Reducing Oilfield Power Consumption

At the depths of the oil price crash a few years ago, PTTC focused on operating costs and the subject remains of interest. Power is a primary cost element, especially in mature U.S. reservoirs that produce lots of water, which describes California's geological environment well. Add in high power rates and a stretched supply system and you have a strong driver for California producers to review their operations. This article highlights results of a federal, state and industry effort in applying energy-savings techniques.

Under a grant from the California Energy Commission and EPRI (Electric Power Research Institute), West Coast PTTC conducted a detailed study on the energy efficiency performance of 1,000 pumping wells throughout California. An astonishing 45% of pumping units were found to be energy inefficient, which led to California Public Utilities Commission (CPUC) becoming involved and funding a pilot study for improving the performance of a limited number of wells and for demonstrating the merits of energy efficient systems. Thus was born a CPUC rebate program administered by Global Energy Partners working through Trouble Shooters associated with PTTC’s West Coast Region to reach producers. Program results were shared in a May 27th workshop in Los Angeles that was also webcast. Several producers have now participated, making changes in 140 wells that realized energy savings of 15,722,910 kWh (as of 5/20/04 per Global Energy Partners). Changes made to realize the savings varied widely, from straightforward pump-off controllers to changing the frequency of power for a submersible pump to decrease consumption during high-price rate periods.

There were some common elements in the information that was shared.

- Few of the technologies were rocket science; that is, they have been around for some time, but for whatever reason, operators hadn't been applying them in their situation.
- Other benefits (increased production, fewer failures, longer equipment life) often equaled or exceeded the benefits from power savings.
- Payout varied widely. Some changes were “no-brainers” with payout even without rebates occurring within just a few months. Some changes, even with rebates and benefits other than power savings, took a couple years to payout. The message here is that each situation must be examined on its own merits and there are instances where rebates are required to stimulate application.

Readers are encouraged to check the West Coast regional website (www.westaaspttc.org/) for an archive of the webcast, or contact Iraj Ershaghi, PTTC’s West Coast Director, E-mail ersaghi@usc.edu, for more information. Most of the techniques described and benefits realized are broadly applicable. What will change is the economics with the rate structure in your area of operations.
developed through joint ventures with other producers and service companies, once technologies are developed and proven, producers often don’t step up to the plate and apply the very concepts they paid to develop. And when they do, the tendency is to squeeze the service sector so hard that their profit incentive disappears. Today’s short-term business focus leads both producers and the service sector to be risk averse. Producers delay adoption and the service sector concentrates on low-risk product improvement and efficiencies, "incrementalism" if you will rather than radical innovation. This may be profitable but it will not lay the foundation for game changing technologies.

So how do we change this? A recent Journal of Petroleum Technology (JPT) roundtable convened specifically to look at the funding and uptake of new upstream technology noted that other industries involve more cooperation among competitors as well as more collaboration between the developers and users of technology. Another well-made point was standardization, or technologies not needing to be tailor-made for individual companies. For adoption, the panel noted how special corporate implementation teams are successfully stimulating technology adoption. These teams work for two reasons—there are "champions" and the teams have funds for initial field tests, taking the financial pressure off risk-averse business units.

Where does PTTC fit in? Although not championing any specific product, PTTC fits in by being a "knowledgeable, unbiased" source of organized information on solutions for problems facing domestic O&G operators. PTTC has the resources to proactively reach out to industry using a variety of tools, with workshops and the web being primary tools. Where additional field demonstration is needed, PTTC helps "connect" industry with governmental programs offering potential funding support and reports results back to producers. Creating an environment where individuals share both good and bad experiences is central to PTTC’s philosophy.

GCPE 2004, in its ninth year, is ready for another opportunity to bring together buyers & sellers, and provide great networking opportunities for you, all in one of the industry’s traditionally great oil centers; Lafayette, Louisiana.

Please join us and if you have any questions, please call me at 972-673-2537 or the LIOGA office at 800-443-1433.

For a Registration Brochure, visit www.lioga.com

I hope to see you there!

Bruce Smith, 2004 GCPE Chairman
Denbury Resources, Inc.
2003 Lost Time Injuries Down 26%

Member companies in the Association of Energy Services Companies (AESC) track safety statistics, reporting LTIR (Lost Time Incident Rate) and TRIR (Total Recordable Incident Rate). Comparing 2002 to 2003 data, the LTIR rate dropped from 3.32 to 2.45 lost time incidents per 100 employees, a 26% improvement. TRIR rates decreased 21% compared to 2002 data. Statistics relate only to the well servicing sector since data are limited for the non-well-serving sector.

Statistics show that the typical injured employee is between the ages of 30-40, works on the rig floor and sustains injury to the back or hand. Experience level is typically in the 1- to 5-year range. The activity being performed is more than likely to involve working with tubulars tripping tubing or rods.

Excerpted from Well Servicing, March/April 2004. For more information about the program and how your company can participate, contact AESC at 800-692-0771.

Alberta Reduces Flaring 50% from 1996 to 2001

Alberta's Energy and Utilities Board (EUB) reports how a voluntary approach led to a 50% reduction in flaring between 1996 and 2001. An EUB spokesperson says the Board cites the "decision tree analysis" in Guide 60, which details EUB's upstream flaring requirements and is being finalized in 2004, as the main impetus behind the reductions.

Guide 60 requires operators to evaluate whether it is possible to eliminate flaring or venting, to reduce a flare or vent and to ensure that flaring or venting meet technical requirements. It also requires operators to evaluate economic feasibility. The Guide helps operators to determine if it is feasible to conserve, and if so, they must do so.

An essential step in conservation is measuring flared and vented gas volumes. Metering technology advances directed towards small and fugitive emissions are giving operators more tools to help them capture gas, which makes them money and protects the environment.


BP Reduces San Juan Basin Well Venting by 50%

As a voluntary partner in the Environmental Protection Agency's (EPA) Natural Gas STAR program, BP reported how an innovative technology, known as the "Smart Automation Well Venting System," reduced methane venting in the San Juan Basin by 50%. Installed on 2,200 wells, the system saves BP an estimated 4 Bcf per year.

The system combines standard hardware and programmable logic controllers (PLCs) with proprietary software developed by BP. On plunger lift wells, the artificial intelligence program allows PLCs to "learn" a well's performance characteristics and adapt the cycle frequency and duration to optimize well performance. The program also works on non-plunger lift, low-pressure gas wells where it minimizes vent volumes by optimizing shut-in periods and reducing venting.

Systems cost about $5,400 per well. Field personnel require training in its use and engineering time is needed to customize the system to each field's producing formations and well parameters. Other similar non-proprietary programs are available.

Excerpted from Natural Gas STAR Update, Spring 2004. For further information on BP's Smart Automation Well Venting System, please contact EPA's Roger Fernandez, phone 202-343-9386 or E-mail Fernandez.roger@epa.gov.

DOE-Supported Mississippi Study Outlines NORM Best Practices

A final report, "Evaluations of Radionuclides of Uranium, Thorium, and Radium Associated with Produced Fluids, Precipitates and Sludges from Oil, Gas, and Oilfield Brine Injection Wells in Mississippi," notes that NORM (Naturally Occurring Radioactive Materials)-enriched barite scales are significantly more radioactive than the brines themselves. Leaching studies suggest that the barite scales, which were thought to be nearly insoluble in the natural environment, can be acted on by soil microorganisms and the enclosed radium can become bioavailable. This suggests that the landspeeding means of scale disposal should be reviewed. The investigation suggests 23 specific best practice components, including both work safety and suggestions to maintain waste isolation.

For further information, contact DOE NETL's John Ford, phone 918-699-2061, E-mail John.Ford@netl.doe.gov.

Top Under-Utilized Opportunities for Reducing Methane Emissions

Within its Natural Gas STAR program, the Environmental Protection Agency (EPA) has identified Best Management Practices (BMPs) that will save producers money. EPA also encourages partners to report other practices, called Partner Reported Opportunities (PROs) that are cost effective. Participating companies have identified nearly 80 PROs. EPA's analysis of 2003 data shows that, even within companies voluntarily participating in the STAR program, not all are implementing the identified PROs.

Within the production sector, the top under-utilized PROs are:

- Install vapor recovery units
- Install plunger lifts
- Install electric compressors/pumps/motors
- Install instrument air systems
- Consolidate tank batteries

A listing of these and all other PROs can be found at www.epa.gov/gasstar/pro/index.htm. Excerpted from article in Natural Gas STAR Partner Update, Spring 2004. View full article at www.epa.gov/gasstar/pdf/partner update.pdf.

2003 SAFE (Safety Award for Excellence) Winners

Annually, the U.S. Minerals Management Service (MMS) makes awards to companies in different categories whose actions demonstrate their commitment to safe operations offshore. Winners for 2003 are:

- High OCS Activity—Stone Energy Corporation
- Moderate OCS Activity—ConocoPhillips
- Drilling Contractor—Helmerich & Payne International Drilling Co.
- Production Contractor—Danos & Curole Marine Contractors, Inc.

For more information about the SAFE program and the activities that led these organizations to be winners, visit MMS's website www.mms.gov/awards.
Tech Transfer Track

PTTC recognizes that products and services featured in "Tech Transfer Track" may not be unique and welcomes information about other upstream technologies. PTTC does not endorse or recommend any of the products or services mentioned in this publication, even though reasonable steps are taken to ensure the reliability of information sources. Input can be directed to HQ@pttc.org.

New Source of Oil & Gas R&D Funding in Canada

Alberta recently announced that it will commit $185 million over five years for the Innovative Technologies Royalty Program. The program, which is a part of Alberta's energy innovation strategy, is designed to encourage the piloting and demonstration of new technologies that will increase the recovery of oil, natural gas and in-situ oil sands resources along with promoting environmentally responsible development. It will build on the $15 million CO₂ Enhanced Oil Recovery program recently announced by the province, which also included support from the federal government.

Working with industry and the Alberta Energy Research Institute (AERI), the province will come up with the criteria and the process by which industry can apply for the support. Alberta will fund 30% of the cost of a project with industry contributing 70%. An energy department spokesman indicated the project should be in operation by fall.


Intellipipe® “1,000,000 Bits/Second” Technology Moving On

Intellipipe®, the high-speed drill pipe telemetry system offered by IntelliServe Inc., a company owned jointly by Grant Prideco and Novatek, continues to move toward commercialization. This new technology, which received initial funding support from DOE, allows data transmission at a million bits per second through drill pipe, a rate that will revolutionize drilling. It was first fully field tested in the Rocky Mountain Oilfield Testing Center in early 2003. In that test (www.fe.doe.gov/news/techlines/03/t1_intellipipe_rmotctest.html), over 4,300 feet of 5 7/8-in Intellipipe was used to sidetrack an existing well, drilling for almost 400 ft and reaming over 600 ft. Since then, almost 4,000 ft of Intellipipe has been in use at a private U.S. test site where it has performed successfully in a full array of drilling operations. Working with a drilling jar manufacturer, IntelliServe has developed and is field testing an Intellijar®. Anticipations are that the Intellipipe system will be deployed to a commercial wellsite soon. More than 11,000 feet of Intellipipe has been completed for use in future field trials.


Expandable Casing Patch System

2T Xpatch, an expandable casing patch system developed by Houston-based TIW (www.tiwtools.com), gives producers a casing patch option where the casing string patch is only slightly smaller in diameter. TIW notes that ID through a liner patch in 5 ½-in casing can be the full diameter of 4 ½-in casing. Maintaining this large of a diameter greatly expands future tool, pump and equipment options.

No special casing is required for either the expanded or straddling pieces and no casing size or length is off limits. Complementary expandable products that TIW is developing include Xpak, a whipstock anchoring system, and an Xpak liner hanger.


SPE Online Consultants Directory

Through the Society of Petroleum Engineers (SPE), a free online database of consultants in the upstream oil and gas industry now is available. Available at www.spe.org/consultant, the directory allows database searches by name, technical terms or geographic region. Searches within the directory return a list of consultants matching criteria specified by the user. Detailed information is available including consultant’s services and contact data to help facilitate inquiries with the consultant.

Solving Liquid-Loading Problems, An Expert’s View

James Lea, Texas Tech University, is widely recognized as an artificial lift expert. He and Henry Nickens with BP shared their insights on gas-well liquid-loading in a recent Distinguished Author Series article in SPE’s Journal of Petroleum Technology. Liquid loading is not always obvious, but common symptoms include: sharp drops in decline curve, onset of liquid slugs at the surface, increasing difference between flowing tubing-casing pressure, and sharp gradient changes in flowing-pressure survey. Critical velocity calculations, nodal analysis and experience should be employed in evaluating liquid loading problems and potential solutions.

Listed solution options include:

- Sizing production strings to eliminate liquid loading—can be very effective for higher flow ranges; may eventually have to be downsized to continue flow.
- Compression—economics and operational reliability can be key issues.
- Beam pumping—an option for low pressure wells; gas interference can be a problem; installation and operational costs can be high.
- Hydraulic pumping—jet pumping power requirements can be high.
- Foaming—a common initial solution that can be evaluated in the lab; condensates will adversely affect; evaluate economics of continued surfactant usage.
- Gas lift—stating the obvious, must have lift gas from compressor or high-pressure gas well.
OTC Recognizes 15 Technology Innovations

New in 2004, the Offshore Technology Conference (OTC) created a "Spotlight on New Technology" program to showcase new and innovative offshore technologies. Criteria evaluated by a panel of judges include: new and innovative, proven, broad interest, and significant impact. 15 technologies were recognized during the recent OTC. Although targeting the offshore environment, some of these technologies are appropriate for land applications, or can be when adapted. Readers are encouraged to at least scan online information, thinking about how the technology might fit their application.

- ABB Offshore Systems VIEC (Vessel Internal Electrostatic Coalescer)
- Baker Hughes INTEQ TesTrak
- Baker Hughes INTEQ Acoustic Properties eXplorer (APG)
- CDS Separation Technologies Inline Deliquidizer
- Epcon Offshore AS Epcon CUF Technology
- FMC Kongsberg Subsea Riserless Light Well Intervention
- Halliburton GeoTap Formation Pressure Tester
- Halliburton DepthStar Tubing Retractable Subsurface Safety Valve
- Natco Group Inc VersaFlo Single Cell Compact Vertical Column Flotation
- Ocean Design Inc FACT (Field Assembled Cable Termination)
- Perkin Elmer Centurion Seals Centurion Swivel Seal
- Schlumberger seismic VISION Seismic While Drilling
- Superior Energy Services CoilTAC (Coil Thrust and Carry)
- Tracero The TRACERCO Profiler
- Weatherford/eProduction Solutions Simply Intelligent (multi-zone intelligent completion system)

View product/service information online at www.otcnet.org/2004/spotlight/index.html.

Protecting Your Computer

Many individuals or small companies working in the petroleum industry do not have the luxury of an IT department to keep their personal computer systems protected and protection is essential. In the best case, infected systems mean downtime getting everything working normally again. In the worst case, critical data are lost and you may crash other's systems. Computer systems are an essential productivity tool and it is your responsibility to protect yourself. In AAPG's latest Explorer magazine, their webmaster, Michael Jones, did a yeoman's job of explaining the steps an individual user should take to protect their systems—from firewalls to virus programs to spyware to regular updating. Make our digital world safer by following the simple steps he outlines.


Visualization Centers, Where To Go When You Need It

For that complex reservoir situation, visualization may be the solution. Knowing which visualization centers are available for lease, listed below from a recent World Oil survey, can speed one to that visualization solution.

- BP Center for Visualization, University of Colorado, Boulder, CO (www.bpviz-center.com)
- Integrated Visualization Technologies, Inc., Houston, TX (www.ivtco.com)
- Landmark Graphics Executive Briefing Center, Houston, TX (www.lgc.com)
- Landmark Decision Centers 1&2, Houston, TX (www.lgc.com)
- Magic Earth Geisler Visualization Center, Houston, TX (www.magicearth.com)
- Paradigm Visualization, Houston, TX (www.paradigmgeo.com)
- Roxar Software Solutions, Houston, TX (www.roxar.com)
- Schlumberger Dairy Ashford iCenter (www.slb.com)
- Veritas DGC Veritas Exploration Services Visualization Theater (www.veritasdgc.com)


The “Don’ts” of Underbalanced Drilling

Sometimes a tongue-in-cheek approach to making a point causes us to really think about what we are doing. Les Skinner, a well control engineering manager with Cudd Well Control, provides this perspective when he lists 11 steps that will doom an underbalanced drilling (UBD) project to failure. Sounds silly, but remember the points when you embark on an UBD well.

- Don’t go through a rigorous candidate selection process.
- Don’t plan the UBD operation.
- Don’t worry about underbalanced well control issues.
- Don’t train the rig crews on underbalanced operations.
- Don’t spend any time or money on drilling fluid design.
- Don’t bother with MWC, LWD or PWD information.
- Limit surface separation equipment to only what can be rented down the road.
- Don’t worry about HAZID and HAZOP plans.
- Don’t worry about safety systems on the rig.
- Once the well is drilled, kill it for logs and completion work.
- Don’t test the well to find out if UBD was successful.


U.S. Rotary Rig Count May 04 1,351 (per Baker Hughes)

Discover more in 2004!

AAPG PROSPECT & PROPERTY EXPO

co-conveners: SIPES and HGS
SEPTEMBER 14-16, 2004

Available online:
- Expo booth contract submission
- Viewer attendance registration

- Prospects presented in the Expo with emphasis on the fundamental role geology and geophysics play in E & P business transactions
- Perspectives Forum examining the role of exploration in energy future
- SIPES/HGS/AAPG Short Course: “Packaging and Selling Your Prospect”

Web site: http://appex.aapg.org

For complete details, contact:
Michelle Mayfield Gentzen, American Association of Petroleum Geologists
PO Box 979 • Tulsa, OK 74101-0979 • USA
Fax: 918 560 2684 • E-mail: mmayfiel@aapg.org
Going Digital, Much More To It Than Just Capturing Data Digitally
by Robert D. (Bob) Kiker, PTTC Texas Permian Basin Director

"What are pumpers in the Permian Basin doing with regards to using hand-holds or laptops to capture their field data, or are they still relying on hand-prepared reports?" This straightforward inquiry led to a survey, primarily of Permian Basin operators. Operators ranged from very small independents to large independents to majors. Visits were with company owners, pumpers, production engineers, field foremen and office accounting managers.

This article focuses on the field perspective and production accounting, while acknowledging that financial accounting exerts significant influence on the systems selected. Consider this an interim report with more visits planned since technology is improving and more oil and gas operators are initiating pilot programs using hand-holds and laptop computers for data gathering and transmission. There are many different perspectives represented in the results so far. If asked to state just one conclusion, the title of this article expresses it well.

Objective of the Survey

The objective of this survey was to: (1) accumulate information on the techniques/methods operators in the Permian Basin were using to collect, record and transmit daily production (oil, gas, water) and other associated operational data; and (2) determine if the methods employed correlated with size of the operator (operations) and/or location (remote or centralized).

The first objective involved visiting operators both in their production offices and field offices. Also a significant amount of information was gathered by telephone. This has been time consuming but rewarding. Below is a list of the companies contacted, followed by a list of companies where some information was gathered. Overall, I talked with 18 different operators, making 25 visits.

Regarding Operator Size and Location, The Survey Reveals: No direct correlations could be made with the method employed. Why?

Practices are in rapid flux, being strongly influenced by continued disruptions from mergers and buy-outs. The two factors that exert the strongest influence on what companies are doing are (1) owner/upper management philosophy and (2) clout of the accounting department, which is stronger in this post Sarbanes-Oxley world. Notice that I did not mention company size. From all the discussions I have had with operators so far, Company Size and Location of Production (remote or centralized) does not have a major impact. In fact, in several smaller companies, good communication between the pumpers/field operators and the office management/production accounting personnel are enabling them to navigate the digital world quite well. Deployment depends upon operators using the information highway to learn what technology is available.

Summary of Methods and Techniques

There is a "mix" of methods being used by the operators surveyed. The method tends to be a result of the needs or the philosophies of the operators, the status of mergers and buy-outs (who is the surviving entity) with new systems being tried, and communications between field and office. There was a genuine interest in the operators to learn what others are doing, and this is fueled by the very recent improvement in the technology of digital data gathering. More companies are initiating pilot projects as a result of the improvement in the technology. The new technology provides more interfacing between the data gathering devices and accounting software, which in the eyes of a lot of operators is a "must." It is quite apparent that accounting is becoming a bigger player. Also the technology can now provide more regulatory reporting than before. The recent developments also provide better user-friendly data displays and the pumpers/lease operators are less fearful of learning the digital world.

- Hand-Held Computers: Field Direct-Production Explorer; Merrick-Pro Count
- Laptops: Used as an alternative to Field Direct and Merrick Hand-held computers (choice of pumper/lease operator), or utilizing individual software components.

<table>
<thead>
<tr>
<th>Companies Visited</th>
<th>Some Company Information Gathered</th>
</tr>
</thead>
<tbody>
<tr>
<td>Henry Petroleum</td>
<td>Pure Resources</td>
</tr>
<tr>
<td>Cowboy Resources</td>
<td>Key Energy</td>
</tr>
<tr>
<td>Concho Resources</td>
<td>Pogo Producing Co.</td>
</tr>
<tr>
<td>Great Western Drilling</td>
<td>Burlington Resources</td>
</tr>
<tr>
<td>Pioneer Natural Resources</td>
<td>Denbury Resources</td>
</tr>
<tr>
<td>Discovery operations</td>
<td>EOG</td>
</tr>
<tr>
<td>Oxy Permian</td>
<td>Basin Financial Resources</td>
</tr>
<tr>
<td>Schlumberger IPM</td>
<td>Saga Petroleum</td>
</tr>
<tr>
<td>ConocoPhillips</td>
<td>Forest Energy</td>
</tr>
<tr>
<td>Permian Resources</td>
<td>Burlington Resources</td>
</tr>
<tr>
<td>Finley Resources</td>
<td>Clayton Williams</td>
</tr>
</tbody>
</table>
Data are gathered and either electronically transmitted via a modem or paper faxed. Laptop software used includes: Local-developed Excel spreadsheets; TOW; LOWIS; WINTANK; ACCESS database internally-developed; TOTAL ROD

- SCADA Systems
- Pencil: Hand-prepared Saddle Blanket and Grease Sheets (Old methods)
- Combination of ALL!!

Field Data Gathering and Transmission Must Satisfy Many “Users”

When going digital, one must understand the role or perspective of the "users." Perspectives that must be considered include:

- The Pumper or Lease Operator
- The Production Supervisor (Foreman/Superintendent)
- The Production Accounting Administrator/Clerk
- The Financial Accounting Department

The Pumper/Lease Operator Perspective

The pumpers favor methods that offer simplicity and reduce their workload, whether it is digital or hand-prepared. For digital, some like hand-helds while others prefer laptops because either their fingers fit the keyboard better, or they like a larger screen display. Others like the old-fashioned hand-entered grease sheet or blanket sheet. Some are using the Field Direct or Merrick System, while others are using locally-developed software in their laptops. Almost all record their tank gages by hand and then transfer the data into the hand-held unit or the laptop. This is good from a safety issue, since it is not wise to carry anything unnecessary up the tank ladder when gauging the tank, especially in an H₂S environment.

Some pumpers fear losing their data with digital recording, so they would still enter their data into a paper document for backup. The new hand-held units provide for data backup, so pumpers are beginning to lose their fear over data loss. In a related vein, one contract pumper stated that the new hand-held he has been using is superior to the previous one. He claims he could "crash the old one" but he can't the new one.

Another contract pumper, who pumps for several operators, said that the hand-held unit he was using for one company on 15 wells reduced his work one hour per day on those 15 wells.

Five company pumpers who are using a sophisticated database on laptops complained about the maintenance of the database. When an update or change was needed, the laptops had to be physically retrieved and worked on, which meant a day or two of operating without the use of the laptop.

The Office “Production Accounting” Perspective

Production accounting here is defined as the software and procedures that are used to take daily production (oil and gas) accounting, and could include water injection and disposal volumes, to properly allocate lease data. Engineers like information, such as well tests, injection pressures, and wellhead pressures, which can now be captured by digital means. Although data are used by engineers, the crux of data gathering techniques are more governed by production accounting, with input from financial accounting in many cases. During this survey, more time was spent with the office production accounting personnel than with the engineering.

Selected Comments From Companies Interviewed

The following excerpts from selected company interviews convey key insights gathered during the survey. In some cases, I have added comments in “italics” addressing their comments. As you will note, the logic of capturing field data digitally to enable more accurate and timely data availability sometimes gets lost in the shuffle of the processes used.

Company 1 (Medium size, privately-owned independent)—Prefers hand-prepared reports.

- Better accuracy (Errors may be more likely the more times data are transferred.)
Company is trying a pilot with hand-helds

- More personal ownership with hand documentation
- Costs—do not like fixed costs (Need to look at cost of paper and time for paper trail)
- Doubt it would reduce the number of pumpers. (The primary reason is to give pumpers more profitable time)
- Would have to switch to a new accounting system. (Most new digital programs interface with accounting systems and, if not, the programming can be done)
- Concerned about implementation time and training costs associated with new system

Company 2 (Small-medium size, privately-owned independent, 700 wells in Permian Basin, 700 wells in Oklahoma)—Prefers hand-held computers.

- Using Field Direct (Considered user friendly), happy with 15 contract pumpers using.
- Piloted for 4 months; has been used Company-wide for over one year
- Only problem encountered is with a few unreliable phone lines in remote areas

Company 3 (Small-medium size, publically-owned independent operating in Mississippi)—Prefers hand-held computers.

- Using the Merrick system since Nov 2002
- Waiting on new pocket units that can expand to include environmental reporting and other functions
- Tried TOW (Landmark oracle production accounting data base, now owned by Halliburton)—did not like the slow response to company requests
- Looking at switching to SAP accounting system

Company 4 (Large publically-owned independent)—Uses Laptops to enter data into a company network.

- Pumpers use laptops to enter their daily production data into TOW
- Pumpers capture data by hand then enter the data into the laptop workstations toward the end of the day.
- Pumpers not happy with system. To change or upgrade the system each laptop has to be retrieved and worked on. Causes delays. Office personnel verified that they were not happy with the TOW support, that it took too long for them to honor requests.
- Company is trying a pilot with hand-helds in the Hugoton Field.

Company 5 (Small-medium size, privately-owned independent)—Uses laptops with software package.

- Uses WINTANK 2.01 software on laptops
- Pumpers mail a computer printout into the office on a weekly basis, unless it is an important new development well or lease and then the pumper calls in the data daily. (If they have a laptop, why not transfer the data electronically daily. Using a modem is cheaper than faxing or mailing.)
- Some pumpers still using hand-prepared reports
- Concerned about fixed costs of one hand-held system. (Need to really look at the costs they are already incurring with the paper system plus the time)

Company 6 (Medium size, publically-owned operating company, 900 wells)—Faxing production data.

- Previously used Field View on a laptop computer system. Only had one computer for 8 pumpers so waiting time became a problem.
- Now they are entering their data by hand-prepared sheets that are faxed to a field production clerk who has to re-enter all the data into a Lowis system for their production accounting. (This is extremely time consuming for the field Production Clerk, as well as the pumper's time. Faxing is slower)
- Also their field supervisors still require a separate excel spreadsheet for use that the production clerk has to prepare.
- They are considering a pilot with hand-helds.

Company 7 (Small privately-owned independent)—Uses hand-held computers and laptops for data collecting.

- Use Field Direct by pumpers for daily production, well tests, downtime, fluids
- Use 4 palm pilot units and 8 laptops
- Office says it cuts the pumpers time by 50%
- Their working interest owners and CEO use Field Direct to monitor daily operators on a "read only" basis.

Company 8 (Small privately-owned independent)—Uses both hand-held and laptops (pumper preference).

- Use Merrick's latest version (eVin)
- Totally pleased—like the 30 day graphs and 7 day averages
- Much faster to enter than Field View
- Does interface with Excalibur and Aries software
- Negative figures can be displayed in red to alert you to a problem

Company 9 (Very large, publically-owned independent)—Uses a combination of methods due to mergers.

Majority of fields are automated. Data is retrieved thru SCADA systems. SCADA systems bring in LACT reading but not test data. Some sites are pencil and paper; hand-helds and laptops are not used for data collection and entry. There is the capability to enter data into the SCADA systems from vehicles. Laptops are used some for data monitoring only. Originally some palm pilots were used to enter data into various meters but they had problems with the data entry. These were a low $ unit, the batteries would die, and they were poorly designed, not allowing for fat fingers. Actually the test of the palm units was doomed in the beginning because the instruments were cheap in quality. This company has just finished a major study on what methods they will be trying in the future.

Moving Beyond Data Capture to Control

Digital data collection by pumpers still requires that they visit the well site, typically every day. With costs for basic automation systems dropping every day, a degree of automation or control becomes more viable. Early morning lists of "normally operating" and "exception" wells/leases allow pumpers/field staff to focus their efforts where it will have the most impact. All wells/leases still need visits, but those operating normally don't need visiting every day. As with the overall subject of field data capture, owner/management philosophy exerts a strong influence on the extent that operators employ automation. The financial accounting perspective may also see benefits from the additional data gathered with automation.

Future Game Plan

As noted, technologies are changing rapidly and many companies are now in the middle of pilot tests of new (for them) systems. I will continue following up with companies I have contacted and welcome comments or insights (phone 432-552-3432, E-mail pttcpermiambasin@marshill.com) from additional companies. My intent is to become an objective resource of "what's happening" in this field. PTTC plans future workshops, so watch the calendar (www.pttc.org/events.htm) this fall for something scheduled in your area.

For further information, contact Lance Cole at lcole@pttc.org.
Stripper Well Consortium Selects 10 Projects For 2004 Funding

Following a May proposal review meeting in Golden, Colorado, the Stripper Well Consortium’s (SWC) Executive Council selected 10 projects to receive 2004 funding. SWC will provide $1.726 million funding while project performers will supply $0.986 million or 43% cost share. Selected projects represent a variety of technologies for either natural gas or oil wells. Although project demonstration work may occur in a selected geographic area, most technologies are broadly applicable.

- Building and Testing a New Type of Compressor for Stripper Well Production Application - W & W Vacuum Compressions, Inc.
- Hydraulic Fracture Imaging - Universal Well Services
- Advanced Technology for Infill and Recompletion Candidate Well Selection - Texas A&M University
- Plunger Lift Process Optimization Using a Surface System for Plunger Generated Acoustic Noise Detection and Digital Signal Processing for Wellbore Plunger Location Monitoring - Tubel Technologies, Inc.
- Resolving Discrepancies in Predicting Critical Rate in Low-Pressure Gas Stripper Wells - Texas Tech University
- A New Look at Foam for Unloading Gas Wells - Colorado School of Mines
- Design, Construction and Evaluation of An Accurate, Low-Cost Portable Production Tester - Oak Resources Inc.
- PVT Study of the Interaction of Nitrogen and Crude Oil, Stage II - The Pennsylvania State University
- Low Friction Production Tubing for Stripper Gas Wells - Dynacoil
- Field testing of the Vortex DXR Retrievable Insert Tool in Conjunction with other Lifting Methods - Vortex Flow LLC

Full information on the selected projects is available on SWC’s website (www.energy.psu.edu/swc). 

Benchmarking Deep Drilling Costs, Practices

Within its Deep Trek program, DOE’s National Energy Technology Laboratory supported a study by Schlumberger Data Systems to benchmark deep drilling costs and technologies. For these studies, DOE defined “deep” as greater than 15,000 feet True Vertical Depth (TVD). Accessing an IHS database, 3,015 deep well locations were identified. Locations were subdivided into 14 different groupings considering major geologic or geographic regions and, for the Gulf Coast, geologic age of the deepest formation penetrated. Selecting only operators that had significant experience in deep drilling in a specific geographic areas, the study was confined to 140 operators, representing 78% of the IHS deep well population. Fifty operators were contacted, with 12 ultimately responding and contributing 22 usable data sets.

Since AFE systems varied, a data management system was established that would categorize costs in a consistent manner across companies. Each AFE line item was analyzed to determine its category. Costs could then be grouped into the larger components, such as drilling, and in subcomponents, such as tangible completion-packer. The system also allowed individual AFE cost components to be associated with technology areas. Once AFE costs were standardized, relevant deep well scenarios could be developed.

Ultimately, benchmarks or averages were established for 11 cost categories across seven drilling scenarios. The full article presents cost data in both dollars and percentages for the seven drilling scenarios. Cost categories comprising high percentages reveal where research or advanced technologies could potentially have the largest impact. Percentages varied by drilling scenarios. Knowing how those percentages vary in different scenarios/locations will help operators beginning deep drilling in a new region to have an idea what to expect and where to focus their attention. Readers are encouraged to view the charts (Figure 5) in the full article.


Drilling Waste Management Information System (Website) Launched

Argonne National Laboratory (Argonne) launched the recently developed Drilling Waste Management Information System (DWMIS) website (http://web.ead.anl.gov/dwm). DWMIS includes a technology description module to familiarize readers with available management options, a regulatory module to summarize existing state and federal regulations concerning drilling waste management and to provide links to agency websites, and an interactive technology identification module to help users identify waste management options available for their region.

The Technology Description Module provides basic information about practices that are currently employed to manage drilling wastes. The module divides management practices into three sections - waste minimization, recycle/reuse, and disposal. Users can click on any of the listed technologies to access separate fact sheets describing each technology and including references for additional information.

In the interactive Technology Identification Module, users are asked to answer a series of questions (mostly "yes" or "no" answers). The replies to these questions lead users through a decision tree, resulting in a suggested subset of waste management options that would make the most sense for a given geographical or environmental setting. The Technology Identification Module does not attempt to tell a company exactly which technology should be employed; rather, it helps to eliminate options that are not appropriate to the user’s specific location.

Funding for DWMIS was provided by DOE’s Office of Fossil Energy and the National Energy Technology Laboratory through the Natural Gas and Oil Technology Partnership program. Argonne developed the technical and regulatory material and designed and built the website, working closely with industry partners ChevronTexaco and Marathon for selecting and reviewing website content. During final development, DWMIS was also reviewed by an external panel with representatives from state and federal government, major producers, independent producers and service companies.
DOE Announces 6 Winners for Microhole RD&D

Six companies, and their partners as appropriate, were recently announced as winners in DOE’s microhole program. DOE is investing more than $3.7 million in these projects, while participants are investing more than $1.4 million. Winners were in four project areas. The single largest award was to Schlumberger for development of a built for purpose coiled tubing rig. Topics and the companies receiving awards include:

- Built for purpose microhole coiled tubing rig (Schlumberger)
- Advanced mud system for microhole coiled tubing drilling (Bandera)
- Radar navigation and radio data transmission for microhole coiled tubing BHAs (Stolar Research)
- Microhole smart steering and logging while drilling system (Baker Hughes)
- Microhole downhole drilling tractor (Western Well Tool)
- Through tubing (microhole) electrical submersible pump artificial lift system (Gas Pro. Spec.)

Watch for more complete information about these awards on DOE NETL’s website www.netl.doe.gov. Plans are already in place for a Round 2 solicitation later this year (see box alert).

Teleperf Method for Sand Control in Heavy Oil Reservoirs Progressing

In a Small Business Incentive Research (SBIR) grant from DOE, Completion Concepts out of Katy, Texas, has developed and now successfully field tested a teleperf system. The teleperf system restrains sand production while eliminating conventional perforating and gravel packing in oil wells producing heavy crude. After casing is set, and a well drilled through the selected completion interval, telescoping, pre-formed devices or “teleperfs” containing a sand control media are assembled as part of the well liner system. The liner is run into the well and set, with the perforation devices in position in the selected completion intervals. They are then energized through wellbore pressure and telescoped into place. The teleperfs, which are currently capable of being extended for 1-1/2 inches, can be installed at four devices per foot. Once set, they are cemented in place.

Full-scale field testing was performed in Baker Oil Tool's Louisiana test well in late April. Following some difficulties in the first deployment, equipment modifications and some teleperf substitutions enabled a successful test. A 7-inch liner, 20 feet in length, was equipped with four teleperfs per foot. Using a "one trip" system, the liner was run, teleperfs energized and cemented inside a 10-inch casing, and rubber to indicate the effective extension of the teleperfs. The liner and cemented 10-inch casing were retrieved and subsequently cut longitudinally. All teleperfs were found to be working properly and fully extended. BP plans to install teleperf equipment in an Alaskan well this summer.

For further information, contact DOE NETL’s Jim Barnes, phone 918-699-2076, E-mail Jim.Barnes@netl.doe.gov.

Data Mining, Computer-Assisted Methodology Identifies Opportunities in Mature Midcontinent Field

Within a DOE Preferred Upstream Management Practices (PUMP) project, the Gas Technology Institute (GTI) and industry partners Chesapeake Energy Corp., Newfield Exploration Co., Triad Energy Corp., Oklahoma Independent Petroleum Association, Intelligent Solutions Inc. and West Virginia University developed a computer-assisted methodology to help identify opportunities in Oklahoma’s mature Golden Trend. The system helped determine the most influential parameters affecting overall well performance and identified specific restimulation opportunities. Knowing the data that are encountered in mature producing areas, soft computing techniques (neural networks, genetic algorithm, and fuzzy logic) were the methods of choice.

Participating operators contributed data from 320 wells, which was narrowed down to 230 wells when wells with insufficient or questionable data were eliminated. The 30-year EUR (Estimated Ultimate Recovery), calculated for all wells from decline curve analysis, was chosen as the primary productivity parameter. Neural network models were used for sensitivity analysis, that is parameters were changed from minimum to maximum to examine trends. Genetic algorithm optimization was employed for predictive analysis. Results from virtual intelligence analyses were produced in several forms and formats.

It was recognized that hydraulic fracturing and perforation densities were the most influential controllable parameters impacting production rate and ultimate recovery. The data suggested oil-based fracturing fluid is more effective for oil production, while acid-fracs are more effective for gas production. In addition, lower pumping rate, higher proppant concentration and smaller number of perforations per foot of pay were shown to result in better production rate and higher ultimate recovery.

Several areas of high production potential were identified in the survey area, and it was apparent that several wells in the high potential areas have not been producing at their expected rates. Further studies of these wells resulted in identifying 23 restimulation candidates for oil production, 25 wells for gas production and 33 wells for combined oil and gas production. The operators participating in this study are considering these candidates in their drilling and completion programs.

A detailed technical description of all stages of work, including an executable version of the software package and results from field applications, will be in the final report available during summer 2004. For more information, contact GTI's Iraj Salehi, phone 847-768-0902, E-mail iraj.salehi@gastechnology.org or DOE NETL's Gary Walker, phone 918-699-2083, E-mail gary.walker@netl.doe.gov.

**Solutions from the Field**

**Solutions from the Field: Online Technologies to Solve Problems Faced by Independent Producers**

Summaries of regional workshops recently sponsored or co-sponsored by PTTC are added to its national web site regularly. For more complete summaries, and for a listing of the hundreds of workshops that PTTC has sponsored since 1995, logon to: www.pttc.org. For more details, contact 1-888-THE-PTTC, e-mail: hq@pttc.org.

---

**California Water Control Study**

*February 12, 2003 (Los Angeles, CA)*

Co-sponsored by PTTC’s West Coast Region and California Energy Commission (CEC)

**Bottom Line**

Produced water management has been a focus for PTTC. In the Midcontinent area, PTTC developed a concise manual outlining the causes and solutions for excess water production, plus operating practices to reduce costs. In California, staff is working alongside producers in a consortium effort. Operators are sharing their data, which is being analyzed to determine trends. Sufficient well and reservoir data is being analyzed for results to be representative of Los Angeles (LA) Basin operations. Results show that water control efforts are generally economic, but more case studies are needed. Data are also clear in that operators need to place more effort in gathering fluid entry data and diagnosing the causes of high water production.

**Problem Addressed**

Mature oil production in the U.S. often produces at high water cut, increasing operating cost and causing operating and other challenges. Causes and solutions for high water production vary geographically depending upon the geological environment. In a concerted effort in the Midcontinent and California, PTTC is working with industry to better identify causes and cost effective technology solutions.

---

**Hydraulic Fracturing Measurement, Characterization and Analysis**

*May 27, 2004 in (Casper, WY)*

Sponsored by PTTC’s Rocky Mountain Region

**Bottom Line**

Understanding the reservoir, its basic rock properties and how they affect fracturing, is a prerequisite for optimizing hydraulic fracturing treatments. Choosing the proper fracturing fluid, proppant, proppant load, and additives are important. Achieving and maintaining fracture conductivity is essential. Modeling, recognizing the underlying theory and limitations, can help operators determine how different parameters affect created fractures and guide them to treatment designs that will be more effective. Data gathered during a frac treatment provides insights for future frac designs. Some testing techniques provide indirect evidence of what is happening in the rock during a frac treatment, while other techniques such as tiltmeter or microseismic techniques directly measure the fractures that are being created. Fracture reorientation, which is just now being recognized, creates restimulation opportunities.

**Problem Addressed**

For most reservoirs, effective well stimulation is required for attractive economics. This is particularly true for tight gas or unconventional reservoirs that are increasingly the target in domestic exploration. Determining when restimulation makes sense is also important in the vast number of existing wells/reservoirs. Hydraulic fracturing is a key stimulation technology, but for maximum effectiveness to be achieved, one must understand the underlying theory, how to design and model treatments, and how to analyze treatment data to determine what happened so subsequent treatments can be redesigned to be more effective.

---

**Michigan Field Experiences, Focus on the Niagaran**

*March 19, 2004 (Mt. Pleasant, MI)*

Sponsored by PTTC’s Midwest Region

**Bottom Line**

Independents that are now the operators in the mature Michigan Basin are profitably employing technologies such as horizontal wells, 3-D seismic, other 3-D visualization tools, production logging, CO2 flooding, and underbalanced drilling to name a few. Sharing and learning from each other in workshops having a case study focus has proven extremely effective, as has leveraging effort with SPE Northern Michigan.

**Problem Addressed**

The northern Michigan reef play is a very mature producing area, remaining reef targets are smaller than early targets, and major oil companies (and sometimes the service sector) have left the region. It is up to the remaining independents active in the region to get the knowledge and technology they need to conduct profitable exploration and production programs.

---

**AAPG Recognition**

*Doug Patchen*

*Appalachian RLO Director*

receives *Honorary Member Award*

This award is presented to members who have distinguished themselves by their accomplishments and through their service to the profession of petroleum geology and to AAPG.

---

*Ernie Mancini*

*Eastern Gulf RLO Director*

*elects as AAPG’s Editor*

---

**American Oil and Gas Reporter**

*June*

Improved Oil Recovery, Time for Action

*May*

Michigan Independents Continue To Have Success With Niagaran Reefs

*April*

California Consortium Identifies Techniques To Control Excess Water Production
2nd Quarter 2004 Case Studies
Petroleum Technology Digest

Well-failure reduction program realizes benefits

**Bottom Line:** Medicine Bow Operating Co. implemented a focused, well-failure reduction program in their watersheds, and gas well operations in southwest Kansas and the Oklahoma Panhandle. The company was experiencing excessive well failures, as many as 112 per month from 200 wells. The team effort, involving company personnel and pump, rod and chemical vendors, focused on getting the metallurgy right, operating lift equipment under proper load conditions, and treating with the right chemicals at appropriate levels. Well failures dropped quickly, rapidly recouping the (approximately) $300,000 investment.

Some three years later, well failures are now stabilizing at about five per month, which represents a 96% decrease. Operating costs have been reduced more than $1.5 million per year, which includes savings in direct operating costs and labor. Lessons learned are being applied in other divisions of the company, and there is competitive advantage in acquisition opportunities, when one knows how to lower operating costs significantly.

Optimized flow device eliminates CBM lift equipment, reduces costs

**Bottom Line:** Marathon Oil Co. successfully deployed new tools to convert coalbed methane (CBM) wells that were being mechanically dewatered to flowing gas producers. By eliminating downhole pumping equipment, variable and fixed LOE costs decreased dramatically - from an average $875 per month to $15 per month. Considering installed cost, the tools paid out in about seven months. Prior artificial lift equipment could be deployed in other CBM wells or sold for salvage. Some lost production was avoided with continuous, stabilized flow and elimination of water-entrained gas volumes that were ultimately vented. In two examples, since prior failures with associated downtime were eliminated, about 2.7 MMBtu per year of deferred production was saved. This $10,000 cash-flow benefit alone essentially pays for tool installation.

Fracture mapping and modeling optimize CBM fracture treatments

**Bottom Line:** Anadarko Petroleum Corporation employed advanced fracture mapping technology by using new, in-well tiltmeters and fracture modeling to optimize hydraulic fracture stimulation treatments in two coalbed methane (CBM) plays. The plays are in Utah's Helper Field and the Copper Ridge field of southwestern Wyoming. At Helper, data from tiltmeters proved that single-stage treatments could stimulate the entire multi-seam interval. Savings of $35,000 to $50,000/well were realized. At Copper Ridge, treatments were optimized to stay away from permeable water sands. Savings from reduced water production alone were $1.3 million in the first year. In addition, individual well treatment costs are lower, ranging from $100,000 to $150,000 less per well. Anadarko's cost savings in stimulations and disposal for the 16-well, Copper Ridge pilot program exceeded the actual costs incurred for fracture treatments.

Petroleum Technology Digest is a joint project of Gulf Publishing (World Oil) and PTTC. See case studies online at www.pttc.org/case_studies/case_studies.htm. Contact lcole@pttc.org.
Celebrating 80 years of technical excellence.

» Reserve space to exhibit, e-mail sales@spe.org.
» For more information visit www.spe.org/atce or call +1.972.952.9393.

SPE ANNUAL TECHNICAL CONFERENCE AND EXHIBITION
26-29 September 2004 » George R. Brown Convention Center » Houston

www.spe.org
PTTC's low-cost regional workshops connect independent oil and gas producers with information about various upstream solutions. For information on the following events, that are sponsored or co-sponsored by PTTC, call the direct contact listed below or 1-888-THE-PTTC. Information also is available at www.pttc.org. Please note that some topics, dates, and locations listed are subject to change.

July 2004

7/8  Texas workshop: Produced Water & Associated Issues (Texas Alliance) - Tyler, TX. Contact: 512-471-0320
7/22 South Midcontinent workshop: Coalbed Methane (Arkansas Oil and Gas Commission, Oklahoma Geological Survey) - Ft. Smith, AR. Contact: 405-325-3031
7/28 Texas workshop: Reservoir Fluids (Core Labs) - Houston, TX. Contact: 512-471-0320

August 2004

Rocky Mountain: 4 Short Courses @ AAPG-RMS and Colorado O&G Association Meeting:
8/8 Identifying and Appraising Coalgas Reservoirs (Denver)
8/8 Horizontal Technology: A Practical, Multi-discipline Approach to Complex Wells (Denver)
8/8 Gas Markets and Pricing Factors, A Primer for Technical Professionals (Denver)
8/5-8 Influence of Depositional Environments on Coal Stratigraphy, Cretaceous Foreland Basin Deposits, Southwest Wyoming (Rock Springs, Wyoming)

8/16 North Midcontinent workshop: Tech Session at KIOGA Meeting - Wichita, KS. Contact: 785-864-7398
8/18 South Midcontinent workshop: Jackfork and Atoka Deep Water Reservoirs (Oklahoma Geological Survey) - Norman, OK. Contact: 405-325-3031
8/18-19 West Coast workshop & field trip: Role of Faults in California Oilfields - Ventura, CA. Contact: 213-740-8076
8/TBD South Midcontinent workshop: Upgrading of Downhole Pumping Equipment - Smackover, AR. Contact: 405-325-3031

September 2004

9/1 Appalachian workshop: Well Safety for Well Tenders - Olean, NY. Contact: 304-293-2867 ext 5446
9/2 Appalachian workshop: Well Safety for Well Tenders - Meadville, PA. Contact: 304-293-2867 ext 5446
9/2 Eastern Gulf workshop: Reservoir Modeling and Simulation; North Blowhorn Creek Field, Vocation Field, and Womack Hill Field - Jackson, MS. Contact: 205-348-1880
9/8 North Midcontinent workshop: Reducing Well Failure Frequency - Wichita, KS. Contact: 785-864-7398
9/17 North Midcontinent: Tech Session at EKOGA Meeting - Chanute, KS. Contact: 785-864-7398
9/22 Eastern Gulf workshop: Seismic Attributes for Reservoir Characterization - Jackson, MS. Contact: 205-348-1880
9/TBD South Midcontinent workshop: Coiled Tubing - Norman, OK. Contact: 405-325-3031
9/TBD Midwest workshop: Modern Log Evaluation - Mt. Vernon, IL. Contact: 217-244-9337
9/TBD Midwest workshop: USGS Current Assessment of Michigan Reserves (Michigan Oil & Gas Association) - Grand Rapids, MI. Contact: 269-387-8633

New Information Accessible From Website Network

Midwest: Air Photo Overlays for Illinois — www.isgs.uiuc.edu/pttc/
Rocksies: Assessing North Dakota Reservoirs for CO2 Miscible Flooding — www.mines.edu/research/PTTC/
Southwest: Maps of Specially Designated Areas by the Farmington Office, BLM — www.nm.blm.gov/nmso/nm952/geo_sci/ffo_main_page.htm

Our Regions continually make new information accessible, so next time you have a few minutes, quickly browse sites where you operate and see what information may be awaiting you.
### PTTC's National Board of Directors

**Guided by Independents for Independents**

**Interested in participating at the regional level? Call 1-888-THE-PTTC**

<table>
<thead>
<tr>
<th>Position</th>
<th>Name</th>
<th>Affiliation</th>
<th>City/State</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chairman</td>
<td>Brook Phifer</td>
<td>NiCo Resources, LLC</td>
<td>Littleton, CO</td>
</tr>
<tr>
<td>Vice Chairman</td>
<td>Brian Sims</td>
<td>Independent</td>
<td>Madison, MS</td>
</tr>
<tr>
<td>Immed. Past Chairman</td>
<td>James Bruning</td>
<td>Bruning Resources, LLC</td>
<td>Ft. Smith, AR</td>
</tr>
<tr>
<td>Appalachian</td>
<td>Bernie Miller</td>
<td>Miller Energy Technologies</td>
<td>Lexington, KY</td>
</tr>
<tr>
<td>Central Gulf</td>
<td>Joe Jacobs</td>
<td>Gas Masters of America, Inc.</td>
<td>Monroe, LA</td>
</tr>
<tr>
<td>Eastern Gulf</td>
<td>Brian Sims</td>
<td>Independent</td>
<td>Madison, MS</td>
</tr>
<tr>
<td>Midwest</td>
<td>Richard Strater</td>
<td>Continental Resources of IL</td>
<td>Mount Vernon, IL</td>
</tr>
<tr>
<td>North Midcontinent</td>
<td>Mark Shreve</td>
<td>Mull Drilling Co., Inc.</td>
<td>Wichita, KS</td>
</tr>
<tr>
<td>Rocky Mountain</td>
<td>Robert McDougall</td>
<td>Westland Energy Inc.</td>
<td>Cody, WY</td>
</tr>
<tr>
<td>South Midcontinent</td>
<td>A. M. &quot;Mac&quot; Allway</td>
<td>Tony Oil Company</td>
<td>Tulsa, OK</td>
</tr>
<tr>
<td>Southwest</td>
<td>David Boneau</td>
<td>Yates Petroleum Corp.</td>
<td>Artesa, NM</td>
</tr>
<tr>
<td>Texas</td>
<td>Gene Ames III</td>
<td>Ames Energy Corp.</td>
<td>San Antonio, TX</td>
</tr>
<tr>
<td>West Coast</td>
<td>Mark Kapelke</td>
<td>Tidelands Production Co.</td>
<td>Long Beach, CA</td>
</tr>
<tr>
<td>AAPG</td>
<td>Eddie David</td>
<td>David Petroleum Corp.</td>
<td>Rosewell, NM</td>
</tr>
<tr>
<td>IOGCC</td>
<td>John King</td>
<td>Michigan Public Service Comm.</td>
<td>Lansing, MI</td>
</tr>
<tr>
<td>IPAA</td>
<td>Steve Layton</td>
<td>E&amp;B Natural Resources</td>
<td>Bakersfield, CA</td>
</tr>
<tr>
<td>SEG</td>
<td>Hugh Rowlett</td>
<td>ConocoPhillips</td>
<td>Houston, TX</td>
</tr>
<tr>
<td>SPE</td>
<td>Ken Oglesby</td>
<td>Oak Resources Inc.</td>
<td>Tulsa, OK</td>
</tr>
<tr>
<td>Large E&amp;P Companies</td>
<td>Robert Lestz</td>
<td>ChevronTexaco</td>
<td>Houston, TX</td>
</tr>
<tr>
<td>Service Companies</td>
<td>Jay Haskell</td>
<td>Schlumberger Oilfield Services</td>
<td>Houston, TX</td>
</tr>
<tr>
<td>Regional Lead Orgs.</td>
<td>David Morse</td>
<td>Illinois Geological Survey</td>
<td>Champaign, IL</td>
</tr>
<tr>
<td>Executive Director</td>
<td>Don Duttlinger</td>
<td>PTTC</td>
<td>Houston, TX</td>
</tr>
</tbody>
</table>

**Moved or changed companies? Let us know:**

- [ ] Please change my address
- [ ] Please add my name to the mailing list
- [ ] Please change name of recipient from __________________________________________________________________________________________
- [ ] Please delete me from the mailing list

Fax new information to 281-921-1723 or e-mail hq@pttc.org.

Name __________________________________________ Title ________________________________

Company/Organization ________________________________________________________________

Address _____________________________________________________________________________

City __________________________ State __________ Zip ________________ Country ___________

Phone ________________________ Fax ____________________ E-mail ________________________