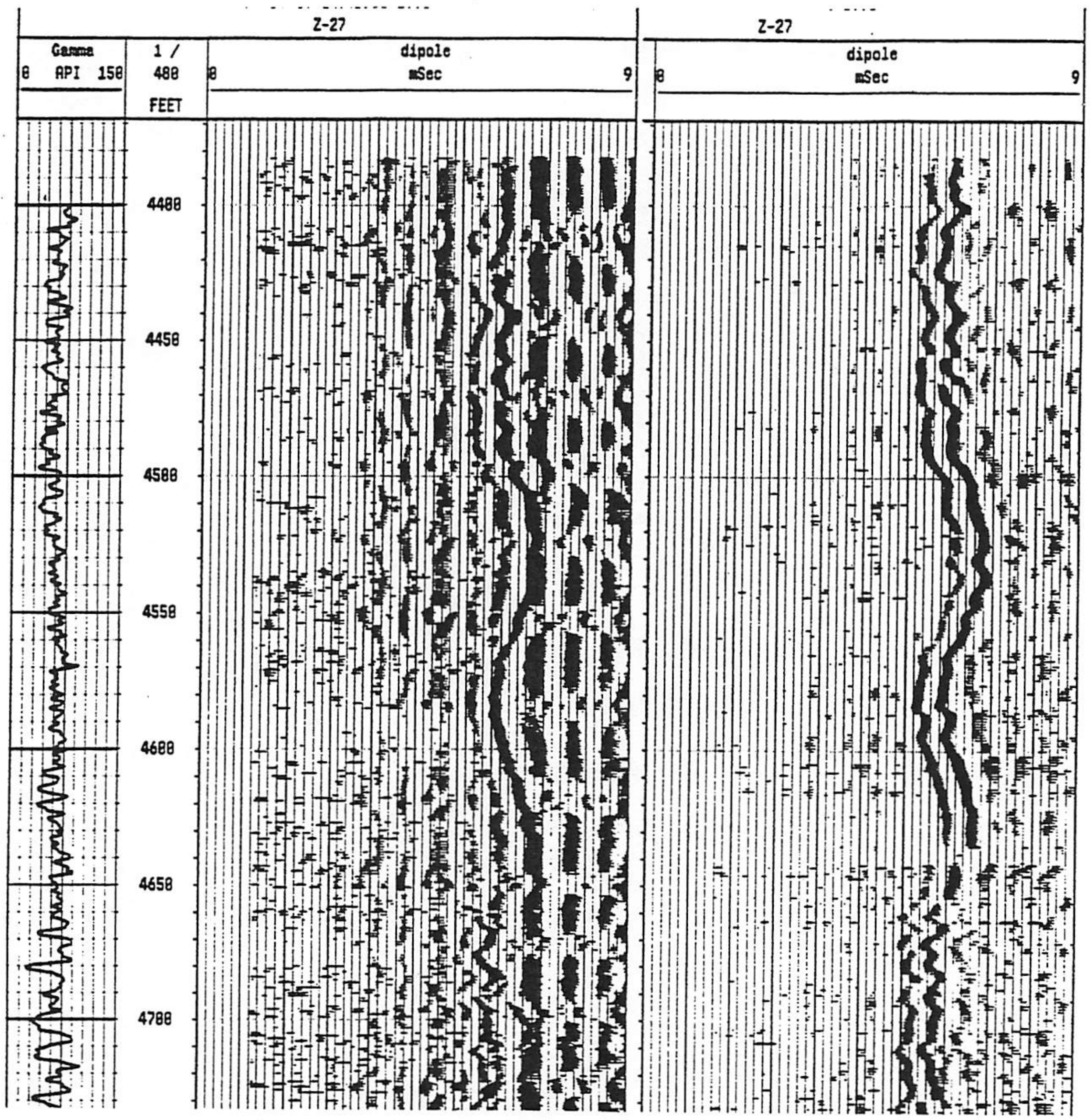
Porosity, M-499



Porosity, 169-W

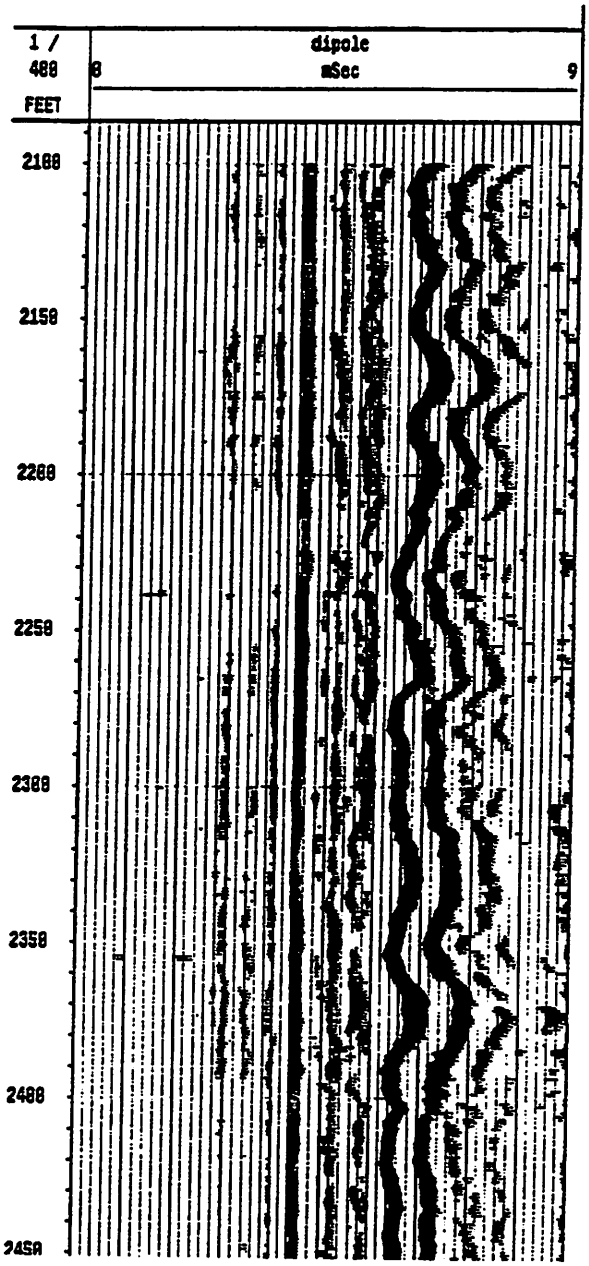


Log quality



PTTC, November 1996

Log quality



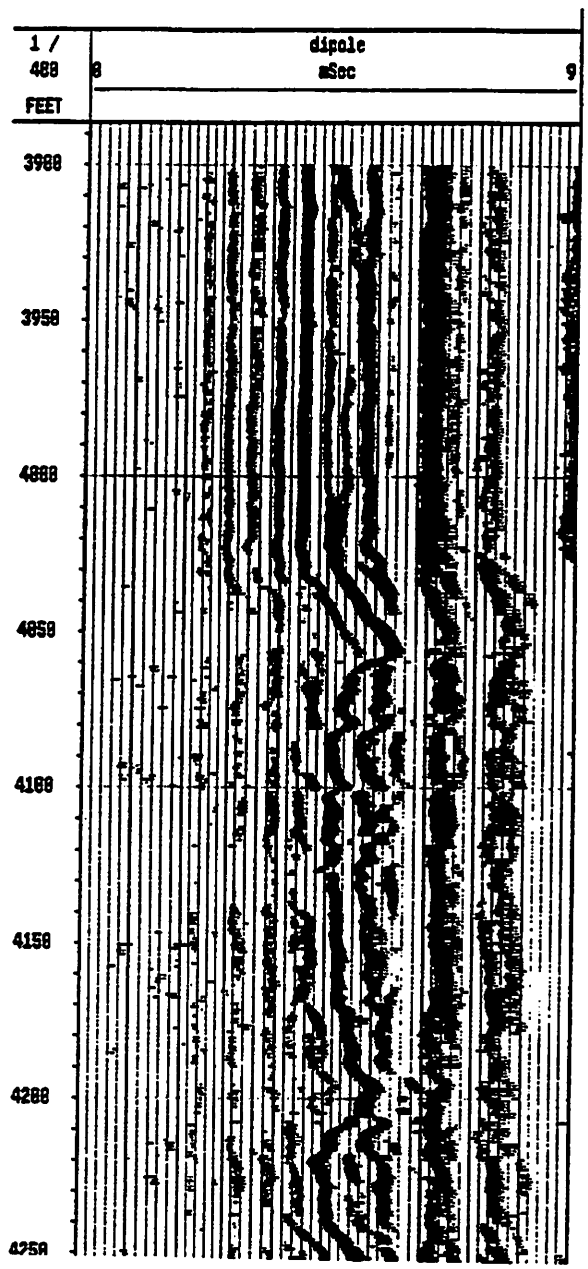


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Table - log recovery

Hole	Depth Interval, kft	Deviation	Year Drilled	Well Type	Other log data	Log Date, Dipole	Result
M-499	2.8-3.7	43°	1993	Prospect	all; CBT; USI; openhole	9/93	Vp & Vs
169-W	3.5-5.0		1995	Open-hole	all	1995	Vp & Vs
167-W	2.5-4.5	30°	1983	Waterflood	SP,GR,cond,USI	9/95;3/96	Vp & Vs*
FY-67	1.6-3.7	17°	1948	Waterflood	SP,cond,USI	9/95	Vp only
Y-63	1.6-3.2	17°	1948	Prospect	SP, cond	9/95; 12/96	No data
X-32	3.0-5.6		1946	Prospect	SP, cond	9/95	Vp only
J-15	1.2-2.9	vertical	1942	Prospect	SP, cond	3/96	No data
Z-223	2.0-4.1	28°	1952	Prospect	SP, cond, GST (1990)	6/96	Vs*
Z-27	2.0-5.3	20°	1949	Prospect	SP, cond		Vs*

*partial Vs

Implications

- Porosity
  - » from shear modulus (compliance)
- Fluid detection
  - » from bulk modulus (compliance)
- Quality control
  - » look at raw data
  - » demand quality from providers

Future Directions

- Since shear modulus is related to rock strength
  - » sand control
  - » production monitoring
  - » stress estimation

- Resistivity through casing(?)
  - » use shear modulus for porosity
  - » analyze using Archie's Law

NOTES

Problems and Opportunities in the Development of Hydrocarbon Resources in the Diatomites

Dr. Tad Patzek, University of California Berkeley and Lawrence Livermore National Laboratory

Problems and Opportunities in the Development of Hydrocarbon Resources in the Diatomites

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Passive Imaging of Hydrofractures in the South Belridge Diatomite

D.C. Ilderton,* SPE, **T.W. Patzek,** SPE, and **J.W. Rector,** U. of California; and **H.J. Vinegar,** SPE, Shell Development Co.

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SPE Formation Evaluation

Passive Imaging of Hydrofractures in the South Belridge Diatomite

D.C. Ilderton,* SPE, **T.W. Patzek,** SPE, and **J.W. Rector,** U. of California; and **H.J. Vinegar,** SPE, Shell Development Co.

Summary

We present the results of a seismic analysis of two hydrofractures spanning the entire diatomite column (1110-1910 ft or 338-582 m) in Shell's Phase II steamdrive pilot in South Belridge, California. These hydrofractures were induced at two depths (1110-1460 and 1560-1910 ft) and imaged passively using the seismic energy released during fracturing. The arrivals of shear waves from the cracking rock ("microseismic events") were recorded at a 1 ms sampling rate by 56 geophones in three remote observation wells, resulting in 10GB of raw data. These arrival times were then inverted for the event locations, from which the hydrofracture geometry was inferred. A five-dimensional conjugate-gradient algorithm with a depth-dependent, but otherwise constant shear wave velocity model (CVM) was developed for the inversions. To validate CVM, we created a layered shear wave velocity model of the formation and used it to calculate synthetic arrival times from known locations chosen at various depths along the estimated fracture plane. These arrival times were then inverted with CVM and the calculated locations compared with the known ones, quantifying the systematic error associated with the assumption of constant shear wave velocity. We also performed Monte Carlo sensitivity analyses on the synthetic arrival times to account for all other random errors that exist in field data. After determining the limitations of the inversion algorithm, we hand-picked the shear wave arrival times for both hydrofractures and inverted them with CVM. Finally, to correct for the areal inhomogeneity of the rock, we calculated the distortion of conical waves that were generated by air gun blasts in a remote observation well. This novel technique improved significantly the accuracy of the event locations in the shallow hydrofracture. The azimuth of both hydrofractures was N21°±4°E. In each treatment well, there were two separate hydrofractures at two different depths that correspond to the diatomite layers with higher permeabilities. Both shallow hydrofractures were asymmetrical. Initially, the upper NE wing was 230 ft long, whereas the lower SW wing was only 30 ft long. The deep hydrofracture was symmetrical and the wings of its two parts were initially 130 and 10 ft long, respectively. These conclusions agree well with temperature surveys in the surrounding observation wells during steam injection.

Introduction

The late and middle Miocene diatomaceous oil fields in the San Joaquin Valley, California, are located in Kern County, some forty miles west of Bakersfield. The largest oil volumes are found in the South, Middle and North Belridge Diatomite and Brown Shale, Lost Hills Diatomite and Brown Shale, Antelope Hills, McDonald Anticline, Chico-Martinez Chert, Cymric Diatomite, McKittrick, Railroad Gap, Belgian Anticline, Asphalto, Elk Hills, Buena Vista Antelope Shale, and Midway Sunset Reef Ridge and Antelope Shale. The major producers of diatomite oil are Shell, Mobil, Chevron, Santa Fe, Crutcher Tufts, Exxon, Texaco, and Unocal. An estimated original-oil-in-place in the Monterey diatomaceous fields exceeds 10 billion barrels and is comparable to that in Prudoe Bay in Alaska.

The uppermost productive member of the Monterey Formations is the Diatomite that passes westward into the argillaceous Reef Ridge Shale. The Diatomite overlies the Brown Shale with the dia genetically defined boundary. The Brown Shale in turn overlies the Antelope Shale member of the Monterey. Cyclic bedding in the siliceous facies is a well documented phenomenon attributed to alternating deposition of detritus beds, clay, and biogenic beds (mostly diatoms; 75 million of these microscopic plants fill a cubic inch). The cycles span length-scales that range from a fraction of an inch to tens of feet, reflecting the duration of depositional phases from semi-annual to thousands of years.

The mineral composition of diatomaceous rocks can be depicted as a mixture of biogenic silica, detritus and shale. For example, the South Belridge diatomite has more biogenic silica, and the Lost Hills diatomite has more shale and sand. Depending on depth and temperature, the unstable biogenic or inorganic silica (Opal-A) dissolves and reprecipitates to form a metastable compound, Opal-CT (Brown Shale), that in turn dissolves and reprecipitates as microcrystalline quartz (Antelope Shale, Chert and/or Chalcedony).

The diatomaceous rocks are very porous (25-65%), rich in oil (35-70%), and almost impermeable (0.1-10 md). The high porosity and oil saturation, together with large thickness (up to 1000 ft) and area (up to a few square miles per field) translate into the gigantic oil-in-place estimates. Unfortunately, the low diatomite permeability makes efficient oil production very difficult, if not impossible, with current technology.[1]

To compensate for the low reservoir permeability, all wells in the diatomite must be hydrofractured. A typical well has 3-8 fractures with the wing span of 300 ft tip-to-tip. Wells are usually spaced along lines following the maximum in-situ stress every 330 ft (2½ acre), 165 ft (1¼ acre) or even 82 ft (⅝ acre). Thousands of hydrofractures have already been induced and thousands more may be created as new recovery processes, such as steamdrive on 5/8 acre spacing, become commercially viable. With so many hydrofractures so close to each other, it is crucial that we know their length, height, azimuth, dip, symmetry, conductivity and dynamics.

The hydrofractures in the diatomite can be imaged passively,[2-3] using the seismic energy released as the rock cracks and is propped open, and actively, using shear wave shadowing. In the case of passive imaging, the microseismic event arrival times are picked and inverted to find the event locations, which are then used to infer the hydrofracture geometry as a function of time. As in any arrival time based inversion, the calculated event locations are very sensitive to the errors in the picked arrival times and the choice of an "average" formation velocity.

We present the results of passive imaging of hydrofractures in two injectors in Shell's Phase II steamdrive pilot in South Belridge. We developed an inversion algorithm based on a modified conjugate gradient method with a constant velocity model (CVM). By using a layered shear velocity model and Monte Carlo simulations, we have delineated the limitations of CVM. Finally, to correct for the azimuthal variability of shear wave velocity in the diatomite, we calculated the distortion of conical waves from air gun blasts in a nearby logging observation well.

Experiment Description

Fig. 1 depicts a plan view of the Phase II steamdrive pilot in Section 29 of the South Belridge diatomite. Hydraulic fractures were induced in three treatment wells: producer 543P, followed by two steam injectors IN2U and IN2L. Wells IN2U and IN2L were perforated from 1110 to 1460 ft and from 1560 to 1910 ft, respectively. Well 543P was perforated in the lower zone between 1540 and 1890 ft. Results of hydrofracture imaging in 543P have been reported elsewhere.[2-3] Three dedicated microseismic observation wells, MO-1, MO-2, and MO-3, were strategically placed about the treat-

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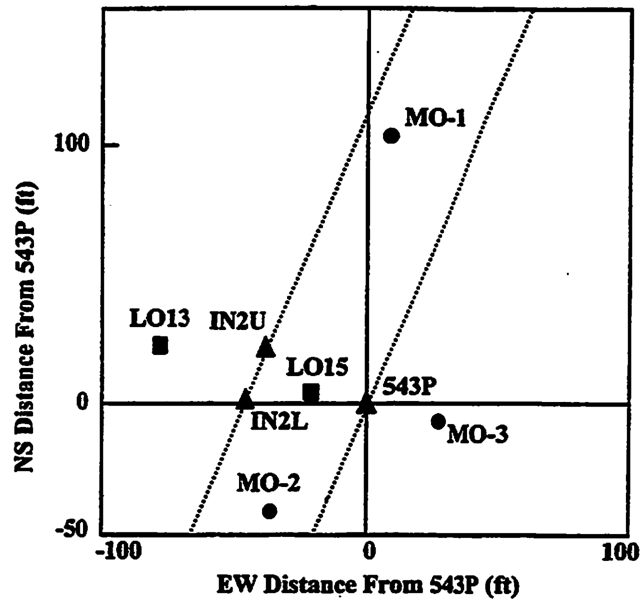

Fig. 1—Plan view of microseismic experiment in the South Belridge field.

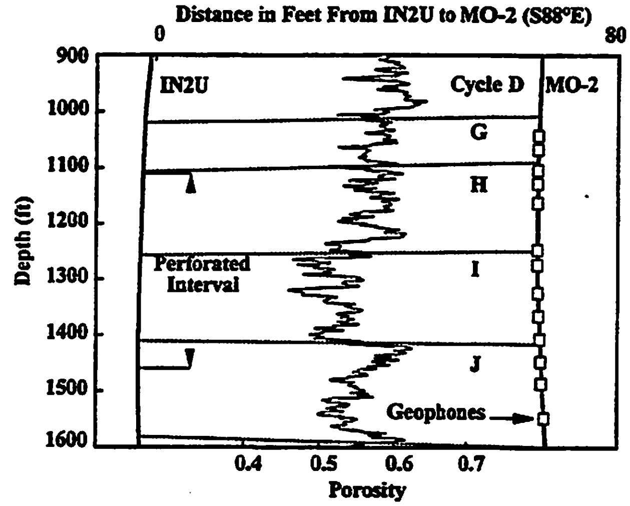

Fig. 2—Cross-sectional view of experiment site shown with porosity log and geologic layering.

ment wells. In each observation well, an array of three-component geophones was strapped onto the casing and cemented in place. The geophone stations were spaced every 20 ft over the entire diatomite column. A second array in MO-3 had geophones positioned every 5 ft over a 200-ft interval at the bottom of the diatomite. Vinegar *et al.*[2] provided a detailed description of the materials used in the construction of the geophone pods. Fig. 2 is a cross-sectional view of the experiment site between IN2U and MO-2. Only the active geophones that span the perforated interval of IN2U are shown. The diatomite cycles and porosity log are also shown. Note that porosity jumps from 30 to over 60% across the top of the diatomite at a depth of about 900 ft.

LO13 is a logging observation well in which an air gun was fired for the purpose of shear-wave shadowing of the fracture in IN2U. These blasts also generated tube waves that proved invaluable in our analysis. A logging observation well LO15 and MO-3 were used to determine the formation shear velocity log by measuring the interwell seismic travel time. The velocity was found to range from about 1800 to 2300 ft/s.

The fracturing of IN2U consisted of a six-stage minifrac and a seven-stage main frac (Table 1). Only the main fracture was induced in IN2L. Generally, the pumping rate was higher with each subsequent stage of the minifracs and was significantly increased during the main frac. All mini frac stages were pumped with 2% KCl brine except the last one in which cross-linked 40 pound gel was used. Main fracs were pumped with 2% KCl brine, cross-linked 40 pound gel, and 20/40 Ottawa sand.

Data Acquisition

Fifty-six channels of data were recorded by Western Geophysical Downhole Seismic Services using a 60-channel DFS-V system with dual 9-track magnetic tape drives. Channel limitations restricted recording to approximately 18 geophones from each observation well during each fracturing stage. Thus, only the geophones spanning the perforated interval in the treatment well were used. The data were collected at a 1 ms sample rate in 16-second blocks separated by a 950 ms gap to allow for the DFS-V to reinitialize the recording sequence. Also, an LRS-1300 triaxial borehole tool was used to acquire the microseismic data in the treatment well. Over five hours of continuous recording time was required for each fracture treatment, resulting in almost 10 GB of data.

The data were band-pass filtered to eliminate 60 Hz electronic noise and low energy frequencies, thus improving the signal to noise ratio. We also used predictive deconvolution to help reduce any coherent noise signal. Despite this processing, we were able to detect the arrival of seismic energy only in the form of shear waves, as shown in Fig. 3. The hyperbolic move out of about 2000 ft/s identifies this shear wave arrival. We did not find any *P*-wave arrivals associated with the microseismic events that could be picked with confidence. Wills *et al.*[3] reported that compressional waves are highly attenuated in diatomite and that shear waves are produced with a much larger amplitude. We believe that our inability to detect *P*-wave arrivals was also because of their horizontal polarization, which inhibited *P*-wave detection by the vertical-component receivers. Unfortunately, analysis of the few horizontal-component channels was inconclusive as well.

When a microseismic event was found, the arrival times were picked by hand for each geophone. We feel that the time-consuming process of picking by hand resulted in greater accuracy of inversions for the microseismic event locations.

Inversion Algorithm

The reason for having three observation wells with multiple geophones was to allow for an accurate inversion of event locations by triangulation. An easy way to view such an inversion in two dimensions is to imagine growing circles at a constant rate about each observation well. The point where these circles intersect defines the

TABLE 1—FRACTURE DATA FOR IN2U AND IN2L

Stage	Starting Time	Volume (bbl)	Rate (bpm)	Fluid Type
Mini 1 (IN2U)	5:56	50.22	9.21	2% KCl brine
Mini 2	6:29	100.22	8.37	2% KCl brine
Mini 3	7:01	375.51	4.99	2% KCl brine
Mini 4	8:19	326.40	18.20	40 lb CLG
Mini 5	8:37	76.57	24.05	2% KCl brine
Mini 6	9:11	11.73	0.90	2% KCl brine
	next day			
Main 1 (IN2U)	10:27	76.30	22.12	2% KCl brine
Main 2	10:49	51.25	23.29	40 lb CLG
Main 3	10:51	193.43	26.26	40 lb CLG and OS
Main 4	10:59	297.39	26.28	40 lb CLG and OS
Main 5	11:10	416.07	26.31	40 lb CLG and OS
Main 6	11:26	432.49	26.29	40 lb CLG and OS
Main 7	11:42	43.40	25.53	40 lb CLG
Main 1 (IN2L)	5:51	201.75	25.06	2% KCl brine
Main 2	6:10	69.28	23.48	CLG
Main 3	6:13	193.95	26.21	CLG and OS
Main 4	6:20	295.72	26.13	CLG and OS
Main 5	6:32	460.05	26.14	CLG and OS
Main 6	6:49	499.35	26.12	CLG and OS
Main 7	7:08	55.73	25.72	2% KCl brine

CLG = Cross-linked gel
OS = 20/40 Ottawa sand

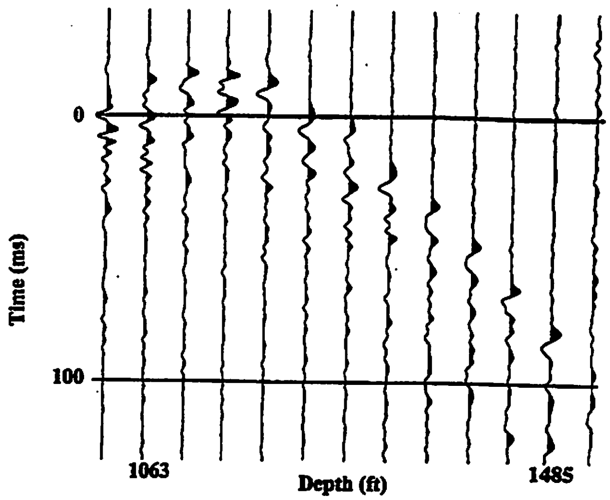

Fig. 3—Shear wave arrival at MO-2 recorded by the vertical component of the geophones (note hyperbolic moveout).

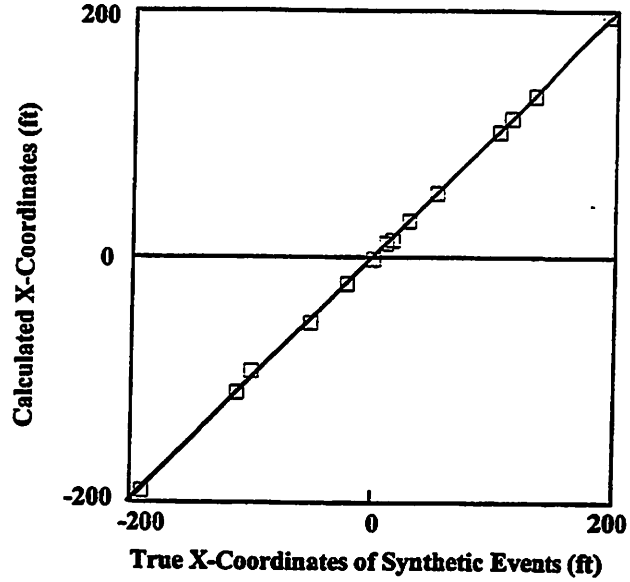

Fig. 4—Each square represents the X-coordinate calculated by the location algorithm vs. the true X-coordinate of the corresponding synthetic event.

event location. We developed a five-dimensional inversion algorithm that uses a modified conjugate gradient method to minimize an objective function:

$$\sum_{i=1}^{\#geophones}\left[\sqrt{(x_i-x_{ev})^2+(y_i-y_{ev})^2+(z_i-z_{ev})^2}-v_{ev}(t_i-t_{ev})\right]^2 \quad \text{.......................} \quad (1)$$

for each event, ev. The unknowns here are x_{ev}, y_{ev}, z_{ev}, t_{ev} and, if desired, v_{ev}.

The algorithm can be executed in one of two modes. In Mode #1, the single velocity used for the inversion is picked from the interwell shear velocity log for the depth of the earliest shear wave arrival at each observation well. In Mode #2, the single best velocity is calculated as a part of minimizing Eq. 1, using a separate Golden Section Search[4] in the velocity dimension (because time and velocity enter Eq. (1) as a product). In either case, the chosen velocity is assumed to be uniform in all directions and constant with depth. Thus, the algorithm *always* assumes a homogeneous or constant velocity model (CVM) during the inversion, regardless of the execution mode.

To test the algorithm, synthetic event locations were selected at various locations and depths throughout the test site, inside and outside of the geophone network. The shear wave travel times to each geophone were computed for a uniform medium of a specified velocity. The arrival times were then inverted in Mode #2, and the calculated locations compared with the selected ones. Fig. 4 shows the results of the calculated x-coordinates versus the selected x-coordinates. The inversion is accurate to within one foot. Similar plots for the other calculated parameters (y-coordinate, depth, origin time, and velocity) reveal the same precision. After thorough testing, we feel that this algorithm is superior to the standard least square fit with Gaussian elimination, which suffers from ill conditioning and round off errors.

Validity Test for Inversion Algorithm. Having established that the inversion algorithm worked numerically in a homogeneous medium, we needed to test its capacity to invert field data. A depth-dependent, but otherwise constant shear velocity model is rarely a good representation of a layered and heterogeneous rock. Seismic waves propagating through such a rock are subject to velocity changes that result in ray-bending. On the other hand, a constant velocity model assumes straight ray paths, and it is necessary to resolve the systematic error incurred when inverting real data with such a model.

To find this error, we first developed a horizontally layered, shear wave velocity model, using the interwell velocity and bulk density logs. The model velocities and layering were chosen to represent the diatomite formation as accurately as possible and are shown in Fig. 5. Fig. 6 compares two sets of arrival times, one generated with our layered model and the other from a real microseismic event. The approximate agreement between these and other arrival times con-

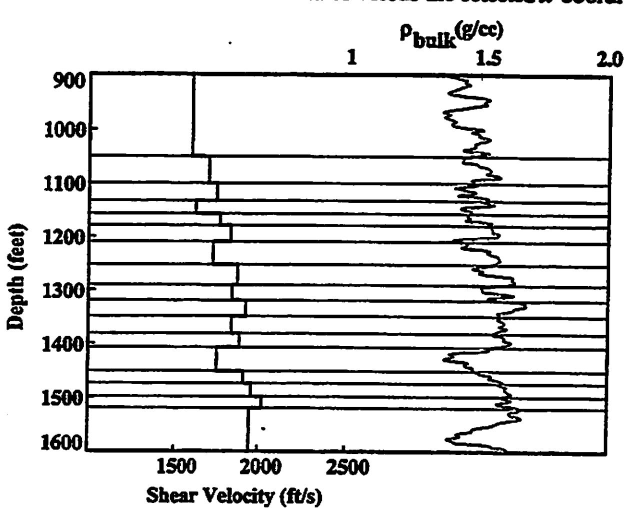

Fig. 5—Layers with respective shear velocities for layered model shown with bulk density log.

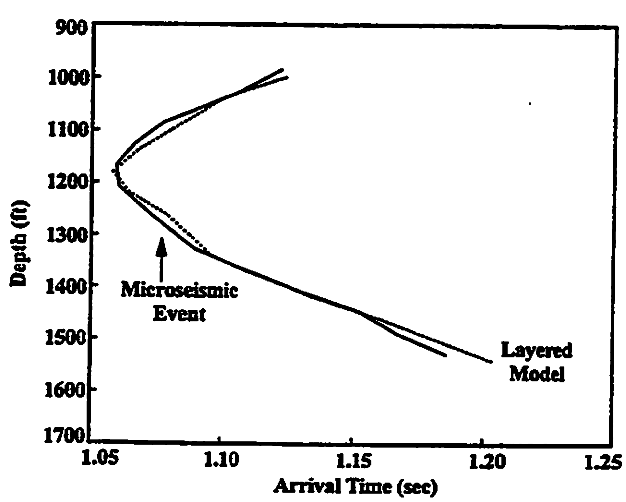

Fig. 6—Arrival times comparison.

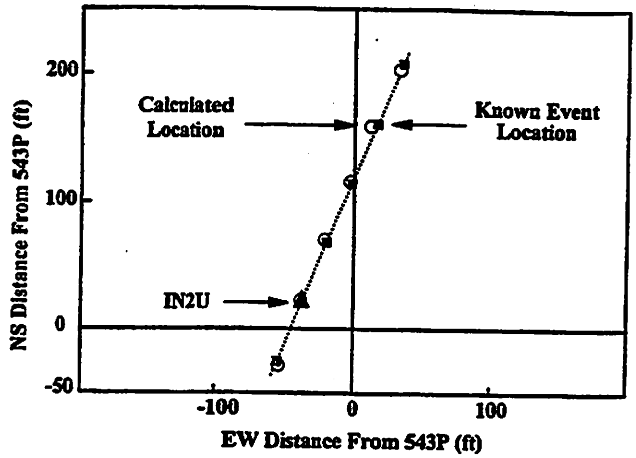

Fig. 7A—Known vs. calculated locations (1200 ft).

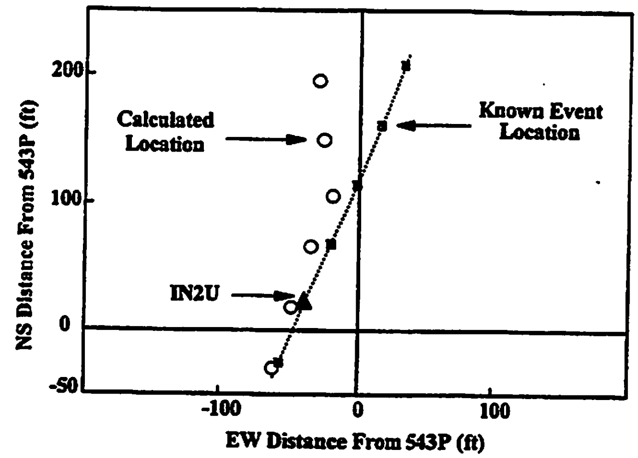

Fig. 7B—Known vs. calculated locations (1400 ft).

vinced us that our layered model was a reasonable representation of the diatomite.

Next, we assumed *known* synthetic event locations at various depths along the estimated hydrofracture plane in IN2U. The shear wave travel times to each geophone were then computed from the *layered* model. These arrival times were in turn inverted with CVM in Mode #1, and the calculated locations were compared with the known ones. Figs. 7A and B show the results of this comparison in plan view for the events at 1200 and 1400 ft, respectively.

The calculated locations may seem acceptable, but they still result from inverting ideal, *error-free* arrival times, which are hardly typical of field data. The arrival times of real seismic events are subject to various errors. There is error because of the recording equipment, noise in the seismic signal, and the actual picking of the arrival times. Unfortunately, these errors are difficult to decouple.

To test the validity of inverting real data with CVM, we had to introduce an element of error into the arrival times computed from the layered model. Accordingly, we perturbed the arrival time at every geophone by a random factor of the order of four milliseconds. This random factor, which is approximately one third of the average period for the real shear wavelengths in our data, was to account for all errors. Inverting the arrival times after each of 500 perturbations yielded an oriented ellipsoid of uncertainty for the calculated locations in Figs. 7A and B.

Figs. 8A and B show the uncertainty "clouds" around the calculated locations, together with the *known* synthetic locations. These plots are more significant than those in Figs. 7A and B, because the calculated location for a real microseismic event corresponds to *any* of the event locations composing the uncertainty ellipsoid. The error associated with inverting real data using a homogeneous model is represented by the distance between the uncertainty cloud and the specified location. If the cloud encompasses the specified location, then such an inversion is valid for that location, given appreciable errors induced by well geometry, geophone spacing, and all other errors discussed above. If the specified location falls outside of the cloud, then inverting with a homogeneous model is insufficient for that location, and a vertically variable velocity inversion (a more difficult task) must be performed.

Conditional Validity. In Fig. 8A, the uncertainty ellipsoids are in good agreement with the specified locations at all distances from the treatment well. However, in Fig. 8B they compare favorably near the treatment well but get progressively worse with distance away from the borehole. We believe that this diminished accuracy is related to the vertical location of the synthetic events. At 1400 ft, the shear wave velocity has a higher gradient than at 1200 ft, which could explain why our accuracy is poorer at 1400 ft. The variation in shear velocity is more important than its magnitude. A larger gradient leads to more seismic ray bending and greater uncertainty. In addition, events farther away from the geophone wells are more prone to ray bending, explaining why accuracy diminishes with distance.

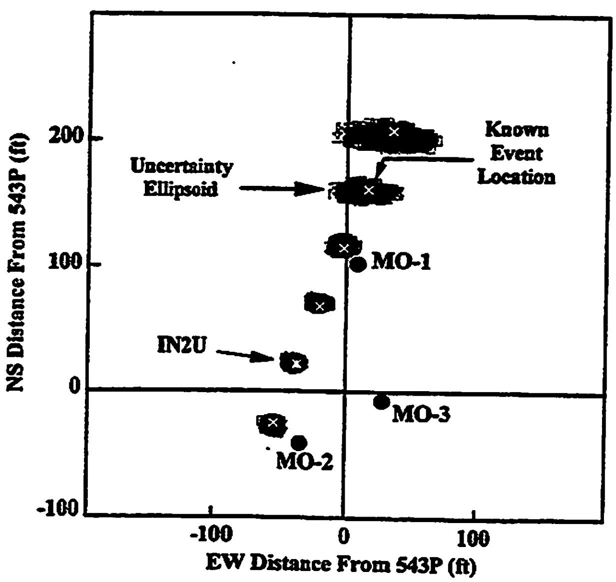

Fig. 8A—Known locations vs. uncertainty ellipsoids (1200 ft).

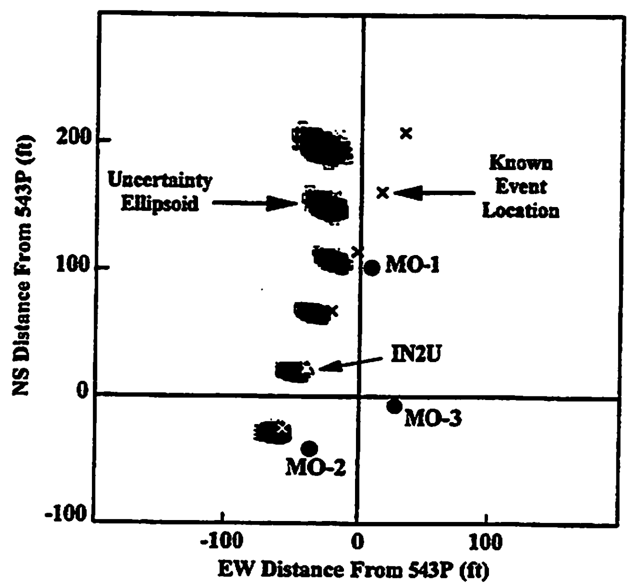

Fig. 8B—Known locations vs. uncertainty ellipsoids (1400 ft).

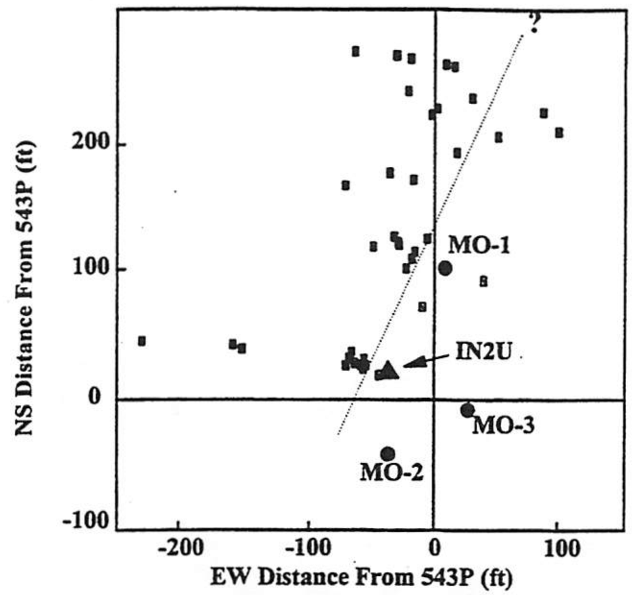

Fig. 9—IN2U microseismic event locations using constant velocity model.

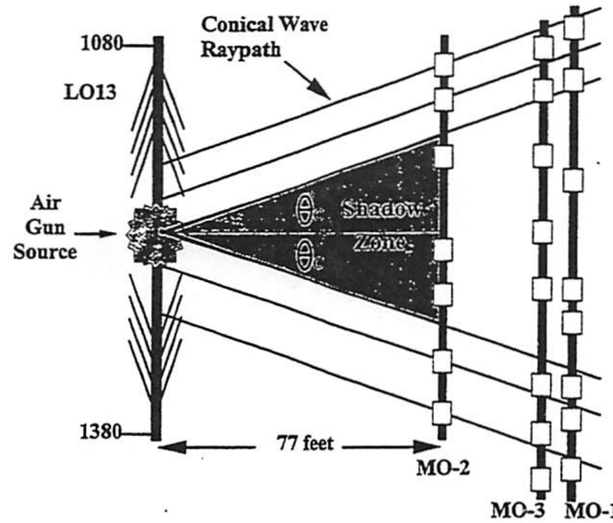

Fig. 10—Conical wave generation and propagation.

Initial Event Locations for IN2U

After determining the accuracy and limitations of our inversion method, we proceeded to invert the arrival times of real microseismic events. The search through all the IN2U hydrofracture data resulted in the detection of about 80 direct arrivals. Unfortunately, half of these were conical waves caused by the air gun shots that were used for the shear wave shadowing analysis.[2] We picked the arrival times for all the microseismic events and inverted them using CVM.

Fig. 9 is a plan view showing the calculated event locations for the microseismic events. The locations are much more dispersed than we expected, and it is difficult to define any fracture plane at all. Also, the fracture is asymmetrical, extending almost entirely northeast of IN2U. These results led us to question again the validity of our inversion routine, but from a different perspective.

The validity tests described above showed that inverting real data with CVM is acceptable for our purposes. However, for the South Belridge diatomite, *lateral* variability of shear velocity may exist and must be taken into account when inverting for the microseismic event locations. In fact, with only three geophone wells, azimuthal variation could be a more significant source of error than vertical variation. Thus, we devised a method to detect directional changes in shear velocity in the diatomite. The conical waves from the air gun blasts in LO13, which had originally been considered an unwanted noise, were now viewed as a potentially useful tool to estimate the shear wave velocity between LO13 and the three observation wells.

Conical Waves

Generation and Propagation. Conical waves are frequently encountered in vertical seismic profiling (VSP). An air gun blast causes a fluid disturbance within the well that emits tube waves which travel up and down the borehole, away from the air gun.[5-6] As the tube waves propagate, they diffract into the formation as conical wave fronts if the tube wave velocity exceeds the velocity of the adjacent formation.[2,7] For our test site, the tube wave velocity is greater than the diatomite's shear velocity but less than its compressional velocity; hence, we can detect only shear conical waves in our data.[8] The conical waves emerge into the formation at an angle θ with respect to the perpendicular to the borehole, where

$$\Theta = \sin^{-1}\left[\frac{V_s(z)}{V_t(z)}\right]. \quad (2)$$

$V_s(z)$ is the depth-dependent shear velocity of the formation, and $V_t(z)$ is the tube wave velocity. The angle in our case varies from about 27° to 45° and is more sensitive to V_s than to V_t. **Fig. 10** illustrates the ray paths taken by the conical waves from LO13 to the observation wells. Note the shadow zone, equal to 2θ, separating the conical waves generated by the up- and downgoing tube waves. Consequently, only geophones whose depths are greater or less than

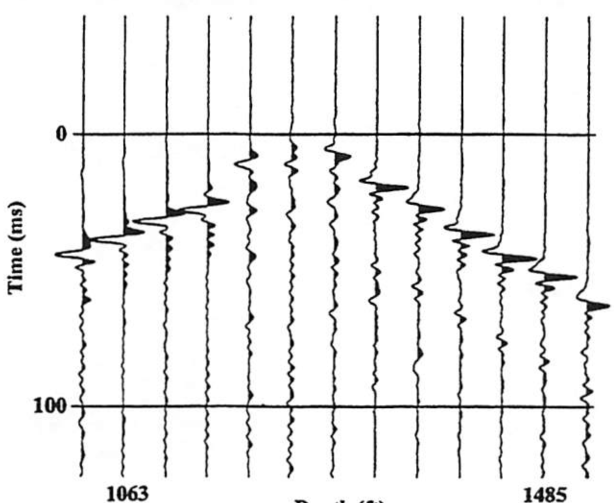

Fig. 11—Conical wave arrival at MO-2 recorded by the vertical component of the geophones (note shadow zone).

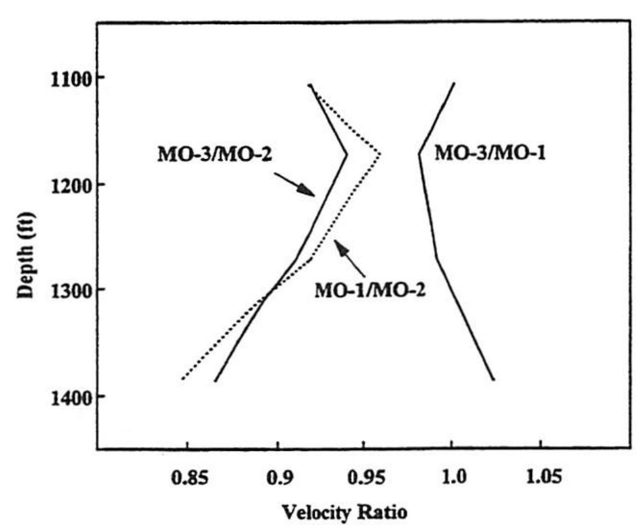

Fig. 12—Relative shear wave velocities.

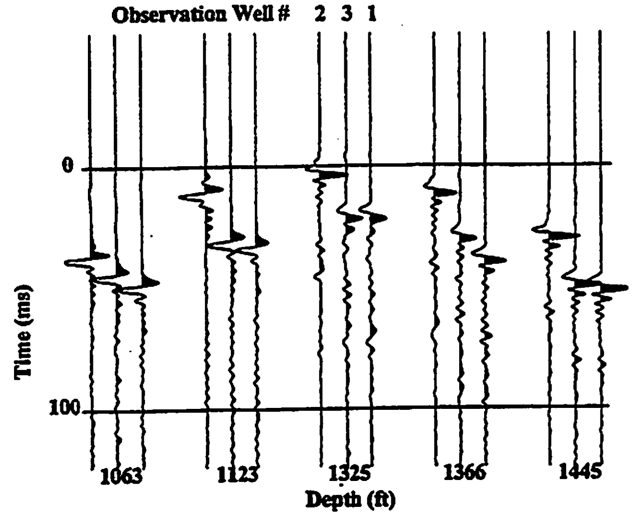

Fig. 13—Conical wave arrivals corrected for both depth and distance.

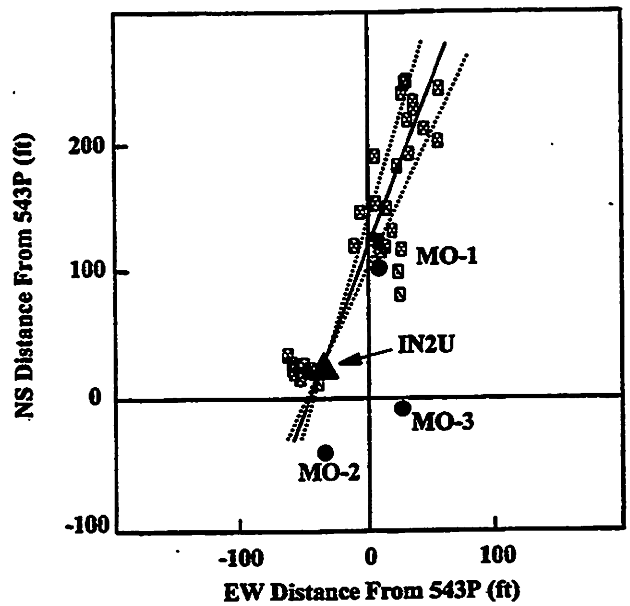

Fig. 14—IN2U microseismic event locations using relative velocities.

the depth of the air gun by an amount equal to $r\tan\theta$, where r is the radial distance from LO13, will record strong conical wave arrivals.

The zero frequency approximation of the tube wave velocity is[9]:

$$V_t(z) = \left\{\rho_f\left[\frac{1}{B_f} + \frac{1}{V_s^2(z)\cdot\rho_r + Eh/d}\right]\right\}^{-1/2}, \quad\text{.......... (3)}$$

where ρ_f is the well fluid density; B_f is the bulk modulus of the well fluid; $V_s(z)$ is the depth-dependent formation shear velocity; ρ_r is the bulk density of the formation; and E, h, and d are the Young's modulus, wall thickness, and inner diameter of the well casing, respectively. The tube wave velocity was computed to be about 4300 ft/s and is most sensitive to ρ_f. Because conical waves attenuate as the square root of the distance from the source well, they can be recorded over large distances away from the borehole.[5] Fig. 11 shows an example of a conical wave arrival in one of the observation wells. The three earliest arrivals are direct shear waves that are visible only because they are within the conical wave's shadow zone. Outside the shadow zone, strong conical wave arrivals can be seen which completely scale out the direct shear wave. The linear moveout at an apparent velocity equal to the tube wave velocity characterizes the conical wave. Contrast Fig. 11 with the shear wave arrival from a microseismic event in Fig. 3, which has hyperbolic moveout and a slower apparent velocity.

Use of Conical Waves to Estimate Relative Shear Velocities. The *relative* variation of shear velocity with azimuth was of greater interest than the velocity magnitudes themselves. Therefore, we specified a shear velocity in one direction as a reference. We chose the direction from LO13 to MO-2 as our reference direction. Five conical wave ray paths, each being emitted from LO13 at a different depth, were then determined in such a way as to intersect MO-2 at a specific geophone depth while intersecting MO-1 and MO-3 at depths where a geophone was positioned nearby (cf. Fig. 10). First, a reference shear velocity was taken from the interwell log and assigned to each ray path according to the ray path's depth. The emergent angles of the conical wave ray paths from LO13 were then calculated using Eqs. (2) and (3) above. We assumed straight ray paths for the conical waves. The three geophones for each ray path were grouped together for the analysis.

The modeled travel time of the conical wave to MO-2 was found by dividing the straight ray distance, r_2, from LO13 to MO-2 by the reference shear velocity, V_r. The origin time, t_o, of the air gun shot was then calculated by subtracting the modeled travel time from the picked arrival time, t_{a2}, at the geophone in MO-2:

$$t_o = t_{a2} - \frac{r_2}{V_r}. \quad\text{.................................. (4)}$$

The arrival times, $t_{a1,3}$, at the geophones in MO-1 and MO-3 were corrected for the difference in depth, $\Delta z_{1,3}$, between the intersection of the chosen conical wave ray path with these observation wells and the nearest geophone:

$$t_{c1,3} = t_{a1,3} \pm \frac{\Delta z_{1,3}}{V_t}, \quad\text{.............................. (5)}$$

where $t_{c1,3}$ is the corrected arrival time in MO-1 or MO-3, and V_t is the tube wave velocity. This correction assumed parallel ray paths for conical waves emanating at depths that were very close to the depths of the five chosen ray paths. Subtracting the origin time, t_o, from the corrected arrival times at MO-1 and MO-3 gave the travel times of the conical waves to those wells. The relative velocities, $V_{rel1,3}$, were then computed by dividing these travel times into the straight ray distances, $r_{1,3}$, to MO-1 and MO-3

$$V_{rel1,3} = \frac{r_{1,3}}{t_{c1,3} - t_o}. \quad\text{.............................. (6)}$$

Since the relative velocities were calculated with respect to the reference velocity in the MO-2 direction, we divided them by the reference velocity to get shear velocity ratios. Fig. 12 shows the shear velocity ratios as a function of the depth at which the five chosen ray paths emerged from LO13. Note that the velocity towards MO-2 is about 10% greater than that towards MO-1 and MO-3 (ratios of 0.9). Failing to account for such a difference in shear velocity when performing inversions can drastically alter the microseismic event locations.

Evidence confirming that the shear velocity does indeed vary with direction can be seen in Fig. 13, which shows the arrival of a conical wave at each of the fifteen geophones. The three receivers for each of the five ray paths have been grouped together, and the arrivals at the geophones in MO-1 and MO-3 have been corrected for depth using Eq. (5) and distance:

$$\Delta t_{1,3} = \frac{r_{1,3} - r_2}{V_r}, \quad\text{.............................. (7)}$$

where $t_{1,3}$ is the time correction for the extra radial distance to MO-1 and MO-3. In other words, Fig. 13 shows what the relative arrival of a conical wave would be at a specific geophone in each observation well if the three receivers were positioned at exactly the same depth, and the distances from LO13 to MO-1, MO-2, and MO-3 were equal. All five geophone groups are shown. If the shear velocity in the diatomite was the same in all directions, the three arrival

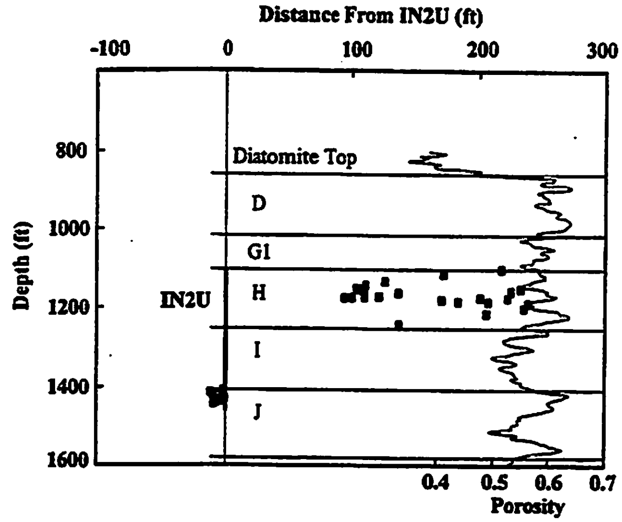

Fig. 15—Side view of IN2U fracture zone (N69°W).

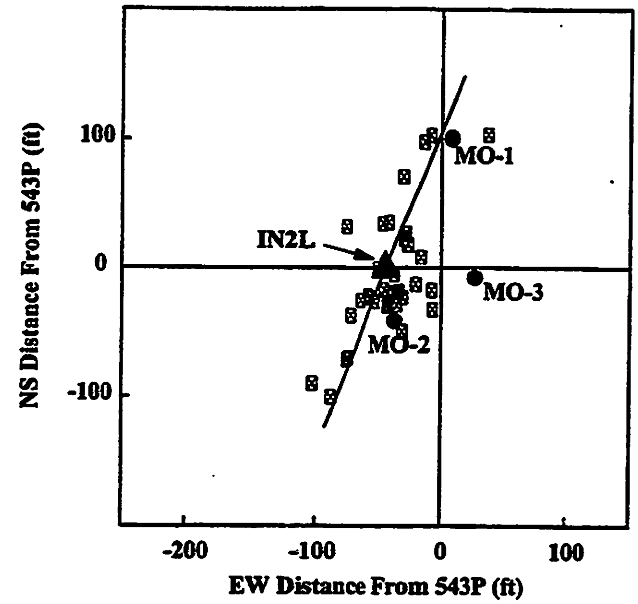

Fig. 16—IN2L microseismic event locations with relative velocities.

times within each group would be synchronous. However, Fig. 13 clearly shows that the arrival time is earlier for the MO-2 geophone in all five groups. Thus, the shear velocity is faster towards MO-2 than towards MO-1 and MO-3 for all five depths.

Improved Event Locations for IN2U

The extent of deformation of conical waves allowed us to estimate the *lateral* variability of shear velocity in the vicinity of IN2U. **Fig. 14** is a plan view of the new locations of the microseismic events, after inverting in Mode #1, with the aid of velocity multipliers. We were pleased to see that these locations have collapsed onto a well-defined fracture plane. This plane is almost vertical and strikes approximately N21°±4°E. The azimuth from a tiltmeter survey by Applied Geophysics, Inc. was N19.4°±4°E. Contrasting Fig. 14 with Fig. 9 reveals the magnitude of improvement in the event locations as a result of accounting for the azimuthal variation in shear velocity. Fig. 14 also confirms that the hydrofracture extended asymmetrically about IN2U. Its NE wing was about 230 ft long and its SW wing was no more than 30 ft long. Another intriguing aspect of the fracture, however, is shown in **Fig. 15**. This side view reveals that the asymmetrical wings occurred at two different depths. There are actually two different fractures—a long NE wing at a depth of about 1200 ft and a short SW wing at about 1400 ft. Both depths correspond to the highest permeabilities in the diatomite layers near IN2U. The lack of symmetry of the fracture wings in IN2U indicates significant reservoir heterogeneity or nonuniform pore pressure. This finding differs from those reported in the literature, e.g. Stewart *et al.*[10]

Event Locations for IN2L

The deep hydrofracture was induced in IN2L, the second steam injector. After picking the arrival times, we inverted for the microseismic event locations in Mode #1, using the relative velocity multipliers of 1.20 for MO-1 and 0.87 for MO-2. The azimuthal variation in shear wave velocity around IN2L could be large as a result of hydrofracturing in 543P over the same vertical interval and only 40 ft east (Fig. 1). As reported in [2], IN2L was next to the disturbed formation around the hydrofracture in 543P. There were no air gun shots during fracturing of IN2L, and the velocity multipliers used above were calculated from the conical wave events in IN2L itself. **Fig. 16** shows the results of the inversion in plan view. Again, we have a fairly well-defined fracture plane that strikes approximately N21°E for this particular set of multipliers (without the multipliers the fracture azimuth was an unacceptable N35°E).

Other conical wave events seem to indicate that the fracture azimuth is closer to N25°E—N30°E, and we continue to refine our analysis. The microseismic analysis of the hydrofracture in 543P yielded[2-3] an azimuth of N26° ± 6°E. This time the hydrofracture is symmetrical about IN2L and both wings are approximately 130 ft long. A side view of the hydrofracture in IN2L is shown in **Fig. 17**. We can see that both fracture wings are at a depth of about 1650 ft, suggesting that there is only one major fracture in IN2L. There is also a short, symmetrical fracture at about 1850 ft depth, extending no more than 10 ft in each direction.

Temperature Data

Fig. 18 shows the locations of the Phase I and Phase II steamdrive pilot injectors, producers and observation wells. Note that the Phase I hydrofractures have azimuths of about N15°E, in agreement with other field data. As the upper cycles of the diatomite have lower permeabilities than the bottom ones, the drawdown from producer 543H resulted in a steeper pressure gradient that attracted the new hydrofracture in IN2U. Similarly, the more significant,[1] but slowly occurring *lateral* extensions of the hydrofracture in IN2U are dominated by the attraction from a full-interval producer 543N, whereas those in IN2L by producer 543P, completed only in the lower zone. In short, both injection hydrofractures are dynamic systems that evolve with time, depending on the local stress field that in turn is influenced by the pore pressure. The early behavior of these hydrofractures, however, is closely related to their original shape and extent and can be verified by the initial temperature surveys in the observation wells.

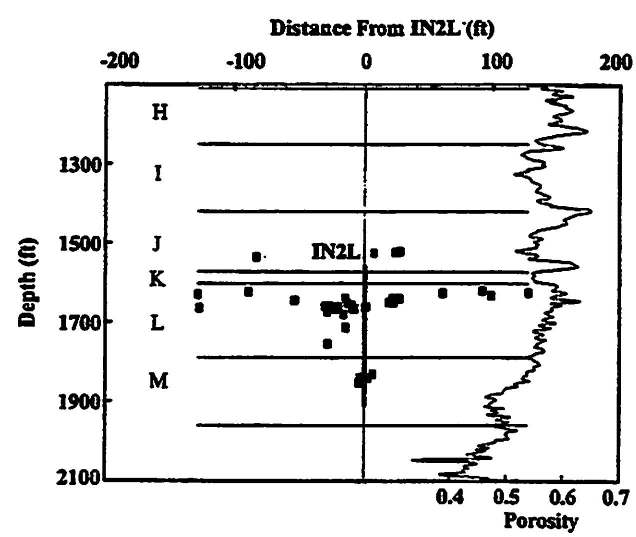

Fig. 17—Side view of IN2L fracture zone (N69°W).

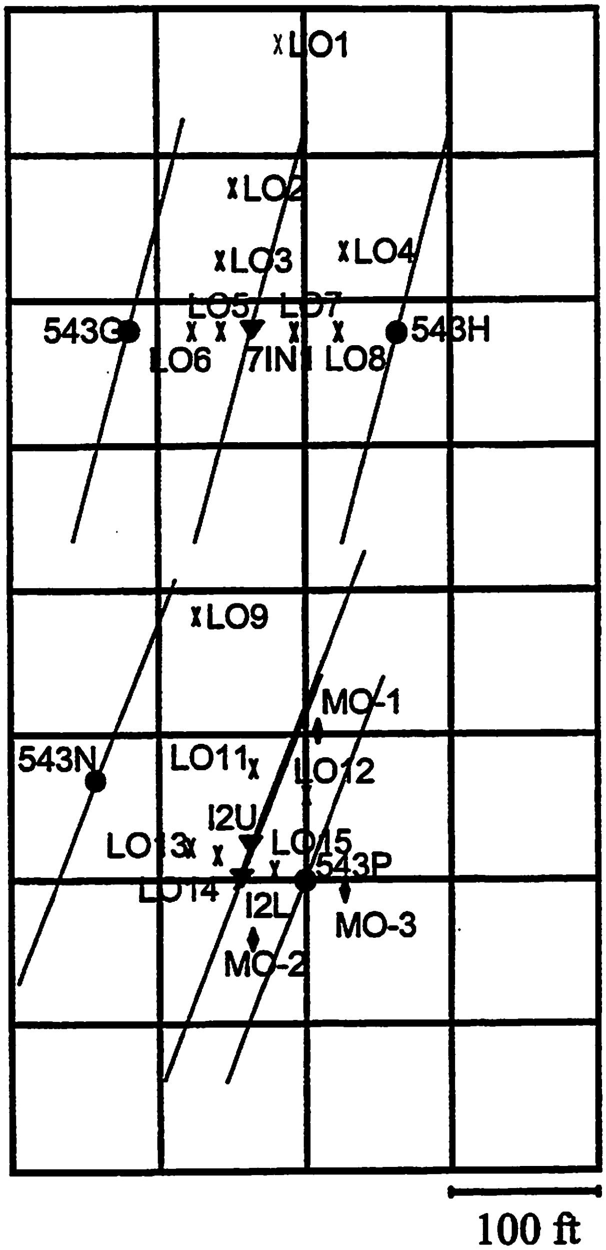

Fig. 18—Plan view of the Phase I and Phase II steam drive pilots.

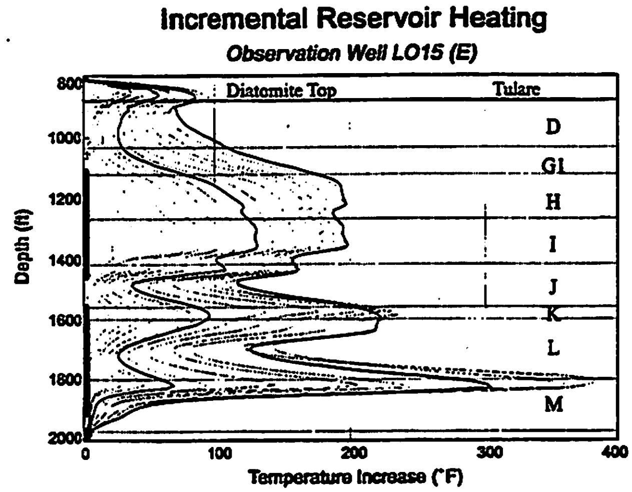

Fig. 19—Square-root-of-time interpolation of temperature surveys in observation well LO15.

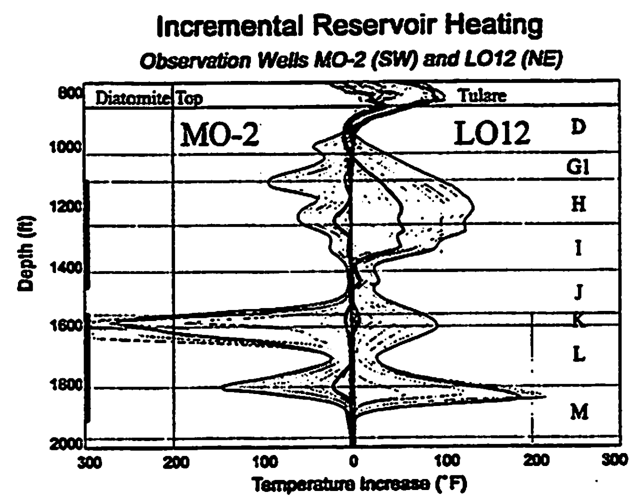

Fig. 20—Square-root-of-time interpolation of temperature surveys in wells MO-2 and LO12.

It is well known that in linear, transient and nonisothermal flow of steam, the reservoir pressure and temperature are governed by a nonlinear pressure diffusion equation coupled with a linear heat conduction equation, and vary approximately as the square root of time.[11,12] Therefore, if there is no deviation from linear flow of mass and heat, the temperature profiles in an observation well should be spaced uniformly when interpolated in equal increments of the square root of time elapsed on steam injection.

Observation well LO15 is located 23 ft east from both injectors. Fig. 19 shows a square-root-of-time interpolation of temperature surveys in this well between 200 and 1400 days of steam injection. The two thick surveys are at 770 and 1400 days. Well LO15 is dominated by the pulverized formation close to the injectors—not the hydrofracture planes far from the injectors—and has responded to steam injection into both upper hydrofractures at 1200 and 1400 ft and both lower hydrofractures at 1650 and 1850 ft.

Geophone/observation well MO-2 is located 63 ft SE from IN2U and 44 ft SE from IN2L. Observation well LO12 is located 53 ft NE from IN2U and 71 ft NE from IN2L. Both observation wells are about 20 ft east of the injector hydrofracture planes. Therefore, one would expect these wells to respond similarly to steam injection. If both wings of the hydrofractures were symmetrical, the response of well MO-2 to IN2U would be slightly *retarded* relative to LO12. Conversely, the response of MO-2 to IN2L would be *accelerated* relative to LO12. However, the *magnitude* of both responses should be similar. The temperature increases in MO-2 and LO12 are shown in Fig. 20. Note that after 770 days of steam injection (the first thick survey), well MO-2 had shown almost no heating across the upper injection interval, whereas LO12 heated uniformly up to 60°F. Even after 1400 days of steam injection and several fracture extensions, the reservoir heating at MO-2 lagged significantly that at LO12. Also note that there is no heating in both wells at 1400 ft, suggesting that the lower hydrofracture in IN2U never increased its length. This is the most direct proof of our conclusions from the microseismic imaging of the hydrofracture in IN2U. Interestingly, almost no response to IN2L was seen at both wells for the first 770 days of steam injection. Thereafter, the heating accelerated more in MO-2 at 1650 ft, but more in LO12 at 1850 ft. This suggests that (1) new flow channels, perpendicular to the hydrofracture plane, opened and (2) the deepest hydrofracture increased its length many-fold. Both heated depths correspond to the microseismic activity.

Conclusions

Two hydrofractures in the South Belridge Diatomite were imaged passively using the seismic energy released during fracture propagation:

1. The azimuth of both hydrofractures was about N21° ± 4°E.

2. In each treatment well, there were initially two separate hydrofractures at two different depths that corresponded to the diatomite layers with highest permeabilities.

3. The IN2U hydrofractures were asymmetrical. Initially, the upper NE wing at 1200 ft was 230 ft long, whereas the lower SW wing at 1400 ft was only 30 ft long. The lower wing never grew significantly.

4. Asymmetry of a new hydrofracture is likely to be caused by the areal nonuniformity of pore pressure around this hydrofracture.

5. The IN2L hydrofractures were symmetrical and their wings were initially 130 ft long at 1650 ft and 10 ft long at 1850 ft. The lower wings increased their length many-fold during steam injection.

6. The above conclusions agree with temperature surveys in the surrounding observation wells.

7. Our sensitivity analysis indicates that the lateral uncertainty in the microseismic event locations is usually ± 20 ft while the vertical one is ± 2-5 ft.

8. The microseismic data are scattered around the most likely fracture planes within ± 20-25 ft. This means that the existence of the disturbed "process zones" around the hydrofractures is neither supported nor rejected by the data.

The hydrofracture in IN2U was very different than that in IN2L. Therefore, the diatomite properties can change dramatically with depth and time, and this has implications for the implementation of steamdrive on a $^5/_8$ acre spacing.

Acknowledgments

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SI Metric Conversion Factors

bbl $\times$ 1.590	E−01	= m
cycles/sec $\times$ 1.0*	E+00	= Hz
ft $\times$ 3.048	E−01	= m
°F (°F−32)/1.8		= °C
in.^{3} $\times$ 1.638 706	E+01	= cm^3
lbm $\times$ 4.536	E−01	= kg
md $\times$ 9.869 233	E−04	= μm^2

*Conversion factor is exact.

SPEFE

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Neural Networks for Field-Wise Waterflood Management in Low Permeability, Fractured Oil Reservoirs

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Abstract

An optimal water injection policy maximizes oil recovery per barrel of injected water while minimizing formation damage and maintaining reservoir pressure. Optimal water injection into low permeability, fractured oil reservoirs is problematic because of highly nonlinear and complex reservoir dynamics. Likewise, current first principle models of fluid movement in fractured, low permeability rock systems are insufficient to design, operate, and predict the performance of large scale waterfloods. Historically, the conflict between prudent reservoir management and meeting field injection-production targets has resulted in reservoir and well damage, injectant recirculation and irreversibly lost oil production.

Here we present the next generation of "intelligent" field surveillance and prediction software based on neural networks and implemented on a PC. We demonstrate a new approach to field-wise performance prediction and optimization of waterfloods that recognizes an oil field as a coupled, highly nonlinear system of injectors and producers. With lease-wide historical data from a waterflood in the Lost Hills Diatomite (Kern County, CA), we construct several neural networks which recognize that individual well behavior may depend on well history and the injection-production conditions of surrounding wells. Some of our neural networks accurately predict wellhead pressure as a function of injection rate, and *vice versa*, for all injectors. Other networks history-match oil and water production on the well-by-well basis, and predict future production on a quarterly or half-year basis. Finally, our neural networks recognize and suggest water injection policies that lead to the minimum injected water and the best oil recovery.

Introduction

This paper outlines a new, field-wise approach to managing large fluid injection projects in tight hydraulically fractured reservoirs. We use neural networks to analyze the past performance of waterflood projects and to predict future oil recovery, and water injection and production. Neural networks are useful in that a structural model between injection and production need not be specified in order to predict performance. The neural network approach recognizes that individual well behavior may depend on the well history and the injection/production conditions of surrounding wells. Also, lease-wide production is the result of injection and production at many wells and their interactions. Our approach discerns injection policies that lead to the minimum injected water and the best oil recovery.

We focus on water injection in tight reservoirs because significant quantities of crude oil remain in them, and state-of-the-art understanding of fluid movement in low permeability rock systems is not sufficient for design and operation of large fluid injection projects. Water injection is also important for mitigating reservoir compaction and surface subsidence. In tight rocks, project operation is problematic because reservoir dynamics are highly nonlinear and complex.

An optimal injection policy (i.e., the schedule of injection rates chosen to produce a field) for tight fields minimizes formation damage while maximizing oil production per unit volume of injectant. Fluid injection into low permeability reservoirs (diatomites, chalks or carbonates), either for pressure maintenance or secondary oil recovery is very difficult. On one hand, injection rates must be low enough to prevent reservoir damage from overpressuring and inducing unwanted fractures. On the other hand, these rates must be high enough to make the costly fluid injection process economic. This conflict between prudent reservoir management and meeting injection targets has resulted in significant reservoir and well damage, injectant recirculation and irreversibly lost oil production. Currently, engineers develop injection policy on the basis of past experience, partial knowledge of the state of reservoir stress, production history, and limited predictions of future reservoir performance from numerical simulation. Injectors are usually controlled individually, with constant set points, and without feedback among neighboring patterns.

The field-wise approach for fluid injection management is applied here to a diatomaceous oil field in California, but it is general and may applied to other deeper, tight reservoirs. The California Diatomites are shallow, densely populated with wells, and undergoing massive water injection, thereby allowing an unprecedented glimpse into the inner workings of tight rocks during fluid injection. However, problems faced in the Diatomites are common to other tight fields. These problems are (a) imbalance of fluid injection and withdrawal, (b) excessive fracturing of the rock by the injected fluids, (c) inability to control fluid injection in an optimal fashion to maximize cumulative injection, while minimizing reservoir damage, (d) lack of injection profile control, (e) thief zones, and (f) difficulties in calculating the incremental oil production.

Neural Networks

During the last decade, the application of neural networks for identification of nonlinear, time varying, and nonstationary systems has increased exponentially [1-8]. Recently, artificial neural networks have been used to model reservoir behavior under steam and water injection[9] model oil and water imbibition processes [10], well test analysis [4, 11, 12], and model reservoir properties [13]. This widespread application resulted from several attractive features of neural networks. Unlike regression, neural networks do not require specification of a structural relationship between input and output, have the ability to approximate arbitrary nonlinear functions to any degree of accuracy [14, 15], can be trained easily using past data records from the system under study [9], have the ability to learn, have the capability of performing massive parallel processing, have significant fault tolerance, and are readily applicable to multivariable systems.

In addition to the above attractive feature, new interest was fueled, in part, by powerful new neural network models such as B-spline Networks, Radial Basis Function Networks, Elman Network, and new learning methods such as Back-Propagation [16, 17] and Associative Learning Rules. The interest in neural networks is also due to advances in computer technology which have made it possible to bring together both a very large number of nodes and massive interconnection of simple neurons, much like the human brain.

Multi-layer perceptron networks with a backpropagation learning algorithm are perhaps the most widely used neural networks for process identification. There are typically two layers with connections to the outside world. These are the input layer, where data are presented to the network and the output layer, which holds the response of the network to a given input. Layers distinct from the input and output layers are called hidden layers. Typically, one hidden layer is used, although there are no restrictions on the number of hidden layers. The modeling capabilities of these networks have been demonstrated in numerous publications and successful industrial applications.

In an artificial neural network, the simple nonlinear elements called nodes, neurons, or processing elements, are interconnected and the strength of interconnections is denoted by parameters called weights. The values of the weights represent the current state of knowledge of the network. These weights are adjusted to improve performance, depending on the task at hand. They are either determined via some prescribed off-line algorithm and thus remain fixed during operation, or adjusted on-line via a learning process [5, 18]. The node weights provide the memory which is necessary in a learning process. Learning may require providing many examples to the network many thousands of times.

Another phase in the operation of a network is recalling. Recalling refers to the way the neural network processes a stimulus presented at its input layer and creates a response at the output layer. Often, recall is an integral part of the learning process.

An additional important characteristic of a neural network is its generalization properties. The nature of neural network memory leads to reasonable network response when presented with incomplete, noisy, or previously unseen input. This is generalization. The quality and meaningfulness of generalization depends on the particular application and the type and sophistication of the network.

Finally, whereas traditional computing systems suffer from even a small amount of damage to memory, neural systems are *fault-tolerant*. For example, if some processing elements are destroyed or impaired the behavior of the network as a whole is only slightly degraded because other neural pathways through the network remain. Performance suffers, but the system does not come to an abrupt halt. Neural network systems are fault tolerant because information is not stored in one place, but is distributed throughout the system.

Neural Networks and Pattern Recognition. In the 1960s and 1970s, pattern recognition techniques were only used by statisticians and were based on statistical theories. Due to recent advances in computer systems and technology, artificial neural networks have been used in many pattern recognition applications from simple character recognition, interpolation, and extrapolation between specific patterns to the most sophisticated robotic applications. To recognize a pattern, one can use the standard multi-layer perceptron with a back-propagation learning algorithm or simpler models such as self-organizing networks [19]. Self-organizing networks can easily learn to recognize the topology, patterns, and distribution in a specific set of information. A detailed account of self-organizing networks and pattern recognition techniques is beyond the scope of this paper, but we will use a self-organizing network to divide the waterflooded field into smaller regions.

Our neural networks are implemented on a PC using MATLAB, a technical computing environment combining computation, numerical analysis, and graphics [20].

Lost Hills Waterflood Project

We examine specifically a waterflood project in Section 2 of the Lost Hills Diatomite (Kern County, California) denoted "Lost Hills I" and operated by Mobil E&P U.S. Across all leases, the Lost Hills Diatomite contains an estimated 34 million bbl of light oil recoverable by primary methods [21], but the OOIP is roughly 2 billion barrels [22] and the target for incremental recovery is huge. In Lost Hills I, the oil-bearing diatomite lies between depths of 1600 and 2650 ft. It is overlain by the Tulare sands and underlain by the Reef Ridge and Antelope shales. Porosities range from 40 to 75%, while the average field permeability is around 1 mD. The reservoir is highly layered and interbedded with oil-bearing, siliceous diatomite composed of a very fine-grained mixture of biogenic silica interlayered between shaley and silty diatomites. Diatomite properties also vary diagenetically with depth. Opal A is found in the upper diatomite interval and transitions to Opal CT as depth and pressure increase. Opal CT is more dense, less porous, and stronger than Opal A. Both rocks types are productive. This layered, interbedded, diatomite/shale geology is a general characteristic of the Diatomites [23, 24].

Extensive development of Lost Hills I began in the late 1970's with the use of hydraulic fracturing to improve injector and producer efficiency and a second phase of hydraulic fracturing followed in 1982 [25]. The presence of gas-rich oil and free gas results in high gas production rates and acceleration of reservoir voidage and compaction. To combat compaction and subsequent subsidence and to maintain reservoir pressure, water injection at Lost Hills I began in 1991. To date, there are roughly 120 producers and 50 injectors in operation. Wells are perforated over a total interval of 600 ft, completed in 3 or 4 stages, and hydraulically fractured. Figure 1 gives a plan view of the injector and producer locations at Lost Hills I. The dark circles are producer locations, while the open circles are injectors. Well configurations yield an incomplete staggered line drive aligned with the induced fracture direction, and on 1 1/4 acre spacing. All wells are hydraulically fractured with a field-wide fracture azimuth averaging N 50° E [25]. The fractures are quite large with an average tip to tip length of about 700 ft.

Diatomite properties contribute to some additional operational problems. For instance, diatomite has relatively low Young's Modulus (50,000 - 200,000 psi) which causes induced fractures to be much more elongated than those in stiffer rocks [25]. Low permeability contributes to high wellhead pressures and low injection rates. If overpressurized, hydrofracture extension and linkage occurs [26]. Likewise, relatively low formation permeability and large formation thickness make it hard to establish uniform displacement fronts in all diatomite layers.

Oil Production. Production responses of individual wells vary widely. Figure 2 catalogs the most likely types of producer behavior during diatomite waterfloods. First, Fig. 2a demonstrates no oil or water production response. The well continues to behave as if it were in an infinite medium. Second, a well may show no waterflood response, but well productivity decreases due to interference with other producers as shown in Fig. 2b. Third, as Fig. 2c demonstrates a water production response may be measured with no oil production response. Fourth, a well may show increased oil production, but no increase in water production as in Fig. 2d. Fifth, Fig. 2e shows a well with both increased oil and water production. Lastly, water production might increase and oil production might show a short-term response and then begin to plateau as in Fig. 2f. Table 1 summarizes the current totals for each type of behavior at Lost Hills I. Each type of response is assigned the letter illustrating its typical response on Fig. 2. Chiefly, waterflood response is either a simultaneous water and oil production response or a water production response with no corresponding oil production response. Together types (c) and (e) account for 104 of the 123 producers cataloged.

Cataloging of producer types was aided by a neural network. The network scans the response of each producer and indicates the most likely type of behavior illustrated in Fig. 2. Table 1 shows how this network helps to define more precisely the pattern in a producer response. Columns 2 and 3 give the results from assignment of producer types manually. We term this process KEE for knowledge of an expert engineer. Instead of repeating the laborious manual process to check assignments, the neural network (NN) was used to predict the patterns according to the types of behavior defined in Fig. 2. Manual and network assignments (KEENN) were compared and when the two differed (Column 3 of Table 1), those individual wells were rechecked manually. Columns 4 and 5 of Table 1 show the result of final refinement. All together 17% of the well types were changed resulting from the network verification of producer behavior. Thus, our understanding of reservoir behavior improved 17%.

Additionally, the network was adapted based on the refined producer cataloging. The producer responses were divided into 3 parts. The first third of the 123 producer responses was used for network training. The second third was used for testing and the rest of the data were used for validation. Table 2 shows the overall performance of the network. It predicts that 64.2 percent of the producers have type (e) behavior, 25.2 have type (c) and 10.6% are the remaining types. This compares favorably with the manual assignment of producer types. Finally, Fig. 2g shows the distribution of producer types after 5 years of waterflood. Note that the producer behavior tends to be extreme as it follows the edges of the plot.

Over the last five years, oil production per well in the Lost Hills I waterflood project has averaged 18.7 BO/day and water production 32.3 BW/day as shown in Fig. 3. The average produced water-oil ratio (WOR) is thus 1.7. The productivity of the wells varies substantially with a maximum oil rate near 65 bbl/day and a minimum at roughly 2 bbl/day. Figure 3 also gives graphically the distribution of WOR's by well for the project. The dark diagonal lines mark water cuts of 1, 2, and 4, respectively. Roughly 43% of the producers make oil at a WOR of 1 or less and 66% make oil at a WOR of 2 or less.

To gauge production response to water injection, Fig. 4 plots the fraction of wells showing oil and water production response versus the square root of time on production. A production response is inferred when cumulative production in a well deviates from that expected for transient flow in an infinite medium or transient flow with interference, i.e., responses shown in Figs. 2c to 2f. Therefore, we consistently plot time as a square root because cumulative production versus the square root of time for a well in an infinite medium is a straight line if formation and fluid properties do not evolve. Figure 4 teaches that the number of wells showing a water production response consistently outpaces the number of wells showing oil production response. After 1600 days (40 days$^{1/2}$), each curve plateaus. All production wells show a waterflood response since the fraction of wells showing water breakthrough is 1. 72% of the wells show increased oil production as a result of water injection. Often this positive oil response diminishes with time and becomes negative. The limited pump capacity of wells, which produce significantly more water after breakthrough, may contribute to this behavior. The average time on production for the onset of a waterflood response is 900 days (30 days$^{1/2}$) as both oil and water production response curves on Fig. 4 are at one-half of their maximum at this time.

Water Injection. Water injection per well has averaged 198 bbl/day. Therefore, the average ratio of injected fluid to produced fluid, per well, is 4.9. This ratio is not unity in order to make up for the voidage caused by primary production and because producers outnumber injectors by a ratio of 2.4 to 1. Figure 5 plots the mean injection pressure at the top of the perforations versus the mean water injection rate for each injector. Although the data are scattered, it is clear that the average injection pressure is slightly more than 300 psi.

Because wells differ in the depths and the lengths over which they are perforated, it is necessary to rescale the injection pressure and rate for each well in order to make meaningful comparisons and to characterize injection well behavior. The dimensional grouping of variables chosen to represent specific injection pressure is the injection pressure at the top of the perforations divided by the depth to the top of the perforations, and the specific injection rate is the water rate divided by the total height of the perforated intervals. The data in Fig. 5 are rescaled accordingly and presented in Fig. 6. This operation significantly reduces the scatter in the injection data, and suggests that many of the wells behave similarly. Rescaling will later prove to be a powerful means of classifying well behavior and subdividing the waterflood project into groups of wells with analogous behavior.

Field-Wise Waterflood Management

Optimally, waterfloods should be managed to produce oil as quickly and efficiently as possible without damaging the reservoir excessively. Limiting damage in the Diatomite is synonymous with minimizing tip extensions of hydrofractures and induction of new fractures that may, or may not, link injectors and producers. However, translating this field-wise goal into an operating procedure for each well is a difficult task, especially since tight oil reservoir dynamics are complex, nonlinear, and difficult to predict. Before quantitatively describing field-wise management with neural networks and applying it to Lost Hills I, we describe the process graphically.

Figure 7 presents a schematic diagram outlining our proposed approach to integrating the predicted behavior of individual wells into an overall waterflood management scheme. Field-wise management lies at the top of the schematic because our overall objectives concern the field as a whole, and not individual wells. Waterflood management might entail setting monthly, quarterly, and yearly production goals. As we move down the schematic, information becomes finer grained. The horizontal line between cumulative injection and production signifies that these two types of information are related even though we may not know how to specify the relationship mathematically.

Immediately below the field-wide cumulative rates lie cumulative injection and production rates in smaller regions of the field. These regions might be organized simply as individual patterns or collections of patterns that behave similarly. Ideally, the process of subdivision should be automated and the criteria for deciding which wells behave in a similar manner should be based upon properly scaled injection and production rates. Other information such as hydrofracture size and azimuth, the geology around the well, time on production, and location of the well with respect to lease boundaries can also be included. Figure 8 displays, schematically, how a field might be subdivided into regions of similarly behaving wells. Region boundaries do not have to be straight, nor do regions have to cover identical surface areas. Of course, once the cumulative water injection in each region is known, the field-wide injection is known. But, Fig. 7 also teaches that the cumulative water injection sets the production for each region of the field even though we might not know the structural relationship. At this level, it can be verified that the production goal set in reservoir management leads to reasonable quantities of injected water.

The behavior of a region is the sum total of the behaviors of the wells within it. Since regions were delineated by groups of wells with similar characteristics and we have neural networks that can predict well by well behavior [9], we can predict the injection per region leading to the best oil recovery. The next lower level is the injection and production rates per well which are set by optimizing region production. At the lowest level, the field engineer now has a suggestion as to how to operate the field in an optimal manner.

Prediction of Daily Oil Production. One of the most important questions asked in managing a waterflood is "How much oil will be produced if the current injection-production policy is continued in the future?" To answer this question, a neural network model is used to estimate the field-wide production, given field-wide injection.

Mobil's Lost Hills I waterflood in Fig. 2 includes 123 producers and 48 injectors. The data set also includes 5 years of historical injection and production rate data collected at 1 to 10-day intervals. Neural network design for predicting the behavior of the field starts with filtering, smoothing, and interpolating values for missing information in the historical data set. A first order digital and a simple linear recursive parameter estimator [27, 28] for interpolating is all that is needed to filter, smooth, and reconstruct the noisy field data.

To model the total daily production in the field, our network uses 10 input nodes representing the current measurement and the 9 most recently measured values of field-wide production rate at 10 day intervals. All rates are scaled according to the following equation

$$Scaled\ Value = \frac{Actual\ Value\ -\ Mean}{Maximum\ -\ Minimum} \qquad (1)$$

and then the scaled value is normalized so that it lies between 0.1 and 0.9. The hidden layer contains 10 nodes with a nonlinear transfer function. The output layer contains 3 nodes representing the prediction of the total daily production rate at 3 subsequent 10-day intervals. For predicting outputs more than 1 month into the future, iteration through the neural network is required. For quarterly prediction of production, the networks were iterated and the daily production rate 3 months into the future was predicted.

The data were divided into training and test data sets. The network was then trained using the test data set, the backpropagation learning algorithm, and an adaptive learning rate coefficient . The network was trained until the prediction suffered upon continued training. Figure 9 shows the performance of the network for the training data set and illustrates that the network accurately predicts the total daily production, using all production wells, 90 days into the future. The dark line represents the smoothed field data and the lighter, dashed line the network prediction. Figure 9 gives the cumulative water injection. We find in Fig. 9 that the network prediction is accurate, and the total daily production averages 2330 BO/day. Note that the network weights are not adjusted while predicting cumulative production or injection for the test data set.

Subdividing the Field into Regions. The information provided in Figs. 5 and 6 detailing injection rate as a function of pressure at the top of the perforations was used to divide the 18 injectors into collections of similarly behaving wells. This task was accomplished with a self-organizing neural network, described below. For brevity though, the creation of only two such regions is discussed in detail.

The network for grouping wells and well behavior into regions is a two dimensional, self-organizing network with two input nodes which represent the scaled mean water injection rate per well and scaled mean injection pressure per well, respectively. In conjunction, 25 neurons are used to classify patterns existing in the injection data. The two-dimensional map is five neurons by five neurons with distances calculated according to the Manhattan distance neighborhood function [20]. In this case study, it is assumed that no other knowledge exists to divide the field into regions. Although this methodology has limitations, the usefulness of the technique is for fast screening and study of different injection policies with reasonable accuracy. Later, the shapes of the hydrofractures will be added as another factor for dividing the field into smaller regions.

Figure 10 presents scaled injection pressure at the top of the perforations versus scaled water injection rate and shows partial results from the neural network subdivision of the field. The filled circles in Fig. 10 are the scaled injection rates and the remaining symbols define the neural network differentiated regions of injection behavior. For example, it is predicted that injectors A1, A2, and A3 display similar behavior. In addition, it is predicted that injectors B1 and B2 will show the similar behavior. All wells have high specific injection pressures, but the scaled water injection differs substantially between these two sets of wells. Fig. 1 shows the location of these injectors, and, as expected, they are in different parts of the field.

To demonstrate that the network accurately recognizes patterns existing in the injection data, and also to show that the field is correctly divided into smaller regions, the behavior of the injectors A1, A2, A3, B1 and B2 is shown in Figures 11-15. Comparing Figs. 11, 12, and 13, one can see that the general behavior of first three injectors is very much the same: the average injection rate is around 780 bbl/day, the average injection pressure at the top of the well perforations is around 450 psi, and all three wells have nearly the same injectivity. Likewise, comparing Figs. 14 and 15, one can conclude that the last two injectors behave similarly, but their behavior is much different from that exhibited by A1 to A3. In the latter case, injection pressure exceeds the injection rate and the injection rate is quite low. Although the injection pressure at the top of the well perforations is around 500 psi for both wells, the injection rate is roughly 150 bbl/day on average. Hence, the injectivity in the first set of wells is much greater than the second set. Figure 10 illustrates that we found 21 such regions in Lost Hills I with the self-organizing network.

Total Injection/Production for a Region. At the second level below reservoir management (Fig. 7), two neural network models are developed to predict the relationship between the total water injection and the *total oil, water and gas* production for a specific region. Here though, we will only predict oil production. This prediction, however, demonstrates the typical behavior found also for water and gas production.

The first neural network model developed predicts the total injection based on known total oil production for a specific region. The second neural network model is developed to perform the so-called "inverse problem" where the total oil production is predicted from known or expected total injection in a specific region. The data presented here are based on the current policy followed by Mobil, but we could begin to screen injection policy scenarios by setting the desired production and then compute required water injection, and *vice versa*.

The first neural network model for estimating water injection has 3 nodes in the input layer representing the current and two past total oil production rates (scaled) at one-day intervals. It has 1 node in the hidden layer with nonlinear transfer function (sigmoid function), and one node in the output layer predicting the current total water injection rate (scaled), with a nonlinear transfer function. Five years of historical data were used for training the neural network. The data were divided into 120-day intervals. The network was trained based on the first 60 days. The next 60 days were used for testing the network performance. The model was updated every 60 days to predict the next 60 days over the entire five-year history. Figure 16 shows the performance of the neural network model for a training and test data set. The network predicts well the total injection based on total production in this region, for the training and test data set in Fig. 16, and for the entire five years of data.

The inverse problem of the network just discussed is to predict the oil production from the total injection. There are two methods for solving the inverse problem: direct and indirect. In the direct method, the inverse of the first network model is used to solve the problem. For simple problems and with a simple network structure, it is possible to calculate the exact inverse of the neural network [29]. For complex neural network models, an optimization routine is needed to solve the inverse problem [29]. In the second approach, a separate neural network model is developed to solve the inverse problem. However, in this case the two network models constrain each other. The output from one network is considered as input into the second network and the two networks in series are considered as a unit transfer function. In this case study, the two approaches were not compared. However, we recommend the direct method for simple and well behaved oil fields and the indirect method for more complex problems.

The neural network to solve the inverse problem was developed independently of the first network following the indirect method. Thus, each of these models can be used as solution to the other inverse problem. The developed neural network model has 3 nodes in the input layer representing the current and two past values of total injection (scaled) at one day intervals, and one node in the hidden layer with a nonlinear transfer function with a sigmoid shape. The single node in the output layer represents the current scaled, total oil production, with a nonlinear transfer function. Five years of historical data were used for training the network. A moving window of 120 days was used for training and testing the network. Hence, the first 60 days were used to train the network and the next 60 days was used for testing the network performance.

Without updating the network, the model has the ability to capture the pattern existing in the oil production behavior for a given region. However, in some cases, a constant offset between model prediction and actual data is found. Figure 17 shows the performance of the neural network model for training and test data set before the network has been updated. Referring to Fig. 17, one can see that the network has a good performance for prediction of the total oil production based on total water injection in this region for both the training and test data set. The offset, if present, is removed by adding the error from the previous time step to the future prediction. This is, in effect, a linear corrector.

Once the total injection and production is predicted for a specific region, the next task is to predict the total injection and production in each injector and producer. In the following section the procedure for doing so is discussed.

Injection in an Individual Well. Another network was created to predict the specific injection per well for each injection well in a given region. The network has 3 nodes in the input layer representing the current and two past total water injection rates at one day intervals. The network has one node in the hidden layer and three nodes in the output layer with a nonlinear, sigmoid, transfer function predicting the current total injection in each well. For example, consider the region containing the injectors C1, C2, and C3 as shown in Fig. 1. The available data were divided into 130 day intervals and the network was trained based on the first 80 days. The model was trained until the prediction suffered upon continued learning. The next 50 days, in each 130 day interval, were used for testing the network performance. To adapt the network to changes in the field, the model was updated on-line every 80 days. The performance of the neural network model for training and test data set is shown in Figure 18. The network shows good performance for prediction of the total water injection in each specific well based on total water injection in this region for both training and test data set.

Production in an Individual Well. The specific region in this case study, includes five producers. The goal is to predict the total production in each well based on the total production in the region. The developed neural network model has 3 nodes in the input layer including the current and two past scaled total oil production at one day intervals. The network has 3 nodes in the hidden layer and 5 nodes in the output layer with a nonlinear transfer function. The network predicts the current total production in each well. Five years of historical data have been used for training the neural network. The data were divided into 100 day intervals. The network was trained based on a moving window of 70 days and the next 30 days were used for testing the network performance. To capture the changes in the injection policy in the region, the model was updated every 70 days. The neural network prediction for total production in each well is in good agreement with the actual data. The typical performance of the neural network model over a 100 day interval is shown in Figure 19. The performance of the network for the rest of the five years and for the rest of the producers was the same.

Once the total injection and production is predicted in a specific injector and producer, the next task is to predict the daily injection and production rate in other injectors and producers. In the following section, we will discuss this procedure. It is important to mention that the neural network models described above emulate the differential operator in conjunction with a nonlinear filter. In other words, a differential operator in conjunction with a nonlinear filter can be used for the next case study instead of using the neural network model. However, the following section will show the usefulness of the neural network models in this application.

Total Injection Related to Daily Injection. In this study, the developed neural network model has 3 nodes in the input layer representing the current and two past total water injection rates (scaled at one-day intervals) and 3 nodes in the hidden layer with a nonlinear, sigmoid transfer function. The model has one node in the output layer with a nonlinear transfer function predicting the current daily water injection rate (scaled). Five years of historical data, divided into 140 day intervals, have been used for training and testing the neural network. The network was trained based on a moving window of 80 days and the next moving window of 60 days was used for testing the network performance. To capture the changes in the behavior of the injector, the model was updated every 80 days. In this study, the network was not trained to exactly emulate the differential operator, but it was trained to approximate the differential operator in conjunction with a nonlinear filter to smooth the actual data. If the network is trained to perfectly emulate the differential operator, which is very common in recent applications, updating of network is not necessary. However, in this case, the network is sensitive to any noise in the data. Figures 20 and 21 show the performance of the neural network model for the training and test data sets. As it is shown, the network has perfect performance for prediction of the daily injection rate in a specific injector based on total water injection in this injector for the training and good performance for test data set.

Once the daily injection rate is predicted in a specific injector, previously developed methodology by Nikravesh et al. [9] can be used to predict the wellhead pressure as a function of injection rate. In addition, it has been shown that neural network models can be used for screening various injection policy and strategies and they are able to accurately predict extensions of injection hydrofracture and provide us with a means of preventing unwanted fracturing [9]. Therefore, they accurately recognize injection policies that lead to the minimum injected water and the best oil recovery.

Total Production Related to Daily Production. Here a neural network model was developed to predict the daily production rate in a specific producer based on its total production rate. The network has 3 nodes in the input layer representing the current and two past total, scaled oil production rates at one day intervals, 3 nodes in the hidden layer with a nonlinear sigmoid transfer function, and one node in the output layer representing the current, scaled daily production with a nonlinear transfer function. The available data were divided into a moving window in 100-day intervals. The network was trained based on a moving widow of 70 days and the next 30 days in the moving window were used to test the network performance. Figures 22 and 23 show the performance of the neural network model for the training and test data set. The network prediction for daily production rate is in good agreement with the actual daily production rate for both the training and test data set. It is important to mention that in this case study, the model is also used as a nonlinear filter to smooth the actual daily oil production. However, it is possible to make the network learn all the peaks, and to observe the exact behavior of the producer (Figure 24). Figures 22, 23, and 24 show typical behavior of network prediction for a period of 1470-1570, 1540-1580, and 1810-1940 days. The performance of the network for the rest of the five years and for the rest of the producers in this case study was also very good.

Conclusions

We have shown that a neural networks can forecast waterflood performance in low permeability, fractured oil reservoirs even if all mechanisms affecting injection and production are not known. In particular, neural networks can be used to:

- Predict total performance of a large waterflood project.
- Divide a waterflooded field into regions of similarly behaving wells and predict the relationship between injection and production within a region.
- Predict the behavior of individual injectors and producers.
- Modify the existing water injection policy to increase oil production and decrease reservoir damage, and
- Predict productivity and injectivity of future infill wells and water breakthrough time.

The neural networks described here were implemented on the PC using MATLAB[20].

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Table 1: Pattern recognition based on the knowlege of and expert engineer (KEE) in Conjunction with a neural network (KEENN).

	KEE	% KEE	Change based on NN	# KEENN	% KEENN
a	5	4.1	+ 1	6	4.9
b	5	4.1	- 1	4	3.2
c	34	27.6	-4	30	24.4
d	1	0.8	0	1	0.8
e	70	56.9	+6/-2	74	60.2
f	8	6.5	+3/-3	8	6.5

Table 2: Comparison between neural network (NN) and engineering prediction (KEENN).

	NN	% NN	KEENN	%KEENN	% of Correct Classifications
a	5	4.1	6	4.9	79
b	2	1.6	4	3.2	79
c	31	25.2	30	24.4	83
d	1	0.8	1	0.8	79
e	79	64.2	74	60.2	93
f	5	4.1	8	6.5	79
				Total	109/123 or 89%

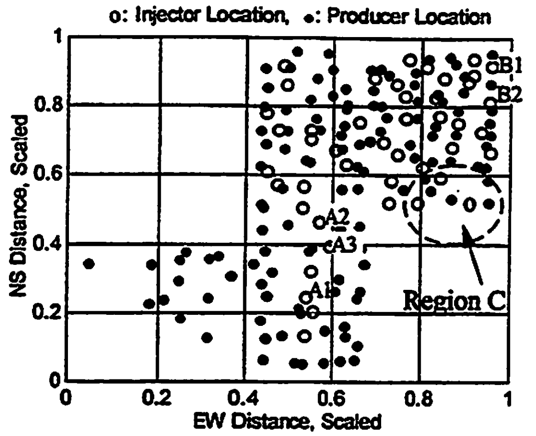

Fig. 1-Plan view of the injector and producer location in Lost Hills I.

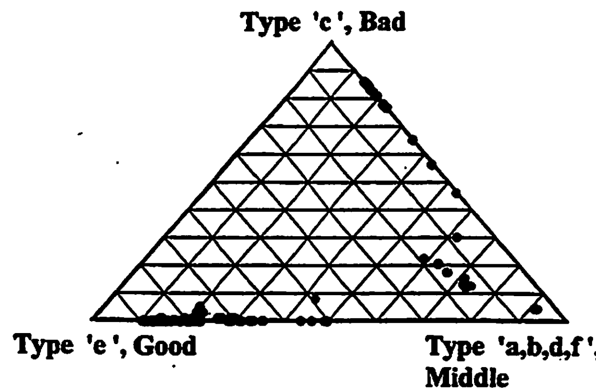

Fig 2.g-Distribution of the most likely types of producer behavior in Lost Hills I.

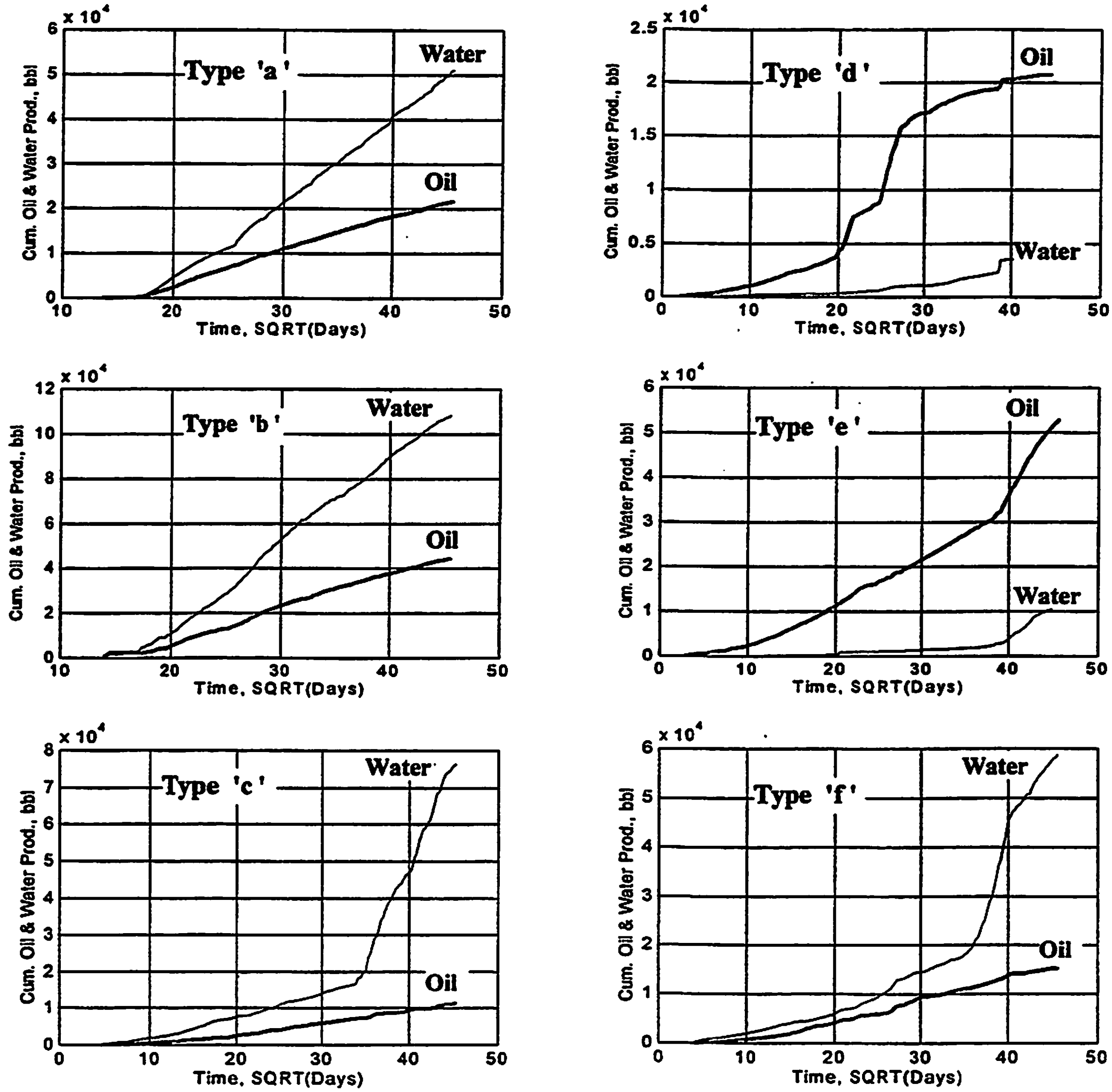

Fig. 2.a-f-Catalogs of the most likely types of producer behavior

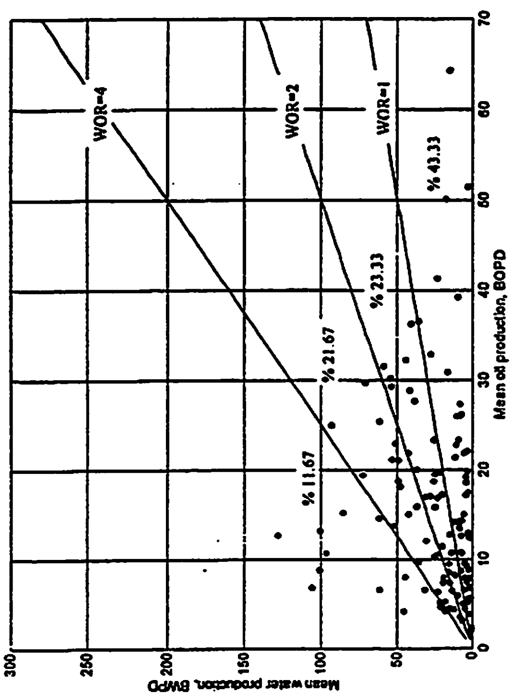

Fig. 3-Distribution of WOR in Lost Hills I.

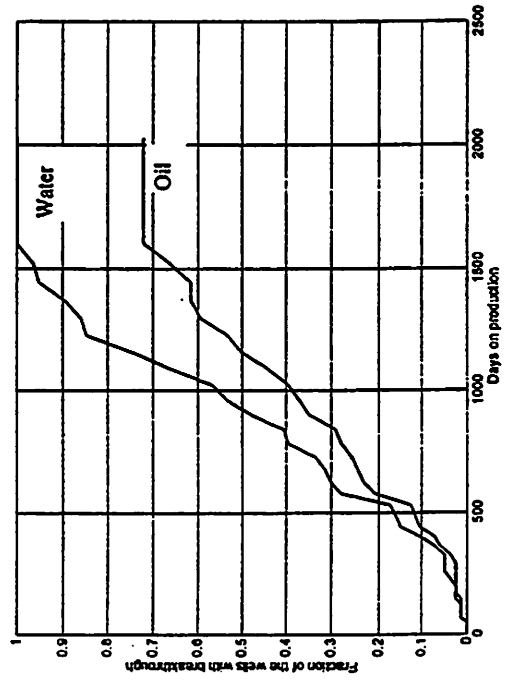

Fig. 4-Lost Hills I oil and water response vs. time on production.

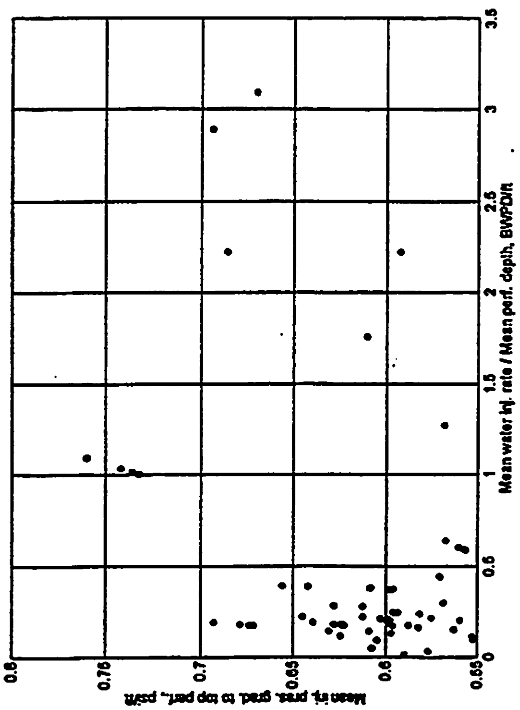

Fig. 5-Distribution of specific injectivity in Lost Hills I.

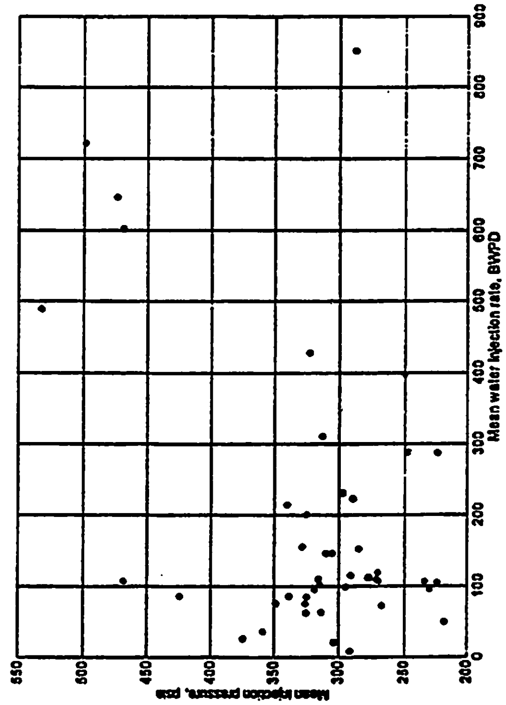

Fig. 6-Relationship between mean water injection rate and mean injection pressure in Lost Hills I.

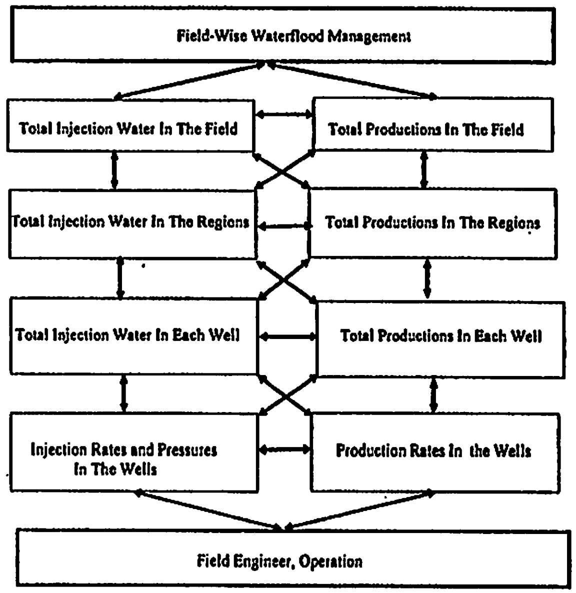

Fig. 7- Schematic diagram of Field-Wise Waterflood Management

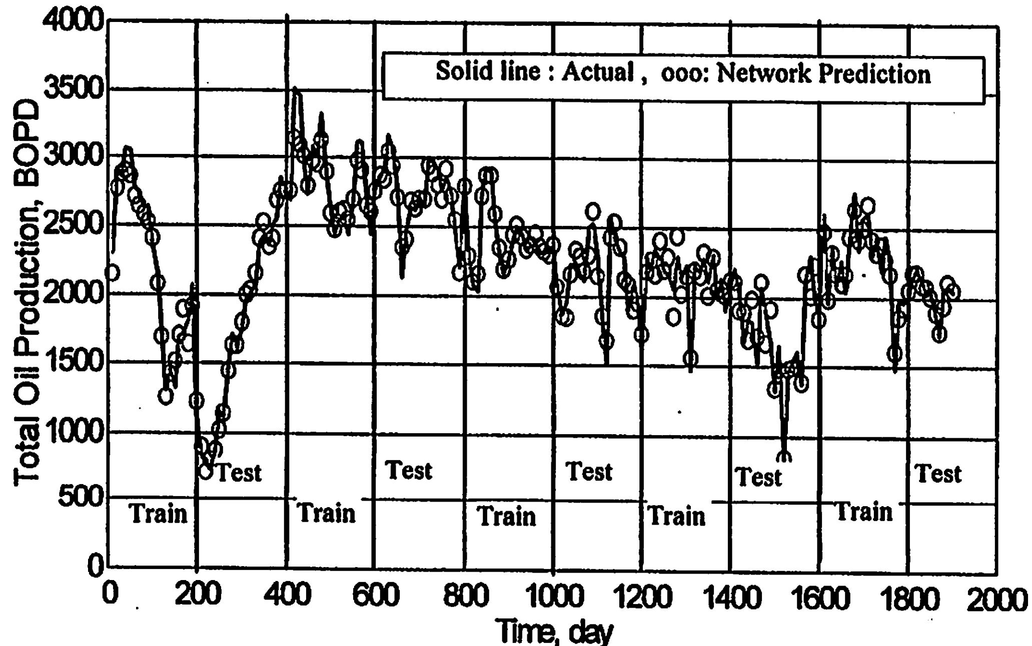

Fig. 9- Performance of neural network for prediction of oil production in Lost Hills I

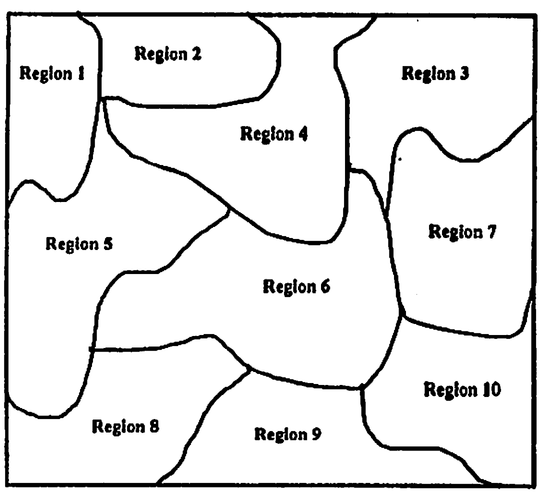

Fig. 8-Subdividing the field into regions

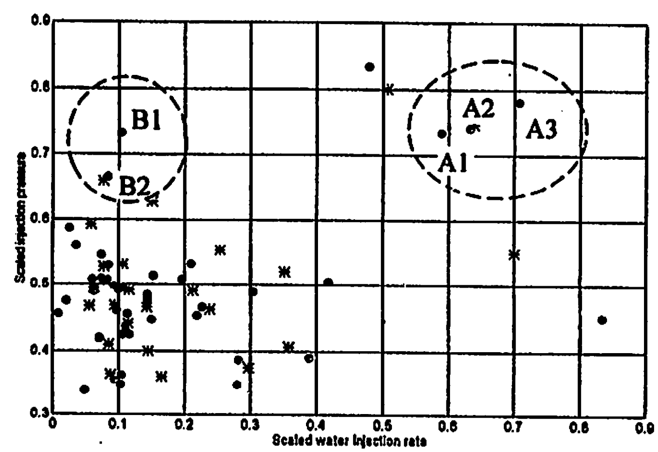

Fig. 10-Subdividing the field into regions using neural network

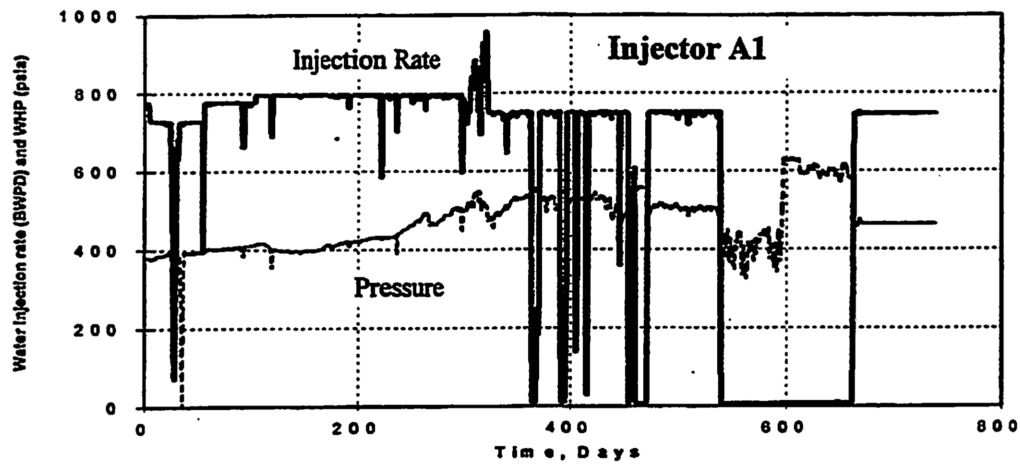

Fig. 11-Behavior of injector A1.

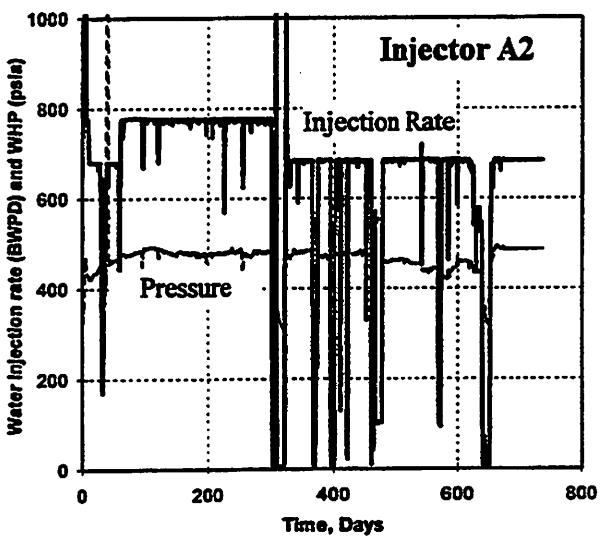

Fig. 12-Behavior of injector A2.

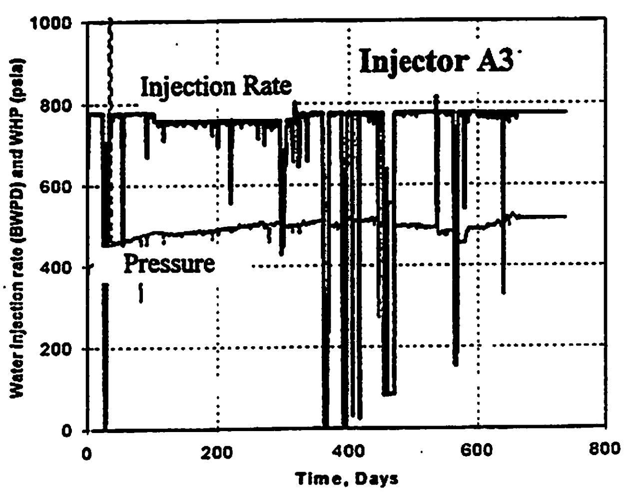

Fig. 13-Behavior of injector A3.

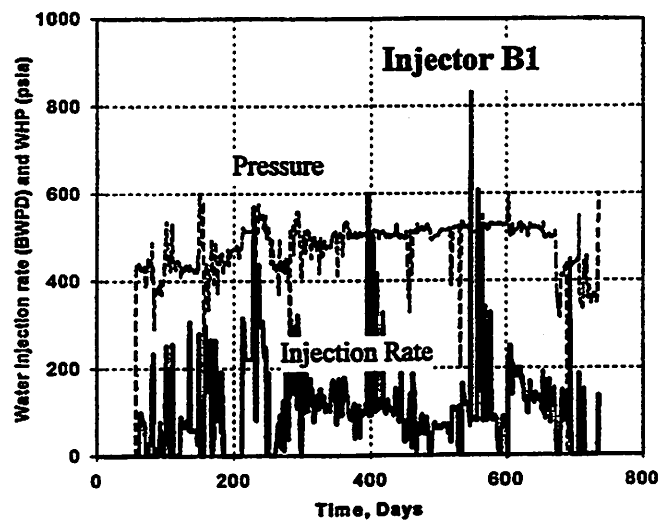

Fig. 14-Behavior of injector B1.

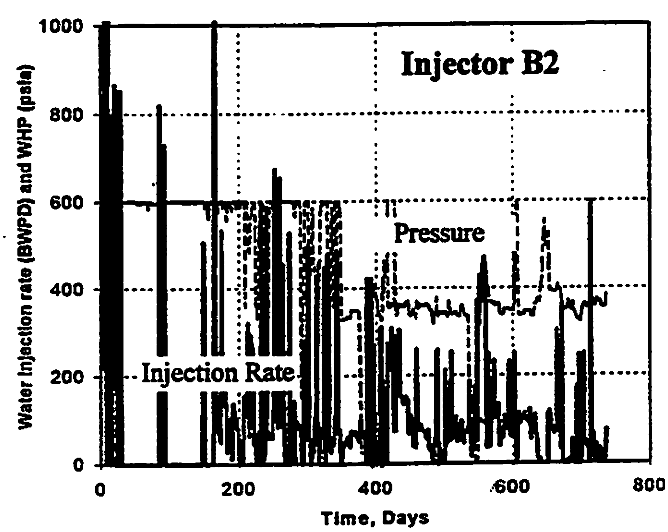

Fig. 15-Behavior of injector B2.

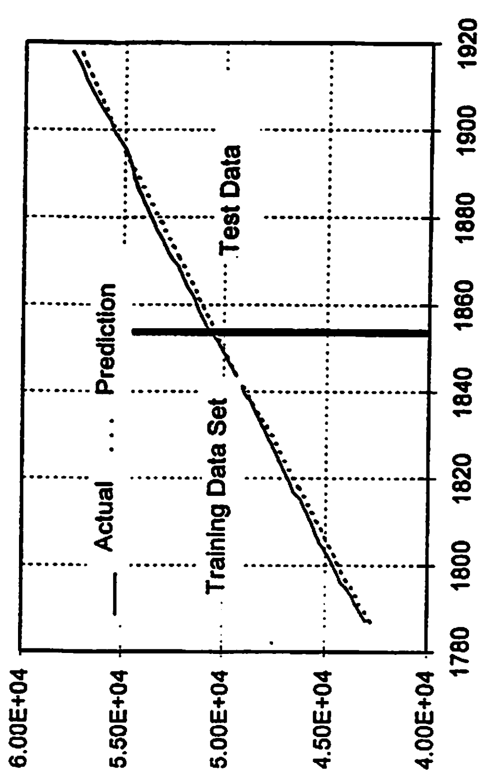

Fig. 16-Network prediction of total water injection in a specific region.

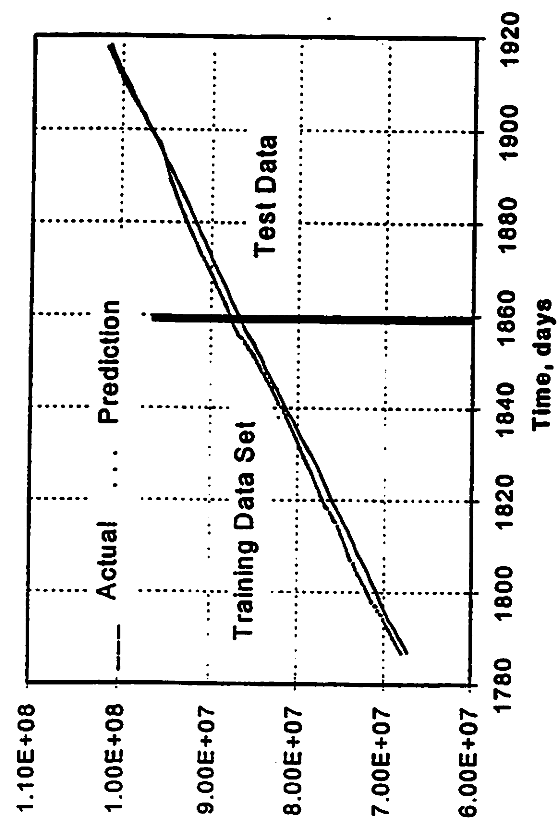

Fig. 17-Network prediction of total oil production in a specific region.

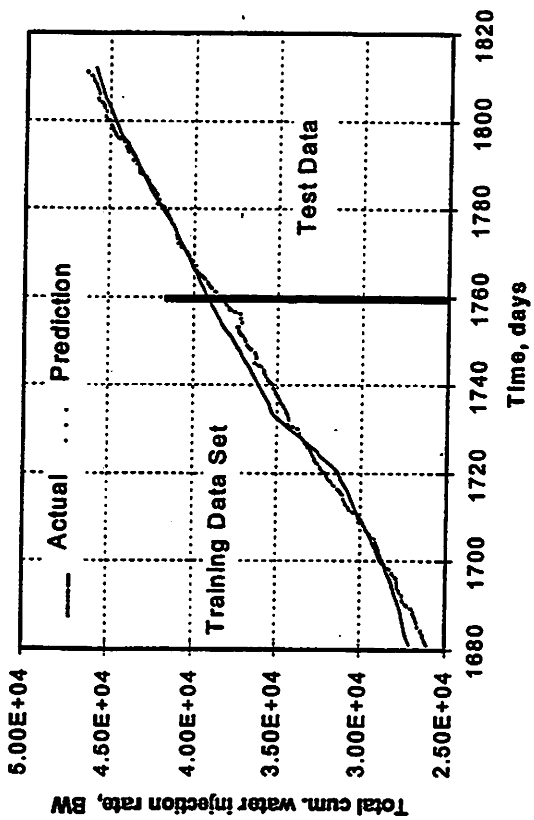

Fig. 18-Network prediction of total water injection in a specific injector.

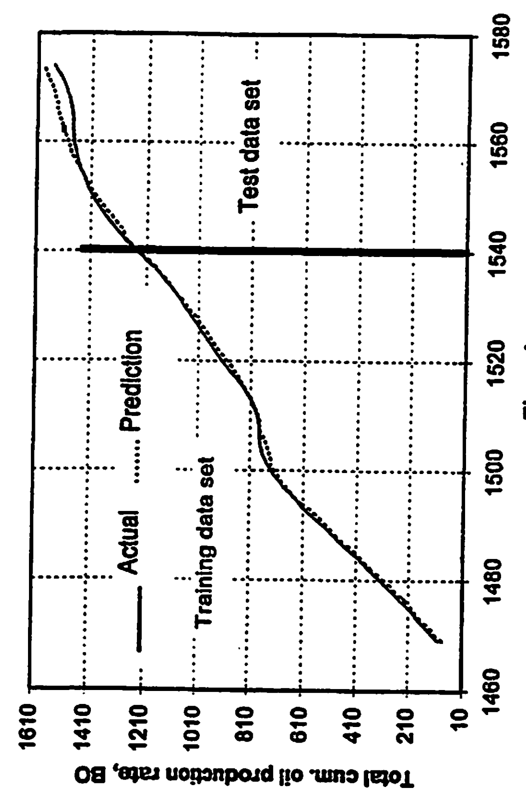

Fig. 19-Network prediction of total oil production in a specific producer.

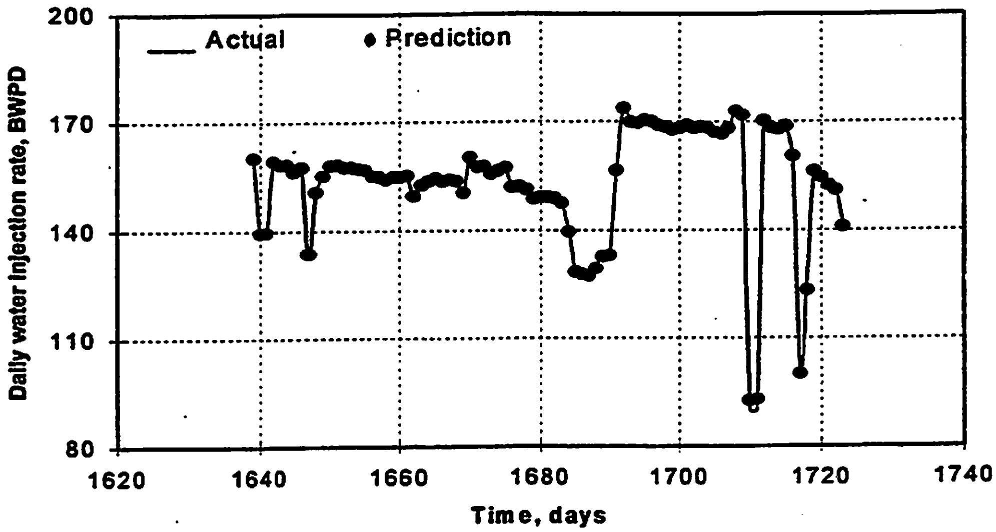

Fig. 20-Network prediction of daily water injection rate in a specific injector, training data set.

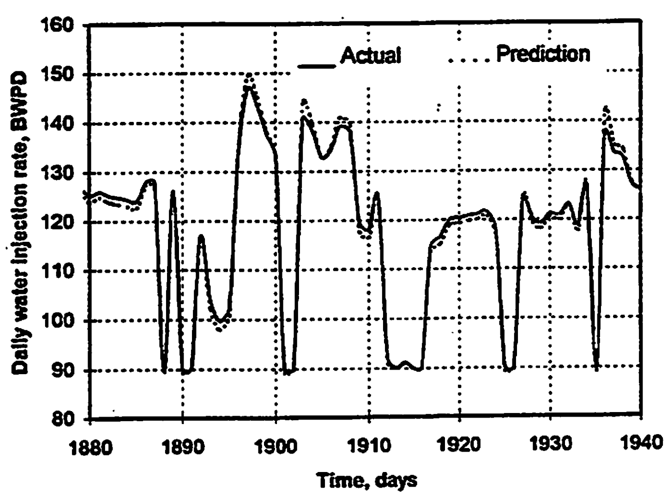

Fig. 21-Network prediction of daily water injection rate in a specific injector, test data set.

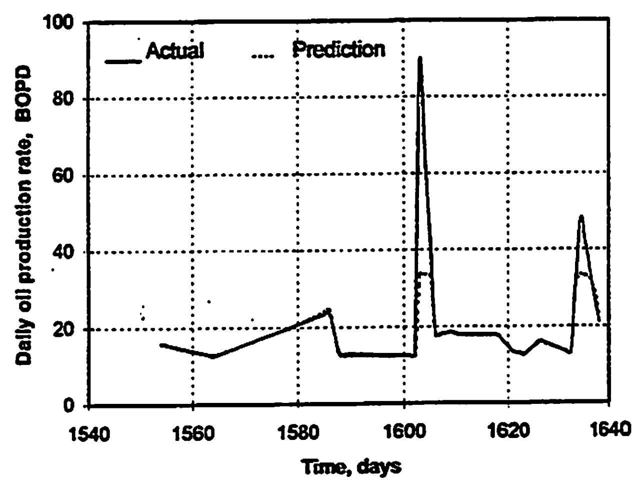

Fig. 23-Network prediction of daily oil production rate in a specific producer, training data set.

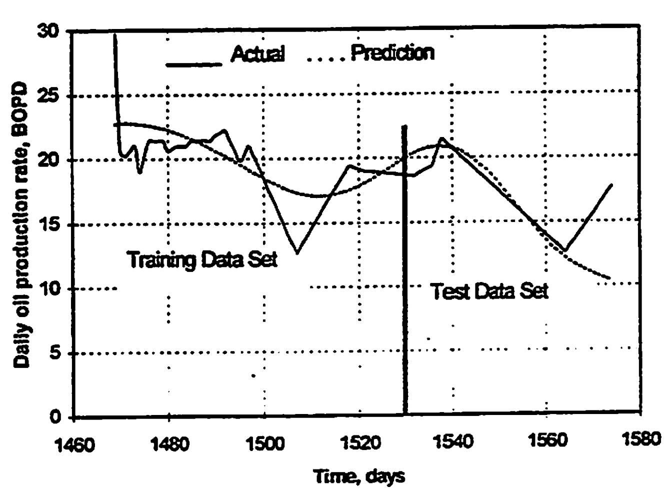

Fig. 22-Network prediction of daily oil production rate in a specific producer, training and test data set.

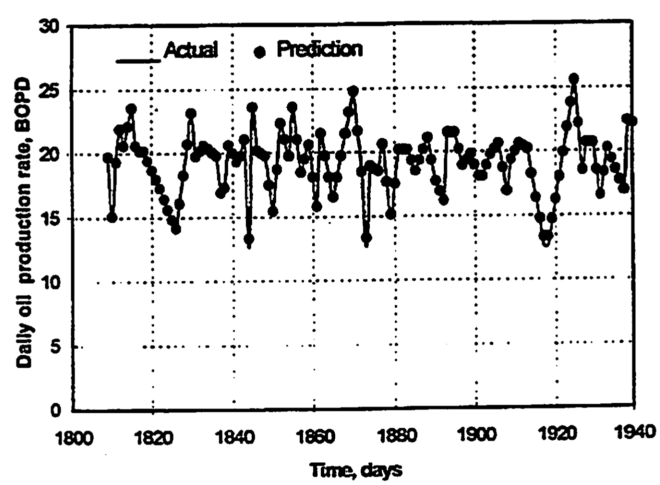

Fig. 24-Network prediction of daily oil production rate in a specific producer, training data set.

SPE 31103

Prediction of Formation Damage During Fluid Injection into Fractured, Low Permeability Reservoirs via Neural Networks

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Abstract

The coupled, nonlinear and dynamic mechanisms that affect fluid injection for pressure maintenance or displacement, and oil production, are not well understood in low permeability fractured reservoirs. Thus, it is difficult to select an injection policy which maximizes oil recovery while minimizing formation damage caused by fluid injection and withdrawal. Here, we show that neural network models can be developed and used to predict, on a well-by-well basis, the dynamics of low permeability, fractured reservoirs undergoing fluid injection. The networks are trained using historical data from field operations.

We present an example from (i) a water and (ii) a steam injection project where over-pressurization has lead to unwanted extensions of fractures. First, using data from a waterflood project in the South Belridge Diatomite (Kern County, CA), we have built a neural network to predict wellhead pressure as a function of injection rate, and vice versa. The resulting model provides an excellent correlation between the inputs and outputs and recognizes major patterns in the input data structure, even though the behavior of the waterflood is complex. Second, using data from a dual injector steamdrive pilot in the same field, we have created neural networks which correlate the injection pressures and rates, and temperature responses in seven observation wells. Assuming a future injection pressure policy, the neural networks predict the injection rate and growth of heated reservoir volume. These predictions are then combined with a history-matching reservoir simulator to demonstrate how predictive simulation can be achieved even when mechanisms of steam injection and oil displacement into a tight fractured rock are not fully understood.

Introduction

Injection of water, CO_2, or steam into low permeability fractured rocks such as diatomite, chalks, or carbonates for either pressure maintenance or oil displacement is problematic. On one hand, injection rates must be low enough to prevent reservoir damage from over pressuring and inducing unwanted fractures. On the other hand, these rates must be high enough to make the costly fluid injection process economic. Historically, the conflict between prudent reservoir management and meeting injection targets has resulted in significant reservoir and well damage, injectant recirculation and irreversibly lost oil production. Much effort has been expended in recent years to develop models and theories for predicting tight rock behavior during fluid injection. However, the outcome has been less than satisfactory, and we still cannot tell reservoir engineers how to best produce low permeability, fractured reservoirs without incurring extensive formation damage.

Currently, reservoir engineers develop fluid injection policy on the basis of past experience, partial knowledge of the state of reservoir stress, production history, and limited predictions of future reservoir performance from numerical simulation. Neural network models for analyzing and predicting complex reservoir behavior are a promising new engineering tool. Unlike other models, neural networks are capable of making accurate predictions even if all mechanisms affecting injection, production, and formation damage are not elucidated because these networks do *not* require specification of a structural relationship between input and output data.

The objective of this paper is to demonstrate the capability of neural networks to model reservoir behavior and to report the steps required to design a neural network model that predicts the dynamics of water or steam injection wells. Likewise, we discuss the frequency of wellhead data collection necessary for accurate modeling. We concentrate on the behavior of individual wells and discuss fieldwise prediction and management of injection in a companion paper [1].

Successful implementation of a neural network model requires extensive data sets, from pilots or computer assisted field operations, that sample a wide variety of reservoir behavior. We choose to analyze historical data from the South Belridge Diatomite (Kern County, CA) because both waterflood and steamdrive operations have been carried out there and the field is shallow, thereby permitting a high density of injection, production, and observation wells. Thus, we can verify the generalization properties of our neural networks for an entire spectrum of reservoir behavior. Although some properties of the diatomite are unique, it is an excellent analog of other deeper fractured reservoirs. Accordingly, the methodology developed here should be applicable to injection into other tight fractured reservoirs such as the Austin Chalk and the West Texas Carbonates.

California Diatomites. The diatomaceous oil fields of California, members of the prolific Monterey formation, are located in the San Joaquin Valley, west of Bakersfield, CA. The estimated original-oil-in-place in the California Diatomites exceeds 10 billion barrels and is comparable to that in Prudhoe Bay, Alaska [2]. They are largely undeveloped, but are relatively well characterized with the oil quantity and quality known. Although the Diatomites contain an astounding volume of oil, they also present *severe* engineering challenges. Matrix permeability is low, ranging between roughly 0.1 and 10 mD, while porosity is quite large, 25 to 65%. Further, the Diatomites have a high rock compressibility, but the rock is also naturally fractured. Natural fractures may be open or cemented shut. Additionally, diatomite is chemically unstable and exists as various forms of opal or quartz depending on depth and temperature [3]. It is possible to dissolve diatomite, transport it some distance, and then reprecipitate it as a different silica phase.

Diatomite reservoir architecture takes the form of a series of stacked silica rich layers with thicknesses ranging from a few inches to tens of feet separated by shales, silty clays or mudstones [3]. To compensate for low permeability and improve efficiency, both injectors and producers are hydrofractured. A typical well has 3 to 8 fractures with tip-to-tip fractures of about 300 ft [2]. Even after fracturing, primary recovery remains transient for many years because of low rock permeability. A typical oil recovery after 10 years on primary is 2.5 to 6.0%. Indefinite primary production is impossible to achieve because of reservoir compaction, subsidence, and severe well failures.

Waterfloods in the diatomite, implemented to sustain oil production and arrest subsidence, have suffered from low injectivity, poor vertical and areal sweep, severe extensions of injection hydrofractures, injector-producer linkage, and increased rates of well failure [4]. Every drop of secondary oil that is displaced during a waterflood must be contacted by water. Low rock permeability, low water injectivity, and large formation thickness all conspire to limit the success of waterflood in the diatomite. The best approach to improve waterflooding is to carefully balance imbibition, water injection, and production so as to promote good volumetric sweep and stable water displacement fronts. This approach demands prediction and monitoring of waterflood performance at an unprecedented level.

On the other hand, steam can displace oil without contacting it directly. Oil heated by thermal conduction expands and evaporates, and is thereby expelled from the rock matrix. Hence, heat sweeps areas of the reservoir *never* directly contacted by steam. With steam injection in low permeability formations, success is predicated on maximizing heat delivery while minimizing the formation damage. To date, steam injection has not yet been applied commercially in the diatomite. Shell has conducted two limited steam drive pilots (Phase I and II) in the South Belridge Diatomite [5, 6], Mobil is conducting a heavy oil steam drive pilot in the South Belridge Diatomite [7], and Chevron has steam soaked producers at Cymric [8].

Both Shell pilots have demonstrated that steam can be injected into the diatomite, significant formation heating over the entire diatomite column can be achieved, and a significant oil production response to steam can occur. The reservoir behavior is far from simple though. For instance, in the Phase I pilot, injectivity increased roughly 10-fold over the first six years of injection due to hydrofracture extension, opening and reconnection of natural fractures, and dissolution of the diatomite by steam. The Phase II pilot exhibited these characteristics, as well as highly unsymmetrical heating due to preferred steam convection channels. Therefore, means of *selecting and controlling injection pressures and rates* must be devised to either prevent or limit the abrupt and large extensions of hydrofractures.

Neural Networks. Both isothermal and thermal oil displacement processes exhibit inherently complex, nonlinear, time varying, and nonstationary behavior. During water or steam injection in the diatomite, there are several factors which cause such behavior: (1) changes in the rock matrix permeability; (2) extension of the existing fractures, creation of new fractures, and linking of fracture networks; (3) changes in the reservoir temperature; (4) changes in the oil viscosity; and (5) dissolution or creation of the gaseous phase.

Unfortunately, only linear and simple nonlinear reservoir behavior can be captured and analyzed with conventional statistical methods such as ordinary Least-Squares, Partial Least-Squares, and nonlinear Quadratic Partial Least-Squares. Neural network analysis, unlike regression, does not require specification of structural relationship between the input and output data. Cybenko [9] and Hect-Nielsen [10] have shown that a neural network model can approximate any continuous nonlinear relation and generate complex decision regions for input-output mapping with useful generalization.

Neural networks have the potential to model reservoir behavior from nonlinear complex multi-dimensional field data and may find wide application in reservoir engineering. To date, they have been used in petroleum engineering mainly as tools for assisting in well test analysis and for well log analysis, c.f. [11-15].

Details regarding neural networks are available in the literature [9, 10, 16, 17]. Therefore, only the important network characteristics are mentioned here. The typical backpropagation neural network has an input layer, an output layer, and at least one hidden layer as illustrated in Fig. 1. There is no theoretical limit on the number of hidden layers, but, typically, there will be one. Each layer is fully connected to the succeeding layer with corresponding weights. The input-output mapping of the multilayer network shown in Fig. 1 can be represented by

$$\underline{y}^{(Net)} = F_2\left(\underline{\underline{W2}}\ \underline{y}_1^{(Net)} + \underline{\theta 2}\right) \qquad (1)$$

with

$$\underline{y}_1^{(Net)} = F_1\left(\underline{\underline{W1}}\ \underline{x} + \underline{\theta 1}\right) \qquad (2)$$

where

n_x:	number of inputs
n_h:	number of hidden layer nodes
n_y:	number of outputs.
$\underline{\underline{W1}}$:	$n_h \bullet n_x$; input/hidden layer weight matrix
$\underline{\underline{W2}}$:	$n_y \bullet n_h$; hidden/output layer weight matrix
$\underline{\theta 1}$:	$n_h \bullet 1$; hidden layer bias vector
$\underline{\theta 2}$:	$n_y \bullet 1$; output layer bias vector
$\underline{y}^{(Net)}$:	$n_y \bullet 1$; network prediction vector
$\underline{x}$:	$n_x \bullet 1$; network input vector
$\underline{y}_1^{(Net)}$:	$n_h \bullet 1$; hidden layer output vector

The nonlinear transfer function, F_i, used in this work for all the network layers is the sigmoid hyperbolic tangent

$$F_i(z) = \frac{e^z - e^{-z}}{e^z + e^{-z}} \qquad (3)$$

As the neural network learns, the information is propagated back through the network and used to update the connection weights. Learning may require showing a network many thousands of examples. The objective function for the training algorithm is usually set-up as an optimization problem and is defined as the sum of errors squared,

$$E = \frac{1}{2} \sum_{i=1}^{P} \left(\underline{y}^{(i)}_{(observed)} - \underline{y}^{(i)}_{(predicted)} \right)^2 \qquad (4)$$

where P is the total number of separate data items used to train the network. This objective function defines a local error for the observed value at the output layer which is propagated back through the network. During learning or training of the network, the weights are adjusted to (i) minimize this sum of squared errors, (ii) improve the performance of the network, and (iii) provide the network with memory necessary in a learning process. Once neural networks are trained with information that spans a wide range of system behavior, they become excellent predictive tools. In addition, neural networks have the ability to infer general rules and extract typical patterns from specific examples, as well as to recognize input-output relationships from complex field data[18]. These properties give neural networks the ability to interpolate between typical patterns of data and generalize their learning in order to extrapolate to the region beyond their training domains.

In general, the performance of neural networks is a function of hidden layer topology. Useful generalization is affected by the number of hidden nodes and not by the number of hidden layers. In comparison with one hidden layer, two or more hidden layers do not significantly aid the recall process [19]. Therefore, depending on the complexity of the problem, useful generalization requires a minimum number of hidden nodes, but not a minimum number of hidden layers. In addition, the generalization results produced by multiple hidden layers and discriminatory capability with more than one hidden layer can lead to erroneous predictions. However, single hidden layer networks offer useful generalization and they generally train faster than multiple hidden layer networks. It can be shown that there exists a neural network with one hidden layer topology which has at least the same performance as a multi-hidden layer network [19]. Therefore, there seems to be no reason to use more than one hidden layer network in preference to a multi-hidden layer network in most applications. In addition, it has been shown [9, 10] that backpropagation networks with three layers can approximate any continuous nonlinear function and generate an accurate input-output mapping. Hence, only single hidden-layer networks are used here.

Waterflood

There are two approaches to analyze and predict the performance of waterfloods. In the first approach, the behavior of each injector or producer is considered independently and modeled with a neural network. For an injector or producer, historical data consisting of flow rate and well pressure are used along with the assumption that the same strategy of well operation will continue into the future. This approach uses a very simple neural network model and is easy to train and implement based on a minimum amount of information from the field.

In the second approach, the behavior of the waterflood is considered as a coupled, highly nonlinear system of injectors and producers. The field-wise objective is to meet a given production goal with the minimum amount of injectant. The oil field is divided into sections with similar characteristic behavior and each well within a section and its interaction with the other wells is studied. The model helps improve waterflood management and the design of recovery strategies. Our field-wise management approach is the subject of another paper [1] and here we concentrate on predicting the performance of single injectors.

Model. Figures 2 and 3 show typical behavior of a waterflood injector located in the South Belridge Diatomite. The well is undergoing a pressure-step test to judge injectivity. The injection rate and pressure data are noisy and occasionally miss information. Actual data are displayed with dashed lines and represent one-hour averages of measurements acquired every second by a Computer-Assisted Operations (CAO) system for Shell's South Belridge diatomite waterfloods.

The design of a neural network to predict the behavior of an injector starts with filtering, smoothing, and interpolating values for missing information in the historical data set. A first order digital or analog filter and a simple linear recursive parameter estimator [20, 21] for interpolating is all that is needed to filter and reconstruct the noisy data. Figures 2 and 3 show the performance of the filtering, smoothing, and reconstruction operation on the wellhead pressure as a dark solid line.

Our model to predict the behavior of an injector has 3 input nodes representing the current scaled values of pressure, current scaled injection rate, and the scaled step change in pressure. All inputs are scaled between 0 and 1 using the maximum rates and pressures for a particular well. The hidden layer contains 10 nodes. The output layer has 75 nodes representing the prediction of the injection rates.

Initially we trained the network using a backpropagation algorithm and the reconstructed data shown in Figs. 2 and 3. The subsets of the historical data marked by the numbers 1, 2, and 4 were presented to the network for training purposes. Training continued until we found that the network prediction suffered upon continued training. Data sets 3 and 5 were used later for interpolation and extrapolation to test the network performance. This network accurately predicts the behavior of the reservoir 75 time steps into the future, where each step represents an interval of 2 hours. For predicting outputs more than 75 time-steps into the future, iteration through the neural network would be required. Hence, the predicted outputs from the network are reused as inputs, and the inputs are shifted accordingly.

Figures 4 through 8 show the performance of the neural network model in more detail. The network models very well the training data sets 1, 2 and 4, as shown in Figs. 4, 5 and 6, respectively. The thick dark line gives the input wellhead pressure to the network. The actual water injection rate is given as a solid line, while the neural network prediction of injection rate as a function of wellhead pressure is given by a dashed line.

To demonstrate the generalization properties of our network, we used it as both an interpolator and extrapolator. Wellhead pressures from data sets 3 and 5 were presented to the network and water injection rate was predicted using the network weights and biases found from training it with data sets 1, 2, and 4. The performance of the network for interpolation (data set 3), and extrapolation (data set 5) is shown in Figs. 7 and 8. As we can see, this neural network maps well the inputs (injection pressures) onto the outputs (injection rates) and serves as an excellent interpolator and extrapolator. Thus, the neural network model has good generalization properties.

Figures 3 through 8 show typical results from our study of waterflood behavior in the South Belridge Diatomite. It is important to note that this study used a minimum amount of field information, i.e., only injection rates and injection pressures. It is possible to introduce more information into the network model to constrain it. For example, a rock mechanics model could be used to predict extensions of a hydrofracture. An estimate of the hydrofracture location, orientation and size might be used to predict injector-producer linkage, etc.

Most of the wells examined in this field showed only a single fracture extension. If the fracture extension data are introduced to the network during the training period, the network captures this extension. However, a perfect match of a past fracture extension is *no guarantee* that the network will accurately predict future fracture extensions. This is because at present there are no other fracture extensions in the well that may be used to retrain the network. A predictive rock-mechanical model used in conjunction with a neural network should remedy this potential deficiency.

To show that it is possible to predict fracture extensions using the neural network model, we studied a more complex situation. First, a part of the waterflooded field was chosen. The network was then trained based on known information from wells in that part. Included in the training set were the fracture extension behavior and normal behavior of several injectors. Hence, the neural network accumulated information from several wells. The network was then used to *predict* the performance of another well within the same part of the field. This particular well had *never* been shown to the network. Figure 9 shows the wellhead pressure as a function of time, while Fig. 10 shows the behavior of the test injector. Data to the left of the dark, vertical, dashed line at roughly 12 days are introduced to the previously developed network model for additional training. It is important to note that this small amount of known information is not a sufficient data set if used as the sole source of training information. Figure 11 shows the network prediction of water injection rate using wellhead pressure as input. Comparing Figs. 10 and 11, it is evident that the network is able to accurately predict injection rate and capture the dynamics of the hydrofracture extension that occurs at roughly 64 days. Hydrofracture extension is marked by a large increase in injection rate over a short period of time.

Since the network has learned the symptoms of injection leading to hydrofracture extension, it can be used to suggest an injection policy for the well that minimizes formation damage. Based on the knowledge contained in the weights and biases, the network model suggests that wellhead pressure not be allowed to exceed 150 psi. In Fig. 9, the actual injection pressure is stepped to approximately 160 psi at 64 days and to about 170 psi at 75 days. The lighter line between 64 and 90 days in Fig. 11 shows the network prediction of injection rate based on the more conservative policy. The network predicted injection rate is low because a wellhead pressure of 150 psi is not high enough to induce a hydrofracture to extend based on the historical data from wells in this part of the field.

Figure 12 replots the injection data for this example as the cumulative injected water as a function of time. The solid dark line is the actual field performance, and the gray line is the neural network prediction of the actual performance. Lying much below these two curves is the result of the injection policy suggested by the neural network. Because the wellhead pressure is limited, no fracture extension occurs and the cumulative injection continues along the same trend. This result is consistent with our goal of maximizing oil recovery while minimizing formation damage and fluid injection.

Fracture Extension

After reviewing waterflood dynamics in the South Belridge Diatomite, we have learned that, historically, an important factor causing fracture extension is the aggressive action of Proportional-Integral-Derivative (PID) controllers during start-up periods, or when the system is near the fracturing gradient. The effects of aggressive controller behavior are evident upon comparing Figs. 2 and 3 with Figs. 9 and 10. The behavior of both injectors is very similar as fracture extension occurs in both wells when the wellhead pressure approaches 150 psi.

However, there are important differences between these two injectors. Figures 2 and 3 show that the behavior of the reservoir around the well after the first fracture extension (point 5) does not differ substantially from the behavior before the fracture extension. Injection response to changes in the wellhead pressure, both before and after hydrofracture extension, displays a classical square root of time decline in the rate of injection [4]. This is not true for the second well shown on Figs. 9 and 10. After hydrofracture extension, injection rates show no decline upon establishing a new wellhead pressure.

Both cases are examples of forced fracture extension. In response to aggressive PID action which creates a water hammer in the wellbore, the fracture opens for a period of time allowing large water injection rates even though the final pressure does not lead to a pressure gradient above the fracturing gradient. Essentially, the fracture fills with liquid as a result of injection, the liquid causes the fracture to extend, and then the liquid squirts into the formation in response to a pressure perturbation. It is important to note that the data available for this study were one hour averages of well behavior. Since we believe that the dynamics of forced fracture extension occur over a much shorter time period than 1 hour, the actual behavior of the PID controller during fracture opening is not shown by these figures. Thus for a time period shorter than the 1 hour average, the pressure gradient exceeds the fracturing gradient. The length of the period of time during which the reservoir stays equal to or above the fracturing gradient, determines whether fracture extension is temporary or permanent. Figures 3 and 4 demonstrate a temporary fracture extension in that the system returns to it pre-extension behavior, while Figs. 10 and 11 display a permanent fracture extension.

There are several ways to prevent such fracture extensions. One is to retune the PID controller to improve performance and reduce controller aggressiveness. In general, retuning PID controllers is time consuming and requires a combination of operational experience and trial-and-error procedures. A neural network model can assist greatly in retuning by learning the good and bad symptoms of the PID controller behavior and then suggesting new controller setpoints and gains. Figures 9 through 11 show that based on what the network learned, it was able to suggest a better operating procedure. Aggressive PID action was prevented, thereby preventing fracture extension.

A second approach is to use the network as a model identifier to assist the PID control. During the past few years, neural networks have been applied effectively as controllers for time varying processes with highly nonlinear behavior. It has been shown that the neural network model based control strategies are robust enough to perform well over a wide range of operating conditions, and they are much easier to design and implement than classical PID control [17]. Currently, we are developing a neural network model based control strategy for water and steam injectors to augment the present PID control strategy.

Steamdrive Behavior

Thus far we have only examined neural network models for the analysis and prediction of single well behavior. However, when used in conjunction with a first principles model, such as a reservoir simulation model, neural networks allow us to achieve predictive simulations while oil displacement and formation damage mechanisms are being explored.

As an example, we use neural network predictions of steam injection rate and temperature profiles in observation wells for the Phase II steamdrive pilot as inputs to a history matching simulator. The simulator functions by using temperature response and cumulative steam injection to infer the portions of a hydrofracture which conduct steam to the formation, the temperature distribution within the formation, and relative changes in matrix permeability [22, 23]. Unfortunately, this simulator is not predictive. Although our model can capture changes in matrix permeability, mechanisms for permeability evolution are not included in it. To be fair, predictive models for fracture extensions and formation plugging by silica precipitation are not parts of more sophisticated commercial simulators either.

Details of this pilot can be found elsewhere [5, 6]. In short, steam is injected through two hydrofractured injection wells, IN2U and IN2L, that span the entire Diatomite column at South Belridge and oil is recovered at two production wells lying to the northwest, 543N, and southeast, 543P, of the injection hydrofractures. IN2U is perforated from 1110 to 1460 ft, while IN2L is perforated from 1560 to 1910 ft; hence, there is no communication between the injection hydrofractures. Heating of the Diatomite by steam is measured in 7 observation wells that are distributed across the pilot area. Figure 13 gives a plan view of the pilot, the surface locations of the wells, as well as the individual names of the observation wells.

The hybrid reservoir simulation-neural network approach for predicting results of the Phase II Pilot functions in the following manner. Given steam injection rate, wellhead pressure, and the temperature responses at the observation wells for a given period of time, say 0 to 700 days of steam injection, a neural network model and the steam injection history matching simulator are run in parallel to obtain a best fit of the Phase II results. In the case of the neural network model, this entails predicting the change in temperature at each observation well for a given time interval.

The trained neural network is then used to extrapolate into the future the temperature response in each observation well and the steam injection rate. The temperature response and the cumulative injected steam predicted by the neural network are used in place of actual data as input to the history matching simulator. The simulator is then restarted with the output from the first 650 days of steam injection as initial conditions and "history matching" of the neural network data is performed.

Hence, this combination of neural network extrapolation of steam-injection response in time and history matching allows us to predict volumetric heating of the diatomite and the zones with the largest steam flow. As a sidenote, the power of neural networks to interpolate between complex nonlinear data also allows us to generate various injection scenarios and visualize their results [1]. Details of the neural network prediction are described prior to displaying the results of this hybrid approach.

Neural Network Model for Steam Injection

Figures 14 and 15 show typical behavior of the IN2L steam injector from the Phase II Pilot. The dashed lines representing the injection rate and wellhead pressure include substantial noise. Similar to the water injectors, the first step in designing a neural network model was to filter and smooth the actual injection data. Next, a series of neural network models for short term prediction of injection behavior were developed.

First, steam injection rate as a function of wellhead pressure is predicted, and then the so-called "inverse problem," wellhead pressure as a function steam injection rate, is predicted. The structure of each neural net is similar. Each model has 6 input nodes, 15 nodes in the hidden layer with nonlinear transfer functions, and 10 nodes in the output layer with nonlinear transfer functions. Network output is a prediction of either the injection rate or the wellhead pressure for the next 10 sampling periods. All rates and pressures are scaled using historical maxima in the data set. The sampling period between known values of wellhead pressure and injection rate is 1 day.

For prediction of steam injection rate the input nodes represent the current wellhead pressure, current injection rate, and 4 past values of wellhead pressure. The six input nodes for the network that predicts injection pressure represent the current injection rate, current injection pressure, and the 4 past values of the injection rate;

Each network is initially trained using a backpropagation algorithm with smoothed and reconstructed data. A moving window is used for training on the first 200 days of data, and the next 100 days of the data set are used for testing the network. The network is trained and updated in the next training window data set based on a simultaneous updating approach [17]. The training data sets labeled in Figs. 14 and 15 were presented to the network, and training was stopped when it was found that the network's prediction suffered upon continued training. Next, steam injection rate and wellhead pressure were predicted by each network, respectively.

The network has excellent prediction for the training data sets, as expected. To show the performance and generality of the network, the model was used for interpolation and extrapolation of injection 3 months into the future. The performance of the network for the test data is marked as a solid line in Figs. 14 and 15. Both figures illustrate that each neural network maps well inputs onto outputs and is a good interpolator and extrapolator. Thus, these neural network models have excellent generalization properties.

For network prediction of injection rate more than 10 time steps into the future, iteration through the neural network is required. Therefore, the predicted output from the network is used as input to the neural network and the input is shifted accordingly. It is important to note that the prediction will deviate gradually from the actual value as the network is iterated. For our model, as long as discontinuous changes in the behavior of the reservoir do not occur (e.g., an extension of the injection hydrofracture), the prediction is reasonable.

Also, note that even though the performance of the networks was perfect for this case study, a comparable performance is not guaranteed for other cases. Therefore, we are conducting a more detailed study of modeling reservoir behavior as well as a model for field-wide management [1].

Long Term Prediction of Steam Injection. Since short term prediction of steam injection behavior was successful, we developed a neural network model for longer term prediction of steam injection rate as a function of injection pressure. This model is used to estimate the long term performance of steam injection in conjunction with a reservoir simulator. Using this network model, the results from different injection scenarios can be predicted allowing us to analyze and choose an optimal scenario. The model has 5 input nodes representing the current and 4 past, scaled values of the injection pressure, 20 nodes in the hidden layer, and 2 nodes in the output layer. The output gives a prediction of injection rates two sampling periods into the future. The model is called a feedforward model, because the injection rate is predicted *solely* from the known pressure history. The network was trained using a backpropagation algorithm with the reconstructed data given in Figs. 14 and 15. Training was stopped when it was found that the network's prediction suffered upon continued training. After the injection rate versus time relationship is known, calculating cumulative steam injection versus time is trivial.

For long term prediction, the error in the cumulative sum of the injection rate is backpropagated through the network for adjusting the weight and bias terms instead of the error in the daily injection rate. The performance of this model on a daily basis is not as accurate as the previous one. However, because the current model is constrained by the total amount of injected steam, its long term prediction of cumulative steam injection is excellent. In addition, the models for short term prediction may be used to assist the feedforward, long term model. Therefore, the combination of feedforward and the previous model for short term prediction can be used for better long term prediction if information is needed on a daily basis.

Figure 16 shows the performance of the network model for predicting the cumulative amount of steam injected versus the actual data. The network has good performance. Also shown are network predictions of cumulative injection given ± 10% changes in the wellhead pressure, thereby allowing us to see the effect of changes in the injection pressure on the cumulative steam injected. We conclude that by using simple neural network models, it is possible to predict the behavior of the injectors for both a short and long time periods to a reasonable degree of accuracy.

Neural Network Model for Observation Wells

The temperature responses in the observation wells displayed in Fig. 13 quantify the extent and uniformity of heating of the reservoir and the rate of expansion of the heated rock volume. The latter rate is a function of the injection pressure, the hydrofracture area and the creation of steam-flow channels in the formation. Hence, prediction of the future temperature responses is crucial to ensuring smooth operation of injectors and the prevention of unwanted fracture extensions.

Briefly, we have developed several neural network models to predict the temperature responses of the observation wells. A typical network has 3 input nodes representing the current and 2 past scaled values of temperature response, 2 nodes in the hidden layer, and 1 node in the output layer that gives a prediction of the temperature response 30 days into the future. The network is trained using a backpropagation algorithm. Figures 17, 18, and 19 show the typical the temperature responses of Wells LO13, LO14, and LO15. Actual temperature measurements are shown as dashed lines, while the neural network predictions are given as solid diamonds connected by straight lines. Only the temperature responses at depths corresponding to the midpoints of the reservoir simulation layers to follow are shown, suggesting an imperfect match of the field data. However, our neural network models the temperature profiles exactly. Although not displayed, temperature responses at observation wells, LO11, LO12, MO1, and MO2 were generated with identical networks. Model predictions can then be used in conjunction with any reservoir simulator for further detailed studies of the reservoir under steam injection. Here we use only our history matching simulator with simplified physics to show that neural networks and reservoir simulators can be used in concert.

Hybrid First Principle-Neural Network Model

Figure 20 displays a plot of wellhead steam injection pressure for well IN2L as a function of time. The dark, dashed line gives the actual history from the pilot for the first 700 days of injection while the solid line gives the pressure input to the history matching simulator. Given the continuation of steam injection between 700 and 1200 days at the pressure indicated on Fig. 20, the neural networks are used to predict the temperature responses in the observation wells, in addition to the cumulative injected steam. These predictions become the inputs to our history matching simulator to estimate the volumetric distribution of heat within the pilot and diagnose future performance.

As a demonstration of the results from this hybrid approach, Fig. 16 superimposes the simulator-predicted cumulative steam injection over the actual and the neural-network-predicted injection. Additionally, Figs. 17 to 19 show the neural network and simulator predictions of temperature response between 700 and 1200 days for observation wells LO13, LO14, and LO15. As shown on Fig. 13, these wells are adjacent to IN2L. The dark dashed line gives the actual temperature response between 1500 and 2000 ft. Neural network predicted temperature response is represented by solid diamonds and the simulator predictions of temperature response are marked by solid circles. The horizontal dashed lines and the letters J through M indicate the geologic layering at South Belridge.

To the east of IN2L, Fig. 19 displays a dramatic temperature response at a depth of roughly 1800 ft. This indicates that continuing the current injection policy will lead to dramatic temperature increases in LO15 and steam breakthrough at the close by producer, 543P. In fact, this *was* observed in the pilot [22, 23]. To the west of IN2L, Figs. 17 and 18 show vertical asymmetry of heating, but no acceleration of the temperature response.

Summary

Neural network models can match and then predict complicated reservoir behavior when historical databases are available. To capture detailed extensions of injection hydrofractures in tight rocks, the historical data must be acquired at 30-60 second intervals. Modern Computer-Assisted Operations (CAO) systems, mass data storage devices, and fast data transfer protocols provide the foundation for rapid data acquisition. With current computer hardware and networks, these requirements can be satisfied at a relatively low cost and the potential savings in terms of otherwise forfeited oil production may be huge. To capture large and permanent fracture extensions a much lower frequency of data acquisition, say 1 measurement per day, is required. The neural networks are capable of making accurate predictions even when all mechanisms affecting injection or production behavior are not known. Further, neural networks provide a way to incorporate *disparate* information because a structural relationship between input and output data is *not* required.

Using steam and water injection data from field operations in the South Belridge Diatomite, we have demonstrated that neural networks are capable of predicting injection rate as a function of wellhead pressure and *vice versa*. The networks used are simple and are based on accepted neural network designs and training algorithms. These networks match field data very well and have exceptional generalization properties. They are able to accurately predict extensions of injection hydrofractures and provide us with a means of preventing unwanted fracturing.

With regard to steam injection, neural networks used in conjunction with reservoir simulation provide a novel tool for predicting, visualizing, and screening various steam injection strategies. Thus, predictive simulation can be achieved several months into the future even when mechanisms of injection and oil displacement are not fully understood.

Nomenclature

- E = objective function
- F = transfer function
- n = number
- W = weight
- x = network input
- y = network prediction or hidden layer output
- θ = bias vector

Subscripts

- h = hidden layer
- x = inputs
- y = outputs

Acknowledgments

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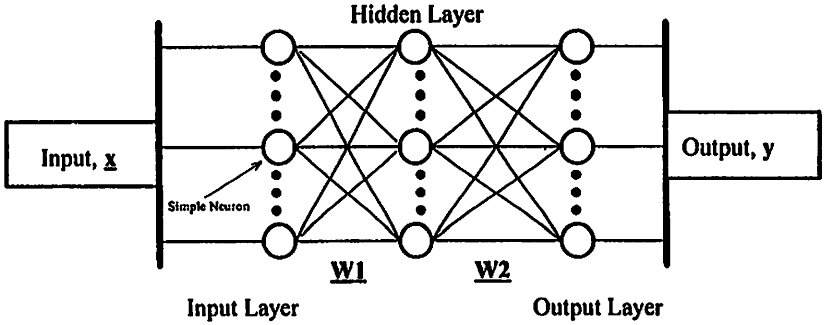

Fig. 1-Typical neural network model

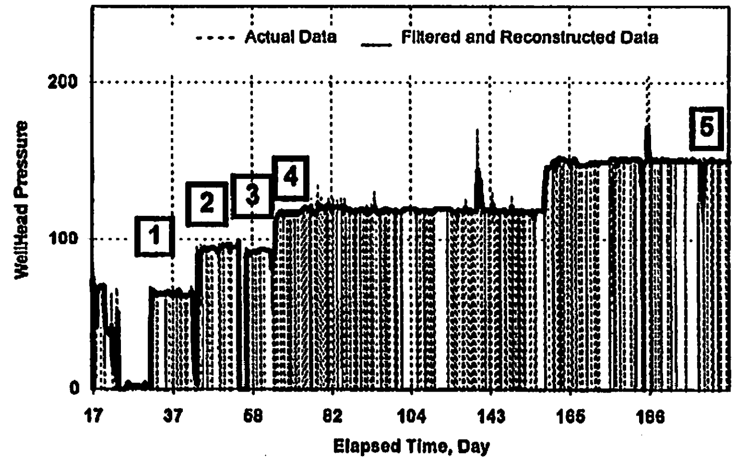

Fig. 2-Typical wellhead pressure behavior of waterflood injectors (South Belridge Diatomite)

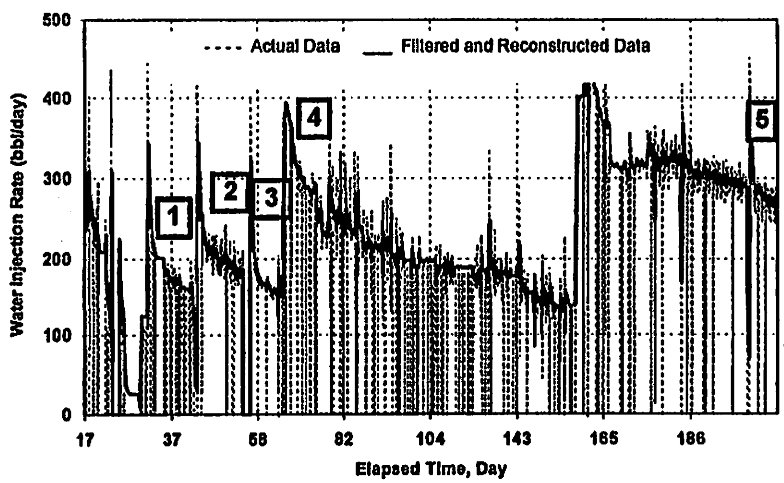

Fig. 3-Typical injection rate behavior of waterflood injectors (South Belridge Diatomite)

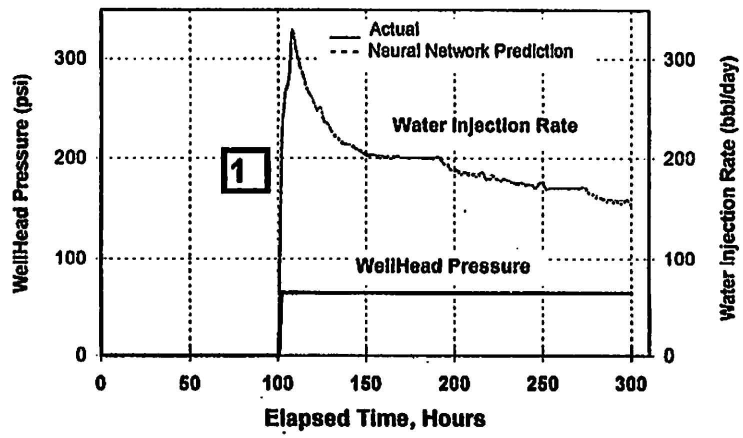

Fig. 4-Performance of neural network model for training data set number 1.

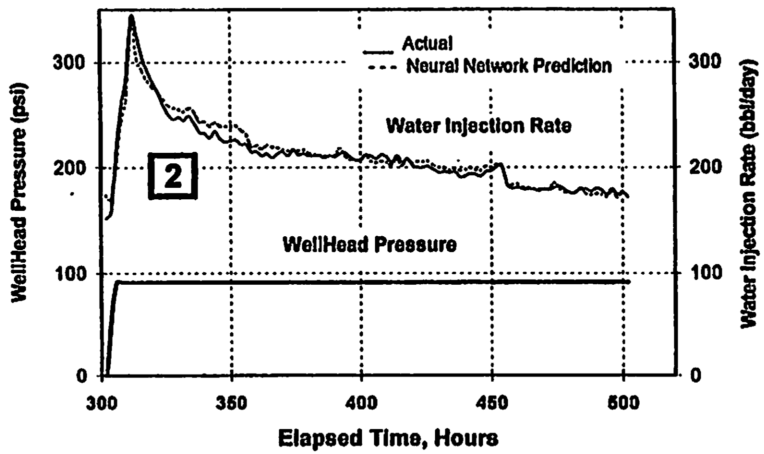

Fig. 5-Performance of neural network model for training data set number 2.

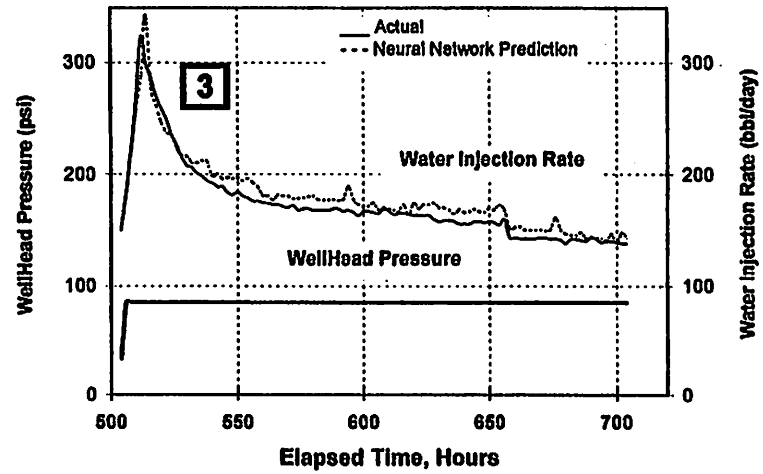

Fig. 6-Performance of neural network model for training data set number 3.

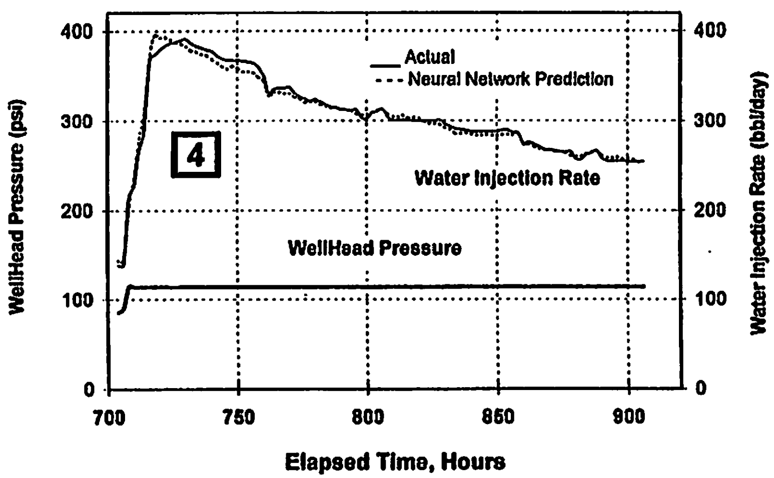

Fig. 7-Interpolation performance of neural network model

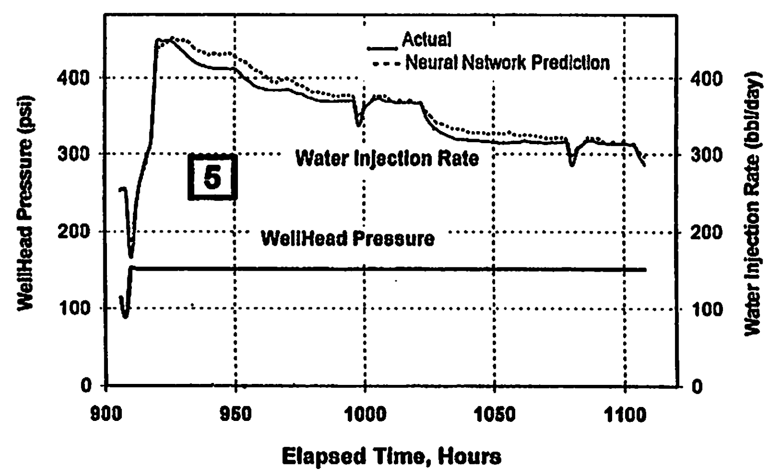

Fig. 8-Extrapolation performance of neural network model

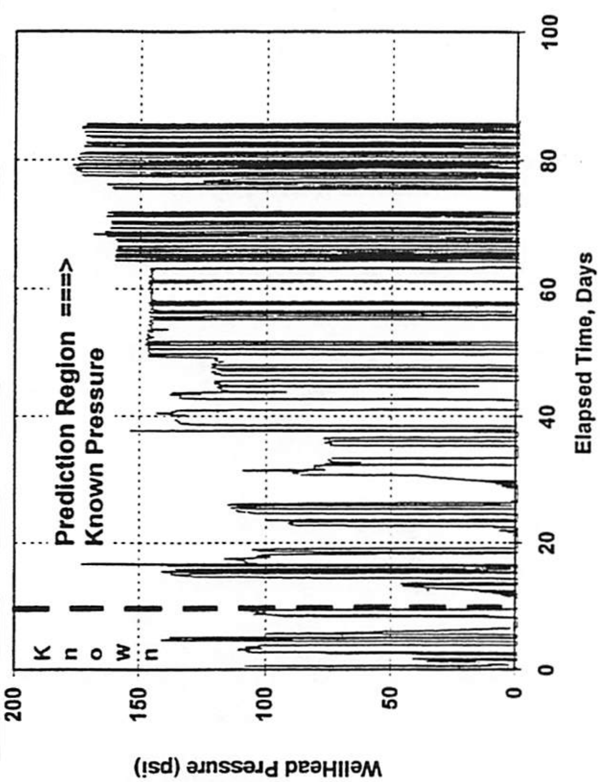

Fig. 9-Wellhead pressure of test injector

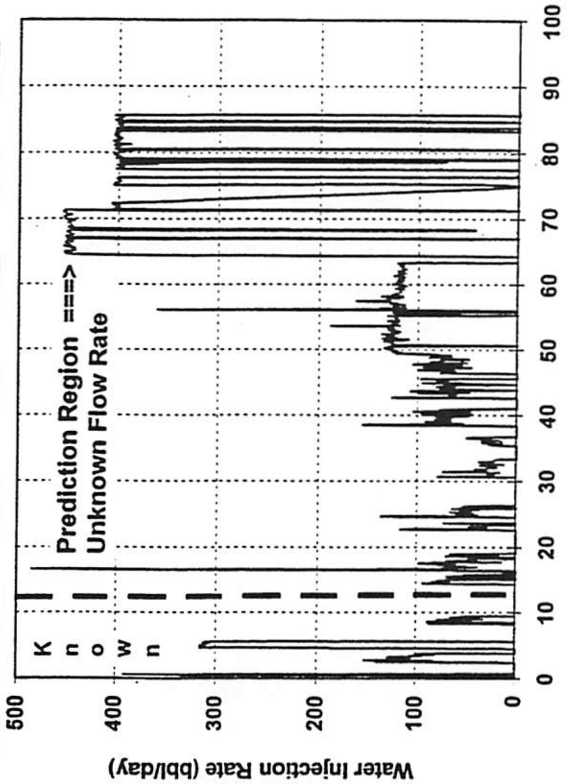

Fig. 10-Injection rate of test injector

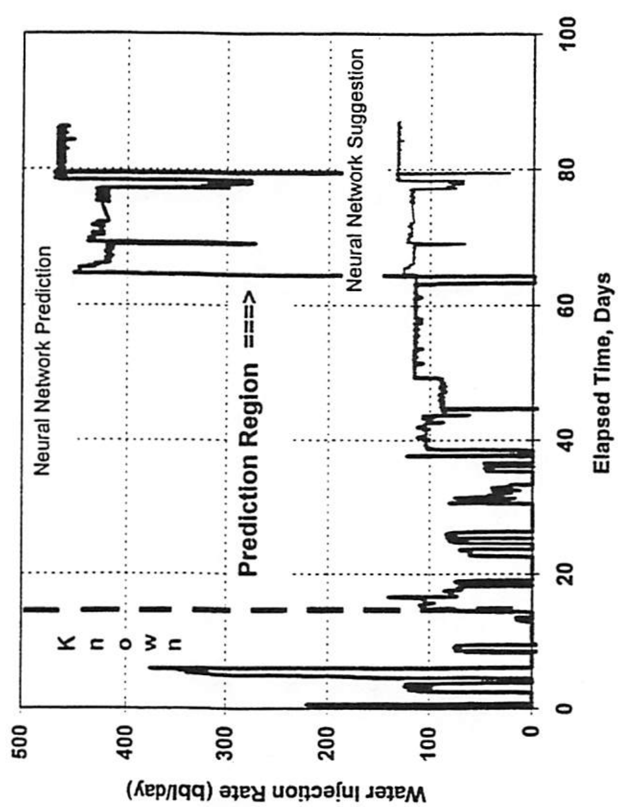

Fig. 11- Neural network prediction and suggestion for injection rate

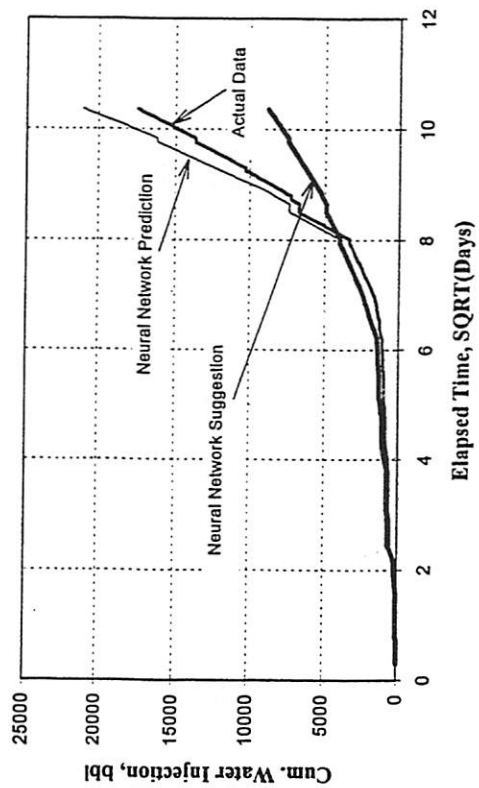

Fig. 12-Comparison between neural network prediction and suggestion with actual injector response

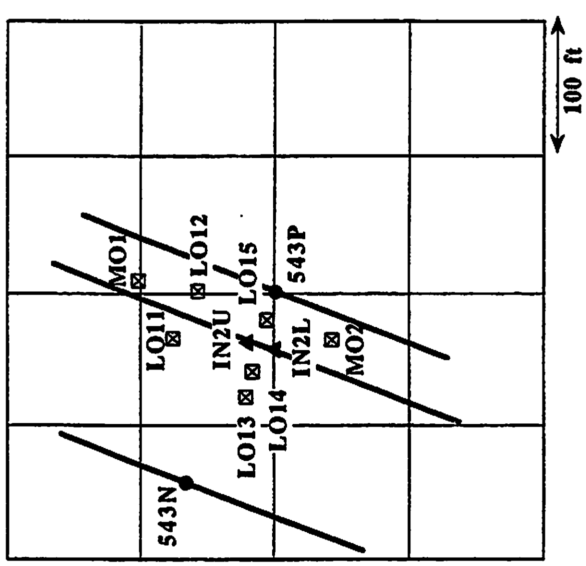

Fig. 13-Plan view of Phase II steam drive pilot.

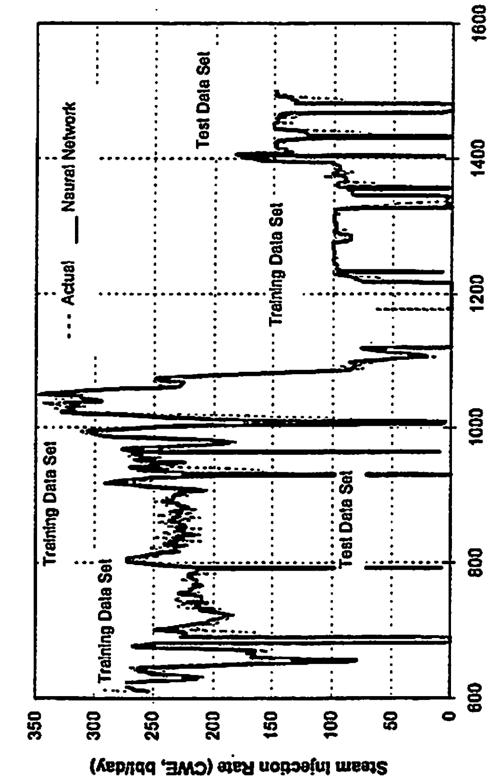

Fig. 14-Typical injection rate behavior of IN2L steam injector and the performance of the neural network model

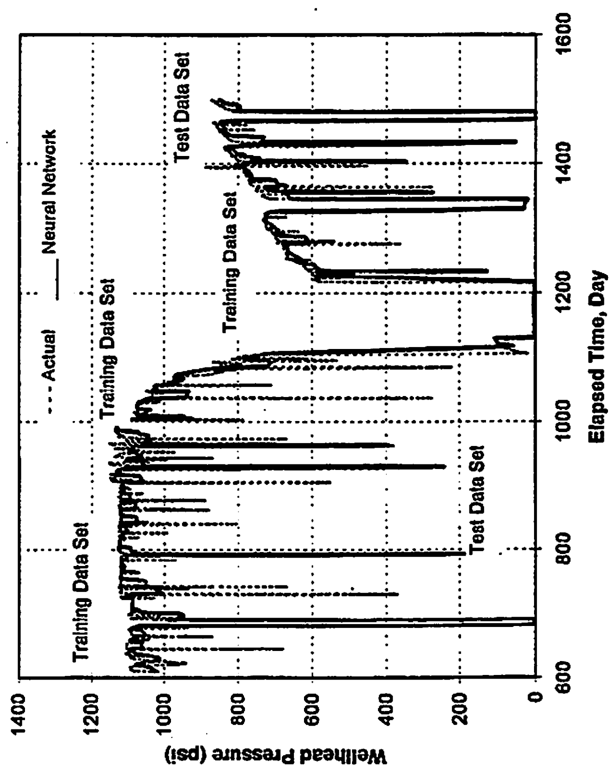

Fig. 15-Typical wellhead pressure behavior IN2L steam injector and the performance of the neural network model

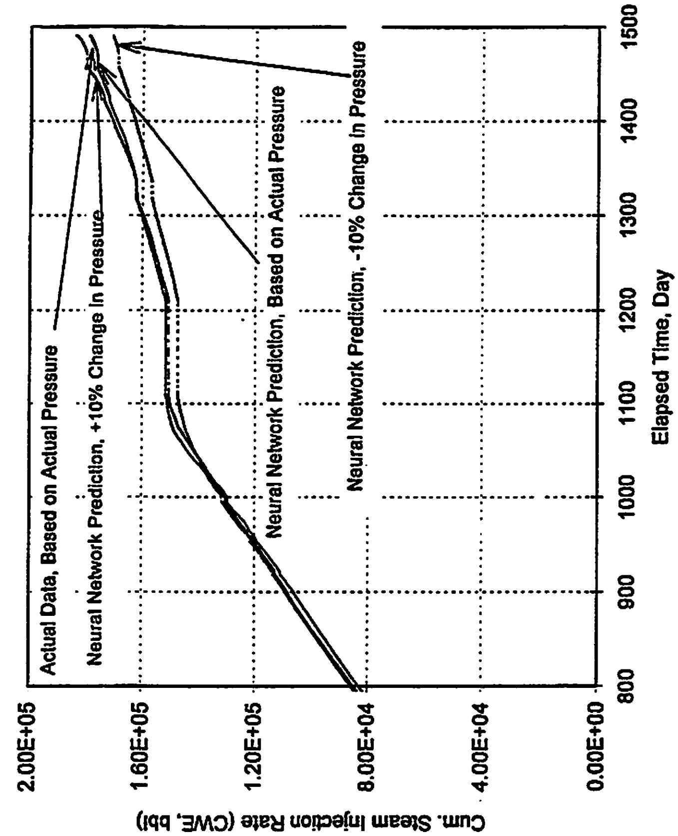

Fig. 16-Performance of the network model for predicting the cumulative amount of steam injected for different injection pressure policy

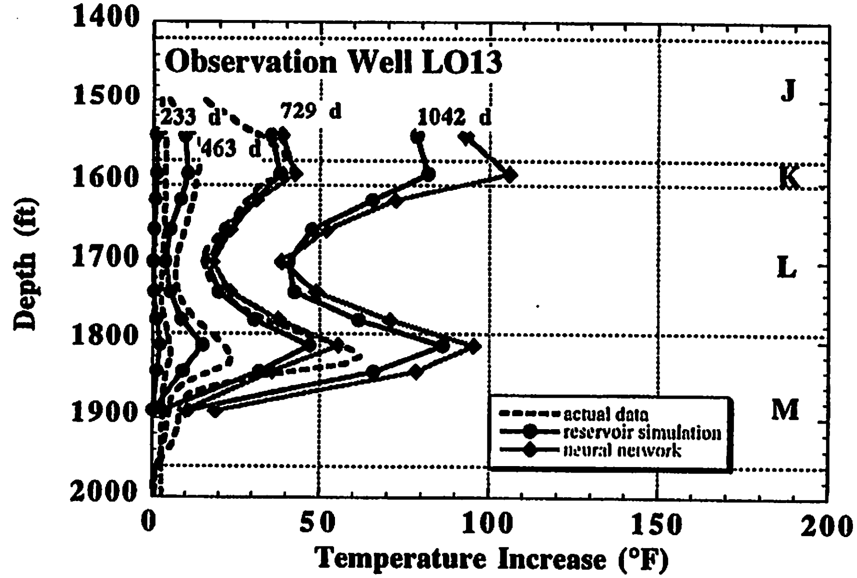

Fig. 17-Temperature response at Observation Well LO13 showing actual response (dashed lines), simulator history match (circles), and neural network prediction (diamonds).

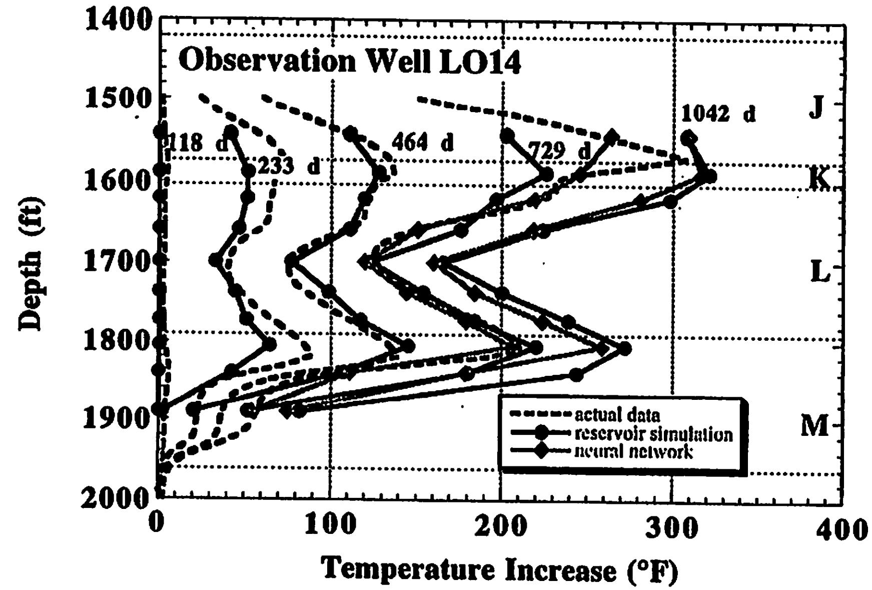

Fig. 18-Temperature response at Observation Well LO14 showing actual response (dashed lines), simulator history match (circles), and neural network prediction (diamonds).

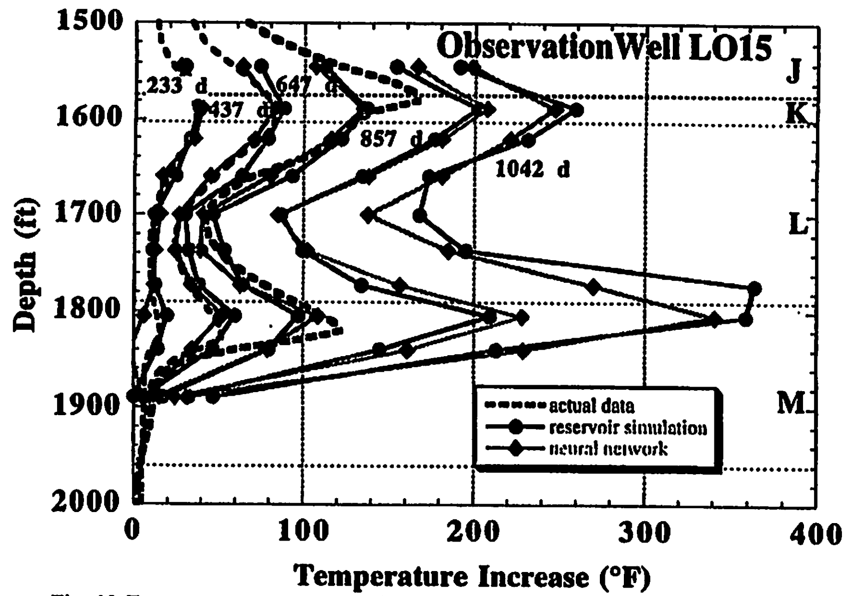

Fig. 19-Temperature response at Observation Well LO15 showing actual response (dashed lines), simulator history match (circles), and neural network prediction (diamonds).

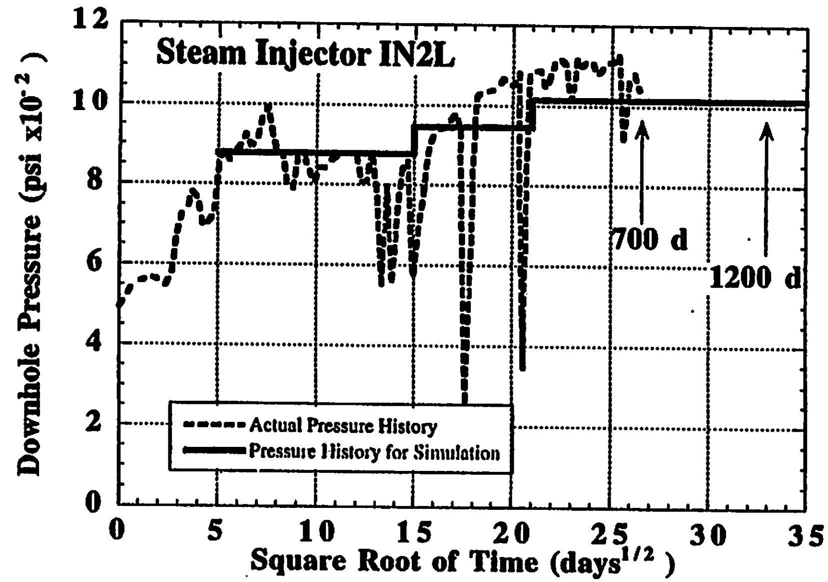

Fig. 20-Steam injection pressure history for IN2L.

SPE 35737

CT Scan and Neural Network Technology for Construction of Detailed Distribution of Residual Oil Saturation During Waterflooding

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Abstract

We present an integrated approach to imaging the progress of air displacement by spontaneous imbibition of oil into sandstone. We combine Computerized Tomography (CT) scanning and neural network image processing. The main aspects of our approach are I) visualization of the distribution of oil and air saturation by CT, II) interpretation of CT scans using neural networks, and III) reconstruction of 3-D images of oil saturation from the CT scans with a neural network model. The neural networks developed here construct 3-D images of fluid distribution at any time and/or location within the core. One neural network model interpolates between the CT images for a given position at different time levels and extrapolates beyond the interval of time during which the images were collected. Likewise, the network interpolates spatially between images at a given time. After interpolation and extrapolation, other network models have been developed to reconstruct the three-dimensional distribution of oil in the core. Excellent agreement between the actual images and the neural network predictions is found.

Introduction

An increasing global demand for energy and simultaneous depletion of conventional hydrocarbon reserves impose a formidable challenge for efficient recovery from nonconventional rock systems, such as naturally fractured reservoirs. Fractured petroleum reservoirs provide over 20 % of the world oil reserves [1]. Examples of prolific fractured reservoirs are: the Monterey Shales in California (estimated tens of billions of barrels of oil-in-place); the California Diatomites (estimated fifteen billion barrels of oil-in-place); the West Texas Carbonates; the North Sea Chalks; and the Asmari Limestones in Iran.

Hydrocarbon recovery from naturally fractured reservoirs is not yet fully understood. This is mainly due to the lack of a complete understanding of multiphase flow through fractured porous media. Two- or three-phase flow in a fractured reservoir depends on the combined nonlinear effects of hydraulic connectivity and physicochemical properties of fractures, relative permeabilities to multiphase flow in the fractures, rock-matrix nature, matrix block size, capillary forces and fracture closure stress. The nonlinear interplay of all these factors determines the ultimate hydrocarbon recovery from fractured reservoirs. In contrast, most of the published data have been produced in controlled experiments that have focused on one or more of the above factors considered in isolation. These data are then upscaled in numerical simulators to model the coupled nonlinear behavior of fractured reservoirs. As a result, current numerical simulation models of fractured reservoirs lack firm predictive capability and must be tuned for each field case with the available data.

Thus, it might be helpful to undertake a systematic experimental and theoretical study of joint effects of all the factors governing multiphase fluid flow in a fractured porous rock. Of course, such a study is beyond the scope of this paper. Nevertheless, we have undertaken a study to evaluate the influence of four major factors on hydrocarbon recovery. These are: fracture configuration, rock-matrix block size, wettability characteristics of the rock, and fluid flow rates. This paper reports our progress on a scoping study of spontaneous imbibition of a hydrocarbon (kerosene) into a single air-filled block of rock matrix (Berea sandstone). Our experiments are a preamble to a more difficult study of the most important production mechanism in fractured reservoirs during waterflooding, i.e., counter-current imbibition of water to displace oil and gas from the matrix. Here, we want to understand the pattern of imbibition from the distribution of fluid saturations and to design a neural network model of in-situ fluid saturations obtained directly from a CT scanner. The model is then used to generate three-dimensional time-lapse images of kerosene imbibition. Finally, we intend to incorporate the experimental results into our integrated-finite difference simulator, M²NOTS (Multiphase Multicomponent Non Isothermal Organics Transport Simulator [2]), to allow for a more realistic simulation of multiphase flow through fractures. The mathematical formulation of M²NOTS does not rely on a global coordinate system; therefore, it naturally extends the method of Multiple Interacting Continua [3] for modeling flow in fractured media to multiphase and multicomponent systems.

In this project, we use high resolution X-ray computerized tomography to obtain images of the cross-sectional distribution of kerosene and air in Berea sandstone cores as a function of time. Scans perpendicular to the axis of the core were made using a high resolution EMI 5005 (second generation) CT scanner. Each CT slice consists of a series of volume elements (voxels). Every voxel has its own characteristic attenuation, and can be mapped into a 2-D image matrix of picture elements (pixels). Using standard computer software, the 2-D fluid distributions at specific times and locations are visualized for each CT slice. CT is a fast, non-destructive imaging technique for determining in-situ fluid saturation with excellent 3-D resolution. Using this technique, attenuation differences as small as 0.1% with a cross sectional resolution of less than 1 mm^3 can be realized. For extrapolating and interpolating between different slices obtained, neural network models were developed.

Neural networks are very useful in modeling nonlinear, complex, and multi-dimensional data and find wide application in analyzing experimental, industrial, and field data. Neural networks, unlike regression analysis, do not require specification of a structural relationship between the input and output data and they can be trained easily by using sufficient data from the system under study. In addition, neural networks have the ability to infer general rules and extract typical patterns from specific examples. These properties give the neural networks the ability to interpolate between typical patterns or data and generalize their learning in order to extrapolate to a region beyond their training domains.

Principles of CT Imaging

Various visualization methods have been used for fluid saturation determination during laboratory core flood experiments [4]. Some of the more common ones in use are transparent models [5], resistivity [6], microwave attenuation [7], NMR, MRI, X-ray, and gamma ray attenuation [8]. While most of these methods provide only average saturation and impose restrictions on experimental techniques, CT is a very fast and accurate technique with few restrictions on experimental conditions and offers fine spatial resolution [9]. Earlier investigators [10-16] have illustrated the importance of computerized X-ray tomography as a powerful tool for petroleum industry researchers.

To obtain a CT slice of an object, an X-ray source is collimated to provide a thin beam which is received by an array of crystal detectors. X-ray photons which strike these crystals cause them to fluoresce with an intensity proportional to the number of photons received. When a body is placed in the beam between the source and detector array, only those photons that are not absorbed by the body reach the detectors. **Fig. 1a** illustrates the principles of X-ray tomography. The values attained when the detectors are read represent the beam attenuation by an object placed in the path of the X-rays. The detectors are in a stationary array surrounding the object. The X-ray beams are always directed through the object aperture as the source moves around it in a circular path. The detectors are read at small rotational intervals and the resulting data are stored in a computer. This rotational excursion is called a pass and the total data acquired during this pass are termed a slice. After all readings for a slice have been acquired and stored in a computer, a cross-sectional image or matrix of attenuation coefficients μ(x, y) is created. Radon [17] established the mathematical foundation for image reconstruction from projection data. The basic synthetic unit is the volume element or voxel. The CT slice is composed of many voxels, each with its own characteristic attenuation, which are displayed as a 2-D image matrix of picture elements (pixels), shown in Fig.1a.

CT measures linear attenuation coefficients μ, which are defined by Beer's law:

$$I / I_o = e^{-(\mu / \rho)\rho x} \quad \text{.......................(1)}$$

where I_o is the source X-ray intensity, I is the intensity measured by the detectors, μ is the linear attenuation coefficient, ρ is the density of the medium, μ/ρ is the linear mass attenuation coefficient, and x is the thickness of the material. If several materials are placed in the path of the X-ray beams, Beer's law can be generalized as:

$$I / I_o = e^{-\Sigma(\mu_i \,/\, \rho_i)\rho x_i} \quad \text{..................(2)}$$

where i is the material considered. If the object contains a mixture of components, the overall mass attenuation coefficient of the mixture is given by:

$$\mu_{mix} = \sum_i \mu_i S_i \quad \text{.........................(3)}$$

where S_i is the saturation of the phase i, i.e., S_i is the volume fraction of component i such as water, oil or gas.

Different mechanisms are involved in the adsorption of X-rays. The relative importance of these mechanisms depends on the energy level of the incident X-rays. In general, μ depends on both electron density, ρ, and atomic number, Z. If the energy is above 100 keV, μ depends mostly on the electron density (Compton scattering). For energy below 100 keV, photo-electric adsorption is the main mechanism, depending mostly on the atomic number Z of the material studied. Thus,

$$\mu = \rho\left(a + bZ^{3.8}/E^{3.2}\right) \qquad (4)$$

where a is the Klein-Nishira coefficient, ρ is the electron density, E is the energy level in keV, Z is the atomic number, and b is a constant with a value of 9.8×10^{-24} keV$^{3.2}$. Some conclusions that can be drawn from Eq. (4) are, I) heavier elements will attenuate more than the lighter ones, II) the coefficient of adsorption, μ, for a given material changes with the energy level of the source and this change depends mostly on the atomic number of the element considered, and III) by measuring adsorption at two or more energy levels, one can obtain two independent measurements. This will help in solution of three phase problems as discussed in the Saturation Determination section.

Since it is impractical to deal with the X-ray attenuation coefficient, μ, a new scale is defined based on the international standard unit of Hounsfield (H or CT number). On this scale, water has a value of zero and air has a value of -1000. Hence, each CT unit represents about a 0.1% change in the attenuation coefficient. Equation (5) defines the CT number

$$CT = \frac{\mu_x - \mu_{water}}{\mu_{water}} \times 1000 \qquad (5)$$

where μ_x is the calculated X-ray attenuation coefficient. In most CT scanners, the range of CT unit varies from -1000, representing air, to 4000, representing very dense materials. Reservoir rocks typically fall in the range of 1000 to 2000 on this scale.

Saturation Determination

In order to obtain fluid saturations, Eq. (1) can be written as:

$$\log I = \log I_o\left[\mu_R\rho_R(1-\phi)x + \rho_f\mu_f\phi\right] \qquad (6)$$

where μ_R is the adsorption of the rock, ρ_R is the density of the rock, μ_f is the adsorption of the fluids, ρ_f is the density of the fluids, and ϕ is the porosity. For two phases (kerosene-air system), the governing equation is given by

$$\rho_B\mu = \mu_R\rho_R(1-\phi) + \phi(\mu_k\rho_k + \mu_a\rho_a) \qquad (7)$$

where ρ_B is the bulk density of the system, μ_k is adsorption coefficient of kerosene, ρ_k is the density of kerosene, μ_a is the adsorption coefficient of air, and ρ_a is the density of air. From the measurement of an evacuated core, $\mu_R\rho_R(1-\phi)$ is obtained. With μ_k and μ_a known, there are two equations with two unknowns:

$$\mu = \mu_k S_k + \mu_a S_a \qquad (8)$$

where S_k and S_a are the saturation of kerosene and air respectively. Also,

$$S_k + S_a = 1 \qquad (9)$$

For three phase saturation (water-kerosene-air system), since there are three unknowns, an additional, independent measurement is required. This is done by scanning at a different energy level. The system of equations for three phase saturation determination are given by

$$\mu_1 = \mu_{k1}S_{k1} + \mu_{w1}S_{w1} + \mu_{a1}S_{a1} \qquad (10)$$

at energy level 1 (100 keV), and

$$\mu_2 = \mu_{k2}S_{k2} + \mu_{w2}S_{w2} + \mu_{a2}S_{a2} \qquad (11)$$

at energy level 2 (>100 keV). Finally,

$$S_k + S_w + S_a = 1 \qquad (12)$$

By scanning a fully kerosene saturated core, a fully water saturated core, and a fully air saturated core, μ_k, μ_w, and μ_a can be obtained.

Neural Networks

Imaging the process of spontaneous imbibition in a Berea core using CT scanning methods has many limitations. One such limitation is the number of slices that can be obtained in space and time. For this study, only 4 sections perpendicular to the core axis were scanned at 20 mm separation and at only a few time intervals. In order to obtain fluid saturation distribution in space and time throughout the core, a neural network model was developed to interpolate between the CT images for a given position versus time and to extrapolate beyond the interval of time during which the images were collected. In this paper, only multi-layer perceptron networks with a back-propagation learning algorithm were used.

Historically, the development of neural networks followed the philosophy of emulating the brain. Many engineers and scientists believed that if the functions of the brain could be emulated, many of the problems which are difficult and seem insoluble by traditional methods could be solved. During the last decade, a great number of neural network software packages and tools were developed. It is important to mention that the new interest in neural networks is due, in part, to advances in computer technology which have made it possible to bring together a large number of nodes and massive interconnections of simple neurons, much like the human brain. However, developing a proper neural network model that is an accurate representation of the process of interest still requires a combination of art, science, and technology.

During the past several years, successful applications of neural networks to solve complex problems have increased exponentially. Considerable attention has been devoted to the use of neural networks as an alternative approach to interpolation and extrapolation, pattern recognition [18], statistical, and mathematical modeling. For example, back-propagation neural networks [19] were used to develop process models as substitutes for complicated empirical and mathematical models [20]. These models can be used as an alternative to statistical and time series analysis. Neural network analysis, unlike regression, does not require specification of structural relationships between the input and output data. However, identification using neural networks is more useful when large amounts of data are available. Once the networks are trained using sufficient information, they achieve excellent predictive capability and show excellent generalization performance. Neural networks may be trained to analyze, predict, and optimize waste management, electrochemical, reservoir, and chemical processes [21]. Self organization maps, such as Kohonen networks [22], are used to classify different patterns of processes. Auto associated networks, such as Hopfield networks [23], are also used in pattern recognition.

Multi-layer perceptron networks with a back-propagation learning algorithm are perhaps the most widely used for process modeling, identification, pattern recognition, and pattern classification. The typical network has an input layer, where data are presented to the network, an output layer, which holds the response of the network to a given input, and at least one hidden layer, which connects the input layer to the output layer. There is no theoretical limit on the number of hidden layers, but typically there will be one. Each layer is fully connected to the succeeding layer with corresponding weights. The values of the weights represent the current state of knowledge of the network. These weights are adjusted to improve the network performance. They are either determined via an off-line algorithm such as the back-propagation algorithm [24], or adjusted on-line via a learning process [20, 25].

Experimental Studies

An EMI 5005 (second generation) CT scanner at Stanford University was used in this study. **Fig. 1b** displays the scanner components. The scanner consists of a mainframe, rotational elements, and scanner electronics. The mainframe houses the X-ray source, detector array, and beam shaping elements. The scanner assembly consists of a support table for positioning the core. The generator group is responsible for generating the X-rays. A combined Viewer/Operator Console consists of a video console, an interactive keyboard for viewing, initiating image generation, and for image manipulation. The computation unit performs sequencing, interprets instructions, and executes them. The Video Generator accepts image information in digital form and converts it to the image seen on the viewing monitors. A Disk Drive stores these images. The Magnetic Tape Unit records images from the Disk Drive for long term storage of information.

The cores were scanned at an energy level of 140 keV and a field size of 13 cm. A small field of scan was used to obtain better spatial resolution, as the number of pixels available remain constant. Slice thickness was made as small as possible, i.e., 3 mm (it varies from 1-10 mm), in order to minimize errors and maximize resolution. Greater slice thickness results in greater measurement error. Also a scan angle of 398° was used as it produces the highest resolution due to an overscan of 38°.

The core holder/experimental cell was constructed from acrylic which is relatively X-ray transparent. A schematic of the experimental setup is shown in **Fig. 2a.** The core holder, 6.4 cm in diameter and 21 cm long, is provided with two end caps for fluids to flow in and out of the core holder. The inlet endcap is connected to a fluid tank through a rubber tube. A control valve attached to the tank controls the flow of fluid from tank to coreholder. The outlet endcap is connected to a measuring vessel. The axis of the cylindrical Berea sandstone core was aligned with the axis of the core holder so that the core was exposed to uniform fluid saturation on all the sides. The sandstone used for this study has a porosity of 22% and a permeability of 300 md. Kerosene used as the hydrocarbon for this study has a specific gravity of 0.80 and viscosity of 1.152 cp at 21°C. Kerosene-air surface tension is 23-32 dynes/cm at 21°C.

Core preparation prior to the start of the experiment involved firing the cores for 24 hours at 750°C. This was done to remove effects of clay swelling and migration from the imbibition process. The cores were initially at 1 atm pressure and saturated with air. At the onset of the experiment, the first images were scanned at four different axial locations within the air-filled core holder in a single run to obtain dry core CT values (CT_{dry}). Four 3 mm thick axial scans were taken at 20 mm spacing. Location of the four faces with reference to the two end faces are shown in **Fig. 2b.** Later, the valve attached to the fluid tank was opened and kerosene filled the core holder until the whole core was uniformly submerged in kerosene. X-ray scanning was done along the core at the same locations to btain CT values (CT_{exp}) at times of 1, 5, 10, 15, 25, 35, 50 minutes, and at every 60 minutes for next 240 minutes after the core was exposed to kerosene to obtain temporal istribution of kerosene within the core. The scanning procedure determined the average saturation of the core sample at each location. Scanning was also conducted at 24 hours and 8 hours after the start of kerosene imbibition. Weight of the core was measured at the beginning and end of the experiment for mass-balance calculations. Scanning was performed at the ame axial locations in all the runs to obtain the spatial istribution of kerosene.

Results

or brevity, we only report images obtained at 5, 10, 15, and 25 minutes after the start of kerosene imbibition. This is because most of the observable dynamics of kerosene nbibition were found to have occurred in first 15 minutes of the experiment. An analysis of images obtained at later periods showed only very small changes in the overall kerosene turation of the core.

For calculating kerosene saturation in any slice of the core, Eq. (13) is applied to each pixel of the slice:

$$S_{\text{kerosene}} = \frac{CT_{\text{kerosene}} - CT_{\text{exp}}}{CT_{\text{kerosene}} - CT_{\text{dry}}} \quad \text{..............(13)}$$

and

$$S_{\text{air}} = 1 - S_{\text{kerosene}} \quad \text{......................(14)}$$

$CT_{kerosene}$ is the CT value for a fully kerosene saturated core. In is study, slices obtained from X-ray scanning after 48 hours . kerosene imbibition were used to determine the fully kerosene saturated core CT values. After 48 hours of kerosene nbibition, the core appeared to have reached irreducible air turation, as no further changes were noticed in the CT values. From mass-balance calculations, the final kerosene saturation in the core is 80%. Thus to obtain accurate turation values, values obtained from Eq. (13) were multiplied by a factor of 0.8. We are currently developing a better method of rescaling the images *directly from the raw X-y attenuation data.*

There were also problems using the CT_{dry} values obtained from scanning the core surrounded only by air. All the other ages were scanned after filling the core holder with kerosene. fferences in densities of the surrounding media cause differences in the absolute values of attenuation coefficient μ inside the core. For obtaining the CT_{dry} values to be used in . (13), inner dry portions of the slices obtained after 1 minute of kerosene imbibition were used. To obtain kerosene saturation profiles, average kerosene saturation was calculated annular rings of each slice, within circles at increasing radii, and finally in sectors. This averaging procedure is illustrated in Fig. 2c.

Fig. 3 shows a series of images obtained after the kerosene has imbibed into the core for 5, 10, 15, and 25 minutes at the four axial sections of the core. The images represent the distribution of kerosene saturation inside the core. In all these images, white represents zero kerosene saturation, and black represents the maximum kerosene saturation or 100%. Figs. a-1 through d-1 are the images of Berea core after 5, 10, 15 and 25 minutes of kerosene imbibition at section 1, located 2 mm from the core face. In these images, there is a clear lack of an oil front, because axial flow dominates over radial flow in this section. Thus at all times, the whole slice appears uniformly saturated. There is the possibility of a kerosene front at very early times. However, nothing conclusive can be said from the information available. Also, kerosene saturation increases uniformly but consistently with time from image a-1 to d-1. Image d-1 appears to 80 % oil saturated.

Berea slices obtained at section 2, 22 mm away from the left core face, are shown in images a-2 through d-2. Due to location of the slices far away from the core faces, radial flow dominates in this section. This is seen as a clear front observed at early times and represented by a dark annulus at the edge of the slice. Image a-2 obtained after 5 minutes of kerosene imbibition shows a very sharp front, that gradually changes to a more diffuse front in image b-2, and finally disperses after 15 minutes as seen in images c-2 and d-2. In image a-2, kerosene is imbibing uniformly into the core from all the sides and imbibes radially into the sample as a sharp front. Analysis of the saturation-matrix shows that the front is dispersed over 3-4 mm range. In image b-2, the kerosene saturation annulus appears to be moving radially inside the core and has thickened as compared to image a-2. There is also a gradual increase in the kerosene saturation towards the core edges as would be expected. Image c-2 shows the kerosene saturation in Berea core after 15 minutes of imbibition. The kerosene front has dispersed by this time. High kerosene saturation values in the center of the section show that the kerosene has reached the center of the core. The kerosene saturation distribution after 25 minutes of imbibition is shown in image d-2. The image d-2 shows that approximately 80% kerosene saturation is obtained uniformly throughout the core and stays constant.

Again in section 3, 25 mm from the right face of the core, an imbibition pattern in time similar to that of section 2 is observed. Radial flow dominates and hence changes in kerosene concentration are observed radially with time. A sharp kerosene front in image a-3 changes to a slightly less sharp front in image b-3 and finally disperses in images c-3 and d-3.

A similar kerosene imbibition history is seen in images obtained at section 4, 5 mm from the right face of the core. Section 4, however, is quite different from section 1, especially at the early stages of the imbibition process. This is also due to a predominance of radial flow. A clear pattern can be seen from a-2 to a-4, and b-2 to b-4. A sharp front exists in the early part of the imbibition, then it diffuses slightly and finally disappears after 15 minutes, as shown in Figs. 3c-4 and 3d-4. However, the distribution of kerosene saturation in section 4 differs from those in sections 2 and 3. Around 10 minutes of imbibition, axial effects combine with radial flow. This cannot be seen in images 3c-4 and 3d-4 as the core reaches uniform saturation distribution and the axial flow effect is masked. In summary, the behavior of section 4 in the early stages of the imbibition process is similar to the behavior seen in section 2 and 3. In the late stages of imbibition, it is a combination of the behaviors of sections 1, 2 and 3.

To illustrate the imbibition pattern of kerosene in Berea sandstone more clearly, saturation profiles along the diameter of the core at each section are presented in Fig. 4. Figures 4a-1 through 4d-1 show kerosene saturation profiles obtained in section 1 at 5, 10, 15 and 25 minutes. In agreement with the images of Fig. 3, the saturation profiles 4a-1 to 4d indicate that axial flow dominates. A consistent increase in kerosene saturation is observed as we go from Fig. 4a-1 to 4d-1. An analysis of Figs. 4a-2 to 4d-2, representing kerosene saturation profiles with time at section 2, show the progression of a very sharp radial front extending over a range of 3-4 pixels or 1.1 to 1.5 mm. The kerosene front width increases to 7-10 pixels or 2.6 to 3.7 mm at 10 minutes in Fig. 4b-2, and finally disappears after 15 and 25 minutes in Figures 4c-2 and 4d-2.

History of average kerosene saturation in a circular annulus of the core at different radii is shown in Fig. 5. Here, average annular kerosene saturation is plotted as a function of radial distance and time. It shows the movement of a kerosene front, the knowledge of which is extremely important for interpolation between the images. In Fig. 5a through 5d, white shading represents zero kerosene saturation and black shading represents 100% kerosene saturation. Shades of gray represent intermediate saturations. Trends found in Figs. 5a through 5d are similar to those shown earlier in Figs. 3 and 4. At section 1 in Fig. 5a, 2 mm from the left face, at times 5-15 minutes, no change in kerosene saturation occurs radially due to predominant axial flow. Uniform increases in kerosene saturation between 5 and 15 minutes is observed. After 15 minutes, no further change in kerosene saturation occurs either radially or with time. Figs. 5b, 5c, and 5d at sections 2, 3, and 4, respectively, exhibit a similar trend in kerosene imbibition and a trend similar to that seen in Figs. 3 and 4 in sections 2, 3, and 4. Kerosene imbibition at 5 minutes occurs only at a radial distance of 20 mm, i.e., near the edge of the core. Kerosene first reaches the center of the core at 12 minutes. Also, a sharp kerosene front is seen during the first 15 minutes, after which the front disappears.

In order to smooth the kerosene saturation distribution, average kerosene saturation within a circle is presented as a function of time and radial distance in Fig. 6. The purpose of these plots is to show minute changes in the kerosene saturation fronts. Kerosene imbibition patterns observed earlier in Figs. 3, 4 and 5 are exactly similar to those shown in Fig. 6 at all the four sections. A lack of front is seen in Fig. 6a at section 1, and sharp fronts in Figures 6b, 6c, and 6d at sections 2, 3, and 4 until 12 minutes. Beyond 15 minutes, the kerosene front becomes non-existent.

Fig. 7 is a plot of percent kerosene saturation versus axial distance from the closest core face at different times. In Fig. 7 at section 1, the core is saturated. Kerosene saturations range from 45 % to 82 % after 5 to 25 minutes of kerosene imbibition.

Plots of average kerosene saturation in a specific annular ring versus time is shown in **Fig. 8-1a through 8-1d**. A nearly uniform kerosene saturation is observed in Fig. 8-1a, representing section 1, at all times. Kerosene saturations increase from the edge to the center of the core at 5, 10, and 15 minutes. The change in saturation with radial distance at 25 minutes is very small indicating that the core has reached a steady state. Figures 8-1b through 8-1d show a very sharp front at 5 minutes that changes to more diffuse front at 10 minutes and no front at times 15 minutes and 25 minutes. Similar trends can be observed in Figs. 8-1c and 8-1d, i.e., sections 2 and 3, respectively, and similar to that in Fig. 8-1d, i.e., section 4 at earlier times. However, the trend is different from Fig. 8-1d at later times and is a combination of sections 1, 2, and 3 at times 15 and 25 minutes.

Average oil saturation within a specific annulus as a function of radial distance versus time is plotted in **Fig. 8-2**. A smaller profile band width in Fig. 8-2a, representing section 1, shows uniform imbibition all throughout the core which is due to the axial flow pattern at section 1, 2 mm from the left face of the core. Figs. 8-2b through 8-2d representing sections 2, 3, and 4, respectively, show a wide profile band width indicating that a radial flow pattern is more prevalent in these sections as there is a large change in saturation with radial distance. However, all the profiles converge to a very narrow region beyond 15 minutes as most of the imbibition process ends before 15 minutes. Figures 8-2b and 8-2c have a similar width as compared to Fig. 8-2d at earlier times. At later times, i.e., after 15 minutes, profile width pattern in Fig. 8-2d becomes a combination of those in Figures 8-2b and 8-2c.

Design of Neural Network Models

The network model for axial mapping has two nodes in the input layer representing the axial coordinate and elapsed time, both scaled uniformly between 0 and 1. It has 3 nodes in the hidden layer with nonlinear transfer function, and one node in the output layer predicting the total average saturation in each circular cross section, and also with nonlinear transfer function. The data in **Fig. 7** were used to train the network. Due to the limited volume of data available, all the data were used in the training. The model was trained until the prediction suffered upon continued learning. Figs. 7a and 7b show the performance of the network model for predicting the average oil saturation as a function of time and axial position. The results show perfect mapping and excellent prediction of the saturation for the training data set. Even though only 4 images were available in the axial direction, the model had excellent performance. Therefore, better performance with higher accuracy and confidence level will be expected if more axial information is introduced into the network model.

To model the radial behavior presented in Figs. 8-1a to 8-1d, and Figs. 8-2a to 8-2d, a different neural network was designed. This network has three nodes in the input layer representing the axial coordinate, radial coordinate, and elapsed time, all scaled uniformly between 0 and 1. It has 15 nodes in the hidden layer with nonlinear transfer function, and one node in the output layer representing the average saturation in a circular ring. Data presented in Figs. 8-1a through 8-1d were used for training and testing the network model. The available data were divided into two groups, a testing and a training data set. The test data set was presented to the network, and the model was trained until the prediction suffered upon continued training. Figs. 8-1e through 8-1h show the performance of the network prediction for both the test and training data set. The mean error in the training data set is equal to 0.000249 with standard deviation equal to 0.000343. The mean error in test data set is equal to 0.000520 with standard deviation equal to 0.001257. Comparing Figs. 8-1a to 8-1d with Figs. 8-1e to 8-1h, and Figs. 8-2a to 8-2d with Figs. 8-2e to 8-2f, one can see that the network for radial mapping has excellent prediction for both the test and training data set. We conclude that the radial network is trained with sufficient information and with data that span a wide range of system behavior; therefore, it is an excellent predictive tool.

3-D Reconstruction of Images

The network model developed earlier can be used for 3-D reconstruction of CT images and prediction of kerosene saturation. Our neural network methodology was used to reconstruct image d-4 in Fig. 3. This particular neural network model can predict the saturation of kerosene at each pixel as a function of axial and radial coordinate at a fixed time. The error predicted for reconstructing the 3-D images of the saturation distribution is less than 5 percent.

To show the usefulness of the model to predict the oil saturation at any point (axial and radial location and time) image b-2 in Fig. 3 is used. Fig. 9a shows the actual data. Fig. 9b shows the reconstruction of Fig. 9a based on linear interpolation in time. Figs. 3a-2 and 3c-2 were used for this interpolation. Comparing Fig. 9a with 9b, one can see that the two images are not similar, and the linear interpolation failed to reconstruct the actual data. As a remedy, the results from the linear interpolation were used in conjunction with the neural network prediction of the average saturation in each concentric ring with a thickness of 4 pixels. The result is shown in Fig. 9c. Comparison of Fig. 9a with 9c demonstrates that the model accurately reconstructed the actual image. The mean error in this case study is less than 10% with a standard deviation of 2.5%. To reduce the error further, a neural network model was developed to calculate the average saturation in a sector of 2 pixels in the radial direction and 10 degrees in the azimuthal direction. In addition, the axial images were also included into the interpolation model. In this study, images a-2, c-2, b-3, and b-4 in conjunction with the network model were used to reconstruct the image 9d. Comparing image 9a and 9d, one can see that the model reconstructed the actual image almost perfectly. The maximum expected error based on this technique is less than 5%.

Conclusions

Kerosene imbibition in a dry Berea core was successfully imaged using CT scans and correct fluid saturations were computed. Images scanned in the interior of the core show a sharp front propagating radially at short times. The front gradually diffuses and disperses totally after 15 minutes, as the entire cross-section fills with kerosene. Spontaneous imbibition of kerosene in an air-saturated Berea core with diameter 5.46 cm and length 6.7 cm is a comparatively fast process with most of the observable dynamics ending in 15 minutes. A relatively fast and accurate technique for imaging fluid flow in a porous medium, such as CT scanning, is quite adequate for tracking kerosene imbibition and for measuring the distribution of in-situ fluid saturations. However, CT experiments must be carefully designed to avoid excessive experimental error in a limited number of images that can be obtained in time and space. As most of the observable dynamics of kerosene imbibition were over in 15 minutes, it was imperative to obtain images at several short time intervals. Also, it is important to scan all the images with a similar medium surrounding the core. A core imaged in surrounding media of different densities has different absolute values of attenuation coefficient, μ. CT values of such images lead to improper determination of saturations.

To train the neural networks for proper prediction of spatial and temporal distribution of fluids, a large number of data points are needed. Due to scanner limitations (heating up of cathode-ray tube), images could only be obtained at 4 time intervals during the first 15 minutes. Thus, data obtained from such experiments are in general quite insufficient for proper neural network modeling. Axial information was sparse and even though our network interpolated properly between the existing images we are uncertain as to its extrapolative quality at core ends. Fortunately, the homogeneous Berea sandstone core behaved predictably, and we obtained sufficient radial information to train the network.

Nomenclature

a = Klein-Nishira coefficient, (-)
b = constant in Eq. (4), 9.8×10^{-24}, mL^2/t^2, $keV^{3.2}$
E = energy level, mL^2/t^2, keV
I = detected X-ray intensity, 1/t, counts/min
I_o = incident X-ray intensity, 1/t, counts/min

ϕ = porosity, percentage
ρ = density, m/L^3, gm/cc
S_i = saturation of the phase i, % PV
μ = linear attenuation coefficient, L^{-1}, cm^{-1}
x = thickness of material, L, mm
Z = atomic number

Acknowledgments

This work was supported by the Assistant Secretary for Fossil Energy, Office of Gas and Petroleum Technology, under contract No. DE-ACO3-76FS00098 to the Lawrence Berkeley National Laboratory of the University of California and is funded through the Natural Gas and Oil Technology Partnership. Support for the CT scan experiments was provided by the SUPRI-A Heavy Oil Industrial Affiliates Program and by U.S. Department of Energy under contract No. DE-FG19-87BC14126 to Stanford University.

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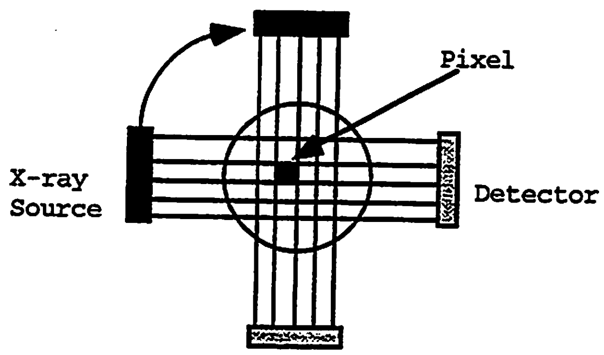


Fig. 1a-CT scanning process

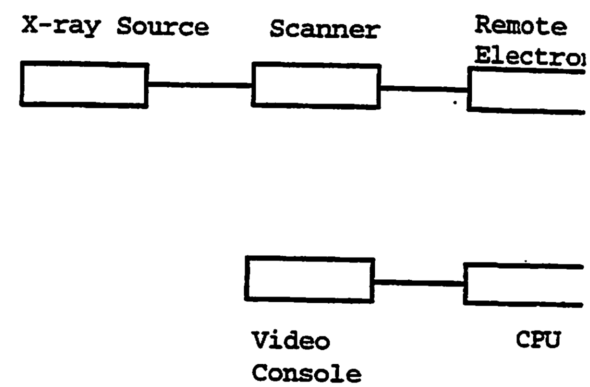


Fig. 1b-The scanner system

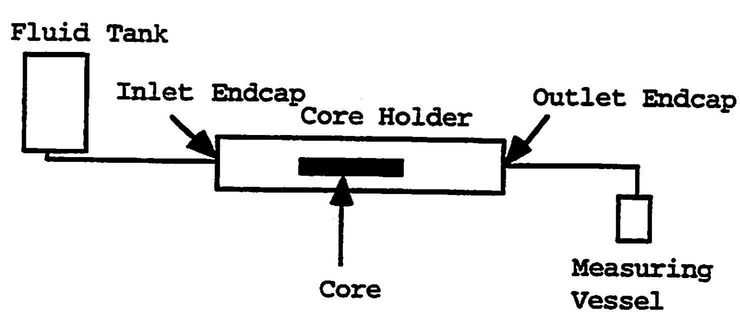


Fig. 2a-Schematic of experimental setup

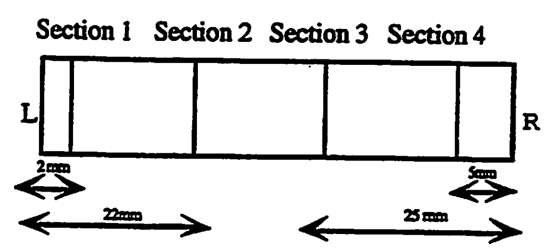


Fig. 2b- Schematic of sections scanned in the Berea core

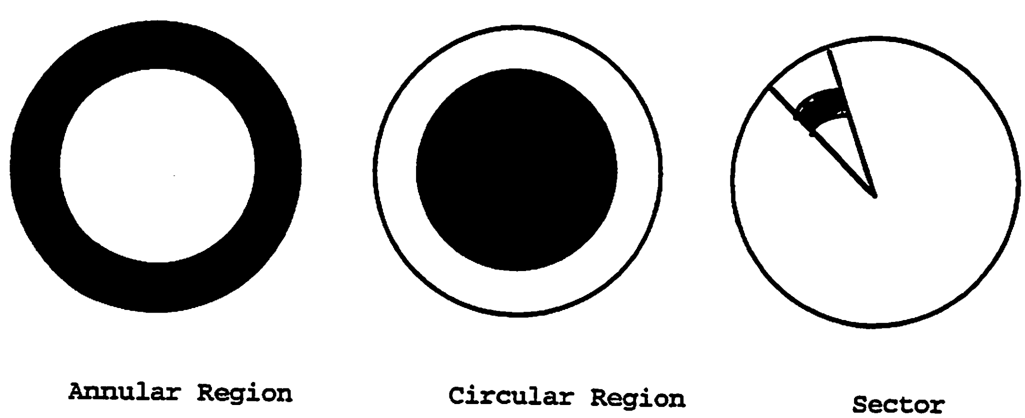


Fig. 2c-Schematic of configurations considered for kerosene average saturation calculation

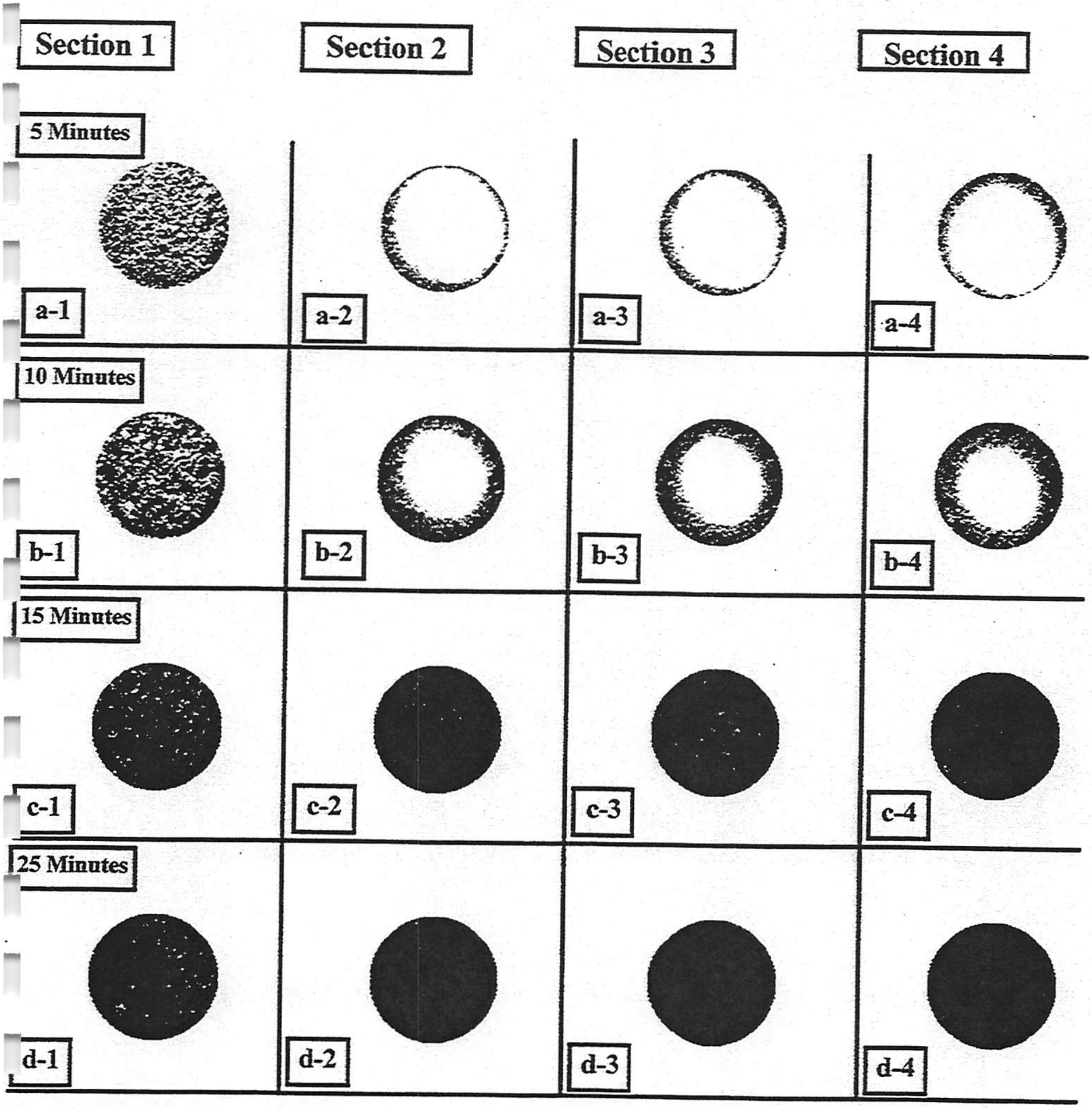


Fig. 3-CT images of kerosene imbibition into Berea Sandstone core

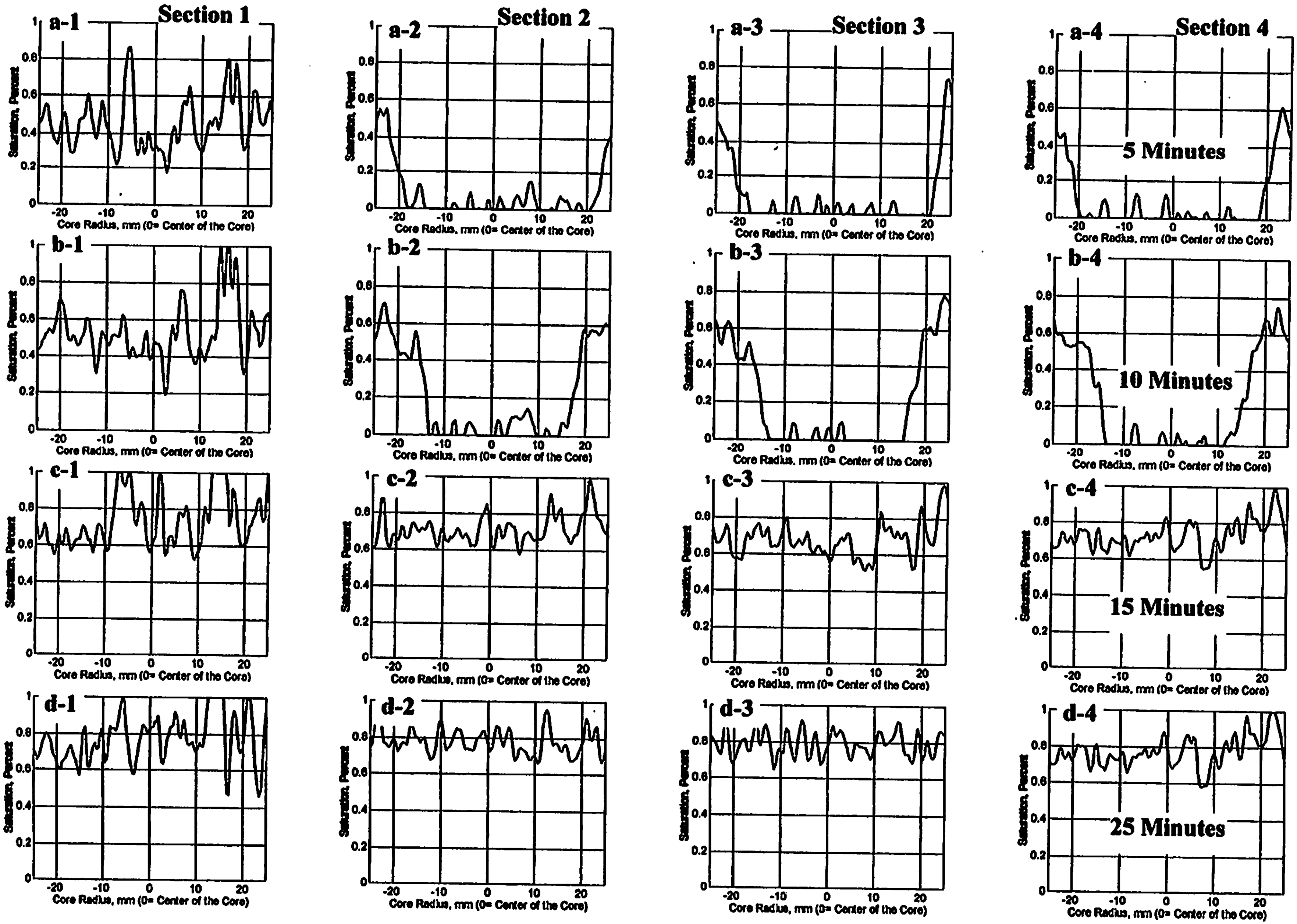


Fig. 4- Kerosene saturation profile along the horizontal diameter of the core.

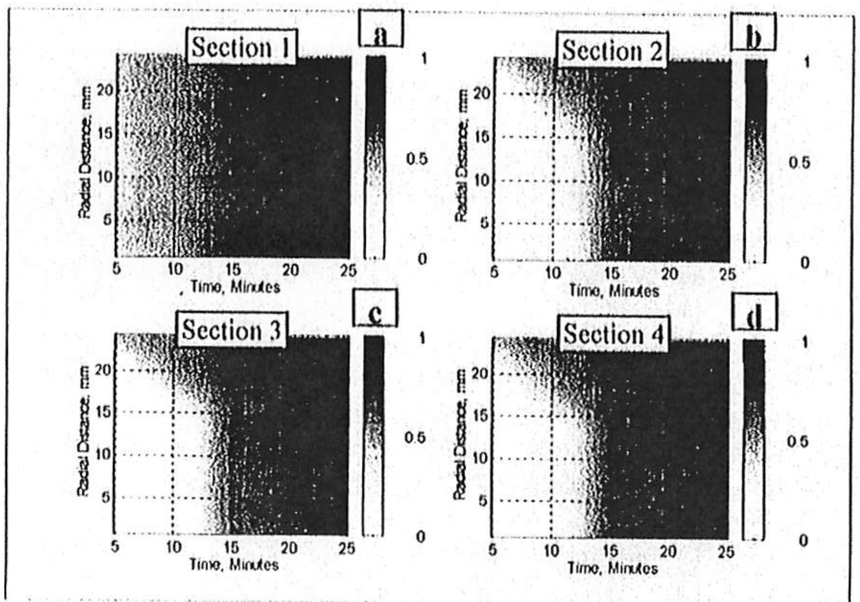


Fig. 5-Average oil saturation within a specific circular ring with a specific radius at different time.

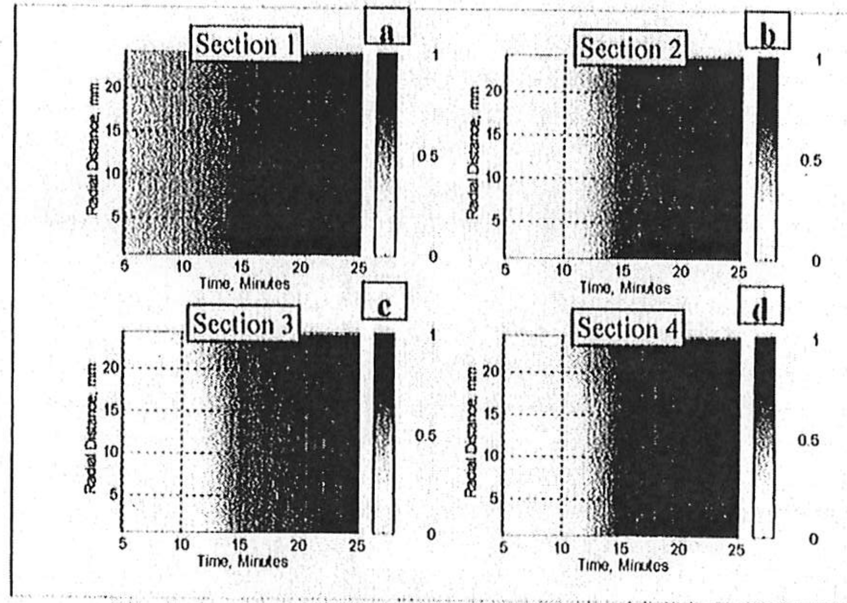
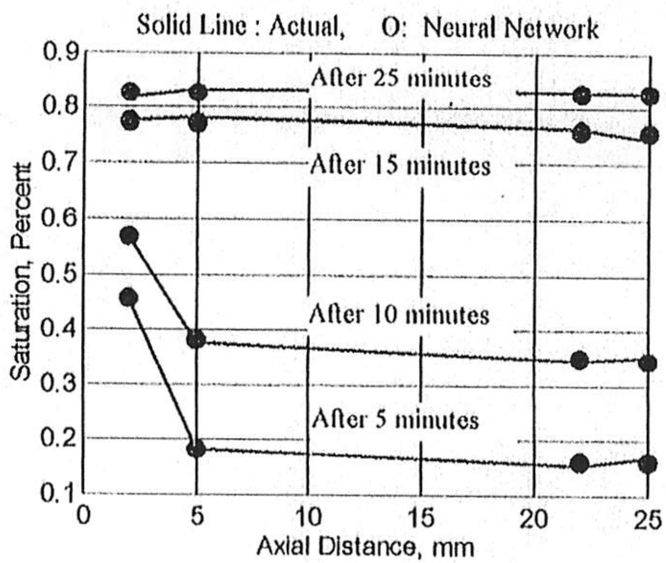


Fig. 6-Average oil saturation within a specific circle with a specific radius at different time.



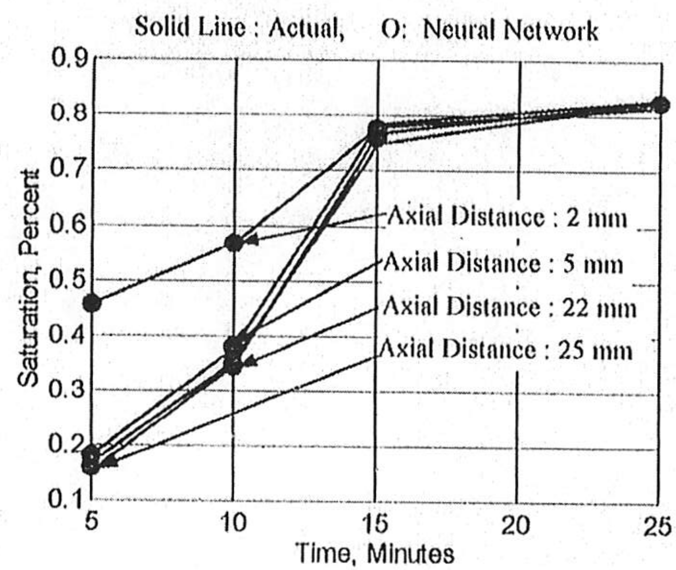


Fig. 7- Comparison between actual data and neural network prediction for average saturation in each section.

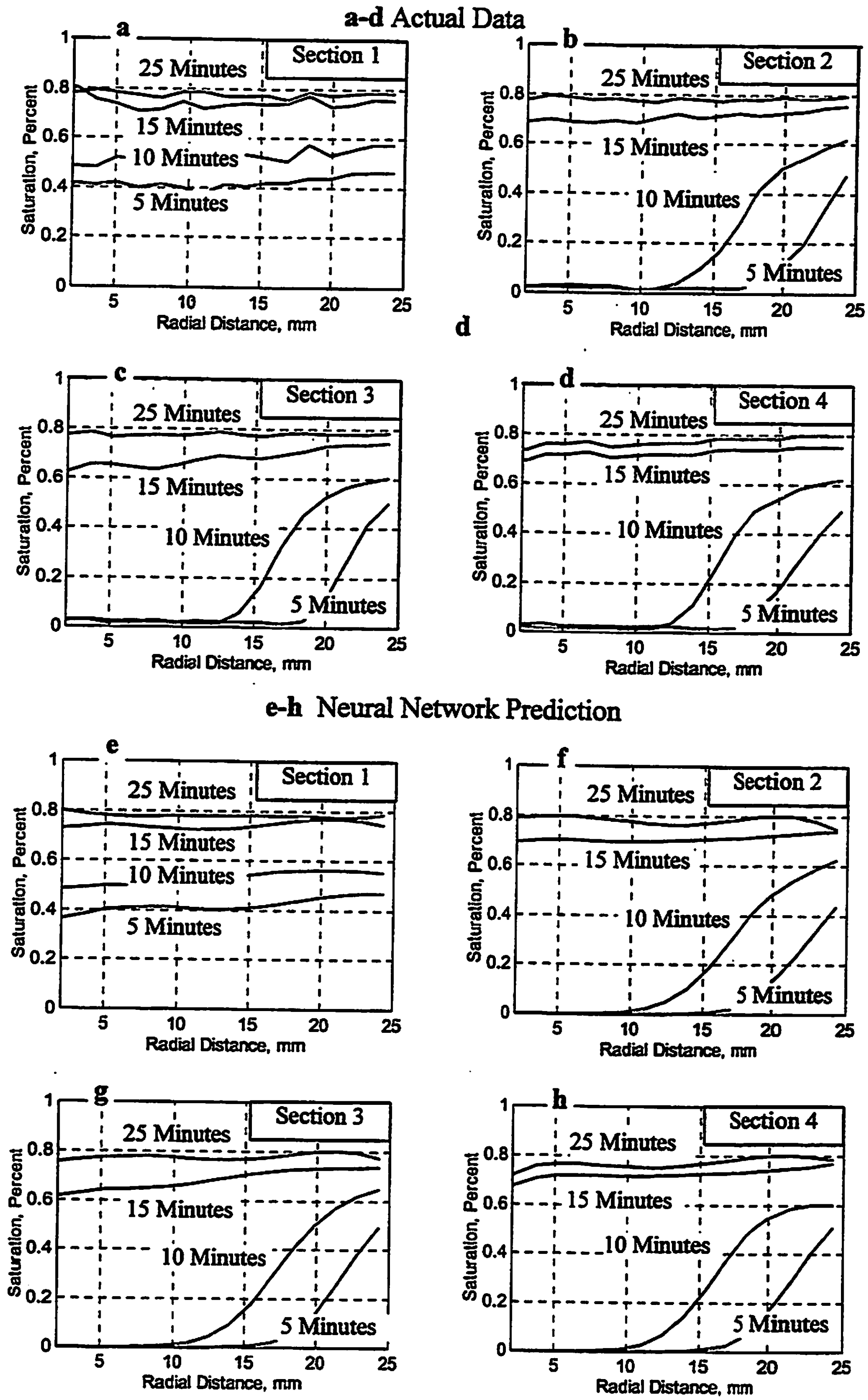


Fig. 8-1 Comparison between actual and neural network prediction for average oil saturation within a specific circular ring with a specific radius at different time.

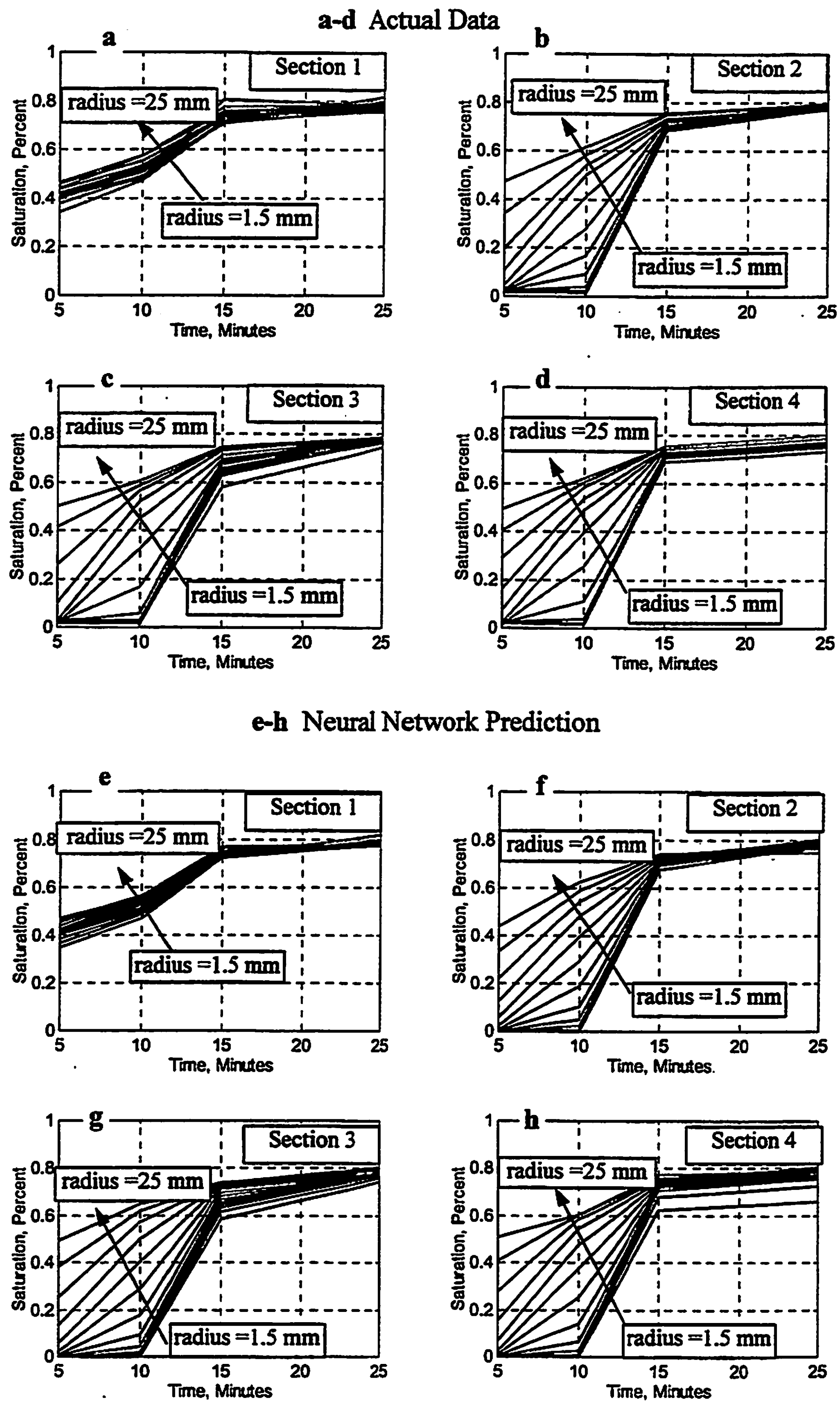


Fig. 8-2 Comparison between actual and neural network prediction for average oil saturation within a specific circular ring with a specific radius at different time.

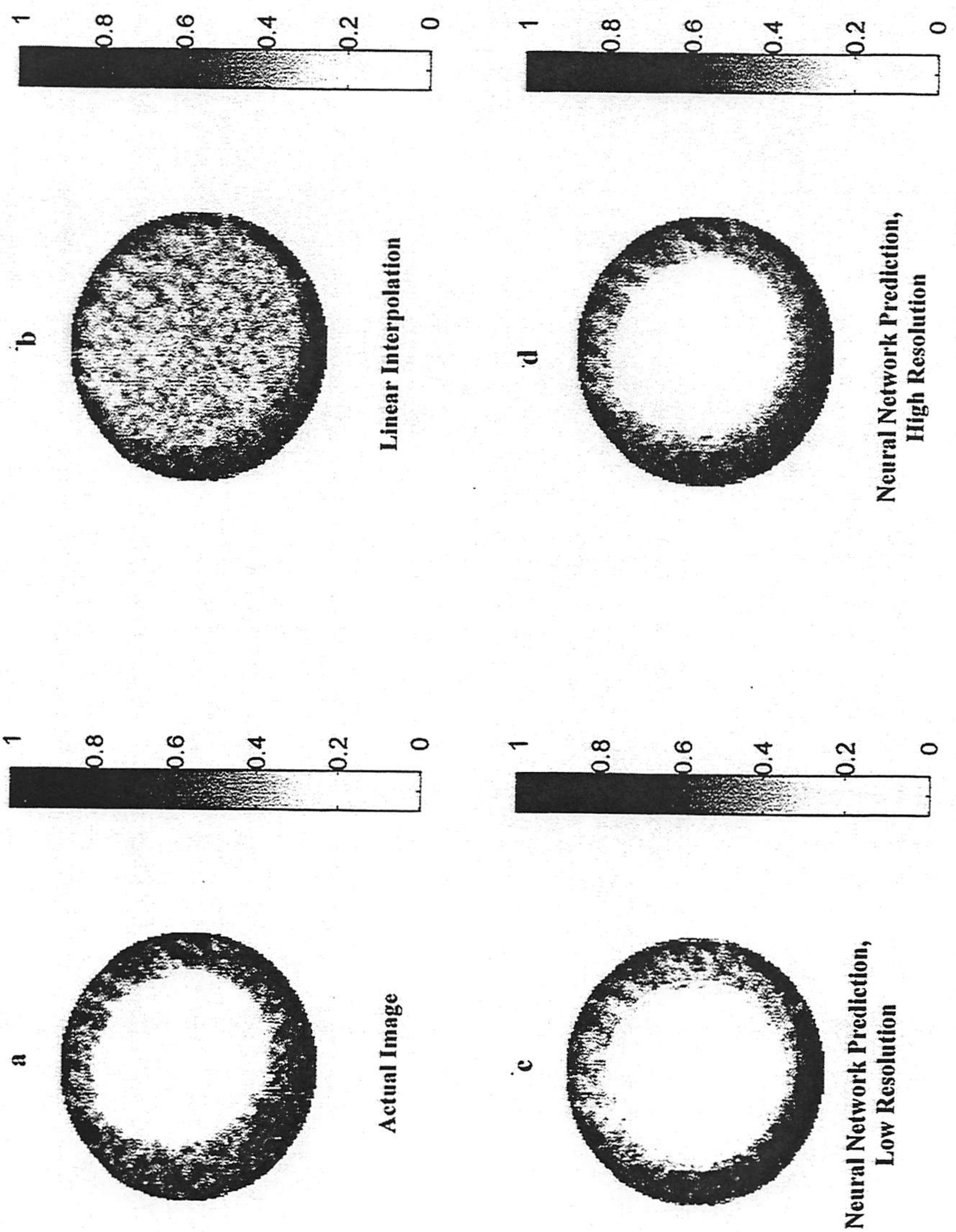


Fig. 9-Comparison between actual CT image with neural network prediction and linear interpolation.

Novel Sand Consolidation Completion Techniques Using Alkaline-Steam Injection in the Tar Zone, Wilmington Field

David K. Davies
David K. Davies and Associates

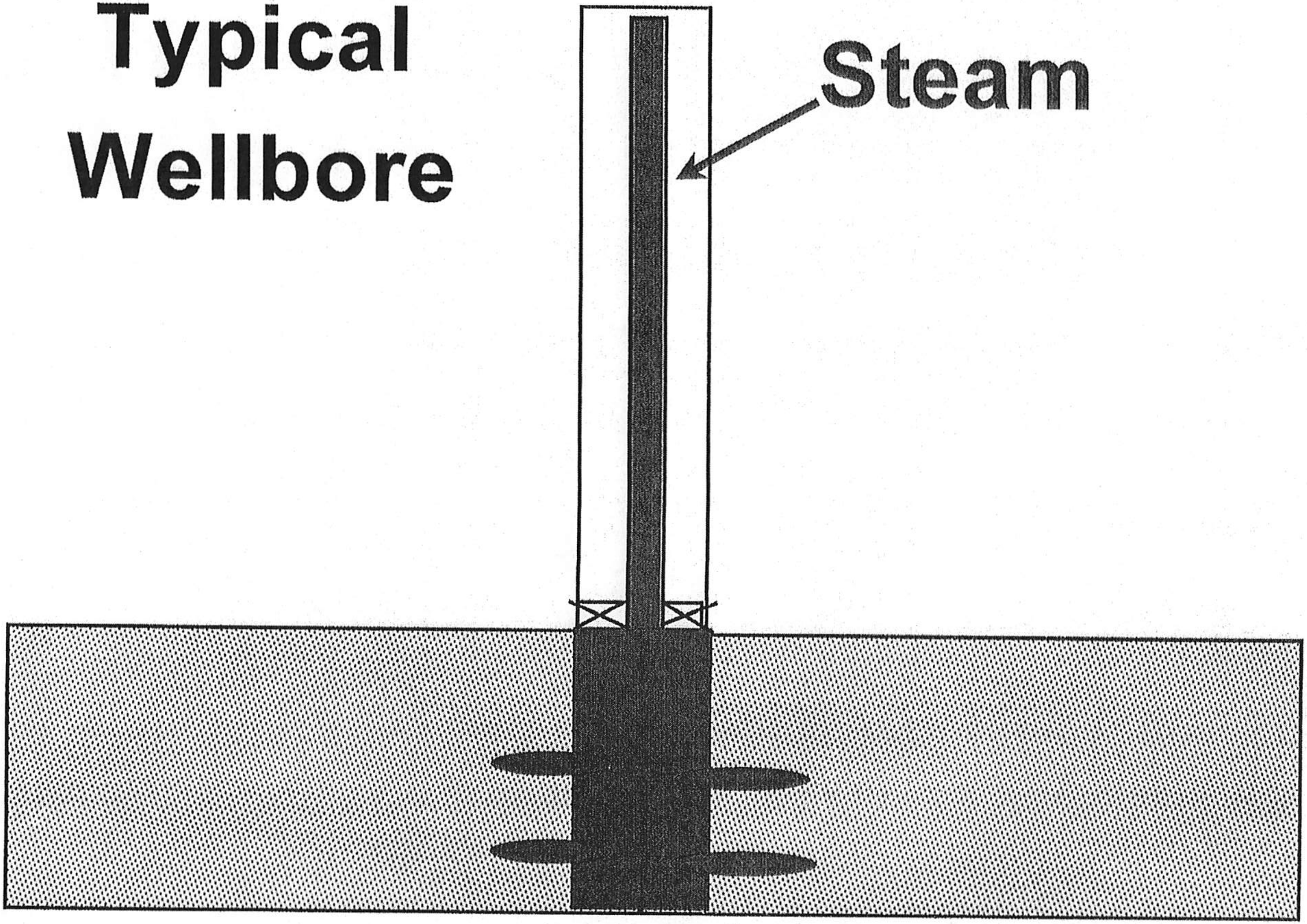
P. Scott Hara & Julius J. Mondragon
Tidelands Oil Production Company

Novel Sand Consolidation Completion Technique Using Alkaline Steam Injection in the Tar Zone, Wilmington Field, California

DAVIES, DAVID K., David K. Davies & Associates, INC, Kingwood, Texas; HARA, P. SCOTT, Tidelands Oil Production Company, Long Beach, Cal.; MONDRAGON, JULIUS J. III * Tidelands Oil Production Company, Long Beach, Cal.

This is a case study of a novel sand consolidation completion technique. We have completed 11 vertical wells and 2 horizontal wells over five years with minor or no sand problems to date or noticeable impairments to well productivity. We believe that the hot alkaline water in 80% quality steam causes silica dissolution which bonds the sand grains and controls sand movement into the wellbore. Although tested in the field, we do not know the long term effects of this process. We plan to perform laboratory test and research to determine the geochemistry occurring, the contribution of the steam phase to the process, the formation around the wellbore which is being treated, and the hot water and steam volumes needed to optimize the process. The results of the laboratory study will be the subject of a future paper.

Typical Wellbore



NOVEL SAND CONSOLIDATION PROCESS

- The Hot Alkaline Water In The 80 % Quality Steam Causes Silica Dissolution Which Bonds The Sand Grains and Controls Sand Movement Into The Wellbore

- Steam Aids In Creating Secondary Porosity And Permeability

- Laboratory Tests Are Being Designed To Determine The Geochemistry Occurring In The Formation Around The Wellbore And The Hot Water And Steam Volumes Needed To Optimize The Process

NOVEL SAND COMPLETION TECHNIQUE

- 11 Vertical Wells
- 2 Horizontal Wells; Fault Block I
- 4 Horizontal Wells; Fault Block II, DOE Project
- Repaired Parted Liner
- Wells Have Been On Production Up To 5 Years With Minor Or No Sand Problems To Date With The Exception Of 1 Horizontal Well
- No Noticeable Impairments To Well Productivity

SAND CONSOLIDATION PROCEDURE

- Cemented Cased Well
- 1/4" to 1/2" Perforations
- 80 % Quality Steam
- Insulated Tubing and Thermal Packer
- Inject 750 CWE Barrels of Steam Per Perforation

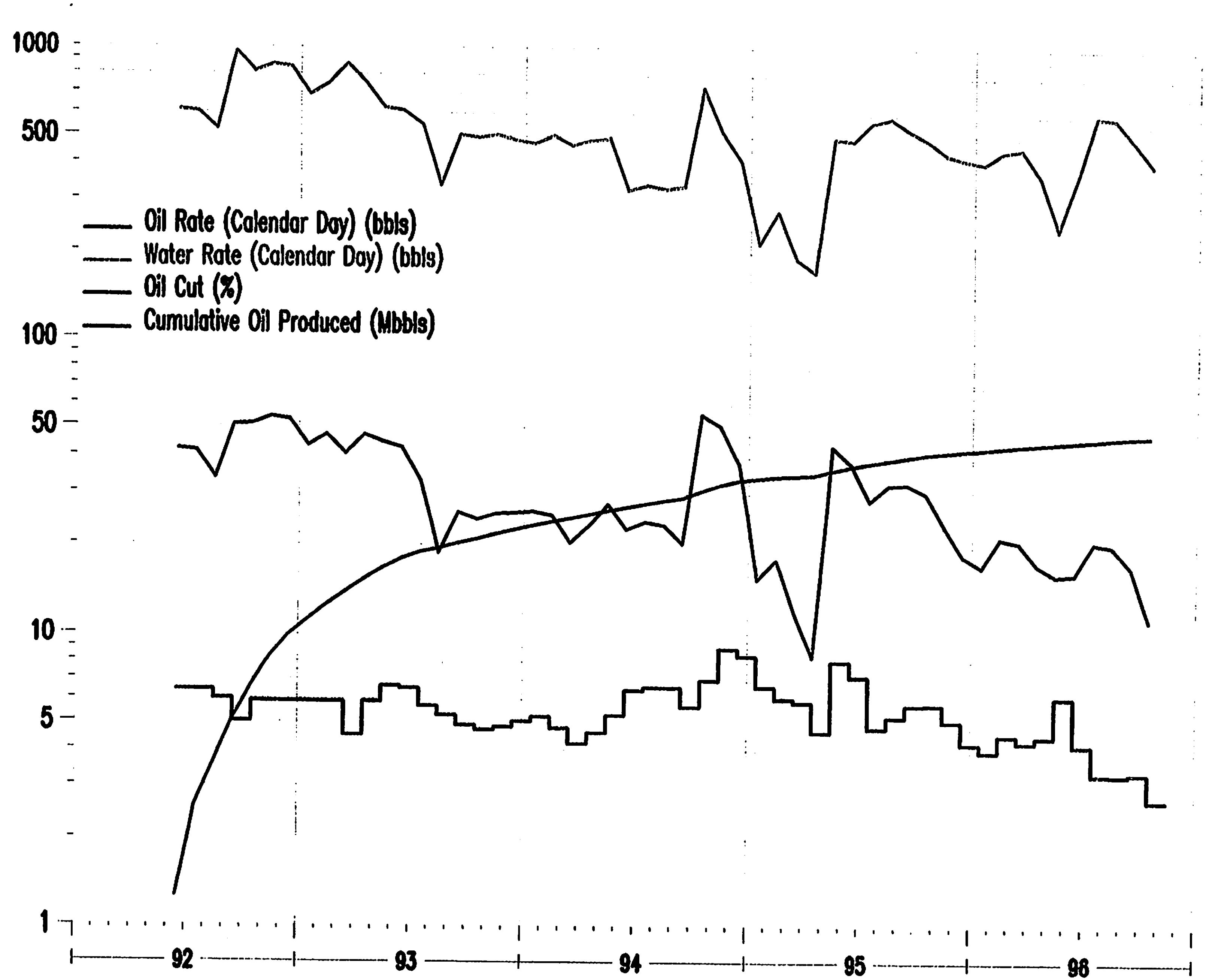
SAND CONSOLIDATION COST

- Perforating, 10 M$
- Insulated Tubing, 4 M$
- Thermal Packer and Expansion Joint, 10 M$
- Cost of Steam 20 Cents / Barrel, 6 M$
- Total Cost, 30 M$

SAND CONSOLIDATION SAVINGS

- Cost For Gravel Pack And Slotted Liner Completion, 120 M$
- Minus Sand Consolidation Cost, 30 M$
- Sand Consolidation Savings, 90 M$

WELL: UP779 B



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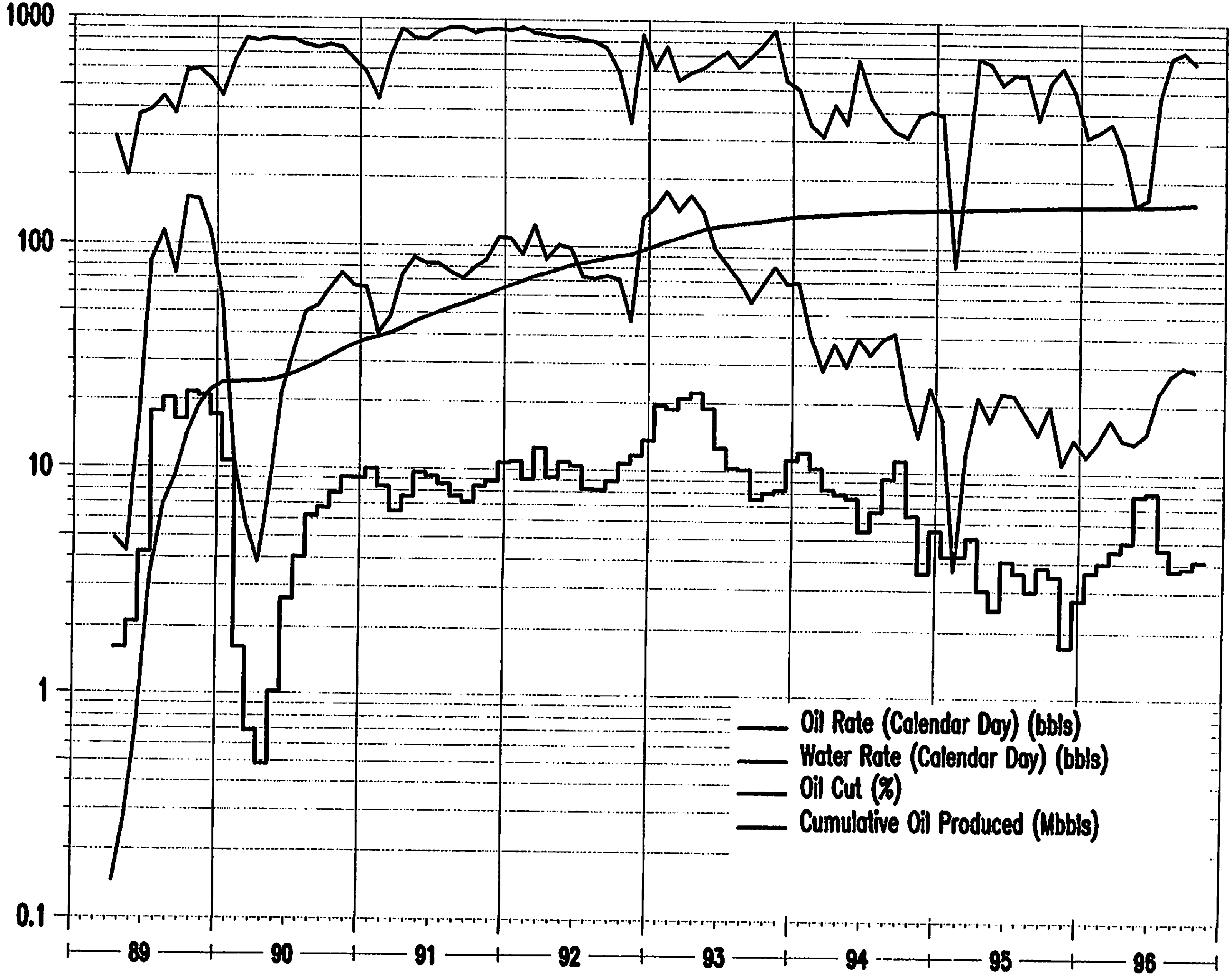
WELL: UP901 B



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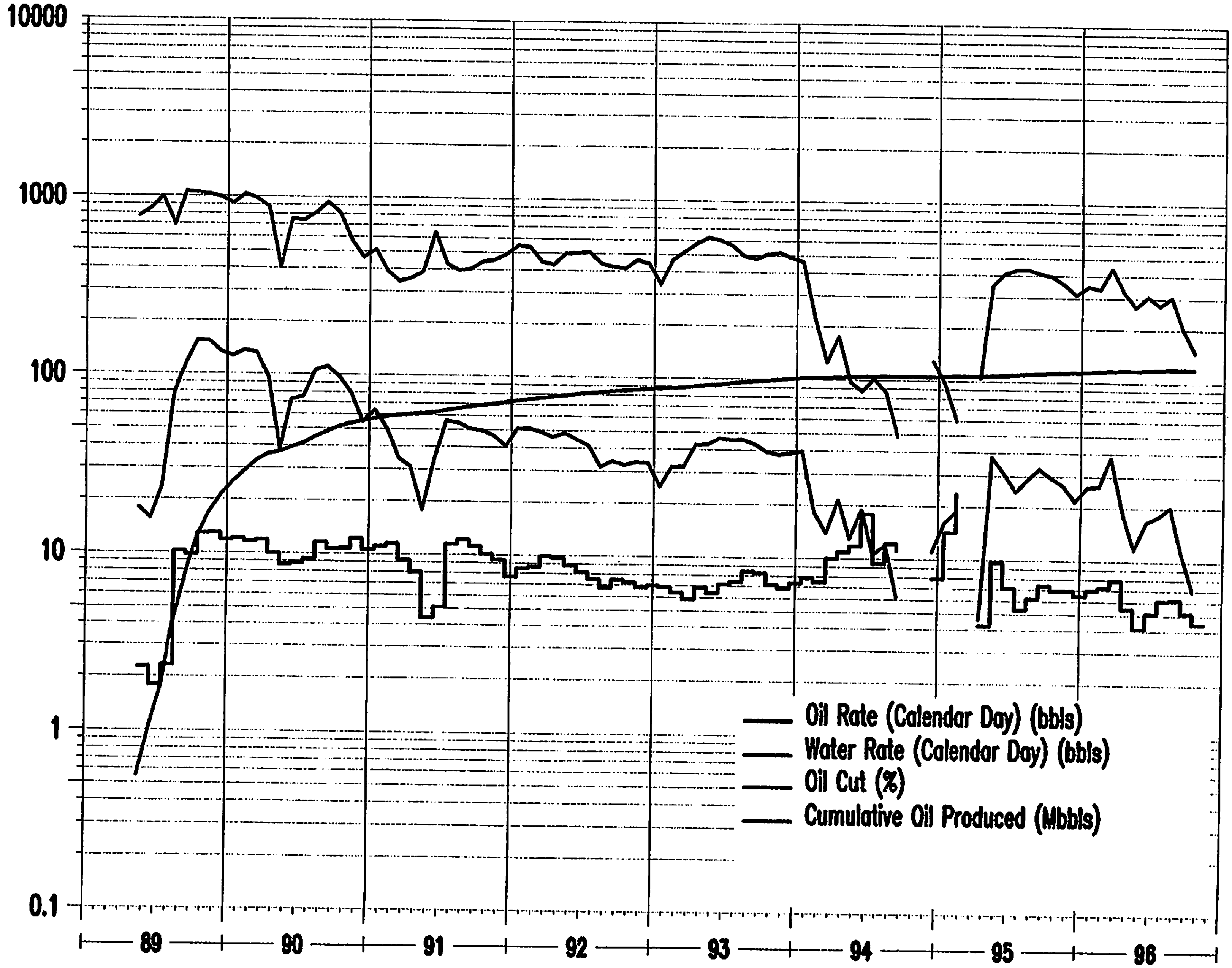
WELL: UP932 B



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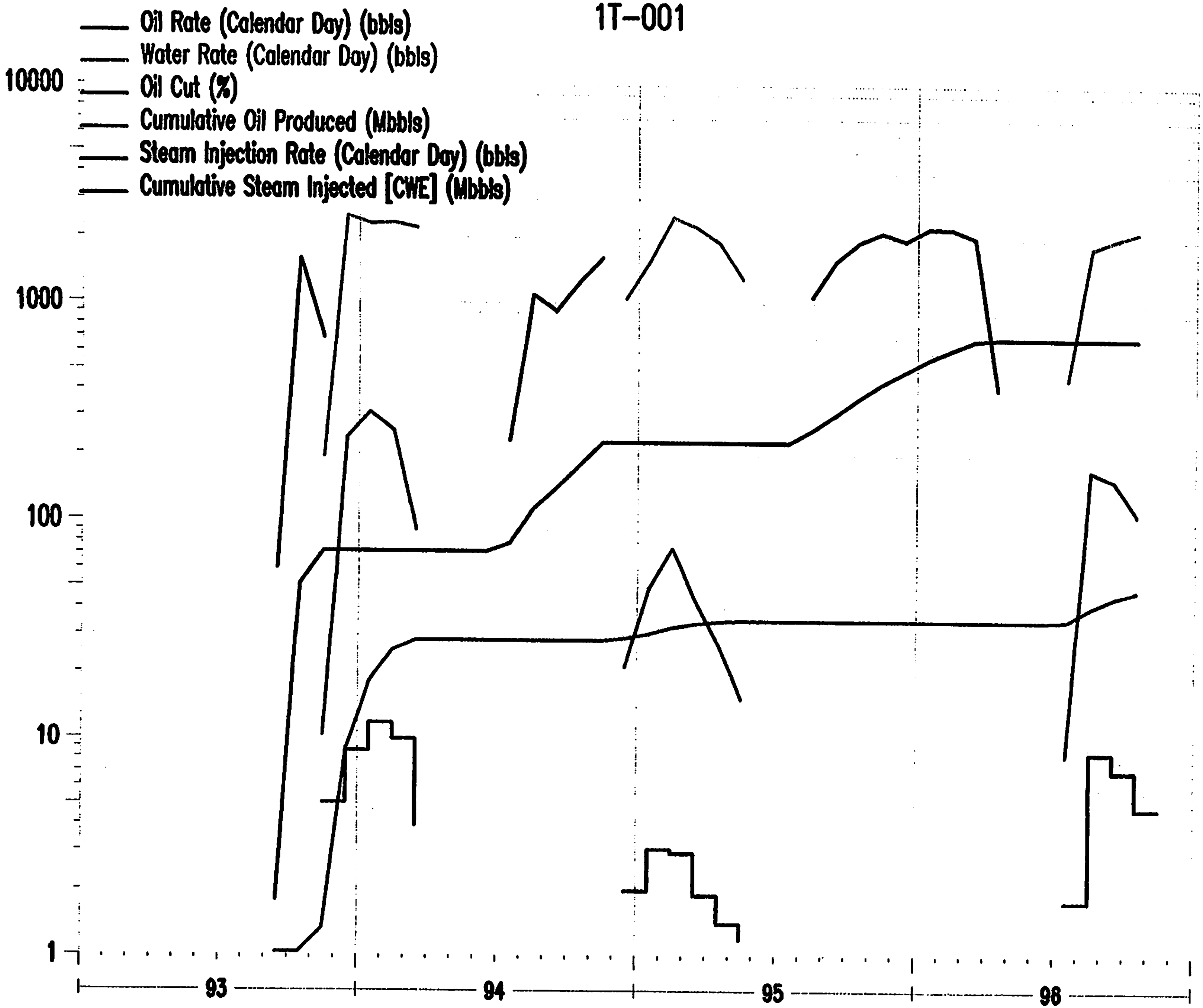
1T-001



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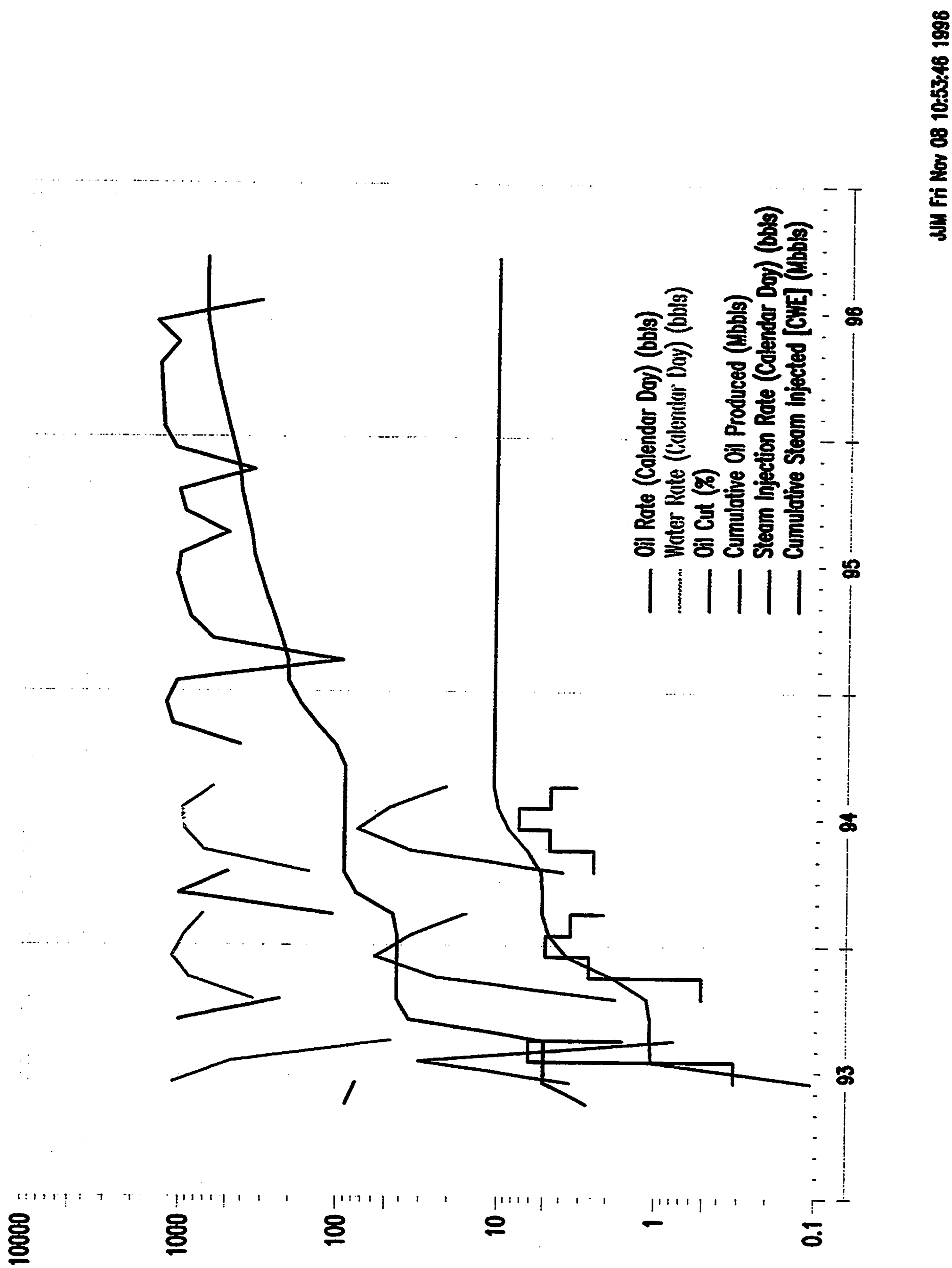
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94
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96
Oil Rate (Calendar Day) (bbls)
Water Rate (Calendar Day) (bbls)
Oil Cut (%)
Cumulative Oil Produced (Mbbls)
Steam Injection Rate (Calendar Day) (bbls)
Cumulative Steam Injected [CWE] (Mbbls)
JJM Fri Nov 08 10:53:46 1996

Idle Well and Well abandonment Issues

Mike Glinzak
California Division of Oil and Gas and Geothermal Resources

Idle Well Management Strategy

Mike Glinzak

California Department of Conservation
Division of Oil and Gas

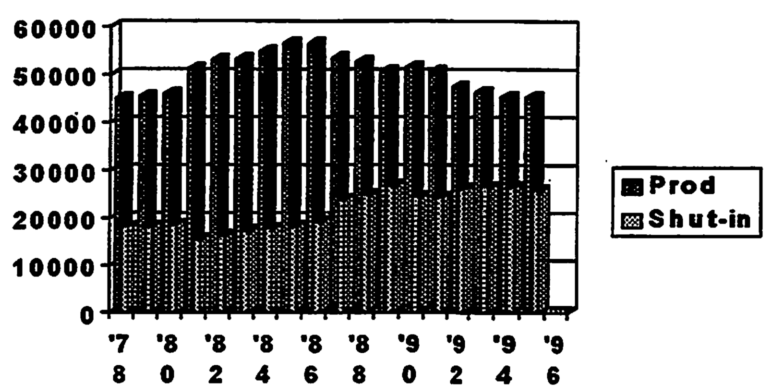
The "IDEAL" Situation

- A Purpose for Every Well
- Every Well Capable of its Purpose

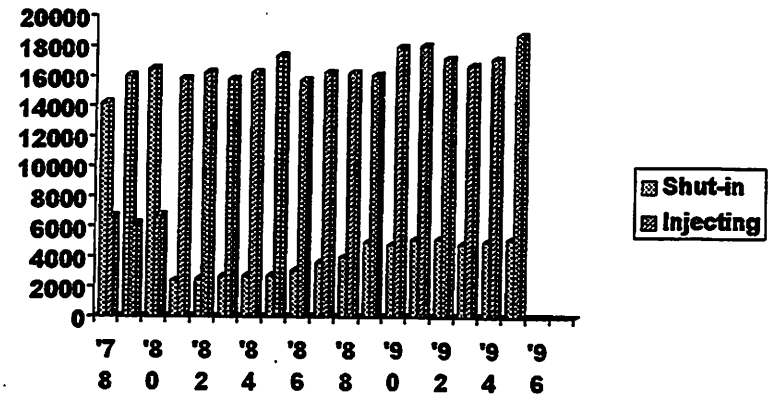
Today's Situation

- **Long-term idle wells increasing**
  - » 20,000+ wells idle 5 years or longer
  - » 70% of wells belong to major oil companies
  - » 1,200+ wells are "orphan"
- **Complaints from surface landowners**
- **DOGGR is aggressively abandoning "orphan" wells**
  - » about $10-12 Million abandonment liability
  - » Need 20 years to complete IF no new wells added

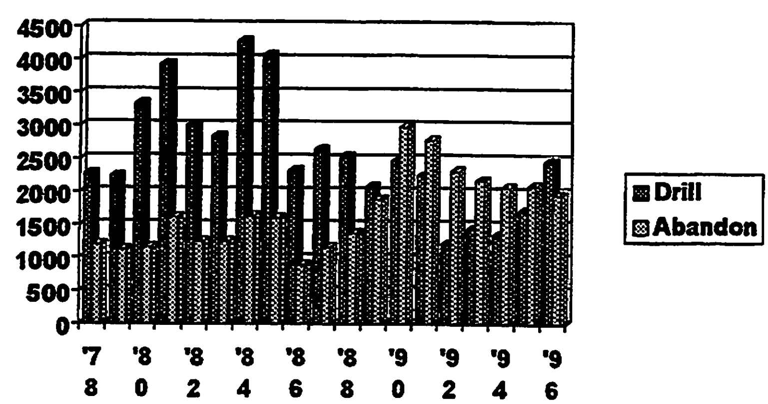
Production Well Trends



Injection Well Trends



Activity Summary



How Did We Get Here?

- "It's the economy, stupid!"
- "I never met a well I didn't like"
- Reorganizations
- Corporate Anorexia
- Permissive state laws

What Happens if We.......
Sell It!

- "There is a law!" - SB 2007
  - » Effective Jan. 1, 1997
  - » Retroactive to Jan. 1, 1996
  - » Previous operators possibly liable for abandonment costs
- Bonding required of 5-year+ idle wells
- Reduced asset value

What Happens if We....... Do Nothing?

- Increased potential of environmental damage
- Increased potential of creating "orphan" wells
- Responsible operators shoulder financial liability of "orphan" wells
- Must follow DOGGR Idle Well Program
- "There oughtta be a law!"

What Happens if We....... Produce It!

- Use the resource
- New Technology?
- "There is a law!" - SB 2007
  - » 5-year+ idle wells pay no DOGGR assessment for 10 years
- Well removed from DOGGR's Idle Well Program after 6 months

What Happens if We.......
Abandon It!

- Well removed from DOGGR's Idle Well Program
- Potential loss of resource
- Potential loss of access to resource
- Increased cost to access resource

What Happens if We.......
Manage It!

- Increase production
- Increase property's asset value
- Decrease long-term well abandonment costs
- Well removed from DOGGR's Idle Well Program
- Maximize Investment - Minimize Risk

A Recommended Management Plan

- Identify damaged or other problem wells
- Evaluate idle wells for future potential
- Return useful wells to service
- Repair or abandon damaged wells
- Abandon wells without future potential
- Monitor remaining wells for damage or contamination

Advantages

- Lower well monitoring costs
- Minimizes possible environmental damage
- Increased operator/DOGGR understanding and cooperation
- Decreases industry/government financial liability
- Industry keeps control of the situation

For More Information.......

- Attend the afternoon breakout session
- Contact your local DOGGR office

STATE OF CALIFORNIA—THE RESOURCES AGENCY

PETE WILSON, *Governor*

DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS,
AND GEOTHERMAL RESOURCES
801 K Street, MS 20 - 20
SACRAMENTO, CALIFORNIA 95814-3530
(916) 445-9686
TDD (916) 324-2555
TELEFAX (916) 323-0424

NOTICE TO OPERATORS

Idle-Well Policy

The number of long-term idle wells has been increasing over the years. Currently, about 21,000 of the 95,000 oil, gas, and injection wells in California have been idle for five or more years. Of those, approximately 10,000 have been idle for ten years or more, and over 5,000 have been idle for more than 15 years. In addition, the number of orphaned (deserted) wells, now at 1,200, has the potential to increase.

To address growing concerns for groundwater and resource protection, the Division developed a program to ensure the mechanical integrity of long-term idle wells. The program requires operators to submit information regarding the future use of such wells, if any, and to conduct periodic well testing. The program's purpose is to encourage the proper management of long-term idle wells having potential future use, rather than force their premature plugging and abandonment.

Although the program has been in place for a number of years, the growth trend of long-term idle wells has not diminished or reversed. Therefore, with some exceptions, the Division is modifying its program to focus on wells that have been idle the longest. In some cases, the modified program will reduce requirements for five-year idle wells and require a more thorough analysis and testing of wells that have been idle for ten years or more. The Division's goal is to maintain a program that is both reasonable and constructive.

It is important to demonstrate that the inventory of long-term idle wells is decreasing, thereby reducing the potential for future orphan wells, and that the idle wells maintained for future use have mechanical integrity sufficient to protect ground water and other natural resources.

William F. Guerard Jr.

William F. Guerard, Jr.
State Oil and Gas Supervisor

June 19, 1996

STATE OF CALIFORNIA-THE RESOURCES AGENCY

PETE WILSON, Governor

DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES
[illegible] STOCKDALE HWY., SUITE 417
BAKERSFIELD, CALIFORNIA 93309-2694
Phone (805) 322-4031
TELEFAX (805) 861-0279

June 19, 1996

IDLE WELL PLANNING AND TESTING PROGRAM

The Division's Idle Well Program requires an operator to provide the following: 1) a fee or bond coverage for wells idle five years or more as required in Section 3206 of the Public Resources Code (PRC); 2) a specific plan for wells idle ten years or longer along with an estimated time of implementation; and, 3) compliance with Section 1723.9 of the California Code of Regulations (CCR) which requires idle well testing. The due date for all information and testing is given in the cover letter which accompanies these guidelines. Specific testing guidelines for this District are contained in the District Testing Schedule attached. Failure to comply with the provisions of the program may result in the imposition of a civil penalty and/or orders to repair or abandon your idle well(s).

The intent of this program is to achieve the overall goals and purposes of the Supervisor's Idle Well Policy. If you have a plan that varies from this program, but achieves the overall goals and purposes, each district has the flexibility to work with you. Please contact the district office which covers the area where your well is located to discuss any proposed variances. **Note: several terms used in these guidelines have very specific meanings. Please see the attached Glossary for their definitions.**

I. <u>FEE/BOND REQUIREMENTS:</u> All wells idle five years or longer must be covered by one of the following:

1. A blanket indemnity or cash bond in the sum of one hundred thousand dollars ($100,000.00), or
2. an individual indemnity or cash bond in the amount specified in Section 3204 of the PRC, or
3. an indemnity or cash bond in the sum of five thousand dollars ($5,000.00) per well, or
4. a fee of one hundred dollars ($100.00) per well, assessed annually, as required in Section 3206 of the PRC.

Note: the bond or fee required in Items 3 and 4 above cannot be substituted for bonds that are already in place and are required pursuant to Sections 3204 and 3205 of the PRC.

Assessment and collection of idle well fees is handled by the Division's headquarters office in Sacramento.

II. <u>FUTURE PLANS:</u> Plans for future use of idle wells are required for wells idle ten years or longer. The plan must include what is planned for the well and when it will be done. If the plan is to return to production when economic conditions warrant, the plan must include specific economic conditions that will justify a return to production. If a well is being held for future use as an injector or a replacement for an injector, a specific proposal including the type and zone of injection must be filed. If a well is incapable of use in its present condition, it must be prepared for the planned future use by cleaning out, plugging, casing repair, etc. Wells idle 15 years or longer must have an engineering study prepared and submitted to the Division detailing the well's future plans. Please see the "15-year Idle Well Engineering Study Requirement" section, which follows immediately.

15-YEAR IDLE WELL ENGINEERING STUDY REQUIREMENT

A detailed, specific, written engineering evaluation is required outlining the *current* condition of the well, specific zones having recompletion potential, and how the well integrates into the overall production plan for the reservoir. This evaluation will aid the Division in understanding your plans regarding these long-term idle wells and in cooperatively prioritizing their return to production, repair, or abandonment. The evaluation must show the general structure of the reservoir and how the well relates to the structure including existing **producing** wells, current gas/oil/water contacts, faults, Base of Fresh Water (BFW, see glossary), additional hydrocarbon bearing and/or high-pressure zones located behind casing, or any other characteristic of the reservoir which has a bearing on the future potential of the well to be returned to active status. This is most easily accomplished with cross-section(s) and plotting the idle well locations on contour maps of the producing horizon(s) which also shows faults, gas/oil/water contacts, etc. Your report must include the presence and location of known casing damage or junk in wells which would prohibit the placement of abandonment plugs as required by Section 1723, *et seq* of the CCR. Documentation of all attempts to remove such junk must be provided. **The evaluation must also include a specific plan and timetable for abandonment or returning the well to active status.** The interpretative nature of portions of the evaluation are acknowledged. **Interpretative data (including geologic exhibits, etc.) will be held confidential by the Division.**

The intent of the 15-year Idle Well Engineering Study Requirement is to be as flexible as possible, provided the intent of the requirement, including an analysis of long-term plans and assurance of financial liability are met. **If you have an alternative plan, please contact the district office with your proposal.**

If an operator has a large number of 15-year idle wells, evaluation of these wells may be conducted on a staggered basis. A firm timetable to complete all evaluations must be submitted to and approved by the Division. If additional time is granted, the wells should be prioritized by the operator, with Division approval, to evaluate the most critical wells first.

In lieu of the engineering evaluation, operators with 15-year idle wells where abandonment is warranted may file a **firm** plan to plug and abandon these wells in accordance with a set schedule. It is understood that a large number of wells will require more time to abandon, but generally, to avoid the engineering evaluation, the program must be for a period not to exceed five years. Notices of Intention to Abandon should be filed immediately for wells to be abandoned within the first year of an abandonment plan. Additional Notices should be filed annually in the year work will be done for the remaining wells in the plan. An operator plan that has the abandonment work "back-loaded" will not be approved. **Failure of an operator to maintain the agreed upon work schedule will cause the idle well testing and engineering requirements to be reinstated for all wells failing to meet the schedule.** If an operator is able to "catch up" and maintain the work schedule, the Division will reinstate the testing exemption.

III. <u>**TEST SCHEDULE:**</u> A well's testing cycle begins the year it first appears on the Division's 5-year idle well list. Section 1723.9 of the CCR states in part: "Any well that has not produced oil or natural gas or been used for fluid injection **for a continuous six-month period during any consecutive five-year period** (emphasis added)...must have either the fluid level determined using acoustical, mechanical, or other reliable methods, or other diagnostic tests as approved by the supervisor." In accordance with Section 1723.9, all wells that have been idle for five years must be tested. Subsequent testing of idle wells varies by district and is outlined in the attached District Idle Well Testing Schedule.

Alternative diagnostic testing, such as a static temperature survey or demonstrating a clean out tag in non-BFW areas, may be allowed. Contact the local district office for further information.

Glossary

See the Glossary Appendix for definitions specific to individual Division district offices.

ADA Test: the fluid level in a well is measured to determine the height of the water column above the perforations, the pressure required to depress this column of water to the top of the perforations is calculated. Nitrogen then is added to the annulus until the pressure no longer increases. If the test pressure stabilizes at or very close to the calculated pressure and remains constant for 30 minutes with no more than a 10% leakoff after closing the valve to the nitrogen source, there are no leaks in the casing above the perforations and mechanical integrity is demonstrated. The test was developed by the U.S. Environmental Protection Agency at the Robert S. Kerr Laboratory research well in Ada, Oklahoma.

It only works in wells with gas tight wellheads. It is a very rigorous test that will pinpoint small casing leaks. Wells with long fluid columns above the perforations are not good candidates for this test because of the high casing pressures needed to depress the fluid column.

Base of Fresh Water (BFW): the depth in a well where the water in overlying aquifers tests less than or equal to 3,000 mg/l (or ppm) Total Dissolved Solids (TDS). Please refer to Division publication TR11, California Oil & Gas Fields, Vols. 1, 2, and 3, or contact the local Division office having jurisdiction over your well(s) for assistance in determining the BFW in individual oilfields and/or areas.

California Code of Regulations (CCR): specific rules the Division uses to implement the laws in the Public Resources Code. See Division publication PRC04, available free at Division offices.

Casing Pressure Test: an acceptable test must be a minimum of 200 psi over formation pressure or hydrostatic pressure, whichever is higher, along the entire length of casing tested. Pressure should be held 15 minutes or more with no more than a 10% pressure decrease. For example; a casing standing full of fluid at the surface requires a minimum of 200 psi surface pressure be applied to be a valid pressure test.

Wells having shut-in casing pressures sufficient to satisfy the pressure test requirement will be deemed to have passed the test if a temperature survey of the well shows no fluid movement.

The casing integrity test must be fully diagnostic over the length of the casing. For example, if a casing pressure test is run to just below the BFW, such as may be done in an ADA test, but leaves several hundred feet of casing above perforations untested, further testing, such as a clean out tag is needed.

Clean out tags: A determination of the top of fill, junk, damaged casing, or other obstruction in the well. Cleanout tags are determined with a bailer or sinker bar weighing 100 pounds or more and a nominal 2" diameter or greater, or with tubing with a nominal 2" diameter or greater.

Effective Depth (ED): the deepest Division approved point that could theoretically be reached during a cleanout tag in a well, provided the well has no casing damage, fill (including sand plugs), or temporary or unauthorized plugs.

Fluid Level Survey: Determination of the casing fluid level by standard industry methods.

Public Resources Code (PRC): California laws which are the basis of Division authority. See Division publication PRC01, available free at Division offices.

DISTRICT 4 - BAKERSFIELD
IDLE WELL TESTING
SCHEDULE

The emphasis of the District 4 Idle Well Program will be on testing 10-year and 15-year idle wells for mechanical integrity. All idle wells must be tested with a fluid level survey once they appear on the 5-year idle well list. Another test will not be required until the well appears on the 10-year idle well list, unless the well is located in a very sensitive area, or there is evidence of damage that could threaten groundwater or the environment.

Prior to any testing, the District 4 office should be given 24 hours notification to witness the test. Wells which will be abandoned within one year are excused from testing, provided a Notice of Intention to Abandon has been filed. Operators with a large number of 10-year, or 15-year idle wells may have some of the testing requirements excused or modified to extend over a longer period of time, if they have filed a plan to plug and abandon wells as outlined in the 15-year Idle Well Engineering Study Requirement.

Testing requirements for 10-year and 15-year idle wells are as follows:

BFW is Present:

A. Testing requirements for 10-year idle wells with open perforations:

1. <u>Fluid Level Survey</u> - If the fluid level is consistent with previous levels and surrounding wells known to have good mechanical integrity; ie., have passed casing pressure tests or the equivalent, the survey <u>passes</u> and no further testing is usually required. Regardless of the results of the fluid level survey, if damaged casing with potential to damage fresh water or hydrocarbon reservoirs or impact the ability to properly plug and abandon the well, as required by Section 1723, *et seq* of the CCR, or to return the well to production or some other beneficial use, be known in the well, go to Step 2.

   The survey <u>fails</u> if anomalous fluid levels are present and the fluid level is above the BFW. Go to Step 2.

   If the fluid level survey is below the BFW but still anomalously high, additional testing may be required after Division review on a well-by-well basis. You will be notified if additional testing is required. Do not proceed to Step 2.

2. If the fluid level survey failed, or damaged casing is known as described in Step 1 above, the operator must do the following:

Further test the well for casing integrity using one or more of several acceptable methods. A casing pressure test is most common, and generally preferred; however, a multi-arm caliper log, electromagnetic thickness log, temperature survey, or other method can be used if approved prior to testing. Wells without packers above the perforations can be pressure tested from the top open perforation to the surface without running a packer by using the U. S. Environmental Protection Agency's ADA test method (see Glossary). If damaged casing with potential to damage fresh water or hydrocarbon reservoirs, or impact the ability to properly plug and abandon the well, as required by Section 1723, *et seq* of the CCR, or to return the well to production or some other beneficial use, is found or known to be in the well, go to Step 3.

3. If adverse conditions described above are known, or encountered, it is necessary to either isolate the damaged casing from the BFW within 90 days, repair the well, or plug and abandon the well **within one year** unless an exemption is granted by the Division. Exemptions will be granted where inter- and intra-zonal fluid migration is not occurring and further deterioration of the casing cannot affect future abandonment operations. Isolation of reservoir fluids from usable fresh water is only allowed with prior Division approval. Isolation may be accomplished with either a cement plug, sand with cement cap plug (minimum of 15' of cement), or a retrievable bridge plug. **Wells utilizing isolation plugs must have the plug removed and the well repaired or abandoned within two years of the original test due date.** Sand with cement cap plugs shall not constitute permanent abandonment of any portion of the hole.

B. Testing requirements for 10-year idle wells without open perforations:

1. A casing pressure test is required.

2. A clean out tag may be required if there is evidence of casing damage. You will be notified if a clean out tag is required. The clean out tag passes if the clean out is demonstrated to be at an ED, the top of the liner, or the top of the production perforations in the well, whichever is shallower. The test fails if the ED, top of the liner, or top production perforation, whichever is shallower, cannot be reached.

   A diligent effort to clean out to ED must be made within 90 days of the original test for wells which fail the clean out tag.

C. **Testing requirements for all wells idle *more than* 15 years in BFW areas:**

Fifteen-year idle wells located in BFW areas **must** have a casing pressure test **in addition to** the mandatory fluid level survey and a clean out tag, if required. The Division district office may require additional testing, such as a casing inspection log which measures minimum and maximum inner casing diameter (multi-arm caliper) from effective depth (ED) to the surface, to determine actual and potential casing damage and threat to fresh water or hydrocarbon reservoirs in areas where casing integrity is often compromised. This includes areas of high subsurface movement, high corrosion potential, and over-pressured zones.

Part of the intent of this section is to acquire as much **current** information about a well's condition as possible with the minimal amount of required testing. Wells in fresh water areas present potential contamination sources for overlying fresh water. The casing pressure test provides a definitive test of the competency of the casing above the test depth, unlike the survey methods used for wells idle less than 15 years. Many of these long-term idle wells have not been entered since they were idled, sometimes well over 15 years ago. Information regarding the difficulty of re-entering the well is lacking. Since the clean out tag required mimics the running of small diameter production tubing, the results of the tag can indicate the potential problems and costs to be encountered should the operator choose to abandon or return the well to production. This information will significantly aid the operator in preparing the Engineering Study and prioritizing wells for abandonment or return to production.

All repairs or abandonment of 15-year idle wells which fail testing must be performed within one year of the original test due date, unless a Division approved work schedule is in place. The Division may require a period shorter than one year if evidence indicates formation damage or contamination is occurring.

D. **Testing Cycle**

Wells idle longer than 10-years in BFW areas must be tested every two (2) years. After the initial test, if subsequent tests show consistent results, the well passes. For example, if the first fluid level for a 10-year idle well is anomalously high, but the casing pressure test indicates the well has mechanical integrity; a subsequent fluid level test at the same depth would pass.

BFW is NOT Present

A. **Testing requirements for 10-year idle wells with open perforations:**

1. <u>Fluid Level Survey</u> - A fluid level survey must be conducted. If anomalous fluid levels, or other evidence indicates damaged casing with potential to damage hydrocarbon reservoirs or impact the ability to properly plug and abandon the well, as required by Section 1723, *et seq* of the CCR, or to return the well to production or

some other beneficial use, be known in the well, go to Step 2. No further testing is required if the test passes and the well has no known damage.

Clean out tags may be made in lieu of a fluid level survey.

2. Clean out tags - The test passes if the cleanout is demonstrated to be at an ED, the top of the liner, or the top of the production perforations in the well, whichever is shallower. The test fails if the ED, top of the liner, or top production perforation, whichever is shallower, cannot be reached.

   A diligent effort to clean out to ED must be made within 90 days of the original test for wells which fail the clean out tag.

3. A casing pressure test from the top open perforation to the surface, or other more definitive test, may be used in lieu of clean out tags.

If a well cannot satisfy these testing requirements, a plan for well repair, return to production or other beneficial use, or abandonment, **including a scheduled date of completion**, must be submitted to the Division. The plan and schedule must be approved by the Division before implementation. Division notification and approval is required prior to beginning any casing repair, plugging, or abandonment work.

B. Testing requirements for 10-year idle wells without open perforations:

1. A casing pressure test, **or**

2. If the water table is significantly below the surface, the well can be filled with fluid to the surface and rechecked after no less than one week. If the fluid level has remained stable at the surface, the test passes, **or**

3. A clean out tag at ED.

C. Testing requirements for all wells idle *more than* 15 years in non-BFW areas:

A clean out tag at ED is **required**, unless a satisfactory tag has been performed and documented for the Division within the past three years. Otherwise, testing requirements are the same as for 10-year idle wells.

The intent of this section is to acquire as much **current** information as possible about a well's condition with the minimum amount of required testing. Many of these long-term idle wells have not been entered since they were idled, sometimes well over 15 years ago. Information regarding the difficulty of re-entering the well is lacking. Unlike the survey methods used for wells idle less than 15 years, the clean out tag mimics the running of small diameter production tubing. The results of the tag can indicate the potential problems and costs to be encountered should the operator choose to abandon or return the well to production. This information will significantly aid the operator in preparing the Engineering Study and prioritizing wells for abandonment or return to production.

All repairs or abandonment of 15-year idle wells must be performed within one year of the original test due date unless a Division approved work schedule is in place.

D. Testing Cycle

10-year and 15-year idle wells in non-BFW areas must be tested every five (5) years.

TESTING TEMPERATURE OBSERVATION WELLS

If certain conditions are met, any well, regardless of its location in a BFW or non-BFW area, classified by the Division and actively used by you as a Temperature Observation well may be excused from idle well testing and the engineering study requirements. The well must have all formerly open perforations sealed with cement, been satisfactorily pressure tested and the test documented for the Division, and you provide the date of the last survey (may not be over three years old), the ED of the well, and the depth the logging tool tagged fill is at ED or at least 100' deeper than the top of the lowermost producing horizon penetrated by the well, whichever is shallower. The lowermost producing horizon is determined from the producing zone in offset wells. Temperature Observation wells that have never been perforated are not required to have the initial pressure test when placed into service.

Retesting/surveying of Temperature Observation wells will be required every five years, based on the date of the last survey provided the Division. If a recent temperature survey is not available or will not be run to satisfy idle well testing requirements, the Temperature Observation well must be tested on the same schedule and in accordance with the testing requirements outlined above for non-observation wells without open perforations and in accordance with the location of the well in a BFW or non-BFW area.

RECEIVING and SUBMITTING WELL and TEST DATA

All operators with more than 30 idle wells will initially receive their list of idle wells in computer format at the discretion of each Division district office. Operators having 30 wells or less on the Idle Well List will be provided Idle Well Data Sheets for entering the needed data. Each well will be noted with its "5-", "10-", or "15-year" idle well status. The enclosed "Response Guidelines" will assist you in supplying the required information in the proper data format even if you file by hardcopy.

Operators with more than 30 wells on the Idle Well List **may be required** to receive and submit data via computer floppy disk unless extenuating circumstances prohibit filing electronically. All requests to file by hardcopy in lieu of computer disk must receive prior approval from the local Division office.

Glossary Appendix
District 4 - Bakersfield

Clean out tags: At a minimum, clean out tags are performed with a nominal 2" or greater diameter bailer/tubing/sinker bar weighing 100 pounds or more. Well conditions, such as very thick hole fluids or having an effective depth greater than a wireline tool can reliably determine a pick-up depth, may require the use of tubing, etc. to perform the tag. A logging tool used in the performance of additional idle well testing on the same well is acceptable in lieu of a bailer, tubing, or sinker bar, provided it tags as described below. An existing tubing string of known length in the well may be extended to tag ED in lieu of a wireline tag.

The test passes if the cleanout is demonstrated to be at ED, the top of the liner, or the top of the production perforations in the well, whichever is shallower. The test fails if the ED, top of the liner, or top production perforation cannot be reached.

A diligent effort to clean out to ED must be made within 90 days of the original test for wells which fail the clean out tag.

RESPONSE GUIDELINES

Because there are over 13,400 idle wells in this district, manual entry of all idle well data has become impossible. You have been provided Idle Well Data Sheets to fill out and return to this office if you have 30 or less idle wells requiring a response from you this year. If you have over 30 wells on the Idle Well List, you must submit your idle well data on the enclosed MSDOS-formatted 3½" floppy disk. If you need a 5 1/4" disk, please return the 3½" disk with your request. The enclosed data files are sorted by the name of the Oil(FIELD), Township (TWN), Range (RGE), Section (SEC), (LEASE), and (WELL #) Number. This should make it easier to separate sections of the data file if you need to get information to/from different field offices. A subset of the data file containing only 15-year idle wells is also included for your convenience in preparing the engineering study. ***All data must be returned on a single disk as a single file. Multiple copies of the data file, on multiple disks, with data from individual field offices, will not be accepted.***

Our office uses Paradox 4.5 for DOS to maintain a database of all idle wells and would prefer your idle well data be returned in Paradox 4.x format; but we realize that operators may not be using the same software. Therefore, we have provided copies on the enclosed floppy disk of the file containing your idle well data in subdirectories for Paradox 4.x and Lotus 1-2-3 release 2. Almost all PC spreadsheet or database software will read at least one of these formats.

We have the capability to import your data in Paradox 4.x format; all Quattro or Quattro Pro versions; Lotus 1-2-3 versions 1A, 2 and 3; Excel; Access; dBase II, III, III PLUS, and IV formats; and comma delimited ASCII. Should you need a different file format to import our idle well file into your software, please contact us with your request. **We strongly recommend you utilize a database program (Access, dBase, Paradox, etc.) rather than a spreadsheet program (Excel, Lotus, etc.) to view, sort, and enter data as some of the longer comment fields may be truncated and data lost in spreadsheet programs. Please note: Microsoft's Excel and Access can both import the Paradox 4.x file format directly as can most newer database and spreadsheet programs.** We cannot accept responses in any other formats. Your responses must be returned in one of these formats to be accepted. Please do not use the ASCII format if one of the other formats is available to you. You will find the names of each field, its data type, and length at the end of these guidelines to assist you in setting up your own data file, if necessary.

ENTERING DATA

It is important you follow these formatting guidelines for entering your data. Failing to follow them results in delays in updating your idle well records. Also, **if data is formatted incorrectly when entered, your filing will be rejected and returned to you for correction.** If you must explain an entry (or lack of entry) for whatever reason, the **only** place you can put your explanation is in either the "LETTER COMMENTS" or "TEST COMMENTS" fields. The "FUTURE PLANS" field is reserved for your specific plans and timetable for returning the well to operation or abandoning it. General comments about the well or data requested, except for comments about any idle well test, should be entered into the "LETTER COMMENTS" field. **Only** comments regarding your idle well **test** should be entered into the "TEST COMMENTS" field. It is better to leave a data field blank with an explanation in a "comments" field rather than to enter improperly formatted data. Extensions of filing deadlines because these guidelines were not followed will not be granted. Please note, all information you received from us on the enclosed floppy disk followed these guidelines.

API # - Entered as a single 8-digit number, **no** hyphens or any other punctuation allowed. The number must begin with the county code. In District 4, all Kern county wells begin "029" or "030, Tulare county wells begin "107", Kings county wells begin "031", and San Luis Obispo county wells begin "079". Examples: 02900345 or 10712345. Do not change or delete it.

OPERATOR - Your company name as used in Division computer files. No entry needed. Do not change or delete it.

FIELD - This is a maximum 30 character field containing the name of the oil field where the well is located. Wells located in a county area and not within the DOGGR recognized administrative boundaries of an oil field will have nothing entered here. Do not change or delete it.

LEASE - This is the lease name according to Division records. Do not change or delete it.

WELL # - This is the well number according to Division records. Do not change or delete it.

SEC - This is the Section number where the well is located. Do not change or delete it.

TWN - This is the Township where the well is located. Do not change or delete it.

RGE - This is the Range where the well is located. Do not change or delete it.

If any errors are found in any of the above fields, please send written notice when you return your data disk. Do not change the entries in the original data file.

BLM - This is a one character field indicating if the Bureau of Land Management (BLM) controls the mineral and/or surface rights at your well's location. If the BLM controls **both** the surface and mineral rights, please enter "Y". If the BLM controls the mineral rights but **not** the surface rights, please enter "M" (for Minerals). If the BLM controls the surface rights but **not** the mineral rights, please enter "S" (for Surface). If the BLM does not control the mineral or surface rights and the well is **not** part of a BLM Unit Operation, please enter "N". If the BLM does not control the mineral or surface rights, but the well **is** part of a BLM Unit Operation, please enter "U" (for Unit). **While testing results are not required to be sent to the Division, "TOP PERF", "BASE OF FRESH WATER", and "URBAN LOCATION" information is required for all wells. If you have answered "Y" or "M" to this question, you must forward your response, including future plans and testing results, to the BLM per the cover letter that accompanied this document.** Please make corrections as needed to the preliminary data we may have supplied.

An "*" indicates the BLM is involved but the status; ie. "Y", "M", "S", or "U" is unknown. Please update the well record with the correct status.

YEARS IDLE - This is the 5-, 10-, or 15-year idle well status of your well according to Division records. Do not change or delete it. **15-year idle wells will have this field circled in red on Idle Well Data Sheets to highlight the need for an engineering study.**

NEXT TEST DUE - This is the date the next (or first if an initial data request) idle well test was/is due. **Your test is overdue if this date is earlier than October 1, 1995.** This field is circled in red on the Idle Well Data Sheets if the test is overdue.

DOG REMARKS - Special testing/information requirements or comments from the DOGGR. Used most commonly on followup requests for testing/information. Do not change or delete it.

FUTURE PLANS - Your plans for returning the well to production or injection and a **firm** date when the work will be performed. If you plan to abandon the well, give an approximate date when the work will be completed.

URBAN LOCATION - This is a one character "Yes/No" field. It is answered with either a "Y" or "N". If the field is blank, you must enter whether the well is or is not in an urban location. Urban location is defined as "a cohesive area of at least twenty-five business establishments, residences, or combination thereof, the perimeter of which is 300 feet beyond the outer limits of the outermost structures". Additionally, all or portions of oil fields that are undergoing urbanization, ie. Fruitvale, Bellevue, West Bellevue, etc. fall into this category. If an urban location status is shown but is incorrect according to the above definition, please make a correction.

BFW (Base of Fresh Water) - If a number is present, it is the depth to the Base of Fresh Water according to Division records or information you have previously supplied. In fields where there is fresh water but the well does not penetrate below the actual BFW, ie. Kern River field, this number is the depth to the uppermost oil sand. If "Y" is noted, there is a BFW but we don't have the value recorded for the well. Please delete the "Y" and enter the depth from the surface in feet (KB measurement preferred) to the BFW or the uppermost oil sand if the actual BFW is not penetrated by the well. Enter the footage **only**, do **not** include a ",", "'" or "ft", etc. If an "N" is noted, there is no BFW according to Division records and you have nothing to enter. If the field is blank, please enter an "N" if no BFW exists, or enter the depth to the actual BFW. If the actual BFW is not penetrated by the well, please enter the depth to the uppermost oil sand.

TOP PERF - If a number is present, it is the depth to the top open perforation in the well according to Division records or information you have previously supplied. You should make corrections if the depth shown is incorrect. If it is blank, you must enter the depth (KB measurement preferred) in feet to the top perforation. Enter the footage only. Do **not** include a ",", "'" or "ft", etc. If your well is **not perforated**, enter "**0**".

LETTER COMMENTS - This field is for entering any general comments not regarding the FUTURE PLANS or TEST COMMENTS. *This is the only place where miscellaneous remarks about a well can be entered.*

TEST DATE - All dates must be entered numerically in **MM/DD/YY** format **only**! Example: 6/4/94, 11/8/93 or 10/31/93. Do not enter any other punctuation or try to spell out the date. You must supply the day (DD) portion of the date. Do not enter a date as 6/94, Jun 4, 1994, 940604, etc. If you don't know the exact day, you may enter an approximation. If this is a temperature observation well, please enter the date of the last survey if the survey is being used as the test.

FLUID LEVEL - If you run a fluid level test on your well, enter the depth to the fluid from the surface (KB measurement preferred). Enter numbers only. Do **not** enter ",", "'", "ft", etc. Enter the results of the test in the "RESULTS" field according to the guidance given in the "Idle Well Testing Schedule". Make any comments about the test in the "Test Comments" field.

C/O - If you run a clean out tag on your well, enter the maximum depth reached from the surface (KB measurement preferred). Enter numbers only. Do **not** enter ",", "'", "ft", etc. Enter the results of the test in the "RESULTS" field according to the guidance given in the "Idle Well Testing Schedule". Make any comments about the test in the "Test Comments" field.

TEST DEPTH - This is the maximum depth tested during idle well tests other than a fluid level. For temperature observation wells, it is the maximum depth reached by the logging tool during the last survey. Enter numbers only. Do **not** enter ",", "'", "ft", etc.

PRESSURE - This is the maximum pressure in pounds per square inch (gauge) applied to the casing at the surface. Enter numbers only. Do **not** enter "psi", etc.

LOG - If your well was tested with a logging tool, enter the type here up to a maximum of 8 characters. Some examples are multiarm caliper (enter as "MULTIARM") and electromagnetic thickness (enter as "EMTHICK"). If the well is an active temperature observation well and you are using the last temperature survey to satisfy your testing requirement, enter "TempSvy" here.

OTHER - This is a single character field. If you have used another type of test, "X" this field and enter an explanation of the test type in the "TEST COMMENTS" field.

RESULTS - This is a single character field. If your idle well test met the testing criteria listed in the "Idle Well Testing Schedule", your test passed. Please enter a "Y". If the test did not meet the testing criteria, the test failed. Please enter an "N". If the test was inconclusive, please enter an "I". If you need to make any comments about your test, such as why it failed or was inconclusive, enter them in the "TEST COMMENTS" field only.

TEST COMMENTS - This field is for your comments about your idle well test. Information about casing holes, damage, fish, etc. should go in this field. *It is the only field where you can list holes, damage, or enter an explanation or clarification about your idle well test.* If you cannot fit your comment into the allotted 75 characters, you may include a written explanation with your data disk. Enter the effective depth of the well here if the you are using the last temperature survey to satisfy your testing requirement.

OPCODE - This field is for Division use only. Do not change or delete it.

FACODE - This field is for Division use only. Do not change or delete it.

IDLE WELL DATABASE STRUCTURE

FIELD NAME	DATA TYPE	LENGTH
API #	ALPHANUMERIC	8
OPERATOR	ALPHANUMERIC	30
FIELD	ALPHANUMERIC	30
LEASE	ALPHANUMERIC	30
WELL #	ALPHANUMERIC	10
SEC	NUMERIC	2
TWN	ALPHANUMERIC	3
RGE	ALPHANUMERIC	3
BLM	ALPHANUMERIC	1
YEARS IDLE	NUMERIC	2
NEXT TEST DUE	DATE	8
DOG REMARKS (DOG use only)	ALPHANUMERIC	110
FUTURE PLANS	ALPHANUMERIC	75
URBAN LOCATION	ALPHANUMERIC	1
BFW	ALPHANUMERIC	5
TOP PERF	NUMERIC	5
LETTER COMMENTS	ALPHANUMERIC	150
TEST DATE	DATE	8
FLUID LEVEL	NUMERIC	5
C/O	NUMERIC	5
TEST DEPTH	NUMERIC	5
PRESSURE	NUMERIC	5
LOG	ALPHANUMERIC	8
OTHER	ALPHANUMERIC	1
RESULTS	ALPHANUMERIC	1
TEST COMMENTS	ALPHANUMERIC	75
OPCODE (DOG use only)	ALPHANUMERIC	5
FACODE (DOG use only)	ALPHANUMERIC	5

New Interfaces for the On-Line Oil and Gas Database

Jeff Wagoner
Lawrence Livermore National Laboratory

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USC/PTTC

ACTI/Oil & Gas Data Infrastructure Project

Project Description

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Marty Medford

California Division of Oil, Gas, and Geothermal Resources

Bill Guerard, State Oil and Gas Supervisor
Jim Campion, Technical Services Manager
Michael Gardner, Chief Information Systems

Texas Railroad Commission

David Garlick, Director, Oil and Gas Division

Minerals Management Service, Pacific OCS Region

Robert Paul, Regional Supervisor for Resource Evaluation

California State Lands Commission

Paul Mount, Chief, Minerals Resource Management Division
Marina Voskanian, Chief Reservoir Engineer

Bureau of Land Management

Joe Chesser

California Independent Petroleum Association (CIPA)

Pete Boyce, President

Individual independent oil and gas producers and consultants

Alferitz Resources Inc., Armstrong Petroleum Corporation, Breitburn Energy Corp., CH2M Hill, Crutcher-Tufts Production Co., Dominion Oil, Gato Corporation, GEO Petroleum, Inc., Graner Oil Co., Harwood Capital, Hunter Living Trust, Long Beach Department of Oil Properties/THUMS, MacFarland Energy, Inc., Mannon Associates Inc., Naftext Holdings, Pacific Energy Resources, Pacific Operators Offshore, Inc., Petroleum Foundation, Reservoir Management Group, Richard C. Slade and Associates, SABA Petroleum, Santa Fe Energy Resources Inc., Signal Hill Petroleum Inc., St., St. James Oil Corporation, Texokan

Texas Independent Producers and Royalty Owners Association (TIPRO)

Scott Anderson, Executive Vice-President

Texas A & M University

Richard Startzman, Professor, Petroleum Engineering Department

University of Southern California

Elmer Dougherty, Professor, Petroleum Engineering Department
Iraj Ershaghi, Professor, Petroleum Engineering Department

Statement of problem and assessment of current technology:

Obtaining a substantially complete set of the relevant data for an oil or gas producing property is a very time-consuming and nearly impossible task which limits the producer's effectiveness in making sound business and engineering decisions. The data are located in a variety of places, some of which are completely inaccessible to the average user. Access to information on existing wells is a crucial component of a producer's ability to assess the feasibility of purchasing and operating a well. The more effective the access the producer has to the information, the greater the likelihood that a wider suite of choices can be considered and a profitable business decision reached.

The States of California and Texas, like a number of other states, provide public access to oil and gas production data, and other types of supplemental well information. However, access mechanisms are often ineffective, tedious, and expensive to maintain as much of the data is centrally located and in a format that is difficult to search, retrieve, and refile. Independent producers want more effective access to this crucial information to expand their business options and support profitable decisions. Majors want the independents to have more effective access to facilitate the sale of properties where they can no longer justify producing, but which an independent might see as viable. State government wants to see more effective access for the independents to avoid the abandonment of wells which could be productive under the right circumstances.

The California Division of Oil and Gas and Geothermal Resources (CA DOGGR) and the Texas Railroad Commission (TRRC) regulate their states' oil and gas drilling and production operations. The two organizations administer the state laws for the conservation of oil and gas resources to prevent damage to life, health, property, and natural resources. The principal mandated objectives in regulating oil and gas exploratory, development, and production operations are to prevent conditions that may be hazardous to health or damaging to the environment. As part of the regulatory program, well records are maintained on each well. There is information for each well consisting of applications to do work, permits issued, drilling and exploration histories, geophysical logs, production data, maps, reports, test results, well logs, abandonment and other types of information which the producers are required to provide to the states on an on-going basis. These well records are also considered vital to the industry because they are the only complete source of public information needed for continued exploration and development work. Making copies of the well records available to the industry and the public is an important function. Today, interested parties must come to the regional offices, identify and locate information they need, and request or create hardcopies of any desired information. Both states are interested in providing electronic systems for well records to both improve public access and reduce operating expenses.

Technical Approach and Tasks:

The Oil and Gas Data Infrastructure Project will design, implement, and integrate inexpensive, standards-based, simple mechanisms for on-line access to all oil and gas data currently available at the CA DOGGR and TRRC. Cost-effective access will be available through the existing Internet infrastructure using defacto Internet protocols and client/server tools. Eventually, widespread use of the system by oil and gas operators will facilitate electronic filing of documentation and permits required in both California and Texas. A standards-based network access Application Programming Interface (API) will be provided to allow the development of customized clients and the integration of access into existing commercial software. The range of beneficiaries from the system is broad. The primary target is the small, independent operator who is becoming the most important player in extending the life of our declining domestic resources. But in addition, city, county and state governments, county assessors, environmental consultants and analysts will, along with larger oil and gas producers, also benefit significantly from use of this system. We will deliver a demonstration system that will set the stage for an electronic infrastructure for access to oil and gas information with future extensibility potential to all states.

Phase 1.1. Prototype information system (year 1)

The objective is to develop a prototype information system to demonstrate the capabilites of new computing technology. The system will contain a small set of historical oil and gas data for fields in both California and Texas. The system will allow remote electronic retrieval of the information and submission of forms using Internet protocols and client/server tools. Access to this prototype will be hardware and operating system independent with emphasis on common desktop PC system configurations. Use of emerging and defacto oil and gas industry standards will be a priority (I.E. POSC, PPDM, REGIS, etc). The prototype system will allow data retrieval in a number of industry formats. Architecture for a network access API will be outlined. Architecture for data security, integrity, and electronic commerce will be outlined.

Phase 1.2. Pilot project (year 1)

The objective is to develop a pilot system with all oil and gas data for all wells in a specific district or large field in both California and Texas, along with digital map data. The pilot system will allow remote electronic retrieval of the information by producers in the oil and gas industry. Access to the pilot will be through the existing Internet infrastructure. The Internet Common Gateway (CGI) and/or LLNL's LINK specification will be extended in order to facilitate access to oil and gas data residing in the underlying distributed database(s). The pilot system will offer access to data on local disk, CD's, and remote servers. The pilot system will offer access to commercial and public domain software. Information on Internet access providers and access alternatives will be made available to the oil and gas community. Training sessions will be provided for those testing the pilot system.

Phase 1.3: Pilot project (year 1)

Data is the essential component required by oil and gas producers in order to make effective business decisions. USC will focus on identifying, characterizing, locating, organizing, and collecting data, in order to provide a complete inventory of the data with a tiered plan for converting to electronic form in the following two years.

Phase 2.1. Electronic filing (year 2)

The objective is to extend the pilot by automating the filing of forms required of operators by both the CADOGGR and TRRC. The automated remote submission system will allow electronic filing of monthly reports and a select number of other forms required by both the CADOGGR and TRRC. Security, encryption, and user authenication will be a priority during this phase. All electronic forms will be designed to closely resemble current printed forms using Internet Hypertext Markup Language (HTML+), Hypertext Transport Protocol (HTTP), and the CGI specification. The pilot system will automatically inform operators using electronic filing (EF) of additional requirements if forms are not complete. EF will allow automated updating of the pilot system, thus decreasing the time required for data to become available to users. HTML+ electronic forms will include all filing instructions and additional information contained in a filing procedures manual. The pilot system will also allow electronic granting of permits and electronic mailing of other correspondence between the state and industry.

Phase 2.2. Network Access Application Programming Interface (year 2)

The objective is to provide standards-based network access Application Programming Interface (API). The API will allow software vendors, producers, service companies, information providers, and consultants to build their own custom desktop clients capable of interacting with the information system in addition to existing commercial clients. The API will also allow industry software developers to incorporate information system access directly into commercial applications. Security and user authenication will be an integral part of the API. Training seminars will be provided. A procedure for updating and maintaining the API through the Request for Comments (RFC) process will need to be outlined.

Phase 3. State wide deployment (year 3)

The objective is to deploy California and Texas state wide information systems and to make the systems available to other oil-producing states.

Plan for the transfer or commercialization of results:

We will deliver a functional system based on UNIX servers and Windows clients. Strong potential exists for a vendor to provide a production quality commercial system and/or to port the server software to Windows. Pilot programs will become production systems during Year 3. Ongoing system enhancement and integration of additional capabilities will be possible through funding from other sources. The network access API will be made available to industry at no cost. An infrastructure for maintaining and updating the API will be provided.

Project Deliverables:

Task 1.1 (year 1)

- Prototype system demonstrating capabilities of new client/server technology and project objectives
- Pilot system providing on-line access to a subset of the California and Texas digital oil and gas data archive

- Customization of CGI and/or LLNL's LINK to better accomodate database access needs
- Inventory of data to be cataloged electronically
- Environment which offers access to commercial and public domain tools
- Set of HTML+/SGML forms required by California and Texas
- Security and authenication architecture definition
- Training

For Additional Information Contact:

Jeff Wagoner
P.O. Box 808, MS:L-221
Lawence Livermore National Laboratory
Livermore, California 94550
voice: 510-422-1374
FAX: 510-422-7438
e-mail: wagoner1@llnl.gov

GODB Application
E-mail comments to the GODB Development Team <ogdip@wildcat.llnl.gov>
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Good **Afternoon** and Welcome to the Wildcat WWW Server today **Oct 29 14:53:20 1996**

A development system at LLNL.

Department of Energy - Advanced Computational Technology Initiative (ACTI) Program Overview

ACTI Projects on this Server

Oil & Gas Data Infrastructure Project (OGDIP) [GODB Application]

Oil & Gas Well Log Imaging Project (OGWLIP) [Sample Well Log Images]

Department of Energy - Gas and Oil National Information Infrastructure (GO-NII) Overview

GO-NII Activities at LLNL

Synthetic Seismic Dataset Project [SSD Access Utility]

Some Oil & Gas Information Services

- Energy Information Administration An independent agency of the U.S. Department of Energy
- Petroleum Technology Transfer Council (PTTC)
- Interstate Oil and Gas Compact Commission (IOGCC)
- Independent Petroleum Association of America (IPAA)
- Petrotechnical Open Software Corporation (POSC)
- California Independent Petroleum Association (CIPA)

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Oil & Gas Data Infrastructure Project

Project Description | What's New | Overview of Data Provided by Participating States | Cost Recovery | Electronic Filing

On-Line Database

To Begin Accessing Data, Please Select a State

(The California data is the most extensive)

Alabama	Alaska*	Arizona*	Arkansas	California
Colorado*	Connecticut	Delaware	Florida	Georgia
Hawaii	Idaho	Illinois	Indiana*	Iowa*
Kansas*	Kentucky	Louisiana	Maine	Maryland
Massachusetts	Michigan*	Minnesota	Mississippi	Missouri*
Montana	Nebraska*	Nevada	New Hampshire	New Jersey
New Mexico*	New York*	North Carolina	North Dakota	Ohio*
Oklahoma*	Oregon	Pennsylvania	Rhode Island	South Carolina
South Dakota*	Tennessee	Texas	Utah*	Vermont
Virginia*	Washington	West Virginia	Wisconsin	Wyoming

* In Progress

GODB v3.4

E-mail comments to the GODB Development Team <godb@wildcat.llnl.gov>

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ACTI/Oil & Gas Data Infrastructure Project Database

California Oil and Gas data are available from the following source(s).

Source: **Lawrence Livermore National Laboratory**

Data Set	Year Range	Reporting Year
Production	1977-1996	1996

Optional output formats include graphs and Excel/Lotus spreadsheet

Data Set	Year Range
CADOGGR Reports	1995-1996

CADOGGR Publications available on the WWW

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ACTI/Oil & Gas Data Infrastructure Project Database

Source: **Lawrence Livermore National Laboratory**

State: **California**

Reporting Year: **1996**

Data Set: **Production**

California production data can be searched by the following criteria.

Select A Query

County

Field

Operator

API Number

Township/Range

Lease Summary

Field Summary

Operator Summary

GODE v3.4

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ACTI/Oil & Gas Data Infrastructure Project Database

Source: **Lawrence Livermore National Laboratory**

State: **California**

Reporting Year: **1996**

Data Set: **Production**

Select A Field

DOMINGUEZ
DUNNIGAN HILLS GAS
DURHAM GAS
DUTCH SLOUGH GAS
EAGLE REST
EAST ISLANDS GAS
EDISON
EDISON, NORTHEAST
EL RIO
EL SEGUNDO
ELDORADO BEND GAS
ELK HILLS
ELWOOD
ELWOOD, SOUTH, OFFSHORE
ENGLISH COLONY

353 Fields

Select A Sub-query

By Lease

By Well

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ACTI/Oil & Gas Data Infrastructure Project Database

Source: **Lawrence Livermore National Laboratory**

Reporting Year: **1996**

State: **California**

Data Set: **Production**

Field: **222 EDISON**

Select A Lease

BERRY FARMS
BILL HANDEL
BLODGET-CROME
BLOEMER
BOWLES
BOWMAN-SCOTT
BROCKMAN
BROWN
BROWN BEAR
BUCHNER
BUCK
BUERKLE
BUNTINE
C & H
C.L. JED

168 Leases

Select A Sub-query

By Well

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ACTI/Oil & Gas Data Infrastructure Project Database

Source: Lawrence Livermore National Laboratory
Reporting Year: 1996
State: California
Data Set: Production
Field: 222 EDISON
Lease: BERRY FARMS

Select A Well
Create A Detailed Report Below

Lease Name	Well No.	API Seq	Oil Prod. (BBL)	Gas Prod. (Mcf)	Water Prod. (BBL)
BERRY FARMS	18-4	04621	229	0	33
BERRY FARMS	38-4	04622	230	0	37
BERRY FARMS	47-4	04623	221	0	36
BERRY FARMS	48X-4	04624	217	0	28
	1996 Reporting Year Total		897	0	134

Create a [Production Detail Report] from [1991] to [1996]

[Create Detail Report] [Reset Report Options]

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ACTI/Oil & Gas Data Infrastructure Project Database

Production Summary from 1991 to 1996

API: 04-029-04623

Total Oil Produced	4375	BBL
Total Gas Produced	0	MCF
Total Water Produced	789	BBL
Total Days Producing	1878	Days

View Graphics (43289 bytes) | View Data File (2959 bytes) | Download to Excel (2959 bytes)

GODB v3.4
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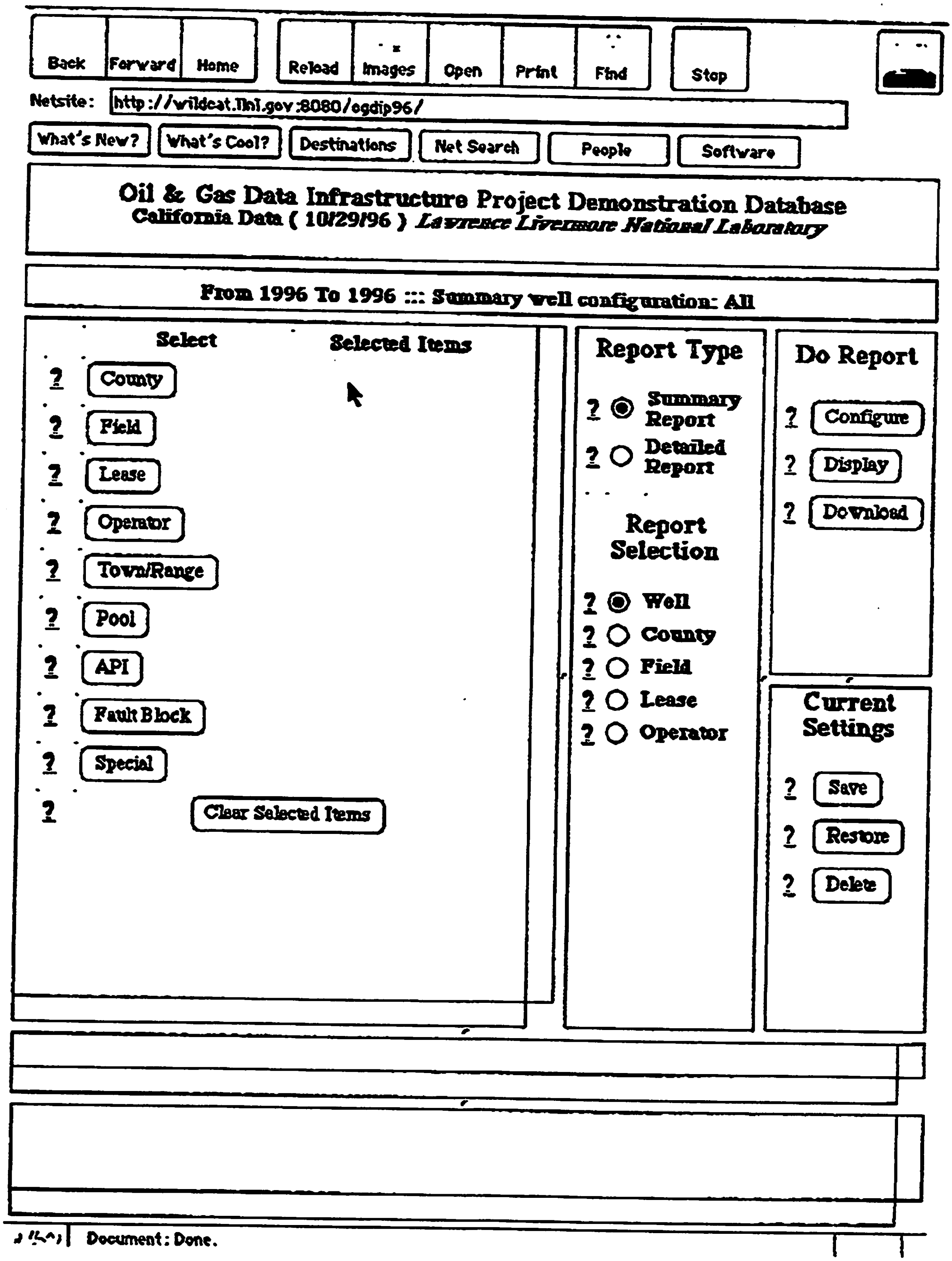
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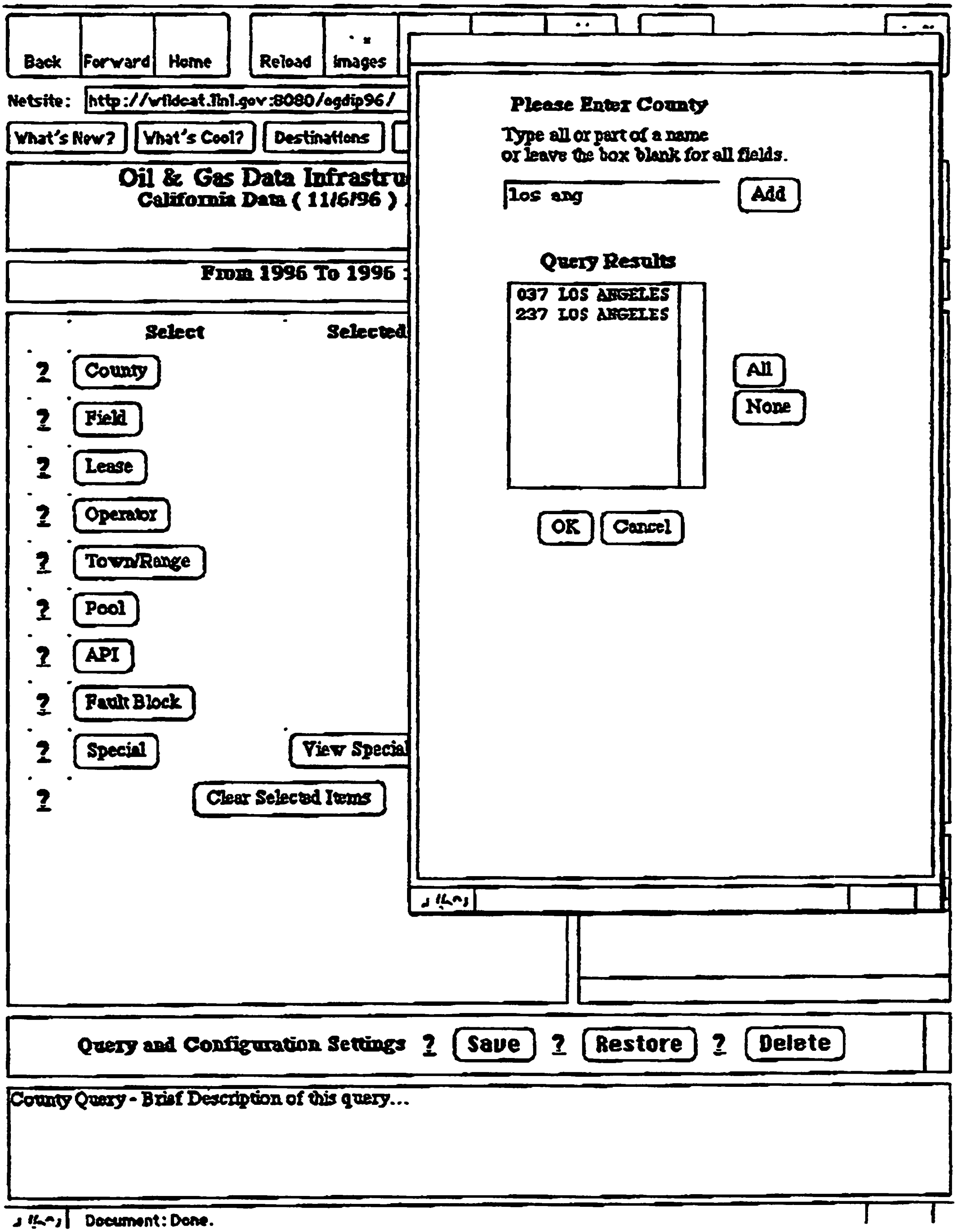
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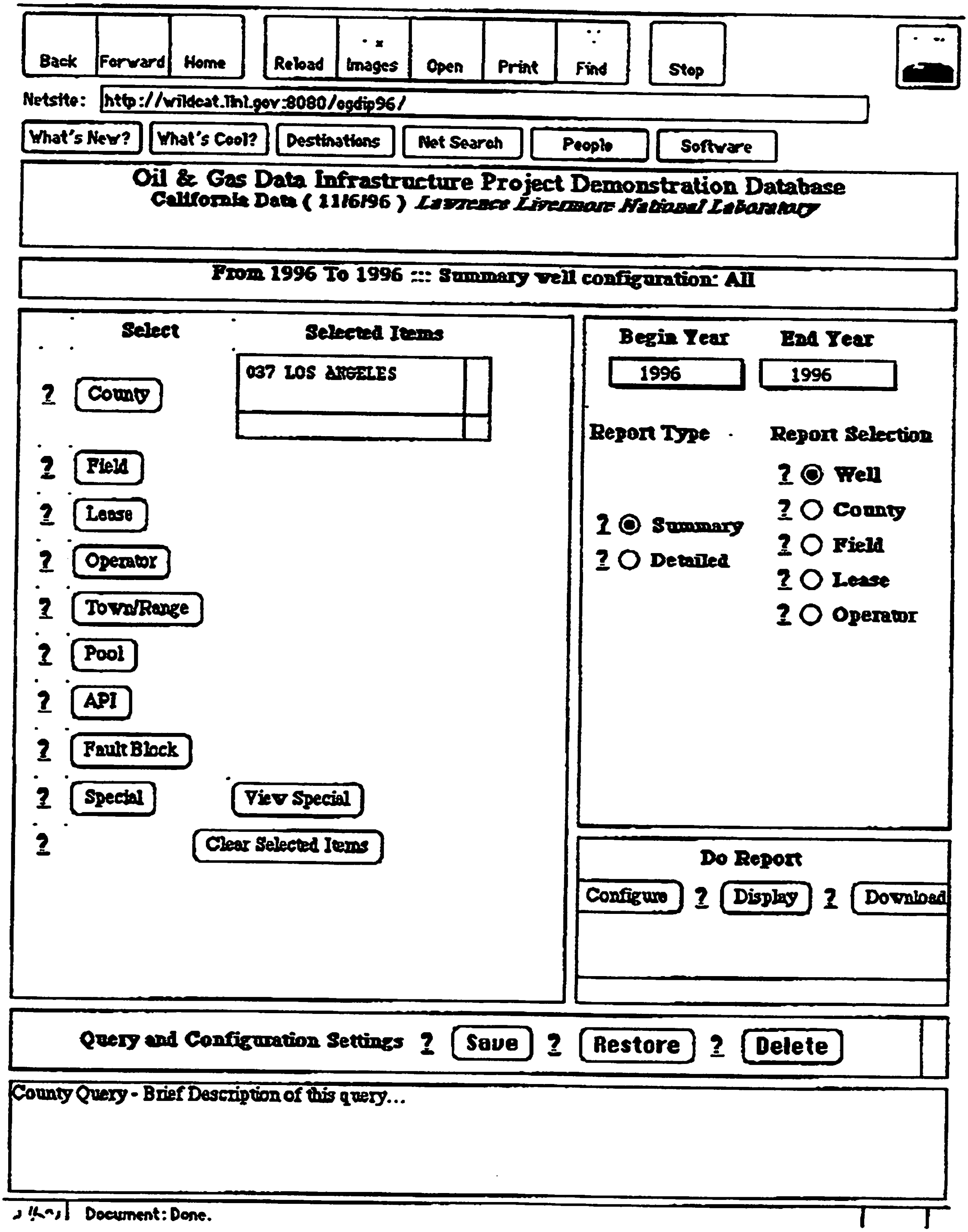
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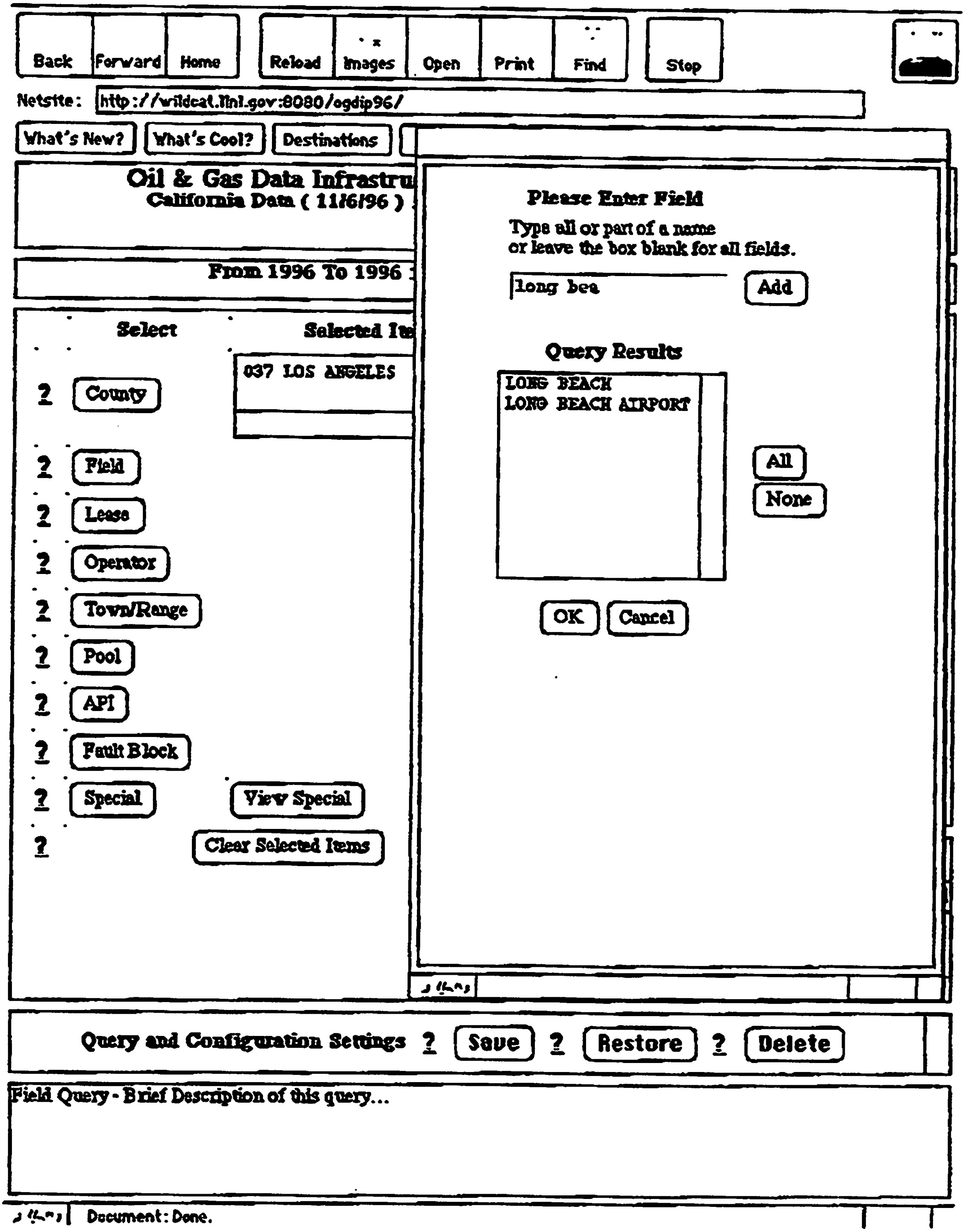
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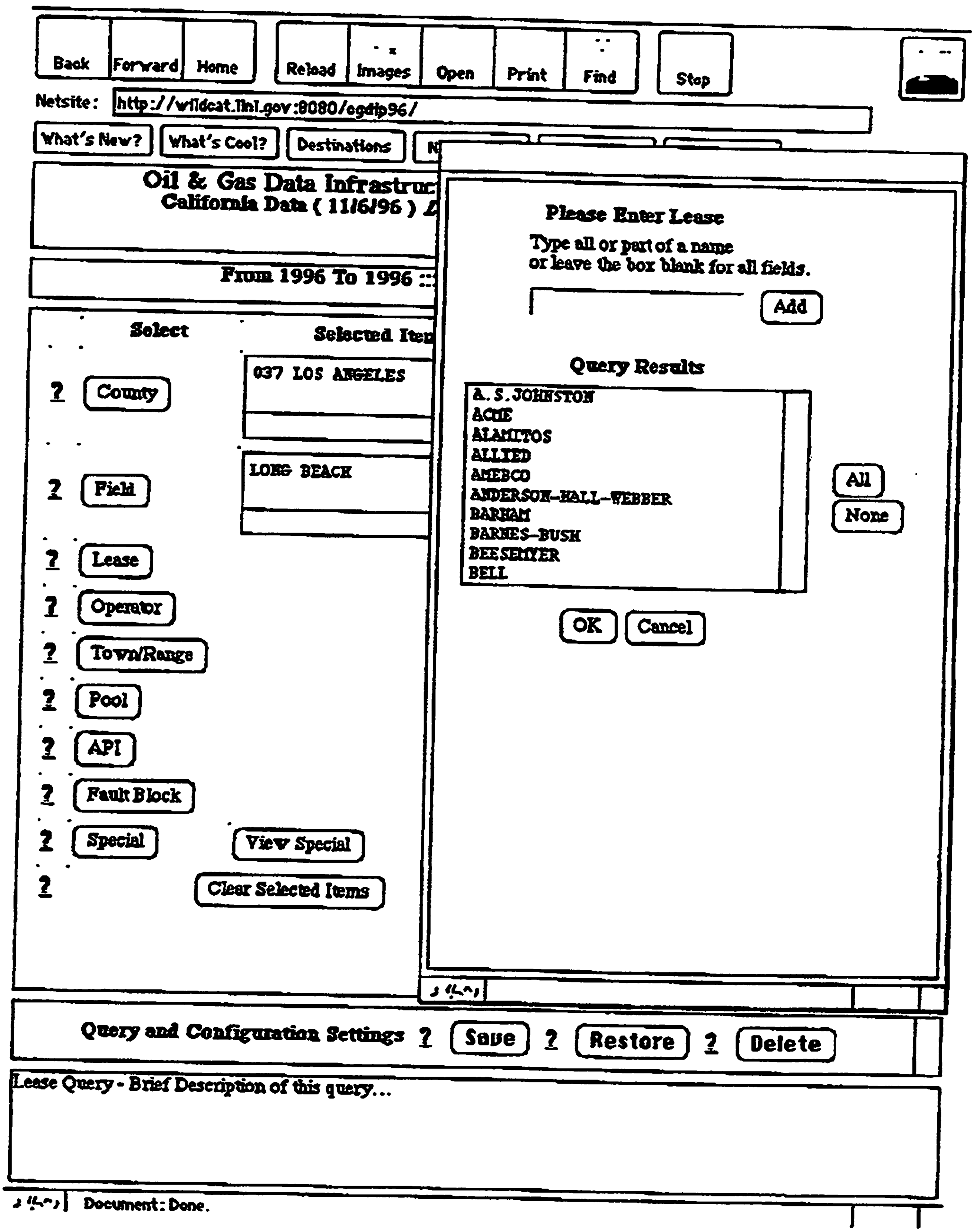
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ALLIED
AMEBCO
ANDERSON-HALL-WEBBER
BARHAM
BARNES-BUSH
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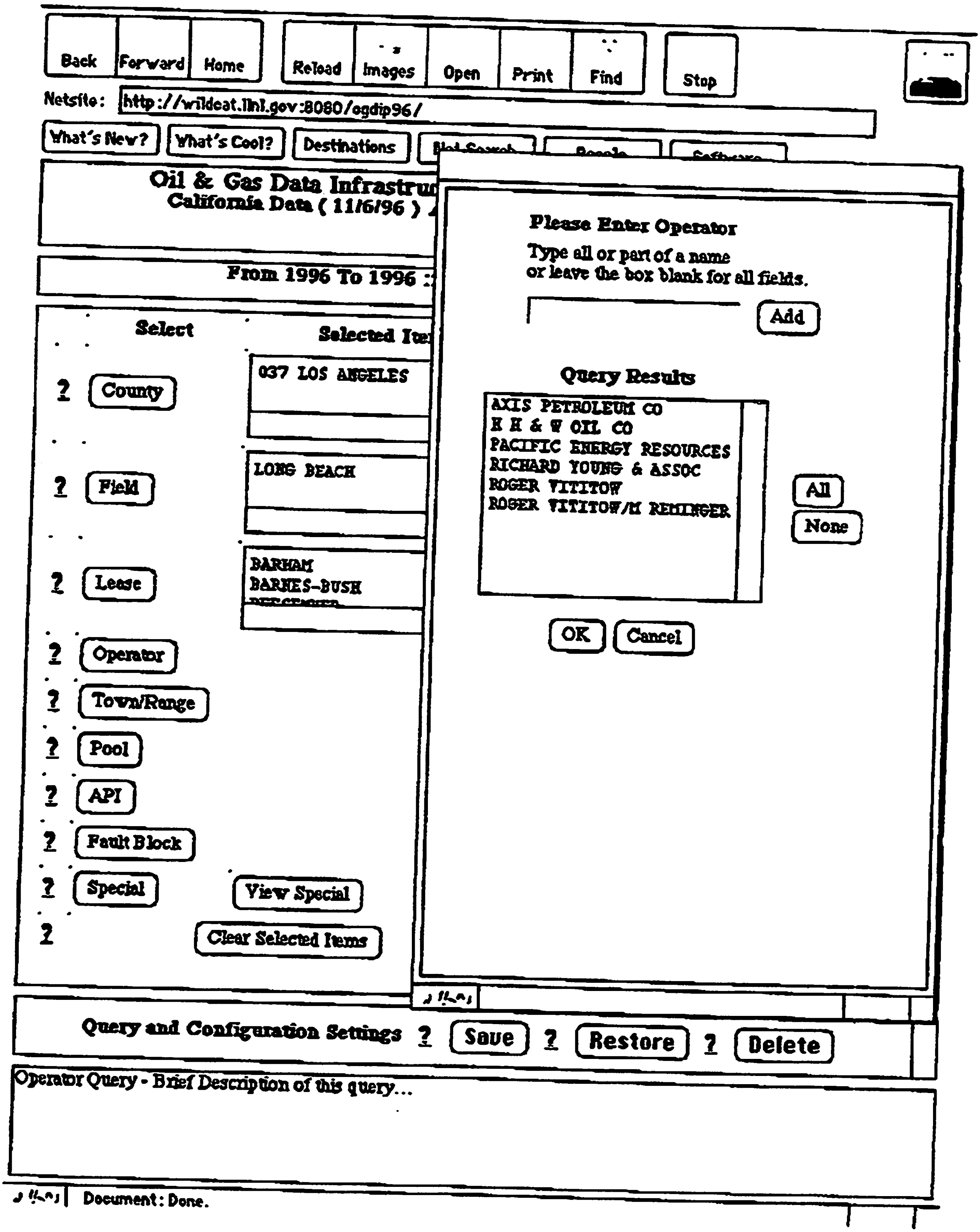
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PACIFIC ENERGY RESOURCES
RICHARD YOUNG & ASSOC
ROGER VITITOW
ROGER VITITOW/M REMINGER
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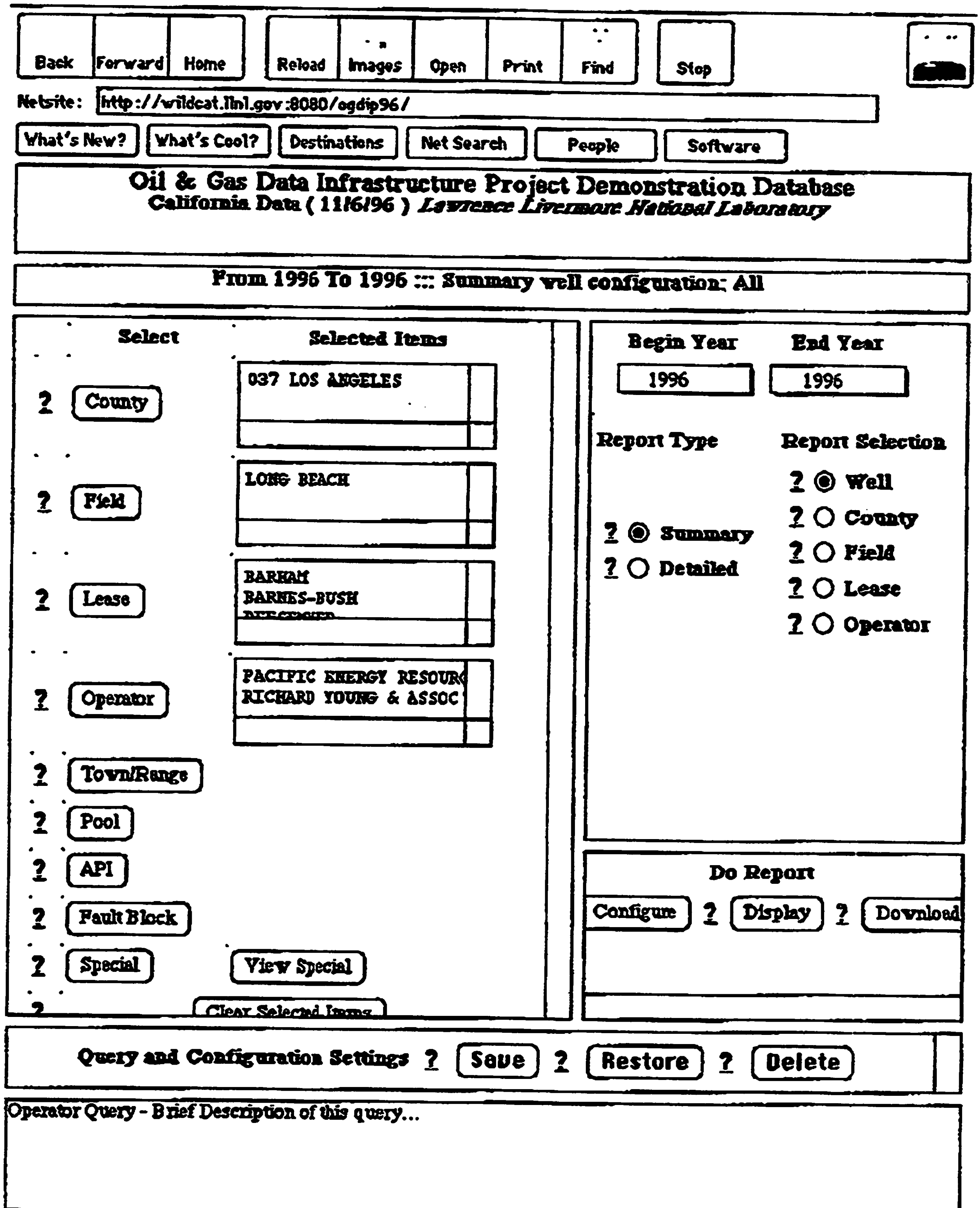
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From 1996 To 1996 ::: Summary well configuration: All
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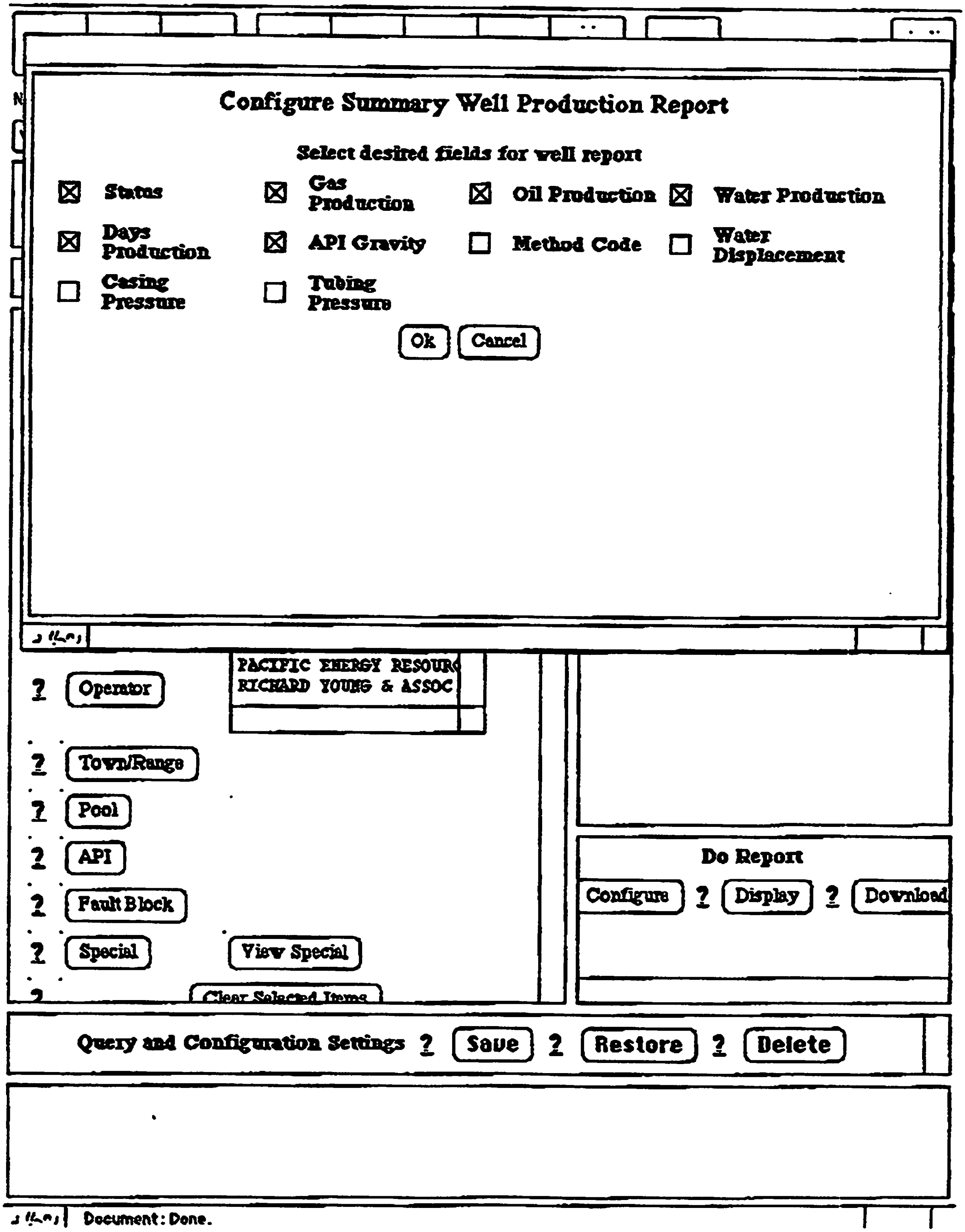
Configure Summary Well Production Report
Select desired fields for well report
Status
Gas Production
Oil Production
Water Production
Days Production
API Gravity
Method Code
Water Displacement
Casing Pressure
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Document: Done.

Summary Well Production Report from 1983 to 1987

Lease=BEESEMYER :: Well Number= 3

Well API: 04-037-10433 :: Field=LONG BEACH(412)

Operators: AXIS PETROLEUM CO(A4800)

Well type: Oil and Associated Gas Withdrawal

YEAR	STATUS	OIL_PROD	GAS_PROD	WATER_PROD	DAYS_PROD	API_GRAVITY
1983	Standing	936	321	29400	42	0
1984	On	1702	475	46530	173	260
1985	On	4545	1246	96030	291	251
1986	ShutDown	1123	629	22770	221	0
1987	On	3446	1025	56366	249	253

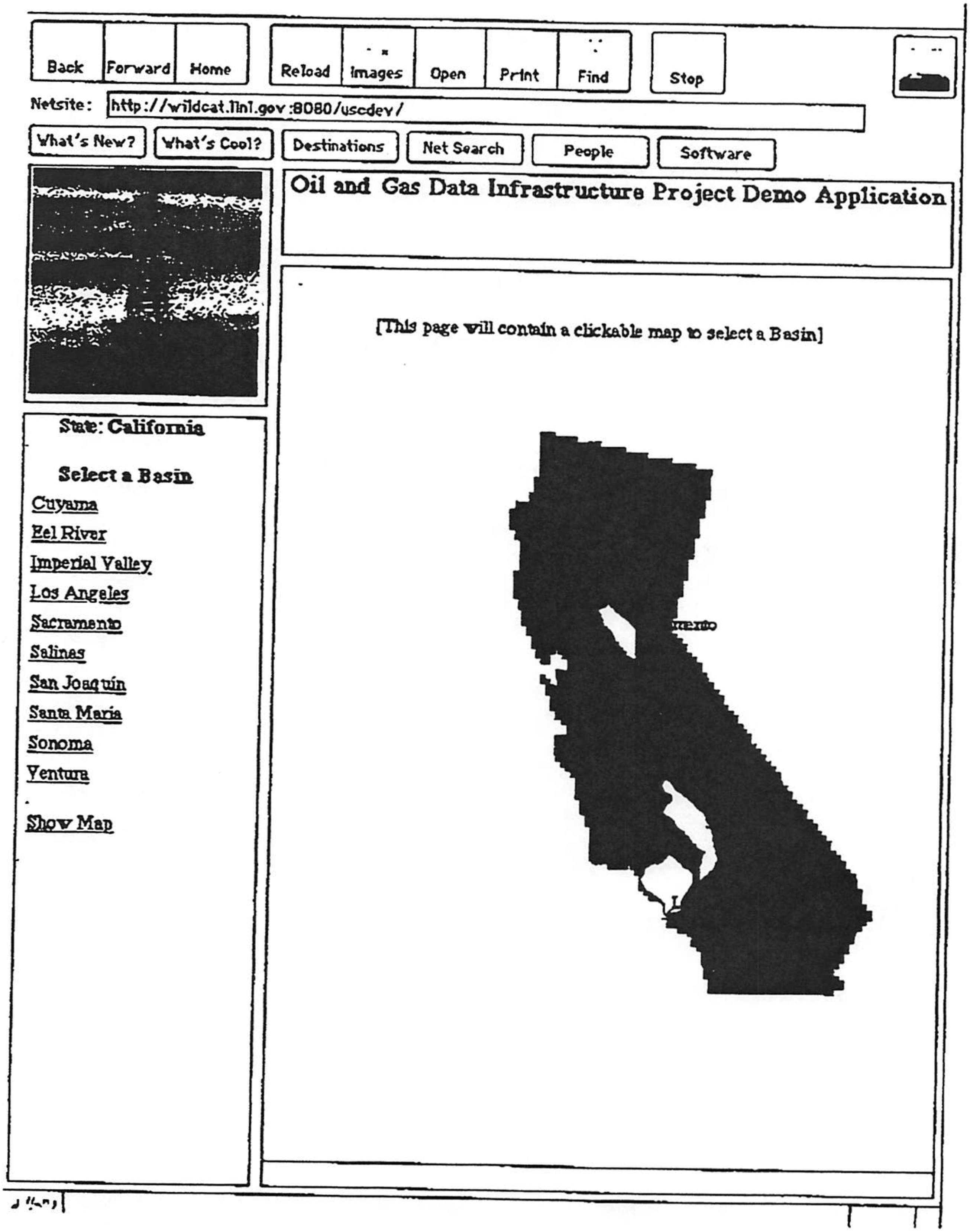
Lease=BARHAM :: Well Number= 2

Well API: 04-037-11293 :: Field=LONG BEACH(412)

Operators: RICHARD YOUNG & ASSOC(Y0200)

Well type: Oil and Associated Gas Withdrawal

YEAR	STATUS	OIL_PROD	GAS_PROD	WATER_PROD	DAYS_PROD	API_GRAVITY
1983	On	4971	4846	149430	345	234
1984	On	3699	4680	110970	339	245
1985	On	3433	3418	102990	339	243
1986	On	3235	3209	97050	322	234
1987	On	3675	2750	101097	331	256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http://wildcat.llnl.gov:8080/uscdev/
What's New?
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Software
Oil and Gas Data Infrastructure Project Demo Application
[This page will contain a clickable map to select a Basin]
State: California
Select a Basin
Cuyama
Eel River
Imperial Valley
Los Angeles
Sacramento
Salinas
San Joaquin
Santa Maria
Sonoma
Ventura
Show Map

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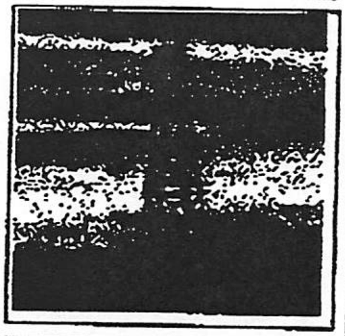

Oil and Gas Data Infrastructure Project Demo Application

State: **California**

Select a Basin

Cuyama
Eel River
Imperial Valley
Los Angeles
Sacramento
Salinas
San Joaquin
Santa Maria
Sonoma
Ventura

Show Map

Los Angeles Basin

[This page will contain general info about the selected Basin]

Select a Field

Huntington Beach
Long Beach
Rosecrans
Sunset Beach
Venice Beach

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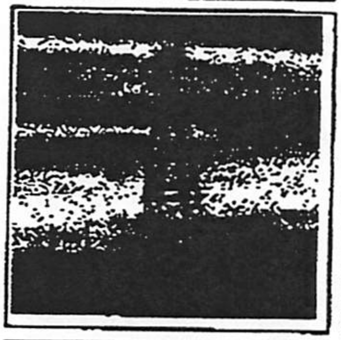

Oil and Gas Data Infrastructure Project Demo Application

State: California

Select Field Info

Field Identification
Geology
Reservoir Data
Production Data
Individual Well Data
Well Log Images
Ownership Information

Change Basin
Change Field

Los Angeles
Huntington Beach

Basin: Los Angeles **Field: Huntington Beach**

[Field Identification Information]

State Postal Code:	CA
Reservoir(s):	ABCDE
DOE/TORIS Reference Number:	0
TORIS Geologic Play Code:	AB2367
Active:	No
Lithology:	Dolomite
Geologic Age:	78
Formation:	null
Correlated with Field:	null

Update Field Identification

[Zones in Field]

Zone Name	Value
Epoch	Value
Geologic Stage	Value
Formation	Value
API Gravity (BTU)	Value
Petrology	Value
Depositional System	Value
Class	Value

Update Zone Information

Zone Name	Value
Epoch	Value
Geologic Stage	Value
Formation	Value

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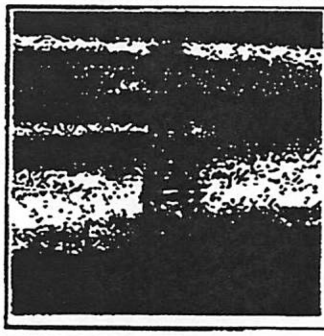

Oil and Gas Data Infrastructure Project Demo Application

Basin: Los Angeles **Field: Huntington Beach**

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Specify Password: to perform Update

or Cancel the request.

State: **California**

Select Field Info

Field Identification

Geology

Reservoir Data

Production Data

Individual Well Data

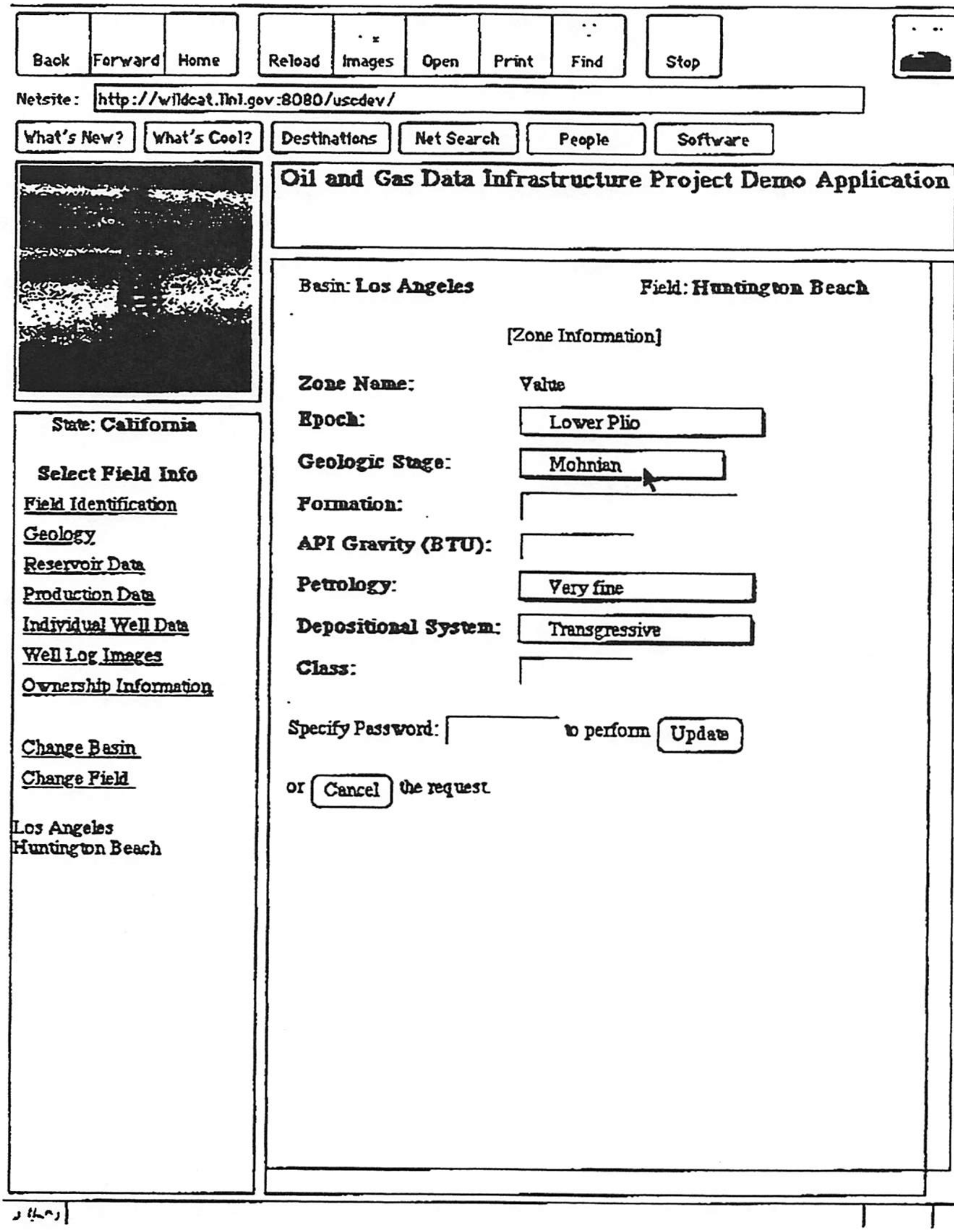
Well Log Images

Ownership Information

Change Basin

Change Field

Los Angeles
Huntington Beach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Production Data
Individual Well Data
Well Log Images
Ownership Information
Change Basin
Change Field
Los Angeles
Huntington Beach
Basin: Los Angeles
Field: Huntington Beach
[Zone Information]
Zone Name:
Value
Epoch:
Lower Plio
Geologic Stage:
Mohnian
Formation:
API Gravity (BTU):
Petrology:
Very fine
Depositional System:
Transgressive
Class:
Specify Password:
to perform
Update
or
Cancel
the request

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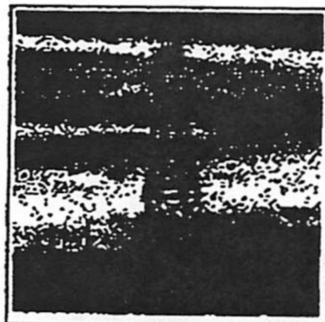

Oil and Gas Data Infrastructure Project Demo Application

State: California

Select Field Info

Field Identification
Geology
Reservoir Data
Production Data
Individual Well Data
Well Log Images
Ownership Information

Change Basin
Change Field

Los Angeles
Huntington Beach

Basin: Los Angeles **Field: Huntington Beach**

[This page will contain Geologic Data]

Series	Formation & Member	Structural Contour Map	Type Log

Geologic Marker/Formation

Consolidated	Yes	**Shaley:**	Yes
Carbonate	Yes	**Sand:**	No
Chert	No	**Schist:**	No
Diatomite	Yes	**Fractured or Faulted**	Yes
Heterogeneity	No		
Clay Content		**Avg. Reservoir Dip**	
Depositional System		**Trap Type**	
Structure Type		**Measured Depth**	
VSS (top,bottom)		**Avg VSS**	
Correlated with Formation			

Document: Done.

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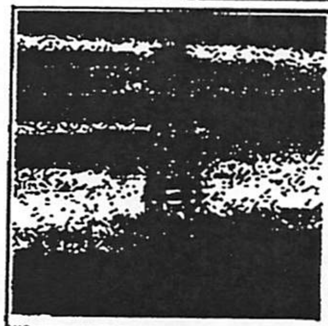

Oil and Gas Data Infrastructure Project Demo Application

Basin: **Los Angeles**

Field: **Huntington Beach**

Select Reservoir Data

Discovery Data	Core Data	Important Dates	Fluid Data	Current Reservoir Data
Diagnostics Plots	Drilling Problems	Typical Completion	Enhanced Recovery Methods	Well Count History

State: **California**

Select Field Info

Field Identification

Geology

Reservoir Data

Production Data

Individual Well Data

Well Log Images

Ownership Information

Change Basin

Change Field

Los Angeles
Huntington Beach

[This page will contain Reservoir Discovery Data]

Date Discovered:

Original Operator:

Discovery Well:

Discovery Well Depth:

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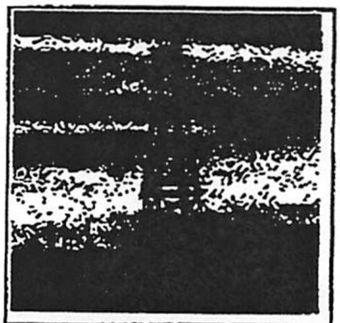

Oil and Gas Data Infrastructure Project Demo Application

State: California

Select Field Info

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Reservoir Data
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Well Log Images
Ownership Information

Change Basin
Change Field

Los Angeles
Huntington Beach

Basin: **Los Angeles**

Field: **Huntington Beach**

Field Production Data (1977-1996)

Year	Oil Prod (BBL)	Gas Prod (Mcf)	Water Prod (BBL)	Days Prod
1977	12459390	3757289	108061250	368883
1978	11195259	3181409	104524060	357826
1979	10355572	2759326	107950193	343498
1980	9741813	2364098	109856613	342377
1981	9894343	2460685	116054940	347466
1982	10035126	2842167	118605307	341804
1983	9031524	2639678	110286959	328459
1984	8671442	2777707	117835448	340053
1985	8077146	3143803	123852363	341323
1986	7106802	3404226	114648643	339191
1987	6058393	2953483	94283302	319492
1988	5539877	2386770	79287394	287013
1989	4772749	2139946	70323620	238664
1990	3836498	1797436	52679910	190414
1991	3841636	1613166	53206081	159767
1992	3657849	1703082	48633344	149494
1993	3783732	2334117	48750366	145759
1994	3711520	2457199	49027548	140863
1995	3043062	1846184	39645582	128248
1996	831967	303083	9833673	29034

Download this Report to your computer

	A	B	C	D	E	
1	Huntington Beach - Field Production Data - Summary by Lease (1996)					
2	Lease Name	Operator Name	# of Wells	Oil Prod(BB	Gas Prod(Mc	Wate
3	<NULL>	CITY OF HUNTINGTON BEACH	1	0	0	
4	<NULL>	HUNTINGTON BEACH COMPANY	5	692	0	
5	<NULL>	HUNTINGTON SIGNAL OIL CO	3	2390	0	
6	<NULL>	KILLINGSWORTH OIL COMPANY	3	709	957	
7	<NULL>	THE TERMO CO	15	54866	0	1
8	<NULL>	THOMAS OILERS	4	0	0	
9	<NULL>	W M ELLIOTT JR	2	229	67	
10	ASHTON	CENTRAL PARK ENERGY	2	0	0	
11	BARNETT ANCHOR	WM J SCOTT	2	708	0	
12	BEARE	BRINDLE/THOMAS	1	1677	0	
13	BLOCK B	WM J SCOTT	1	376	0	
14	BOLSA	HUNTINGTON BEACH COMPANY	50	8480	0	
15	BOLSA CHICA	HUNTINGTON BEACH COMPANY	2	0	0	
16	BRADLEY	HUNTINGTON BEACH COMPANY	2	0	0	
17	BROOKS	HUNTINGTON BEACH COMPANY	5	0	0	
18	C & B	HUNTINGTON BEACH COMPANY	1	0	0	
19	CARROLL	HUNTINGTON BEACH COMPANY	1	0	0	
20	CATALINA	JOHN A THOMAS	1	1285	0	
21	CIVIC CENTER	CITY OF HUNTINGTON BEACH	3	6438	0	
22	CLARK	HUNTINGTON BEACH COMPANY	1	0	0	
23	COLUMBIA	W M ELLIOTT JR	1	4	6	
24	COLUMBIA ONE	WEAVER & THOMAS	1	673	325	
25	CONCORD	THOMAS OILERS	2	0	0	
26	CONNELL-DOWD	CATHER & CREE OIL CO	1	357	642	
27	COOKERLY	MILLER & WILSON	1	316	0	
28	COPELAND	BRINDLE/THOMAS	7	4598	0	
29	CRANE	HUNTINGTON BEACH COMPANY	1	0	0	
30	DABNEY	HUNTINGTON BEACH COMPANY	2	0	0	
31	DAVIS	OCEAN FRONT OIL CO	1	0	0	
32	DOLLAR	JOHN S ROUNTREE	1	640	0	
33	DONNA	JEANNE E NEVINS	1	529	0	
34	ELLIOTT	W M ELLIOTT JR	1	0	0	
35	FEE	WEIR OIL CO INC	2	0	0	
36	FRASER	CATHER BARNES & CREE	1	131	642	
37	H.B.FEE	S & C OIL CO INC	2	1070	0	
38	H.S.KOHLBUSH	HUNTINGTON BEACH COMPANY	1	0	0	
39	HAMILTON	ROBERT D VIGUE	2	0	0	
40	HANSEN	WEAVER'S PROD SERVICE	1	2178	1423	
41	HARVEY	ALEXANDER OIL COMPANY	1	357	0	
42	HOUSTON	HUNTINGTON BEACH COMPANY	1	0	0	
43	HUNNICUTT	CATHER ROGERS	1	223	642	
44	HUNTINGTON BEACH ASSI	A L K OIL CO	1	466	0	

1996-Huntington+Beach.tsv

Development and Operations Under Environmental Constraints

Paul Mount
State Lands Commission

DEVELOPMENT AND OPERATIONS UNDER ENVIRONMENTAL CONSTRAINTS

Mineral Resources Management Division

PURPOSE

- Review of Issues
- History of Oil and Gas Development
- Factors Influencing Development and Operations
- Current Situation
- Resolution to Conflict
- Creating Win-Win Scenario
- Sustainable Development

Mineral Resources Management Division

ISSUES

- Pollution/Spills
- Visual Impacts
- Noise Impacts
- Air Quality Impacts
- Safety
- Increase in Other Development
- Impact on Endangered Species or Marine Life
- Contributes to Other Global Impacts
- Reduced Property Value

Mineral Resources Management Division

POLLUTION/SPILLS

- Onshore -- Guadalupe, Avila Beach, Etc.
- Offshore -- Santa Barbara Spill, Montalvo, others
- Soil Contamination in Old Oil Fields
- Soil Contamination in Old Processing Plants
- Oil Flow into Rivers, Channels

Mineral Resources Management Division

VISUAL IMPACTS

- Unsightly plants, wells, rigs on Coastline
- Unsightly Platforms and Offshore Facilities
- Block of Ocean Views
- Visual Impact in non-industrial areas

Mineral Resources Management Division

NOISE IMPACTS

- Rigs, Service rigs
- Processing Plants
- Traffic

Mineral Resources Management Division

AIR QUALITY IMPACTS

- Emissions from Well Heads
- Emissions from Rig, Vehicle, Pumps, Engines
- Emissions from Construction Equipment
- Emissions from Processing Plant,
  - Fittings
  - Tanks
  - Lines
  - Leaks
- Emissions from Associated Vehicle/Vessel Traffic

Mineral Resources Management Division

SAFETY

- H2S and Other Gas Emissions
- Explosions
- Increased Vehicle and Vessel Traffic
- Fires

Mineral Resources Management Division

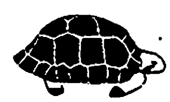
INCREASE IN OTHER DEVELOPMENT

- Support Industry
  - Pumps and Pumps Support Facilities
  - Welders, Field Contractors
  - Rig Contractors
  - Other Contractors
  - Processing Facilities
  - Suppliers
  - Roads
- Refineries
- Pipelines
- Marine Terminals
- Tank Farms

Mineral Resources Management Division

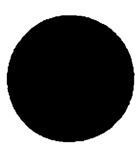
IMPACT ON ENDANGERED SPECIES OR MARINE LIFE

- Facilities Cited on Land with Endangered Plants or Species
- Facilities and wells located on Coastline
- Construction and or Activities Around Marine Life
  - Whale Migration
  - Seismic Surveys
  - Fish Spawning
  - Disruption of Fishing Sites



Mineral Resources Management Division

CONTRIBUTION TO OTHER GLOBAL IMPACTS



- Warming
- Air Pollution
- Oil in Ocean
- Increased Industrialization
- Reduction of Forests
- Reduction of Land for use by Wildlife

Mineral Resources Management Division

HISTORY IN CALIFORNIA

- 1886: Natural gas and crude discovered in Summerland
- 1904: Union Oil's "Old Maud" well blows out one million barrels in first 100 days
- 1908: Oil pipeline on Stearns Wharf Opposed
- 1925-1931: Purchase of beach and waterfront for public use
- 1926: El Capitan oil field discovered
- 1927: Ellwood oil field discovered
- 1929: Santa Barbara opposes oil drilling in city limits
- 1936: Voters narrowly defeat referendum to only allow drilling offshore from onshore.
- 1938: California State Lands Act allow offshore oil development with restrictions

Mineral Resources Management Division

HISTORY IN CALIFORNIA
(cont)

- 1947 and 1949: Seismic Survey's halted because of fisherman complaints
- 1947: Interim Agreement of the State Lands Commission allows CA to continue administration of lands within 3 miles
- 1952: Union Oil director Herbert Hoover, Jr. tells Santa Barbara audience oil development consistent with environmental concerns and that immediate development was needed due to Korean War. Santa Barbarans begin to mistrust the federal government's offshore oil policies
- 1954: UCSB opens its Goleta Campus

Mineral Resources Management Division

HISTORY IN CALIFORNIA
(cont)

- 1954: Santa Barbara City and county lobby the State Legislature to grant them a development-free offshore sanctuary and the authority to restrict offshore development through zoning
- 1955: State Legislature passes Shell-Cunningham Tidelands Act
  - Grant tidelands to SLC
  - Create development-free Santa Barbara Oil Sanctuary
  - Authorize development elsewhere in the Channel with 200 day wait period.
- 1956: State Lands Commission issues first permit for an offshore lease, near Summerland
- 1967: Platform Hogan, first in federal waters installed
- 1967: Santa Barbara County Adopts consolidation policy

Mineral Resources Management Division

HISTORY IN CALIFORNIA
(cont)

- 1969: Blowout occurs at Union Oil Co;s Platform A. GOO is founded
- 1969: State sanctuaries expanded.
- 1970: Wave of environmental legislation enacted
- 1971: Moratorium on existing development lifted offshore
- 1972: Ban on new development lifted
- 1974: Platform Harry removed
- 1976: Court ruling overturns CCC approval for Arco's expanded drilling on Platform Holly

Mineral Resources Management Division

HISTORY IN CALIFORNIA
(cont)

- 1978: Federal Lease Sale 48 - 9 active leases
- 1981: Federal Lease Sale 53 blocked Sale 68 results in 4 leases.
- 1986: Measure A San Luis Obispo approved Subjecting all Offshore Development to Vote
- 1986: Falling Oil Prices Halt Development
- 1989: Federal Lease Sale 95 – deferred
- 1990: Tanker Oil Spill Huntington Beach
- 1993: McGrath Lake leak 84,000 gallons crude.
- 1993: 370,000 gallon Condensate Leak near Ventura River
- 1996: Mobile Oil Clearview Project Dead

Mineral Resources Management Division

FACTORS INFLUENCING DEVELOPMENT AND OPERATIONS

- Public Opinion
- Environmental Group Opinion
- Land use Policies
- CA Coastal Commission
- Governor's position
- Politicians
- Mineral Ownership
- Laws, regulations, permits
- State and Local agency jurisdiction (16)
- Federal Agencies (7)

Mineral Resources Management Division

FACTORS INFLUENCING DEVELOPMENT AND OPERATIONS

- Resource reserves and value
- Location of oil and gas reserves
- Advantages of development outweigh disadvantages to local citizens
- New media attention
- Court rulings
- Land ownership
- Technical feasibility

Mineral Resources Management Division

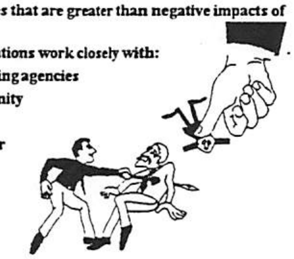
CURRENT SITUATION

- Oil and gas development not popular
- Transportation of crude by pipeline a must
- Development prohibited in many areas of California
- Technology still improving
- Many environmental groups still opposed
- Tighter and tougher regulations and spill prevention
- Greater liability protection required to protect against oil spills
- Consolidation of facilities being required
- More agencies, federal, state and local involved than every before
- Endangered species act having a great effect
- Low oil prices reduce rewards and risk /reward ration high

Mineral Resources Management Division

RESOLUTION TO CONFLICT!!!!

- Create Win-Win situations
- Generate positives that are greater than negative impacts of a project
- On existing operations work closely with:
  - Local permitting agencies
  - Local community
  - Land owner
  - Mineral owner
  - State agencies



Mineral Resources Management Division

RESOLUTION TO CONFLICT !!!!
(cont)

- Keep public and every one informed at the right time
- Listen to concerns with empathy
- Plan and set goals and let all know what they are
- Use facilitators
- Create Win-Win
- Seek Input from Others Who hae been sucessful

Mineral Resources Management Division

CREATING WIN-WIN SCENARIO

- Something in it for everyone (not necessarily $)
- Create local jobs, prosperity, quality of life
- Do not satisfy one group at expense of other
- Offset negative project impacts with very positive environmental or public benefits elsewhere.
- Understand fully what each party wants, don't assume!

Mineral Resources Management Division

SUSTAINABLE DEVELOPMENT

- THUMS
- BEVERLY HILLS
- HUNTINGTON BEACH TOWN LOTS
- LAS CIENEGAS
- MIDWAY SUNSET
- MOLINO

Mineral Resources Management Division

RESOLVING THE CONFLICT REMEMBER

- ☑ Conflict is a Choice
- ☑ Communications
- ☑ Faith in the Process
- ☑ No Hidden Agendas
- ☑ Facilitation
- ☑ Ask for Help Sorting Out Problem
- ☑ Lead not Manage

Mineral Resources Management Division

ANWR development would help California economy

The narrow coastal plain of the Arctic National Wildlife Refuge (ANWR) in remote and nearly uninhabited northeastern Alaska offers an outstanding opportunity to increase both U.S. energy and economic security. The region could hold enough oil to rank it on a par with the world's top oil-producing nations; developing that oil could increase employment across the country in sectors ranging from manufacturing to a variety of service industries.

Opening the coastal plain to oil and natural gas development could increase domestic oil supplies by an average of more than 1 million barrels a day for at least 20 years. The oil can be produced in an environmentally responsible manner. The petroleum industry's record in developing the four producing fields near ANWR reflects the great care that has been taken in the search for oil on Alaska's North Slope.

Developing coastal plain oil could also boost the gross national product by $50.4 billion and increase employment nationwide by about 735,000 jobs by the year 2005, according to an economic analysis prepared by Wharton Econometrics Forecasting Associates (WEFA Group). According to the WEFA study, all sectors of the U.S. economy would benefit and almost 80,000 jobs could be created in California. Development of coastal plain oil could also slow growth in oil prices, reduce imports and improve the U.S. trade balance.

Coastal plain holds petroleum potential

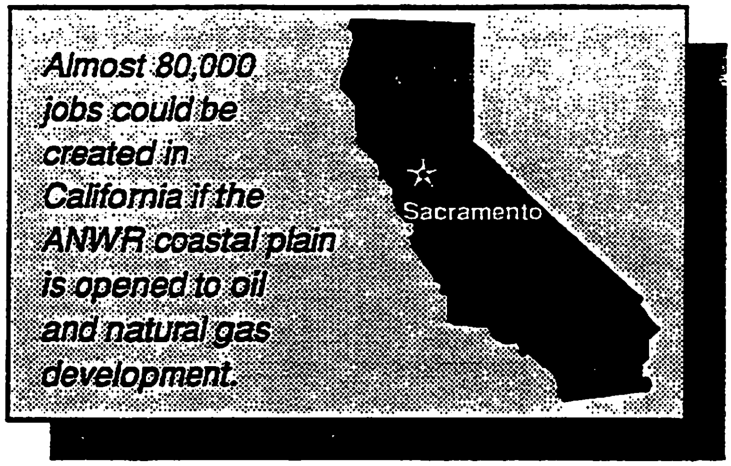
Crude oil from Alaska's North Slope fields currently accounts for about 25 percent of this nation's total oil production. However, America's dependence on

California energy facts

California consumes nearly twice as much oil as it produces. More than 60 percent of refined products—such as gasoline—consumed by West Coast states, including California, come from Alaska oil.

Oil production:	1 million barrels per day
Oil consumption:	1.8 million barrels per day
Alaska oil shipments received at refineries:	1.3 million barrels per day*
Refinery workers:	26,000
Motor vehicle registrations:	21,657,000
Vehicle miles traveled:	241,575,000

*Includes Washington State shipments, although most goes to California refineries.



foreign oil this year is at a record 50 percent and could increase in the future. One reason is that the older fields in the lower-48 states, have reached peak production and are declining.

One of the most promising places to look for replacement production is the ANWR coastal plain. The Interior Department estimates that recoverable reserves beneath the coastal plain—economically producible based on today's technology—could range up to 9.2 billion barrels of oil.

Based on U.S. Geological Survey estimates, the WEFA Group projects that the ANWR coastal plain could produce an average of more than 1 million barrels of oil every day for at least 20 years—with production peaking just below 2 million barrels a day by the year 2005. By that time, 2 million barrels might constitute close to one-third of the nation's domestic production. To put the area's potential in further perspective, consider that if the ANWR coastal plain were a nation, that level of production would place it among the top eight oil-producing nations in the world.

Moreover, coastal plain oil would be developed in an environmentally responsible manner. The U.S. petroleum industry's more than 20 years of experience on Alaska's North Slope provide overwhelming evidence that oil and natural gas development would pose little threat to the ecology of the area.

At nearby Prudhoe Bay, stringent federal, state and local regulation and the industry's own strict standards and innovative technology have demonstrated the compatibility between oil operations and the environment. In fact, what has been learned at Prudhoe Bay should result in improved protection to the coastal plain if petroleum operations are allowed there—and greatly limit the area actually affected by development.

Development could mean economic gains

The WEFA Group's analysis concludes that opening ANWR's coastal plain to petroleum development would expand "the nation's productive potential by tapping a currently unused ... resource." WEFA predicts that developing ANWR's potentially vast petroleum resources would "stimulate U.S. investment, moderately temper the growth in world oil prices and significantly reduce U.S. petroleum imports and improve the U.S. trade balance."

"Moreover," the WEFA analysis continues, "such effects act to reduce U.S. prices and increase U.S. GNP and employment. These effects are widely dispersed across sectors and regions."

The manufacturing sector, for example, stands to gain 128,000 new jobs nationwide by 2005, while the nation's service sector is expected to grow by as many as 225,000 jobs. While boosting the U.S. GNP by $50.4 billion, WEFA predicts that ANWR development could boost U.S. employment by 735,000 by the year 2005.

New jobs in California. About 80,000 jobs could be created in California as a result of ANWR development, according to the WEFA report. Several sectors would benefit substantially: the state's construction industry, with more than 16,000 jobs; the services industry, with more than 17,000 jobs; and the trade sector, with more than 25,000 jobs.

Refineries. California's 26,000 refinery workers also would benefit from ANWR production. About 1.3 million barrels of Alaska crude is shipped to the West Coast daily. California refineries receive the bulk of these shipments. But production of oil from Alaska fields is declining. Thus, coastal plain oil would help maintain the flow of crude oil to California refineries.

Shipyards. The West Coast's vast shipbuilding industry—which employs more than 18,000 people in yards from Washington State to southern California—could benefit significantly from coastal plain development. Many of the oil tankers used to transport Alaskan crude are built and maintained on the West Coast.

Alaska oil has helped U.S. economy

Since 1977, oil development on Alaska's North Slope near ANWR has contributed more than $300 billion to the U.S. economy. It has increased federal revenues and new employment opportunities nationwide. And it has created additional business in every state in the union for the thousands of firms providing goods and services used in oil and natural gas development.

North Slope oil production has also given a boost to industries across the economic spectrum. As North Slope production climbed through mid-1989, jobs were added in a variety of sectors, from service industries to trade. Alaska alone benefited from 6,000 new jobs, and the state received about $200 million a year because of North Slope production.

ANWR development makes sense

The petroleum resources of the ANWR coastal plain could give a substantial boost to U.S. energy security, by helping to offset the nation's growing reliance on imports. The U.S. economy, which depends on a readily available, reasonably priced source of oil to thrive, also could benefit greatly. Development of ANWR's coastal plain makes both energy and economic sense.

April 3, 1991

ARCTIC OIL RESERVE
JOBS AND ENERGY FOR AMERICA

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(907) 563-2697
Fax (907) 562-6782

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Washington, D.C. 20002
(202) 544-6355
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ARCTIC POWER

Arctic Power is a grassroots, non-profit organization of Alaska citizens organized to promote oil exploration and production within the Coastal Plain of ANWR.

Arctic Power has secured more than 10,000 members since its inception in mid-1992 and is enrolling new members daily.

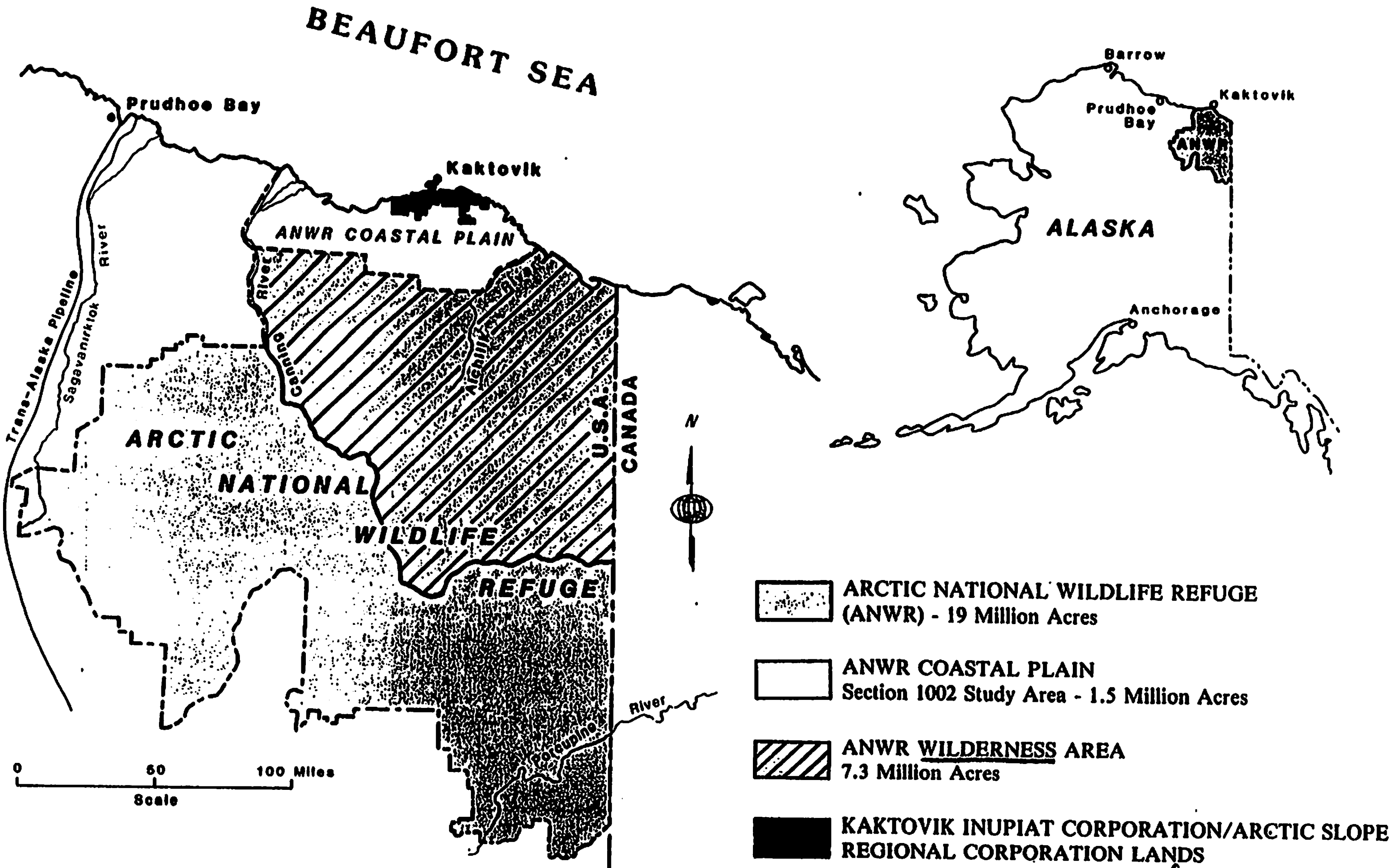
Arctic Power membership spans the economic spectrum - including miners, fishermen, loggers, tourism operators, transportation businesses, labor unions, banks, teachers, the legal community, retail firms, service industries, non-profit organizations, Alaska Native corporations, local elected officials, and many others. Interest groups represented on the Arctic Power board and through its membership are The Alaska Support Industry Alliance, the Alaska State Chamber of Commerce, the Resource Development Council, the Alaska Trucking Association, the Alaska Oil & Gas Association, the Anchorage Chamber of Commerce, the Alaska Miner's Association, and the Alaska Forest Association.

A statewide board oversees the activities of Arctic Power and includes representatives from Barrow to Ketchikan - all regions of the state are represented. The board of Arctic Power includes businesses from a variety of industry sectors, including but not limited to, law firms, trucking businesses, the visitor industry, media firms, Native corporations, oilfield service companies and pubic relations agencies.

The Alaska congressional delegation has endorsed Arctic Power and works closely with the board and staff of the organization. Arctic Power and the state of Alaska work together in their congressional outreach efforts in Washington, D.C.

The organization is committed to securing congressional and presidential approval of legislation opening the Coastal Plain of ANWR to responsible oil development.

7/96



Native land within the refuge

NOTE: The Coastal Plain of ANWR (or Coastal Plain) defined here refers to the legally designated area specified in Section 1002 of the Alaska National Interest Lands Conservation Act (ANILCA). The generic term "coastal plain" refers to the lowlands of the North Slope which lie between the Brooks Range and the Beaufort Sea coast.

ANWR UPDATE

September 1995

Not "America's Last Wilderness"

Only the 1002 Area of the Arctic National Wildlife Refuge can be considered for development. The remaining 18.3 million acres would still be off limits, with 8 million acres permanently designated as Wilderness. The small fraction of the total wildlife refuge is not a pristine, untouched wilderness area. There are communities and military developments. The wilderness values of the refuge would not be impacted by development of the 1002 Area.

ANWR is not the last remaining Alaskan Wilderness.

- More than 192 million acres of the State of Alaska are *already* protected in Wilderness Areas, National Parks, National Preserves, National Forests, National Wildlife Refuges, National Wild and Scenic Rivers, State Parks, State Preserves, State Critical Habitat Areas, State Marine Parks, and many other federal and state conservation units.
- Wilderness areas in Alaska - 18 million acres - equal the *combined* area of Pennsylvania, New Jersey, West Virginia, and Maryland.
- New government proposals could add over 12 million acres of new federal Wilderness across Alaska, leaving the state with over two-thirds of *all* federally designated Wilderness.
- Other Wilderness Areas exist that provide more complete, diverse and virtually undisturbed habitat.

ANWR is not the last remaining undisturbed arctic Wilderness.

- More than half a million acres of coastal lands between the 1002 Area and the Canadian border are already designated as Wilderness, adjoining Canada's 3-million-acre Northern Yukon National Park.
- More than 943 miles of Arctic Alaskan coastline to the west of the Colville River is *not* open to development; much of this is the 23-million-acre National Petroleum Reserve-Alaska (NPRA), which is under consideration for National Wildlife Refuge status.
- Wilderness in ANWR after development of the 1002 Area would be larger than South Carolina.
- The 1002 Area has been used extensively by local and commercial hunters and for military installations.

Industry is not seeking to open the Wilderness Area to development.

- The 1002 Area is not designated as Wilderness; it was set aside for special study because of its unique petroleum potential.
- Only 1.5 million acres (8%) of the 19.8-million-acre Arctic National Wildlife Refuge are under consideration for leasing.
- The Office of Technology Assessment has estimated that structures and pipelines would directly affect only 2,000 acres of the coastal plain - less than half of one percent.
- More than 99% of the Refuge will remain untouched, even under full leasing.
- After four decades of experience in the Alaskan Arctic, there are no scientific studies by regulatory agencies, academic institutions, or industry that have ever documented a population decline of any species in response to arctic oil field operations.

ANWR UPDATE

September 1995

Reducing the "Footprint" of Arctic Energy Development

Many new technologies and operational practices have dramatically reduced the impact of exploratory drilling and development in the Arctic. All oil field infrastructure — from wells to pipelines to production centers and support facilities — is developed with the goal of minimizing environmental impact. Three decades of success on the North Slope prove that the ANWR 1002 Area would be developed responsibly and with minimal impact.

North Slope facilities cover minimal surface area.

- Current North Slope facilities cover only 0.05% of the Arctic Coastal Plain (8,180 acres).
- Prudhoe Bay production facilities cover less than 8 square miles of land.
- Prudhoe Bay operations cover only 2% of its unitized area; Kuparuk oil field 0.8%, and Badami only 0.5%.
- The Office of Technology Assessment (OTA) estimated that less than 2000 acres of the 1.5 million acre 1002 Area - less than 0.5% - would be affected in a full development scenario.

Technological advances have dramatically reduced the surface area required for drilling and producing oil and gas.

- If Prudhoe Bay were built today, the footprint would be less than 2,000 acres (60% smaller).
- Today's production well pads are 70% smaller than 20 years ago (10 acres vs. 40 acres).
- Today's production pads use 75% less gravel than 20 years ago (112,700 cu. yds vs. 198,000 cu. yds.).
- Spacing between wellheads has been reduced from 135 feet to 35 feet for onshore production pads, and to 10 feet for some offshore wells.
- Ice roads for winter construction have eliminated the need for many gravel access roads.
- Oil and gas separating facilities in ANWR will be at least half the size of comparable Prudhoe facilities.

New operating practices and consolidation of facilities further reduce the impact of the oil industry.

- Directional drilling, slimhole drilling, and other advancements cluster wellheads and allow access to targets 3 miles away.
- Consolidation of oil-field service-company operations at Kuparuk Industrial Center as opposed to individual leases (Deadhorse) reduces area requirements and ensures greater regulatory compliance.
- Field operations use shared facilities, such as a single power-generating facility for the entire Prudhoe field.

Other operating practices have evolved to minimize waste and improve waste handling.

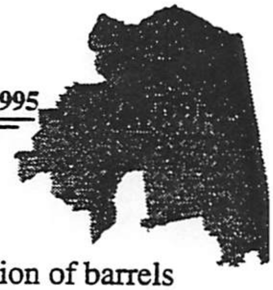
- Use of new grinder for drilling muds and cuttings has eliminated the need for reserve pits.
- Reserve pits will not be used in the ANWR 1002 Area.
- Improved waste management and recycling will reduce or eliminate much waste.
- Facilities in the 1002 Area will be designed halon-free.

The potential 2,000-acre footprint assumed for development in the 19-million-acre Refuge is analogous to the area occupied by:

- A computer disk in a large 4 bedroom house (2,500 sq. ft.).
- A very small button in a large bathtub (540 sq. in.).
- A briefcase on a football field (100 yards long).
- 10 parking spots at the John F. Kennedy Center for the Performing Arts.
- One step up Mt. McKinley (20,320 feet).
- Rock Creek Park compared to the entire State of Maine (19.8 million acres).

ANWR UPDATE

September 1995



Economics and National Energy Security

Domestic oil production in the U.S. is decreasing rapidly and will continue to decline by million of barrels per day over the next few years. At the same time, national demand for oil has steadily increased to the highest levels since the 1970's. Foreign oil imports create a dependence on potentially unstable sources and put the U.S. in a state of import vulnerability. Our national security and economic stability depend on sufficient availability of domestic oil supplies. Development of oil and gas reserves in the 1002 Area is critical to a steady supply of domestic crude oil.

Domestic production in the U.S. is declining rapidly.

- Domestic oil production fell to 6.6 million bbl/day in 1994 — the lowest annual level since 1954.
- Domestic crude output fell 1.5 million bbl/day in 1994 compared with 1980 levels; during the same time, domestic consumption increased by 3.4%.
- The current drilling rig count in the US is down 80% from 1981.
- Decline cannot be offset solely by increased conservation and alternate energy sources.
- North Slope production (25% of U.S. total) is expected to decline annually at a rate of 10%, from an average of 1.8 million bbl/ day in 1991.
- More than 450,000 jobs - half of all the available jobs in the U.S. petroleum industry - have been lost since 1982.

U.S. demand for oil is continuing to increase rapidly.

- National demand for oil has steadily increased to more than 17.7 million bbl/day, the highest level since the mid-1970's.
- Even with increased conservation, U.S. energy demand could increase 19% in the next 10 years.
- Oil and gas account for 65% of U.S. energy use.
- Oil will still provide 38% of U.S. energy demand by the year 2030.
- The transportation sector of the U.S. economy uses 63% of the petroleum and is 98% dependent on oil.
- National security and economic stability depend on sufficient availability of domestic oil supplies.

Dependence on foreign imports is increasing rapidly.

- During 1973 Arab oil embargo, the U.S. imported 35% of its oil.
- By 1994, the U.S. imported 50.4% of its oil.
- In 1990, imports cost the nation $64.6 billion and accounted for 60% of the U.S. trade deficit, creating dangerous dependence on potentially unstable sources.
- U.S. Dept, of Energy has stated that by the year 2000, the U.S. could be importing close to 70% of its oil.
- Unless oil prices increase appreciably, U.S. exploration will remain stagnant, foreign imports will continue to rise, and U.S. vulnerability to oil price shocks and possible shortages or stoppages could have large economic impacts.
- The initial ANWR lease sale could bring between $1.5 and $3.5 billion.

There is no conflict between lifting the Alaska North Slope export ban and development of the 1002 Area.

- The 22-year-old ban is the only law today that requires that a resource be sold only in the other 49 states.
- Allowing the export of North Slope crude will decrease transportation costs (Gulf Coast vs. Pacific Rim).
- By the time ANWR is developed, Prudhoe Bay production will be at 400,000 barrels per day.
- Even if oil drilling in ANWR brings TAPS back to up capacity of 2.1 million barrels per day, by the time the field is developed (2005), the growth on the West Coast will justify development.
- Lifting the ban now will reduce the overall cost of importing oil (more than 50% of U.S. trade deficit) and add 25,000 new jobs by the year 2000.
- Allowing ANWR development to begin will reduce the cost of imported oil in the next 10 years. Even if all the oil isn't needed at that time, the surplus could be sold to foreign markets to further reduce the balance-of-trade deficit.

Anchorage Daily News Wednesday, September 25, 1996

By FRANK MURKOWSKI

Once again, American military personnel are engaged in the Persian Gulf for the sole purpose of keeping oil flowing. And just as Iraqis saw their radar installations explode earlier this month, Americans are seeing another explosion in the price of gasoline at their local filling station pumps.

Many Americans wonder why we keep fighting the Persian Gulf war that we won in 1991. Perhaps soon they will start asking why we keep fighting price hikes at the gasoline pumps every time there is a hiccup in world supplies. Or, as is the case this time, why prices jump only because of the threat the future new supplies — the 50 million barrels a quarter, or $1 billion worth of oil that Iraq was about to sell on the world market — won't come on line as quickly as projected.

The reason is simply that even with America's considerable improvements in energy conservation of recent years, the world is consuming more and more oil, while the United States continues to produced less and less of it.


Murkowski

Worldwide consumption is up, especially in Asian nations. World oil consumption is up to 69 million barrels a day, from just 62 million barrels six years ago. At the same time, American oil production has fallen nearly 30 percent since 1973. America now produces less crude oil than we did in 1955.

As American production falls, our imports rise. While we were only dependent on foreign sources for 36 percent of our oil at the time of the Arab oil embargo of 1973, we now spend more than $150 million a day to buy the 52 percent of the oil we import. Estimates by the Energy Information Agency are that we could be two-thirds dependent on foreign nations by the new century — a dependence that has serious implications for our economy, energy security and foreign policy.

Even if we escape the future blackmail threat of an oil cutoff, unless we drop our opposition to terrorism, we face the continued economic bleeding that comes from spending $50 billion a year overseas to buy oil — roughly a third of our balance of trade deficit.

This state of affairs is especially sad since there is a ready solution that can come without harm to our environment. It is simply to allow America to meet more of its oil needs, helping to stabilize our domestic supply, thus reducing price hikes, while keeping our money at home and creating jobs here — not in Iraq.

Alaska, the home of the nation's largest oil field — the giant Prudhoe Bay field — also is home to what likely will prove to be the nation's second-largest oil find — oil lying under a small area of the Arctic coastal plain. According to estimates by the federal Bureau of Land Management, just a small part of the 1.5 million-acre coastal plain contains as much as 9.2 billion barrels — enough to equal about a quarter of the nation's domestic reserves.

By permitting development of just a few thousand acres — less than a hundredth of 1 percent of the 19 million-acre Arctic National Wildlife Refuge — we would stabilize our oil production, increase our gross national product by $50.4 billion, decrease our balance of payments deficit by more than $10 billion a year, and generate an improvement to our economy of about $325 billion over the life of the anticipated field.

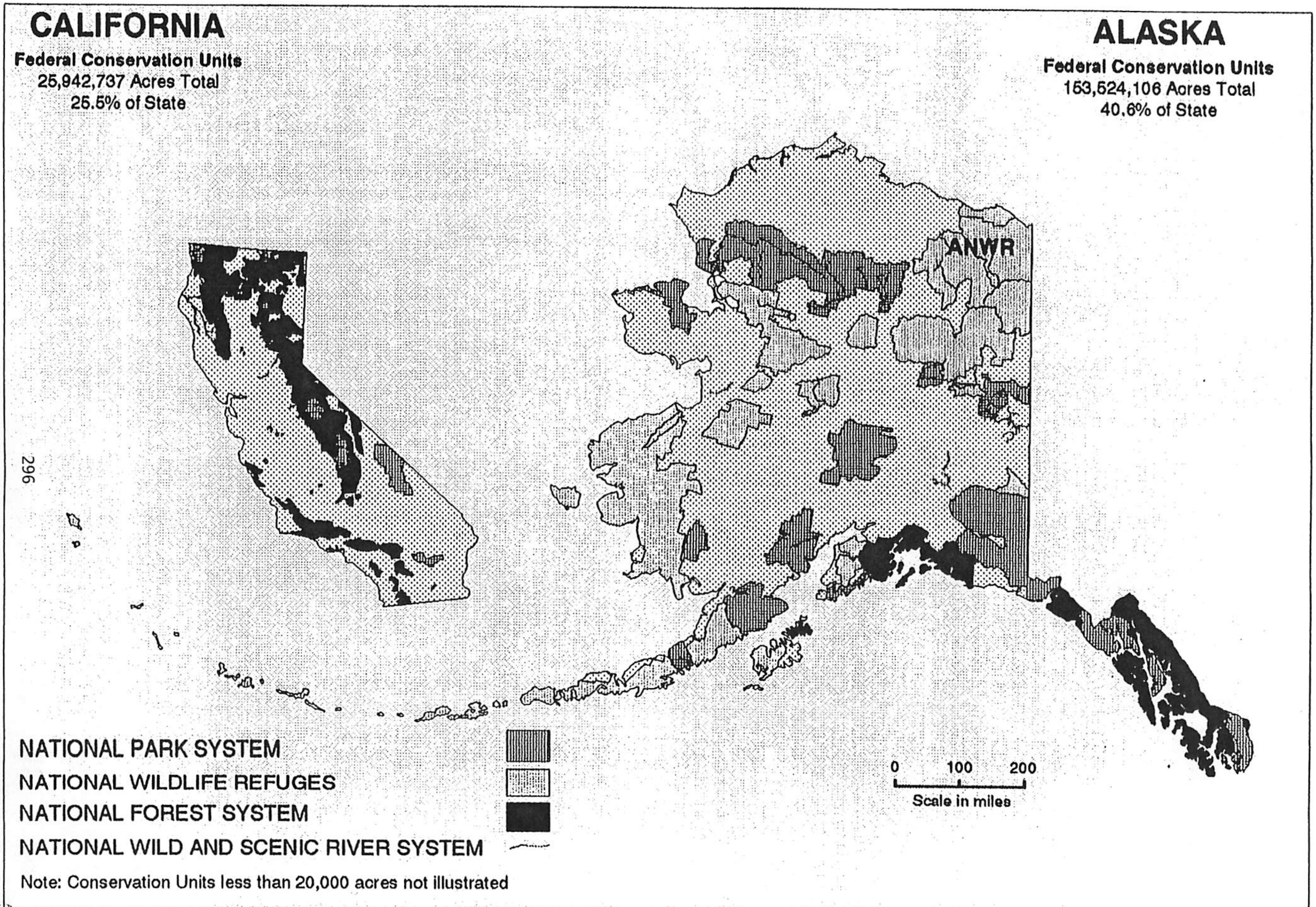
On top of those benefits, as organized labor well knows, oil development will produce tens of thousands of new jobs — up to 735,000 in all 50 states by one estimate.

Now, if this were required to come at the expense of our Arctic environment, it might not be worth the cost. But our experience at Prudhoe Bay has shown that careful development can fit hand in glove with the environment. In Alaska, the caribou herd at Prudhoe Bay is now more than three times larger than it was before construction started on the Prudhoe Bay field. Bird nesting populations are larger than they were before the oil field, and there has been no damage to polar bears.

It is past time that Americans look at all the new technology that has been developed to permit Arctic oil development to occur safely and explode the myths that have stopped us from taking the only realistic step available to us to help control volatile U.S. oil supplies. That is to produce all the oil that we safely can in America, giving us time to continue research to develop new energy sources and fuel conservation technologies for the future.

Make no mistake, our continuing presence in the Gulf is to keep an uninterrupted supply of oil flowing to the Free World.

Frank Murkowski represents the state of Alaska in the U.S. Senate.


CALIFORNIA
Federal Conservation Units
25,942,737 Acres Total
25.5% of State
ALASKA
Federal Conservation Units
153,524,106 Acres Total
40.6% of State
ANWR
0 100 200
Scale in miles
NATIONAL PARK SYSTEM
NATIONAL WILDLIFE REFUGES
NATIONAL FOREST SYSTEM
NATIONAL WILD AND SCENIC RIVER SYSTEM
Note: Conservation Units less than 20,000 acres not illustrated

ARCTIC POWER

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"WHAT DEVELOPMENT OF ALASKA'S ARCTIC COASTAL PLAIN MEANS TO THE NATION"

Jobs

Jobs that **could** be created from Coastal Plain development nationally:	**735,000 jobs**
Direct petroleum industry jobs nationwide:	**1.5 million jobs**

Economic Impact

Since discovering oil on Alaska's North Slope, spending on exploration and development nationwide is over:	**$50.0 billion**
Nationwide vendors doing business in AK oil fields since 1990:	**over 10,000**
To buy foreign oil in 1995 America spent:	**$55.1 billion**

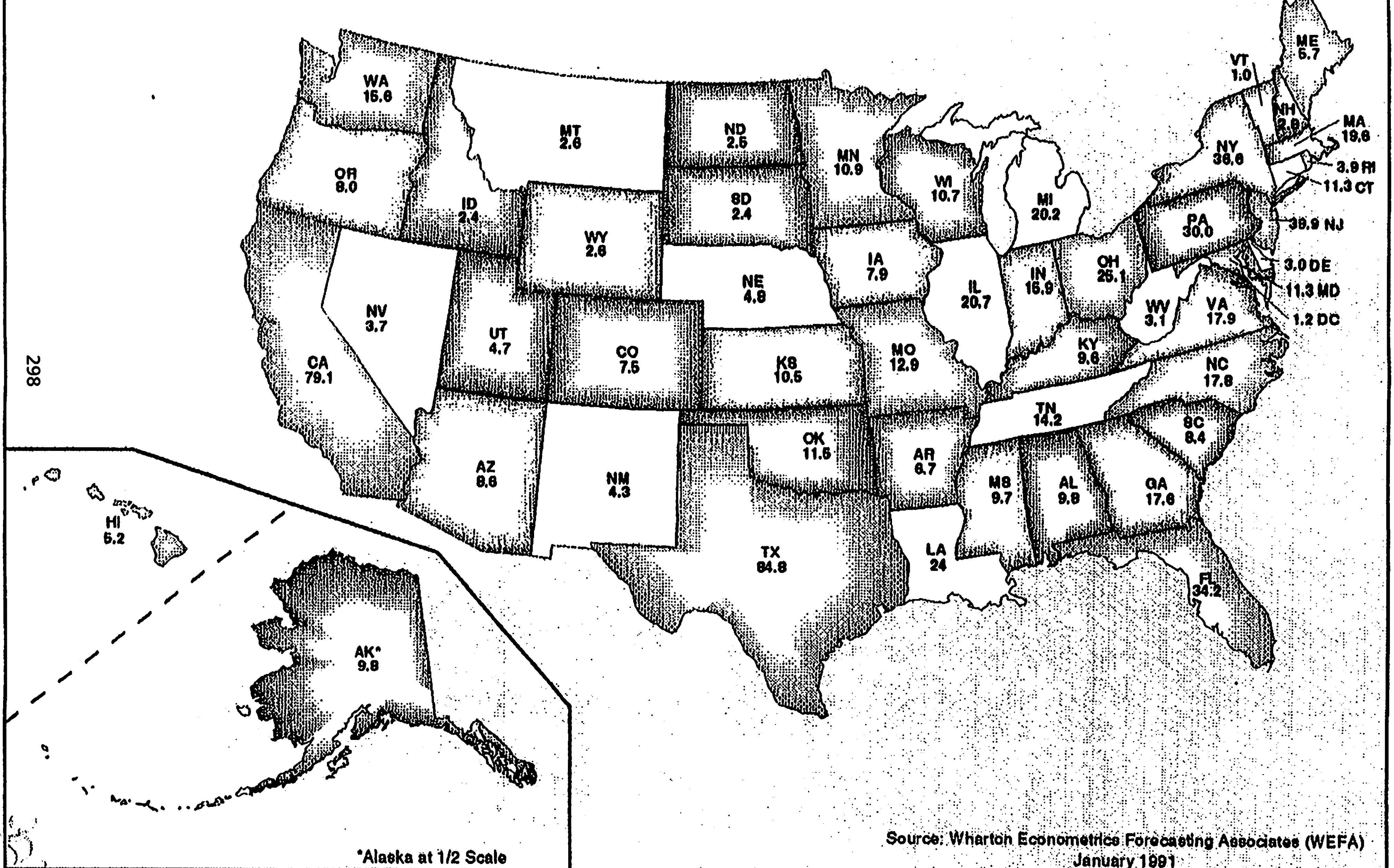
Petroleum Statistics

Today U.S. imports of foreign oil exceeds:	**52%**
Current U.S. imports of oil per day:	**9 billion barrels**

8/96

Daily Consumption of Petroleum Products

All Numbers Are in Millions of Gallons



A CASE FOR OIL DEVELOPMENT IN ALASKA

* The U.S. imports over 50% of the nation's needed petroleum. These oil imports cost more than $55.1 billion a year. These figures are rising and could exceed 67% imports by the year 2000.

* Beneath a 1.5 million acre tract on the North Slope of Alaska is estimated to be between 3 and 9 billion barrels of recoverable oil. This area is a specially designated area within the 19 million-acre Arctic National Wildlife Refuge (ANWR). Known as the "Coastal Plain", this area was designated by Congress in 1981 as requiring special study to determine its oil and gas potential and the effects of development on the environment. In 1987, the Department of Interior recommended development. Congressional authorization is required for the Coastal Plain to be open.

* Prudhoe Bay, located 60 miles to the west of ANWR, has been operating for nearly 20 years and has produced in excess of 10 billion barrels of oil during that time. It is among the most environmentally sensitive oil operations in the world. Present output at Prudhoe Bay has declined to 1.4 million barrels per day, and is continuing to decline.

* The Coastal Plain of ANWR is America's best bet for the discovery of another giant "Prudhoe Bay-sized" oil and gas field in North America. Many economic benefits would result:

  - The Coastal Plain could produce up to 1.5 million barrels per day for at least 25 years - nearly 25% of current daily U.S. production.
  - The U.S. would save $14 billion per year in oil imports.
  - Between 250,000 and 735,000 jobs are estimated to be created by development of the Coastal Plain.
  - Federal revenues would be enhanced by billions of dollars from bonus bids, lease rentals, royalties, and taxes.

* Advancing technology has greatly reduced the "footprint" of arctic oil development. If Prudhoe Bay were built today, the footprint would be 1,526 acres, 64% smaller.

* Oil and gas development and wildlife are successfully coexisting in Alaska's arctic. For example, the Central Arctic caribou herd at Prudhoe Bay has grown from 3,000 to as high as 23,400 during the last 20 years.

* More than 75% of Alaskans favor exploration and production in ANWR.

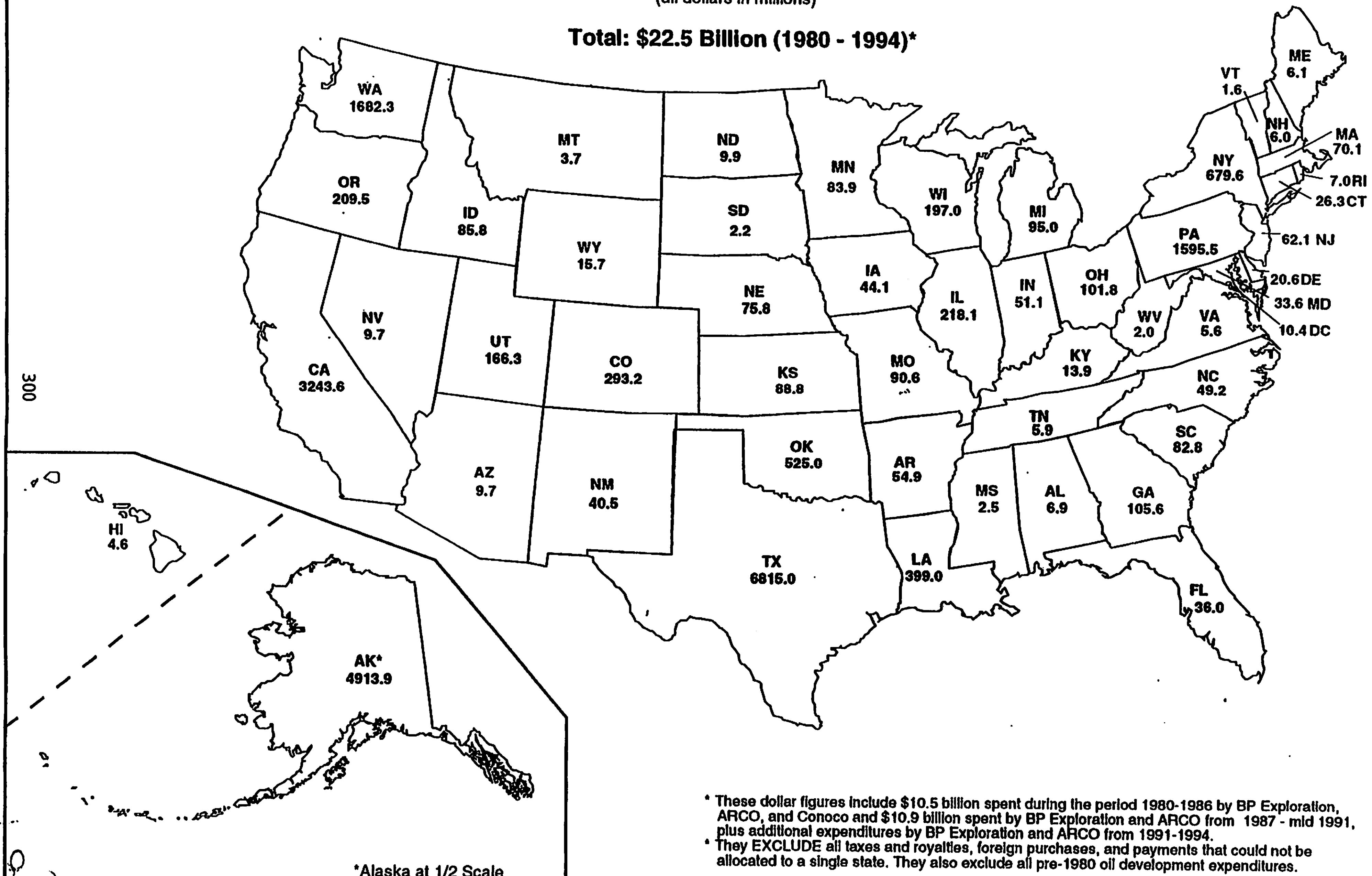
* The Inupiat Eskimos who live in and near ANWR support onshore oil development on the Coastal Plain.

6/25/96

Dollars Spent in Each State for North Slope Oil Development

(all dollars in millions)

Total: $22.5 Billion (1980 - 1994)*

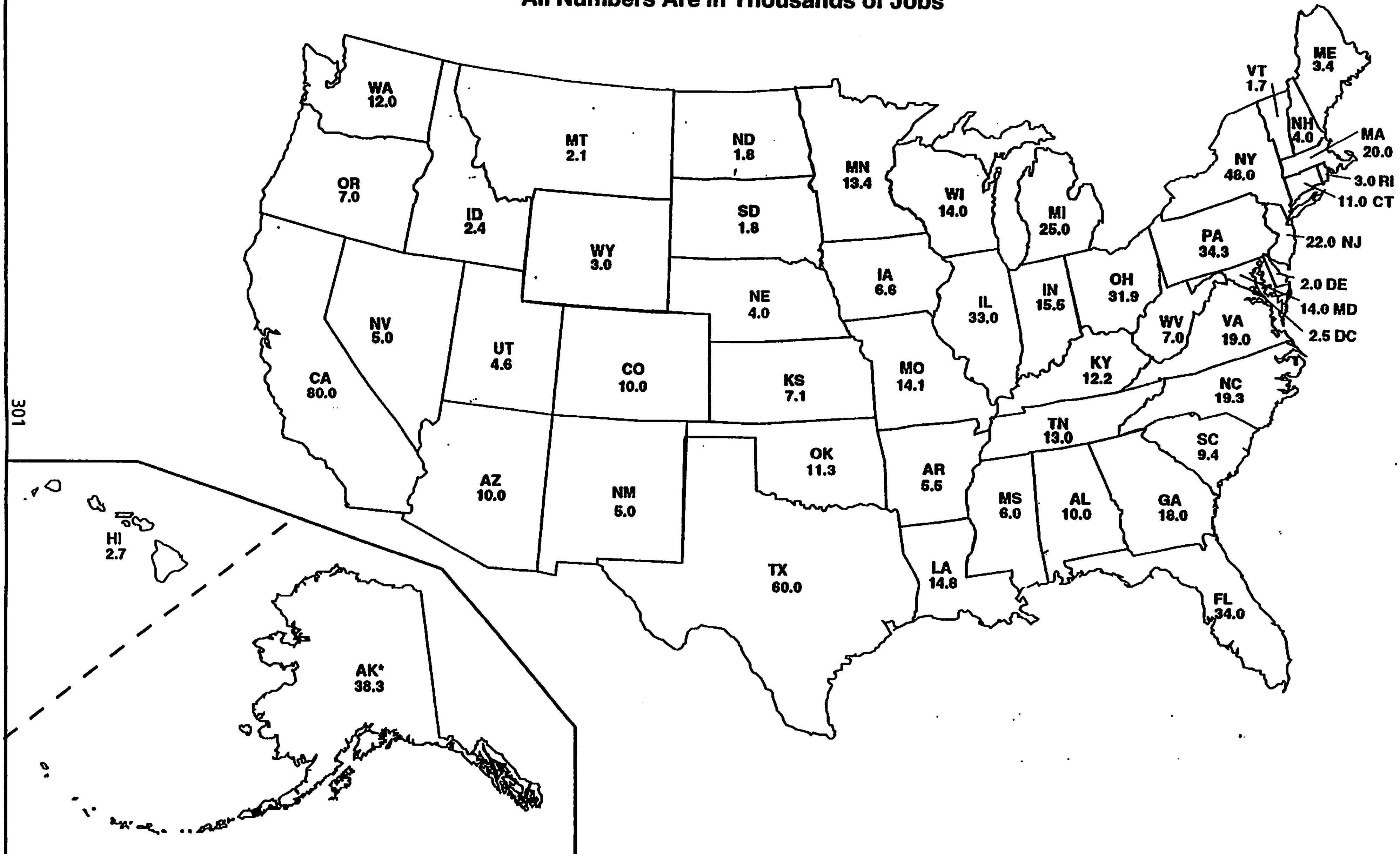


* These dollar figures include $10.5 billion spent during the period 1980-1986 by BP Exploration, ARCO, and Conoco and $10.9 billion spent by BP Exploration and ARCO from 1987 - mid 1991, plus additional expenditures by BP Exploration and ARCO from 1991-1994.
* They EXCLUDE all taxes and royalties, foreign purchases, and payments that could not be allocated to a single state. They also exclude all pre-1980 oil development expenditures.

Basemap from \890271410\MACUSA.DGN

735,000 Potential New Jobs if ANWR is Opened to Oil & Gas Leasing

All Numbers Are in Thousands of Jobs



*Alaska at 1/2 Scale

Potential jobs created by ANWR activiy
as forecasted by WEFA (1991)

NOTES

Multimedia and Petroleum Tech Transfer

Mark Kapelke
Tidelands Oil Production Company
and
PAG Vice Chairman

DOE WATERFLOOD PROJECT SUMMARY

SCOPE OF WORK

- Use innovative technology to identify bypassed oil in a mature water flooded oil field. Capture this bypassed oil by recompleting and placing on production existing idle wells using new technology.

BUDGET

- $4.0 Million over 5 years
- $1.8 Million or 45% of project funded by the DOE Class III Program
- $1.0 Million actual expenditure to date

PARTNERS

- U.S. Department of Energy
- City of Long Beach
- Tidelands Oil Production Co.
- Stanford University
- Magnetic Pulse Inc.

PROJECTED OIL RECOVERY

- 5.3 Million barrels from this project
- 28 Million barrels from the Wilmington Field
- 761 Million barrels from Southern California

MILESTONES

- Completed 3-dimensional reservoir computer model of localized areas
- Logged 8 wells
- Recompleted two idle wells using new completion technology
- Identified 4 additional idle wells for recompletion
- Completed a CD-ROM for technology transfer

DOE STEAMFLOOD PROJECT SUMMARY

SCOPE OF WORK

- Expand and improve an existing marginally economic steamflood project in the Fault Block IIA Tar Zone

BUDGET

- $21.3 Million over 7 years
- $7.9 Million or 37% of project funded by the DOE Class III Program
- $7.8 Million actual expenditure through 7/96

PARTNERS

- U.S. Department of Energy
- City of Long Beach
- Tidelands Oil Production Co.
- University of Southern California
- David K. Davies and Associates

PROJECTED OIL RECOVERY

- 13 Million barrels from this project
- 525 Million barrels from the Wilmington Field
- 1.4 Billion barrels from Southern California

MILESTONES

- Completed 3-dimensional geologic model
- Completed a 2400-foot channel crossing
- Drilled 4 horizontal wells
- Steam injection into horizontal wells started December 16, 1995
- Production from horizontal wells started June 11, 1996
- Completed a CD-ROM for technology transfer
- Applying DOE technology to Fault Block V

DOE STEAMFLOOD PROJECT DESCRIPTION

GOAL

- Expand existing steamflood project to the South and improve the economics of the expansion through technology innovation. Share our findings.

WILMINGTON FIELD CHALLENGES

- Subsidence
- Difficult Geology
- Sand Production

CONCERNS WITH STEAMFLOOD EXPANSION

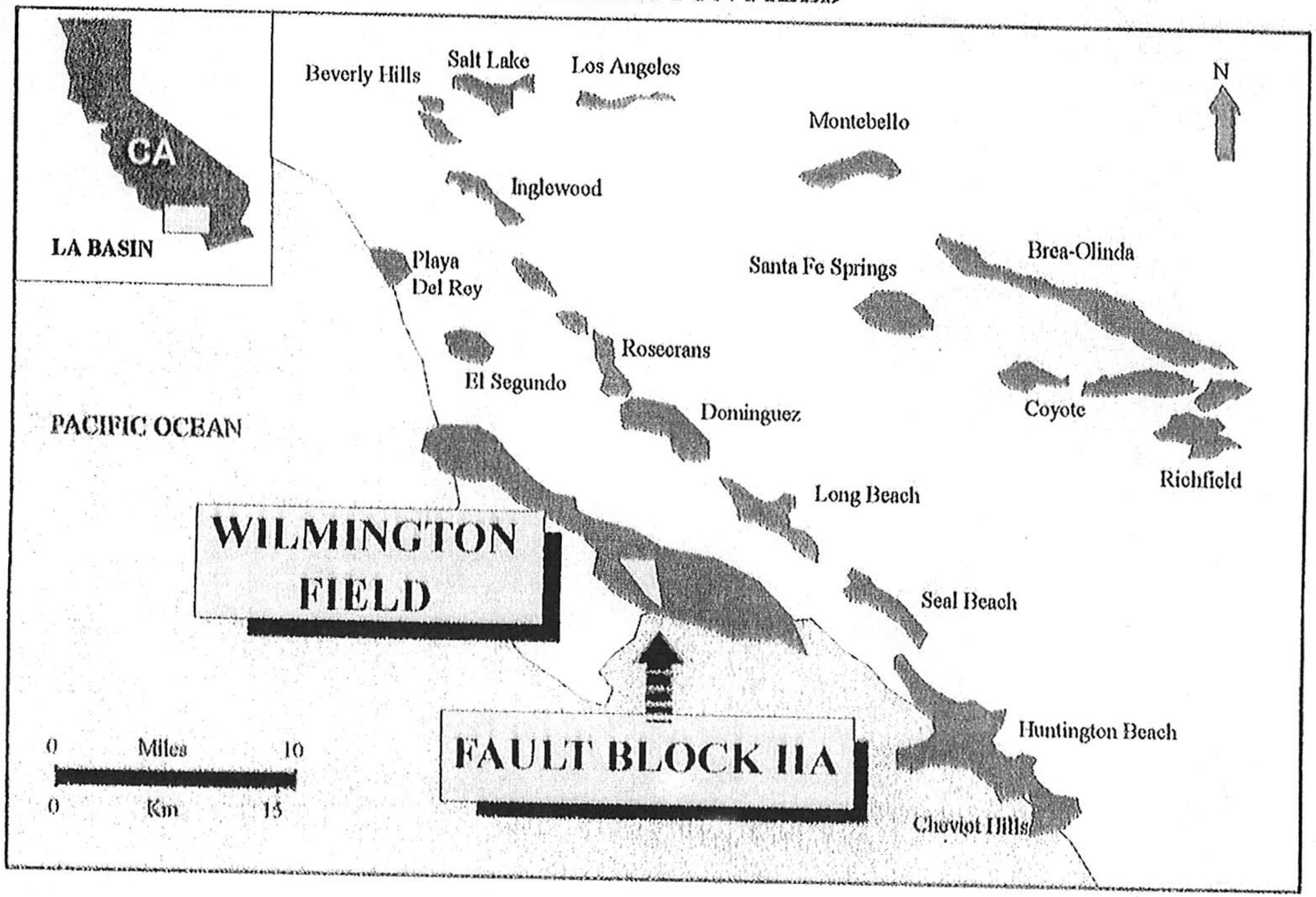
- Marginal Economics
- Relatively Deep (2500'±)
- High Bottomhole Pressure (700 - 1000 psi)
- Steam Needed across a Water Channel

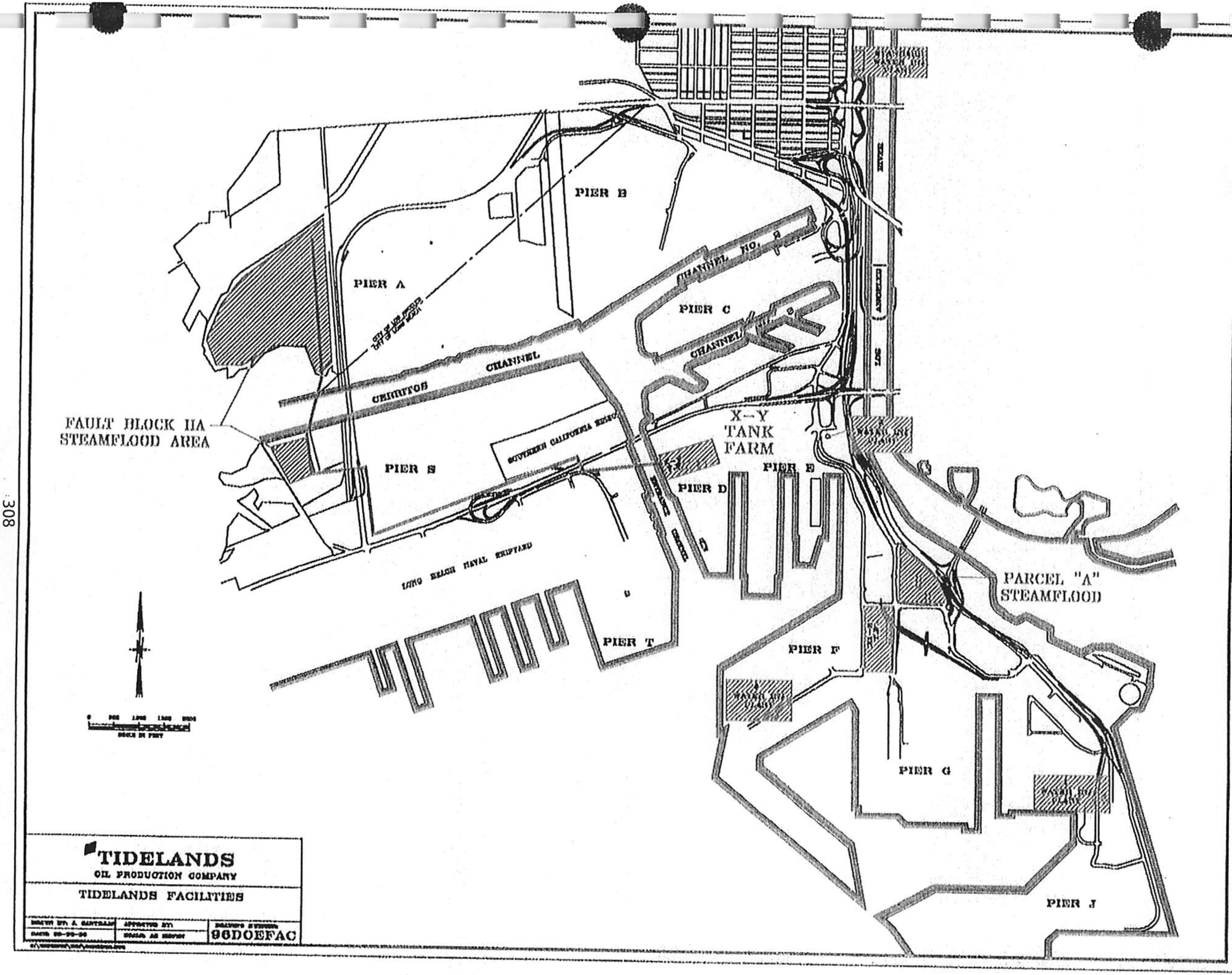
TECHNOLOGICAL INNOVATIONS

- 3-Dimensional Geologic Model
- 3-Dimensional Thermal Simulator
- Use New Horizontal Wells
- Use Alkaline Water and Steam Sand Consolidation Completion
- Drill a 2400 foot Insulated Channel Crossing
- Develop a CD-ROM for Technology Transfer

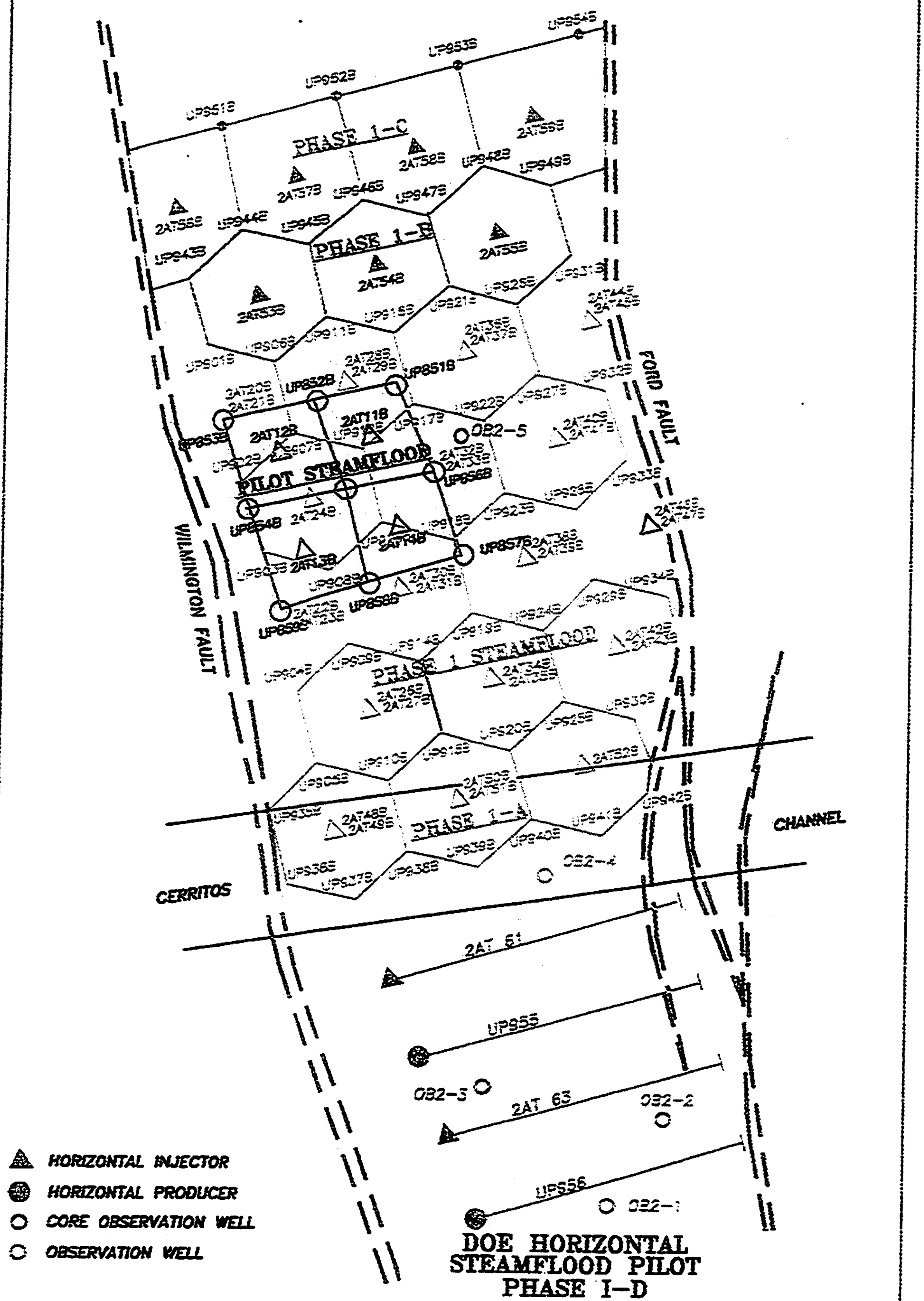
Figure 1

LOCATION MAP
WILMINGTON FIELD




PIER A
PIER B
PIER C
PIER D
PIER E
PIER F
PIER G
PIER J
PIER S
PIER T
CHANNEL NO. 3
CHANNEL
CERRITOS CHANNEL
ENTRANCE CHANNEL
X–Y
TANK
FARM
FAULT BLOCK IIA
STEAMFLOOD AREA
PARCEL "A"
STEAMFLOOD
LONG BEACH NAVAL SHIPYARD
SOUTHERN CALIFORNIA EDISON
LOS ANGELES RIVER
TIDELANDS
OIL PRODUCTION COMPANY
TIDELANDS FACILITIES
96DOEFAC

BOTTOMHOLE LOCATIONS



WILMINGTON FIELD
STEAMFLOOD

TAR ZONE, FAULT BLOCK II-A

500' 200' 0' 200' 500'
SCALE

DWG. NO. 95STM-1D

G:\DRAWINGS\DOE\STEAM\SUB\95STM-1D.DWG

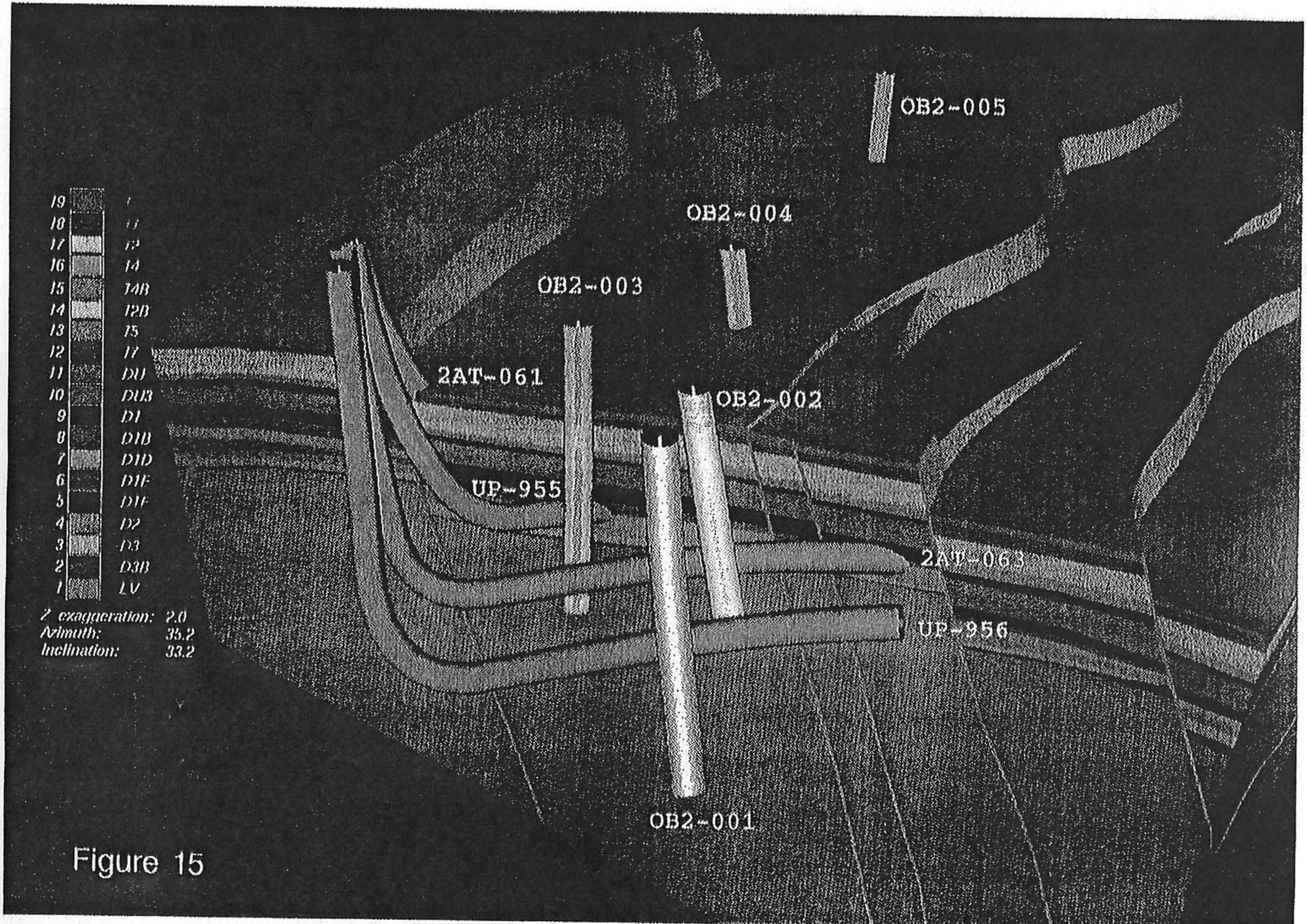

OB2-005
OB2-004
OB2-003
OB2-002
OB2-001
2AT-061
UP-955
2AT-063
UP-956
Z exaggeration: 2.0
Azimuth: 35.2
Inclination: 33.2

Figure 15

D2 HORIZON

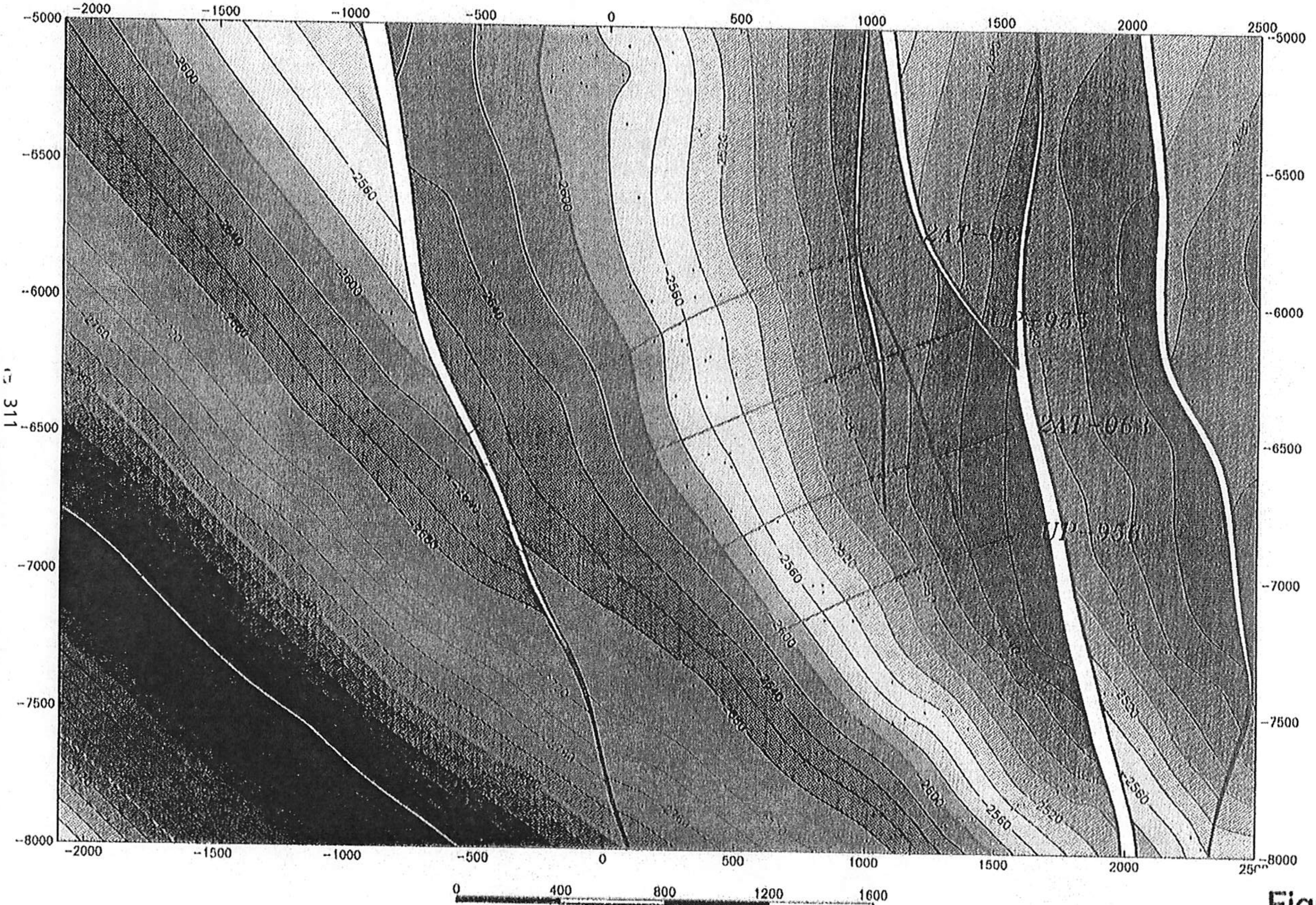
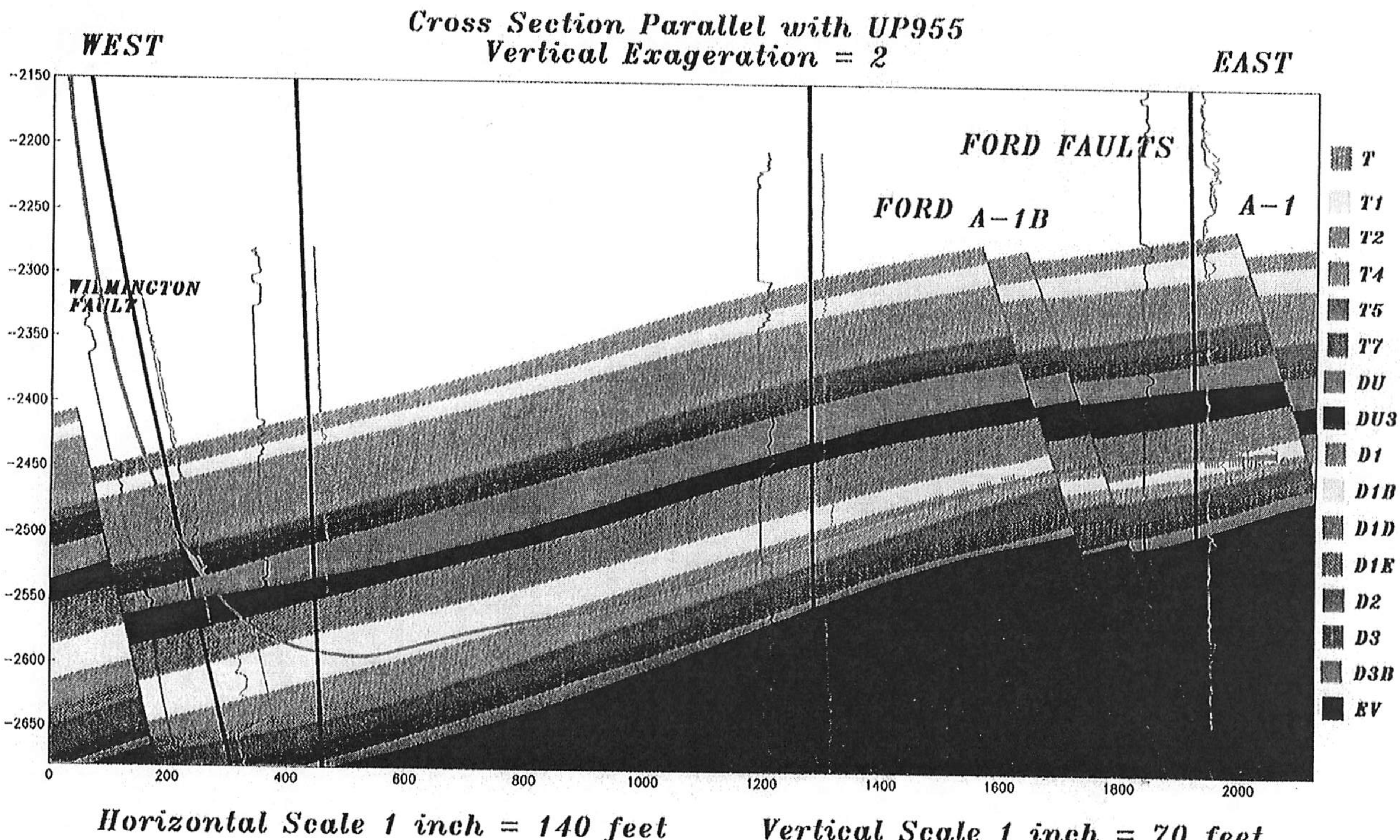


Figure 23


Cross Section Parallel with UP955
Vertical Exageration = 2
WEST
EAST
FORD FAULTS
FORD
A-1B
A-1
WILMINGTON FAULT
-2150
-2200
-2250
-2300
-2350
-2400
-2450
-2500
-2550
-2600
-2650
0
200
400
600
800
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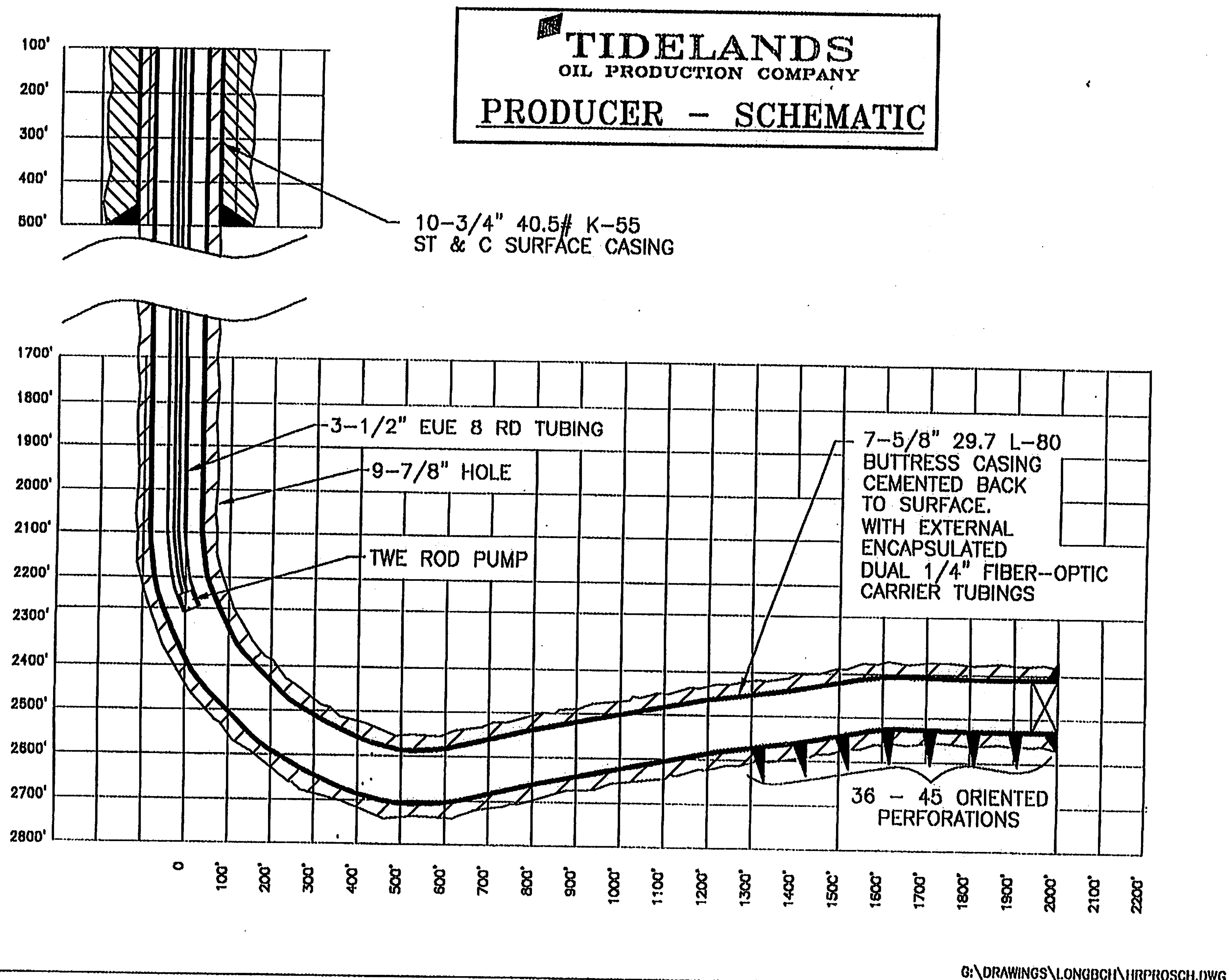
1200
1400
1600
1800
2000
T
T1
T2
T4
T5
T7
DU
DU3
D1
D1B
D1D
D1E
D2
D3
D3B
EV
Horizontal Scale 1 inch = 140 feet
Vertical Scale 1 inch = 70 feet

Figure 6


TIDELANDS
OIL PRODUCTION COMPANY
PRODUCER - SCHEMATIC
10-3/4" 40.5# K-55
ST & C SURFACE CASING
3-1/2" EUE 8 RD TUBING
9-7/8" HOLE
TWE ROD PUMP
7-5/8" 29.7 L-80
BUTTRESS CASING
CEMENTED BACK
TO SURFACE.
WITH EXTERNAL
ENCAPSULATED
DUAL 1/4" FIBER-OPTIC
CARRIER TUBINGS
36 - 45 ORIENTED
PERFORATIONS
100'
200'
300'
400'
500'
1700'
1800'
1900'
2000'
2100'
2200'
2300'
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2200'
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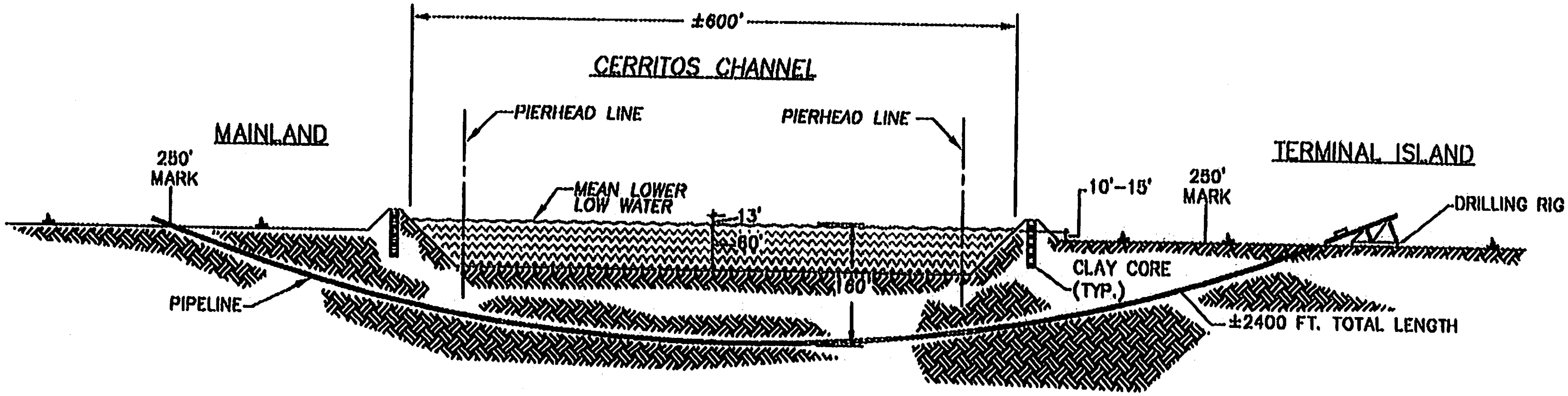
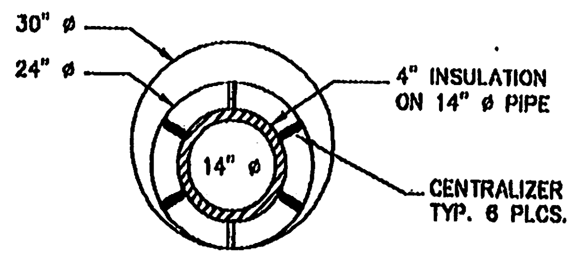
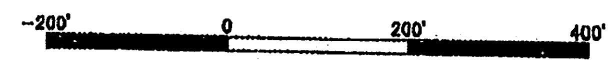




TYPICAL CROSS SECTION DETAIL

STEAM PIPELINE INSULATED INSIDE CASING



TIDELANDS
OIL PRODUCTION COMPANY

STEAM TRANSMISSION LINE
UNDER SHIP CHANNEL

DRAWN BY: J.M.S.	APPROVED BY:	RBC	DRAWING NUMBER:
DATE: 8-6-96	SCALE: AS NOTED		96STMXLN

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NOTES

NOTES

Problems and a Potential Solution to Excess Water Production from the Turbidite Sands

Steve Coombs
Pacific Operators Offshore, Inc.

Problems and a Potential Solution to Excess Water Production from the Turbidite Sands, The Carpinteria field

Steve Coombs

Pacific Operators Offshore

Farhad Sobbi and I. Ershaghi USC

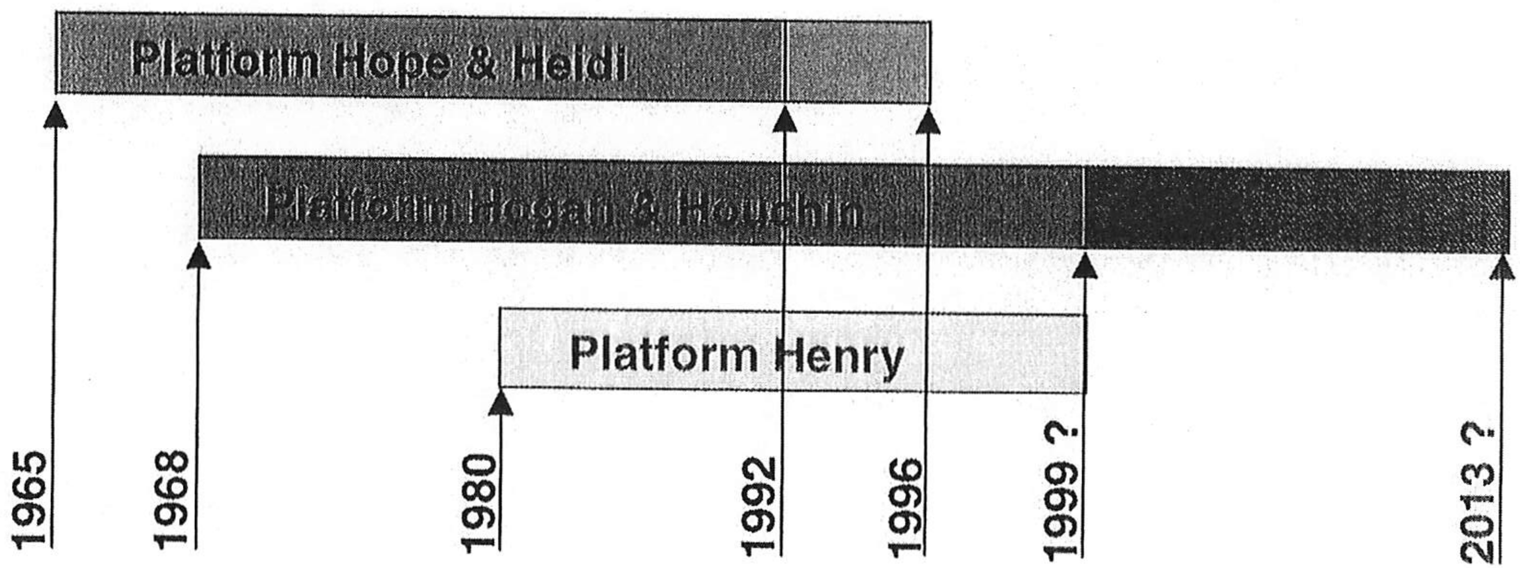
PTTC Problem ID Workshop

November 26, 1996

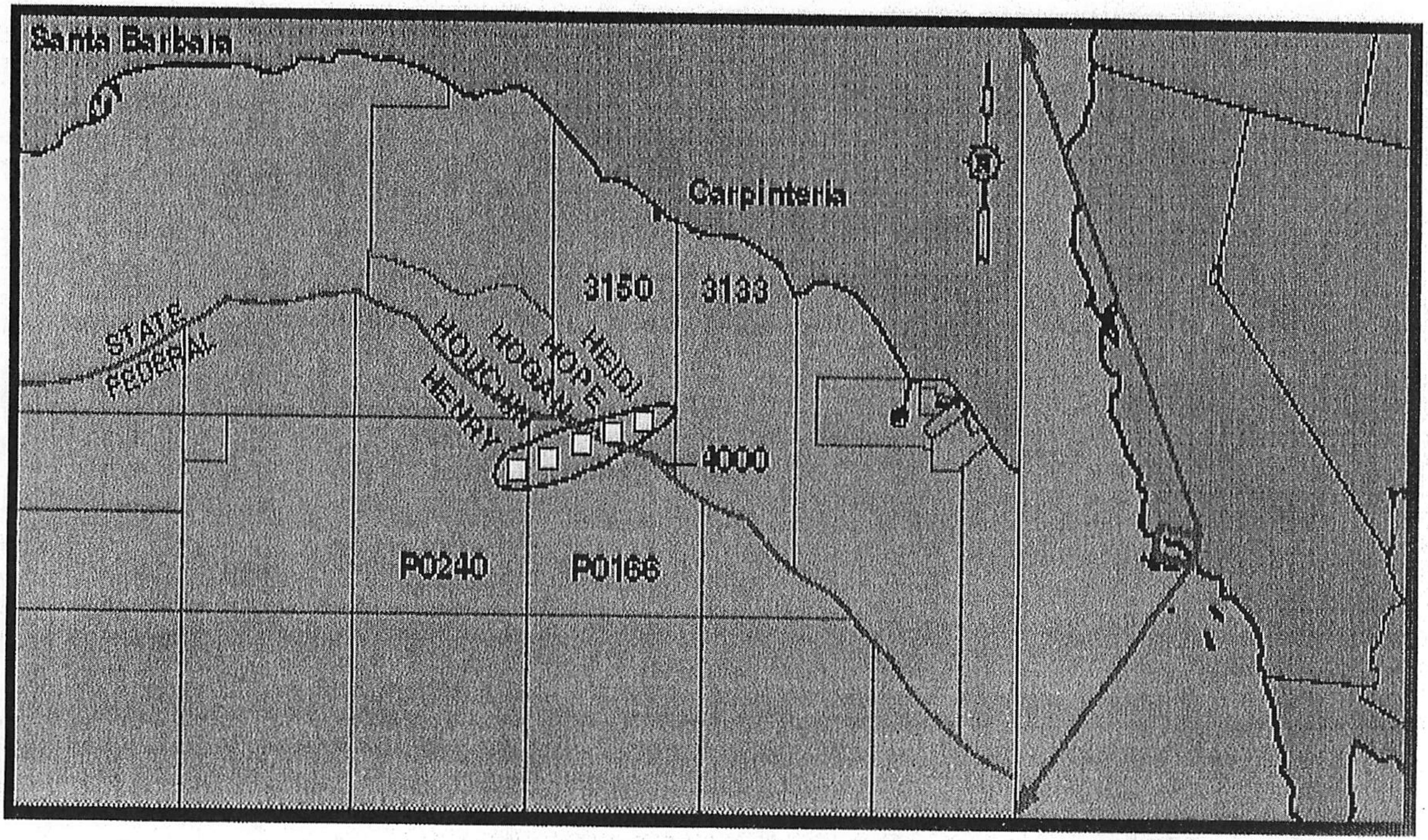
PACIFIC OPERATORS OFFSHORE, INC.

TM

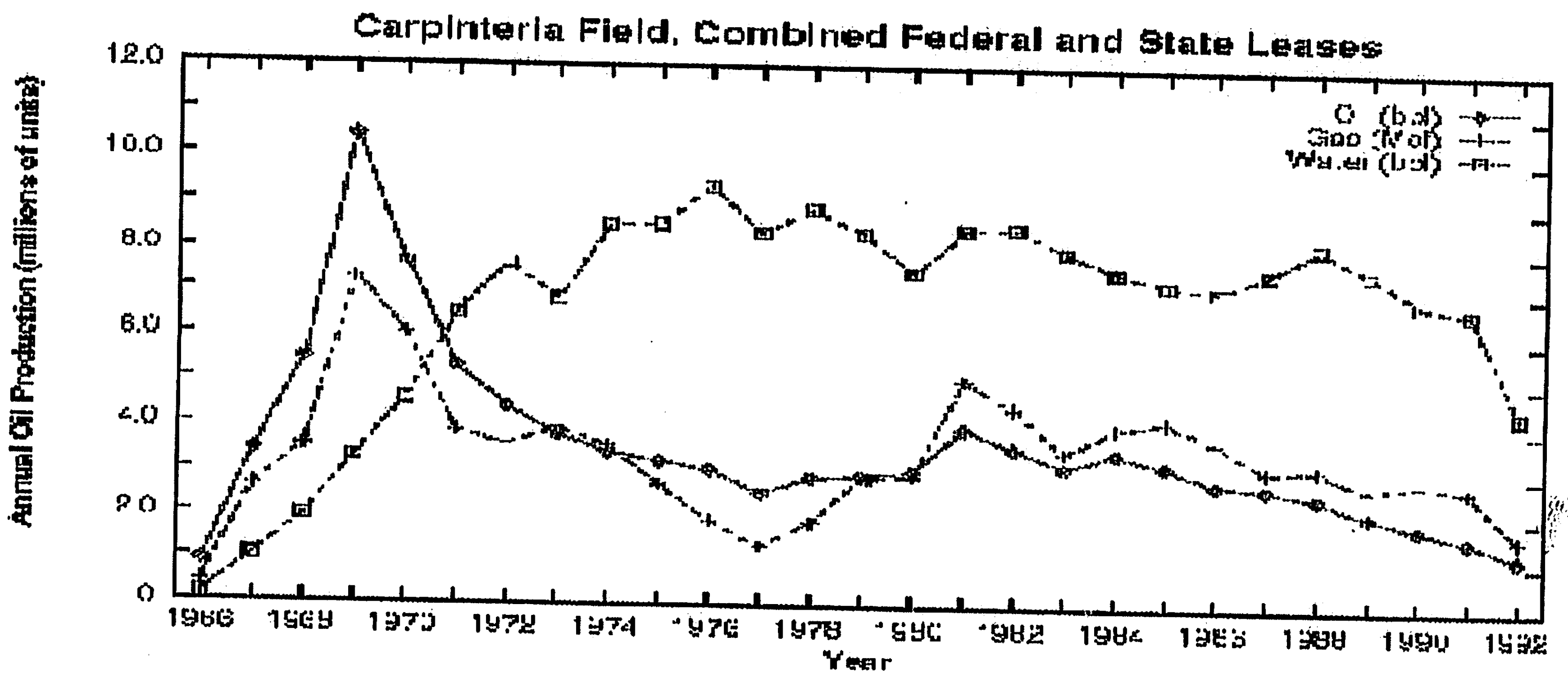
5 Platforms Set in the Field From 1965 Through 1980



Location Map



Production History



Main Questions

- What is the Original Oil in Place ?
- Where are the Sweet Spots ?
- What are the Causes of Low Well Productivity's ?
- How can we Minimize Water Production ?
- How can we Allocate Production Back to Individual Layers ?

Trouble Shooting Approach

- Simplify Access to the Scattered Hardcopy Database
- Revisit the Well Logs/Completion Methods
- Justify Further Development Efforts
- Scrutinize Alternative Solutions

Nature of the Database

- Production and Injection Data
- Pressure Data
- PVT Data
- Core Analysis Data
- Well Log Data
- Fluid Chemistry

Reservoir Performance

- Oil Production
- Gas Production
  - Initial Gas Oil Ratios From Well Tests in the Range 215-500 SCF/STB
- Water Production
- Pressure History
  - Initial Reservoir Pressure, 1500+/- PSIG at 3300 FT. SS
- Dominant Drive Mechanism: Solution Gas Drive

Analysis of Initial Well Tests

- Correlation of Initial Liquid Rates (IP) vs. Total Perforation Intervals
  - Wells Grouped by Completion
  - Slope is Proportional to Transmissibility

Analysis of Pressure Buildup Tests

- Single Layer Tests-Analysis and Results
- Commingled Tests and the Need for Special Modeling

Analysis of Reservoir Pressure Data

- Static Pressure Surveys
  - Incomplete Pressure Buildups
  - Inaccuracies in Wellbore Fluid Gradients
  - Interference Effects From Surrounding Wells
- Extrapolated Pressure From Buildup Analysis
  - Commingled Flow Problems
  - Effect of Flowing Time Duration

Permeabilities Estimated From DST's

F-1 Sand	387 Md
G-1 Sand	46 Md
Subthrust	1.4 Md

Estimation of Reservoir Heterogeneity Characteristics

- Analysis of Pressure Buildup Tests
- Analysis of PVT Data
- Core Data

Analysis of PVT Data

- Variations in Reservoir Fluids and Their Properties
- Saturation Pressure - Methane Content Correlation
- Work in Progress to Examine Laboratory Data vs. Standardized Correlations

Core Data

- Reservoir Rock Compressibility
- Reservoir Porosity
- Reservoir Permeability
- Porosity & Permeability Compaction Correlations
- Limited Sieve Analysis Results to be Analyzed

Rock Compressibility

	B-45	A-9
E Sand	66.8×10^{-6}	110×10^{-6}
F Sand	68.6×10^{-6}	95×10^{-6}
G Sand	100.9×10^{-6}	74×10^{-6}
ST Sand	--	65×10^{-6}

Analysis of Water Disposal Program

- 14,881,263 Bbls of Produced Water Was Injected Into 5 Downdip Wells Along Southern Flank (A-8,•A-25. A-29, A-31 & A-32)
- Severe Channeling of Water in the Disposal Wells
- Further Profile Surveys will be Obtained Following Re-initiation of Injection
- Limited Oil Production Response

Analysis of Gas Storage Program

- Gas Injection into AG-27Subthrust “G” Zone Began in 1978
- Average Daily Injection Rate Was 1500 MCF @ 1500 PSIG
- In June 1981 Additional Compressor Was Installed, Average Rate Increased to 2600 MCFD @ 1800 Psig
- Gas Channeling Between AG-27, A-51 and A-53
- GOR Increased in Offset Wells Open to Subthrust

Potential Causes of High Water Production

- Field Wide East-West Up-dip Water Advancement
- North and South Flank Aquifer Expansion
- Wet Stringers
  - Commingled with Oil Sands
  - Behind Pipe Communication

Redevelopment Alternatives

- Recomplete Existing Wells
- Use Existing Wells for Pressure Maintenance
- Redrill Existing Wells
- Drill New Directional Wells
- Drill New Horizontal Wells
- Drill Multilateral Wells

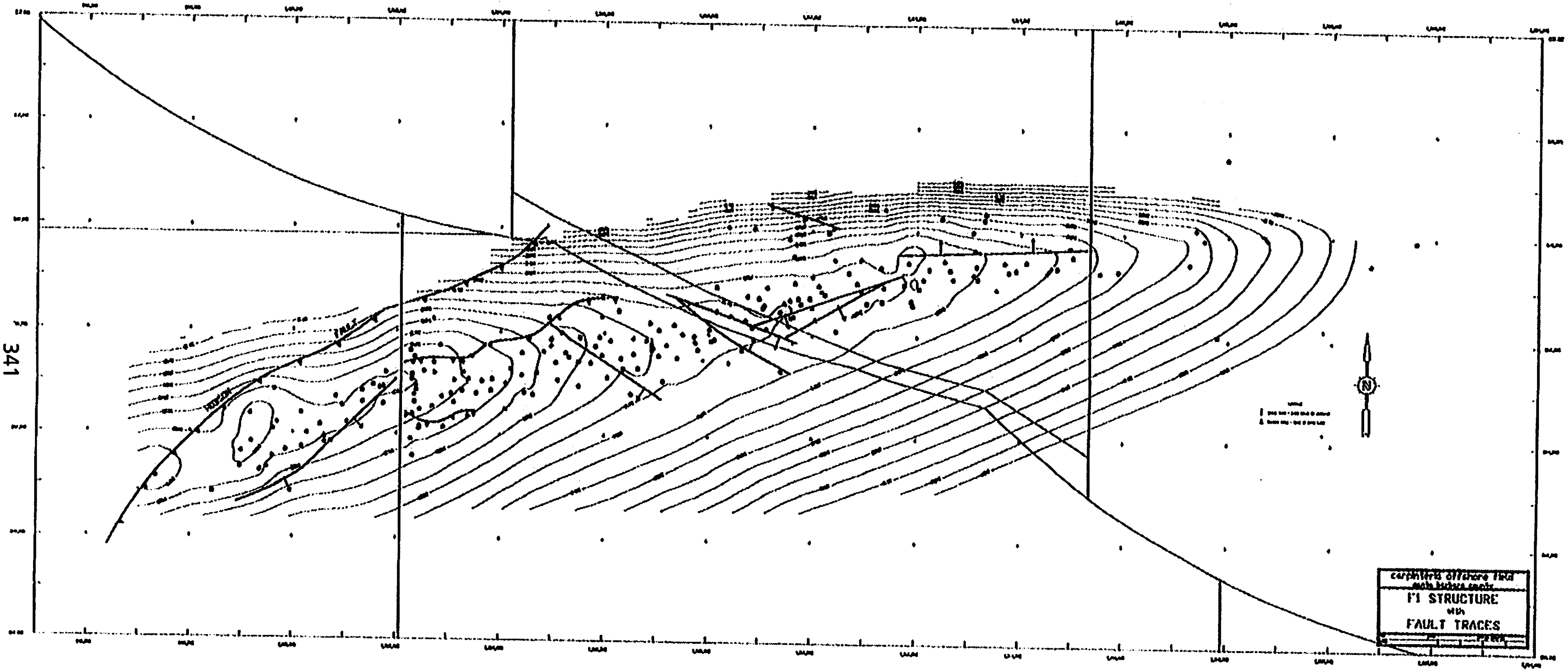
Interpretation Needed

- Remaining Oil In Place
- Geological Definition
- Economic Feasibility Study

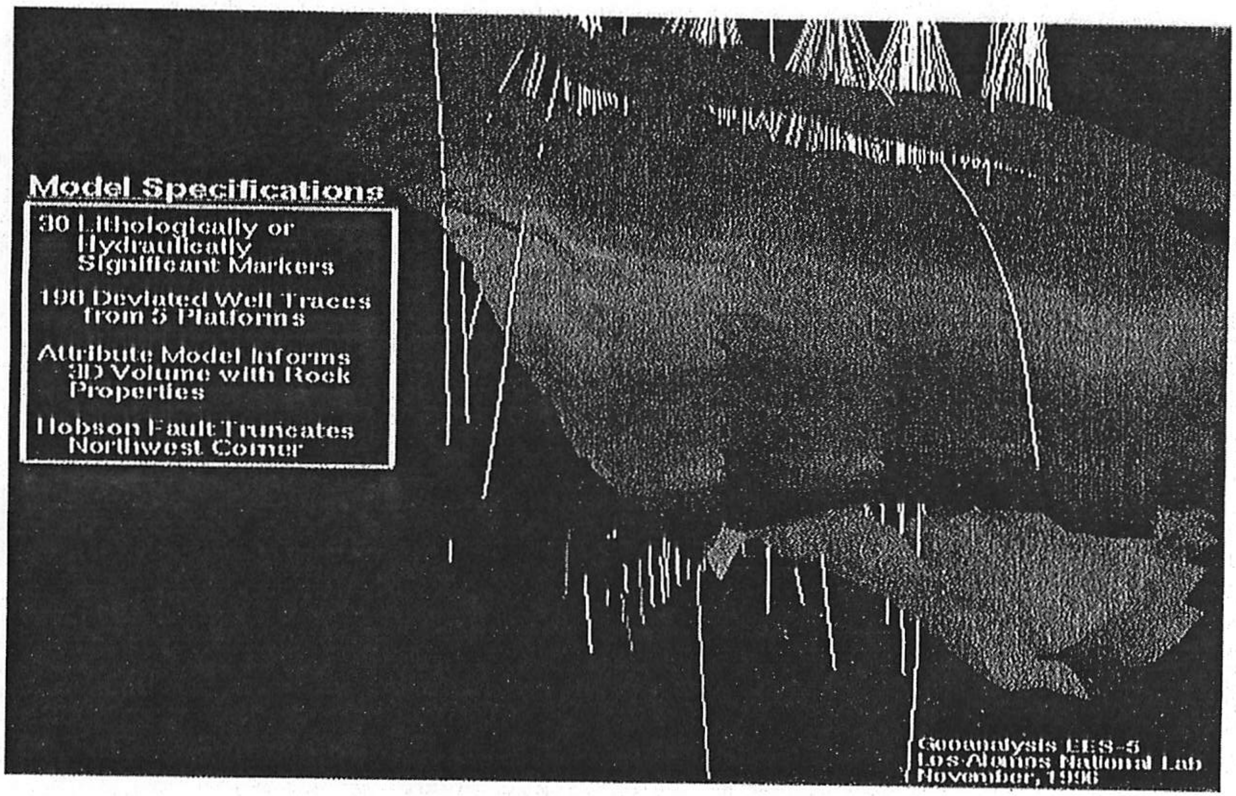
Estimation of Remaining Oil and Distribution of Sweet Spots

- Proposed Method for Allocation of Past Production to Individual Layers
- Qualitative Distribution of Remaining Oil

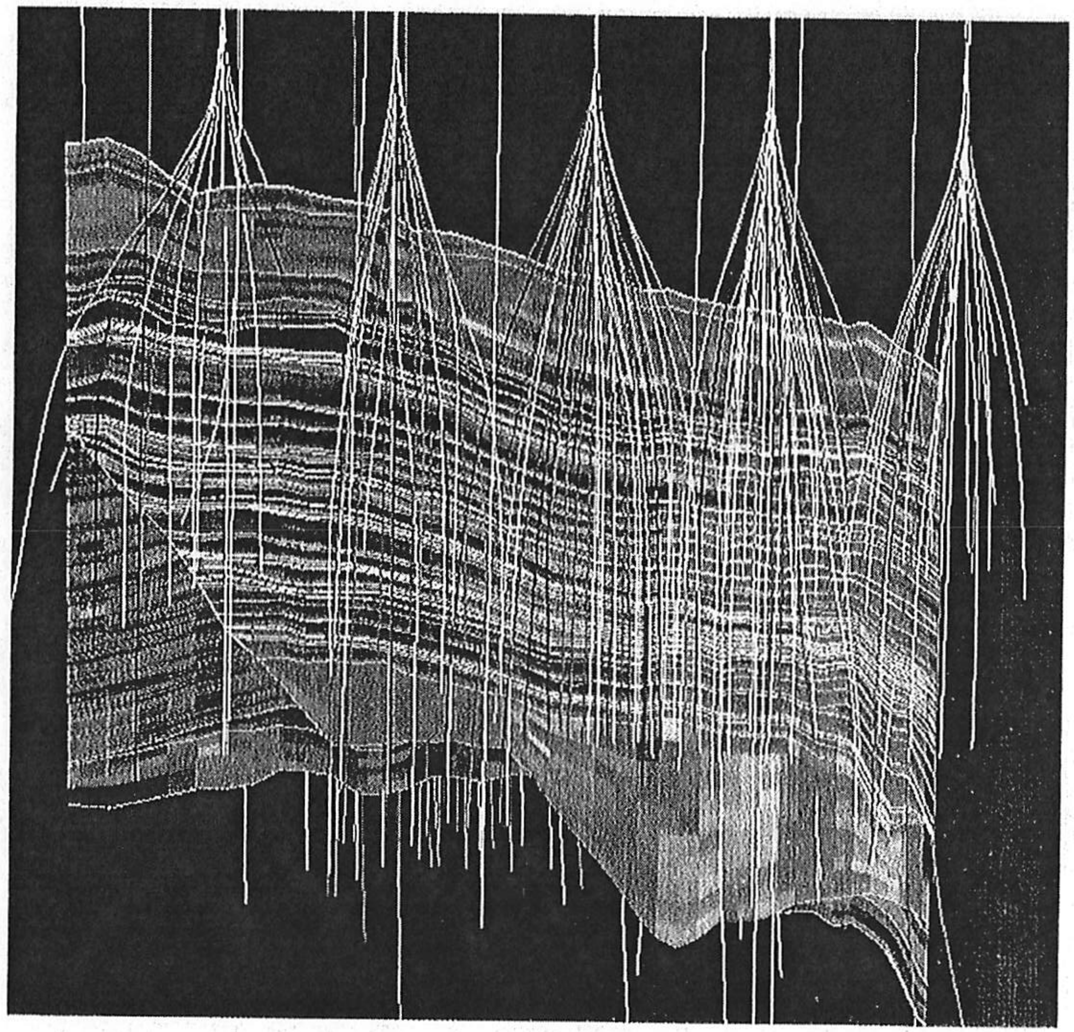
Current Geologic Model: F-1 Sand



3-D Geologic Model



Geologic Cross Section



Estimation of Initial Oil in Place

- Volumetric Method
- Material Balance Method

Volumetric Method

- Assumptions
  - Five Acres / Well
  - Shale Cut Off = 35%
  - Net Pay Cut Off $\phi_t > 15\%$ and Sw < 70%
  - Effective Porosity Cut Off = 12%
  - Effective Water Saturation Cut Off = 60%
- Result: OOIP (Suprathrust) = 172,477 MSTB

Oil in Place - Material Balance

- PVT Data - Well A-4 Sample
- Water Influx - X-plot model
- Least Square Method
  - $z_i = a\, x_i + b\, y_i$
- b = 1.053×10^{-7} 1/bbl
- Oil in Place, a = 155.865 MMSTB
- Lease x-plot slope = 1.037×10^{-7} 1/bbl
- Influx as of 12/95 = 67.212 MMSbbl

Material Balance - Assumptions

- Initial Reservoir Pressure = 1,500
- Saturation Pressure, psig = 1,500
- Reservoir Temperature, F = 110
- Initial Water Saturation = 0.40
- Water Compressibility, 1/psi = $3x10^{-6}$
- Rock Compressibility, 1/psi = $86x10^{-6}$
- Initial Solution GOR, SCF/B = 349
- Initial FVF, BBL/STB = 1.18
- Initial gas FVF, BBL/SCF = 0.00132

Conclusions

- Evidence of Influx and Pressure Support Appeared in 1971
- Early Production was by Solution Gas Drive
- There are Strong Indications of Channel Sands and Reservoir Heterogeneities
- Preliminary Material Balance Computation Substantiate X-Plot Estimation of Influx
- TriLateral Drilling Offers a Most Effective Completion Strategy

Future Analysis

- Estimation of Lateral Variation in Reservoir Properties from Performance Data
- Improve Material Balance Computations from Proposed Static Pressure Measurements
- Reconcile the MB Calculations and the Volumetric from the Stratamodel Results
- Estimation of WaterFlood Response
- Determine Optimum Redevelopment Strategy

NOTES

NOTES

DOE-Industry Partnership Projects in California

Dr. Norm Goldstein
Lawrence Berkeley National Laboratory

DOE's Oil Technology RD&D Program in California

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Earth Sciences Division
Ernest Orlando Lawrence
Berkeley National Laboratory
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e-mail: negoldstein@lbl.gov

DOE's Oil Technology RD&D Program

1. **Reservoir Class Field Demonstration Program**
   - *To increase production from U.S. oil fields*
   - *To prevent premature abandonment*

   There are six Class III - Slope and Basin Clastic Reservoir Projects in California (fe.doe.gov/oilclass.html)

2. **Longer Range R&D Program**
   "Natural Gas and Oil Technology Partnership Program (NGOTP)" (bpo.gov and sandia.gov/ngotp/)

   - *To find innovative approaches that will slow down abandonment of existing fields and find new fields.*

   - *Industry driven, industry reviewed, cost-shared*

   There are 12 NGOTP projects underway in California in partnership with majors, independents, service companies, and specific to California reservoirs.

3. **Environmental/Regulatory Streamlining**
   In conjunction with the California Oil Survival Team (COST)
   6 projects underway

NGOTP California Projects
sandia.gov/ngotp

A. Computational Technology

1. Oil and Gas Well Log Imaging

2. Advanced Reservoir Management (ARM) for Independent Producers

3. Velocity Analysis, Parameter Estimation, and Constraints on Lithology for Transversely Isotropic Sediments

4. Subsidence, Analysis and Control

5. Optimal Fluid Injection Policy and Producibility

6. Optimization of Pyrolysis and Aqueous Pyrolysis of Heavy Oil from California

7. Oil and Gas Data Infrastructure

NGOTP California Projects

B. Oil Recovery Technology

1. Fluid Injection into Tight Rocks

2. Reduction of Well Failures in Diatomite

3. Reduction of Well Failures in Diatomite

4. Extending Electromagnetic Borehole Imaging to Cased Wells

5. Tiltmeter Hydraulic Fracture Imaging

C. Environmental

Newly created partnership activity for 1997

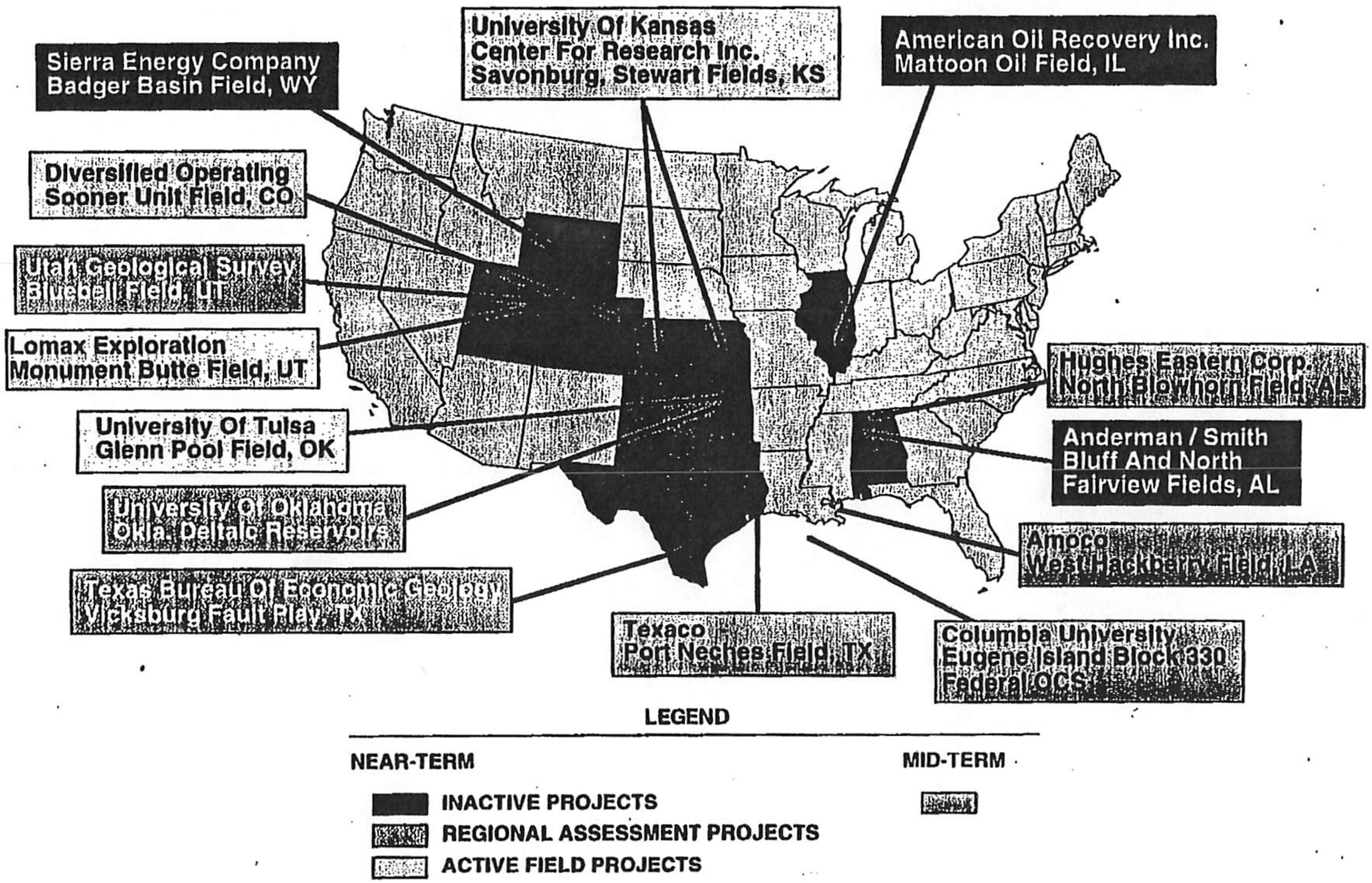
CLASS I PRODUCTION BENEFITS

- Over 20 million barrels of incremental production are expected from the projects.
- Expansion of the demonstrated technologies to other reservoirs will significantly boost incremental recovery.

CLASS I TECHNOLOGY PRODUCTS

- **4-D seismic technology patented and commercially available from Global Basins Research Network.**
- **Play portfolios on Booch, Layton and Osage-Layton, and Morrow plays in Oklahoma are available from the Oklahoma Geological Survey.**
- **"CO_2 Screening Model," to determine feasibility of applying the technology, is available from DOE (Internet).**
- **"Geologic Advisor," software for infill drilling decisionmaking, is available from the Texas Bureau of Economic Geology.**

CLASS I OIL RECOVERY PROJECTS

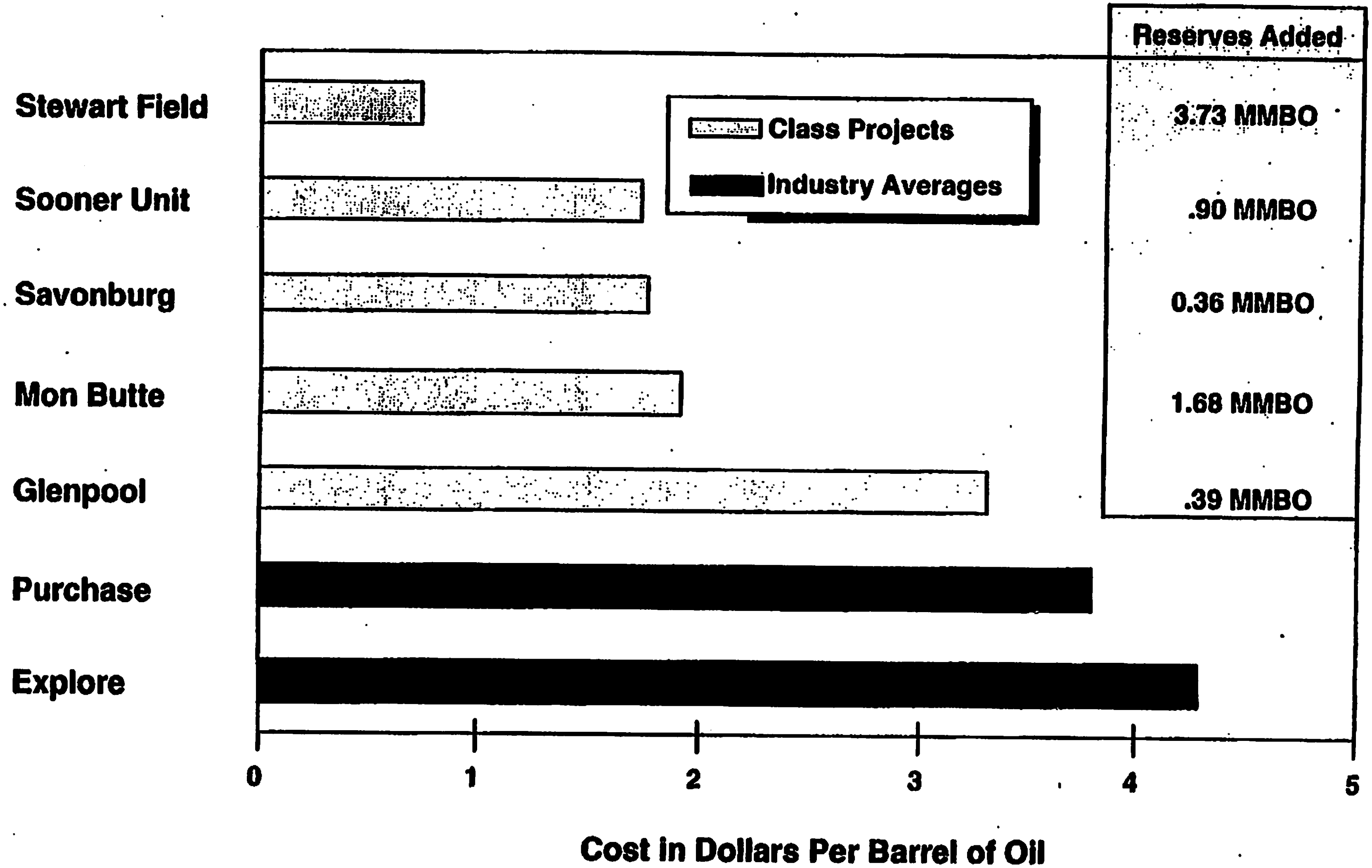


DOE-BPO-ECA-96-9002

CLASS I TECHNOLOGY CHART

	Core/Fluid Analysis	Outcrop Analysis	Biostratigraphy	Seismic	Advanced Logging	Well Tests	Digital Database	Reservoir Modeling	Geostatistics	Num. Simulation	Reservoir Mgmt.	Recompletion	Paraffin Control	Infill Drilling	Directional Drilling	Waterflood	Gravity/Air Injection	CO_2 Injection	Microbial	Polymer Injection
	Reservoir Data						Analysis Method					Production Enhancement								
Diversified Operating	●			●		●		●		●	●			●		●				
Lomax Exploration	●				●	●		●		●			●	●		●				
Univ. of Kansas	●					●	●			●	●			●		●				●
Univ. of Oklahoma							●		●	●										
Univ. of Texas	●	●		●			●	●	●			●		●						
Univ. of Tulsa	●	●		●	●	●		●	●	●	●				●	●				
Utah Geological Surv.	●	●	●		●		●		●	●		●	●	●						
Amoco Production	●					●		●			●	●					●			
Columbia University	●		●	●	●	●	●	●		●				●						
Hughes Eastern	●		●											●		●			●	
Texaco E&P	●		●			●		●		●		●		●	●			●		

COMPARISION OF FINDING COSTS EXPLORATION AND PRODUCTION RESERVES vs CLASS I PROJECT RESERVE ADDITIONS



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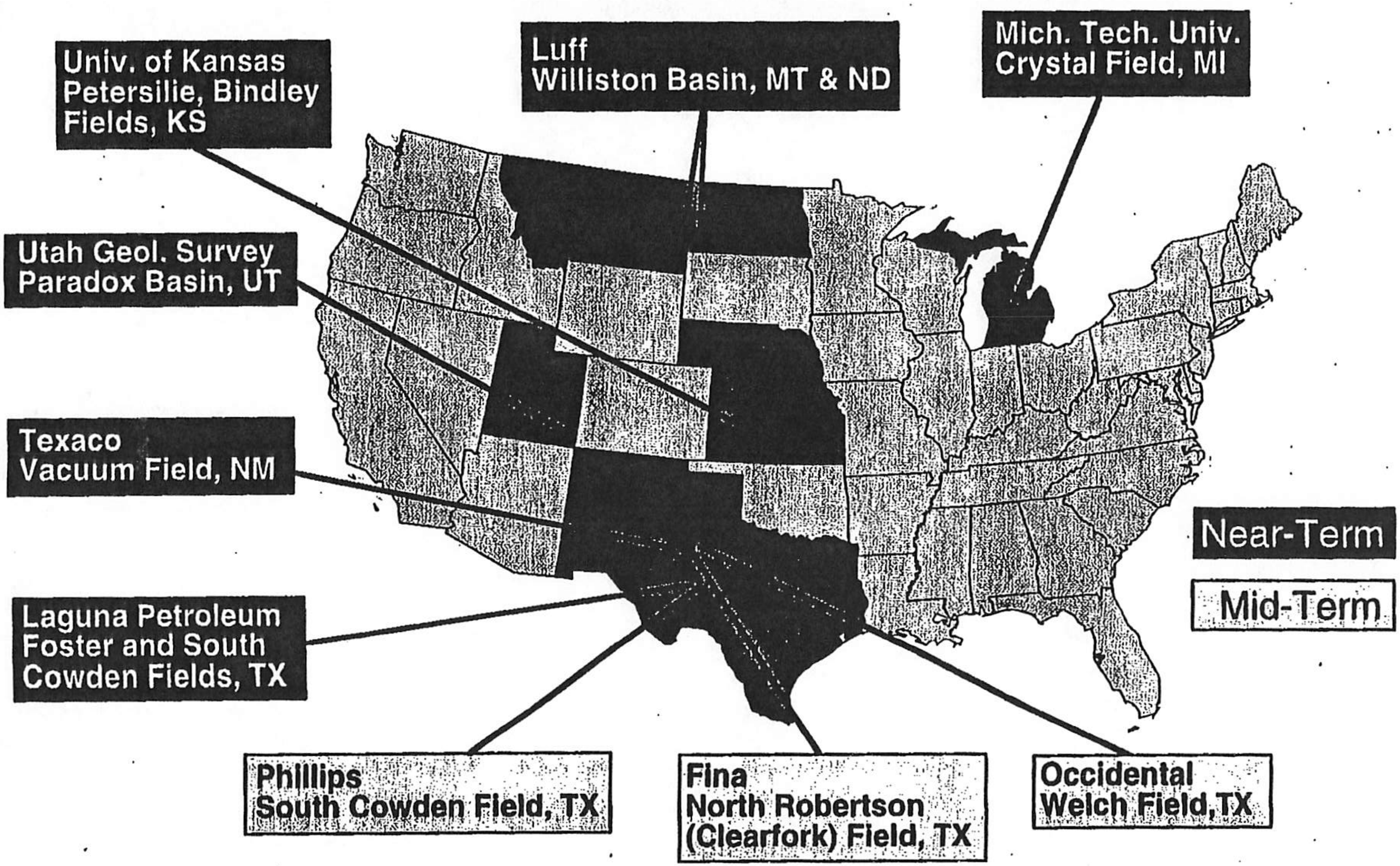
CLASS II OIL RECOVERY PROJECTS



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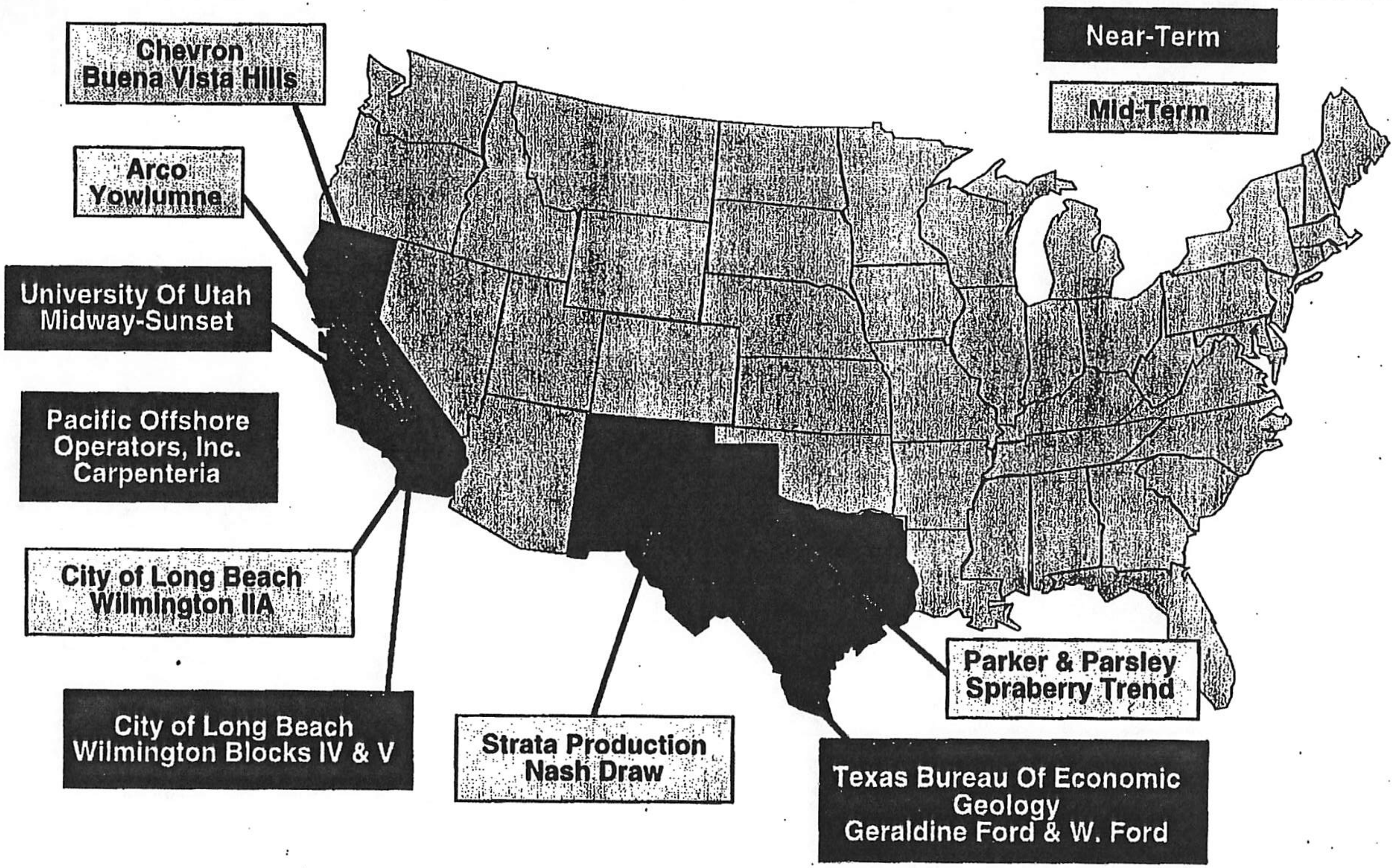
CLASS II TECHNOLOGY CHART

	Reservoir Data										Analysis Method				Production Enhancement			
	Core Analysis	Fluid Analysis	Fracture Char.	Seismic	Advanced Logging	Well Tests	Digital Database	Reservoir Modeling	Geostatistics	Num. Simulation	Reservoir Mgmt.	Well Stimulation	Recompletion	Infill Drilling	Directional Drilling	Waterflood	Gravity Drainage	CO_2 Injection
Laguna Petroleum	●			●						●		●	●	●		●		
Luff Exploration	●	●	●	●		●				●		●	●	●		●		
Michigan Tech. Univ.	●	●					●	●			●				●		●	
Texaco	●	●					●	●	●	●								●
Univ. of Kansas	●		●			●	●	●	●	●			●	●				
Utah Geological Surv.	●	●				●	●	●		●	●			●		●		●
Fina, USA	●	●		●	●	●		●	●	●	●	●		●		●		
Oxy, USA	●		●	●		●				●	●	●		●				●
Phillips Petroleum	●			●		●					●				●			●

DOE-BPO-ECA-96-9007

CLASS III OIL RECOVERY PROJECTS



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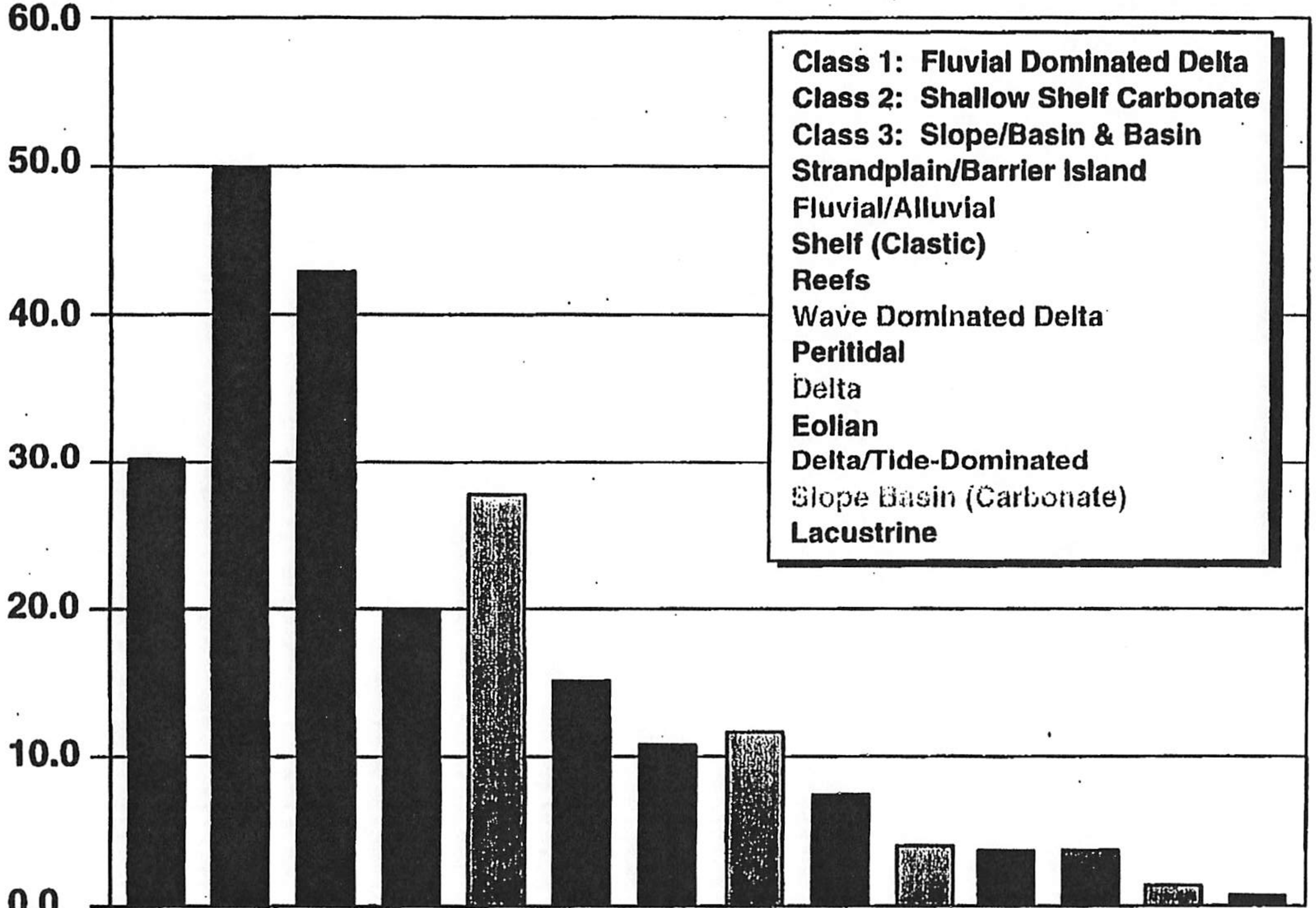
CLASS III TECHNOLOGY CHART

	Reservoir Data						Analysis Method					Production Enhancement								
	Core/Fluid Analysis	Outcrop Analysis	Fracture Analysis	Seismic	Advanced Logging	Well Tests	Digital Database	Reservoir Modeling	Geostatistics	Num. Simulation	Reservoir Mgmt.	Recompletion	Stimulation	Infill Drilling	Directional Drilling	Waterflood	Gravity Drainage	CO_2 Injection	Thermal	Polymer Injection
City of Long Beach	●				●	●	●	●			●	●			●	●				
Pacific Operators	●					●	●								●					
Univ. of Texas BEG	●	●		●		●	●	●	●	●				●		●		●		●
Univ. of Utah	●				●	●	●	●		●				●					●	
ARCO Western	●		●	●	●	●		●		●	●		●		●					
Chevron, USA	●	●	●	●	●	●		●	●	●	●							●		
City of Long Beach	●					●	●	●		●	●		●		●				●	
Parker & Parsley	●	●	●		●	●	●	●	●	●				●	●		●	●		
Strata	●			●		●	●	●	●	●				●	●	●				

DOE-BPO-ECA-96-9010

REMAINING OIL IN PLACE



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